



Whole power system impacts of electricity generation technologies

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Table of Contents

Acknowledgements	v
Executive Summary	1
1 Introduction	13
2 What are whole system impacts?	15
2.1 <i>Scope</i>	16
2.2 <i>Assessing whole system impacts</i>	21
2.3 <i>Decomposing whole system impacts</i>	30
3 Characteristics that drive these impacts	45
3.1 <i>Overview of fundamental drivers</i>	46
3.2 <i>Displaced generation costs</i>	50
3.3 <i>Capacity adequacy</i>	57
3.4 <i>Balancing impacts</i>	66
3.5 <i>Network impacts</i>	75
3.6 <i>How do different technologies perform?</i>	80
4 Who bears whole system impacts?	89
4.1 <i>Displaced Generation Costs</i>	90
4.2 <i>Capacity adequacy</i>	92
4.3 <i>Balancing Costs</i>	93
4.4 <i>Network costs and losses</i>	94
4.5 <i>Summary of cost allocation in the UK</i>	97
5 Conclusions	99
Annexe 1: Bibliography	101
Annexe 2: List of stakeholders consulted	107

Table of Figures

Figure 1. Whole system impacts	4
Figure 2. The scope of whole system impacts	17
Figure 3. Defining whole system impacts	22
Figure 4. The importance of the counterfactual	24
Figure 5. Optimal dispatchable power mix with and without variable renewables	28
Figure 6. System costs and benefits	34
Figure 7. Scope of network costs	40
Figure 8. Using the whole system impacts framework as an investment decision tool	43
Figure 9. Example merit curve	51
Figure 10. Generation duration curves for solar and wind power	54
Figure 11. The level of PV output at daily peak demand across one year period in Greece	60
Figure 12. The level of PV output at daily peak demand across one year period in the UK	60
Figure 13. Capacity credit of wind assumed in the capacity market design	63
Figure 14. Increase in reserve requirements as a function of wind power penetration	67
Figure 15. Improvement in wind power forecasts in Spain, 2008-12	68
Figure 16. Operating reserve requirement under National Grid's Gone Green Scenario	69
Figure 17. Key Balancing Services as highlighted by National Grid	73
Figure 18. Drivers of change for important future balancing services	74
Figure 19. Generation capacity map for the Eastern distribution network	78

Table 1. Are generators incentivised to minimise overall power system costs under the current market framework in the UK?	10
Table 2. Defining the scope of whole system impacts	19
Table 3. Further explanation of impacts beyond the 'power system' costs	20
Table 4. System impacts before and after re-optimisation	44
Table 5. Technology characteristics	47
Table 6. Power system characteristics	48
Table 7. Location characteristics	49
Table 8. Drivers of displaced generation costs	50
Table 9. Assessment of flexible generation according to dimensions of flexibility.	56
Table 10. Drivers of capacity adequacy benefits	58
Table 11. Capacity credits assumed by National Grid for 2015 capacity auction	62
Table 12. Drivers of balancing costs	66
Table 13. Drivers of network costs and losses	75
Table 14. Map of drivers against cost components	81
Table 15. Mapping of drivers to technologies	86
Table 16. Cost allocation for technologies connecting to the GB network	96
Table 17. Are generators incentivised to minimise system costs under the current market framework in the UK?	97

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Executive Summary

To meet ambitious climate and sustainability targets the UK power system needs to transform. It will require significant investment in renewable and low-carbon technologies. The future generation mix remains uncertain, and decisions by policymakers will be important. The key determinant of future policy, and hence of the mix, will be the relative cost of different technologies.

Traditionally, technology costs are compared on the basis of ‘levelised costs of electricity’ (LCOE). However, there is a growing body of literature that suggests that comparisons on this basis do not capture all the costs and benefits associated with a particular technology. One issue is that the “LCOE is blind to the when, where and how of power generation” (IEA, 2014). In other words, technologies with identical LCOE may have very different effects on the power system. For example:

- the power produced by a technology which only produces during off-peak periods is of lower value to the system, increasing costs elsewhere, compared to a technology which can be relied upon to deliver during peak periods;
- technologies located closer to the load they are serving should lead to lower transportation costs; and,
- there may be technology-specific characteristics which reduce their value compared to others, such as the variability or uncertainty of the power production.

This report aims to develop a comprehensive and clear framework for understanding and explaining whole system impacts that borrows from and builds on the existing work in the literature. We have also tested this framework extensively with academics and industry participants. The relevant findings from this report are being used by Lane Clark and Peacock (LCP) to develop DECC’s dynamic despatch model (DDM) so that an assessment of these impacts can be better internalised in the modelling of future generation scenarios.

What are whole system impacts?

The concept of whole system impacts, and the related concepts of ‘whole system costs’, ‘system effects’, ‘additional system costs’ and ‘integration costs’, are variously defined in the literature. As part of this study we follow the majority of the literature and define whole system impacts as the change in the costs of constructing and operating the power system that result from the addition of a given quantity of a new technology to that system.

There are three important points to note:

- **The scope of this study is confined to power system impacts** i.e. those that relate directly to the construction and operation of the power system, including the ‘plant-level costs’ of the additional capacity, and costs borne by network and system operators, and other generators. This definition does not include wider effects that are beyond the power system but could still be considered the result of adding new capacity to the system, such as the macroeconomic effects on overall employment or environmental externalities that are not appropriately priced.¹ While out of scope here, these wider effects may be important for policymakers to consider.
- **The counterfactual is critical for determining whole system impacts** – impacts can vary significantly depending on the characteristics of the power system that the technology is added to. Typically in the literature the system impacts of a technology are assessed by comparing two scenarios, where one scenario includes the technology in question and the other either does not include it or does but at a lower penetration level. Differences in the total costs of each scenario are then calculated, and subsequently allocated to the technology in question. However, the size of the differences in costs will depend on the mix of capacity assumed to be in place, and therefore on the specific power system under examination.
- **This study takes a longer-term perspective that allows for re-optimisation of the system** – this allows, for example, for capacity to retire or investment to be forgone to keep overall system reliability constant as new capacity is added. Similarly, the system can be re-optimised, making use of ‘integration options’ or ‘mitigation measures’, to minimise the costs of using alternative generation technologies, just as the current system has been optimised to operate efficiently using existing generation technologies.

What are the component parts of whole system impacts?

We have developed a framework for defining and categorising whole system impacts based on the existing literature, the bulk of which focuses on assessing differences in cost between variable renewable and fossil fuel generation technologies. Our decomposition of whole system impacts has been designed to maintain some consistency with the existing literature and, as such, tends to emphasise key differences between these types of generation. However, our

¹ Participants in the power system currently face a price of carbon, through the EU Emissions Trading System and domestic Carbon Price Support. This price is included in grid- and plant-level costs. However, to the extent that the carbon price used fails to reflect the true social cost of carbon, carbon impacts will not be appropriately accounted for in the framework.

framework is applicable to all types of electricity generation technologies. We believe this framework is comprehensive, avoids overlap, and provides a sensible platform for developing DECC's modelling capability to assess whole system impacts.

Our framework is summarised in Figure 1. This can best be viewed as a thought experiment. Imagine a counterfactual where a generation mix is sufficient to meet the security of supply standard in each year of the period of analysis.² We then build capacity for a single technology, allow the system to re-optimize and assess each of the component costs of constructing and operating the system as a whole. Note that where we say that a technology provides a benefit, we mean that it has reduced the aggregate costs of the system, at least with respect to the relevant component.

² Alternatively a joint security and emissions standard could be imposed.

Figure 1. Whole system impacts

1 Technology direct costs	<ul style="list-style-type: none"> There are capital and operational costs associated with the incremental technology.
2 Displaced generation costs	<ul style="list-style-type: none"> Output from the incremental technology displaces higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. The scale of this is diminished if generators in the rest of system operate less efficiently, or the incremental technology is curtailed.
3 Capacity adequacy	<ul style="list-style-type: none"> The incremental technology may contribute to meeting peak demand, reducing the LOLE. To the extent existing capacity can be retired, or new capacity forgone to ensure the same level of security of supply as the counterfactual, there is a cost saving to the system. This would also include the incremental costs associated with the re-optimisation of the system over time.
4 Balancing costs	<ul style="list-style-type: none"> If the incremental capacity increases the uncertainty of supply, generators in the rest of the system may be called on to help support system stability by altering their output, or ensuring they are prepared to do so at short notice, potentially increasing their staffing, fuel, and/or maintenance costs.
5 Network costs	<ul style="list-style-type: none"> Our capacity may require investments to reinforce or extend the existing grid, and changes to power flows may increase or decrease power losses due to transmission and distribution. This also includes costs associated with the management of constraints.

Notes: Capacity cost changes not directly related to the additional technology are captured under capacity adequacy. Balancing costs do not capture costs due to predicted variation. These are instead captured under displaced generation costs.

Source: Frontier Economics

The first category of costs, technology direct costs, reflect the direct costs of the technology itself, such as its construction costs, and are well understood through existing work, including DECC's levelised costs.³

By building capacity, and bearing the associated technology direct costs, we may well give rise to reductions in costs elsewhere in the system, i.e. benefits. For example, any new technology that is added to the system should displace generation with higher short-run marginal costs, eliminating the costs associated with that generation. Similarly, on the assumption that the system maintains a constant security of supply standard, we may be able to retire some capacity early

³ <https://www.gov.uk/government/collections/energy-generation-cost-projections>

or to forgo capacity investment relative to the counterfactual. These effects are captured under ‘displaced generation costs’ and ‘capacity adequacy’ respectively. New capacity will typically result in cost savings in both these areas, i.e. give rise to benefits, although the size of these benefits is very dependent on the additional technology in question.

The categories of, ‘balancing costs’ and ‘network costs’, can be increased or decreased by the addition of capacity. For example, generation technologies may increase or decrease the need for investment in the transmission system, depending on their location. Or generation technologies may change the level of uncertainty in system output, increasing or decreasing the overall cost of balancing supply and demand.

Interpreting whole system impacts

The sum of these component impacts is the whole system impact, i.e. the aggregate difference in the cost of building and operating the power system relative to a counterfactual scenario. This whole system impact could be a cost, in which case the system is more expensive relative to the counterfactual, or a benefit, in which case it is cheaper.

If all externalities were appropriately priced (e.g. carbon) into the costs of building and running the power system, and therefore included in the estimation of the various impacts, then generation capacity with a positive whole system impact would increase the costs of the system overall and, consequently, ought not to be built, on the basis of power system costs alone. Conversely, where the whole system impact implies a net reduction in total costs, the associated capacity ought to be built.

What are the drivers of whole system impacts?

We have examined the technology characteristics that drive the size of whole system impacts. This is based on evidence from the relatively small set of technologies examined in the literature, but provides insights that have wider applicability. This is because it is the underlying characteristics of a generating technology that are relevant to understanding its effect on whole system impacts. DECC will be able to assess whole system impacts of unstudied technologies to the extent that the underlying characteristics of these technologies relate to those of another technology that has been studied.

The sections below set out the drivers of the different components of whole system impacts. Technology direct costs, which are not a focus of this study, are not covered.

Displaced generation costs

Provided that the counterfactual system is currently meeting electricity demand, any new capacity that is built and generates will be displacing the output of

another, existing generator. Assuming this displaced generator has some positive variable cost of generation, e.g. a fuel and/or carbon cost, displacing this generation implies a cost saving. The size of this saving will be dependent on the timing of the new plant's output. Generators who typically produce during peak periods will displace more expensive generation, leading to higher savings.

For technologies which are variable or inflexible in nature, these benefits will diminish as more capacity is added to the system. This is because where a technology's output is correlated with a large amount of existing low marginal cost generation, it will tend to displace plants that already have a relatively low marginal cost, reducing the value of the savings. In the extreme, the power could be curtailed reducing the savings further. The actual shape of the load curve and the merit curve now and in future will be important drivers of these savings.

Some of these savings could potentially be offset by changes in the efficiency of thermal generation. Variable generators, such as wind, solar, wave or tidal, require the rest of the system to accommodate gradual but significant changes in output, requiring other generators to be started up or switched off, ramped up and down, or otherwise operated less efficiently. The size of this offsetting inefficiency effect is determined by both the variability of the additional technology's output and the cycling efficiency of the rest of the system.

Capacity adequacy

The capacity adequacy saving from additional capacity reflects its ability to substitute for existing capacity on the system without harming system reliability. This is measured in the literature using the capacity credit, which is defined as the amount of additional peak load that can be served due to the addition of the plant while maintaining the same level of system reliability. It is commonly expressed as a percentage of the plant's nameplate capacity. The higher the capacity credit, the more capable the technology is at contributing to capacity adequacy and the larger the implied benefit to the system.

Those technologies with variable outputs that are less correlated with demand, such as wind, tidal and solar, will have lower capacity credits. These capacity credits will decline as the penetration of the technology increases because system stress events will become increasingly linked to periods when output from these generators is low. This problem of a diminishing capacity credit as penetration levels increase can be avoided by mixing diverse sources of variable generation, such that the output from these different variable sources is not strongly positively correlated and hence results in more effective firm capacity. Geographic diversity can also help to limit correlation even within a single technology.

Executive Summary

Balancing

All generation technologies suffer from uncertainty⁴ in their output. Even dispatchable technologies experience unexpected outages. However, the system as a whole needs to be operated such that, barring extremely unlikely eventualities, it can continue to meet demand. The cost of providing a given level of resilience is influenced by the makeup of generation.

Variable sources of generation tend to exhibit greater uncertainty of short-term output than dispatchable technologies, and so require larger, more rapid and ultimately more costly actions to balance the system.

Technologies with very large capacities can make the system vulnerable to a sudden large infeed loss and so require additional reserve to be kept on stand-by as a contingency.

The costs with managing these issues will depend on:

- the prevalence of other technologies, including demand side response and storage, which allow the system to operate securely by offering greater system flexibility,
- the accuracy of forecasts for different technologies; and
- the size of plant relative to the largest, existing single infeed.

The contribution of the technology to system inertia also affects balancing costs. In the event of an imbalance in energy supply, any change in system frequency will be resisted by the significant rotational inertia of synchronous generators,⁵ buying time for the imbalance to be corrected. For non-synchronous generators, there is no direct electromechanical link with the grid and so no natural contribution to system inertia that helps the system resist frequency deviations. This could lead to new balancing services in future, and an associated financial cost.

Network infrastructure and losses

Network impacts are very specific to the placement of the generator within the transmission or distribution network and timing as the grid evolves over time.

⁴ It is important to note that uncertainty is distinguished from output variability in our framework. Output may vary in a way that is known with certainty. These expected variations may alter displaced generation costs, but are by definition not considered to result in balancing costs. The impact of unexpected fluctuations in output, however, is considered within balancing costs. Note that the costs of uncertainty are related to timescale, in that last-minute responses to changing expectations are likely to be costly. However, such changing expectations, and the associated cost, can occur at any timescale.

⁵ Predominately thermal generators

The same technology can, depending on context, result in significant costs, or in significant savings. Consequently it can be difficult to generalise as to the impacts of additional generation capacity on network infrastructure requirements, losses and congestion management in the absence of location specific information.

All technologies face location constraints. However, it is clear that some technologies have siting considerations that draw them away from locations that could help to minimise network costs more than others. Renewable sources may be driven to locations distant from load by the relative abundance of renewable resource, CCS plant need good access to the gas and CO₂ networks, and nuclear may be forced to locate away from population centres for reasons of acceptability or to secure necessary cooling resources.

Distributed generators that are co-located with demand, can help to reduce and flatten net demand profiles if their output is reasonably correlated with demand. Where this is the case, they may actually help to free up network capacity that was otherwise in use.

However, in the case of non-dispatchable distributed generation, poor correlation between output and demand, clusters of correlated generation or both can contribute to voltage problems and the reversal of power flows, potentially implying significant infrastructure costs to adapt the network. These problems have been highlighted through discussions with DNOs.

The impacts associated with the connection of different technologies at the same point on the network can be quite different. The problems caused by intermittency are concentrated in relatively few days of the year. This allows DNOs to explore potentially more cost-effective solutions than simply reinforcement e.g. flexible connection agreements could avoid the need to reinforce the network.

How do whole system impacts relate to different technologies?

The literature is concentrated on relatively few technologies so, using the drivers identified above, we have mapped our understanding of the key drivers to a broader set of technologies. To do this, we have grouped technologies where we expect their system impacts to be similar, and then highlighted the important characteristics for each of the technology drivers. Although technology direct costs and displaced generation impacts are an integral part of whole system impacts, they are already comparatively well understood. We have therefore focused this report on the characteristics of technologies which affect the remaining impacts: capacity adequacy, balancing, and network costs and losses.

Note that the whole system impacts framework used can also be applied to help with consideration of non-generation technologies, such as DSR, but the conclusions below reflect the report's focus on generation.

From this analysis we conclude:

Executive Summary

- Those technologies with variable outputs which are poorly correlated with demand but highly correlated with existing non-dispatchable generation will have the lowest capacity adequacy savings. This can be mitigated at the system level by combining technologies with complementary or uncorrelated output, or through future innovation in technology design.
- Non-synchronous, inflexible and uncertain generators drive the highest balancing costs. The value of additional, very flexible generation is to reduce balancing costs, relative to systems with less flexible generation. The scale of this flexibility benefit will depend on the need for flexibility and, by extension, the quantity of uncertain generation on the system.
- Generators connecting to constrained parts of the network, with significant positive correlation to other local generators can drive higher reinforcement costs. Conversely, distributed generation that works to lower net demand can actually lower network costs. All technologies have location constraints to some extent, but the nature and severity of these constraints differ. Intermittency can create opportunities for ‘smarter’ solutions such as flexible connection agreements, particularly at the local level significantly reducing costs.

Who bears whole system impacts?

Understanding the incidence of these impacts is important. If generators face all the relevant impacts, the market will be more effective in investing in the least-cost technologies from a system perspective. Whether impacts are internalised is a product of the regulatory structure of the market, and therefore will vary across different markets. Where it is found that technologies do not face these impacts then a policy intervention may be required to achieve superior outcomes and lower overall power system costs.

This is not to say that full internalisation is always the best policy response. However, it is important for policy makers to consider how costs and benefits are currently attributed, and whether this attribution reflects an appropriate allocation of impacts in terms of the implied incentives.

Despite this, the literature we have reviewed as part of this study largely focuses on defining and assessing the nature and scale of the impacts. It seldom investigates how they are allocated to different market participants. To make an assessment we have drawn predominantly on evidence gathered through stakeholder interviews, as well as desk research on current UK market design.

Table 1 summarises the extent to which generators are currently incentivised to help minimise overall power system costs i.e. the extent to which under the current market framework whole system impacts are internalised to the additional technology.

Table 1. Are generators incentivised to minimise overall power system costs under the current market framework in the UK?

System Impact	Current GB system
Displaced generation costs	<p>The energy market encourages electricity to be generated at least cost, and thereby maximises any potential displaced generation benefit. Generators are effectively remunerated for the value of their power, so to the extent that generators produce during less valuable hours of the day, this is directly reflected in the revenues of the plant.</p> <p>It is worth noting that plant dispatch decisions can be distorted however by output-linked taxes or subsidies that do not perfectly reflect social costs.</p>
Capacity adequacy	<p>Depending on the technology, additional capacity will either be eligible or ineligible to participate in the capacity market.</p> <ul style="list-style-type: none"> □ If eligible, it will be encouraged to maximise its contribution to capacity adequacy up to the efficient level, and, □ If ineligible it will not be fully incentivised to consider its impact on capacity adequacy, for as long as it remains ineligible. <p>Therefore, the revenues for a low carbon generator in receipt of support payments will be less affected by the level of its contribution to system adequacy, than generators within the capacity market.</p>
Balancing costs⁶	<p>Energy balancing costs are generally internalised through imbalance charging for large generators, albeit imperfectly, which is now more cost-reflective following cash-out reform. System balancing costs not covered by imbalance prices are socialised through BSUoS payments. This is not the case for small generators without balancing responsibility.</p>

⁶ Note that given the definition of balancing costs used in our framework, these will not account for predictable variations in generator output.

**Network costs
and losses**

Impacts are variously internalised and socialised.

Distribution costs are internalised through 'deep' connection charges where formal connection occurs. However, the system impacts of smaller, on-site generation are fully socialised.

If distributed generation exceeds local demand, the resultant transmission system costs would not be passed to the relevant distributed generator.

Transmission impacts are partially internalised to the extent that TNUoS charges in part reflect location, but constraint management costs (which are charged through BSUoS) and losses are socialised.

Source: Frontier Economics

1 Introduction

To meet ambitious climate and sustainability targets the UK power system is undergoing a significant transformation. Over the past decade, investment in renewables, in particular wind and solar, has increased substantially in the UK and across the EU, and this is expected to continue. There are also potential new investments taking place in nuclear and carbon capture and storage (CCS) technologies. The future generation mix remains uncertain, and decisions by policymakers will be important. The key determinant of future policy, and hence of the mix will be the relative cost of different technologies.

Traditionally, technology costs are compared on the basis of the ‘levelised costs of electricity’ (LCOE), and in the UK these estimates are an important determinant of the level of support payments paid to different technologies. Estimates of LCOE are focused at the plant level by summing the present (discounted) value of all lifetime fixed and variable costs of a generation technology, and dividing it by the discounted amount of electricity the plant will produce. This approach is widely understood, comparatively well-evidenced and avoids many of the challenges introduced when trying to account for the whole electricity system.

However, there is a growing body of literature that suggests that comparisons on this basis do not capture all the costs and benefits associated with a particular technology. One issue is that the “LCOE is blind to the when, where and how of power generation” (IEA, 2014). In other words, technologies with identical LCOE may have very different effects on the power system. For example:

- the power produced by a technology which only produces during the off-peak period is of lower value to the system, increasing costs elsewhere, compared to a technology which can be relied upon to deliver during peak periods;
- technologies located closer to the load they are serving should lead to lower transportation costs; and,
- there may be technology specific characteristics which reduce their value compared to others, such as the variability or uncertainty of the power production.

These wider costs and benefits are part of what is termed the ‘whole system impacts’ of adding a new generation technology to the mix. Although levelised costs are a practical response to the need to quantify technology costs, a more complete understanding of these wider costs and benefits will be critically important to decisions on future energy policy and in allocating finite resources to different technologies.

Because levelised costs only partially account for wider system impacts, if policy support is based purely on estimates of the LCOE, it is unlikely to minimise the overall costs of the system.

As part of DECC's efforts to better account for whole system impacts, this report sets out:

- a clear and workable definition of aggregate whole system impacts and its components;
- the drivers of these impacts; and
- how these drivers relate to different generation technologies.

This is based on our review of economics frameworks for whole system impacts in the literature and discussions with a range of industry stakeholders. The relevant learning from this report is being used by Lane Clark and Peacock (LCP) to develop DECC's dynamic despatch model (DDM) so that an assessment of these impacts can be better internalised in the modelling of future generation scenarios.

The report is structured in the following sections:

- **Section 2** establishes a pragmatic definition of whole system impacts and its component parts;
- **Section 3** considers what the characteristics drive of these impacts are and how they relate to different technologies;
- **Section 4** sets out who bears these costs, on the basis of the current GB market; and,
- **Section 5** draws together the key implications of this study for DECC.

2 What are whole system impacts?

SUMMARY

- We have defined whole system impacts as the change in the total power system costs associated with the addition of a new technology to that system. This change is assessed as the difference in the total costs between two long-term scenarios.
- As such, a technology will reduce total system costs, and ought to be built, if its direct costs are more than offset by the rest of its whole system impacts.
- Whole system impacts relate to the resource costs, in a similar way to a government's assessment of societal costs and benefits. We consider the financial implications of these costs which are more important for investment decisions later.
- Whole system impacts are not constant for all technologies under all circumstances. The nature and scale of these impacts are very context specific. They can be positive or negative depending on the specific technology and the scenario in question.
- They are typically assessed by comparing the total system costs between two scenarios, one with the technology in question and one without it or at a lower penetration. As such the scenario into which the technology is being added is of critical importance.
- Systems will re-optimize in response to the addition of a new technology, and taking a long-term perspective when considering whole system impacts will allow this to be accounted for in the analysis. The benefits of this re-optimization should be accounted for alongside any costs. For example, new flexible technologies could be incentivised, or plant may retire in response to excess capacity.
- Whole system impacts can be decomposed into: technology direct costs, displaced generation savings, capacity adequacy benefits, balancing impacts; and, network costs.

Technology costs are traditionally assessed based on their plant-level costs, the most common metric being the levelised cost of electricity (LCOE). However, an individual electricity generator operates as one part of a wider power system and as a result will be responsible for costs and benefits, or system effects, beyond

What are whole system impacts?

those related directly to the building and operation of the specific generator itself. This is true for all generators, irrespective of the technology, and these costs will vary depending on that technology's share of the overall mix and on the properties of the wider power system.

In this section we outline the different ways that whole system impacts are considered in the literature. We then go on to recommend a conceptual framework for their consideration, as well as breaking them down into their constituent parts. The characteristics that drive these impacts and attribution to specific technologies are addressed in subsequent chapters.

Specifically in this section we:

- set the scope of our investigation i.e. identify what we mean by whole system impacts;
- discuss the importance of the counterfactual and the timeframe for the investigations; and,
- finally, we decompose whole system impacts into its component parts.

2.1 Scope

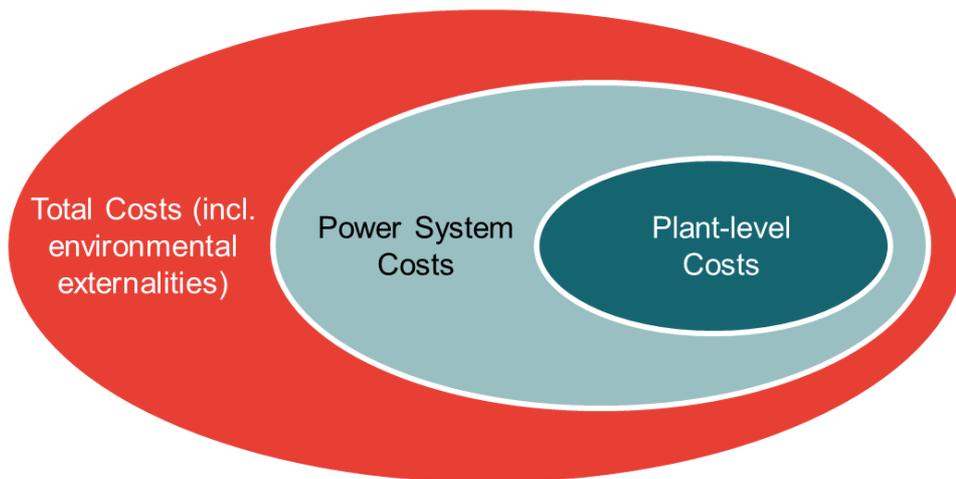
The concept of whole system impacts, and the related concepts of 'whole system costs', 'system effects', 'additional system costs' and 'integration costs', are variously defined in the literature.

However, they all consider the additional costs (and benefits) associated with building and operating the power system resulting from the addition of generation capacity to that system. This is our starting point for defining whole system impacts.

Given the literature identifies a wide-range of impacts, which are potentially overlapping in nature, we consider it helpful to develop a structure to facilitate their further investigation. We follow the majority of the literature which limits its interest to impacts related to the power system directly. To clarify what this means, the OECD's discussion of system effects provides a helpful framework for defining the scope of this project even if, in practice, the delineation of costs between categories is not always clear cut.

What are whole system impacts?

Figure 2. The scope of whole system impacts



Within the OECD framework each cost category is a subset of:

- **‘Plant-level costs’** - direct costs and benefits, such as the construction costs of building and operating the individual generator itself. Typically we can think of these impacts as those within the boundary fence of the generator.
- **‘Power system costs’** – impacts that relate directly to the construction and operation of the power system, including the ‘plant-level costs’ and costs borne by network and system operators, and other generators. This is sometimes classified in the literature as being the sum of plant-level and system impacts. These impacts would include environmental externalities to the extent that they are priced within the system e.g. the cost of purchasing carbon permits would be considered a ‘power system’ cost. Note that to the extent these externalities are priced incorrectly, or not priced at all, they will not be accurately represented in the costs. So, for example, if the price of carbon is below its true social cost, the costs of fossil fuel generation will be understated.
- **‘Total-system costs’** – in addition to power system costs, this includes wider effects which are beyond the power system itself but that still could be considered the result of adding new generating capacity to the system. These include impacts on the wider economy, international trade and technological innovation.

Note that because these categories include benefits as well as costs, expanding the scope does not imply strictly increasing costs. For example, expanding the

What are whole system impacts?

scope for low-carbon generators might reduce costs by capturing further environmental benefits.

In this study we restrict our focus to ‘power system’ costs. Therefore for the remainder of this study we are not referring to the wider impacts outside of the power system. However, policymakers may wish to consider these impacts alongside those identified in this report when analysing the costs and benefits of future generation mixes.

With that in mind, we provide an overview in Table 2 of terms typically used in the literature to describe aspects of ‘whole system impacts’, and identify which broadly can be considered as in scope of the ‘power system’ and which are out of scope. Table 3 provides a further explanation of the wider impacts listed as out of scope.

However, the terms in scope of the project do not yet represent a coherent set of impacts to assess. Some can be considered a cost, such as ‘connection costs’. Others are a system characteristic, such as ‘system flexibility’, or a system constraint, such as ‘system inertia’. All are relevant, and if used in the correct context represent an important concept related to whole system impacts.

However, our task in this section of the report, is to create a comprehensive framework, which identifies consistent categories of cost, avoids double-counting and can be applied in DECC’s DDM.

What are whole system impacts?

Table 2. Defining the scope of whole system impacts

'Power system' costs (in scope)	Wider impacts (out of scope)
Technology direct costs	Non-priced environmental emissions
Fuel savings	Visual Impacts
Capacity adequacy	Transport impacts
System flexibility	Financing conditions
System cycling	Balance of trade
System inertia	Strategic energy security
Curtailement	Macroeconomic effects and employment
System load factors	Changes in fuel prices and use
Generator profitability	Innovation benefits
Connection costs	Fuel infrastructure requirements
Network reinforcement and extension	
Network losses	
Carbon prices	

Source: Frontier Economics

What are whole system impacts?

Table 3. Further explanation of impacts beyond the 'power system' costs

Wider impacts	Description
Non-priced environmental emissions	Emissions that contribute to environmental damage through climate change or acid rain, but which fall outside of regulatory mechanisms to assign a cost to the polluter, for example because the relevant generator or emissions type is excluded.
Visual Impacts	Visual impacts that impose an aesthetic externality, e.g. tall smokestacks spoiling an otherwise beautiful view.
Transport impacts	Logistical supply chain effects that themselves have wider costs and benefits. For example, transporting coal to a plant may imply changes to the rail network.
Financing conditions	Adding new plant may affect the financing conditions faced by other developers. For example, it could contribute to electricity price volatility, increasing revenue risk for financiers and indirectly increasing financing costs.
Balance of trade	Adding new plant may have trade impacts. For example, the capacity mix affects national fossil fuel use, and in turn the trade balance for such fuels.
Strategic energy security	For example, the power system may become over-reliant on specific fuels or plant designs and therefore vulnerable to problems affecting them. See the box on p.37 for further information.
Macroeconomic effects and employment	Adding new plant will have employment and supply chain effects associated with its construction and operation.
Changes in fuel prices and use	Adding new plant may affect fuel demand and prices. For example, the addition of significant biomass capacity might push up the costs of biomass.
Innovation benefits	Adding new plant may give rise to additional learning, for example about how to use some capacity more efficiently.
Fuel infrastructure requirements	New plant will have different infrastructure requirements. Those associated with the fuel for generation e.g. the gas network, an LNG terminal, or a uranium enrichment facility, are not considered explicitly. However, they are considered to the extent they are internalised within the fuel cost for the generator.

Source: Frontier Economics

What are whole system impacts?

In our discussion of power system costs it is important to note the distinction between resource costs and financial costs. Resource costs reflect the consumption of scarce resources in economic processes, such as the consumption of gas to generate electricity. It is this cost perspective that underpins government assessments of societal costs and benefits and, unless stated otherwise, this is what we are referring to when we talk about system costs and benefits. We consider later financial implications, which can be more relevant to private investment decisions.

Assessments of resource and financial costs will not always match. To give just one example, imagine the costs associated with increasing the variability in output of a non-dispatchable technology. If this greater variability requires the marginal generator to operate in a slightly less fuel efficient way, some additional fuel will be consumed and, because the marginal generator sets the energy price for all energy, the wholesale price of energy will rise. The resource cost of this change accounts only for the increased fuel consumption. However, a financial cost assessment may account for the fact that consumers will pay more for energy not just from the affected marginal generator, but for energy from all generators, including energy from generators otherwise unaffected by the change. In this example therefore, an assessment of the financial cost to consumers might come up with a cost that is significantly larger than the underlying fuel cost to the marginal generator.

The remainder of this section is focused on developing a framework for considering these impacts, which is exhaustive in its coverage, and avoids any overlap or double-counting.

2.2 Assessing whole system impacts

Our framework requires us to address two further conceptual questions:

- first, what are we comparing against, or in other words, what is the counterfactual, and
- second, over what period are we considering the impacts?

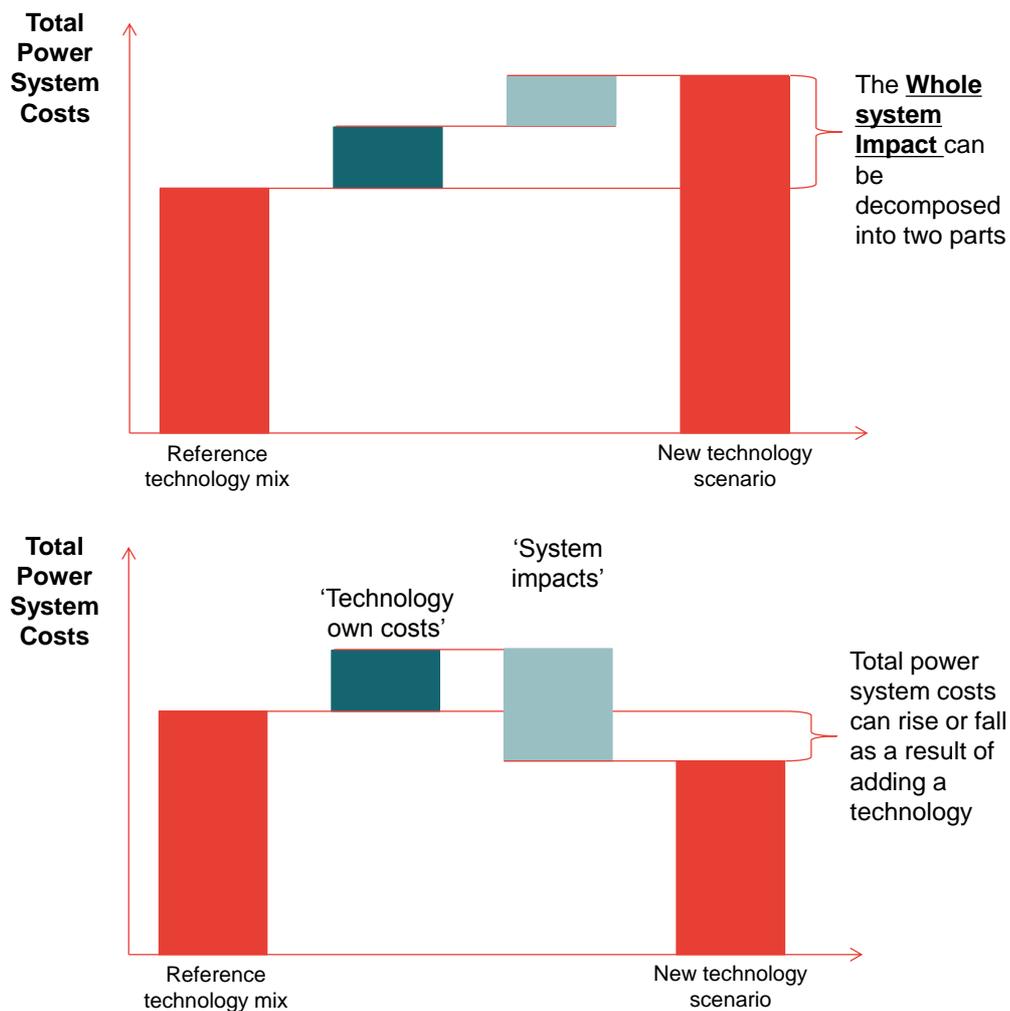
The counterfactual

System impacts result exclusively from the interaction between a generation technology and the wider power system. Although we typically look to attribute these impacts to generation technologies, they could just as validly be attributed to the system in which a generation technology is placed. Because system impacts are the result of this interaction between technology and system, estimates of any technology's whole system impacts are specific to the system in which they are assessed. Estimates of system impacts from the literature demonstrate significant variation in part because these estimates vary with respect to the system involved.

What are whole system impacts?

Typically in the literature, the system impacts of a technology are assessed by comparing two scenarios, where one scenario includes the technology in question and the other, the so-called counterfactual, either does not include it or does, but at a lower penetration level. In both scenarios, the profile and structure of load⁷, as well as the power prices in interconnected markets, are taken to be fixed. Differences in the whole system cost in each scenario are then calculated, and subsequently allocated to the technology in question.

Figure 3. Defining whole system impacts



⁷ Before any demand-based or efficiency measures are accounted for. Although the scope of this report focuses on generation technologies, there is no reason that this framework could not be used to consider the whole system impacts of demand-based measures such as Demand Side Response and energy efficiency.

What are whole system impacts?

Our framework is intended to investigate the overall effect of a change in the technology mix.⁸ Figure 3 illustrates the costs associated with building and operating the power system for a reference technology mix. These are the total power system costs. When we make a change to the system by adding a particular technology this leads to whole system impacts. These can be decomposed into ‘technology direct costs’ and ‘system impacts’. It is the system impacts which are the focus of this project and can be made up of system costs or system benefits. Note that Figure 3 shows two examples of ‘system impacts’, first, as additional costs and, second, as reduced costs (system benefits).

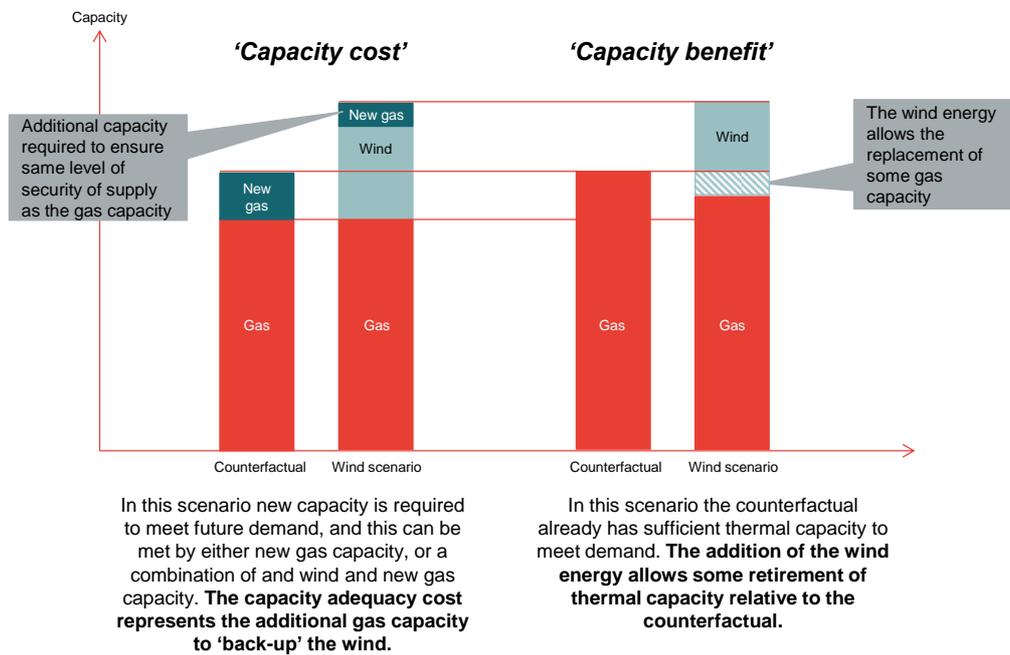
Figure 3 also highlights the importance of the counterfactual. This raises the obvious question of how it should be defined. Papers differ with respect to their choice of counterfactual, and it can lead to what appears like a very different answer. For example some authors assert that variable renewable generation gives rise to a cost, the need to provide ‘back-up’ generation. However, in a framework that considers increasing capacity, the addition of any technology will bring a capacity benefit. Either framework can be used to address the relevant policy questions. Differences are merely presentational.

To give one example, set out in Figure 4, consider the contribution of adding wind energy to meeting total energy demand:

- **‘Capacity cost’** - we might choose to compare a scenario with an amount of wind generated energy, to one where we add an equal amount of gas generated energy. In this case, we would discover that the wind is less able to meet peak demand than a conventional gas plant, implying a need for additional capacity alongside the wind plant to ensure peak demand is met with equal probability in each scenario. This identifies a capacity cost associated with adding the wind energy.
- **‘Capacity benefit’** – alternatively, measured against a counterfactual in which demand is already sufficiently met by gas generated energy, adding an increment of wind generated energy might be expressed as giving rise to a capacity benefit equal to the amount of gas plant we no longer have to build.

⁸ Note that this theoretical framework is robust to the consideration of significant changes in the system and to non-linear changes in total system costs. However, the modelling of such changes may be less accurate both because existing experience becomes a less reliable guide of the impacts involved, and non-linearity increases the sensitivity of the results to relatively small initial errors.

Figure 4. The importance of the counterfactual



In both cases, the characteristics of the plant and the underlying concepts involved are identical, but the choice of counterfactual leads to answers that appear to be very different. In one case we are describing a capacity benefit and in the other a capacity cost. These differences are very apparent in the literature, with some papers, like Strbac et al (2007) discussing the capacity benefit of variable renewables, while several others, like the OECD-NEA (2012), consider net back-up costs.

To further complicate matters, where comparisons are made relative to capacity additions of another technology, as set out in the 'capacity cost' example above, there are differences in the choice of this reference technology. While some studies benchmark against idealised real-world technologies, such as gas CCGT, some papers, like Hirth (2012), use theoretical constructs, such as a constant perfectly-reliable source located at an average distance to consumers.

The latter approach has been conducted where the objective has been to isolate the impact of a specific system characteristic, for instance the increasing variability and uncertainty associated with higher penetrations of variable technologies. The theoretical benchmark technology is identical in terms of its location, when it generates and how it generates, except is not variable or uncertain. This kind of analysis is useful for identifying the importance of variability to system impacts, but it does not identify impacts which can be related to a real-world situation, and will typically overstate the system cost associated with particular technologies.

What are whole system impacts?

For the purposes of thinking about whole system impacts, we go on to set out a framework where a comparison is made against a case in which no technology is added, but one in which a counterfactual generation mix that meets the security of supply standard is specified. A block of energy from a given technology in question is then added to the counterfactual generation mix. We propose to maintain the same security of supply standard, for example expressed as a fixed Loss of Load Expectation (LOLE), across both the counterfactual and the technology scenario. This implies that adding any technology potentially allows one to forgo capacity investment or else retire existing capacity, or in other words, that it provides a strictly non-negative capacity benefit.

However, it is equally valid to compare the impact of a technology against the impact of adding a reference technology, and the framework proposed can easily be adapted to this approach as well.

Finally, the chosen approach can be flexible depending on the policy question being addressed. For example, the LOLE could be allowed to vary if that was the stated policy objective – this would simply remove the ‘capacity benefit’ associated with an additional capacity.

Alternatively, an additional constraint could be imposed such as ensuring that the generation mix meets a carbon intensity target in both the counterfactual and the technology scenario. Imagine if both carbon intensity and security of supply targets are met in the counterfactual. Then adding wind generated energy will improve security of supply and reduce carbon intensity. The capacity benefit will come from not investing in a technology or combination of technologies which bring both targets back in line with the counterfactual.

Timescale for assessing the impacts

Another important area of variation in how different sources think about and quantify whole system impacts is the timescale over which the assessment is made. This is important since it sets the extent to which the power system re-optimises to the addition of generation capacity. The OECD-NEA (2012) distinguishes between two possible approaches analogous to those below.

- **Short-term** – in this case adding a new technology does not affect capacity retirements or other capacity investments relative to the counterfactual. Security of supply is improved.
- **Long-term** – in this case a longer-term perspective is taken and the system is allowed to re-optimize. As we have already mentioned this may allow some capacity to retire or investment to be forgone to maintain the same level of LOLE. But importantly, and in addition, the optimal generation mix might change in response to an increase in certain technologies. The long-term approach includes the costs and benefits of this long-run equilibrium as

What are whole system impacts?

well as the transitional costs needed to get there from our current system. The most common example of this re-optimisation in the literature is the increase in more flexible plant that might arise in response to increased intermittency on the system. How intermittency may drive re-optimisation of the mix is set out in the box on the next page.

An assessment of the impacts under each approach will lead to different answers. For example, consider the case of adding a variable generation technology to the system and retiring enough dispatchable capacity to keep the overall LOLE constant. This revised setup will require dispatchable plants to flex their output to compensate for the variable generation, implying inefficient fuel use and higher system maintenance in the rest of the system. Initially, these additional costs will be relatively high because the plants involved are not built to operate in this way. But over time, the plants in the residual system and the operating processes in place will re-optimize through the addition of plant better suited to deal with the operational challenges, mitigating these cycling costs.

Sijm (2014) identifies the following types of system adaptation that could influence whole system impacts:

- Improving the flexibility of the power plant mix;
- Enhancing demand responsiveness;
- Extending and reinforcing grid infrastructure; and
- Introducing more flexible system and market operations.

It is worth noting that re-optimising the system entails its own costs and benefits. For example, increasing the flexibility of the residual generation mix imposes a cost, while also unlocking potential cost savings. The total size of these re-optimisation costs will depend on the extent of the differences between new and existing forms of generation and is discussed further in the box on path dependency (p.28).

We take the view that these second-order re-optimisation costs and benefits should also be accounted for in an assessment of whole system impacts. So, for example, if the addition of variable sources of generation implied that the rest of the plant on the system should be made more flexible to run the system cost-effectively, the capital costs and balancing benefits of this enhanced flexibility should be accounted for when assessing the system impacts of the original variable generation source.

This approach captures the costs and benefits associated with adding a new technology more fully and will therefore provide a better basis for addressing key policy questions. A long-term perspective is required when considering the Government's objective to deliver secure, clean and affordable energy, and this fits with the objective of this project to develop DECC's DDM.

What are whole system impacts?

The impact of variable technologies on the optimal power plant mix

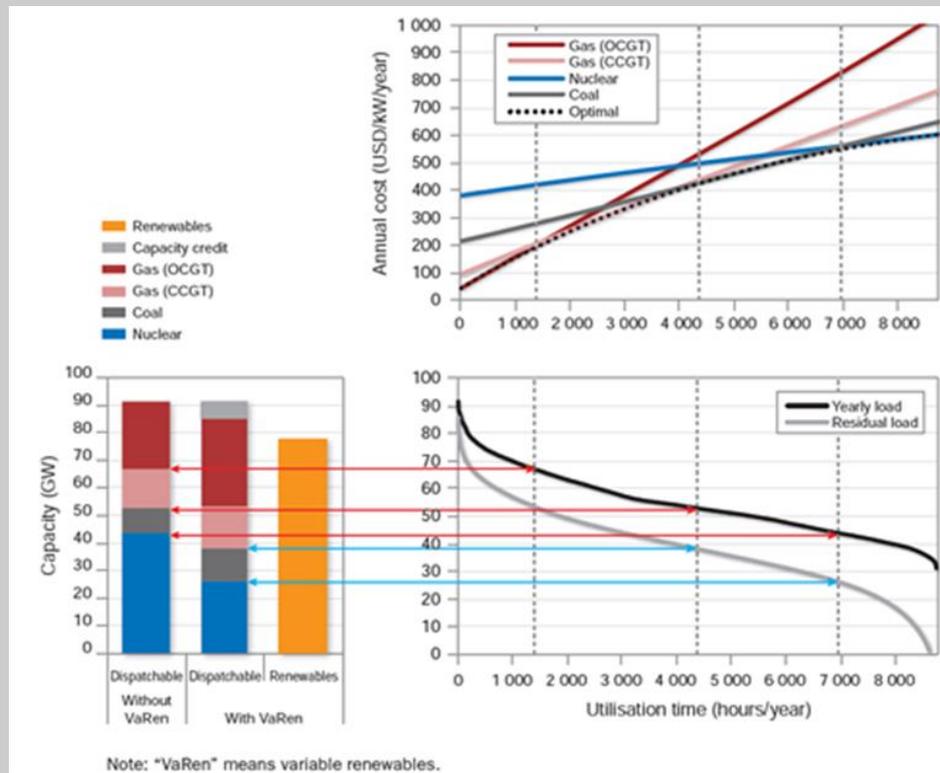
The addition of large amounts of renewables into the power system reduces the amount of thermal capacity running at high load factors and increases the value of flexible generation. This has important implications for the structure of the optimal generation mix in the long-term when changes have been fully anticipated by the market and the system has had time to re-optimize.

Figure 5 uses a standard economic framework to illustrate how the addition of renewables into the power system impacts the generation mix which can satisfy a given level of demand with the lowest total cost, using information on fixed and variable production costs of various dispatchable generating technologies.

- The figure in the upper right corner presents total cost curves for a range of dispatchable power plants as a function of their utilisation time. For example, the red line shows the cost curve for gas OCGT which has low annualised fixed costs and higher variable costs. On the other hand, baseload plants like nuclear, shown with the blue line, have high annualised fixed costs and low variable costs. The optimal choice plant changes depending on its running hours. So nuclear is the least cost plant if it runs for over 7,000 hours. But an OCGT is optimal at less than 1,500 hours.
- The bottom right figure shows an annual load curve (dark line) and the residual load with 30% penetration of wind (grey line). Graphically, the optimal generation capacity for each technology is shown by the intersection between the annual load curve and the number of hours at which it becomes the most cost-effective technology. The optimal generation mix for the two scenarios is then shown in the left bottom figure. The figure also illustrates the renewable installed generating capacity in the third vertical bar, and the amount of dispatchable capacity that could be effectively replaced by renewables (the green share of generation in the middle bar).

What are whole system impacts?

Figure 5. Optimal dispatchable power mix with and without variable renewables



Source: OECD-NEA (2012). Load curves are based on data from the French transport system operator, RTE.

The specific analysis shown relates to France, a power system with significantly larger nuclear baseload and interconnection capacity than GB. As such, the scale of the changes shown is unlikely to be transferable. However, the nature of the changes shown is of general relevance. In particular, we can see that the optimal mix is different in the two cases. Without the renewable generation, the optimal mix includes more baseload generation, like nuclear. The introduction of renewables reduces the amount of baseload generation, as technologies with lower fixed costs and higher running costs are favoured. As such, the addition of renewables increases the share of gas OCGT in the optimal mix, while the share of nuclear drops.

Path dependency and the costs of re-optimisation

The current power system has been optimised around existing generation capacity, which primarily consists of large fossil fuel plant. As a result, it is comparatively easy and cheap for the system to accommodate similar forms of generation capacity in the future. One example of this more general point is the

What are whole system impacts?

way in which new nuclear plants locate on the sites of old nuclear plants in order to benefit from sunk investments, for example in transmission infrastructure, made to integrate the old plant.

This property, in which past decisions affect the decisions we face now, is known as path dependency. The nature of this dependency in the power system is such that it is generally easier and cheaper to continue to operate the system in the same way, replacing old capacity with similar capacity.

Our approach in this report, and the approach used by most of the related literature, is to assess costs in relation to the current system, since this is directly relevant to the costs we face today. As such, although we take a long-term perspective on costs, we don't take a 'greenfield' approach, e.g. by ignoring the effects of the system we have to today on the costs of achieving different long-term outcomes.

As a result, existing forms of generation may have lower whole system costs relative to alternative generation technologies in part because the current power system has been optimised around these existing forms of generation. Had the power system instead been optimised around distributed forms of generation and had not sunk investment in the gas network, the costs of adding large fossil fuel plants to the system would look very different.

What are whole system impacts?

2.3 Decomposing whole system impacts

In this section we attempt to decompose whole system impacts into more manageable and meaningful effects that we go on to discuss throughout the rest of the paper. Doing so is useful both as a means of making the impacts less abstract and because it facilitates a discussion of these impacts' underlying causes. As with the definitional issues discussed above, there is no single decomposition of whole system impacts that is used consistently throughout the literature. However, the real world impacts are ultimately the same irrespective of how they are grouped.

In our decomposition of the impacts, we need to identify a set of impacts which are:

- exhaustive;
- non-overlapping (no double-counting);
- aid in the development of DECC's modelling; and,
- where possible, consistent with the wider literature, to ensure we can fit the work of others into our framework and that others can build on our work.

The starting point for most of the literature is that the levelised cost of energy measure, which is traditionally being used to compare technology costs, is limited in scope and can, if used inappropriately, lead to poor decisions with respect to system design. Critically, the levelised cost of energy implicitly treats all energy output as having equal value. In reality, energy markets have always recognised different prices for energy produced at different times,⁹ and the location, shape and reliability of output all have a bearing on the value of generation and cost to the system.¹⁰

In attempting to decompose whole system impacts into its constituent parts, there are broadly two approaches used in the literature.¹¹ The most common of these is to decompose the whole system impact into 'adequacy costs', 'grid costs',

⁹ See in particular Joskow (2010)

¹⁰ See Sijm (2014)

¹¹ A separate but related branch of the literature considers the 'economic value of electricity' from new capacity. It doesn't attempt to account for all system impacts, and generally excludes consideration of both the costs of the generation capacity itself and network-related impacts. However, it does provide relevant insights into other cost aspects considered here, including the value of displacing other sources of generation (including both the variable and capital costs underlying that generation) and the costs of balancing the system as a whole. The avoided variable and capital costs considered as part of the 'economic value of electricity' literature relate directly to the displaced generation and capacity adequacy benefits developed later in this chapter.

What are whole system impacts?

and ‘balancing costs’, or differently named, but roughly equivalent groupings. These groupings tend to align fairly naturally to constraints associated with operating the power system and so are fairly intuitive.

Another approach, which is detailed in papers by Hirth (2012) and Ueckerdt (2013) and explained in further detail in the box below, decomposes the impacts based on three properties of the technology: variability, uncertainty, and location-specificity. Each of these drivers give rise to a cost associated with integrating the technology into the system: profile costs, balancing costs and grid costs respectively.

Profile costs are measured as the difference in the market value of a generator’s actual output and the system average price of electricity, and they reflect impacts such as the technology’s contribution to capacity adequacy and the cycling costs associated with ramping other generators output (which might be captured under a broader definition of balancing costs under the common decomposition described above). Because they are drawn directly from market prices, profile costs are easy to calculate when prices are known. However, using prices in this way assumes that they are fully cost-reflective, an assumption that may not hold in practice.

Critically, these different ways of grouping and thinking about costs don’t imply differences of opinion about the real world impacts. However, any specific impact may be grouped with a different set of effects depending on the framework being used.

It should also be noted that the objective underlying most of the related literature is an assessment of cost difference between variable renewable and fossil fuel technologies. Given this objective, the frameworks used focus on areas where costs differ between these technology groups. As noted above, any power system will have a cost, regardless of the technology mix. However, the most salient determinants of this cost will vary depending on the nature of the question and technologies under examination. For example, in a system dominated by nuclear, we are more likely to be interested in the costs of dealing with large in-feed losses, common mode failures, and building transmission capacity, but when considering a system dominated by CCS, the costs of transporting carbon may be foremost in our minds. While every effort has been made to note potentially important determinants of cost, regardless of the technology mix under consideration, it must be acknowledged that the decomposition of costs detailed below is intended to be broadly compatible with the existing literature. As such, it likely to emphasize cost differences between variable renewable and fossil fuel generators.

In our approach, we keep some of the intuitive categories found in the majority of the literature and add a further two categories to ensure the final framework is comprehensive. We also draw on the theoretical distinctions between uncertainty

What are whole system impacts?

and variability, as highlighted in the profile costs framework, to help make our cost categories clear and mutually exclusive.

Understanding ‘profile costs’ – another classification of whole system impacts

Although whole system impacts are frequently separated into ‘adequacy costs’, ‘balancing costs’ and ‘grid costs’ within the literature, an alternative framework decomposes costs into profile costs, balancing costs and grid costs.

Profile costs reflect the fact that non-dispatchable generators cannot respond to market prices. The cost of this inability is easily quantified within this framework based on the difference between the average market price received by the non-dispatchable generator and the average market price paid for electricity.

This profile cost, which equals the discount on average prices given to a non-dispatchable generator, is the sum of two effects - the flexibility effect and the utilisation effect, both of which are consequences of a plant’s variability. The flexibility effect reflects the costs to residual generators of trying to even out the variable load (including the fuel inefficiencies and increased maintenance costs discussed above). The utilisation effect refers to that fact that residual plant will, following the introduction of variable load, be run with lower average load factors. This gives rise to a capacity and capital inefficiency. In an energy only market, the cost of this plant will need to be covered by higher prices when these plant are running, and so will be reflected in the profile cost.

While this is a slightly different articulation of whole system impacts it is not contradictory to the framework we recommend in this paper. Each of the components of profile costs are incorporated in our framework.¹²

2.3.1 A comprehensive framework

The framework set out below borrows from and builds on the variety of impacts covered in the literature, structuring the issues so that they can be discussed clearly. It has been tested and refined through the stakeholder interview process to ensure it can be used to discuss all manner of technologies.

The five components that make up the framework are shown in Figure 6 below and each is explained in detail in the sub-sections that follow. Although we have found this framework useful as means of understanding and structuring discussions about whole system impacts, it is worth noting at the outset that these components are not fully interdependent and, on occasion, some systems

¹² Specifically, profile costs are an aggregate of capacity costs with any increase in ‘displaced generation costs’ owing to the flexibility effect.

What are whole system impacts?

costs could conceivably be assigned to more than one group.¹³ We have tried to make explicit our use of these terms where differences of interpretation are likely. However, the interdependence between various elements of the power system is an intrinsic feature of power system itself and therefore an unavoidable feature of our framework as well.

Note also that although we frame these categories in terms of “costs” or “benefits” for reasons of simplicity, a technology’s whole system impact may actually be to reduce the relevant cost. For example, a new technology could increase or decrease balancing or network costs.

¹³ For example, a re-optimisation of the system to accommodate variable source of generation may mitigate increases in balancing costs while also requiring increased capital expenditure that offsets capacity adequacy savings. Similarly, one can argue about whether curtailment should reflect a reduction in displaced generation costs or an increase in balancing costs.

Figure 6. System costs and benefits

1 Technology direct costs	<ul style="list-style-type: none"> There are capital and operational costs associated with the incremental technology.
2 Displaced generation costs	<ul style="list-style-type: none"> Output from the incremental technology displaces higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. The scale of this is diminished if generators in the rest of system operate less efficiently, or the incremental technology is curtailed.
3 Capacity adequacy	<ul style="list-style-type: none"> The incremental technology may contribute to meeting peak demand, reducing the LOLE. To the extent existing capacity can be retired, or new capacity forgone to ensure the same level of security of supply as the counterfactual, there is a cost saving to the system. This would also include the incremental costs associated with the re-optimisation of the system over time.
4 Balancing costs	<ul style="list-style-type: none"> If the incremental capacity increases the uncertainty of supply, generators in the rest of the system may be called on to help support system stability by altering their output, or ensuring they are prepared to do so at short notice, potentially increasing their staffing, fuel, and/or maintenance costs.
5 Network costs	<ul style="list-style-type: none"> Our capacity may require investments to reinforce or extend the existing grid, and changes to power flows may increase or decrease power losses due to transmission and distribution. This also includes costs associated with the management of constraints.

Source: Frontier Economics

Technology direct costs

Technology direct costs refer to the resource costs associated with building and operating the capacity we are adding to the system. These impacts are sometimes implicitly excluded from the consideration of whole system impacts and are generally not the focus of research in this area. However, we think it is helpful to have a comprehensive definition that includes these impacts so that the Whole System Impact reflects whether the power system has, overall, become more or less expensive.

This cost category most neatly relates to the concepts of plant-level costs, the Levelised Cost of Energy (LCOE), and private costs. However, as noted above the levelised costs (including DECC's) are often calculated on the basis of financial costs, in which the generator may bear, through system charges, some of the financial cost of its system impacts. Technology direct costs in our framework exclude these financial costs and are based exclusively on the resource

What are whole system impacts?

costs of the capacity itself. DECC covers these costs already through their updates to generation costs.

Displaced generation costs

As technology direct costs include the variable and fuel costs of the added capacity, we must also account for any offsetting change in the variable costs of all other generators in order for our framework to be comprehensive. Thus, for example, when considering the impact of adding biomass generation to the system, we need to account for both the biomass plant's fuel costs and for the fuel savings among the rest of the system due to the existence of its output.

As with technology direct costs, the value of displaced generation is sometimes overlooked in the literature when discussing whole system impacts. We have included both here to ensure that our cost framework is comprehensive.

Displaced generation costs are the balance of three effects.

- First, any output from the new capacity need no longer be produced by the rest of the system. This reduction in other generators' output reduces their total generation costs due, for example, to fuel and carbon savings. This is most clearly true for low marginal cost generators, but would also be true for any new thermal capacity that displaces less efficient thermal generation.
- Second, if the generation profile of the new capacity is variable, increasing the magnitude and frequency of changes to the net load that must be met by residual generators, it will push up other generators costs, in terms of inefficient fuel use and additional plant maintenance. This is referred to in the literature as the ramping effect or flexibility effect.
- Third, if the output of the technology is curtailed due to total generation exceeding demand, then the savings will be reduced. For the avoidance of any doubt, in this framework, curtailment costs appear only as a failure to effectively displace the generation costs of other generators.

The total displacement of other generators' costs is the net effect, taking each of these individual impacts into account. Typically it will be a benefit, but theoretically some fuel costs may actually increase. Note that this cost category does not account for any changes in capital costs, which are dealt with separately by 'capacity adequacy' costs

The value of carbon savings achieved by displacing fossil fuel generation depends critically on the assumed carbon price.¹⁴ To the extent that this assumed price

¹⁴ The carbon price is also relevant to the calculation of technology direct costs where the technology emits greenhouse gas emissions.

fails to reflect the true social cost of carbon, any estimate of the value of displacing fossil fuel generation will be systematically biased. The current price of carbon implied by the EU Emissions Trading System is generally regarded as being too low. Using this price may therefore underestimate the social benefits of displacing carbon-intensive forms of generation and, by extension, underestimate the benefits of adding low-carbon forms of generation capacity to the power system.

Capacity adequacy

In order to ensure security of supply, generation capacity must be sufficient to meet demand.

To the extent that the technology added to the system enables other capacity to be retired or otherwise forgone while maintaining a fixed level of reliability, often quantified in terms of the Loss of Load Expectation, it provides a benefit to the system. The capacity adequacy component of whole system impacts values a technology's contribution to ensuring system reliability.

As noted in our discussion of the choice of counterfactual, this effect is typically quantified in the literature as a 'back-up' cost equal to the cost of additional capacity which, when combined with the technology in question, would bring their collective contribution to system reliability up to the level of a given reference technology.

However, the concept of 'back-up' capacity is misleading as it implies that certain technologies with variable output require support from other generation technologies. The IEA (2014) point out that it is in fact power demand that needs to be adequately covered with an appropriate generation mix. Additional dispatchable capacity does not need to be built to support variable technologies. Therefore, when we consider the addition of capacity relative to a scenario which already meets peak demand, this new capacity implies a capacity adequacy benefit realised through capacity retirements or forgone capacity investments, as described above.

It is this primary effect on capacity, to ensure that capacity is adequate to meet peak demand, which is called 'capacity adequacy' in the literature.

We noted earlier on p.25 that in the long term, as the system re-optimises, there may be other changes in the capacity mix needed to cost-effectively manage the system following the introduction of new capacity. For example, it might be necessary to adopt more flexible capacity to cost-effectively deal with the addition of variable generation sources, even after adjustments have been made to ensure that capacity is sufficient to meet peak demand.

Where the re-optimisation of the system entails more extensive changes in capacity than the retirement of some existing capacity, for example because new flexible capacity is built to help manage balancing costs, we define our measure

What are whole system impacts?

of capacity adequacy to include all of these capacity changes. In other words, the introduction of variable generation capacity may, following re-optimisation of the system, result in the retirement of some baseload capacity and the construction of some flexible capacity. The net capacity impact of the variable generation should account for the net effect on total capacity costs, and should therefore include both changes. These capacity changes are valued on the basis of the difference in the economic costs of constructing capacity relative to the counterfactual. Again, this ensures that the cost framework is comprehensive and that, where appropriate, the costs of re-optimising the system are properly accounted for.

It should be noted that although capacity adequacy is necessary to ensure energy reliability, there are a number of factors influencing system reliability that are not typically accounted for as part of capacity adequacy or Loss of Load Expectation assessments. For completeness, these factors are discussed briefly in the box below.

Other determinants of system reliability

In addition to insufficient generation capacity, power system failures have historically also resulted from:

- Transmission system failures, for example due to extreme weather events or where circuit breakers have tripped in a cascade;
- Fuel shortages; for example due to international hostilities, logistical disruptions or industrial action;
- Droughts, for example where hydro resources are used to generate power or cool thermal plant; and
- Common mode failures, for example where multiple generation units all possess the same vulnerability and either fail collectively, or are shutdown simultaneously over safety concerns.

These risks are not typically accounted for in assessments of capacity adequacy and argue in favour of greater diversification in the type and location of generation than implied by assessments of capacity adequacy alone.

The 'compression effect'

One important effect of adding low marginal cost generation to a system, which is not explicitly mentioned above but frequently debated both in the literature and among the stakeholders we have spoken to, is the effect of this generation on the average utilisation or load factor of residual, comparatively high marginal

What are whole system impacts?

cost generators. This is the so-called ‘compression effect’. While not explicitly discussed previously, it is inherently captured in the framework we have developed.

Low marginal cost generation will, by virtue of its low cost, be used to meet demand when it is available and generating. Assuming total demand is the same, the residual output needed from existing generators falls, pushing up their LCOE. Is this a cost to the system and if so, where does it appear within our framework?

Imagine that this low marginal cost generation were flexible, dispatchable plant. In this case, we could safely retire some of the residual plant with reduced load factors, restoring the load on those plants that remained. Far from being a cost, this plant provides a capacity adequacy benefit, since we no longer need to replace the retired plant.

A problem can arise however when we imagine that the low marginal cost generation is highly variable, such that we can no longer safely retire the underutilised plant. In this case therefore, the new technology may provide little to no capacity benefit, because no capacity can actually be retired.

In our framework, the compression effect is accounted for through a technology’s capacity adequacy benefit, or rather, the lack thereof. Generation capacity that adds that technology’s direct costs to the system, but fails to provide any capacity adequacy saving, since other generation capacity cannot be permanently retired, is likely to raise overall system costs.

The stranding of existing generation capacity is not an additional cost under our framework, since, by definition, the costs of that capacity are already sunk. However, the capacity adequacy benefit of any new capacity will take account of whether or not the capacity it replaces is close to the end of its useful life, since the replacement costs that are avoided will be higher for plants requiring replacement soon, due to the discounting of costs over time.

In terms of financing generation capacity that is needed for system reliability, but otherwise little utilised, the energy revenues that previously met the costs of keeping this plant open may need to be replaced from different sources. For example, they may need to come from higher peak wholesale prices or, in the UK context, through increased costs in the capacity market, which will have to pay more to little used plant to keep it on the system.

Balancing impacts

The concept of balancing impacts is variously defined in the literature. Efforts to maintain system stability take many forms, across different periods, through a variety of mechanisms and, as result, different papers often look at different

What are whole system impacts?

elements of the associated costs when considering ‘balancing’. What is clear is that these efforts impose costs and that these costs can be affected by the introduction of new generation capacity.

We have already noted in the discussion of displaced generation costs that the variability of generation, i.e. the extent to which the level of output undergoes large and frequent changes, can affect other generators costs of generation. As such, these impacts are already accounted for in the framework and not counted again here. They may however be included in discussions of balancing costs elsewhere in the literature.

To ensure that our definition of balancing does not overlap with our other cost categories, we consider balancing impacts to cover only those costs that stem from the uncertainty of a technology’s output, as opposed to its variability. Whereas variability concerns the expected magnitude and frequency of changes in output, uncertainty reflects the extent to which our expectation matches real outcomes and, in particular, the risk and incidence of forecast errors.¹⁵ This approach mirrors that of Hirth (2012) and Ueckerdt (2013).

The distinction is perhaps clearest when we consider an idealised tidal generator. Because the output of a tidal generator depends on the tides, its output is inherently variable, rising and falling in sync with the tides. However, because the tides are so well understood, even the tidal generators variable output can be forecast with near certainty. Therefore, in this framework we consider a tidal generator to have a flexibility effect which is counted for under displaced generation, but that it does not contribute to balancing costs, except due to the risk of an unplanned outage of the plant.

Ensuring that the system is secure in the face of unexpected errors in the prediction of supply and demand is part of the role of the System Operator, which makes provision for such errors based on a probabilistic assessment of the size of the imbalance between supply and demand. This assessment will account for forecasting errors in both demand and variable generation, and the risk of unexpected outages at large plant. When the penetration of variable generation is low, it is unlikely to factor heavily into the System Operator’s provisioning, but becomes increasingly important as penetration increases and the cumulative size of forecasting errors grows.

Uncertainty of output implies the need to keep generation capacity in reserve and may call for costly changes to generators’ output. Much of this activity will be orchestrated by the System Operator. However, it is worth noting that some of

¹⁵ Be aware that what we refer to here as ‘uncertainty’, as distinct from ‘variability’, is also referred to elsewhere as ‘intra dispatch period variability’.

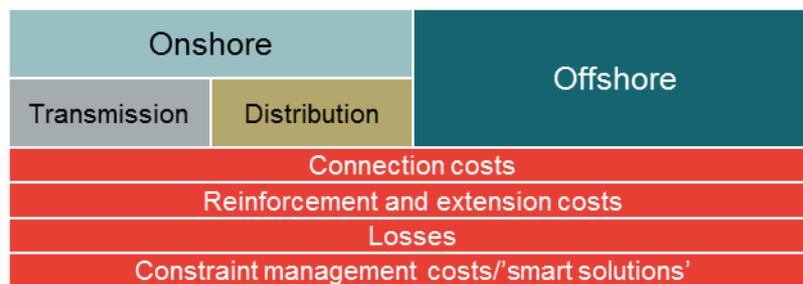
the resource costs of uncertainty (e.g. self-balancing intra-day) may also be borne outside the TSO's formal processes.

One element of costs that we choose not to consider here, but which could conceivably be considered a balancing cost, are TSO actions to change generator output for the purpose of network congestion management i.e. 'constraint costs'. In practice, the resource costs of these actions will be identical to balancing actions undertaken for other reasons. However, these costs are grouped alongside network costs below because congestion management and infrastructure investment are used as substitutes for meeting the same network needs.

Network impacts

This category covers changes in the cost of transporting power from generators to final consumers. The key categories of cost are set out in Figure 7.

Figure 7. Scope of network costs



Note: Ancillary services are considered separately under 'balancing costs'.

It includes infrastructure costs, such as the costs of reinforcing or extending existing transmission or distribution networks, as well as the costs of connecting new capacity to the system, both offshore and onshore. It also covers the costs of managing network congestion by altering generators' output and the power losses that occur on the journey from generator to end user. While constraint costs are in practice more closely related to balancing actions, we include them here since they are a substitute for network investment and so should be considered together. Constraint costs are tolerated up to a certain point before they trigger an investment in network. These network costs are very difficult to estimate in the abstract and allocate to particular technologies, since they arise as the result of the aggregate effect of many supply and demand decisions.

These impacts all relate directly to the power network and, as we will discuss later in section 4, have powerful locational drivers.

The addition of new generation capacity to the system does not always increase costs. For example, in some cases distributed generation can effectively lower

What are whole system impacts?

end-users net demand without changing the direction of power flows, although this will only be the case in certain circumstances. In doing so, distributed generation may free up capacity in the transmission and distribution networks, reducing or preventing the need for future reinforcement at higher voltage levels or easing network congestion.

This is the case where generation connects close to demand i.e. it reduces the net inflow of power over the distribution network. However, DNOs have highlighted to us that this is frequently not the case. The increase in connections of solar and wind farms in recent years onto the distribution networks is often not well aligned with local demand, typically clustered and located away from urban centres. As a result, the generation output produced can lead to net outflows of power (e.g. solar output is not necessarily aligned with peak demand) from local distribution networks, and in some cases in excess of the capacity of the network. The increased complexity in power flows can create voltage, thermal and fault management problems for DNOs, which can trigger the need for costly reinforcement or ‘smart solutions’ such as demand-side response and storage.¹⁶

As with whole system impacts more generally, the appropriate attribution to a specific technology of network costs, both at the transmission and distribution levels, is often not clear cut. A number of stakeholders have commented on the difficulties of isolating the network cost associated with any single generator. This is because once built a reinforcement may bring benefits to other participants on the system who were not directly responsible for triggering the investment. For example:

- Reinforcing the distribution network, triggered by the connection of a generator, creates ‘headroom’ for the future connection of demand. In the context of decarbonisation this may be important to enable future take-up of heat pumps and electric vehicles. However, if the demand had triggered the reinforcement first, then generation could connect without cost.
- Reinforcement in response to a new generator connection is likely to be based on their peak output, however, there may still be spare capacity available for other, potentially complementary, generators to utilise at no additional network reinforcement. For example, a wind generator will only use the full-rated capacity of a new line a fraction of the time, creating spare capacity for a flexible generator such as hydro.

¹⁶ We believe that the issues noted here can represent real costs from the use of distribution-connected generation. However, we remind the reader that DNOs can have a commercial interest in emphasizing the need for investment in the distribution network.

- Investments in networks are typically large lumpy investments which anticipate future connections and/or load growth. Once these have been built and the costs sunk, future connections are made with no additional network investment.

In other words, sequencing matters and these examples illustrate some of the challenges in allocating network costs to different parties. As part of the framework we have set out, we think they are best dealt with through the definition of the counterfactual in an assessment of system impacts. By that we mean if an additional network investment is triggered relative to the counterfactual then there is an increase in system costs associated with the connection of that technology which needs to be accounted for.

However, it needs to be recognised that there are potential future benefits associated with that investment which are shared beyond the generator that triggered the investment. As such, changes to the power system that trigger large scale network investments may have the corresponding system cost exaggerated where the costs of this investment is fully attributed to the triggering change alone.¹⁷

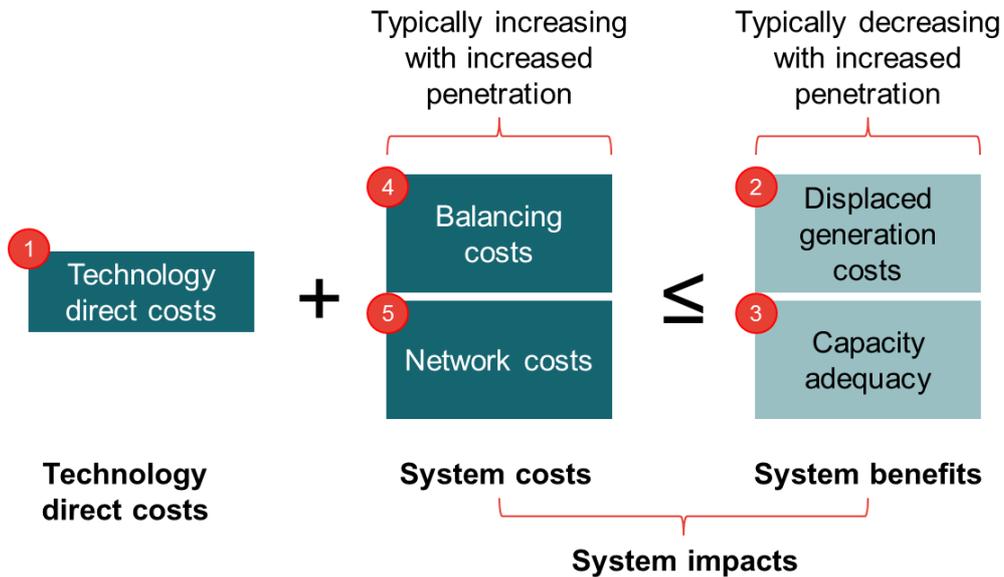
2.3.2 Investing to minimise Total System Costs

From a system perspective, assuming that externalities are properly priced into the assessment of costs, it makes sense to invest in a technology if its net whole system impact is a benefit. This might occur, for example, because the value of the generation costs displaced more than offset any direct technology costs. Where the net whole system impact is a benefit, total power system costs are reduced, relative to the counterfactual, as a result of adding the new technology. This framework is set out in Figure 8.

¹⁷ In order to avoid this problem, any extensions to DECC's modelling capability are likely to use an approach based on avoiding lumpy network investments in favour of a more gradual increase in network costs. Although actual costs are likely to be lumpy in practise, modelling them in this way risks spuriously attributing large network costs to relatively minor system changes (the straw that broke the camel's back) and of failing to account for the wider shared benefits of investments in network infrastructure.

What are whole system impacts?

Figure 8. Using the whole system impacts framework as an investment decision tool¹⁸



Source: Frontier Economics

Calculating the whole system impacts of a technology can be useful as a means to identify effects that are not appropriately factored into investment decisions. In general, developers' decisions will be most efficient where their private costs accurately reflect all of their investment's whole system impacts, or else, where policy support levels are set to compensate for any mismatches between developer costs and whole system impacts. The level of policy support that leads to efficient investment will ultimately depend on the size of the discrepancy between the various cost components and developers' private costs.

As set out earlier, there are also likely to be other considerations which policymakers will also want to consider as part of an effective support framework. For example, we have already set out that there are potentially wider benefits beyond our definition of power system costs, and policymakers may face other constraints such as binding targets for particular technologies that this framework does not take into account. As such, the cost framework represents a sensible starting place on which to base future support, but is unlikely to reflect all considerations relevant to determining the level of support appropriate to any technology.

¹⁸ Where developers fully and correctly internalise all the impacts of additional generation capacity you would expect the markets to deliver capacity up until the point where this inequality holds as an equation.

2.3.3 System effects before and after re-optimisation

Earlier in this section we stressed the importance of taking a long-run perspective when considering system impacts. The key reason being, that this allows for re-optimisation of the system which is important for minimising the system impacts associated with certain technologies. With this in mind we now illustrate the system impacts under our framework before and after re-optimisation.

Table 4. System impacts before and after re-optimisation

Whole System Impact category	Before re-optimisation	Allowing for re-optimisation
Technology direct costs	No difference in impacts before and after re-optimisation	
Displaced generation costs	Generation savings for certain technologies could in part be eroded by increased ramping	If required, system re-optimises to become more flexible and impact on ramping is reduced.
Capacity adequacy	No capacity saving realised, though security of supply improved.	Capacity saving due to retirements/foregone investment. Need to account for cost of re-optimisation
Balancing costs	Changes in uncertainty will affect ramping and cycling of plant.	If required, system re-optimises to improve power system flexibility and impact of uncertainty is reduced.
Network costs	Saturation of the distribution and transmission grid increasing constraint management costs.	Increased grid capacity if cost-effective to reduce constraints.

Source: Frontier Economics

What are whole system impacts?

3 Characteristics that drive these impacts

SUMMARY

- This chapter focuses on developing a deeper understanding of the causal drivers of system impacts and, in particular, seeks to identify the characteristics of different generation technologies that determine the scale of any impacts. Identifying these characteristics from the set of technologies covered by the existing literature, we then extrapolate the results to a broader set of technologies by considering these technologies' intrinsic properties and inferring their effect on system impacts.
- From this assessment we conclude the following:
 - **Displaced generation savings** are driven by the timing of generation. They will be lower where output is correlated with low demand or the output of existing low marginal cost generation, since the marginal cost of generation displaced will be lower. In the extreme, output will be curtailed, leading to no savings at all in certain periods. Savings will be diminished further, for a variable technology, if dispatchable generators have a low level of cycling efficiency.
 - Technologies with variable outputs, poorly correlated with demand, but highly correlated with existing non-dispatchable generation will have the lowest **capacity adequacy savings**. This can be mitigated by combining technologies with complementary or uncorrelated output, such as combining wind with solar deployment, or through encouraging diversity.
 - Uncertain, inflexible and non-synchronous generators drive the highest **balancing costs**. The value of incremental, very flexible generation is to reduce balancing costs, relative to systems with less flexible generation.
 - Generators connecting to constrained parts of the **network**, with significant positive correlation to other local generators can drive higher **network reinforcement or extension costs**. All technologies face location constraints, but to differing degrees. Intermittency can create opportunities for 'smarter' solutions such as flexible connection agreements, particularly at the local level significantly reducing costs.

We have set out a conceptual framework for considering the whole system impacts of different technologies. This is designed to be comprehensive and

applicable to all generating technologies. In this chapter we go on to develop our understanding of how different technologies affect the impact categories identified in our framework.

As noted previously, the majority of the literature focuses on assessing the system impacts of variable renewable technologies, such as wind and solar, and to a lesser degree nuclear and some dispatchable technologies. As such, much of our discussion of the literature inevitably focuses on those categories of whole system impacts that are particularly relevant to an assessment of variable renewable technologies.

However, as part of this project we want to go further and help develop an understanding of all the generating technologies that DECC considers in its policy making. To do so, we have extrapolated from the existing literature.

Our approach is based on the fact that each technology's system impacts can be traced back causally to various technological characteristics. We can therefore take the technologies that have been studied in full and identify the important causal drivers of their system impacts. By considering whether these causal drivers are present for other forms of generation, we can then extrapolate the results from these well-understood technologies to other technologies and infer these other technologies' whole system impacts.

This section:

- first, provides an overview of the technology, power system and locational drivers of system impacts;
- second, maps these drivers to each of the four system impact categories (displaced generation costs, capacity adequacy, balancing impacts and network impacts), drawing on evidence from those technologies examined in the literature; and,
- finally, it extrapolates the findings from this exercise to a broader set of technologies based on their intrinsic characteristics.

3.1 Overview of fundamental drivers

We begin by listing and defining the drivers which have been identified from our examination of the literature, grouped into three categories: characteristics of the generation technology itself, characteristics of the wider power system, and characteristics of the specific location in which the technology is built. We then go on to discuss how they relate to each of the categories of whole system impacts we have identified.

Characteristics that drive these impacts

3.1.1 Technology characteristics

Table 5. Technology characteristics

Characteristic	Description
Marginal generation cost	The variable cost associated with generating more or less energy
Average load factor	Average output as a proportion of theoretical maximum plant output.
Plant capacity	A plant's maximum achievable rate of generation
Variability	The magnitude and frequency of uncontrollable but predictable changes in output
Uncertainty	The magnitude and likelihood of unexpected changes in output
Correlation of output and demand	The extent to which higher output coincides with higher demand on the system as a whole
Correlation of output and non-dispatchable system generation	The extent to which higher output from the plant coincides with higher non-dispatchable output in the rest of the system as a whole
System inertia	The extent to which the technology contributes to system inertia either directly or through use of appropriate power system electronics

Source: Frontier Economics

3.1.2 Power system characteristics

Table 6. Power system characteristics

Characteristic	Description
Merit curve	The shape and composition of the system supply curve for the generation of electricity
Cycling efficiency	The efficiency with which other generators, storage or interconnection can start up, shut down, ramp their output and/or operate at sub-optimal loads, as well as the scope for demand to be reduced or shifted, so that predictable changes in variable output can be accommodated
Flexibility	The feasibility and cost of ordering large, short-notice changes in output ¹⁹
Size of the system balancing area	The size of the power pool that must be kept in balance by the System Operator ²⁰
Largest infeed loss	The largest amount of power that could suddenly be withdrawn as the result of a generator or transmission fault
Efficiency of balancing process	The cost-effectiveness of processes designed to ensure system stability
Cost of capacity	The cost of generation capacity that could be retired or added to the system to meet capacity needs

Source: Frontier Economics

¹⁹ Storage, interconnection, reservoir hydropower and interruptible loads will all tend to enhance system flexibility.

²⁰ In general, a larger pool is easier to keep in aggregate balance because discrepancies become more diversified and individual imbalances become smaller relative to the overall size of the system.

Characteristics that drive these impacts

3.1.3 Location characteristics

Table 7. Location characteristics

Characteristic	Description
Distance from load	The distance that a generator's output must travel to reach final consumption
Level of congestion	The remaining unused capacity available in the transmission and distribution networks
Local correlation of output and demand	The extent to which higher output coincides with higher demand in the surrounding network
Correlation of output with local non-dispatchable generation	The extent to which higher output from the plant coincides with higher non-dispatchable output in the local network
Distributed	Whether the technology is embedded in the distribution network or connected to the transmission network

Source: Frontier Economics

Characteristics that drive these impacts

3.2 Displaced generation costs

The displaced generation cost component covers changes in the generation costs of other generators on the system.

When we add a technology to the power system, its output will displace the generation from existing generators, providing it is not curtailed, reducing existing generators' variable costs (e.g. fuel, carbon, variable operating costs). However, if the additional technology's output increased the variability of residual generators, other generators may face additional ramping/cycling costs associated with the need to follow this variable load. Displaced generation costs reflect the sum of these two effects. It is important to note, that as set out earlier, there will also be changes in generation costs due to the uncertainty of output. These resource costs are captured under the 'balancing costs' category.

The drivers of these savings are set out in Table 8.

Table 8. Drivers of displaced generation costs

Technology	Power system
Marginal cost of generation	Merit curve
Average load factor	Cycling efficiency
Variability	
Correlation with other output and demand	

Source: Frontier Economics

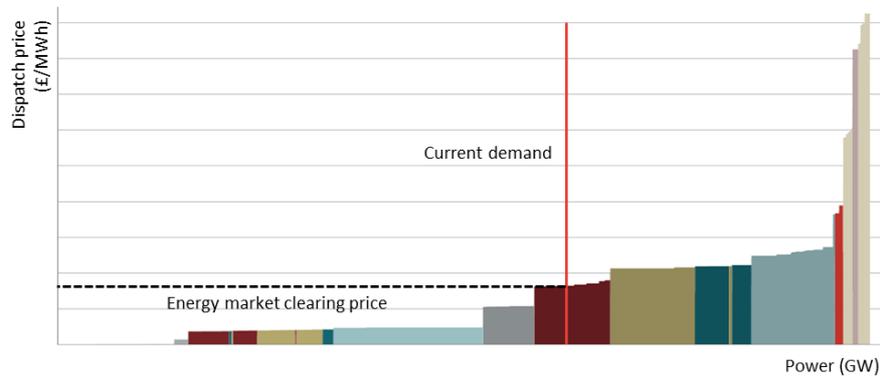
3.2.1 Reduction in system variable costs

The first effect is determined by the quantity and cost of the displaced generation. The quantity component is simply the product of the technology's load factor and plant capacity; the load factor will vary across periods. The cost saving associated with a reduction in other generator's output is complicated and depends on exactly what generation capacity is displaced.

The supply curve for the system is generally referred to as the merit curve and an example is shown in Figure 9. The marginal source of generation is shown for each level of generation, and as demand changes, the marginal source of generation may change.

Characteristics that drive these impacts

Figure 9. Example merit curve



Source: Frontier Economics

Some low-carbon technologies have near-zero marginal costs, appearing to the far left of the curve and so potentially displace generation from a wide variety of alternative technologies.²¹ If the system is currently relying on high marginal cost technologies, the savings due to this displacement will tend to be large, but a system that is already making extensive use of low marginal cost generation will have less to gain from displacing existing generators.

The marginal cost of generation also depends on the amount of demand and how much low marginal cost generation is feasible. Where a technology's output is correlated with a large amount of existing low marginal cost generation, or with periods of low demand, it will tend to displace plants that already have a comparatively low marginal cost, reducing the value of the savings. In the extreme, the additional technology may end up being curtailed when its output is not required to meet demand. This curtailed energy displaces no generation, and therefore fails to displace any generation costs (e.g. fuel, carbon, variable operating costs).

It is for this reason that these displaced generation savings diminish with the penetration of certain technologies, creating diminishing marginal savings as more and more of the same type of capacity is added. This is true for variable technologies, as well as baseload technologies such as an inflexible nuclear plant. For example, placing large quantities of baseload generation on the system may displace a large quantity of existing generation. However, if the displaced generation is mostly from low-marginal-cost wind power, e.g. during the night,

²¹ In reality, the merit curve will reflect not just the resource costs of dispatch, but the financial costs as well. Generators with support payments linked to output may offer energy at negative prices if support payments are large enough to offset the associated energy market losses.

the actual reduction in system variable costs might be relatively small. Again, in the extreme, the inflexible baseload technology may have to be itself curtailed.

Changes in the shape of future demand could mitigate this effect to a degree. For example the take-up of electric vehicles could increase demand during the night reducing the probability of curtailment.

The overall shape of the merit curve is also important. A steep curve implies that the value of displacement will be very sensitive both to the level of demand when the displacement occurs, and to the amount of additional generation we are considering adding to the system. It will also exaggerate the importance of the correlation effects discussed above.

Displaced generation benefits are not confined to low marginal cost plant. The addition of any relatively efficient dispatchable generation to the system should also result in a net benefit in terms of the displacement of other generators costs. In order for the framework to add up, the size of this displaced generation saving reflects the cost of the generation being displaced only, rather than the difference between these generation costs and the generation costs of the new capacity. We account for the generation cost of the technology being added separately under ‘technology direct costs’.

As described above in relation to low marginal cost plant, for a given quantity of energy produced, it is the timing of the generation that is important to the displaced generation saving. The value of the saving will be less for a technology which only generates during off-peak periods. For dispatchable technologies with higher marginal costs, the value of any energy they displace may be higher if the displacement occurs during a peak period. However, their relatively high marginal costs may imply that relatively little energy may be displaced overall.

Provided the energy market results in efficient dispatching decisions, displacement should always yield a net reduction in overall power system costs. In other words, the displaced generation savings that result should exceed the technology’s own generation costs. Distortions to efficient dispatch could arise where subsidy payments linked to generation output encourage high marginal cost plants to run ahead of more cost-effective plants. Where this occurs, the impact of displacement would be a net cost to the system, regardless of whether or not the associated technology is dispatchable.

3.2.2 Increases in variable costs due to cycling/ramping

So far we have only considered direct savings which result from a reduction in the total output required from the rest of the system. However, as noted above, these may be offset, at least in part, by additional start-up and ramping costs due to the variability of the added technology’s output. Ramping costs due to uncertainty are discussed under balancing costs.

Characteristics that drive these impacts

Variable generators, such as wind, solar, wave or tidal, require the rest of the system to accommodate gradual but significant changes in output, requiring other generators to be started up or shut down, ramped up and down, or otherwise operated less efficiently. The size of this offsetting inefficiency effect is determined by both the variability of the additional technology's output and the cycling efficiency of the rest of the system. It is an empirical question as to whether this effect is significant or not. We discuss both variability and cycling efficiency below.

There is some debate about the importance of this effect. However, on the basis of our stakeholder conversations, it was generally thought to be quite small. Often Ireland is cited as an example where large amounts of wind generation have imposed sizeable ramping costs on the system, which have therefore offset some of the wind capacity's displaced generation savings.

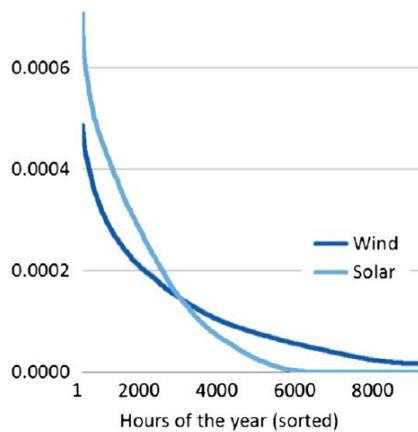
However, this does not necessarily apply to larger, more interconnected markets like the UK. National Grid quantified the impacts for the period from April 2011 until September 2012 and found that it based on the existing relatively low levels of wind generation the effect resulted in an increase in emissions of just 0.08% in the period.²²

Variability

The variability of wind and solar is a topic covered extensively in the literature. Solar variability is mainly driven by day-night and season cycles, with clouds, snow, fog and dust adding a random component to the generation pattern. Wind output typically exhibits greater apparent randomness. On the other hand, solar generation is generally peakier, concentrated in fewer hours of the year than wind generation, as can be seen in Figure 10.

²² http://www.scottish.parliament.uk/S4_EconomyEnergyandTourismCommittee/NATIONAL_GRID.pdf

Figure 10. Generation duration curves for solar and wind power



Source: Hirth (2012)

Marine technologies also demonstrate considerable variability. Wave shows high seasonal variability, with almost half of the annual output occurring in the winter months; however, it shows less variability in the short-term than tidal (ECI, 2005). The variability of tidal is driven by positioning of the sun and the moon; it shows very little variability by season, but considerably more at smaller timescales.

Cycling efficiency

The cycling efficiency of a given technology is often referred to as ‘flexibility’, and it has different dimensions such as:

- adjustability - the possible generation level that can be chosen given a long lead time; it is constrained by the minimum and maximum output of the power plant;
- ramping - the speed at which the output level can be changed; and
- lead time/start-up time - the required notice to make generation available.

Differences in flexibility of the existing mix which is assumed in the counterfactual are important when assessing the system impact of an additional technology. Dispatchable technologies differ in their ability to provide flexibility, and hence the cost of doing so. They can be broadly categorised in three categories based on data from Table 9 (IEA 2014):

- **Inflexible technologies:** inflexible types of nuclear generation, lignite and coal power plants, some steam turbines with oil/gas as boiler fuel, and to some extent also gas CCGT plants, if designed in a certain way. Most

Characteristics that drive these impacts

geothermal plants are also categorized as inflexible as this type of plant was designed for baseload operation, and start-up and ramping are rare and time-consuming due to thermal stresses in the machinery operating at high pressures.

- **Flexible technologies:** flexible CCGT, flexible coal, flexible nuclear, biomass, biogas and CSP technologies. These plants are designed to operate as mid-merit plants and are able to adjust their generation to deal with load variations, as well as to start on shorter timescales.
- **Very flexible technologies:** reservoir hydro, combustion engines, aero-derivative gas turbines, OCGT (where some types will perform better than others). The additional costs of operating these plants can be very low.

An important aspect of flexibility not mentioned in this table relates to the demand-side. The impact on existing generators due to variability can be reduced if the demand-side can better respond to accommodate the variability. The degree of demand-side flexibility is therefore an important assumption to be made in setting up the counterfactual for any analysis of whole system impacts.

In summary:

- all new technologies should in theory produce a benefit from displaced generation costs, however, the value of this benefit will depend on the timing of generation from each technology;
- where the output is correlated with existing low marginal cost plant, the marginal benefit from each additional unit of a new technology will decline; and,
- where the output is variable and the cycling efficiency of the system has not adjusted in response displaced generation costs will be offset further.

Table 9. Assessment of flexible generation according to dimensions of flexibility.

Technology	Min stable output (%)	Ramp rate (%/min)	Lead time, warm (h)
Reservoir hydro	5-6**	15-25	<0.1
Solid biomass	.***	.***	.***
Biogas	.***	.***	.***
Solar CSP/STE (with storage)	20-30	4-8	1-4****
Geothermal	10-20	5-6	1-2
Combustion engine bank CC	0	10-100	0.1-0.16
Gas CCGT inflexible	40-50	0.8-6	2-4
Gas CCGT flexible	15-30*****	6-15	1-2
Gas OCGT	0-30	7-30	0.1-1
Steam turbine (gas/oil)	10-50	0.6-7	1-4
Coal inflexible	40-60	0.6-4	5-7
Coal flexible	20-40	4-8	2-5
Lignite	40-60	0.6-6	2-8
Nuclear inflexible	100*****	0*****	N/A*****
Nuclear flexible	40-60*****	0.3-5	N/A*****

Source: Source: IEA (2014)

Notes: CC = combined cycle; CSP = concentrated solar power; STE = solar thermal energy. The table refers to typical characteristics of existing generation plants; specific arrangements, especially in new-build flexible coal, lignite and nuclear power plants may increase generation flexibility; operational and environmental constraints can have a significant impact on how much of this technical flexibility is actually available.

** Environmental and other constraints can have a significant impact on the availability of this flexibility.

*** Solid biomass and biogas can be combusted in plants that have the characteristics of coal and gas plants. Data on solid biomass and biogas is thus included in those on coal and gas plants.

**** If thermal storage is not fully available, lead time can be considerably higher.

***** 15% is reached by plants with steam cycle bypass at reduced efficiency.

***** Security regulations may prohibit nuclear from changing output. Reported start-up times are two hours from hot state to two days.

Characteristics that drive these impacts

3.3 Capacity adequacy

The impact on capacity adequacy of adding a technology reflects the additional technology's ability to substitute for existing capacity on the system without harming system reliability, as measured by the Loss of Load Expectation (LOLE) (See the box below). This saving is on the basis of an approach that assumes the counterfactual and the technology scenario achieve the same LOLE.

As noted in the box on p.37, calculations of LOLE only consider one dimension of system reliability, namely the adequacy of generation capacity to meet demand. Security of supply depends on a variety of other factors as well and will, in general, be enhanced by a diversity of generation sources.

Finally, it should also be remembered that changes to system capacity may be driven not only by the need to avoid an increase in the LOLE, but also by the system's re-optimisation to accommodate any new capacity. These wider capacity changes would also, under our framework, be captured by the idea of capacity adequacy.

Probabilistic nature of Loss of Load Expectation

Loss of Load Expectation is the number of hours per year, on average, in which power supply is expected to be lower than demand, assuming the otherwise normal operation of the power system. In the UK, this measure reflects the number of hours in which National Grid, as the System Operator, will resort to mitigation actions due to insufficient power supply. Importantly, it is not the expected numbers of hours in which there will be controlled disconnections of customers, as National Grid would be expected to use alternative mitigation actions ahead of controlled disconnection.

LOLE is estimated using probabilistic modelling of both demand and supply. A generation technology's contribution to capacity adequacy reflects its ability to reduce the LOLE. Variable generation technologies will still reduce the LOLE, provided that there is a positive probability of them generating at times when the power system would otherwise have insufficient supply. As a result, almost all generation technologies will reduce LOLE if added to a system. Technologies with the highest probability of generating when the system is expected to be short of power will provide the greatest contribution to capacity adequacy. Adding many units, as opposed to a large single unit, may also increase the contribution, due to the enhanced reliability of diversified supply.

The drivers of a generation technology's ability to substitute for other capacity, as described above, and of the implied costs and savings associated with this substitution are set out in Table 10.

Characteristics that drive these impacts

Table 10. Drivers of capacity adequacy benefits

Technology	Power system
Variability	Cost of capacity
Average load factor	
Correlation with output and demand	

Source: Frontier Economics

At the most basic level, a plant's average load and capacity will determine its average power output and, in turn, the amount of capacity it could displace on this basis alone. However, although these features are relevant to an assessment of capacity adequacy, this calculation fails to account adequately for all relevant effects on system reliability.

In particular, the system may be less able to rely on capacity with variable output being there when it's actually needed, even if its power output is the same *on average* as a quantity of dispatchable capacity. Consequently, technologies with greater variability in output may contribute less to capacity adequacy than their average output might suggest.

3.3.1 Correlation with demand

The reliance we can have in variable technologies like wind and solar depends critically on how their output varies with both demand and supply. Taking the correlation with demand first, imagine a non-dispatchable technology whose output fluctuated between zero and the level of peak demand, and which was guaranteed to produce its maximum output at peak demand. Because we know this, it can safely substitute for some capacity needed only to meet peak demand. More generally, where a variable plant's output is positively correlated with demand, it contributes more to system reliability than would otherwise be the case.

An excellent example of this effect is solar generation in hot countries, where peak demand is driven by the use of air-conditioning during the day which coincides with high solar energy output. This is the case in for example Southern Europe, where capacity credit of solar is quite high (Imperial College, 2014).

Figure 12 shows the magnitude of daily peak demand with the corresponding PV output across one year period in Greece, taking into account temporal demand variation, including generally lower peaks during the weekends. The blue line shows the percentage of peak demand occurring in every day throughout a period of one year, and the red line shows how much of that peak demand was met by solar generation. We can see that there is high correlation between peak

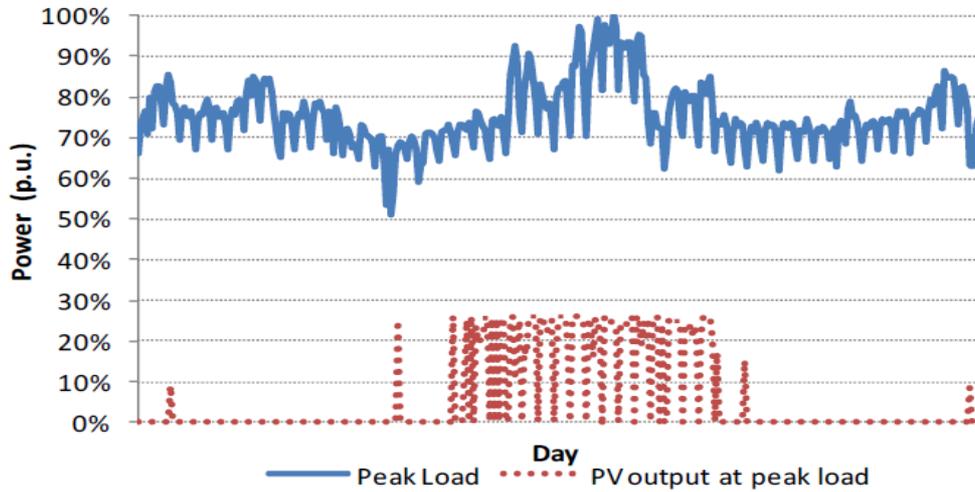
Characteristics that drive these impacts

demand and peak PV output in Greece. Figure 12 shows this relationship for the UK, where solar output is typically zero during peak periods.

The effect of correlation, and of intermittency more generally, is weakened or eliminated where a variable technology incorporates storage capacity. Where this is the case, power generated off-peak can be dispatched to meet peak demand. However, the increased capacity adequacy benefit achieved with the addition of inherent storage would need to be considered alongside the increase in the technology's direct costs, or the variable technology and the storage should be viewed as two separate, albeit complementary technologies.²³

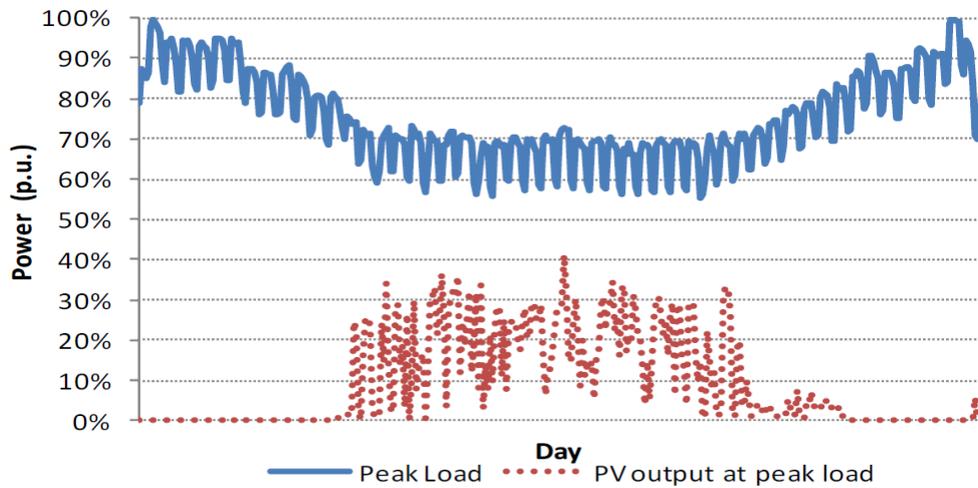
²³ The same system impacts will also be observed where additions of variable generation capacity are accompanied by increases in storage capacity at the system level. However, in such cases, we would expect the impacts of the storage and generation installations to be accounted for separately, rather than amalgamated.

Figure 11. The level of PV output at daily peak demand across one year period in Greece



Source: Imperial College (2014)

Figure 12. The level of PV output at daily peak demand across one year period in the UK



Source: Imperial College (2014)

For wind generation, the correlation of output and load depends on the location of the plants. In the UK, this correlation is lower for offshore wind than onshore wind, since offshore output is comparatively high at night. Similarly, wind in the UK is generally stronger in the winter, improving the correlation with demand compared relative to other locations. It has been found that wind has a weakly positive correlation with current electricity demand patterns. Sinden (2007) found

Characteristics that drive these impacts

that during periods of peak demand, the capacity factor of wind is around 30% higher than average annual capacity factor. However, more recent evidence has emphasised the importance of anti-cyclones, where cold and still periods produce coincident high demand.

Output of tidal in the UK shows zero correlation with peak demand although it is very predictable, whereas output of wave shows positive correlation: ECI (2005) estimates that, like electricity demand, wave output is seasonal and largest during the winter. They estimate that were annual wave output scaled to deliver 15% of total electricity demand over the year, it would meet an average of 24% of demand in winter and 6% of demand in summer.

3.3.2 Correlation with the output of other generators

The ability of a technology to substitute for existing capacity also depends on the correlation of its output with other non-dispatchable generation on the system. The reason for this is that the system is more resilient when it has diversified sources of generation and less resilient when its non-dispatchable generation is all highly correlated.

Consider adding wind to a system which already has a high penetration of wind and in which all wind generation is highly correlated. Given the high penetration of wind, the system is likely to be hardest pressed to meet demand when wind output is low, which is exactly when our additional wind will be of least use. A high correlation between the technology's output and the output of existing non-dispatchable generation on the system means that, far from helping to compensate when other sources of generation are low, it is adding to the systemic vulnerability of the system. As a result, very little capacity can be substituted for without harming system reliability and increasing the loss of load expectation. This example demonstrates a more general result that a variable technology's marginal contribution to capacity adequacy tends to decline as that technology's total penetration increases. We demonstrate this effect in the next section, when we discuss how to measure capacity adequacy.

Conversely, additional technologies which are not highly correlated with existing technologies tend to be most valuable in terms of increasing the likelihood of meeting peak demand. The availability of wind and solar energy generally do not show positive correlation; which suggests that combining these two resources in the system can substantially mitigate their individual variability (IEA, 2014). Similarly, there is no correlation between the output of wind and tidal, thus mixing these technologies in the power system can provide diversification benefits and smooth the variability of wind. While there is a positive correlation between output of wave and wind, hour-to-hour changes in wave are less extreme than those of wind, and this non-perfect correlation gives a diversification effect which is positive for the system (Redpoint, 2009).

Characteristics that drive these impacts

Note that geographic diversity can also help to limit correlation even within a single technology. For example, wind added in an area with substantially different output characteristics than those observed in the rest of a high-wind system may nevertheless be useful. It is not technology penetration *per se* that is problematic, but rather a lack of diversity in variable output.

3.3.3 Measuring capacity adequacy

A technology's contribution to capacity adequacy is often summarised by a capacity credit, which draws on all of the drivers discussed above. A plant's capacity credit is defined as the amount of additional peak load that can be served due to the addition of the plant while maintaining the same level of system reliability, and is commonly expressed as a percentage of the plant's nameplate capacity. The higher the capacity credit, the more capable the technology is at contributing to capacity adequacy and the larger the implied benefit to the system.

Table 11. Capacity credits assumed by National Grid for 2015 capacity auction

Technology	Capacity credit (%)
Oil-fired steam generators	84.61
OCGT	94.54
CCGT	89.00
CHP and autogeneration	90.00
Coal/biomass/energy from waste	87.86
Nuclear	82.31
Hydro	84.87
Storage (including pumped storage)	96.63

Source: National Grid

Note: In interpreting a technology's capacity credit, remember that capacity credit is measured relative to a plant's nameplate capacity. Variable technologies like wind do not, on average, generate power close to their nameplate capacities and so their lower capacity credits often reflect, in large part, their lower capacity factors (the ratio of average output to nameplate capacity).

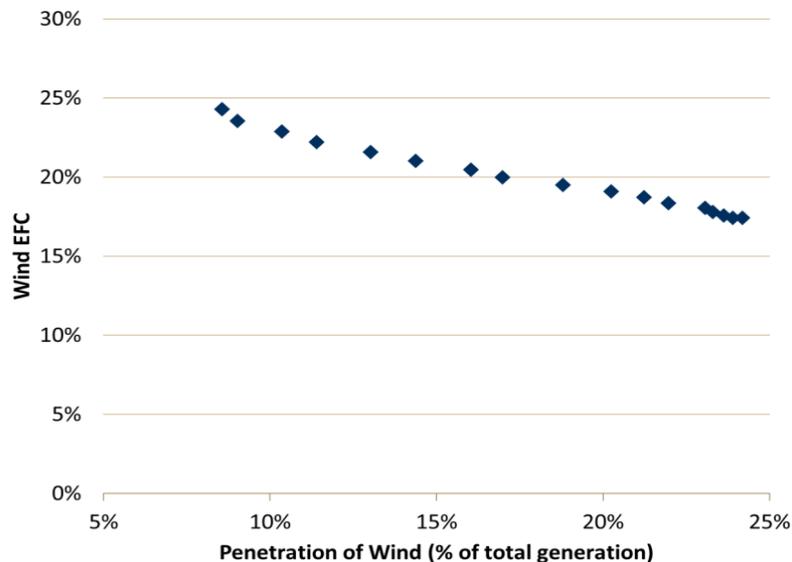
Table 11 presents estimates of capacity credit in the UK for a range of technologies. The output of dispatchable power plants is not variable in the period of peak demand except for the unplanned outages (as scheduled maintenance can always be organized outside of peak demand times).

Characteristics that drive these impacts

For some renewable technologies, with high variability of output and low correlation with demand, the capacity credit will be low. The capacity credit for solar is close to zero given its very low correlation with peak demand.

The capacity credit of a non-dispatchable technology will tend to fall as that technology's installed capacity increases, due to the correlation between any new capacity's output and the output of existing non-dispatchable generation. Consequently, as with displaced generation benefits, capacity adequacy benefits are generally subject to diminishing marginal returns as more and more of the same technology is added to the system. This is illustrated for wind using analysis by LCP in Figure 13 for the capacity credit of wind in the UK. The exact relationship will depend on the assumed load factors, and the final analysis will need to be consistent with DECC's Delivery Plan assumptions.

Figure 13. Capacity credit of wind assumed in the capacity market design



Source: LCP analysis

Calculations of capacity credit can be highly sensitive to assumptions, and are context specific. For example, the correlation of output from wind generation with other non-dispatchable generation tends to be lower for larger power systems, where there is greater scope for weather variability. Availability of interconnection also helps to reduce this correlation further. These factors are therefore likely to increase the capacity credit of variable renewables.

Although capacity credit is a useful measure of a technology's contribution to capacity adequacy, it can sometimes fail to account for other relevant security of supply effects. As noted in the box on p.57, LOLE is assessed using probabilistic modelling. This modelling accounts for the fact that some capacity must be held

Characteristics that drive these impacts

in reserve to ensure that the system can cope with the unexpected loss of its largest single infeed. Where new generation capacity affects the size of the largest infeed loss, the implications for LOLE and, by extension, capacity adequacy may be different than implied by the technology's capacity credit. For example, a very large nuclear plant will benefit from the technology's high capacity credit, but if that plant also increases the potential size of the largest infeed loss, its contribution to the LOLE will be partly offset by the need to hold more generation capacity in reserve.

In this case, we would expect capacity adequacy savings to be lower than otherwise, because some capacity needs to be maintained and held in reserve in order to meet increased balancing needs. While the capital costs of this need for more reserve capacity would be captured under capacity adequacy, the operational costs of maintaining and running this plant would be captured as a balancing cost associated with an increase in the largest single infeed loss.

3.3.4 GB capacity market

In GB, the introduction of a capacity market provides a regulated means for estimating the capacity saving. The capacity requirement is set in order to achieve a reliability standard of three hours LOLE, and the capacity costs associated with meeting this target can be used to proxy for capacity adequacy savings.

Additional capacity will increase available supply and reduce the target capacity. We can use this as a potential way to value the capacity saving that results from additional capacity.

There are two possible approaches to this:

- First is to estimate the capacity market clearing price in the technology scenario and use this to value each kW that the target capacity was reduced by. However, this approach relies on the capacity market clearing price reflecting the fixed costs associated with the marginal unit of capacity on the power system. In reality this is not the case, as it really reflects the additional revenue required by the marginal unit of capacity to participate in the capacity market. This could be less than the fixed costs of the plant if energy revenues remain high, or vice versa if energy revenues are lower.
- An alternative approach is to value the reduction in target capacity based on estimates (e.g. DECC generation costs) of the fixed costs of the marginal unit of capacity. This avoids the need for using the clearing price, but relies on being able to identify what the marginal unit of capacity is likely to be. For example, new CCGT, OCGT, or existing capacity.

Either approach could be used to extend DECC's existing modelling.

Characteristics that drive these impacts

In summary:

- the size of the capacity adequacy benefit is largely based on the capacity credit of the additional technology;
- the capacity credit is a function of the correlation of a technology with peak demand, and whilst all technologies are uncertain to some degree, variable technologies such as wind and solar typically are relied upon less to generate during the peak period in the UK; and,
- the capacity credit declines for those technologies whose output is correlated with existing non-dispatchable technologies on the system.

Characteristics that drive these impacts

3.4 Balancing impacts

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. The drivers of these costs are set out in Table 12.

Table 12. Drivers of balancing costs

Technology	Power system
Uncertainty	Flexibility
Average load factor	Balancing area size
Plant capacity	Largest infeed loss
Contribution to system inertia	Efficiency of balancing process

Source: Frontier Economics

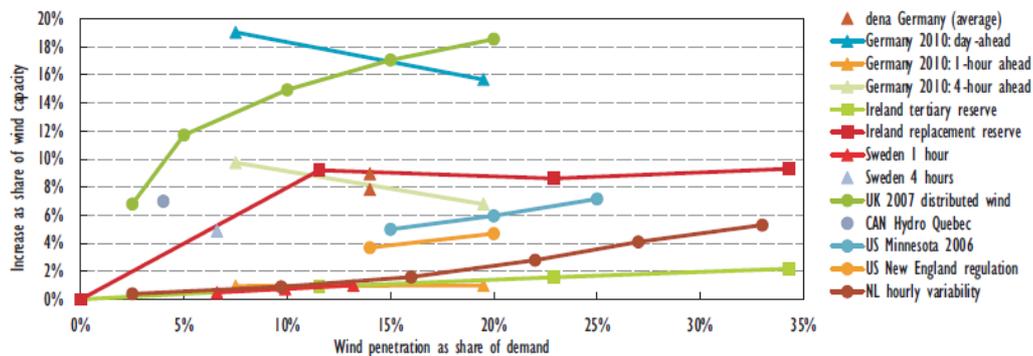
3.4.1 Uncertainty

All generation technologies suffer from uncertainty in their output. Even dispatchable technologies suffer unexpected outages. However, the system as a whole needs to be operated such that, barring extremely unlikely eventualities, it can continue to meet demand. The cost of providing a given level of resilience increases if the sources of generation that make up the system become more uncertain.

Variable renewable sources of generation tend to exhibit greater uncertainty of short-term output than dispatchable technologies. Although this uncertainty may be lost in the noise at low penetrations, at higher penetrations, these technologies can create a significant source of overall uncertainty and, by extension, require larger, more rapid and ultimately more costly actions to balance the system. Other technologies, including demand side response and storage, may allow the system to operate securely despite uncertainty in output by offering greater system flexibility.

Characteristics that drive these impacts

Figure 14. Increase in reserve requirements as a function of wind power penetration



Source: IEA (2014)

A key implication of increased uncertainty of output, or equivalently a larger share of output coming from more uncertain technologies, is that more generation capacity must be held in reserve to cover unexpected shortfalls. Figure 14 shows the increase in the balancing reserves required under different levels of wind penetration, and is based on results taken from a range of studies collected by the IEA (2014). The increase in the reserve requirement is expressed as a share of wind capacity.

For the vast majority of the studies, the reserve requirement increases with penetration of wind. The estimated increase in the requirement varies by study, but the increase generally does not exceed 10% of wind capacity at wind penetration levels of no more than 35%. Notably however, a UK study (Strbac, 2007) provides an important outlier, suggesting increases in the reserve requirements approaching 20% of wind capacity. However, it was noted in a more recent paper co-written by the author that this did not reflect more recent improvements in forecasting (Holtinen et al, 2011b).

3.4.2 Forecasting

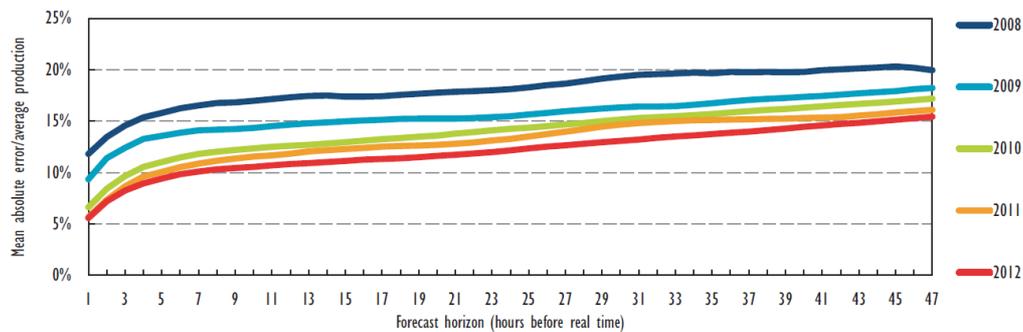
Although we discuss forecasting separately here given its importance, it is really just a means of reducing uncertainty. The ability of forecasting to help mitigate uncertainty depends on:

- how accurate the methods used are;
- how far in advance the forecast is trying to predict the output - on the hour-ahead forecasts are around three times as accurate as forecasts for one day ahead.; and
- the size of the area for which the forecast is generated – errors will tend to cancel each other out to some extent, so larger areas allow for relatively precise prediction.

Characteristics that drive these impacts

Figure 15 below shows both how, in respect of wind, forecasting accuracy improves closer to real-time and how forecasting has become more accurate over recent years. These year-on-year improvements in forecasting are due to both methodological improvements and increased observability of wind.

Figure 15. Improvement in wind power forecasts in Spain, 2008-12



Source: IEA (2014)

Other technologies tend to exhibit less mature forecasting methods than wind, but may nevertheless benefit in the same way if their uncertainty can be reduced:

- If the skies are clear, solar PV output can be predicted with high accuracy, because it is determined by the position of the sun, which is easy to calculate. However, in the case of snow or fog, rare but high forecast errors can take place (IEA, 2014), hampering the accuracy of daily forecasting.
- The output of wave can be predicted up to five days ahead with the use of numerical wave models, although more work is required to improve the accuracy of these predictions. Oceanic buoys can be used to get advance warning of waves arriving from far locations, allowing a significant share of hourly variability to be predicted a few hours in advance.
- In contrast, tidal is predictable – its output can be predicted many years in advance, allowing future electricity output to be known accurately at hourly or smaller timeframe (ECI, 2005).

3.4.3 Largest infeed loss

Although output uncertainty drives much of the use of balancing reserves, the total quantity of reserves that must be available is currently determined by the size of the largest potential infeed loss. Consequently even relatively certain technologies have the potential to increase balancing costs if they increase the size of the largest infeed. We have already discussed the impact that this has on the capacity requirement in the capacity market, and how this could be valued.

Characteristics that drive these impacts

However, there is an additional operational cost of keeping reserves on standby which needs to be accounted for. This factor is particularly relevant to nuclear, which typically has some of the largest plant capacities of any generation technology.

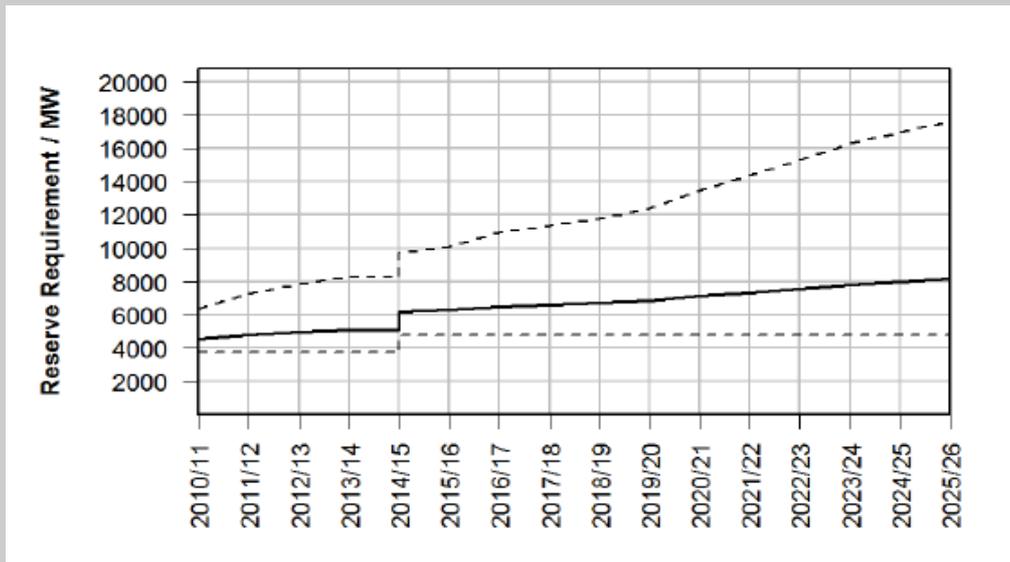
National Grid's projected reserve and frequency response requirements

National Grid examines the future of balancing costs in the context of operating reserve requirements necessary to ensure that sufficient generation or flexible demand is available at all times to manage uncertainties around generation output and demand fluctuation. This is set at such a level to ensure there is less than a 0.3% (1 in 365) chance of being unable to maintain security of supply from approximately 4 hours ahead of time.

Figure 16 below shows how reserve requirements were expected to rise when this forecast was published in 2011. The three lines refer to wind load factors of 0%, 30% and 100%. Altering this assumption helps to illustrate how greater reliance on uncertain generation capacity results in a higher operating reserve requirement. On windy days, when wind load factors are high, more operating reserve is required to manage the risk of a change in wind output from four hours ahead.

With an assumed load factor of 30%, reserve requirements were projected to increase from around 5GW today up to 8GW in 2020/21, owing to a combination of larger potential in-feed losses and greater deployment of uncertain generation capacity.

Figure 16. Operating reserve requirement under National Grid's Gone Green Scenario



Source: National Grid Operating the Network in 2020

Characteristics that drive these impacts

Frequency response requirements, which cover even shorter term balancing (second by second), are also expected to increase, and again this is due to both increased wind penetration and larger in-feed loss from bigger generation units.

It is worth noting that these reserves are different from the issue of capacity adequacy discussed earlier and relate instead to the need to hold capacity in active standby for use in case there is a shortfall in output elsewhere. Whereas the capacity adequacy needs of the system will be stressed when output from variable generation is low, the reserve requirement is likely to be stressed when the output from uncertain generators is high, because the system must then cope with the risk of losing a lot of this output at short notice. As a result, those periods with highest reserve requirements due to output uncertainty may well correspond with those periods where there is a relatively large amount of unused capacity on the system available to act as reserve.

3.4.4 System inertia and reactive power

Another feature of the generation technology with implications for the costs of balancing the system is the manner and extent to which it contributes to system inertia. Conventional ‘synchronous generators’ share a direct electromechanical link to the grid and its frequency. In the event of an imbalance in energy supply, any change in system frequency will be resisted by the significant rotational inertia of these generators, buying time for the imbalance to be corrected. For non-synchronous generators, there is no direct electromechanical link with the grid and so no natural contribution to system inertia that helps the system resist frequency deviations.

The Grid Code requires that grid-connected generation makes some contribution to inertia and so even non-synchronous technologies like wind and solar will typically incorporate power electronics designed to do so. In the case of wind this ‘synthetic inertia’ can be provided by the rotational inertia of the turbine blades themselves. For solar generators this facility is provided by very fast response energy storage which, rather than providing inertia in the mechanical sense, helps resist frequency changes by altering the level of output.

A study commissioned by the Irish system operators (EirGrid/SONI, 2010) found that the Irish system, in its current shape, could, at most, cope with 50% of capacity coming from non-synchronous sources (including wind power and net imports over DC interconnectors). As this operational limit has already been reached, EirGrid is implementing a programme to increase the potential penetration of non-synchronous generation to 75%.

Another study found that in Germany, the system may require a minimal level of conventional generation to provide a number of necessary system services (CONSENTEC, 2012). Currently, voltage control requirements mean that the required minimum level of generation from conventional sources is between 4

Characteristics that drive these impacts

and 8 GW for strong wind power generation with low load, and between 12 and 16 GW for strong wind power generation with strong load. The study suggests that this lower bound could be lowered if new procedures are found to provide system services, but did not consider these options in detail.

National Grid has identified projected declines in system inertia as an operational challenge between now and 2035, with periods of low demand and/or high asynchronous renewable generation being the most problematic. Critical to projections of future system inertia in GB are assumptions on the construction of new nuclear plant, which provide considerable inertia when running. Faced with the challenge of falling inertia over the coming decade, National Grid are developing a variety of new management services that would, for example, allow for very rapid changes in power supply and demand in response to frequency changes. These services may support new types of technology, like large-scale battery storage, as a means of preserving system security despite lower levels of inertia.

In addition to system inertia, the synchronous nature of generation is also important to the provision of reactive power services. However, unlike system inertia, reactive power requirements are specific to the local area and so it is very difficult to assess the impact of a particular technology on the needs for reactive power services at the system level. At an aggregate system level the requirement for reactive power is expected to increase as overall demand and the size of the network increases.

3.4.5 Power system factors

The technology characteristics described above help define the extent to which any technology will pose a challenge to the System Operator when attempting to maintain system stability in the short-run. However, the cost associated with overcoming these challenges will reflect the nature of the power system itself and the efficiency with which the System Operator is able to use the resources available to it.

The short-term flexibility of the system is key. A system that has sizeable capacities of plant that can provide low-cost balancing services, potentially including pumped hydro, storage, interconnection and demand-side response, will be able to accommodate uncertain generation capacity at far lower cost than a system that only has recourse to more expensive means of balancing.

In addition to the features of the technology itself, the scale of the challenge facing the System Operator will be affected by the scale of the network that it needs to be balanced. A large network will tend to be more resilient to the uncertainty of a specific plant because that plant represents a comparatively small share of total generation. Also, large networks will tend to benefit from greater geographic dispersion, which can help to avoid correlation among the deviations in plants' output from expected levels due, for example, to local weather patterns.

Characteristics that drive these impacts

Finally, even a large system with ample access to low-cost balancing sources may exhibit high balancing impacts where the System Operator fails to efficiently exploit the balancing resources available to it. Key aspects of system operation highlighted in the literature include the use of interconnection capacity for balancing, the use of improved forecasting methods, shorter gate closer windows and closer to real-time scheduling of balancing operations (see Sijm, 2014). In addition, a smarter power system may also allow the System Operator to access services, such as aggregated demand-based frequency response or coordinated curtailment,²⁴ that have not previously been feasible.

²⁴ We understand that the Spanish SO uses directed curtailment of wind generation to help alleviate ramping costs elsewhere in the system.

Implications for the UK costs of system operation

Balancing actions in the UK market are achieved both through the balancing market, which enables National Grid to request variations to a generators’ output, and through a series of balancing services contracted by National Grid. Approximately 20 such balancing services are contracted for.

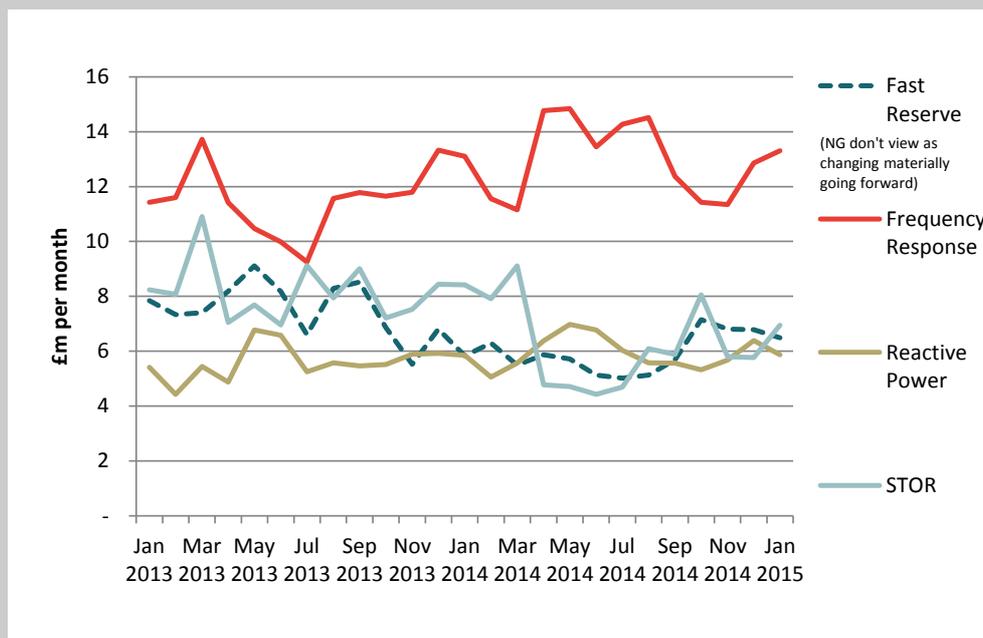
In order to estimate the total cost of balancing impacts it is necessary therefore to consider both the cost implication for these services, and the cost of actions orchestrated through the balancing market.

Our discussions with National Grid have identified 4 key contracted services that are considered material and are expected to change going forward. These are

- Reactive power
- STOR (Short-term operating reserve)
- Frequency response
- Inertia

Figure 17 sets out expenditure on these services in recent years. Note that inertia is not included as there is currently no bespoke service for inertia. However, faced with the challenge of falling inertia over the coming decade, National Grid are developing a variety of new management services that would help dealing with inertia, for example services that allow for very rapid changes in power supply and demand in response to frequency changes.

Figure 17. Key Balancing Services as highlighted by National Grid



Source: National Grid

Characteristics that drive these impacts

Figure 18 summarises our discussion with National Grid on the drivers behind these costs and its own estimation of which services' costs are likely to be most affected.

Figure 18. Drivers of change for important future balancing services

	Future significance	Drivers	Providers
Reactive power	<ul style="list-style-type: none"> Small increase expected in future, as generation becomes more dispersed. 	<ul style="list-style-type: none"> Location of gen & demand. Amount of reactive assets on transmission network. Low demand on dist. network. 	<ul style="list-style-type: none"> Obligatory for transmission connected generation over 50MW. Reactive assets.
STOR	<ul style="list-style-type: none"> Currently 3.5GW contracted. Small increase expected in future. 	<ul style="list-style-type: none"> Uncertainty of generation and demand (forecast accuracy) ~4 hours ahead 	<ul style="list-style-type: none"> Plant (> 3MW) contracted to deliver as instructed within 4 hours, for 2 hours.
Frequency response	<ul style="list-style-type: none"> Expected to significantly increase in future, and require even faster response times (~2 secs). 	<ul style="list-style-type: none"> Variability & uncertainty in net demand over very short timescales (2-30 secs). Largest credible loss. Low demand periods. 	<ul style="list-style-type: none"> Plant with ability to respond in very short timescales.
Inertia	<ul style="list-style-type: none"> Expected to significantly increase in future. Problems arise when the Rate of Change of Frequency (ROCOF) is too high. 	<ul style="list-style-type: none"> Proportion of generation that is non-synchronous. 	<ul style="list-style-type: none"> Synchronous generation with ability to tolerate fast changes in frequency (e.g. Ireland has set max of 1Hz per sec).

Source: Frontier Economics and LCP

The costs of balancing actions procured through the balancing market following 'gate closure' would need to be considered alongside and in addition to the National Grid services listed above as part of a comprehensive accounting of balancing impacts. Assuming that the balancing market is competitive, the cost of balancing actions procured through the market should be a reasonable indication of the cost to the system of such actions. However, as noted earlier, balancing services revenue may also help to cover the fixed costs of building flexible capacity. Within our framework of five elements for assessing whole system impacts, this would need to be stripped out of the market cost, if relevant, to isolate the cost of the balancing actions themselves, as opposed to the cost of the corresponding capacity.

In summary:

- all technologies suffer from uncertainty, however variable technologies exhibit greater uncertainty of short-term output than dispatchable technologies;

Characteristics that drive these impacts

- improvements in forecasting and the size of the balancing area can reduce this uncertainty;
- increases in non-synchronous generation reduces the system's natural inertia, or resistance, to changes in frequency; and,
- the technology mix is therefore important determinant of the volume of balancing contracts procured by National Grid and the balancing actions taken.

3.5 Network impacts

This last group of impacts covers costs related to power flows through the transmission and distribution networks. The drivers of these costs are set out in Table 13.

Table 13. Drivers of network costs and losses

Technology	Power system	Location
Variability	Flexibility	Distance from load
Average load factor		Level of congestion
		Local correlation of output and demand
		Correlation with local non-dispatchable generation
		Distributed

Source: Frontier Economics

As can be seen from the above, a number of these key drivers will be specific to the placement of the generation capacity within the distribution or transmission network. Consequently it can be difficult to generalise as to the impacts of additional generation capacity on network infrastructure requirements, losses and congestion management in the absence of location specific information.

All technologies face location constraints. However, it is clear that some technologies have siting considerations that draw them away from locations that could help to minimise network costs more than others. Renewable sources may be driven to locations distant from load by the relative abundance of renewable resource, gas plant need good access to the gas network, and nuclear may be forced to locate away from population centres for reasons of acceptability or to secure necessary cooling resources.

Characteristics that drive these impacts

Longer transmission distances imply both larger infrastructure costs and greater losses. These effects will scale with the plant's capacity and load factor and may be further compounded by variability, which implies that the associated network infrastructure is used below its technical capacity for periods of time.²⁵

The marginal infrastructure costs needed to support additional generation capacity will also depend on how congested the relevant network infrastructure is already. A system with ample spare capacity may be able to support additional generation with relatively little need for further infrastructure, while a network close to its limits may need significant reinforcement to accommodate even small quantities of capacity.

For wind and solar technologies there is a trade-off to be made between the value of the resource and the cost associated with a specific location. In the UK context, many of the best quality wind sites are far from the existing network, for example in Northern Scotland or offshore.

Solar can be more flexible in terms of its siting decisions. Solar resource is less geographically varied, but south facing fields present the optimal conditions. In practice, the new solar plants in the UK are constrained to be located within a relatively short distance from the grid to limit the connection costs, and generally developers try to locate the plants in areas where the distribution network can accommodate the extra voltage to avoid reinforcement costs.

Non-renewable generators also face locational constraints, as described below. However, network infrastructure has, in many instances, already been built up in areas where these constraints are satisfied. As noted in the box on p.28, existing technologies tend to benefit from the fact that existing infrastructure has been designed to service them. Large thermal plants require proximity to fuel supply infrastructure, a large free surface (several tens of hectares), as well as soil homogeneity and resistance required to cope with the heavy loads of plant structures. Unabated coal plants can no longer be legally built, but would otherwise be unable to site themselves near to large population centres due to pollution constraints. Gas power plants will want to locate on the gas grid, but benefit from the fairly extensive gas network that already exists in Great Britain. Contrast this with CCS, where the relevant network infrastructure does not currently exist. The location of nuclear power plants is constrained by certain specific siting requirements related to security; most notably the need for a large load centre and a cooling resource in the vicinity of the plant (OECD-NEA, 2012).

²⁵ This consequence of output variability is exactly analogous to the utilisation effect for generation capacity, but here is applied to network capacity.

Characteristics that drive these impacts

3.5.1 Distributed generation

Distributed generators that are co-located with demand, such as solar and wind, can help to reduce and flatten net demand profiles if their output is reasonably correlated with demand. Where this is the case, they may actually help to free up network capacity that was otherwise in use and thereby lower network costs.

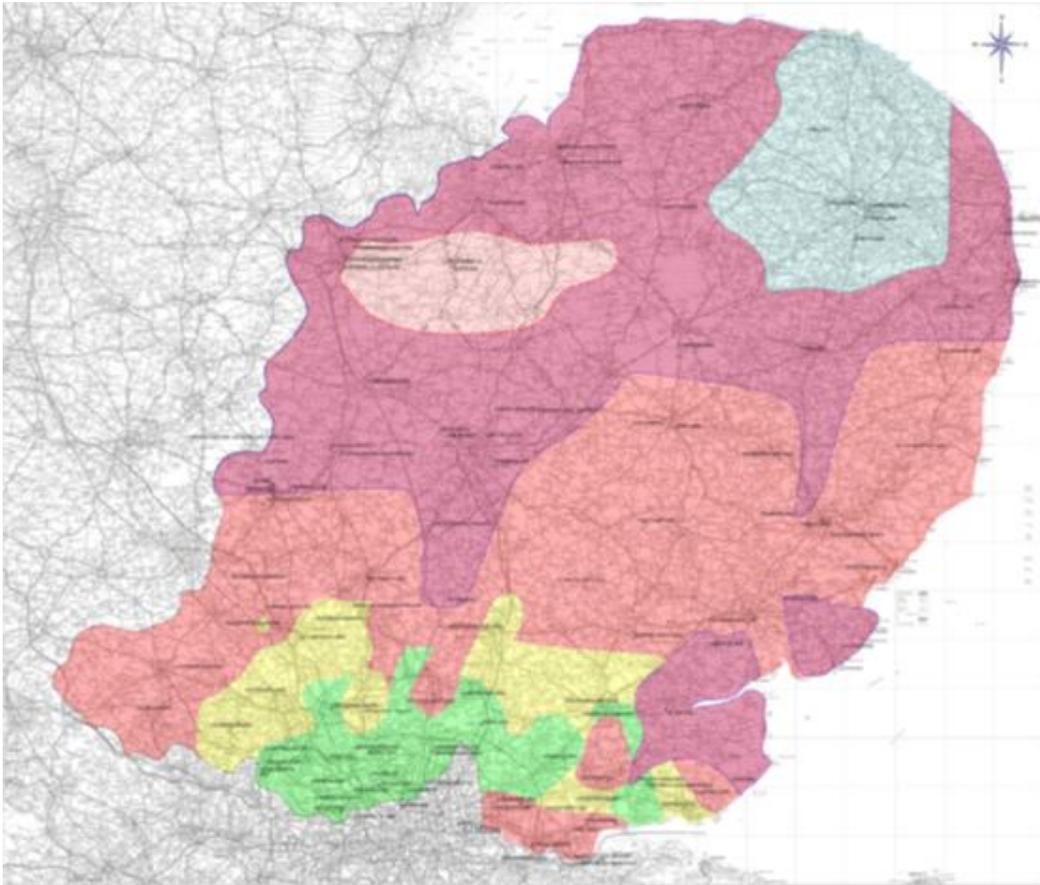
Our discussions with DNOs have highlighted how problems can arise where non-dispatchable and highly correlated sources of generation cluster on any part of the network. The correlation between such generators exacerbates the variability of any single source of generation, meaning that the network must deal with larger net flows and hence potentially require reinforcement. In the case of distributed generation, poor correlation between output and demand, clusters of correlated generation or both can contribute to voltage problems and the reversal of power flows, potentially implying infrastructure costs to adapt the network.

One example is solar PV, where depending on the penetration level, the impacts of deployment can be positive or negative for the power system. While lower penetration levels may release some capacity off the network and thus reduce network losses and reinforcement costs, at higher penetrations it may trigger problems due to reverse power flows.

In regions with high deployment of PV it might be necessary to upgrade infrastructure to provide capacity to feed generation up to higher levels of voltage. In Southern Germany, where the amount of distributed solar generation is high, the size of infrastructure is determined by the power flows from the distribution to the transmission network. The scale of existing infrastructure and availability of alternative solutions are the factors that determine the level of distributed generation at which these issues arise (IEA, 2014).

In the UK there is evidence to suggest that large parts of the distribution network are already congested. In other words, they will require reinforcement before new connections are possible. This is illustrated in Figure 19 where we can see significant saturation of the network highlighted by the areas in red. The amber and green areas indicate limited or spare capacity respectively. Connection is however possible everywhere, and in fact DNOs have to offer a connection. However, in the red areas reinforcement is likely to be required, suggesting the connection charge for new generation will be much higher.

Figure 19. Generation capacity map for the Eastern distribution network



Source: UK Power Networks

The costs associated with the connection of different technologies in a constrained part of the network can also vary dependent on the connecting technology. The problems created by variable technologies for DNOs are concentrated in relatively few days of the year. These rare events still trigger investments by the DNOs given their statutory requirements.

However, the rarity of the events does create the possibility of alternative potentially more cost-effective solutions. In the case of a baseload generator capacity constraints on the network are likely to be met every day. For variable generators DNOs are exploring more cost-effective ‘smarter’ options. For example, the cost to the DNO of a flexible connection agreement, where the generator pays lower connection costs but could be curtailed in the rare event of network problems, may be lower than network reinforcement. In addition DNOs are exploring options such as local storage and real-time thermal ratings to improve the management of the network and delay potential network investments. As a result, network costs associated with distributed generators have the potential to fall in future, although, in the case of a flexible connection

Characteristics that drive these impacts

agreement, this saving will potentially be offset by a reduction in displaced generation costs.

In summary:

- it is difficult to generalise about the impact on network costs and losses without specific location information;
- technologies will differ to the extent they face location constraints which may prevent them from locating on parts of the network that lead to the lowest network costs, with renewable sources more likely to be driven to locations far from load and the existing network; but,
- distributed technologies can reduce losses and lead to avoided transmission investment where their output is well correlated with local peak demand although this is frequently not the case.

3.6 How do different technologies perform?

We have summarised the evidence in the literature and from stakeholder conversations enhancing our understanding of how the characteristics of different generating technologies and the power system drive the different components of technologies' whole system impacts. Table 14 summarises the driver relationships we have covered in a single table, showing which drivers influence capacity adequacy, balancing and network impacts respectively.

As a conclusion to this section we draw together these findings and apply them to a broader range of technologies as set out in the matrices below. To do this we have grouped technologies where we expect their system impacts to be similar, and then highlighted the important characteristics for each of the technology drivers. We have focused on the categories of technologies which affect the three main impact categories covered in the literature: capacity adequacy; balancing; and, network costs and losses.

Characteristics that drive these impacts

Table 14. Map of drivers against cost components

Driver	Capacity adequacy	Balancing impacts	Network impacts
Technology			
Variability	✓		✓
Average load factor	✓	✓	✓
Correlation with output and demand	✓		
Uncertainty		✓	
Contribution to system inertia		✓	
Power system			
Cost of capacity	✓		
Flexibility		✓	✓
Balancing area size		✓	
Efficiency of balancing process		✓	
Location			
Distance from load			✓
Level of congestion			✓
Local correlation of output and demand			✓
Correlation with local non-dispatchable generation			✓
Distributed			✓

Source: Frontier Economics

Characteristics that drive these impacts

3.6.1 Interpreting the matrices

For each technology/technology group, we have applied these drivers to identify the implied system impacts. The results are summarised in the matrices shown in Table 15.

The matrices largely focus on the technology drivers, although we have also noted the degree to which technologies face a location constraint, which is an important driver of the network costs.

Care needs to be taken in the interpretation of these matrices. They describe the causal link between a particular technology and a system impact driver. However, as we have set out, the importance of the technology characteristic will very much depend on the system to which the new technology is added. For example:

- The impact of the variable renewable technologies such as wind and solar will change depending on the degree of flexibility assumed in demand or existing generation. Given the importance of system flexibility, we have drawn together the key messages from this report in the box later in this section.
- The impacts of inflexible baseload technologies may not drive large system impacts against a background of inflexible demand. However, if it is added to a system in need of flexibility i.e. one already with large amounts of baseload or other variable generation, then system impacts may be higher.

Understanding the drivers help to identify the impacts in different scenarios. They do not in themselves directly determine their relative scale.

3.6.2 Key messages from the matrices

Assuming technology and power system characteristics like those observed in the UK currently,²⁶ we can draw some conclusions about the types of technologies most likely to drive system impacts:

- **Capacity adequacy** - those technologies with variable outputs which are poorly correlated with demand but highly correlated with the existing non-dispatchable generators will have the lowest capacity adequacy savings. This can be mitigated by combining technologies which complement each other with uncorrelated output e.g. there is some evidence on the value of combining wind and solar.

²⁶ See Table 5 and Table 6 for further details.

Characteristics that drive these impacts

- **Balancing costs** - non-synchronous, inflexible and uncertain generators drive the highest balancing costs. The value of additional very flexible generation is to reduce balancing costs, though this benefit will be limited without increases in variable generation.
- **Network costs** – all technologies have location constraints to some extent, but the nature and severity of these constraints differ. Technologies that face strict locational constraints, especially where these constraints take the generator away from centres of demand, are less likely to be able to connect to unconstrained parts of the network. Distributed forms of generation may actually help to lower network costs where this generation works to lower net demand. Local correlation with the output of other generators tends to increase network costs, although variable output can still create opportunities for cheaper ‘smarter’ solutions than traditional reinforcement.

The importance of system flexibility

Much of the evidence focuses on the impact of adding technologies to a system configured for the operation of traditional thermal technologies and with inflexible demand. And as such, the system may not always be well equipped to accommodate new sources of variable and uncertain generation. However, despite this the literature does stress the importance of the system context, or counterfactual, for determining the nature and scale of system impacts that are attributable to a particular technology. This section draws together the points stressed throughout this report.

NewThe availability of new types of flexibility in future could change significantly the impact of variable technologies:

- **Improving the flexibility of the power plant mix** – this could involve shifting the balance of the mix away from CCGTs towards OCGTs or other small-scale flexible generation.
- **Enhancing demand responsiveness** – this could be the result of increased consumer engagement and take-up of flexible technologies such as heat pumps and electric vehicles, or due to enhanced participation from commercial and industrial customers.
- **Development of cost-effective storage** – examples could include the commercialisation of large-scale or distributed batteries, or the development of new pumped hydro projects.
- **Extending and reinforcing grid infrastructure** – grid infrastructure can be deployed creating new capacity for connections in previously

Characteristics that drive these impacts

hard to reach, constrained parts of the networks.

- **Introducing more flexible system and market operations** – new roles and responsibilities may improve the management of the system in future, in particular on distribution networks, where new smarter solutions could improve the efficiency with which existing capacity is used. These include flexible connection agreements, local storage and real-time thermal ratings.
- **The variable technologies themselves can evolve** – variable technologies could improve their forecasting further, or smooth out their profile by for example adding storage to the site. They may also be able to utilise the technical capabilities of their plant to participate more in balancing services e.g. a wind farm could provide frequency response through the tilting of its blades.

These developments in system flexibility will have an impact on each of the impact categories in our framework. If we assess the addition of new variable generating technologies against a background of flexible demand, generation and network management, the assessment against each impact category could change:

- **Technology direct costs** – these will change over time, but will also need to reflect the costs of technological innovations.
- **Displaced generation costs** - the impacts of following a variable load due to cycling inefficiency of the residual thermal fleet will be reduced.
- **Capacity adequacy** – available storage capacity can effectively shift output from variable generators to peak periods, or demand-side response can shift the peak to better match the variable load, reducing the need to build new thermal generation to meet system security constraints in peak hours.
- **Balancing** – balancing costs will be lower with a greater pool of low cost options offering fast flexibility to balance the system and maintain inertia.
- **Network costs** – flexible technologies can operate to make better use of available network capacity when variable generation output is low. New network investments can be avoided if demand-side response is available when variable output exceeds statutory limits on local distribution networks.

Equally, these new flexible technologies can be assessed in exactly the same framework. For example, the addition of new demand-side technologies will bring benefits in terms of reduced balancing and network costs.

When analysing technologies' whole system impacts it is therefore important to consider the role of flexibility. This could be achieved by comparing the system

Characteristics that drive these impacts

impacts from an incremental technology in a system with and without flexibility. Or by assessing the impacts when a technology is added to the system and the system is allowed to re-optimize over time.

In the latter case, this will show how system re-optimization can reduce system costs over time, but also correctly account for the cost of that re-optimization. By that we mean, the costs of new flexible generators and demand-side technologies over and above what would have taken place anyway in the reference case.

Characteristics that drive these impacts

Table 15. Mapping of drivers to technologies

		Capacity adequacy		Balancing costs			Network costs	
Technology		Variability	Correlation with demand	Correlation of output with the rest of the system	Uncertainty	Contribution to system inertia	Flexibility	Location constraints
Fossil-fuel thermal	Gas CCGT						Moderately high	
	Gas OCGT	Dispatchable	Dispatchable	Dispatchable	Dispatchable	Synchronous	Very high	Cooling, fuel logistics only
	Coal						Moderate	
	Biomass						Moderate	
CCS		Dispatchable	Dispatchable	Dispatchable	Dispatchable	Synchronous	Expected low-moderate, but subject to design specification	Fuel and CO ₂ network
Nuclear		Dispatchable	Dispatchable	Dispatchable	Dispatchable but size may increase reserve requirement	Synchronous	Low/moderate (dependent on technology)	Cooling and security, local acceptability limited to existing sites
Transmission connected wind	Onshore >5 MW	Stochastic, but less peaky than solar	Weakly positive in the UK	No correlation with solar and tidal, and combining with wave brings diversification benefits as can smooth out variability	Low predictability but forecasting methods improving over time	Synthetic inertia only (increase tech direct costs)	Curtailment	Wind resource
	Offshore		Weaker than onshore as more output at night					

Source: Frontier Economics

Characteristics that drive these impacts

Table 15. Mapping of drivers to technologies (continued)

Technology	Variability	Correlation with demand	Correlation of output with the rest of the system	Uncertainty	Contribution to system inertia	Flexibility	Location constraints
Large scale CHP	May vary with heat demand	Dispatchable	Dispatchable	Dispatchable	Synchronous	Heat demand constraint	Heat demand
Distributed solar	Day-night and seasonal cycles, peaky - concentrated in fewer hours in the year than wind	Negligible in the UK	Local correlation may be problematic	Predictable on a yearly basis, not daily. Generally easier to predict than wind but factors like fog or snow can cause rare but very large errors	Power electronics	Curtailement	Low
Distributed wind	Stochastic, but less peaky than solar	Weakly positive in the UK, but in very high demand can be negative (anti-cyclone effect)	Local correlation may be problematic	Low predictability but forecasting methods improving over time	Synthetic inertia only	Curtailement	Wind resource
Distributed wave	Stochastic, but less peaky than solar	Weakly positive in the UK	Correlated with wind but different variability so diversification benefit	Can be predicted up to 5 days, but methods not ideal. Ocean buoys help to predict hourly variations	Power electronics	Curtailement	Wave resource

Source: Frontier Economics

Characteristics that drive these impacts

Table 15. Mapping of drivers to technologies (continued)

Technology	Variability	Correlation with demand	Correlation of output with the rest of the system	Uncertainty	Contribution to system inertia	Flexibility	Location constraints
Tidal	Varies little by season, but more at shorter timescales.	No correlation in the UK	No correlation with wind	Predictable	Synthetic inertia possible	Curtailement	Tidal resource
Hydro	Reservoir	Dispatchable	Dispatchable	Dispatchable	Synchronous	High	V. high geographical requirements
	Run of the river	Stochastic	Negligible	Negligible	Predictable	Low	
Small baseload (e.g. AD, biogas EfW)	Dispatchable	Dispatchable	Dispatchable	Dispatchable	Can be synchronous	Low-Moderate	Low (except geothermal)
Interconnection (DC)	Determined by wholesale price differentials	Determined by wholesale price differentials	Determined by wholesale price differentials	Determined by wholesale price differentials	Potential to share inertia across systems	Moderate	Proximity of markets

Source: Frontier Economics

Characteristics that drive these impacts

4 Who bears whole system impacts?

Summary

- This section focuses on the financial incidence of system impacts in the current GB regulatory framework, and hence the degree to which the resource costs we have identified are already taken into account by project developers.
- The degree to which developers bear system impacts varies across the different impact categories:
 - **Displaced generation costs** – both generators’ motivation to minimise their own costs and the incentives of the wholesale electricity market encourage least-cost generation by the power system. Generators are effectively remunerated for the value of their power, so to the extent that generators produce in less valuable hours of the day, this is directly reflected in the revenues of the plant. However, the presence of unpriced externalities and/or output-linked subsidies may prevent a fully efficient outcome.
 - **Capacity adequacy** – although there are energy market incentives to maximise output at times of peak demand, generators outside of the capacity market are shielded from their capacity adequacy impacts.
 - **Balancing costs** - the cost of actions taken to correct forecasting errors are passed back, albeit imperfectly, onto the parties causing the imbalance. This could be through the cost of trading in the intra-day market, direct exposure to cost-reflective imbalance prices, or a discount on a power purchase agreement. Where balancing costs are not reflected in the cash-out price, they are socialised through the BSUoS charges.
 - **Network charges** – charges on network users vary in the extent to which they are internalised to the developer or socialised. For example, distribution reinforcement costs are internalised through ‘deep’ connection charges, although for smaller on-site generators the costs are socialised. Transmission costs are partially internalised through locational charges, but constraint costs and losses are socialised.

Earlier we identified the components that make up the whole system impact. But who bears the resultant costs and benefits?

Understanding the incidence of these costs can be important for policy makers. In particular, where these costs represent an externality, then the market can

Who bears whole system impacts?

generally be encouraged to operate more efficiently if these effects are internalised by the relevant generator. Similarly, where Government support for generation is competitively auctioned, ensuring that wider system costs are borne by developers will help to ensure that those technologies with the lowest overall system costs secure the greatest level of investment. Where externalities are not internalised by developers, a policy intervention may be able to achieve superior outcomes and lower system costs.

This is not to say that full internalisation is always the best policy response. As noted previously, the current energy system benefits from significant sunk investments designed to facilitate efficient operation given the use of existing technologies. Long-term cost minimisation may actually necessitate a shift change in some aspects of the energy system and considerable investments, for example in carbon transport and storage infrastructure, which might more appropriately be socialised than imposed on the first user. However, it is important for policy makers to consider how costs are currently attributed, and whether this attribution reflects an appropriate distribution in terms of its implied incentives.

The literature we have reviewed as part of this study largely focuses on defining and assessing the scale of the impacts. It seldom investigates how they are allocated to different market participants. This section therefore draws predominantly on evidence gathered through stakeholder interviews, as well as desk research on current UK market design.

In the UK, some of the costs we have been discussing are already allocated to the developer, and therefore are included in the LCOE estimates produced by DECC. The most obvious examples are the cost of connecting to the network and the cost of extending the network to offshore wind farms. In this section we systematically address the question of who, in the UK context, bears each of the costs and benefits described earlier, and identify, where relevant, if the allocation of cost changes depending on the technology we are considering.

4.1 Displaced Generation Costs

The introduction of new capacity to a power system, and the re-optimisation of the system, will change both other generators' output and the resources used to generate that output. Consumption of some fuels may increase, while consumption of others may decline. Variable maintenance costs may change.

Displaced generation costs are best thought of as the net reduction in the variable costs of other generators due to the output from the additional capacity. They will predominantly reflect the cost savings associated with fuel and carbon permits that are no longer used by other generators.

These resource savings are a benefit to society and observed as a reduction in other generators' costs.

Who bears whole system impacts?

Because other generators' output and revenues are also affected by the addition of new capacity, they may be financially worse off, as they no longer receive the revenues (less variable costs) associated with the displaced power.

However, on the basis that prices are reflective of the short-run marginal cost of generation, this displacement does not represent the impact of an externality. Rather, it represents the outcome of a normal competitive market process where cheaper generation displaces more expensive generation.

Developers do not receive payments equal to the net effect on system generation costs, but nevertheless they face appropriate incentives.

Generators are incentivised to minimise their own costs and the power market helps to ensure that generation is dispatched to minimise the costs of generation. To the extent that this output takes place in less valuable hours of the day, or is curtailed, this is reflected in the revenues for the plant. And, as we have already set out, the displaced generation saving diminishes as the penetration of variable technologies increase. This reduction in value of their generation is reflected in the wholesale market revenues they receive. Therefore, the displaced generation savings are efficiently allocated in the market.

The question of whether generators internalise the impacts of their output's variability on the efficiency of other generators following variable load is less clear cut. However, there are reasons to believe that such variability-based efficiency impacts may be fed back to variable generators through a discount to the market price, or through PPA discounts.

Imagine the case of a particular generation technology that is only capable of generating electricity with a variable time profile that does not match the demand profile closely. The supplier willing to purchase this plant's output would need to be able to combine this output with the output from another (flexible) plant in order that their aggregate output more closely matched the demand profile. If it is costly to procure the corresponding flexible output because, for example, this profile requires the flexible plant to operate very inefficiently, the supplier will only be willing to purchase the original, variable profile at a discount. More precisely, this discount will need to be at least as big as the flexible generator's efficiency losses in order to induce the supplier to purchase the variable output.

This conceptual example of the need for a discount may be borne out in reality either in the form of a PPA discount (see box below) or through the dispatch and investment decisions of a portfolio generator that owns both variable and flexible generators. In either case, we would expect the variable output to be valued less and to be reimbursed accordingly.

Who bears whole system impacts?

Power Purchase Agreements (PPA)

Variable generators are able to trade directly in the wholesale market, but in doing so they would be responsible for managing the risk of imbalances through trading in the intra-day or balancing markets, and be liable to charges under imbalance settlement.

To avoid this risk, generators often sign long-term ‘offtake’ contracts with a larger incumbent that is more able to manage this risk within their portfolio or through their trading desk. Such contracts are called Power Purchase Agreements (PPAs).

This approach provides a secure route to market for the generators and a means of transferring the balancing risk to another party. In exchange, they receive the wholesale price for their power less a discount. In a competitive market for PPAs we would expect this discount to reflect both the overall value of the output profile and the cost of managing the imbalances.

4.2 Capacity adequacy

The direct cost of capacity investments are met by project developers. Depending on the regulatory design of the particular market, the fixed costs of new plants may be recovered by investors through the wholesale market, balancing markets, or through capacity remuneration mechanisms such as a capacity market or strategic reserve.

In the UK context the primary route for remuneration of fixed costs of new thermal plant will be through the capacity market, which is paid for directly from consumer bills. Plant not eligible to participate in the capacity market, in other words those receiving other low-carbon support payments, recover their fixed costs from a combination of the wholesale market and direct support payments.

When considering the impact of adding a certain quantity of capacity, the impact will be different depending on whether or not the capacity is remunerated through the capacity market. Simply put, if a technology does participate in the capacity market, capacity adequacy is not an externality. But for technologies outside of the capacity market, it is.

Generators outside the capacity market

If the new technology we are considering does not itself participate in the capacity market, (e.g. technologies receiving support to account for other externalities, such as other low-carbon support payments), capacity adequacy savings are realised through a lower target capacity purchased by the Government in the capacity market auction. The reduction in the volume of

Who bears whole system impacts?

capacity supported under the capacity mechanism reduces the total support costs under the mechanism directly.

However, such capacity adequacy savings will not affect the relevant plant's revenues if it is outside of the capacity market. Therefore, the current system does not fully internalise the capacity adequacy savings for those technologies.

To the extent that these generators still see market prices, and those prices reflect scarcity when the system is tight, then these generators will see some of the capacity value of their generation. However, this signal is likely to be weaker following the introduction of the capacity market, compared to an energy only market.

Generators participating in the capacity market

If the new technology we are considering is able to participate in the capacity market, in other words it is a new-build gas plant, then the impact will be different. Adding a new plant into the capacity market will add its de-rated capacity to the auction's supply, reducing the clearing price if the new plant displaces more expensive capacity that would otherwise have cleared.

Therefore generators within the capacity market do benefit from their contribution to capacity adequacy through the capacity market payment they receive, and face efficient incentives to contribute to capacity adequacy.

The capacity market only relates to the system's ability to generate power however, and some capacity may be required, not because of its contribution to peak output, but because of its contribution to system flexibility.

To the extent that the fixed costs of balancing plant are met through balancing services revenue and generators face the impacts of their effect on balancing requirements, they will internalise this aspect of capacity adequacy as well. To give an example, if an uncertain source of generation is often out of balance and these imbalances require more flexible capacity on the system, the generator will internalise this impact if:

- balancing services payments cover the fixed costs of this flexible capacity; and,
- the imbalance charges facing the uncertain generator reflect the cost of these balancing services payments.

4.3 Balancing Costs

Balancing costs arise because of the uncertainty of output. The actions taken to correct such forecasting errors play out in the wholesale market, or through the Balancing Market and other ancillary services procured by National Grid.

Who bears whole system impacts?

- Where generators' forecasts change prior to 'gate closure' such that they are not expected to meet their contracted output and face a risk of being exposed to imbalance settlement, they have a number of options. They can either trade in the intra-day market to purchase replacement power, or they could manage the costs by adjusting the output of other plant in their portfolio.

In some cases generators are insulated from having to make intra-day adjustments through a PPA. In this case, a portion of the discount applied to the price of their power can be viewed as compensation to the offtaker for bearing the costs of managing imbalance.

- Where these additional costs are met through actions taken in the balancing market or through formal balancing services payments after 'gate closure', these costs are passed back to the parties causing the imbalance through cost-reflective imbalance charging. Therefore, the additional system costs of balancing will be passed back to the generation responsible for causing the cost. This will be reinforced by the move to a more cost reflective single cash-out price in the UK.

However, it is not possible to perfectly reflect the cost of all balancing actions. For example, generators providing ancillary services such as STOR or BM Start-up are paid option or availability fees in addition to the utilisation payment made when called upon to generate. These fixed costs of ancillary services are reflected in imbalance prices, but only on an approximate basis reflecting historic utilisation.

In the current regime it is therefore reasonable to assume that there is an attempt within the regulations to internalise the costs of short-term balancing actions on the generator. However, this cannot be achieved perfectly, and to the extent that there are other costs not picked up by imbalance prices, these are recovered through BSUoS charges, which are socialised evenly across generators and load.

It is also important to note that small distribution connected generation, such as roof-top solar PV, do not have balancing responsibility. These effectively appear as negative demand, and the uncertainty of their output is borne by the relevant retail supplier. The supplier will incorporate any change in uncertainty associated with their customer demand into their forecasts, and will face charges for any resultant imbalances they face. They therefore directly bear the balancing cost of this type of generation, rather than the generators themselves.

4.4 Network costs and losses

These costs are borne by the relevant TNO or DNO but are passed back to generators and consumers through a series of charges. The extent to which these charges reflect the costs created by the payee varies, with some costs charged

Who bears whole system impacts?

directly to the responsible generator, while others are socialised across generators or consumers.

It should be noted that several network effects are the culmination of actions by a great many parties and it can be very difficult in practice to identify the share of the cost that is rightly attributable to any particular one.

Table 16 summarises the key charging mechanisms used to recoup network costs and losses, and the implications of these mechanisms for the internalisation of wider system impacts.

Who bears whole system impacts?

Table 16. Cost allocation for technologies connecting to the GB network

Network cost category		Cost allocation
Connecting to onshore transmission		
<i>Connection</i>	Internalised	'Shallow' charge - connecting parties pay for the cost of connection to the grid, including the cost of any particular assets that are for the sole use of that party.
<i>Reinforcement/extension</i>	Partial internalisation	The costs are recovered through use of system charges (TNUoS), which vary by location. Full internalisation can only be associated with a locational marginal pricing regime.
<i>Losses</i>	Socialised	Losses are effectively socialised across all generators. An assumed Transmission Loss Factor (TLM) is applied to the output/consumption of all generators/consumers no matter where they are located. Locational factors can in theory be applied though they are not currently.
<i>Constraints</i>	Socialised	Constraint management costs are socialised across all generators (50%) and consumers (50%) through BSUoS payments. Distributed generators do not pay.
Connecting to onshore distribution		
<i>Connection & Reinforcement/extension</i>	Internalised or socialised	<u>For generation needing formal connection:</u> 'Deep' charges – connecting parties pay for the cost of the connection and a share of necessary grid reinforcement. Connection must be at the point which minimises total cost, even if this means not connecting the generator at the nearest point. Distributed generators avoid TNUoS charges. <u>For small, e.g. roof mounted, generation:</u> Onsite connection is paid for by developer but reinforcement is fully socialised.
<i>Losses</i>	Socialised/ partly internalised	Losses are effectively socialised across all generators/load. An assumed Line Loss Factor (LLF) is applied to the output/consumption depending on its location.
Connecting offshore		
<i>Connection & Reinforcement/extension</i>	Internalised	The cost of offshore transmission is paid for by the developer of an offshore wind farm.

Source: Frontier Economics

Who bears whole system impacts?

4.5 Summary of cost allocation in the UK

We have summarised our assessment of the incidence of system costs in the UK in Table 17. In particular we have assessed the extent to which generators are incentivised to help minimise total system costs.

Table 17. Are generators incentivised to minimise system costs under the current market framework in the UK?

System Impact	Current GB system
Displaced generation costs	<p>The energy market encourages electricity to be generated at least cost, and thereby maximises any potential displaced generation benefit. Generators are effectively remunerated for the value of their power, so to the extent that generators produce in less valuable hours of the day, this is directly reflected in the revenues of the plant.</p> <p>It is worth noting that plant dispatch decisions can be distorted however by output-linked taxes or subsidies that don't perfectly reflect social costs.</p>
Capacity adequacy	<p>Depending on the technology, additional capacity will either be eligible or ineligible to participate in the capacity market.</p> <ul style="list-style-type: none"> □ If eligible, it will be encouraged to maximise its contribution to capacity adequacy up to the efficient level, and, □ If ineligible it will not be fully incentivised to consider its impact on capacity adequacy, for as long as it remains ineligible. <p>Therefore, the revenues for a low carbon generator in receipt of support payments will be less affected by the level of its contribution to system adequacy, than generators within the capacity market.</p>

Who bears whole system impacts?

Balancing costs²⁷	Balancing costs are generally internalised through imbalance charging for large generators, albeit imperfectly, which is now more cost-reflective following cash-out reform. Residual costs not covered by imbalance prices are socialised through BSUoS payments. This is not the case for small generators without balancing responsibility.
Network costs and losses	<p>Impacts are variously internalised and socialised.</p> <p>Distribution costs are internalised through 'deep' connection charges where formal connection occurs. However, the system impacts of smaller, on-site generation are fully socialised.</p> <p>If distributed generation exceeds local demand, the resultant transmission system costs would not be passed to the relevant distributed generator.</p> <p>Transmission impacts are partially internalised to the extent that TNUoS charges in part reflect location, but constraint management costs (which are charged through BSUoS) and losses are socialised.</p>

Source: Frontier Economics

²⁷ Note that given the definition of balancing costs used in our framework, these will not account for predictable variations in generator output.

5 Conclusions

This paper seeks to help DECC understand the whole system impacts of adding different types of generation capacity to the power system. It sets out a robust framework for considering these impacts that can inform extensions to DECC's Dynamic Dispatch Model.

The framework developed in this report borrows from and builds on the existing work in the literature. It has also been tested extensively through an interview process with industry participants, including academics, National Grid, Ofgem, DNOs and a range of developers and industry trade associations. This framework aims to ensure:

- that DECC is able to take informed decisions on some of the major, but sometimes implicit choices, that divide the literature;
- that impacts are comprehensively and consistently accounted for; and
- that any results from the modelling can be meaningfully interpreted after the fact.

For each cost category defined under this framework, we have also identified the underlying causal drivers which determine the size of any system impact and sought to map these to a variety of generation technologies.

The literature and interviews we have undertaken as part of this process, underline the fact that there are a wide range of different approaches to thinking about system impacts, and stress the importance of both the specific system context considered and the timeframe over which any assessment is made.

Despite this, there are some conclusions that hold in general.

- **A technology's system costs tend to increase with that technology's penetration level** – For example, both savings from displaced generation and contribution to capacity adequacy decline where the output from additional capacity is correlated with the output of a large amount of existing variable generation on the system. This can be mitigated in part through technological or geographical diversity.
- **Variable technologies' system costs can be mitigated by the presence of flexible technologies** – A system with greater access to sources of flexibility, whether through generation or on the demand side, is better able to cope with the addition of new variable technologies such as wind, solar or tidal. The system costs of variable generation can be reduced by adding flexible technologies to the system.

- **System costs are reduced over time through the process of re-optimisation** – For example, though the initial balancing costs associated with adding variable generation capacity may be high, these costs may be mitigated over time by subsequent changes to the rest of the plant mix. These subsequent changes support a process of re-optimisation, such that the system can more efficiently meet the operational challenges of using variable generation. The same process will also apply to network infrastructure, which can be reconfigured to accommodate new sources of supply, or to incorporate new ‘smarter solutions’ for managing network congestion, such as flexible connection agreements on distribution networks. This re-optimisation is not costless however and also needs to be properly accounted for in the overall assessment of system costs.
- **Finally, technologies themselves can adapt to alter their system impacts** – For example, through improved forecasting of variable technologies, or by utilising the technical capabilities of plant more effectively to provide balancing services.

The framework and causal drivers identified through this work are being used to inform developments to DECC’s Dynamic Dispatch Model. By incorporating an assessment of system impacts directly into DECC’s modelling, DECC will both be able to examine the system context most relevant to its analysis and account for how system impacts differ under alternative scenarios.

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Annexe 2: List of stakeholders consulted

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SSE

Western Power Distribution

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International Energy Association

Carbon Capture and Storage Association

Renewables UK

Solar Trade Association

British Photovoltaic Association

Renewable Energy Association

Environmental Services Association

AD and Bio-resources Association

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