System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications

Prepared for the Committee on Climate Change

19 October 2015

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Executive Summary

Policy Context and the Importance of System Integration Costs

The UK electricity industry is undergoing significant change. Amongst other policy developments, the Electricity Market Reform (EMR) programme has introduced two major new policies which alter how generators are remunerated: Contract for Difference (CFD) Feed-in Tariffs (FITs) are a new mechanism for subsidising low carbon generation, and a new Capacity Market (CM) provides long-term contracts and payments to generators for capacity that is reliably available. In essence, both these reforms involve the state taking an increasing role in planning the generation mix by awarding long-term contracts to generators. These mechanisms mitigate the long-term risks investors would face from future policy decisions on the generation mix and the rate of decarbonisation, if their revenues and ability to recover fixed investment costs were dependent entirely on market prices.

Against this background, this study commissioned by the Committee on Climate Change (CCC) from NERA Economic Consulting is concerned with the interaction between these reforms with other aspects of the prevailing market and regulatory arrangements in the electricity market, and in particular the system integration costs associated with alternative low carbon generation technologies. It draws on a modelling report produced in parallel by Imperial College London ("Imperial") for the CCC, which should be read alongside this report.

System integration costs exist because, when a change in the generation mix occurs, optimal generation despatch to meet energy demand changes, the generation investment required to maintain a given security standard changes, network infrastructure requirements change, and the requirements for ancillary services change. Hence, the Levelised Cost of Energy (LCOE) of competing technologies is not the only consideration government faces when estimating the costs of alternative generation mixes. The Imperial modelling estimates these system integration costs, and finds, amongst other things, that they are significantly higher for intermittent renewables than other forms of low carbon generation such as nuclear or CCS.

Therefore, if the government does not consider the whole system costs that competing technologies impose on the power system, consumers could end up paying more than necessary to achieve the objectives of decarbonisation and security of supply.

The Magnitude and Drivers of System Integration Costs

The modelling by Imperial estimates system integration costs for a range of technologies. These estimates for individual technologies are computed relative to each other. For instance, Imperial finds, in a scenario where the power sector decarbonises to 100gCO_2/kWh by 2030, that system integration costs for wind and solar are around £6-£9/MWh higher than for nuclear, and the integration cost for the more flexible CCS technology is lower still by up to £6/MWh.

More generally, Imperial finds that the level of system integration costs increase as the level of assumed decarbonisation rises and the amount of flexibility assumed to be provided by thermal plant, and alternative technologies such as demand response and storage, falls. For instance, as the power system decarbonises further to 50g/kWh, the magnitude of these system integration costs rises. System integration costs for wind and solar (relative to nuclear) rise to £13-£16/MWh in a 50gCO2/kWh scenario, and the system integration costs of CCS are around £11-£12/MWh lower than for nuclear. And in a scenario in which Imperial assumes a particularly high penetration of solar PV, the integration costs associated with this technology also rise relative to competing technologies.

The drivers of system integration include the need to pay for back-up plant to ensure security of supply when the wind is not blowing or the sun is not shining, and the need to pay for additional system flexibility through ancillary services. Indeed, one particularly important finding from this study relates to the interaction between system integration costs and flexibility. As noted above, higher levels of flexibility reduce integration costs. However, Imperial also finds that, unless the flexibility of the system increases compared to current levels, it will be challenging to reach very low levels of carbon intensity, such as between 50 and 100g/kWh, whilst maintaining the levels of ancillary services required in a system with high levels of low carbon plant. Additional flexibility may therefore be required through means such as improving the dynamic constraints and efficiency of thermal plant, adding electrical storage, demand response and interconnection to the system, and increasing the use of low carbon plant for the provision of ancillary services.

Policy Implications from the Imperial Modelling

Potential Reforms to Subsidy Arrangements

Despite Imperial's finding that system integration costs are material, this report explains that current market and low carbon support mechanisms do not fully reflect the effects of system integration costs. Many aspects of system integration costs can be signalled through energy market prices. However, generators supported by the CFD FIT are not exposed to market prices, as contract payments ensure they receive a fixed price for their output.[1] As a result, the CFD FIT auctions are based on bids driven by generators' own LCOEs, not the system integration costs reflected in market prices.

This report sets out a range of options to address the problem that, under current subsidy arrangements, neither government nor developers of low carbon plant fully take into account the impact of technology choice on the costs of the power system as a whole. These options include:

- First, the CFD FIT regime could better account for differences in the system integration costs associated with different technologies if the contract form were altered to provide generators with more exposure to market price signals. This would involve:
  - Allowing projects with CFD FIT contracts to participate in the capacity market auctions, to better account for differences in the capacity value of different low carbon technologies (discussed further below); and

[1] Assuming they are able to sell their output at the market reference price specified in their contract. CFD plant are still incentivised by the wholesale market price to the extent that they are able to receive a higher price for their output than the reference price.

  - Adjusting the structure of the CFD FIT contract to provide generators with stronger incentives to respond to wholesale price energy signals, such as by linking subsidy payments to capacity or expected energy production, rather than actual metered production, and/or changing the market reference price index.

- However, government may opt not to change the structure of the CFD FIT contract in these ways. Also, it may be the case that the wholesale prices to which generators are exposed does not fully reflect system integration costs anyway (see below). In these conditions, some further adjustments to CFD FIT allocation mechanisms may be required to account for differences in system integration costs across technologies. This would involve:
  - Identifying which components of the system integration costs associated with each technology are priced into their LCOEs; then
  - Adjusting the CFD FIT allocation mechanism to promote technologies that provide system benefits (or lower system integration costs). This might involve applying handicaps in the allocation procedure to technologies causing relatively high integration costs, or setting maxima/minima on the deployment of low carbon plant associated with relatively high/low integration costs, or adjusting the pot budgets towards technologies with lower system integration costs.

The notable exception to our finding that the CFD FIT mechanism prevents generators from being exposed the system integration costs they impose is network access charges. Distribution and Transmission Network Use of System Charges (DUoS and TNUoS) seek to charge generators in different places and of different technologies a price for network access reflecting the marginal cost their presence imposes on the networks. Hence, the system integration costs Imperial estimates to be associated with network reinforcement ought not to require a policy intervention, on the assumption that Ofgem keeps under review the extent to which these charges are cost reflective.

Potential Reforms to Market and Regulatory Arrangements

In theory, if prices reflected system marginal cost of production perfectly and in real time, and all generators were exposed to those prices, there would be no challenge associated with system integration costs. Hence, one way to ensure that generators account for system integration costs when taking investment decisions is to expose them to market price signals. Moreover, in principle, it is possible to signal the value of flexibility through market price signals, and thus encourage generators and other investors to provide the flexibility that the Imperial modelling suggests the system will need as it is decarbonised.

However, at present, power trading arrangements are limited in their ability to signal system integration costs, suggesting that some reforms may improve the extent to which system integration costs are factored into the prices faced by generators, and flexibility is rewarded adequately by the market.

- Allowing low carbon plant to participate in the CM would allow those low carbon technologies providing relatively a high amounts of firm capacity to benefit from doing so, and then factor these revenues into their CFD FIT auction bids;

- Similarly, to ensure providers of flexibility from innovative and small scale technologies can compete on an even-footing with larger scale generation plant, all such technologies should be able to participate in the CM on comparable terms;
- Shortening trading intervals from their current length of 30 minutes to, for example, 5 minutes would improve the extent to which the value of providing flexibility can be reflected in market prices;
- For flexibility required over shorter time scales, new ancillary service products may be required that ask providers to respond much quicker than has been required in the past, although we recognise this process is already underway; and
- It may be beneficial to create more transparent market mechanisms for procurement of ancillary services, such as in other markets where real time markets for ancillary services operate alongside wholesale markets for energy.

Conclusions

This study, and the Imperial modelling report that accompanies it, demonstrate that system integration costs are a material cost to the power system that should be considered when government takes policy decisions that influence the future generation mix. To ensure that these system integration costs are considered when new generation investments are selected, some reform of current subsidy mechanisms would be required.

Moreover, the Imperial modelling finds that the provision of flexibility by generators and others such as storage, demand response, interconnection, etc, will be essential for managing the costs associated with integrating low carbon plant onto the power system, and achieving high levels of decarbonisation. As discussed above, a range of reforms to current power trading arrangements would allow the value of flexibility to be better signaled through market mechanisms, allowing flexibility providers to realise the full value of their assets and services, and thus encourage provision.

1. Introduction

This report, commissioned from NERA Economic Consulting (NERA) and Imperial College London (Imperial) by the Committee on Climate Change (CCC), considers the policy implications of a modelling exercise undertaken by Imperial, which estimates the change in power system costs that results from the integration of low carbon generation technologies.

As described further in Chapter 2, the system integration costs for a particular low carbon generation technology (wind, solar PV, etc) is defined as a premium above those technologies' own levelised cost of energy (LCOE). In represents the additional costs of adjusting the generation mix and despatch patterns, network infrastructure, and the supply of/demand for ancillary services to accommodate marginal changes in the penetration and mix of low carbon plant. This chapter also describes the interactions identified by the modelling between estimated system integration costs and the supply of "flexibility" from means such as increasing the flexibility of thermal generation, DSR, electrical storage, and so on.

Chapters 3 and 4 then discuss the policy implications of the Imperial modelling results, focussing on what policy interventions might be desirable to achieve an economically efficient balance between low carbon generation that accounts, not only for the levelised costs of alternative technologies, but also for system integration costs. These chapters also discuss the implications of Imperial's modelling results in respect of the role for those technologies providing flexibility to the power system. Finally, Chapter 5 discusses possible implications for existing low carbon support mechanisms, and Chapter 6 concludes.

2. Background: Imperial's Quantitative Modelling of System Integration Costs

2.1. Estimating System Integration Costs

2.1.1. Approach to estimating integration costs

Imperial's modelling work defines the integration costs for each technology as a premium above its LCOE. This system integration cost exists because, when a change in the generation mix occurs, optimal generation despatch to meet energy demand changes, the generation investment required to maintain a given security standard changes, network infrastructure requirements change, and the requirements for ancillary services change.

As described extensively in Section 2.2 and Appendix C of the Imperial report,[2] Imperial's Whole Electricity System Modelling Approach (WeSIM) is a fundamentals model of the whole British electricity system that schedules and despatches generation to meet energy demand and ancillary service requirements, builds sufficient generation capacity to meet a required security standard, optimises investment in additional distribution and transmission network capacity, and despatches alternative balancing technologies such as storage, interconnection and demand side response (DSR).

Given there is no consensus in the literature on a single "correct" method for defining and calculating system integration costs, the Imperial modelling adopts three alternative methods to estimate a plausible range of integration costs (see Section 2.4 of the Imperial report for more detail). We summarise these in Appendix A to this report. However, they all involve estimating integration costs by adding a small amount of each low carbon technology and removing another, while achieving the same overall security standard and the same carbon intensity of the power mix.

2.1.2. Estimates of integration costs

Imperial's modelling shows that the system integration costs associated with low carbon generation are material and that they vary across technologies. As Figure 2.1 shows, the estimated integration costs are broken down into three categories:

1. Generation capital costs, which accounts for changes in the cost of installing the optimal mix of generation capacity following a change in the low carbon mix to maintain given emissions and security standards;
2. Generation operating costs, which accounts for changes in the cost of despatching the generation fleet following a change in the low carbon mix to maintain given emissions and security standards; and

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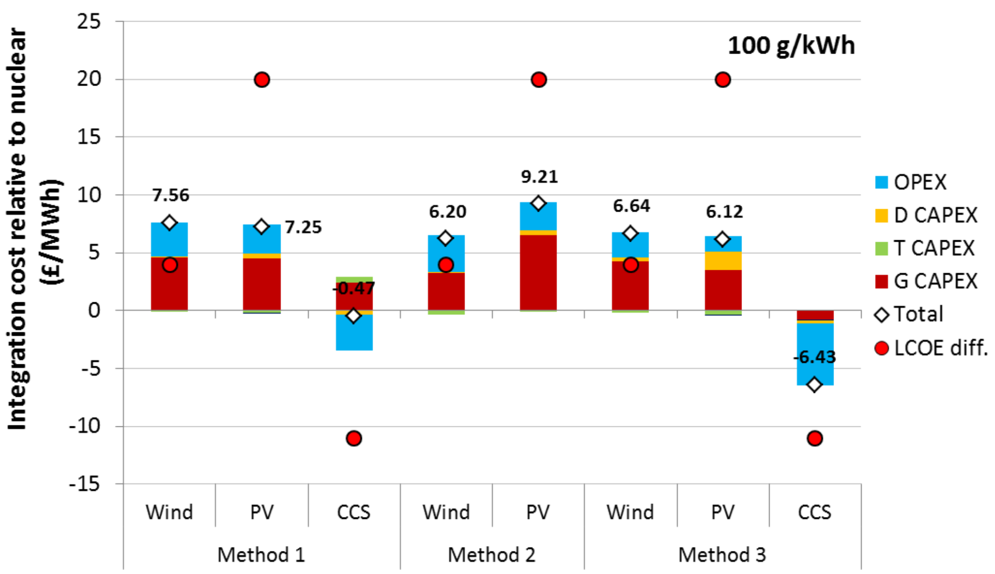
[2] Imperial College London, "Value of Flexibility in a Decarbonised Power System and System Externalities of Power Sector Technologies", report for the Climate Change Committee, October 2015.. Henceforth, the "Imperial report". Note, this chapter presents a selection of key results from the Imperial modelling. It is, however, a very brief summary. Please see the Imperial report for a more detailed discussion of the assumptions and methods used.

3. (Separately) changes in transmission and distribution infrastructure costs to accommodate the output from adjusted mix of plant.

Figure 2.1 shows estimated integration costs for the 100g/kWh baseline scenario, which assumes a mix of nuclear, wind,[3] solar PV and CCS is developed to meet this emissions target. It shows that the system integration costs associated with wind (relative to nuclear[4]) are £6-£7/MWh, which are similar to the range of integration costs associated with solar PV of £6-£9/MWh, depending on the method used (see above). The integration costs associated with both technologies are significantly higher than for CCS. Across the three methods, the majority of integration costs for all technologies are associated with changes in generation operating and capital costs.

The element of integration costs associated with transmission capital costs tends to be small because, when Imperial removes nuclear capacity and replaces it with an alternative to compute integration costs (see the methods described in Appendix A), it places the alternative plant in a similar location, so the change in transmission requirements tends to be modest. However, it is possible that different technologies might trigger different amounts of transmission capacity, even if they are in the same location. Hence, this category of cost may be a more significant component of estimated integration costs in some cases. The figure also demonstrates that solar PV can cause some growth in distribution capital costs, as placing more capacity into distribution systems creates the need for additional reinforcement.

Figure 2.1
Modelled Integration Costs Relative to Nuclear (100g/kWh Baseline Scenario in 2030)



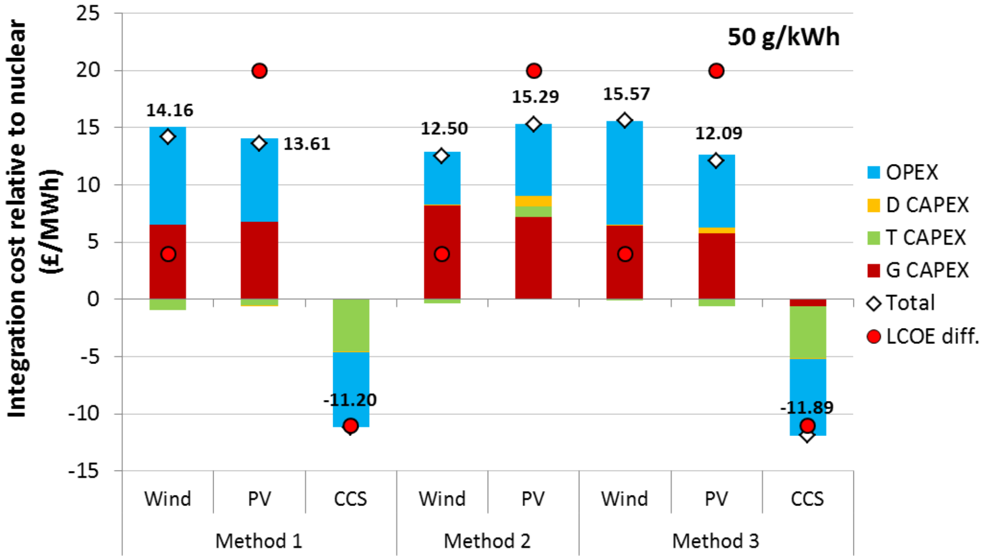
Source: Imperial Modelling

3 For the purpose of this analysis, we make no distinction between offshore and onshore wind, on the basis that the integration costs associated these technologies, once they connect to the onshore system, are common.

4 Note, the system integration costs shown are all relative to other technologies. Hence, the choice of nuclear as the reference technology, as opposed to wind, solar or CCS, is arbitrary.

Furthermore, a comparison of Figure 2.1 and Figure 2.2, which presents results for the 50g/kWh baseline scenario, shows that the magnitude of relative system integration costs increases across all technologies as emissions fall due to a higher penetration of low carbon plant. The system integration costs associated with wind and solar PV (again, relative to nuclear) are £13-£16/MWh, depending on the method (see above), and CCS has materially lower integration costs. The integration costs associated with wind and PV are primarily attributable to changes in generation operating and capital costs, as in the 100g/kWh case, but CCS also appears to trigger less transmission capital costs than nuclear,[5] which makes up around half of the integration cost for this technology.

Figure 2.2
Modelled Integration Costs Relative to Nuclear (50g/kWh Baseline Scenario in 2030)

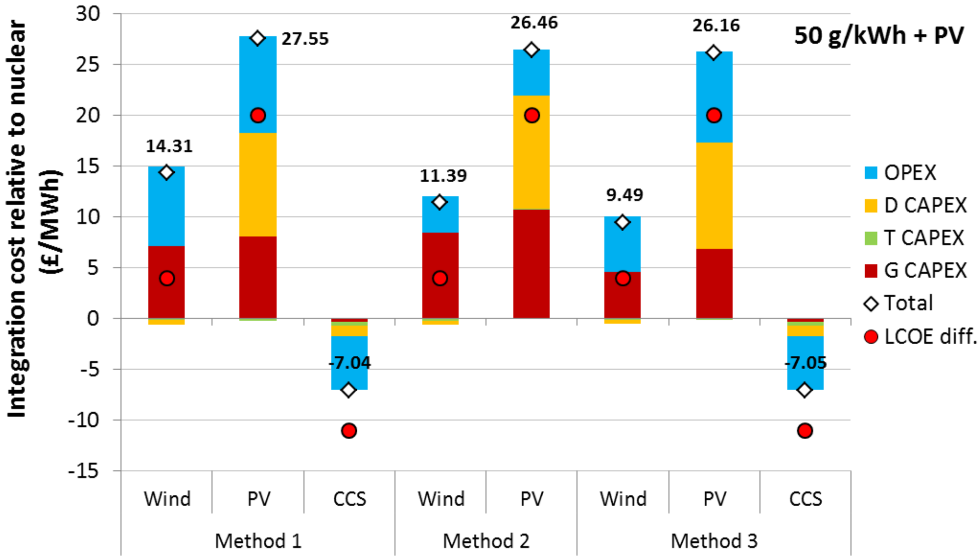


Source: Imperial Modelling

The results shown above therefore demonstrate that the level of integration costs appear to rise with the penetration of low carbon plant, and that there is potentially material variation in integration costs across technologies. However, as Figure 2.3 shows, the relative integration costs across technologies changes if the mix of low carbon plant assumed in the baseline changes. Assuming a higher penetration of solar PV (50GW, rather than the 20GW assumed in the 50g/KWh baseline) makes the relative integration costs of solar PV materially higher than for wind. CCS still has a materially lower integration cost than all other technologies in this scenario, as it provides more firm capacity to the power system than wind and solar, and its production can be ramped up/down in accordance with the needs of the system more easily than nuclear.

5 A possible explanation for CCS trigger less transmission investment than alternative low carbon technologies is that, at times when transmission capacity is constrained, it is cheaper to constrain down production from CCS than it is to constrain down production from nuclear or wind/solar PV.

Figure 2.3
Modelled Integration Costs Relative to Nuclear, with Increased Solar PV (50g/kWh in 2030)



Source: Imperial Modelling

2.1.3. The importance of flexibility for achieving high levels of decarbonisation in the power sector

As explained in the Imperial report, our starting point for calibrating the generation mix used in the 50g/kWh and 100g/kWh baseline scenarios was a set of generation capacity assumptions that the CCC, based on previous work, had estimated would deliver the assumed levels of decarbonisation using a mix of low carbon generation technologies. However, when Imperial incorporated these generation mixes into its scheduling and despatch models, it found that these mixes would not, in fact, produce the required 50-100g/kWh decarbonisation targets. The main reason for this was that the remaining fossil fuel-fired plant on the system had to run at higher load factors to provide sufficient reserves to balance the system in real time. We therefore explored with the CCC alternative means of balancing the system by providing higher levels of flexibility from alternative sources.

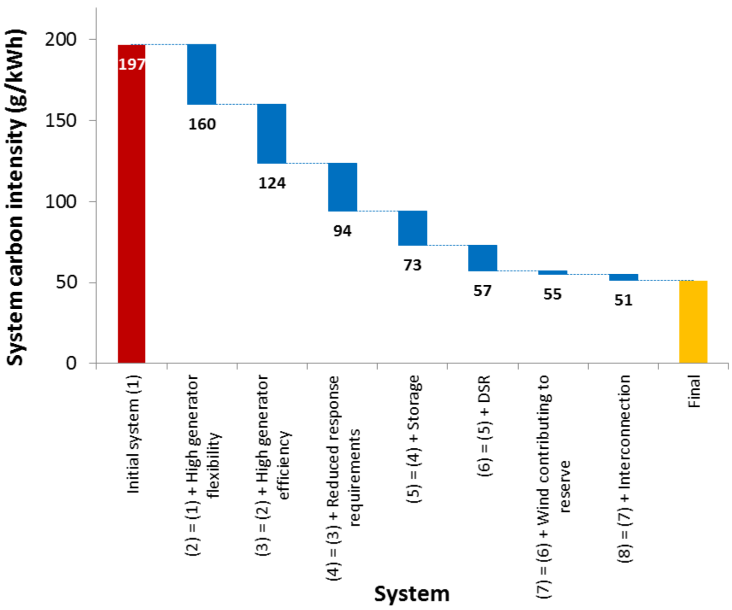
For instance, as Figure 2.4 shows, with the initial system composition provided by the CCC, Imperial's modelling suggested a carbon intensity of 197g/kWh instead of the target of 50g/kWh. However, by assuming some incremental increases in the flexibility of the power system from a range of technologies, we developed an adjusted baseline that achieved the emissions target. The additional flexibility comes from a range of sources, including:

- Increasing the flexibility of thermal generation, eg. so they can run at lower levels of minimum stable load and ramp up/down more quickly;
- Improving generator thermal efficiency, so the fuel consumption is lower when the plant is part-loaded to provide reserve, for instance;
- Technological and operational improvements in system operation to reduce response requirements;

- Increased penetration of electrical storage capacity, DSR and interconnection capacity; and
- Allowing wind plant to provide reserves.

This analysis indicates that the costs of decarbonising the electricity system will depend on the levels of flexibility provided by generators, through the decisions they take to make their plant more/less flexible, as well as the supply of flexibility from other sources, such as DSR, new interconnection, storage, and so on. Innovations in system operation to reduce reserve requirements and allow wind to provide reserve also reduce the need for flexibility from other sources.

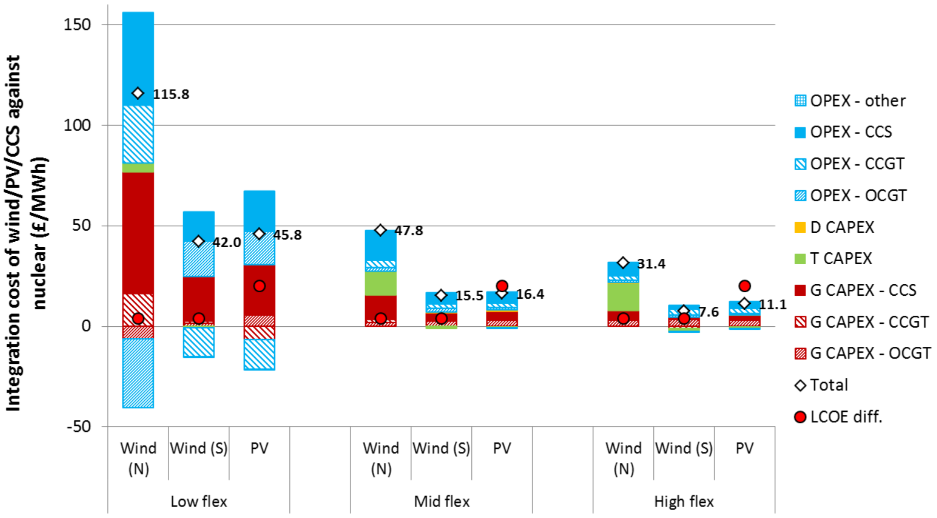
Figure 2.4
System Carbon Intensity with Increased Flexibility
(50g/kWh Baseline Scenario in 2030)



Source: Imperial Modelling

Further, as Figure 2.5 shows, the magnitude of integration costs associated with different technologies varies depending on the level of flexibility in the power system. It shows that more flexibility reduces the costs of integrating all solar and wind capacity onto the system.

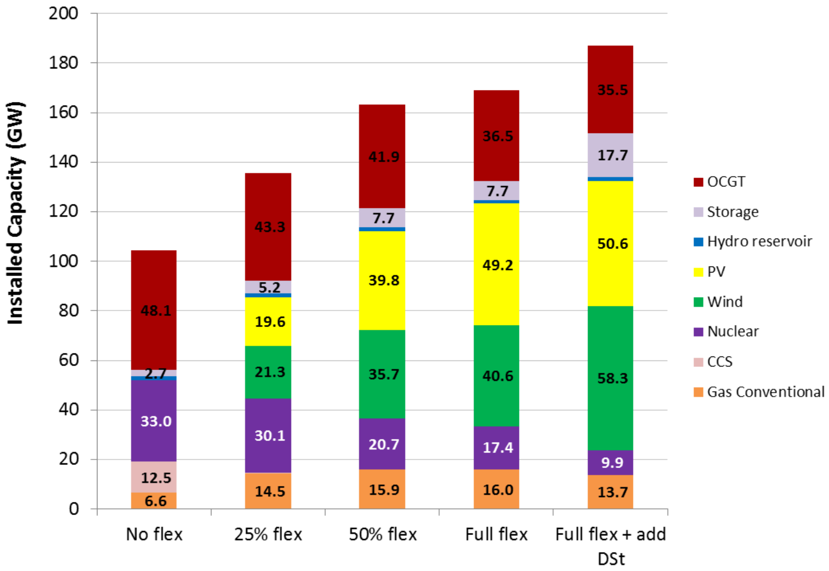
Figure 2.5
Impact of Flexibility on Relative Integration Costs of Wind and Solar PV (50g/kWh Baseline Scenario in 2030)



Source: Imperial Modelling. Note, Wind (S) and Wind (N) represent wind plant in the north and south of GB, respectively.

However, this analysis alone provides little evidence as to the optimal penetration of flexibility technologies. For instance, depending on the costs of providing these alternative sources of flexibility, it might be more efficient to reduce emissions to the 50 or 100g/kWh targets by adding more low carbon plant, changing the mix of low carbon plant, or adding flexibility from other sources. To illustrate this point, Imperial also performed some runs of its WeSIM model in which it allowed the model to choose the optimal mix of low carbon plant in order to minimise cost, while achieving a given 50g/kWh emissions target, and taking a range of different assumptions on the supply of flexibility from other sources as given. As Figure 2.6 shows, as the flexibility provided by other sources increases, the least-cost penetration of solar PV and wind capacity rises, and nuclear capacity falls. Also, as flexibility increases, the optimal penetration of both OCGT and CCS plant falls, as these are competing sources of flexibility.

Figure 2.6
Generation Mixes Proposed by WeSIM to Achieve 50g/kWh Carbon Intensity in 2030 with Different Levels of System Flexibility



Source: Imperial Modelling

2.2. Implications for Policymakers

We recognise that policymakers seek to balance a range of objectives when deciding how to ensure the efficient procurement of generation, and the modelling summarised in this report provides lessons on a range of factors that may influence policy around topics such as low carbon support and power market design.

Probably the clearest lesson for policymakers from the results summarised above is that decisions on the mix of low carbon generation that ignore variation in system integration costs are likely to be inefficient. Put another way, a simple comparison of alternative technologies' LCOEs is inadequate.[6]

However, while material, system integration costs are to some extent already allocated to the developers of low carbon generation, and thus included in generators' LCOE. Only to the extent that developers of low carbon generation cause integration costs that represent "externalities"[7] is an intervention needed to account for integration costs in planning the power system:

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[6] There may be reasons why policymakers would wish to pursue a low carbon technology mix that is not least cost, even after considering both the LCOE and integration costs of alternative low carbon technologies, such as a desire to support emerging technologies in order to promote innovation and future cost reduction. However, to the extent that a comparison of the cost of alternative technologies is considered by policymakers, the Imperial modelling demonstrates that system integration costs are a material component of the total cost of generation that merits consideration.

[7] An "externality" is a term used in economics to describe a situation in which the production or consumption of a good/service (here, the integration of a given generation technology into the power system) imposes costs or benefits on others, in a way that is not reflected in the costs faced or benefits enjoyed by that producer or consumer.

- Imperial's modelling framework estimates integration costs in a whole electricity system simulation model that minimises power system costs subject to a range of constraints. In other words, it uses a computer program to define the costs associated with the integration of low carbon generation technologies, based on a perfectly efficient pattern of despatch and investment. Within this framework, generators' LCOEs only include the cost of constructing and operating the generator itself, excluding any changes in grid or ancillary service costs, etc, that they cause. These excluded components represent the system integration costs associated with particular technologies.
- In reality, however, a range of market and regulatory mechanisms and commercial arrangements exist to allocate and recover system integration costs. Ideally, such arrangements should ensure that the operational and investment decisions made by private entities achieve outcomes as close as possible to the theoretical ideal prescribed by Imperial's modelling.[8] In essence, they should promote a least cost outcome.
- These arrangements should seek to "internalise" the externality associated with system integration costs. Current arrangements in Great Britain are, however, imperfect, and so the costs that generators incur, and the revenues they earn, only partially reflect the system integration costs they impose. In other words, generators' real LCOEs may include some of the integration costs identified by the Imperial modelling, but not all.

In the remainder of this report, we therefore consider the extent to which the externalities associated with system integration costs are "priced in" through the prevailing market arrangements. To the extent they are not, we make recommendations for improving the efficiency with which low carbon generation is integrated onto the grid.

As described above, the modelling conducted by Imperial also demonstrates the potentially significant effect of the supply of flexibility on the optimal mix of plant to decarbonise, and the achievable level of decarbonisation taking the mix/penetration of low carbon plant as given. As discussed further in the rest of this report, in theory, the value to the system from providing flexibility can be priced in through changes in the prices of energy over time and the prices of ancillary service products. Improvements in the efficiency of energy and ancillary service price signals would therefore improve the efficiency with which flexibility is provided by generators, consumers, and so on.

However, there may also be implications for government in selecting the optimal mix of low carbon plant. For instance, different mixes of low carbon plant will impose different flexibility requirements on the system, and providing additional flexibility may be costly. As discussed below, it may also be important for providers of flexibility services to compete with conventional generators on an even footing, such as in the capacity market.

2.3. Scope of this Report

The remainder of this report is structured as follows:

8 As noted further below, Imperial's model may not perfectly represent reality and so the investment and operational decisions it takes may not perfectly mimic those that would, in reality, be efficient.

- Chapter 3 considers the component of system integration costs associated with changes in generation capital and operating costs in the system as a whole. These costs arise, as noted above, when the addition of a particular renewable generator changes the scheduling and despatch of other plant and the requirement for capacity from other plants to meet security standards. Chapter 3 considers the extent to which prevailing wholesale market arrangements in the British power sector, including the energy market, capacity mechanism and ancillary service markets, send economic signals[9] to generators regarding the system integration costs they impose on the system, or the value they provide by reducing integration costs. It considers changes to these arrangements that would promote more efficient trade-offs between generators' own costs and the grid integration costs they impose. It also considers whether they signal the value of flexibility to the power system.
- Chapter 4 considers the component of system integration costs associated with changes in transmission and distribution network costs. It considers the extent to which charging arrangements send economic signals to generators regarding the change in investment costs their presence triggers. It considers changes to network charging arrangements that would promote more efficient trade-offs between generators' own costs and the grid integration costs they impose.
- Efforts to create efficient market and network charging arrangements that "price in" system integration costs may be undermined if some generators are, in effect, taken out of the market through subsidy arrangements. Therefore, Chapter 5 examines the commercial features of the Contract for Difference Feed-in Tariff ("CFD FIT") regime to assess the extent to which CFD FIT contracts, and the process for allocating them, will ensure an efficient trade-off between the LCOE of individual generators and variation in the system integration costs they impose on the system. It also considers possible changes to the CFD FIT regime that would better account for system integration costs.
- Chapter 5 summarises our conclusions and suggests future work on this topic to enhance the commercial, regulatory and market arrangements associated with the grid integration costs of low carbon generation.

[9] We define this term to mean information conveyed to market participants through the pricing of a product or service regarding the cost of providing that product or service or its value to the power system.

3. System Integration Costs Associated with Scheduling and Despatch of Generation Plant and Generation Adequacy

3.1. Changes in Generation Capital and Operating Costs from Integrating Low Carbon Power Generation

As noted above, in this chapter we consider the component of system integration costs associated with changes in generation capital and operating costs. We also consider the extent to which prevailing wholesale market arrangements send economic signals regarding the system integration costs generators impose on the system, or the value generators (and others such as storage providers, etc) provide by reducing integration costs by providing additional flexibility. Finally, we also consider changes to these arrangements that would promote more efficient trade-offs between generators' own costs and the grid integration costs they impose.

As described in the Imperial report and in Section 2.1.2 above, adding a small amount of low carbon generation to the power system, or marginally altering the mix of low carbon plant, has a number of effects on generation operating and capital costs:

1. Its output displaces generation from other generation capacity that may already be on the system, reducing the load factors of other plants. By changing the load factors of other plants in the market, adding low carbon generation may affect the mix of conventional technologies it is optimal to build, such as in respect of the balance between Open Cycle and Combined Cycle Gas Turbines (OCGTs and CCGTs);[10]
2. It provides additional capacity, which depending on the extent to which this capacity is available reliably, contributes to meeting the target security standard, which Imperial assumes is 3 hours of expected loss of load (LOLE) per annum. Hence, adding low carbon generation may change the need to procure other forms of generation to ensure security of supply;
3. It may affect the amount of ancillary services that the System Operator (SO) needs to procure in real time, and it may do so in a number of ways. For instance, adding a large nuclear power station to the system, if it affects the size of the maximum in-feed to the grid, may affect the volume of spinning reserves required to maintain an N-1 standard.[11] Adding intermittent wind plant to the system may also affect the volume of reserves required to balance the system in real time. And by displacing conventional thermal "spinning" plant, adding some low carbon technologies like wind and solar may reduce the supply of some ancillary services, most notably frequency response, which may also increase generation operating and capital costs.

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[10] As compared to CCGTs, OCGTs have relatively low fixed costs but relatively high variable operating costs because of their lower thermal efficiency. Hence, if conventional plant is required to produce less energy and/or operate less frequently, it becomes more efficient to build OCGTs in place of CCGTs.

[11] An "N-1" standard means that there is sufficient reserve in place to maintain frequency, and hence the operation of the system, following the loss of the single largest in-feed to the system.

We discuss each of these three effects, as well as possible policy implications in Sections 3.2, 3.3 and 3.4 respectively.

3.2. System Integration Costs Associated with Changes in Despatch

3.2.1. Exposing low carbon generators to efficient market prices would ensure they account for the value of their energy production

In any competitive power market, a new generator connecting to the system receives a price for its output defined by the prevailing market price, and it will therefore wish to produce power, as long as it is physically able to do so, whenever the price rises above its own opportunity cost of generation.[12]

Assuming the market works "perfectly", theory suggests that the market price earned by the plant should reflect the System Marginal Cost (SMC). SMC is defined by the cost of marginally increasing demand, and may be defined by the cost of marginally increasing supply from a generator, compensating a consumer for curtailing their demand, reducing net flows to storage, increasing net imports from neighbouring markets, or other similar measures.

Hence, the value each generator earns (ie. SMC) is set by the cost to the system that its output saves. As such, a low carbon generator that produces energy frequently and/or when SMC is relatively high, will earn more than a generator that produces energy less frequently and/or in periods when SMC is low. For instance, data from 2014 suggests that the output from wind plants in GB, valued at the prevailing market price, was worth around £41.8/MWh on average, as compared to annual baseload prices of £42.1/MWh, and the average value of output from gas plant of £44.9/MWh.[13]

Accordingly, as long as low carbon generators receive the market value of their output, and the market price equals SMC, generators will receive economic signals regarding the savings in operating costs that they create. Investors faced with a decision over which type of low carbon plant to build will therefore account for these system-wide savings, as well as numerous other factors such as each generation technology's own production costs, when making technology choices.

In other words, as long as low carbon generators are exposed to market prices, and market prices reflect SMC, there is no reason why the system integration costs associated with generation operating costs should represent an "externality" that warrants any particular policy intervention.

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[12] For most types of plant, this opportunity cost is defined by the fuel, carbon and variable operating costs it incurs from the decision to generate electricity, and in the case of many low carbon technologies, is close to zero because these costs are all small. For low carbon plant that receive a subsidy payment per MWh of energy production, the opportunity cost may be negative.

[13] NERA analysis, based on production data from Platts Powervision, and price data from Bloomberg. We calculated these figures by multiplying prevailing half-hourly prices by half-hourly output, summing across hours and computing a weighted average captured price by technology.

3.2.2. Wholesale energy prices also signal the integration costs due to changes in the required mix of conventional generation

A change in the output from low carbon generation affects the supply of available generation to the market as a whole, which will influence SMC and thus power prices. As a result, the prices captured by all generators will be lower in periods when output from low carbon generation increases and higher when output from low carbon generation decreases. Market prices therefore act as a channel through which other generators receive economic signals to increase or decrease their despatch in a way that accommodates changes in output from (or the capacity of) low carbon generation. If prices accurately reflect SMC, then the economic signals conveyed to generators will encourage efficient behaviour.

For instance, as a result of an increase in the amount of output from low carbon generation, existing generators will earn less (through lower prices and/or fewer operating hours), but also incur lower costs, with the balance of these effects reducing their profit margins from providing energy. Lower margins from the production of energy will tend to deter investment in generators like CCGTs that are relatively cheap (per MWh) when then produce a lot of energy, and encourage investment in generators that are, like OCGTs, relatively cheap (per MWh) when then produce less energy or operate less frequently.

Hence, the integration costs associated with changing the required mix of conventional generation technologies will be reflected in the market prices captured by those (and other) generators. If low carbon generators are exposed to energy market prices, there should be no need for any intervention to internalise externalities associated with the system integration costs resulting from changes in the despatch patterns of other generators.

Similarly, the value that potential providers of flexibility deliver to the system can be reflected in the price they receive. Flexibility is, in essence, the ability to react quickly by altering generation or consumption as conditions on the power system change. If those conditions alter SMC, market prices keep track with changes in SMC, and providers of flexibility can capture those prices, there is no reason why they should not capture the full value they provide to the system.

3.2.3. The need for policy interventions to ensure generation investors account for how the value of energy production varies by technology

As described above, market prices can act as a channel through which investors in low carbon generation receive an economic signal regarding differences in the value of energy production from different technologies. Hence, there is no reason why generators that are exposed to efficient market prices should not take investment decisions, such as in respect of technology choice and the timing and location of investment, that account for their respective impacts on the whole system costs associated with the changes in scheduling and despatch that they cause, as well as their own LCOEs.

However, while this result holds in theory, there are two limitations:

- First, market prices do not necessarily reflect marginal cost as closely as the theoretical discussion above suggests:

- In reality wholesale prices are set at the level of the country as a whole, so do not reflect how marginal costs vary across locations. Hence, market prices would not account for the fact that, for instance, the integration costs of adding a wind farm in a region where there are already a lot of wind farms installed may differ from the cost of integrating a wind farm into an area dominated by thermal generation. Policy interventions to improve the efficiency of locational signals conveyed through power prices or more cost-reflective network access charges could solve this problem, as we discuss further in Chapter 4; and
- Wholesale power prices are also determined, in effect, by average conditions during a trading interval, which in Great Britain lasts 30 minutes. There is therefore no mechanism in the energy market to reflect the value of flexibility in energy pricing within the 30 minute trading interval, during which the underlying marginal cost of the system may vary considerably, as the value of real time flexibility identified in the Imperial modelling suggests is the case.
- In practice, the costs of managing real time variations in marginal cost, including to the extent that they are affected by the integration of different types of generator, largely fall on the System Operator and not the individual generators that cause system marginal cost to vary within a trading period. The value captured by providers of flexibility that can adjust their demand or supply within a trading interval may therefore understate the value they deliver to the system. More efficient arrangements for the pricing of ancillary services might go some way towards solving this problem, as discussed further in the remainder of this chapter; and

▪ Second, while it is possible to design low carbon support arrangements that subject supported generators to market price signals, the government’s primary support mechanism, the CFD FIT regime, does not do so.[14] As a result, some intervention is needed, as we discuss further in Chapter 5, to ensure the arrangements for planning the power system and procuring low carbon generation reflect this category of system integration costs.

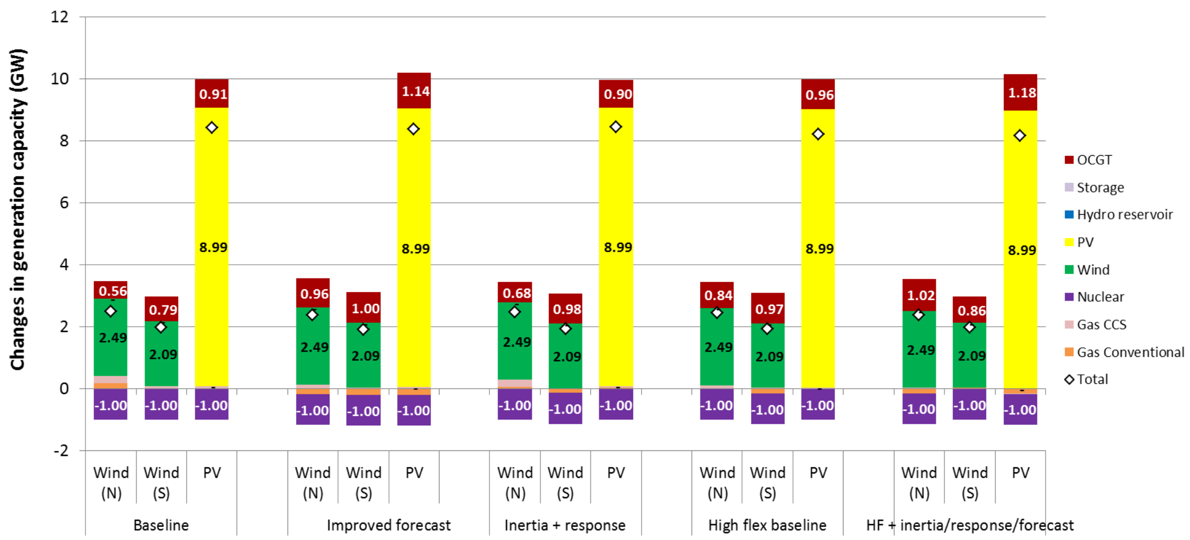
3.3. System Integration Costs Associated with Generation Adequacy

Changing the amount (or type) of low carbon power generation will also affect the amount of reliably available capacity in place to meet peak requirements. For instance, a 1GW nuclear plant adds more reliably available capacity than a 1GW solar or wind plant, as the availability of the latter depends on the weather. For instance, Figure 3.1 shows that replacing 1GW of nuclear (the negative purple bars) with the energy-equivalent amount of wind or solar PV also requires the addition of roughly 1GW of OCGT plant (the maroon bars) to provide firm capacity.

[14] CFD supported generators may be able to marginally increase revenue by “beating” the market reference index included in the CFD FIT contract. This kind of opportunity might create some incentive to respond to market price signals. However, the effect is likely to be marginal and, moreover, does not change the broader problem that generators with high integration costs that tend to produce energy in low price periods, will have more or less the same offer price in CFD allocation auctions as a generator with the same LCOE, but lower integration costs because it produces in high price periods.

To the extent that energy market prices signal scarcity, all generators exposed to wholesale market prices will receive the marginal benefit that their presence provides to ensuring capacity adequacy, and how this value changes as new low carbon generation connects to the system. In practice, however, constraints on peak prices created by explicit regulatory price caps, or the perception by market participants that government may intervene if prices spike to high levels, may prevent the energy market from signalling the scarcity value of generation. Given this problem with reliance energy markets to signal scarcity, an alternative is to pay generators the "missing money" associated with constraints on peak prices through a payment for capacity.

Figure 3.1
Changes in Required Generation Capacity from Changing the Low Carbon Plant Mix (50g/kWh Baseline Scenario in 2030)



Source: Imperial Modelling

In the case of the new British Capacity Market, National Grid procures an amount of capacity that the Secretary of State believes is adequate to meet a security standard to 3 hours of LOLE. As the mix of low carbon generation changes, the amount of generation that needs to be procured through capacity mechanisms auctions changes, and the clearing price in the auction should signal the economic value of capacity to all parties that are eligible to supply capacity contracts.

Hence, any market participant that is exposed to capacity market prices should be exposed to economic signals regarding the system integration costs they impose due to the need to ensure generation adequacy. In practice, however, subsidised low carbon generators, including those supported through the CFD FIT regime, are not eligible to participate in the Capacity Mechanism. As for the integration costs associate with changes in despatch (see above), some intervention is therefore also needed to ensure the arrangements for planning the power system and procuring low carbon generation reflect this category of system integration costs. We discuss this further in Chapter 5.

It will also be desirable to ensure that all potential suppliers of capacity can compete on an equal footing in the capacity market. For instance, some potential suppliers of flexibility services are small scale DSR and storage providers. Developing capacity market rules that allow these types of market participants to compete alongside large thermal generators will also support the efficient provision of flexibility services.[15]

3.4. System Integration Costs Associated with Ancillary Services

Even if low carbon generators are exposed to market prices that signal differences in the value of their capacity and energy production, as discussed in Sections 3.1 and 3.2, and thus the system integration costs they impose, the signals conveyed to generators would not encompass all effects on generation operating and capital costs. This is because the energy market prices represent average conditions within trading intervals and so cannot send economic signals regarding the costs of balancing in real time. The integration costs associated with real time balancing therefore show up in ancillary service markets, and signalling such costs to generators therefore requires that regulation and market arrangements for these services are designed efficiently:

- Competitive electricity markets typically require the trading of electricity as a standardised product defined such that the supply of and demand for electricity is fungible within a trading interval. In essence, market participants' costs and revenues do not depend on when consumers take electricity or when generators supply it, as long as they meet their obligations within the trading interval, which in Great Britain is 30 minutes long.
- In reality, however, the need to balance supply and demand and to make the system resilient to variation in supply and demand means there is a "missing market" (in the vernacular of economists) for the provision of system balancing within the trading period.
- Measures such as minimising the duration of trading intervals can reduce the effect of this missing market problem. For instance, some power markets have trading intervals as short as 5 minutes, as compared to 30 minutes in Great Britain. Reducing the length of trading intervals in the British market would be of particular benefit in ensuring providers of flexibility services receive efficient signals, as this would allow them to earn revenues that better reflect the marginal benefits associated with the ability to rapidly change their demand/supply from/to the system:
  - For instance, as Figure 2.4 and Figure 2.5 show for the 100g/kWh and 50g/kWh scenarios, decarbonised power systems including a large penetration of wind, solar PV and nuclear have an acute need for flexibility to achieve these low levels of emissions. By contrast, however, Imperial's analysis of a 200g/kWh scenario in which penetration of wind, solar and nuclear is lower suggests the impact of a lack of flexibility is less acute. As Figure 3.2 shows, Imperial estimates that a system designed to target 200g/kWh achieves emissions of 229g/kWh in the "25% flex" case.

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[15] See, for instance:

(1) Written evidence submitted by Supergen Hubnet Imperial College (EDM0016) to the Energy and Climate Change Committee, 20 July 2014. URL: http://data.parliament.uk/writtenevidence/committeeevidence.svc/evidencedocument/energy-and-climate-change-committee/electricity-demandside-measures/written/11265.html

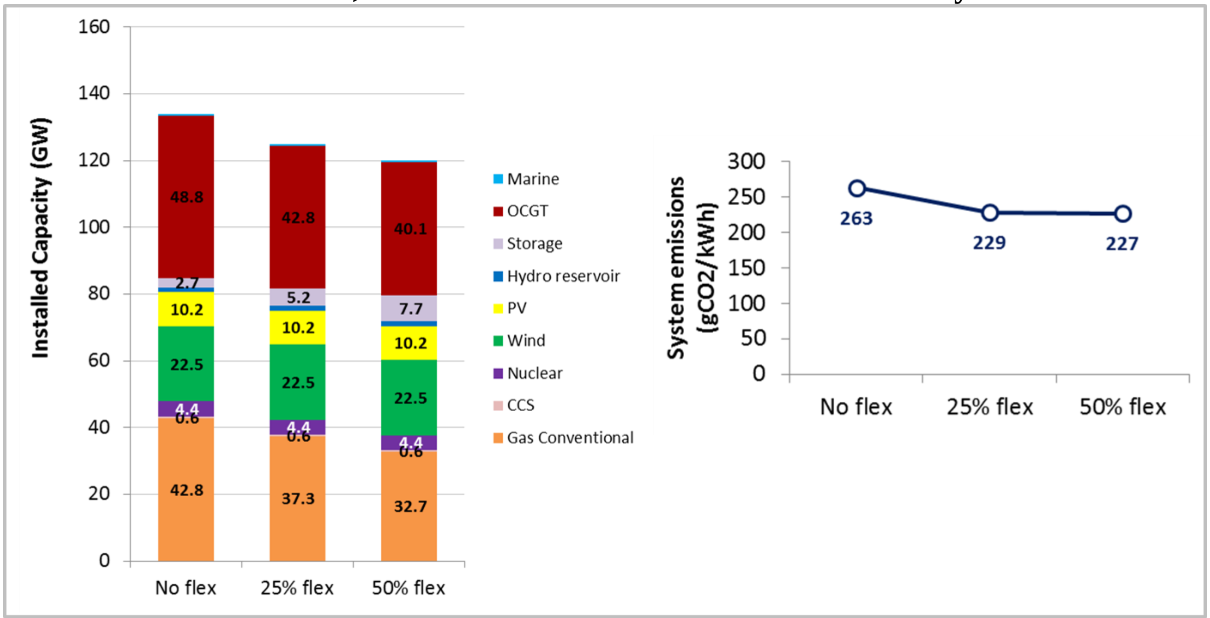
(2) The Potential Impact of Demand-Side Response on Customer Bills, NERA Economic Consulting, 29 August 2014.

Current market arrangements' inability to signal the value of flexibility (see further discussion below) may therefore become increasingly detrimental as the power sector attempts to transition from around 200g/kWh to 100g/kWh.

- Hence, any lack of incentive on the part of market participants to provide flexibility in today's market conditions may reflect a combination of (1) the modest need for flexibility at present given the high remaining supply of flexibility from older thermal generation, (2) the absence of a market mechanism that will place a value on flexibility as it becomes scarce, and (3) any perception amongst investors that the pace of decarbonisation, and thus the emerging need for additional flexibility, is likely to be slow, causing them to discount the value of investments in flexibility made today.

▪ However, to some degree, the missing market problem remains and needs to be addressed through the procurement of a range of ancillary services that enable the System Operator (SO) to balance the system in real time. As the Imperial modelling demonstrates, and as we discuss below, changes in the mix of low carbon generation technologies can have a material impact on the demand for ancillary services, and the supply of generation that is available for (and capable of) supplying certain ancillary service products. The Imperial modelling work also illustrates changes in the demand and supply of ancillary services compared to the current situation as the penetration of low carbon generation increases.

Figure 3.2
Capacity Mix (GW - left) Emissions Intensity (g/kWh – right) in a 200g/kWh Scenario for 2030, with Different Levels of Assumed Flexibility



Source: Imperial Modelling

3.4.1. Changes in the demand for ancillary services due to growth in low carbon generation

National Grid, the SO, procures a range of ancillary services. As the Imperial modelling illustrates (see Table 3.1), the need for ancillary services rises as the penetration of low carbon generation increases, as we discuss further below.

Table 3.1
Illustration of Variation in Reserve/Response Requirements in 2030
(Annual Average Requirements in MW Across Main Scenarios)

Scenario	Reserve (MW)	Response (MW)
50 g	17,347	2,058
50 g + PV	14,767	1,741
100 g	12,277	1,626
200 g	7,838	1,197
10 g	29,622	3,288

Source: Imperial Modelling

Frequency response requirements will rise as additional low carbon generation connects to the system.

- With the connection of the next generation of new nuclear power stations, which have a larger unit size than any other plant on the system, the SO will need to procure more frequency response. However, once the first of these large new nuclear stations has connected to the grid, the connection of further new plants does not cause a further growth in frequency response requirements, so this integration cost is only associated with the first new nuclear plant. As such, assuming at least one plant will be developed as seems likely given the government's decision to support the Hinkley Point project, no further intervention is necessary to ensure that policy (or commercial) decisions to develop further nuclear plants account for this type of integration cost.
- Frequency response requirements may also increase to compensate for the possibility of sudden variation in intermittent generation like solar and wind;
  - As the penetration of these types of low carbon generation rises (primarily wind and solar), "spinning" conventional plant is squeezed out of the merit order, which reduces the supply of "inertia". Inertia affects the rate at which frequency falls following a sudden shock to demand/supply.
  - This change may require that the SO schedules more frequency response to compensate for the reduction in inertia, suggesting that some types of new low carbon generator may drive higher integration costs than others in relation to frequency response requirements.
  - The Imperial modelling suggests that, in power systems dominated by low carbon plant that lack system inertia, generators that have the technical capability to respond to frequency variation within 5 seconds provide significantly more value to the system than plant that can respond within 10 seconds.

- o Until recently, none of the ancillary service products procured in the British market have differentiated between plant that can respond within 5 as opposed to 10 seconds. However, National Grid has recently added a new product, Rapid Response, to its portfolio of frequency response services, which is defined as the provision of primary frequency response within 5 seconds rather than 10 seconds.[16] As it is relatively new, it has yet to be procured as of August 2015.[17]
- o An even more recent addition to the suite of ancillary service products is called Enhanced Frequency Response, and is defined as frequency response that achieves 100% active power output at 1 second (or less) of registering a frequency deviation.[18] We understand it targets primarily battery storage developers, but any technology can compete if it meets the response time requirements. Hence, the required reform of the range and definition of ancillary service products to ensure generators (and other providers, eg. storage/DSR) are able to capture the marginal benefit associated with providing flexibility to the system already appears to be underway, but it is too early to assess the efficacy of these reforms at signalling the value of flexibility.

- It may also be possible for wind farms to provide "synthetic inertia",[19] and thus avoid the additional integration cost they impose through the need to schedule more frequency response. At present, grid connections typically requested by wind farms do not enable them to provide this service. But, if wind farms were remunerated for providing synthetic inertia, and thus incentivised to obtain a different type of grid connection, or if they were obliged to obtain such a grid connection, the additional cost they impose through reducing the supply of inertia would be avoidable.[20]

Reactive power requirements rise as the transmission network becomes larger, which may be required to connect low carbon generation, especially in more remote parts of the country.

Short Term Operating Reserve (STOR) requirements, according to some sources, will also rise to ensure there is sufficient back-up to accommodate variation in the output of intermittent generation as the penetration of low carbon generation rises. However, there is some debate about whether an increase in STOR is really necessary, and whether this simply crowds out the supply that would (or could) be provided through the market anyway.[21] A

16 Rapid Frequency Response, BSSG/CBSG– 04/09/2013, National Grid.

17 Source: Imperial discussions with National Grid.

18 National Grid Website, visited on 30 September 2015. URL: http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx

19 The kinetic energy stored in rotational parts of wind turbines can be extracted through a control strategy referred to as "synthetic inertia". The control system detects the frequency deviation and adjusts the power flow into the grid based on this. In this way the turbine contributes to the system as if it would have inertia just like conventional units; hence the term "synthetic inertia". Source: The utilization of synthetic inertia from wind farms and its impact on existing speed governors and system performance (Part 2 Report of Vindforsk Project V-369), Elforsk rapport 13:02, Mohammad Seyedi, Math Bollen, STRI January 2013.

20 The SO would need to account for the expected generation from wind plants, and thus the supply of inertia they provide, when deciding how much frequency response to commission.

21 The latest market reforms reduce the apparent need for STOR, Graham Shuttleworth and George Anstey, New Power, Issue 55, August 2013.

range of potential reforms to the energy market trading arrangements would also undermine the case for increasing STOR as the penetration of low carbon generation capacity rises. For instance, shifting gate closure closer to real time delivery would reduce the need for the SO to take centralised balancing actions. Shorter trading intervals would also place greater responsibility for system balancing on market participants, and less responsibility on the SO (see above).

Growth in the need for ancillary services (ie. higher demand) will tend to increase the costs that the SO incurs, which in Great Britain are socialised through flat £/MWh Balancing Services Use of System (BSUoS) charges. Hence, no low carbon generators face the additional costs they impose on the system in respect of higher ancillary service requirements. Because they do not face these costs, some intervention is therefore needed to ensure the arrangements for planning the power system and procuring low carbon generation reflect this category of system integration costs.

3.4.2. Changes in the supply of ancillary services due to growth in low carbon generation

On the supply-side, one way to address this challenge would be to reconsider wind farms' derogation from the obligations to provide mandatory frequency response. The increasing penetration of low carbon generation will restrict the amount of plant that is capable of supplying ancillary services. Reducing the number of spinning plant on the system constricts the supply of frequency response compared to the current situation. For instance, at present all large conventional generators are required by the Grid Code to provide some "mandatory" frequency response if they are generating, but as they get squeezed out of merit by low carbon plant, less of this service will be available. This gap could be filled by wind farms providing this service instead.

Moreover, it is possible that it will become economic for wind farms, or possibly other low carbon generators, to start to supply more ancillary services than they do at present. For instance, wind farms can provide downward response by constraining down their output following an instruction from the SO, or provide upward response by constraining down their output to a level less than prevailing wind speeds would allow, giving them the option of increasing generation at short notice. The Imperial modelling illustrates that allowing wind farms to provide reserve in this way is potentially beneficial to the power system (see Figure 2.4, for instance).

At present, we understand that the SO chooses not to procure frequency response services from wind farms, possibly because other conventional generators are available that can provide the service more cheaply. As noted above, it may also become economic for the SO to pay wind farms to provide synthetic inertia to reduce the need to procure frequency response from other forms of generation, eg. paying conventional generators to part load their plants in periods when they would not otherwise choose to generate.

Eventually, as wind penetration rises, the SO may face a choice between procuring synthetic inertia from wind farms, curtailing wind and compensating them for their opportunity cost of generation, or procuring ancillary services from alternative technologies such as storage or DSR. However, the relative cost of these alternatives remains uncertain, for reasons such as the uncertain capital costs of electrical storage.

3.4.3. Developing more market-based mechanisms for procurement of ancillary services

Whichever technologies are available to provide ancillary services, the best way to ensure the efficient provision is to:

- Ensure that the definition of ancillary service products is sufficiently granular that all services likely to be required by the system are recognised and defined such that a market channel exists through which providers of such services can realise a revenue stream that reflects the marginal benefit they provide to the system to the system (see above); and
- That efficient market arrangements are put in place that allow potential providers of ancillary services to observe a market price for the range of required products, and that this market price reflects as accurately as possible the system marginal cost of provision. This might involve, for instance, reforming the predominantly tender-based mechanisms for procuring ancillary services that result in contracts between generators and the SO. While we have no reason to believe these contractual relationships between the SO and providers of ancillary services should not result in efficient pricing, improving the transparency of ancillary service procurement, such as through the development of real time markets for ancillary services, would provide more information on the value associated of ancillary services to generation investors. This innovation would therefore support generators in optimally allocating their plant between the energy and ancillary service markets.

These measures would ensure that both flexibility providers and those low carbon generators providing ancillary services can monetise the marginal benefit they provide to the system. If such market arrangements exist, investors will therefore be able to make an economic trade-off between the marginal costs of providing ancillary services and the marginal benefits provided to the system. For instance:

- Better information on the price of ancillary services would also help investors to assess the economic case for incurring higher capital costs to develop conventional plant with enhanced flexibility.
- More flexible plant with lower minimum stable generation and/or faster ramp rates are better able to provide ancillary services than less flexible units, as the Imperial modelling illustrates (see Figure 2.4, for instance) but we understand that investments in enhanced flexibility are now rarely undertaken at new generation plant.
- Current investors' decisions to provide relatively inflexible conventional plant might reflect, for instance, the limited need for (and low value of) flexibility in the current power system, but as the underlying need for flexibility rises with growth in low carbon plant, transparent pricing of ancillary services may be necessary to encourage investors to provide additional flexibility.

In contrast, rather than more market-based mechanisms for ancillary service procurement, the increasing need for ancillary services that comes with growth in low carbon generation might lead policymakers to consider new obligations on generators to provide ancillary services. There may be some cases when obligations to provide ancillary services are efficient, such as when the opportunity cost of providing an ancillary service is consistently negligible, and the costs of organising ancillary service markets are large. However, obligations on generators to provide mandatory ancillary services might increase the costs of integrating low carbon generation through over procurement, deterrence of innovation and inefficient scheduling of plant. Hence, mandatory provision of ancillary services should, in general, be avoided.

Some changes to the way in which the SO behaves, and is incentivised to behave through its regulatory settlement, may also be desirable to minimise integration costs. As noted above, the procurement of ancillary services from low carbon technologies might require that the SO adopts new techniques for balancing the system in real time, makes investments in new IT and control systems, and innovates. The SO may also have reputational incentives to over-procure the services to ensure reliability, and to place more reliance on tried and tested approaches such as contracting with conventional generators for reserves. Expanding the role of competitive and transparent markets for the supply of ancillary services might prevent any form of positive discrimination in favour of conventional plant in ancillary service procurement. It may also be appropriate to consider changes to the SO's regulatory framework to deter it from over procuring ancillary services.

3.5. Conclusions

Efficient markets for energy, capacity and ancillary services can, in principle price in a large portion of the system integration costs that low carbon generators cause when they connect to the power system. They can also ensure that providers of flexibility services earn a revenue stream reflecting the marginal value that they provide to the system in supporting the increasing penetration of low carbon generation plant. However, in practice, their ability to do so is limited because (1) low carbon generators' subsidy payments largely insulate them from price signals in the energy and capacity markets, and (2) the ancillary services costs associated with integrating low carbon generators are socialised.

Hence, new policies that improve the efficiency of market price signals will therefore help to internalise the externalities associated with system integration costs, but such reforms would need to be combined with reform of subsidy arrangements to expose supported generators to market price signals, or to ensure integration costs are factored into central procurement decisions, as we discuss in Chapter 5.

Policies to target the integration costs associated with the growth in ancillary service costs more precisely on the party that causes them would also help to internalise the externalities associated with system integration costs, but such mechanisms are likely to be complex and challenging to design and implement. It is likely, therefore, that government will need to consider explicitly the relative system integration costs associated with growth in ancillary service costs when procuring low carbon plant as we discuss further in Chapter 5.

4. System Integration Costs Associated with Transport Costs

4.1. Transport Costs in Electricity Markets

Electricity is a homogenous product at the points of production and consumption, but it is characterised by significant transport costs. As a result, the location of generation capacity relative to the location of consumption within an electricity grid can significantly affect the overall costs of supplying end-users.

The costs of transporting electricity fall into two broad categories: infrastructure costs and short-run marginal costs (congestion and losses), as defined below:

- **Infrastructure Costs:** The Transmission Owners (TOs) provide transmission infrastructure to move power around the country from generators to large customers and distribution systems. Distribution Network Operators (DNOs) provide the infrastructure required to transport power from the high voltage transmission system to consumers. Some smaller "embedded" generators are also connected directly to distribution systems.
- **Short-Run Marginal Costs:** Once energy starts to flow over the infrastructure assets, it imposes additional costs of two kinds:[22]
  - **Constraint Costs:** Electricity transport costs show up as congestion within the transmission system when insufficient transport capacity is available to accommodate power flows. In a congested system, instead of using the transmission system to transport power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all areas. Output from other, cheaper generators, that would be producing electricity in an unconstrained system, must be reduced. In this case, electricity transport costs show up as the extra costs of altering the pattern of dispatch to resolve constraints.
  - **Losses:** Losses are also a cost of transporting electricity between two locations. The further energy travels along a distribution or transmission line, the higher the proportion of the energy that is lost. This lost energy has to be replaced, at a cost, by increasing total generation output.

As the Imperial modelling work summarised in Section 2.1.2 above demonstrates, different types of low carbon generation impose different levels of transmission and distribution investment costs on the system. If they are made to pay for these costs through the prevailing market and regulatory arrangements, then they do not constitute an externality and there is no need for further intervention to ensure efficient choices between low carbon generation technologies on grounds of differences in the system integration costs they impose. Differences in network access costs will be priced into the LCOEs that influence generators' offer prices in CFD FIT allocation processes. Conversely, if they do not face these costs, as

[22] Both constraint costs and losses can, to some degree, be avoided through the provision of additional transmission or distribution infrastructure. Hence, network operators face a trade-off between the capital costs of providing infrastructure and the variable costs of constraints and losses.

is the case in relation to socialised ancillary service costs (see the previous chapter), some policy intervention may be warranted.

4.2. Losses

In principle, differences in the losses caused by generators in different places and with different production profiles could be considered as one component of system integration costs,[23] which suggests some policy intervention may be warranted to ensure an efficient mix of low carbon generation technologies.

Under current trading arrangements, transmission-connected generators are asked to produce a little extra electricity to cover around half of total transmission losses, and consumers are asked to buy a little more electricity to cover the remainder. The shares of transmission losses allocated to generators and consumers do not vary according to their location. However, some generators are located a long way from areas with high demand (relative to supply), so their output has to travel long distances and results in relatively high losses. Similarly, some consumers are located a relatively long distance from the generation required to supply them, so a relatively high proportion of the generation required to supply them is lost. The overall consequences are that the allocation of losses does not promote efficient locational decisions by producers and consumers, and that some parties bear a greater share of the cost of losses than they impose (and vice versa).

Despite the absence of locational signals in respect of losses, distributed generators do, however, receive an “embedded benefit” associated with being closer to load, as their consumption attracts a negative loss factor, rewarding them for the avoided losses that would have come from the use of the transmission system. Hence, there is some differential between the system integration costs associated with losses that are caused by distribution-connected as compared to transmission-connected plant, but no differentiation between different types of generation in different parts of the transmission system.

The lack of a mechanism for setting locational and/or time-varying loss factors means that there may be some case for a policy intervention aimed at ensuring an efficient mix of low carbon plant that accounts for differences in the losses caused by different plant. However, as part of the CMA’s Energy Sector Investigation, it has proposed to introduce a locational loss scheme.[24] Hence other policy interventions should correct the market failure associated with a lack of locational loss factors, so there is no obvious case for further intervention.

4.3. Constraint Costs

As for losses, differences in the constraint costs caused by different types of generators will show up in the Imperial modelling as one component of the integration costs classified as generation operating and capital costs.

[23] Albeit, transmission and distribution losses are not accounted for within the WeSIM modelling framework. As discussed below, the potential system integration costs associated with losses does not justify a further policy intervention, on grounds that a more efficient system of loss allocation is currently in development. Hence, not considering losses explicitly in the system integration costs is not a material problem.

[24] Energy market investigation, Summary of provisional findings report, CMA, 7 July 2015.

In markets like Great Britain that apply a single national electricity market price without zonal variation in energy prices, constraint costs are incurred by the SO. The British government has decided (following the "connect and manage" decision) that constraint costs should be socialised across generation though the BSUoS charge. Hence, as for ancillary services, generators that cause constraints do not receive lower revenues or incur higher charges as a result. This fact reinforces the conclusion in the previous chapter that generation operating and capital costs do represent system externalities that justify some policy intervention to ensure an efficient choice between low carbon generation technologies.

It is possible that some types of low carbon generators that help the SO to *relieve* transmission constraints, e.g. because their output is flexible and they are located in parts of the system where generation is relatively scarce, may earn some additional revenues reflecting this benefit through the balancing mechanism. However, this benefit is probably marginal for low carbon plant.

4.4. Transmission Investment Costs

In the absence of locational energy pricing, which would probably improve efficiency, as described in Chapter 3, locational signals can be sent to generators through other channels. For instance, in theory, the same locational signals of transmission investment and constraint costs that are conveyed to generators through the locational marginal pricing of energy can be conveyed to generators through transmission tariffs that reflect the long-run marginal cost (LRMC) of generation required to efficiently accommodate generation onto the transmission grid.[25]

Locational variation in Transmission Network Use of System (TNUoS) charges can therefore be used to signal to generators of different types and in different locations how the transmission and constraint costs they impose on the system vary. Hence, if structured to reflect LRMC, different types of low carbon generators in different parts of the country will face different TNUoS reflecting differences in the transmission investment costs they impose, so this category of costs does not constitute an externality that warrants specific interventions to ensure efficient technology choice.

Recent reforms to TNUoS through Ofgem's "Project TransmiT" have sought to better reflect the costs that different types of generator impose on the system. The main impact of these changes is to compress regional variation in tariffs for intermittent plant. How closely these new charges reflect differences in the LRMC that intermittent plants face is a source of some disagreement amongst experts and industry bodies. For instance, recent work by NERA and Imperial suggests that the new charging methodology produces tariffs that reflect the LRMC of transmission less closely than the old methodology.[26] Specifically, we found that the cost of providing large reinforcements to the transmission system between Scotland and England are not reflected in the marginal tariffs paid by northern generation under the proposed

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[25] NERA Economic Consulting and Imperial College London, Assessing the Cost Reflectivity of Alternative TNUoS Methodologies: Prepared for RWE npower, 21 February 2014, Chapter 2.

[26] NERA Economic Consulting and Imperial College London, Assessing the Cost Reflectivity of Alternative TNUoS Methodologies: Prepared for RWE npower, 21 February 2014, Chapters 5 and 6.

reforms. However, Ofgem's decision to implement these reforms shows it considers the new methodology to be more cost reflective.

Nonetheless, from the perspective of the challenge government faces to select the optimal generation mix, it is probably reasonable to assume that no further adjustment is required to account for differences in the transmission infrastructure costs imposed by different types of low carbon plant in different locations. This approach assumes Ofgem will keep under review transmission pricing arrangements, and ensure charges reflect the LRMC of transmission.

4.5. Distribution Investment Costs

As with transmission pricing, if different types of low carbon generator face different types of Distribution Use of System (DUoS) charge reflecting the costs they impose, this category of system integration costs should not constitute an externality that warrants specific interventions to ensure efficient technology choice.

A distribution charging regime that sets tariffs equal to the incremental cost caused or avoided by the presence of particular users on the network will therefore promote efficient decisions by users, including developers of low carbon generation, with regard to the distribution costs they impose. In practice, this may be achieved by setting distribution charges that reflect users' locations on the grid, and their consumption (or export to the grid) at times when network capacity is constrained. Hence, locational and time-of-use DUoS charges, which have recently been introduced under the EHV Distribution Charging Methodology (EDCM) for larger users of distribution networks,[27] can price-in the costs of integrating low carbon generators onto the distribution system. However, the DUoS regime in place for users connecting at lower voltage levels are somewhat simpler and thus less capable of sending efficient signals to users.

Therefore, as for transmission investment costs, from the perspective of the challenge government faces to select the optimal generation mix, it is probably reasonable to assume that no further adjustment is required to account for differences in the distribution infrastructure costs imposed by different types of low carbon plant in different locations. This approach assumes Ofgem will keep under review charging arrangements, and ensure charges reflect the LRMC of distribution infrastructure as closely as possible.

4.6. Conclusions

If distribution and transmission access prices are cost reflective, which they are intended to be, then the system integration costs associated with distribution and transmission investment costs should be reflected in the costs incurred by low carbon power generators, and thus factored into policy decisions on technology choice and in the CFD FIT allocation auctions. However, TNUoS and DUoS reflect cost imperfectly, suggesting that some reforms to improve their cost reflectivity might be desirable.

[27] EHV Distribution Charging Methodology (EDCM), Energy Networks Association, April 2011.

5. Accounting for System Integration Costs in Designing Low Carbon Support Mechanisms

The first best way to ensure generators make decisions that minimise the costs of the electricity system as a whole is to ensure they face the marginal costs, or receive the marginal benefit of their actions, through the most proximate instrument. For instance, if they impose an additional system cost through the need to extend or strengthen the transmission network this would most efficiently be reflected in the transmission network charges they face, as discussed in the preceding chapter. Similarly, the benefit low carbon generators deliver by displacing production from other (often conventional) technologies is reflected in the market price of energy, as discussed in Chapter 3.

However, the CFD FIT regime insulates supported generators from the signals conveyed through wholesale electricity prices regarding the system integration costs they drive. Low carbon generators therefore have a limited incentive to operate in a way that supports their efficient integration into the power system, and the process of selecting the technologies and/or projects that are awarded CFD FIT contracts may be distorted by a failure to consider integration costs.

5.1. The CFD FIT Regime

5.1.1. Key commercial features of the CFD FIT contracts

The government has introduced a new subsidy regime for renewable and other low carbon generation technologies called the CFD FIT. These are long term contracts (generally 15 years for renewable technologies) which entitle the generator to a subsidy payment for each MWh of low carbon electricity they produce. The size of the subsidy payment is calculated as the difference between the strike price in the contract (set through auctions for renewable technologies) and the reference price for that technology. For intermittent technologies the market reference price is the day ahead hourly price in some combination of the APX and N2EX indices.

Generators with CFD FIT contracts are therefore largely insulated from the price signals produced by the wholesale market:

- Whatever the market reference price index included in the contract, generators receive the strike price they obtained following a competitive allocation process or through bilateral negotiation with the government. If market prices are below their strike price they receive a subsidy payment that provides a top-up to the strike price, or if prices are higher than the strike price they make a payment back to the CFD Counterparty Company equal to the difference between market prices and the strike prices. Hence, generators with CFD FIT contracts are largely insulated from variation in market prices, at least to the extent that they are driven by factors known to (or expected by) the market at the time when the reference price index is fixed.
- Generators supported by CFD FITs do still face a wholesale market price to some extent, because if they can “beat” the reference price in their contract they can earn additional revenues. However, in practice this has little effect as it is probably drowned out by the vast majority of their revenues coming from the difference between the strike price and

reference price, and in the case of intermittent generation, there being very little they can do to adjust their output in response to price signals.

- Generators covered by CFD FITs are still responsible for their imbalances, but this feature of the contracts only "prices in" the variation between day-ahead prices and real time balancing prices for the trading interval, as well as changes in their output that become known (or expected) between the day-ahead stage and gate closure. Hence, contracted generators are only exposed to the effects of new information that becomes available about supply and demand conditions between the time at which the reference price is set and delivery. For intermittent plant, this may "internalise" some of the costs associated with the unpredictable nature of their production, but many of these costs are not reflected in half-hourly market prices anyway, and under current market are socialised through ancillary service arrangements;
- Recently announced changes to future CFD FIT contracts for renewables alter this structure slightly, as generators' subsidy payments will cease when prices are consistently negative for 6 hours or more.[28] This means that supported generators will be exposed to market prices in periods when residual demand (demand, less output from must-run and low marginal cost plant) is negative. This change in approach means that generators expecting to be available in such periods of surplus would assume lower output in computing the LCOE that informs their offer prices in CFD FIT auctions. In effect, generators would price-in some of the integration costs associated with the need to curtail their output in periods when there is a surplus of energy. This change does not, however, encourage generators to price-in differences in the value of their output at other times, and this change is only likely to have any effect in a very small number of hours.[29]
- Many independent generators will choose to sign PPAs which protect them from balancing charges, in effect paying an offtaker to manage balancing risk, but this does not change the allocation of system costs to different generation technologies. It simply passes responsibility for despatch, balancing, and so on, as well as the value derived from subsidies and energy market revenues, from the developer to an offtaker.
  - In exchange for bearing this balancing risk as well as other costs of trading, such as any basis risk associated with the offtaker not being able to sell power at the market reference price specified in the contract.
- The link between subsidy payments and energy generated means that generators covered by the CFD FIT regime see a distorted signal regarding the economic value of their output to the energy system as a whole, and will be slow to respond to price signals (eg. negative balancing prices) that suggest it would be economic for them to curtail their production; and

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28 Electricity Market Reform – Contracts for Difference – Government Response to Consultation on Changes to the CFD Contract and CFD Regulations, June 2015.

29 Recent analysis commissioned by DECC suggests that this new provision for negative prices in the CFD FIT contract will only be triggered 80 times throughout the whole period to 2040, even under a relatively ambitious scenario regarding decarbonisation. Source: Electricity Market Reform – Contracts for Difference – Government Response to Consultation on Changes to the CFD Contract and CFD Regulations, June 2015, para 2.21.

- Generators covered by CFD FIT contracts do not participate in the Capacity Mechanism, so, combined with their insulation from most market price signals, they receive little or no signal regarding the capacity value of their plant; but
- Generators do still pay for the costs they impose on the transmission and distribution networks to the extent they are reflected in TNUoS and DUoS charges (see Chapter 4); and
- Low carbon generators can also provide ancillary services and earn revenues from doing so through payments from the SO, and they will compete with conventional generators in ancillary service markets. However, the link between subsidy payments and energy production blunts their incentives to do so, and the SO may also have weak incentives to procure ancillary services from non-conventional sources. This is because, at present, there is probably sufficient conventional capacity in place to provide the required supply of ancillary services reasonably economically, and because procuring ancillary services from low carbon plant creates technical challenges for the SO that, whilst not insurmountable, may require the adoption of new and innovative approaches

5.1.2. The CFD FIT allocation process

CFD FITs for renewable technologies are allocated through auctions for 3 different budgets or "pots":

- Pot 1 (established technologies): Onshore wind (>5MW), Solar Photovoltaic (PV) (>5MW), Energy from Waste with CHP, Hydro (>5MW and <50MW), Landfill Gas and Sewage Gas;
- Pot 2 (less established technologies): Offshore Wind, Wave, Tidal Stream, Advanced Conversion Technologies, Anaerobic Digestion, Dedicated biomass with CHP, and Geothermal; and
- Pot 3: Biomass conversion.

Rational bidders in these auctions would be expected to include within their strike price bids their own levelised cost of energy, including their expectations of the network and balancing charges for which they would be liable. Other low-carbon technologies (principally nuclear and CCS projects) can receive CFD FIT contracts through bilateral negotiations and agreements with government. Through these negotiations, developers would also factor in all relevant costs for their project including the network and balancing charges for which they would be liable.

However, as noted above, the costs faced by CFD generators will not fully reflect the costs they impose on the system in respect of changes in the capital and operational costs of other generation.

5.1.3. Identifying options for reform

There are a number of potential adjustments to both the format of the CFD FIT contracts and the process through which they are allocated to generators that could better account for the system integration costs they cause. Below we identify a series of policy options and assess at a very high level the merits of each. We recognise, of course, that a fuller cost-benefit analysis would be required to investigate more fully the options proposed.

5.2. Changes to the Allocation of CFD FIT Contracts

There are a number of potential adjustments, listed as follows and explained further below, to the CFD FIT allocation framework, which could improve the extent to which generators are exposed to the system integration costs of their project.

5.2.1. Constraints on allocation of subsidies to technologies with relatively high integration costs

One approach that would account for differences in the integration costs caused by low carbon generation technologies would be to constrain the allocation of subsidies to those technologies with relatively high integration costs. Conceptually, this involves government performing some analysis to

1. Quantify the system integration costs associated with different low carbon technologies, such as using the Imperial estimates summarised in Chapter 2. Calculating the relative system integration costs for each participating technology may be technically challenging, though as the Imperial modelling demonstrates, it is not impossible. Also, we understand that DECC is enhancing its ability to model system integration costs, so it should not be infeasible for government to perform this calculation;
2. Estimating a supply curve of low carbon projects and how this supply curve would change after adding the estimated system integration costs for each project/technology that are not already reflected in the charges or costs faced by generators (eg. it would not be appropriate to include network costs in this calculation if TNUoS and DUoS are already factored into estimated LCOEs); and
3. Using the adjusted supply curve resulting from (2), identify the mix of low carbon plant that minimises total costs, after accounting for any constraints on government's desired deployment of some (eg. emerging) technologies. This estimated technology mix can then be used to set minima/maxima on deployment, or to pre-allocate funding to particular groups of technologies.

In practice, the policy option of setting CFD budgets for each pot in a way which takes account of the system integration costs is something that can be done relatively quickly and easily by government, following the above modelling procedure. For instance, one way to get a technology mix that includes more capacity from technologies with relatively low whole system costs and less capacity from technologies with high whole system costs would be to put more budget into pot 3 (biomass conversion) and less budget into pot 2 (mainly offshore wind) or pot 1 (onshore wind and solar).

However, this would not account for the different integration costs caused by different technologies in the same pot. Splitting technologies into a larger number of pots would be one way to address this concern, but it would come at the cost of reducing the extent of competition between low carbon technologies through the allocation mechanism.

The similar policy of introducing maxima (or minima) for certain technologies to limit deployment of those technologies that impose relatively high (or low) system integration costs would have similar effects. However, introducing maxima might be a more logical approach where research indicates that the system integration costs associated with particular technologies increases markedly at a certain level of deployment.

Defining maximum levels of deployment comes with the disadvantage, however, that if a technology turns out to be cheaper than expected (before accounting for system integration costs), the auction clearing mechanism would be constrained in its ability to increase demand for that technology. This problem would apply to the approach of constraining the budget allocated to particular technologies, but to a lesser extent because unexpectedly low bids would still result in procurement of more capacity for a fixed budget.

However, because, as the Imperial modelling shows, the system integration cost caused by particular technologies can be sensitive to the modelling assumptions used, calibrating any constraints on the allocation of contracts to particular technologies is likely to entail substantial subjectivity.

5.2.2. Introducing handicaps to reflect differential system integration costs

Another policy option that allows the CFD FIT allocation mechanism to consider integration costs would be to introduce handicaps for each technology based on its relative system integration costs. This approach would require that the government

1. Quantify the system integration costs associated with different low carbon technologies, such as using the Imperial estimates summarised in Chapter 2;
2. For each technology identify which components of system integration costs are already likely to be included within low carbon generators' offer prices (eg. TNUoS and DUoS), and excluding those parts of estimate system integration costs from the calculation; and
3. Using the remaining system integration costs not already priced into generators' LCOEs through other mechanisms to derive bid adders that would be applied when choosing between generators' offer prices in the CFD FIT auctions.

The main benefit of this approach, as compared to constraining the CFD FIT allocation mechanism by adjusting budgets for each pot or applying maxima or minima is that it would better allow different technologies to compete alongside each other for subsidy. It may also place less reliance on government's estimate of the LCOEs of different generation technologies. The downside is that, like all the options for adjusting the allocation procedure, they rely on modelled estimates of system integration costs.

5.2.3. The need to identify which components of integration costs are priced into generators' LCOEs

As described above, adjustments to the CFD FIT allocation mechanism to account for integration costs all require an administered estimate of the relative integration costs associated with each technology, from which government would need top subtract those elements of integration costs already priced into estimated LCOEs. As discussed above, for some aspects of generation cost, identifying which cost categories are priced in through market or regulatory mechanisms and included in LCOEs is relatively clear cut. For instance, as discussed in Chapter 4, TNUoS and DUoS charges should price in the integration costs associated with network reinforcement. In contrast, as Chapter 3 explains, LCOEs will not tend to price in the integration costs associated with generation operational and capital costs.

There may some grey areas, however, that mean it is not entirely straightforward to identify which cost categories are included or excluded. In particular, and as discussed above, all generators, including those receiving CFD FIT contracts, bear the risk that their output will be different from the amount they expect to generate (and sell) at the day-ahead stage, and that prices will change between the day-ahead stage and real time. This balancing risk is one component of system integration costs, and in practice is hard to separate from the other components of the integration costs associated with generation operational and capital costs. A solution to this problem could be to identify market evidence on the extent to which this cost currently imposes a cost on different generation technologies based on real market data, and then to subtract these costs from generators relative integration costs. However, performing such calculations is beyond the scope of this report.

5.3. Changes to the Structure of CFD FIT Contracts

Changes to the structure of the CFD FIT contracts might also improve the extent to which generators are exposed to market prices and signals, and thus account for the system integration costs.

For instance, one option would be to change the reference price to expose generators to price signals in the energy market. For example, all types of low carbon plant could face a market reference price, such as a year-ahead baseload price, which would incentivise them to be more responsive to system needs. We are conscious that DECC did consider this as part of the development of the final CFD contract terms and decided against it due to the inability of wind farms to control their output – they generate when the wind blows. However, it is possible for wind farms to turn down their output in response to market signals that there is oversupply and even to turn the blades and provide some form of fast-response. This reform would also provide wind farms with an incentive to schedule maintenance outages for times of the year when the market is likely to be relatively well-supplied, which they do not have under the current structure.

However, this reform would not address the problem that subsidy payments would be linked to energy production, leaving wind farms' offer prices markedly below their variable costs of production and muting their incentive to respond to price signals. An alternative (more radical) reform that would address this problem would be to switch from paying subsidies based on actual production to some measure of expected or contracted production. This would decouple subsidy payments from actual output, thus providing a marginal incentive to generators to increase or decrease their output in response to price signals from both energy and potentially the ancillary service markets too.

Enabling projects with CFDs to also participate in the capacity market auctions and potentially receive capacity payments would also provide additional remuneration to those plant with relatively high expected availability at peak time, recognising the system benefit they provide by offsetting the need for thermal back-up plant to ensure demand can be met in peak demand conditions.[30]

[30] On the face of it, this may appear to policymakers as providing wind farms with unnecessary additional subsidy through the capacity market. This is not the case, however, as generators would factor in their expected capacity market revenues when selecting their offer prices into the CFD FIT auction.

5.4. Support for Technologies that Reduce Integration Costs

Increasing the penetration of flexibility technologies such as storage, DSR interconnection or flexible generation may materially reduce the integration costs associated with intermittent renewable technologies, as the Imperial modelling shows (see Figure 2.4, for instance). In fact, as the Imperial modelling shows, some increase in the penetration of these technologies may be a pre-requisite for achieving low levels of carbon intensity in the power sector, as Figure 2.4 demonstrates.

In principle, all of these technologies make money from arbitraging spreads between high prices in periods (or locations, in the case of interconnection) of relative scarcity, and low prices in periods (or locations) of relative surplus. They also provide ancillary services, and help to avoid the need for grid reinforcement. Hence, if energy and ancillary service prices, as well as grid access charges, are reflective of marginal cost, the deployment of these technologies should be economically efficient. However, as noted in previous chapters, some reform of these market/charging mechanisms is probably desirable to ensure producers and consumers of electricity receive more efficient price signals.

Absent such reforms, it may not be possible to achieve an economically efficient deployment of storage and DSR, and some form of explicit support may be required. And even then, the case for investing in flexibility technologies today may be undermined by uncertainty over future government policy in relation to the future generation mix. However, further work would be needed to assess the case for supporting these technologies through some form of subsidy or long-term contract. For instance, while some aspects of current market arrangements might undervalue services such as storage, other forms of government intervention, in particular energy-based subsidy schemes, might exaggerate differentials between peak and off-peak prices compared to underlying differences in system marginal cost, thus exaggerating the value of some flexibility technologies.

Further, even if government support to flexibility technologies were desirable, further work would also be required to design the commercial mechanisms through which such technologies were offered support. For instance, a CFD contract structure linked to the actual production or consumption of storage of demand side units would almost certainly lead to inefficient usage of storage plant; it would be essential for efficiency that providers of flexibility services are exposed to market price signals.

5.5. Conclusions and Recommendations

Generators with CFD FIT contracts are largely insulated from the price signals produced by the wholesale electricity market, and save for some marginal to changes in market prices between the time when the market reference price is fixed and delivery, they receive blunted economic signals regarding the value of their output to the system as a whole and therefore (1) provide less responsiveness to system needs than would be economically efficient, and (2) the process of selecting between low carbon generation technologies (in the allocation of CFD FIT contracts) ignores differences in the integration costs generators impose.

Some enhancements to the process for allocating CFD contracts and to the contract terms themselves might therefore be necessary to internalise system integration costs and ensure an efficient mix of low carbon technologies is developed under the CFD FIT subsidy regime.

If, as we recommend, generation technologies supported through subsidies are exposed to market price signals to a greater extent, the reforms described in previous chapters to improve the efficiency of market price signals become more important in ensuring generators and policymakers account for system integration costs efficiently.

We recognise, of course, that while the policy options outlined in this chapter warrant further consideration by government, further analysis is needed to develop and appraise them further.

6. Summary and Conclusions

When new low carbon generation capacity is added to the power system, the increase in costs is not determined solely by the costs of developing and operating the newly connected generation capacity; changing the generation mix has a series of knock-on effects. The despatch of other generation plant, the need for back-up capacity to ensure peak demand can be met, network investment and constraint costs, and ancillary services costs can all be affected. These additional costs are known as system integration costs.

In a well-functioning, competitive power market, there is no reason why these integration costs would constitute an externality that justifies government intervention. In reality, however, the idealised notion of a perfectly competitive market does not apply. In fact, the current power market design is limited in its ability to signal system integration costs to generators that cause system integration costs to be incurred and to the benefits of mitigating any such increases in system integration costs provided by others (eg. flexibility providers). In this report, we have set out a range of reforms to market arrangements that would better signal integration costs to all market participants, including improving the extent to which energy prices reflect underlying system marginal cost by introducing shorter trading intervals, and introducing real time markets for ancillary services.

However, even with these reforms to better reflect system integration costs through more efficient energy, capacity and ancillary service markets, the effect of efficient markets to account for integration costs is constrained because (1) low carbon generators' subsidy payments largely insulate them from energy and capacity price signals, and (2) the ancillary services costs associated with integrating low carbon generators are socialised.

Hence, while new policies that improve the efficiency of market price signals will help to internalise the externalities associated with system integration costs, such reforms would be more effective if they were combined with reform of subsidy arrangements to expose supported generators to market price signals. Some enhancements to the process for allocating CFD contracts and to the contract terms themselves might therefore be necessary to internalise system integration costs and ensure an efficient mix of low carbon technologies is developed under the CFD FIT subsidy regime.

Another important dimension of system integration costs are the costs of developing the transmission and distribution networks to accommodate changes in the generation mix. If distribution and transmission access prices are cost reflective, which they are intended to be, then the system integration costs associated with distribution and transmission investment costs should be reflected in the costs incurred by low carbon power generators, and thus factored into policy decisions on technology choice and in the CFD FIT allocation auctions. It is therefore important that the structure of TNUoS and DUoS charges be kept under review to ensure they remain as cost reflective as possible.

Finally, we recognise, of course, that while the policy options outlined in this chapter warrant further consideration by government, further analysis is needed to develop and appraise them further. There may also be transaction costs associated with some of the changes we propose, which warrant separate study.

Appendix A. Alternative Methods for Estimating System Integration Costs

- **Method 1:**
  - Imperial starts by defining a baseline scenario in which the British electricity sector decarbonises to achieve emissions intensity of either 50g/kWh or 100g/kWh by 2030 using a mix of low carbon generation technologies, which forms the basis for the analysis performed under each Method. See Figure E.2. in the Imperial report, for instance.
  - To implement Method 1, Imperial then adds a moderate amount of wind, solar photovoltaic (PV) or carbon capture and storage (CCS) generation capacity to the system.
  - At the same time, Imperial removes an amount of nuclear capacity that produces the same amount of energy. Hence, adding 1GW of wind running at a 30% load factor, would result in removing 333MW of nuclear running at a 90% load factor,[31] so total energy production from low carbon generation sources remains the same.[32]
  - The model is also constrained to maintain the same level of carbon emissions. Imperial imposes this constraint because (1) adding CCS capacity increases emissions slightly if it replaces nuclear, solar PV or wind capacity, (2) changing the technology mix may change the required capacity mix and despatch of other fossil fuel-fired technologies to provide ancillary services and meet the given security standard, and (3) when some low carbon plant is added to the system, not all of its theoretically available output can be absorbed in periods of low demand and/or high output from intermittent plant (ie. less renewables output is absorbed than nuclear output removed, and resulting increase in emissions is offset by the model adding extra CCS capacity).
  - Imperial then computes the changes in total system costs, excluding the investment and operation costs (ie. LCOEs) of the pairs of technologies that are being swapped, and divides this figure by the annual output of the added technology to establish its *relative integration cost* against nuclear power.
  - The same approach could be applied while using any other low-carbon generation technology as a reference. But under this approach, integration costs are all defined as relative to another technology.
- **Method 2:**
  - A moderate amount of nuclear capacity is removed from (or added to) the system, while the model is allowed to increase (or decrease) either wind or PV capacity to maintain same level of CO_2 emissions as before the nuclear was removed. In choosing how much capacity to add, the model can either add wind/PV capacity,

31 333MW = 1GW * 30% / 90%

32 Imperial also performed the calculation the other way around to (partially) compensate for the effects of non-linearity in the cost effects of adding/removing capacity to/from the system. Specifically, they also added 1GW of nuclear and removed energy-equivalent amount of wind or PV. Values plotted in the figures below represent averages of these two approaches.

and/or re-despatch the rest of the generation fleet to maintain the given level of emissions at least cost.

  - As in Method 1, Imperial then divides the change in total system cost by the increase in generation output from either wind or PV, as in Method 1 to identify the relative integration cost. However, if the model chooses to add more (or less) wind/solar than the energy-equivalent amount of nuclear removed from the system, the additional cost (or saving) is also factored into the numerator of this integration cost calculation.

- **Method 3:**
  - A moderate amount of nuclear, wind, PV or CCS capacity is added to the system, and the system is allowed to readjust its CCS capacity (or nuclear if CCS is added) to minimise cost while maintaining the same system level of emissions and security standard as in the baseline.
  - Imperial then divides the reduction in total system costs (ignoring the capital and operating costs of the added low-carbon plant) by the additional output of the added technology to establish the *marginal system benefit* per MWh of output for that technology. Differences in this marginal benefit across technologies (computed relative to the cost of plant that is added) allows Imperial to quantify system integration costs.

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