Intermittency and the cost of integrating solar in the GB power market

September 2016

Foreword

This report commissioned by the Solar Trade Association was prepared by Aurora Energy Research.

The analysis represents Aurora's independent views. The assumptions made and forecasts underpinning the analysis are consistent with Aurora's widely used GB Power Market Quarterly Forecast, unless noted otherwise.

For more information about Aurora Energy Research, see www.auroraer.com.

About Aurora Energy Research

Aurora Energy Research is an independent energy market analytics firm, providing data, forecasts and insights on UK, European and global energy markets. Our power market models simulate wholesale, balancing and capacity markets, and economic investment decisions across all generation technologies (including battery storage) to provide internally consistent forecasts. Our reports and advisory work provide unique and powerful insights to our clients and subscribers who include generators, developers, banks, regulators and NGOs.

Contents

Executive Summary

As renewable power capacity increases in Great Britain's electricity system, assurance is needed that the costs of integrating and managing the intermittency associated with renewable power, such as solar, is manageable. Greater articulation of the system costs will also enable fairer competition with other sources of low-carbon power and more informed policy choices.

In this report we estimate the current and future costs of intermittency for solar, that is, the cost of *integrating and backing up* solar's variable output, rather than the cost of *generating* the solar power in the first place.

We find that the cost of intermittency for the 11GW of solar currently on the system is £1.3/MWh. This figure would increase to around £6.8/MWh by 2030 as solar capacity reaches 40GW – a cost in the order of one tenth that of the total cost of a MWh of solar electricity today. This cost comprises three components:

1. Part of this cost (around £3/MWh) is driven by the output variability, that is, the fact that solar power is produced when the sun shines, and not necessarily the time at which it would be the most valuable;
2. A further £4.5/MWh of intermittency cost comes from the need for backup generation that can provide security of supply when the sun is not shining;

Intermittency costs of solar

£/MWh

	Central forecast	45GW of wind	No new nuclear	High battery penetration
	6.8	5.1	3.1	-3.7

1.3

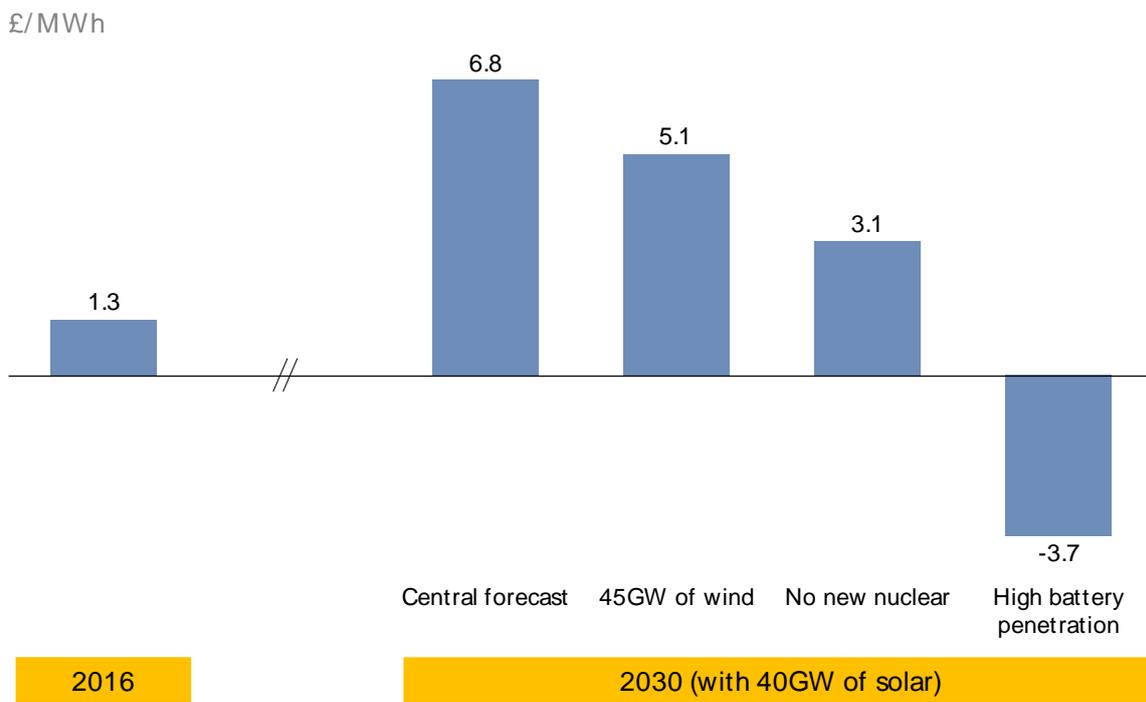| 2016 | 2030 (with 40GW of solar) |

Figure 1

and

3. Balancing costs passed onto the system by solar are more than offset by the additional system flexibility provided by the backup generation brought on. The presence of substantial backup capacity has the side benefit of reducing the costs of balancing, taking £0.7/MWh off the overall intermittency cost.

With additional wind on the system (up to 45GW by 2030), we find that the cost of intermittency for solar would be reduced to £5.1/MWh. This demonstrates the benefit of a diverse renewables portfolio, as solar and wind deliver their output at different times.

We further find that such an intermittency cost would be reduced in a scenario with no further nuclear build out to around £3.1/MWh, due to the more flexible alternative generation technologies we would expect to see emerge from the capacity market in the absence of new nuclear.

A scenario with cheaper batteries would also have a lower solar intermittency cost. Batteries allow excess power to be delivered at a more valuable time and reduce the need for backup generation. In a scenario with 8GW of batteries on the system by 2030, we find the overall intermittency cost would in fact become negative, falling to around £-3.7/MWh. This effectively means that the intermittency of solar provides a net benefit through enabling the entry of batteries.

In the context of rapidly falling solar and wind generation costs and an increasing need for affordable low-carbon power, we do not see these costs as a major barrier to further renewable penetration.

1. Introduction

1.1. Context

As the amount of renewable generation on the system increases, the challenges and costs associated with integrating the intermittent output into the energy system are more commonly being considered in the debate about renewables subsidies and build-out rates.

The "cost of intermittency" is a many-facetted concept, requiring detailed analysis to quantify. The most common and intuitive claim against renewable generation is that it cannot deliver if the wind does not blow and the sun does not shine, and therefore results in either an unreliable generation system or one with a large amount of costly backup capacity.

While this report focuses on the cost of integrating renewables, it also acknowledges that renewable generation has significant benefits. For instance, renewables provide power that is carbon-emission free. Furthermore, the costs of many renewable technologies are falling rapidly and are may be cheaper on a per MWh[1] basis than fossil fuel alternatives in the future.

Understanding the costs of variable renewable generation is important in order to identify the most cost-effective pathways for decarbonising the power system, and for enabling the true comparison of generation options, or fair competition between technologies, within the available carbon budgets.

It is this intermittency cost that we seek to both define and quantify in this report with a view to informing the broader debate about the best generation mix for the GB economy. The quantification and forecasting of intermittency costs is highly technical, and underpinned by Aurora's system-level energy market model that forecasts simultaneously across energy, capacity and balancing markets. As much as is possible, this report focusses on the results and implications of the modelling and analysis rather than on detailed and technical discussions of methodology.

1.2. Defining intermittency cost

We define the cost of intermittency as:

---

[1] Megawatt-hour, an amount of electricity worth around £50 in the wholesale market.

The external[2] costs imposed on the energy system resulting from the timing and predictability of a given generation technology's power output relative to a case where the same number of MWhs are generated evenly over every hour of the year.

By focusing on net *external* costs, we exclude costs of intermittency that are paid for by the renewable asset owner and count only those costs borne by other market participants or the consumer. By comparing the renewable technology's output to an alternative scenario where the only changed factor is the timing of the output, we are able to focus exclusively on intermittency costs. This is distinct from comparisons that also include other cost differences such as construction and operating costs.

The term "intermittent" is commonly used to describe the output from solar and wind, but some industry analysts prefer the term "variable" to describe such generation. For example, the International Energy Agency (IEA) refers to solar and wind generation as variable renewable electricity. For the purposes of this report, we use intermittent and variable synonymously to describe the output of solar.

We break down the total intermittency cost into three component parts, each of which can be quantified separately and easily understood.

1.2.1.   Timeliness of delivery

"Not all MWhs are created equal".

A MWh delivered at times of the year when demand is high and supply is low is inherently more valuable than a MWh delivered when demand is low and supply is high.

This constantly changing value of a MWh of electricity is efficiently represented by the wholesale power price, something that can be readily observed and forecasted with half-hourly resolution. The wholesale power price can vary dramatically over the course of a year to over £100 per MWh in high demand/low supply periods and to negligibly low or even negative levels when demand is low and supply is high.

So to quantify the extent to which the timeliness of delivery adds or subtracts value from the MWh of electricity produced by driving out more expensive forms of generation and reducing the wholesale power price, we calculate the weighted average wholesale power market price in all the hours of a year when power is

---

[2] That is, the costs passed on to the energy system and ultimately paid by the consumer rather than paid for by the generation asset itself

typically delivered by a given technology (sometimes called the "capture price") and compare it to the baseload power price. If the capture price is on average less than the baseload power price, then the timeliness of delivery of the MWhs produced over a year is disadvantaging this generation technology against a baseload alternative.

1.2.2. Need for backup generation

"When the wind doesn't blow and the sun doesn't shine".

The second component of intermittency cost we describe is the need for backup, that is, in the event that the wind does not blow and the sun does not shine, there is a cost of maintaining sufficient backup generation on the system to keep the lights on year around. This backup generation is typically gas- or diesel-fired generation, and in the future will also be provided by batteries.

Whilst intuitively a simple concept, quantifying it is difficult. The calculation has to be done at a system level, and with consideration of the "averaging effect" that a diverse set of technologies, geographic locations and weather patterns can offer. This averaging effect means that the backup cost at a system level is less than the cost of backing up every individual renewable asset with a dedicated gas or diesel plant that does nothing other than even out the generation output or guarantee delivery during times of system stress.

The backup cost must also take into consideration the revenue such backup capacity can capture by simultaneously offering other services to the market in addition to the backup of renewables. If, for example, a backup plant could provide an ancillary service such as frequency response without this interfering with its ability to provide backup, the net cost to the system of the backup capacity would be less.

We calculate this cost at a system level by calculating the amount and type of generation that would enter the power system via the capacity market in order to provide the necessary security of supply[3] for a given level of renewable penetration, and compare this to the case where renewable generation output is evenly distributed and hence less backup capacity enters the system.

1.2.3. Short-term forecasting accuracy

"Does it deliver exactly when it says it will?"

The third and final component of the cost of intermittency we describe as "short term forecasting accuracy", that is, the degree to which the technology delivers the power

---

[3] Technically, this is determined by the 3-hour Loss of Load Expectation (LOLE) specified in the capacity market design

it says it will, 30 minutes ahead of time. This time window is important since it corresponds to the operation of the balancing market, where supply and demand are balanced in real time by the system operator.

Wind and solar, like all generators, will submit their expected output to the system operator 30 minutes in advance of delivering it. If the weather then changes and the power cannot be delivered, the system operator will procure other sources of generation at short notice and the renewable generator will be penalised for non-delivery.

While the financial penalty for non-delivery of the renewable power known as the "cash-out price" is borne by the asset owner and therefore not included in our definition of intermittency cost, there is a subtler knock-on effect to the cash-out price itself, with more demand for balancing driving up the cash-out price paid by the rest of the system. It is these additional costs we quantify as the impact of short-term forecasting accuracy.

1.3. Other costs and benefits associated with renewable power

We do not quantify the impact renewables have on **transmission and distribution costs or benefits** in this report. Any such costs paid for by the renewable developer or asset owner would in any case not be included, but there are other costs renewables can impose on transmission and distribution by exacerbating congestion and increasing the amount of capacity required to cope with low utilisation and volatile demand. Conversely distributed renewables can defer or avoid more expensive grid reinforcement costs at higher voltages.

We do however capture the impact on headroom and footroom, and balancing mechanism constraint management through our balancing market modelling.

We do take account of what are sometimes called **spill costs,** where not all power from renewable generation can be used and is 'spilt', typically by paying the generator not to deliver it. This is accounted for in our 'timeliness of delivery' category, since power produced and not used is by definition worthless and thus drags down the capture price.

Our 'timeliness of delivery' measure also takes into account the **merit order effects** of power system. This effect occurs when solar is generating, which reduces the generation required from other technologies and thus changes the power price and the total cost of the power system.

2. The cost of intermittency for solar PV today

We currently have around 11 GW of solar generation on the GB power system, which includes all types of solar from domestic rooftops to ground mounted solar farms. At these levels, we estimate solar's cost of intermittency today is around £1.3/MWh.

Intermittency costs of solar in 2016
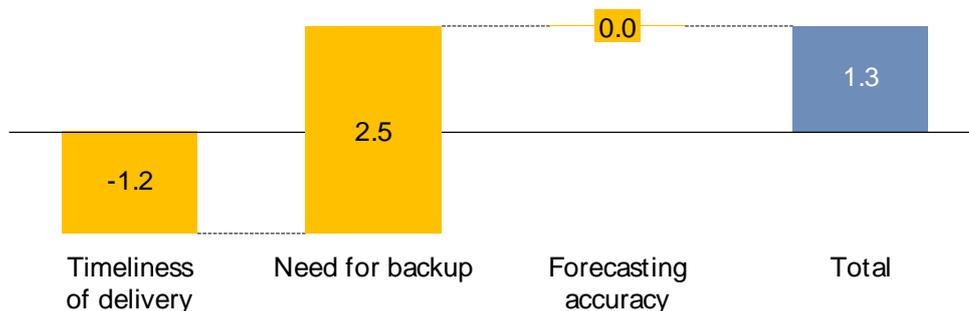
£/MWh

Figure 2

For solar, we see the timeliness of delivery explaining about £-1.2/MWh of the cost since solar delivers its output at times when the power price is higher than the baseload price. Solar has the advantage of delivering output during the day when demand is higher rather than overnight when demand is lower. However as solar penetration levels increase over time, so much power may be available during sunny

periods that the wholesale price is pushed own and solar cannibalises its own capture price.

The need for backup capacity for solar creates a corresponding intermittency cost of £2.5/MWh. As the capacity market is not yet enacted in 2016, we use instead the cost of reserve capacity[4] to quantify the cost of backup for the existing renewable generation.

The cost associated with short-term forecasting accuracy we find to be roughly zero today. This is not because there is no forecasting error; unexpected under- or over-delivery does occur and the cost associated with this is borne by the generator (and thus not included in the cost of intermittency). Rather, current levels of solar penetration have a negligible impact on the overall cost of balancing the system because its forecasting errors diffused at a system level by wind and demand uncertainty.

---

[4] National Grid has procured 3.5GW of Supplemental Balancing Reserve (SBR) for the winter of 2016/17, used to ensure security of supply.

3. The cost of intermittency for solar PV in the future

3.1.   40GW of solar by 2030

To understand the impact a future increase in solar penetration may have on intermittency cost, we have simulated the evolution of the energy market under a scenario where the total installed solar capacity increases from 11GW today to 40GW by 2030.

With this increased solar penetration, capture price cannibalisation begins to occur. This increases the intermittency cost associated with the timeliness of delivery from £-1.2/MWh today to £3/MWh by 2030. While solar continues to benefit from delivering much of its power during peak summer afternoon periods, eventually so much power is delivered at these times that thermal generation with a higher marginal cost is frequently not required, and the capture price falls.

The cost of backup capacity for solar increases from £2.5/MWh today to £4.5/MWh by 2030. The high penetration of solar on the system necessitates more backup procured through the capacity market. The backup procured would also require higher capacity payments to incentivise entry as the high levels of solar lowers day time power prices.

Because of this increased backup capacity, the impact of the short-term 'forecastability' of solar is £-0.7/MWh, which is a net benefit. The reason for this is that the substantial backup capacity that emerges to ensure security of supply is flexible generation. This capacity plays into the balancing mechanism, and a useful side effect is to reduce the cash-out price and therefore balancing cost paid by the rest of the generation fleet.

Intermittency costs of solar by 2030, with 40GW of solar
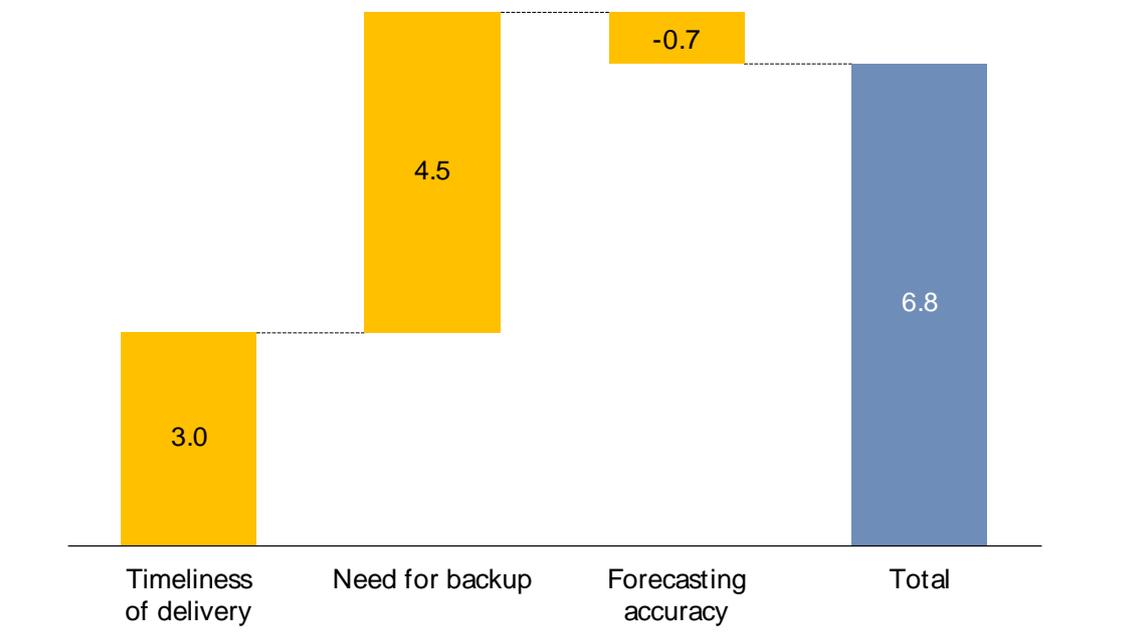
£/MWh, average 2025-2035

Figure 3

3.2. Lesser levels of solar penetration by 2030

With lower levels of solar penetration, the intermittency cost of solar is also lower. From model simulations with incremental levels of solar penetration (with 2030 solar capacity at 12GW, 15GW, 20GW etc.), we find that there is a near linear relationship between solar capacity and its intermittency cost, not the 'exponential' increase that might be expected at these penetration levels. A doubling of solar capacity from today's 11GW would bring the cost of intermittency from £1.3/MWh to £3.4/MWh.

Additional solar capacity primarily increases the intermittency cost associated with timeliness of delivery. High solar penetrations push down the power price when solar delivers its output and thus cannibalises the capture price.

Higher levels of solar capacity also increase the costs for the need for backup. The added solar cannot be used to meet the winter peaks, so there is an additional cost to procure adequate backup generation to ensure security of supply.

Intermittency cost of solar by 2030, at different levels of solar penetration
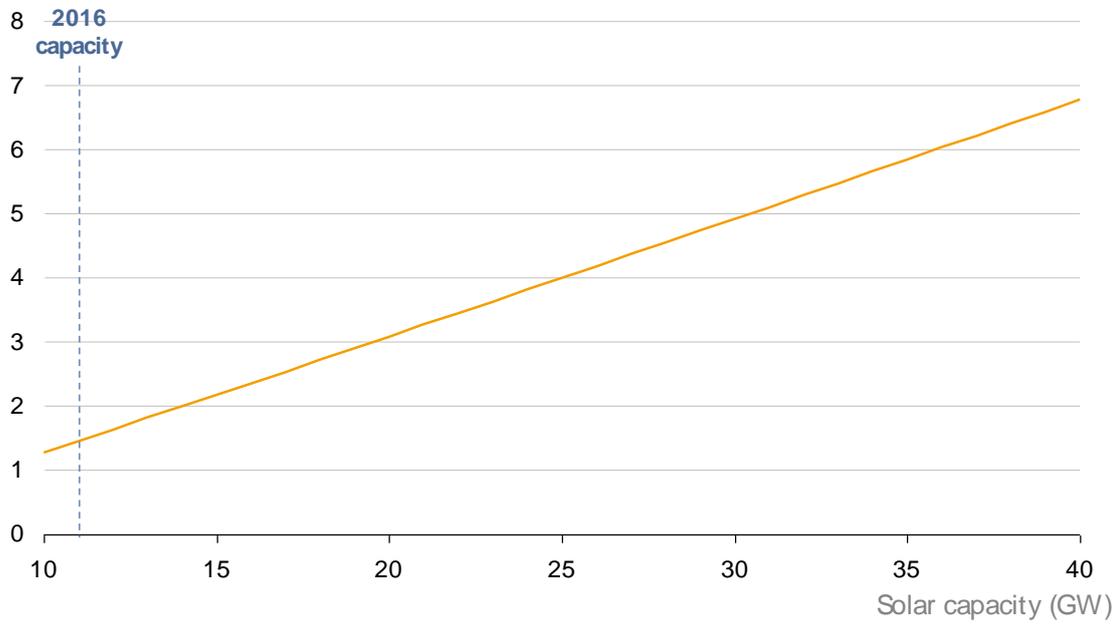
£/MWh, average 2025-2035

Figure 4

4. The impact of other generation technologies on solar intermittency costs

4.1. The impact of additional wind

Solar output is delivered at different times than wind output, and thus having both on the system allows for their intermittency to be diversified. In a system with a lot of wind, the ability of solar to generate at times when there is less wind output becomes proportionately more valuable.

We quantify this portfolio benefit by comparing our central case, in which we hold today's 16GW of wind constant, to a scenario with wind capacity reaching 45GW by 2030.

As the additional wind contributes a small amount to the security of supply in winter months, there would be a slight reduction in generation procured through the capacity market in this scenario. We find that the additional 29GW of wind capacity decreases the intermittency cost of solar from £6.8/MWh to £5.1/MWh, a difference of about one quarter.

The main added value of solar when there is additional wind is through the improved timeliness of delivery. The high wind penetration would depress prices whenever wind generates, which is often overnight and in the winter. However, solar output is generated in the daytime and at higher volumes during the summer. This allows solar to avoid the lower prices caused by wind generation and achieve an improved capture price relative to the baseload price.

While wind also creates an own intermittency cost of its own, the ability of additional wind to reduce the intermittency cost of solar (and vice versa) highlights the value of having a diversified portfolio of renewables on the system.

The impact of additional wind on intermittency cost (with 40GW of solar)
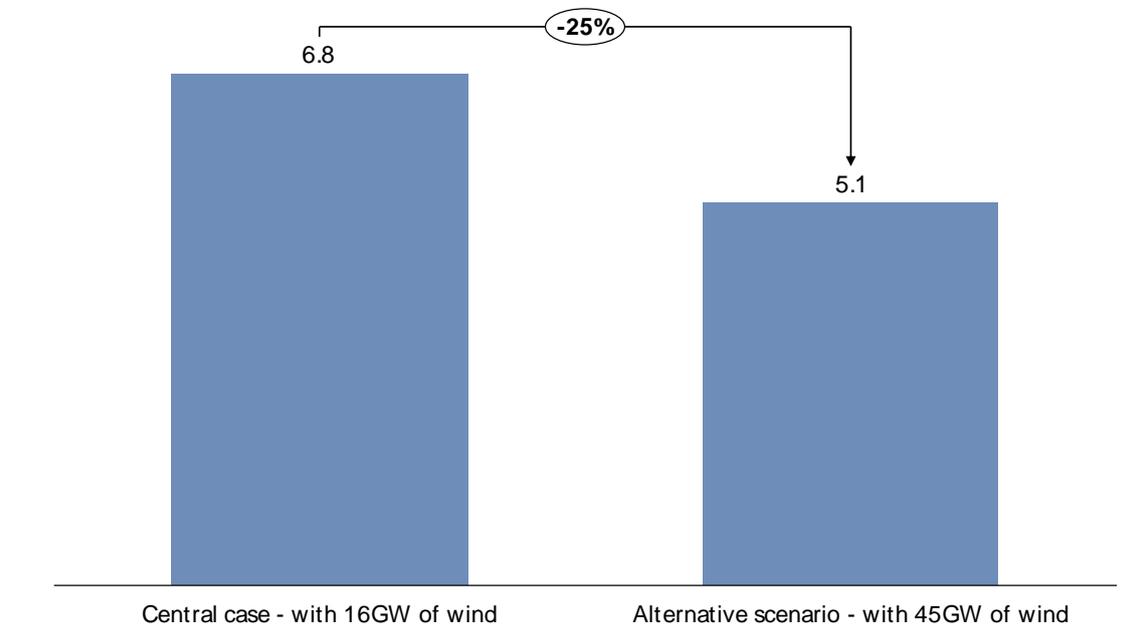
£/MWh, average 2025-2035

Figure 5

4.2. The impact of no new nuclear

Intermittency cost is a function not just of the nature of renewable generation, but also of the system into which the renewable generation is placed. If the system is generally flexible, with the ability to deliver more or less power at minimal cost, then renewable intermittency has minimal associated cost.

Nuclear power is inflexible, designed to run more than 90% of the hours in a year. While some forms of nuclear technology can technically ramp down at short notice, the reality is they are extremely reluctant to do so, and bid into the balancing mechanism in such a way that they will always be the last technology to turn down in the event of there being excess power on the system.

It follows therefore that if more nuclear is added to the GB generation system, first with Hinkley C, and subsequently with a number of other projects, the flexibility of the GB system will be reduced, and the cost of renewable intermittency will therefore be higher than a scenario in which no further nuclear generation is added.

Our analysis supports this hypothesis. We have compared our Central case scenario in section 3 in which Hinkley C is delivered in 2027 and other subsequent projects are delivered two years behind schedule, to a scenario where no further nuclear generation is added. Instead, additional capacity is procured through the capacity

market. By modelling the competition of technologies in the capacity market auctions, we find that a combination of CCGT, demand side response, battery storage and reciprocating engines will take the place of nuclear.[5]

We find that replacing new nuclear generation with more of these more flexible forms of generation decreases the intermittency cost of solar from £6.8/MWh to £3.1/MWh, more than halving the cost.

This benefit is driven by two forces, each in roughly equal proportion. First, related to the timeliness of delivery: the absence of 'must run' nuclear means that high renewable penetration causes less cannibalisation of its own capture price. When renewable output is high, flexible generation simply shuts down and prices remain relatively high compared to our Central case scenario where new nuclear stays running and prices fall by a greater amount.

Second, the cost of backup also falls in the no new nuclear scenario. With no new nuclear, existing CCGT runs higher load factors and incurs less ramping cost to deliver the flexibility demanded by additional solar. As a result, it is more profitable and bids less in the capacity market, driving down the capacity market clearing price and the cost of backup.

---

[5] Such a scenario would also increase carbon emissions. There are alternative generation mixes with a lower carbon impact that could also replace new nuclear, including additional renewable generation.

The impact of no new nuclear on intermittency cost (with 40GW of solar)
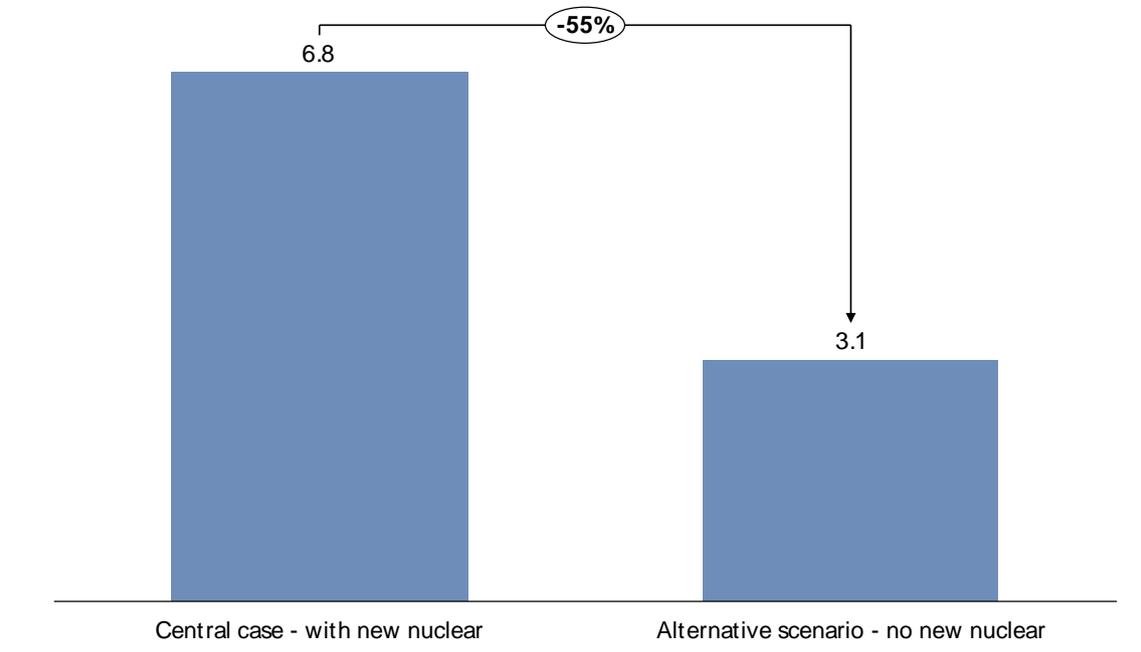
£/MWh, average 2025-2035

Figure 6

It should be noted that this alternative scenario with no nuclear, whilst benefiting from the additional flexibility of CCGT and other technologies, is expected to also have higher carbon emissions. An alternative scenario with comparable carbon emissions would inevitably require more renewables, and hence the intermittency cost may be higher rather than lower. Further, while the existence of new nuclear drives the cost of intermittency up, the magnitude is relatively small and unlikely to shift the overall cost-benefit economics of new nuclear.

4.3. The impact of large-scale battery penetration

The prospects for grid-scale energy storage have recently become significantly more promising. This has been driven primarily by substantial decreases in the cost of lithium ion batteries, to the point where the investment case for batteries for a wide range of applications is likely to be viable in the next five years. For niche

applications such as frequency response, battery technology is already being rolled out in the GB market[6].

Aurora estimates that if costs continue to decrease to the level of £100/kWh by the early 2020s (today the cost is nearer £300/kWh), economically attractive investment opportunities for up to 8GW of batteries would arise on the GB electricity system by 2030.

In our central case scenario in section 3 we assumed only modest cost improvements in batteries of 4 percent per annum, and thus negligible battery penetration, but here we consider the impact that 8GW of batteries could have.

Batteries are a natural counterpart to renewable generation, allowing excess power to be stored and released back onto the system when it is needed, thus reducing the cost of intermittency.

We estimate solar's cost of intermittency falls from £6.8/MWh without batteries to £-3.7/MWh with batteries i.e. there is a system benefit rather than a cost. This is due to two factors: firstly, the existence of batteries on the system smooths out prices in the energy and balancing markets, thus reducing the impact that the timeliness of delivery has on intermittency cost. Second, batteries play a useful role in the capacity market, reducing capacity prices and therefore the cost of backup for renewables.

With a large amount of batteries on the system, solar has a 'negative cost' of intermittency, meaning that the generation profile of solar is actually more desirable for a battery-enabled system than a baseload-equivalent output profile. Batteries and solar are a complementary combination, with batteries improving the capture prices of solar, and solar creating a generation profile whereby batteries can profitably store and then deliver to the market as needed.

---

[6] 200 MW of primarily battery storage generation was procured by National Grid for 'enhanced frequency response' in August 2016.

The impact of high battery penetration on intermittency cost (with 40GW of solar)
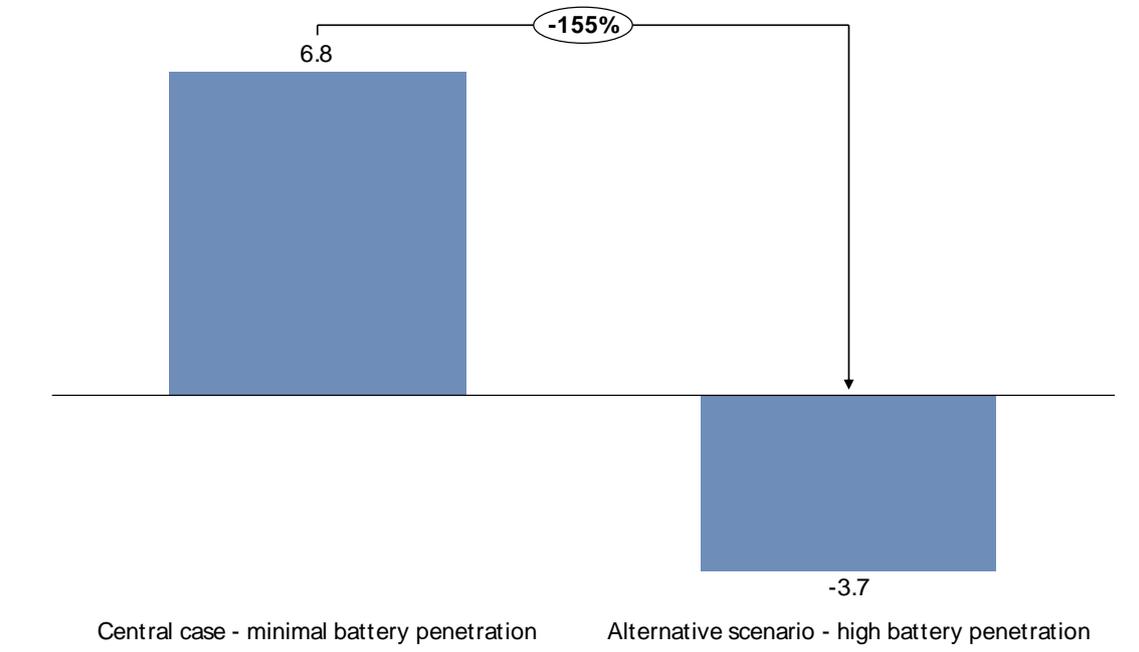
£/MWh, average 2025-2035

Figure 7

5. Conclusion

Returning to the question posed at the start of this report, do intermittency costs present a major hurdle to the further penetration of renewable generation?

Our analysis has shown that substantial further solar penetration is possible and affordable. Security of supply can be maintained, with sufficient flexible capacity emerging to manage the intermittency associated with up to 40GW of solar at a modest cost.

With intermittency costs today of around £1.3/MWh for solar, increasing to £6.8/MWh with a substantial 40GW of solar on the system by 2030, we would suggest these costs do not provide a strong argument against the further build out of renewable generation.

While £6.8/MWh of additional cost on top of the cost of each MWh of renewable power generation is a non-trivial amount, when set against the substantial year-on-year cost decreases being exhibited by both wind and solar and the benefits of a renewable low carbon power source, these costs are justifiable and competitive with fossil fuel alternatives.

Furthermore, the figure of £6.8/MWh of intermittency cost by 2030 represents a 'worst case' scenario; Should battery costs fall to £100/kWh as many commentators expect they will, if wind power grows significantly, or if new nuclear is cancelled or delayed, intermittency costs will be lower or could in fact be negative.

Technical appendix

Aurora's power market modelling approach

The analysis for this report is underpinned by the Aurora Energy Research Electricity System model for Great Britain ("AER-ES GB"). This model, which was independently developed by Aurora Energy Research, is a market-leading dynamic dispatch model used by many major private and public sector participants in the GB and European power markets to forecast plant performance and valuation.

Given a set of assumptions around solar buildout, policy, fuel prices and technological progress, Aurora's model calculates the economic entry and exit of other generation types through the capacity market based on economic incentives. In the context of this report the model has been used to estimates the capacity mix that would result from different levels of solar penetration based on half-hourly electricity and system prices and yearly capacity prices.

Key assumptions

The assumptions that underpin the analysis presented in this report are consistent with Aurora's quarterly GB Power Market Forecast (2016 Q3).

GB carbon price trajectory

In our modelling, we assume that the Carbon Price Support ("CPS") freeze will last until 2019/20, as currently legislated. Beyond 2020 we assume that the CPS will be adjusted year-by-year so as to achieve the government's target carbon price trajectory (Carbon Price Floor – "CPF"), taking into account the evolution of the European price of carbon – the EU Emissions Trading System ("EU ETS") allowance ("EUA"). During this period, we assume the carbon price trajectory will rise from the level of £22/tonne in 2020 to £40/tonne in 2040[7].

Figure 8 summarises our carbon price assumptions. With weak EUA prices, and the UK's ambition to lead the EU's decarbonisation effort, we forecast a policy-driven GB carbon price that is above the price of European emission allowances. However, we also disaggregate our overall carbon price into EUA and CPS outlooks and report our official EUA forecast separately (see below).

---

[7] We do not specify the measure of these values contributed by the CPS, as we assume that it is adjusted accordingly in order to adhere to these targets. Our implicit assumption is that the EUAs prices do not exceed this trajectory.

Aurora carbon price

£ / tonne, real 2014

Legend:
— Total carbon price (Carbon Price Floor)
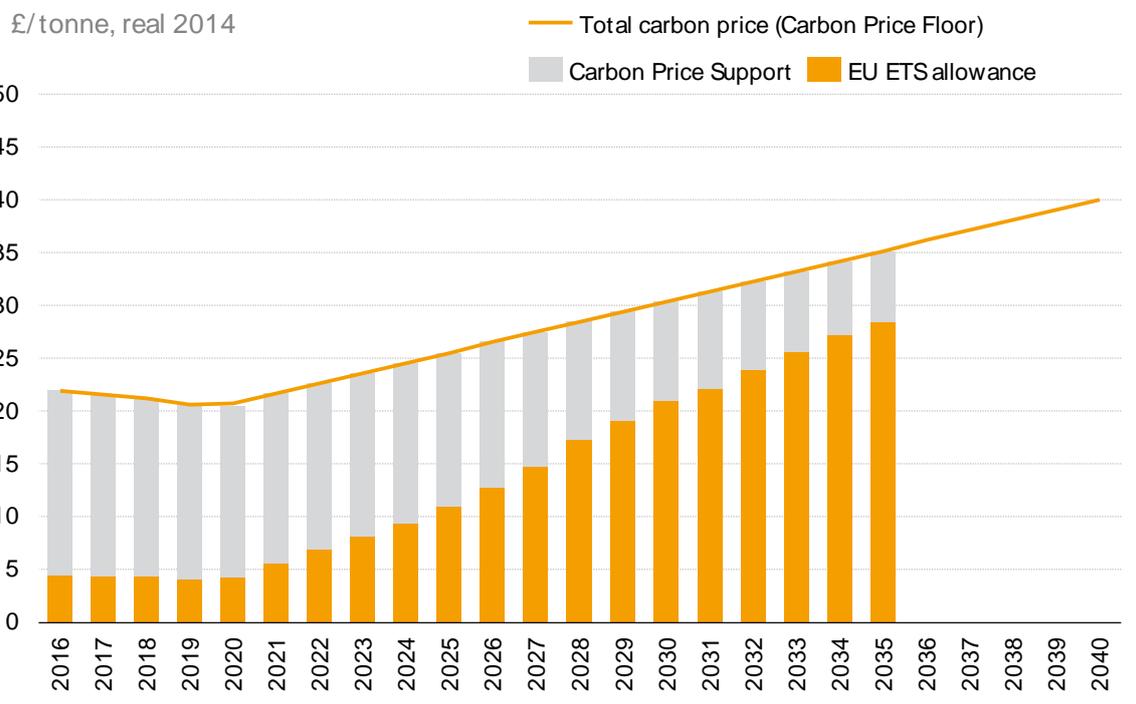▬ Carbon Price Support ▬ EU ETS allowance

Figure 8

EU ETS allowance price trajectory

In our modelling of the EUA prices, we account for recent policy developments, including 2030 targets for decarbonisation, renewables deployment and efficiency improvements, as well as the tightening of emission caps under Phase IV of the ETS, and the introduction of the Market Stability Reserve.

To produce our internal EUA forecast, we employ a hybrid modelling approach that links our European power dispatch model AER-ES EU and our global general equilibrium model AER-GLO. The hybrid model solves for the price of carbon required to achieve a given carbon emissions cap in each year. The combination of a general equilibrium model that captures all economic activity, and a power dispatch model, captures the detailed mechanics of fuel substitution in the power sector at an

hourly resolution, which is of critical importance for the carbon price trajectory. Details of this approach are outlined in our report "Coal-to-gas switching in Europe"[8].

The resulting ETS allowance price forecast is broadly flat until 2020, before increasing steeply during Phase IV, reaching €29/tCO2 in 2030, and €39/tCO2 in 2035. We expect relatively little impact from "back-loading" in Phase III of the EU-ETS – the postponement of the auction of 900 million allowances until 2019/2020.

Fuel prices

Fuel prices are the single most important driver of electricity market outcomes. Accurate forecasts for trends in fuel prices are therefore of paramount importance for electricity market modelling.

The Global Energy Markets Modelling team at Aurora produces regular baseline fuel prices forecasts, using our global general equilibrium model ("AER-GLO"). The model represents the economies of 129 countries, each broken down into 57 sectors. By using a general equilibrium model, which describes the interactions between sectors and countries in great detail, we capture the structural evolution of the economy in response to changes in demand. A general equilibrium approach offers a substantial advantage over partial equilibrium approaches, which tend to rely on exogenous growth patterns, locking the structure of the economy into past trends.

On the supply side, we adopt a detailed dynamic resource extraction module, which is calibrated to our global extraction cost database. Aurora's long-term commodity price forecasts are explained in substantial detail in our annual Global Energy Market Forecast (December 2015).

The fuel price forecast used for this report includes the following key projections (all in real 2014 terms):

- In the European gas market, relatively low short-term prices reflect a current period of regional oversupply, characterized by final years of robust domestic production, and the onset of new global LNG capacity. To 2025, three factors gradually rebalance the market towards a higher fundamental long-run marginal cost of supply – European demand experiences slower growth, domestic production declines, and other sources of global LNG demand arrive on the scene. These dynamics eventually take GB prices to a fairly flat medium- to long-term average level of £5.6/MMBtu beyond 2025.

- The coal price sees a short-term price recovery in our Central scenario, as capacity cuts resulting from the current commodity slump begin to bite.

---

[8] Coal-to-gas switching in Europe: Policy levers, winners and losers, global impact, July 2015, Aurora Energy Research

Though production and consumption in the US and Europe decline throughout the next decade (and our entire forecast horizon), rising prices are supported in the short term as demand reductions are more than offset by emerging markets and China, whose consumption only peaks in 2025. In the medium-to-long term, beyond 2025, prices settle much lower than historic highs, which were overwhelmingly driven by rapid growth in Chinese demand. With China gradually shifting its development path away from coal, and global carbon policy strengthening, global production levels off and prices reach their equilibrium in the range of £40–45 per tonne.

We use the gas and coal price forecasts produced by AER-GLO throughout this report. However, in the initial periods our assumed prices follow the latest available forward curves and over time converge to trajectories defined by the market fundamentals captured by AER-GLO.

NPB gas price assumption
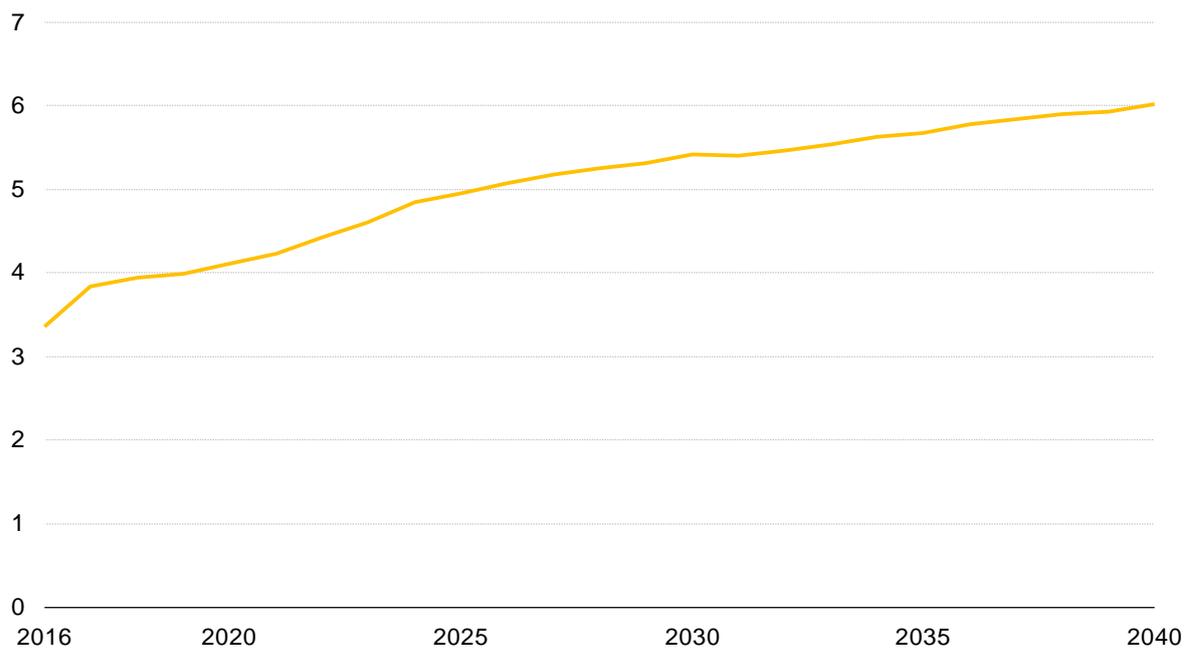
£/MMBtu, National Balancing Point (NBP), real 2014

Figure 9