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Do British wind generators behave strategically in response to the Western Link interconnector?

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Abstract

In Britain, the key source of renewable generation is wind, most abundant on the west coast of Scotland, where there is relatively little demand. For this reason, an interconnector, the Western Link, was built to take electricity closer to demand. When the Link is operating, payments by National Grid to constrain wind farms not to produce will be lower, we may predict, since fewer or less restrictive constraints need be imposed. But the Link has not been working consistently. We empirically estimate the link's value. Focusing on the three most recent episodes of outage, starting on 4th May 2018 up to 25th September 2019, our essential approach is to treat these outages as a natural experiment using hourly data. Our results reveal that the Link had an important role in costs saved and price constrained and MWh curtailed reductions. We estimate a cost-saving of almost £30m. However, the saving appears to drop over time, so we investigate wind farms' behavior. We find that wind farms behave strategically since the accuracy of wind forecasting depends on the relevant prices impacting their earnings.

Keywords: Interconnector, Electricity Market, Wind forecasting, Wind Generators, Pricing Strategies.

JEL classifications: D22, D47, H54, L22, Q41, Q47.

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1. Introduction

The recent rapid growth in renewable generation of electricity has led to significant issues for traditional electrical grids. One of the problems is geography- commonly, it is windiest, or sunniest, in an area of a country that is not near traditional power plants nor major demand. Great Britain is a typical example, but other countries such as Germany have similar issues (E. ON-Netz, 2015). As a result, Britain's National Grid (NG) has needed to enhance its network and, after some debate, developed the Western Link, a subsea DC interconnector between Scotland and North Wales.

In Britain, the strategic source of renewable generation is wind, which is most productive on the west coast of Scotland far from demand and, to a lesser extent, the (west) coast of Wales, as well as offshore locations, of which many are off Scotland. Herein lies the problem: traditional interconnection between Scotland and the rest of the island is relatively weak, partly as a result of recent history under which a slightly different pattern for privatisation was adopted in Scotland, but also because Scottish fossil fuel power stations traditionally supplied the populous industrial belt of the country, rather than there being much interchange over the difficult and sparsely populated terrain between Scotland and England. Overland options for enhanced links were assessed, but were subject to substantial challenge on environmental grounds, amongst other things, so the option of strengthening them was abandoned.

The primary purpose of the Link is to move power from west Scotland down nearer to the national grid in the North Wales industrial area. Thus, it is designed as a one-way subsea interconnector, with DC convertors at each end; its capacity is 2250MW. The working voltage is exceptionally high, at 600kV. The implied benefits are to reduce constraint payments made to wind operators to cease generation in situations of potential excess supply. When it appears that too much electricity will be generated locally, National Grid invites bids from wind farms to curtail or cease generation. A natural prediction is that when the Link is operating, constraint payments will be lowered, since rather than needing to generate power in England due to crowded interconnection links, fewer or less restrictive constraints need be imposed.

Unfortunately, the Link has not been working well, for reasons that are not obvious (and may eventually result in a legal action once underlying causes are uncovered). As a consequence, it was not only late but has had periods when it was working at reduced power and periods where it was not working at all.

Another important aspect to consider is related to wind generators' revenues. Most existing wind generators[1] in Britain receive revenue from two sources, selling energy into the market, at market prices, and from the Renewables Obligation (RO) (House of Commons Library, 2016). The latter is a 20-year requirement on conventional generators to purchase Renewables Obligation Certificates (ROCs) from renewable generators. For each MWh generated, an accredited onshore wind generator currently receives 0.9 ROCs/MWh generated. To meet their obligations, conventional generators need to purchase 0.154 ROCs/MWh. The resulting market price of a ROC was around £43.65 in 2014/15. Therefore, 0.9 of a ROC was worth approximately £39.29 to an onshore wind generator. The effect is roughly to double the achieved revenue per MWh, although the marginal impact is greatest at times of low prices. Offshore wind generators receive 1.5 ROCs/MWh and so obtain larger subsidies.

Two further significant factors determine the earnings of a wind generator. The first is that having declared availability of a certain capacity to National Grid (NG), failure to produce requires an operator to buy the shortfall in the short-term market, at a price that creates a significant penalty in most instances. There is thus a risk in declaring a capacity too close to your predictions of wind, which can significantly impact on revenue. The second significant factor is that, at times of high wind, particularly in Scotland, but low consumer demand, NG may constrain a wind farm not to produce. The farm must offer a price at which it is willing to leave the turbines idle. The achieved prices for curtailing generation are high, on average around the level of the market price plus RO. Hence, substantial curtailment can result in significant additional earnings for not operating.

In sum, we can write the expected revenue function (1) for a wind generator as:

$$\Pr(G \geq G^d).G^d.(p^w + r^w) - \Pr(G < G^d).\min(G^d - G, 0).p^s + \Pr(\bar{G} = 0).G^d.p^c \tag{1}$$

Here G is the amount generated, p^w is the wholesale price, r^w is the renewables obligation certificate price, p^s is the short-term price that has to be paid by a wind farm that fails to meet its declared generation[2], G^d, p^c is the price at which wind farms are paid to be constrained off $(\bar{G} = 0)$. Prices and probabilities are time-specific; time subscripts have been suppressed in (1). Note that the first

[1] Small generators are compensated under a different scheme. The renewables obligation incentive scheme is being phased out for new wind generators in favour of feed-in tariffs (FiTs), but existing wind generators will retain their RO rights and most existing wind farm capacity is operated under this scheme.

[2] Declarations are made the day before delivery.

two probabilities sum to 1 assuming the wind farm generates; the third is not determined by the firm and is separate, relating to when the wind farm does not generate, due to constraint.

Starting from these considerations, in this paper, we want to investigate two specific phenomena. First, we want to measure how much the Western Link is worth in terms of saved constraint payments, treating all prices and quantities above as exogenous. When the Link is out of action, *other things equal*, $\Pr(\bar{G}=0)$ increases. In that circumstance, the benefit of the Link is measured by the foregone payments as a result of the foregone higher probability of constraints. Our approach is to examine the impact of the Link being available, rather than unavailable, on average price paid to constrained farms, the number of MWh constrained, and overall costs of the constraint payments. Second, and discussed later, we want to assess whether wind farms may be gaming the system in making their declarations.

The novel aspect of the first part of our paper is the approach to calculating the value of that link. We focus on the three most recent episodes of outage, starting on 4th May 2018, since when it has had periods of outage, full design flow, outage, full flow, outage, and full flow, up to 25th September 2019. It is common to write that interconnection provides benefits, but much less common to be able to put a figure on it. Our essential approach is to treat these outages as a natural experiment. After controlling for other obvious factors, what was the cost in terms of constraint payments of the Link being out of action? Comparing this with constraint payments when the link was in operation, we calculate the costs, prices and MWh foregone as a result of the Link. The frequent sequence of operation and outage allows us to obtain estimates far more easily and accurately than a before-and-after experiment. This is particularly important in the context such as ours, where the stock of wind farms is growing over time meaning it would be difficult to maintain the assumption of common trends.

Our results reveal that the Link had an important role in costs saved and price and MWh reductions. On the basis of the whole period, we estimate a cost-saving of almost £30m. However, the effect appears to differ sharply between our three periods, which implies a need to examine whether wind farms are reacting to influences other than the amount of wind. It is also modest in comparison with construction costs.

Turning to the second element, so far as we can glean,[3] National Grid bases its wind generation forecasts on Met Office forecasts of wind speeds around the country. This assumes that wind farms react passively to the amount of wind, rather than behaving strategically according to the prevailing prices, in other words making use of the revenue they will obtain (from equation 1) to determine production. Thus our alternative assumption is that an individual firm can determine its G^d, subject to weather forecasts. What it will do will depend on the relative values of the prices. Thus if (p^w +r^w) increases relative to p^s, the wind farm will have an incentive to produce more, and vice versa. In doing this, we assume the wind farm bases its generation decision on the monthly value of wholesale price and use the buyback price of ROCs for r^w. In other words, so far as the regular payments to wind farms are concerned, they take the expected values of these (assuming in effect that they input at times that are undetermined in advance), but in determining G^d they trade off the probabilities of not meeting their target (which are determined broadly by the pattern of wind generation as observed) along with the likely penalties of performing below target in terms of having to pay p^s. All the factors determining G^d so far are given by the system. The possibility of being constrained off adds another dimension, in which the firm could, if the constrained prices are right, strategically raise G^d to take advantage. Our hypothesis is that these price-related factors do indeed influence the divergence between the forecasted wind value and actual production, the null being that they do not.

The paper is organised as follows. In section 2 we discuss the relevant literature in the field. In section 3 we describe the British electricity market, focusing also on the wind farm constraint payment. In section 4 we present the data collected and the empirical model used. In section 5 we discuss the results of the two elements and in section 6 we provide some conclusions and policy implications.

2. Literature Review

There is a certain amount of relevant literature on the two aspects that our paper aims to analyse: the role of the Link for the electricity market and the competitive behaviours of wind farms. There is no way of knowing if will be particularly windy or calm more than a few hours out; predictions for the next 24 hours have high variance. Thus, interconnectors and alternative mechanisms for bringing demand and supply into line can be useful but are not relevant for the long term (Waterson, 2017). Increasing electricity interconnection is relevant for closer market integration and facilitating renewable generation across Europe (Dutton and Lockwood, 2017). The idea is that if there is a large

[3] Source: Private correspondence with NG employees.

amount of wind in one system, interconnection can be used to balance the variable wind output. These interconnections are generally viewed as beneficial for different reasons. Access to lower-cost imports, producers export opportunities, a decreased necessity for spare generation capacity and the possibility of reducing local market power are some of the benefits. Furthermore, interconnectors guarantee a better geographical distribution of variable wind production, reducing variability (Denny et al., 2010). Nevertheless, market power exists, and differing assumptions change the estimated benefit of coupling and its distribution. Few electricity markets are perfectly competitive and market power mitigation is a priority on the agenda of policymakers (Ehrenmann and Neuhoff, 2009). For these reasons, performance evaluation of market design is important and any analysis in this field must account for farms' strategic behaviour (Hobbs et al., 2005).

Different papers focus on the welfare improvement of electricity interconnection. Several carry out a theoretical analysis (Ehrenmann and Neuhoff, 2009; Neuhoff and Newbery, 2005) or use simulation techniques (Hobbs et al., 2005; Denny et al., 2010; Valeri, 2009). Others take a descriptive approach to the issue (Dutton and Lockwood, 2017; Puka and Szulecki, 2014). Most of them focus on the interests of consumers and producers of electricity in the countries to be interconnected. Puka and Szulecki (2014) consider also the government, the TSOs, regulators and merchant investors.

Neuhoff and Newbery (2005), measuring the welfare effect of an integrated electricity market within Europe, find that the general integrated market leads to an improvement in social welfare than separate markets. There are different reasons why an increase in the number of competing firms might lead to higher price-cost margins, and they provide theoretical models to define the conditions under which this might happen. Consistently, Hobbs et al. (2005), using a transmission-constrained Cournot model, detect an increase in the social surplus due to the interconnection between Belgium and the Netherlands. However, the size of the efficiency improvements and their distribution depend on companies' pricing behaviour. If the Belgian incumbent behaves as a Cournot competitor, Dutch consumers incur higher electricity prices. On the other hand, if the Belgian incumbent is price taker, gains in social surplus are smaller but better distributed between the countries. Ehrenmann and Neuhoff (2009), using an equilibrium model with equilibrium constraint (EPEC) in which strategic generators can anticipate the reaction of fringe generators, confirm that the integrated market reduces market power and increases welfare. Furthermore, Valeri (2009), analysing the Irish and English electricity market through a static optimal dispatch model, finds that social welfare increases with interconnection, although at a decreasing rate. She detects also that if the interconnections increase, this generates more competition in the less competitive of the two. The appropriate regulatory framework, therefore, appears to be of decisive importance for the success of the project (Battaglini et al., 2012). Finally, Denny et al. (2010), using a stochastic unit commitment model, focus on the impact of the interconnector for Irish and British markets with their large penetrations of wind generation, observing how this link reduces the average prices and the price variability in Ireland.

What is absent from this literature is an empirical analysis of interconnector operation. One of the papers closest to examining this is Parail's (2009) working paper. The question analysed relates to price effects, using standard time series techniques, and ultimately on whether the interconnector can be operated commercially. Thus the focus is different from ours, since we seek evidence on the worth of the interconnector in reducing costs and we are able to examine several different regimes.

There is also a set of papers, including several empirical papers, which focus on the effects of energy storage, which is a partial substitute for interconnection. These include Giulietti et al. (2018), Sioshansi (2014, also Sioshansi et al., 2009; Sioshansi, 2010; Sioshansi, 2011), Schill and Kemfert, (2011), Dai and Qiao, (2015) and Waterson (2017).

In the short term, different models analysing bidding strategies assume that wind farms are price takers. Few papers have made alternative assumptions. Dai and Qiao (2015) formulate a bilevel optimization problem for a price-maker producer in an electricity market. They show that wind farms achieve the highest profit being strategic players both in day-ahead and in real-time markets. The day-ahead market has more influence on the wind power producer than the real-time market.

3. The British Electricity Market

3.1 Electricity Market: an overview

The British electricity market is constantly developing over time. In 2018 the economic value of the sector rose to £32 billion. By 2018, low-carbon generation accounted for 52% of total power generation, with renewable sources alone representing 33% (Dukes, 2019). This result has been made possible by recent regulations, together with cost reductions. A central role is played by The Climate Change Act approved in 2008. This establishes an ambitious target of 80% reduction of greenhouse gas (GHG) emissions by 2050 compared to 1990 levels. To further stimulate investment in low carbon technologies, the government launched the Electricity Market Reform (EMR) in 2013, composed by Contract for Difference (CfD) and the Capacity Market (CM). This has led to a substantial transformation in the UK energy industry. In fact, according to the Energy UK Report (2018), between 2008 and 2017, England's renewable capacity has grown hugely from 2,618 to 25,801 MW.

Scotland, with a capacity of over 10,000 MW, had a share of wind energy amounting to 75% of its total capacity, followed by hydropower. Wales has seen the largest increase in solar capacity since 2008, building 960 MW of solar energy.[4]

It is well known that grid-scale electricity has features that set it apart from any other good. Supply and demand for electricity must be matched at all times, otherwise the system fails. But supply and demand naturally fluctuate over time. To accomplish this, storage takes place through a switch from other forms of energy e.g. by combustion or from chemical energy in batteries (Giulietti et al., 2018). Furthermore, solar power is intermittent, wind power is intermittent and has a time-correlated variance. By contrast, nuclear power is inflexible. This means that these kinds of energy power require additional facilities to be present in the electricity transmission and distribution systems (Waterson, 2017). One additional facility is increased energy storage (Denholm et al., 2010; Greve and Pollitt, 2016). Most of the storage historically has taken place at the input level, via storage of coal, natural gas and fuel oil. This approach to storage is however compromised by the increasing contribution of energy from renewable sources in modern energy systems. Thus, alternative approaches are considered like compressed air, heat or battery storage (Giulietti et al., 2018).

The British electricity market is structured as follows. For the most part, electricity is considered to be generated, transported, delivered and used in half-hour segments called Settlement Periods. For each half-hour, the suppliers assess in advance the electricity volume with Generators. In this half-hour, Generators are expected to produce and deliver their quantity of electricity and Suppliers are expected to consume the energy stipulated. But in this market, not everything is predictable. It can happen that suppliers have wrongly made their forecasts of necessary energy or that the producers are not able to produce the defined quantity (or for transmission-related problems). In this context, the role of National Grid Electricity Transmission (NGET), the system operator, becomes very important. NGET has overall responsibility as a "residual balancer" of the electricity system and takes actions to ensure that electricity supply and demand match on a second-by-second basis, using different tools, including the Balancing Mechanism. This mechanism allows NGET to accept offers of electricity (generation increases or demand reductions) and bids for electricity (generation reductions or demand increases) at very short notice. Specifically, if a Supplier used more electricity than the amount communicated, they must buy additional electricity from the grid to meet the amount

[4] For details: https://www.energy-uk.org.uk/files/docs/Research%20and%20reports/Energy_in_the_UK/EnergyintheUK2018finalweb.pdf. We omit Northern Ireland since its system operates essentially in conjunction with the rest of Ireland, rather than with Great Britain.

used and vice-versa. On the same lines, where a Generator has produced less than the level contracted for, they must buy supplementary electricity from the grid to meet their contracted levels and vice-versa. These differences generate the so-called imbalances.

Another key aspect of the market concerns price determination. This happens increasingly through the EPEX/APX SPOT auction. This is a day ahead auction in which trading takes place on one day for the distribution of electricity the next day. Specifically, the system is based on the transactions that took place the day before the electricity was delivered, based on anonymous transactions made by members registered on the platform. Members are distribution companies, large consumers, industrial end-users and traders. The auction operates as a double-sided blind auction. At the end of these transactions, the demand is compared with the supply and the price is calculated for every half hour of the next day. Individual hourly instruments are traded in pounds/MWh. There are clear aspects that seek to protect the pricing process. In fact, it is possible to trade "Spot Block Orders". These apply to a consecutive number of hours, where the transactions are subject to a Maximum Payment Condition or a Minimum Income Condition. The minimum price of any Day-Ahead Market instrument is euro 500/MWh and the maximum euro 3000/MWh[5].

3.2 Wind Farm Constraint Payments

Wind power has important characteristics that provide challenges to the modern electrical power system. Of the 33% of electricity produced by renewables, 27.5% was produced by onshore wind and 24.3% by offshore wind in 2018 (Dukes, 2019). Most UK farms are linked to the low voltage regional electricity networks managed by Distribution Network Operators (REF, no-date). Generators may be asked to decrease generation even if they are contracted into the market if there is inaccuracy in the demand forecast and/or a lower level of electricity is required. But, if wind farms decrease the production, for this reason, they lose subsidies like the Renewable Obligation Certificates and (prior to 2015) the Climate Change Levy Exemption Certificates. Wind generator participants in the Balance Mechanism submit positive bids representing the need to be paid by National Grid to reduce output. However, the amount charged by wind farms significantly exceeds the value of the predetermined subsidies. For example, as noted by The Renewable Energy Foundation (REF) the average price paid to Scottish wind farms to reduce output in 2011 was £220 per MWh, whereas the lost subsidy was approximately £55 per MWh. In subsequent periods, following advertising campaigns by media and trade associations, the prices were reduced. However, the relevant aspect is

[5] For details: https://www.apxgroup.com/trading-clearing/apx-power-uk/

that not all constraint payments are in the public domain, something we discuss later. REF observes that "for a market to function efficiently and in the consumer interest, all charges made on those consumers should be publicly visible to ensure confidence that such charges are reasonable and to facilitate competition and drive down costs"[6]. Furthermore, when a wind farm is required to diminish production north of a grid constraint, another producer is required to raise output south of that constraint to make up the gap in energy and to correct the level of the reserve offered on the system. Thus, this means that in addition to payments made to wind farms to reduce production, additional non-constraint payments are made to fossil-fuelled generators making up the loss in energy and reserve to increase output.

A significant constraint exists between Scotland and England. Scotland is characterized by high winds and low energy demand and this excess could be used for England. In this context, the Western Link project takes on considerable importance since bringing renewable energy from Scotland (Hunterston) to homes and businesses in England and Wales (Deeside), as illustrated in figure 1. This Link involves direct current subsea and underground cables. It incorporates a converter station at each end of the link to change the electricity into and from direct current to alternating current to enable it to be used within the existing electricity transmission system. The construction required capital expenditure of somewhat over £1 billion. Unfortunately, the Link was not only late but has had periods when it was working at reduced power and cases where it was not working at all. Table 1 reports the different activity periods.

Figure 1. The Western Link (source: Western Link)

[6] For details: https://www.ref.org.uk/press-releases/249-ref-calls-for-transparency-over-secret-wind-power-constraint-payments

Table 1. The Western Link Service History

Start Date	**End Date**	**Status**	**N. of Days**	**Period**
01/01/2016	07/12/2017	*Late (non-operational)*	706	
08/12/2017	04/05/2018	*Low level operation*	146	
05/05/2018	16/10/2018	*Outage*	164	1
17/10/2018	19/02/2019	*Operating*	125	1
20/02/2019	23/03/2019	*Outage*	31	2
24/03/2019	06/04/2019	*Operating*	13	2
07/04/2019	02/06/2019	*Outage*	56	3
03/06/2019	25/09/2019*	*Operating*	114	3

Source: Renewables Energy Foundation and Western Link website *Note that the 25th September 2019 represents the final date of our analysis

4. Data and Empirical Model

We combine a set of variables stemming from different sources for the period 5th May 2018 to 25th September 2019, where feasible and justified at the hourly frequency at which they are reported. The main variables at a lower frequency are the wholesale price, where we assume firms react instead to expected price rather than the hourly price in making their decisions,[7] and the Renewables Obligation Price, which OFGEM changes annually although there is a shorter-term market (which is somewhat opaque). The *Number of Wind Farms Constrained,* amount of *Wind Generation curtailed in MWh,* the *Price per MWh* at which wind farms curtail and overall *Constraint Costs* are collected for every hour from the Renewable Energy Foundation (REF). Other variables come from Gridwatch, Gridwatch Templar, OFGEM or BMR reports. In Table 2 we summarize the definitions and the data sources for the variables in the empirical analysis, while in Table 3 we provide some descriptive statistics.

For our analysis, we consider 503 days of observations, split into 251 days when the Link was working, and 252 days when it was not working, starting with the first total outage period. However, these interruptions were not homogeneous during the period considered. Specifically, as shown in Table 1, there were 3 phases of activity and 3 phases of inactivity. For this reason, it is useful to check our variables of interest for each period. Table 4 illustrates the summary statistics for each period. Note that the relevant variables are not equal across the three different periods. The period in which the Link was off where all the average values of variables examined present the highest value is the third one (20/02/2019-23/03/2019). The lowest average values are present in the last period (03/06/2019-25/09/2019), except for the price variable whose minimum average value is detected in

[7] Note that we include a Peak variable, which will take some account of the fact that there is diurnal price variation.

the penultimate period (when the Link was off). We experiment with examining the three phases separately, in addition to examining the whole period.

To gain different perspectives on the impact of the Link, we define three different dependent variables, y_{it}, namely the *Constraint Costs,* the total amount charged in £ per hour for wind power output reduction (constraint payments to wind farms via the Balancing Mechanism over the period of investigation), the *Price constraint value per MWh* and the *Wind Generation curtailed in MWh*. Our first baseline specification takes the following form:[8]

$$(2) \qquad y_{it} = \alpha + \beta Link\ dummy_{it} + \gamma TotalDemand_{it} + \delta Final\ Forecast\ Wind\ Value_{it} + +\tau Number\ of\ Wind\ Farms\ Constrained_{it} + \rho Peak\ Period_{it} + \varepsilon_{it}$$

Apart from the *Link dummy* that takes value 1 if the Link was operating, 0 otherwise, we control for *Total Demand* across all fuels and interconnectors from "Gridwatch.co.uk". We include the *Final Forecast Wind Value* in MW from "Gridwatch.templar.co.uk" because this indicates any potential problem with over-generation. We control also for demand *Peak Period* effects that take into account the time 17.30-19.30 of each day when demand is highest and for the *Number of Wind Farms Constrained*, which is likely to influence costs. All these control variables are collected on an hourly basis. Furthermore, we check the Link effect also for each period according to Table 1. There is one more consideration, relating to the third period. On Friday 9th August 2019, there was a power cut that was unusual in the extent of its effects, and this had some knock-on effects over the following weekend. To allow for this unusual abnormality, we experiment with including a dummy for these three days in the results for the third period and consequently also for the period as a whole, although the impact is uncertain.

Since the Link dummy is a daily variable, we don't know the time variation of this dummy within the day. For this reason, we cluster standard errors over hours within a day. In the case of the *Wind Generation curtailed in MWh* dependent variable we include an additional regressor that could have an important influence in the estimate- the *Wind capacity in MW from Scotland*. We limit this to Scotland and not to other parts of the Great Britain as the Link transfers energy from Scotland south and not vice versa.

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8 We do not pursue a standard "diff-in-diff" strategy since significant but lumpy additions to the stock of wind generators over the whole period means that the common trends assumption cannot be maintained.

Regarding the second purpose of our paper, whether prices influence wind farm generation, we consider two different indexes relating to the difference between forecast and actual generation:

$$(3)\ Percent\ wrong\ 1 = \frac{(Final\ Forecast\ Wind\ Value - Actual\ wind\ Value)}{(Final\ Forecast\ Wind\ Value)} * 100$$

$$(4)\ Percent\ wrong\ 2 = \frac{[Final\ Forecast\ Wind\ Value - (Actual\ wind\ Value + Wind\ Gen.Curtailed\ in\ MWh)}{(Final\ Forecast\ Wind\ Value)} *100$$

Specifically, using equations 3 and 4, we want to identify whether the wind farms behave strategically when declaring their generation plans by examining the differences between the National Grid predictions and the actual outcome (*wpi1*, formula n.3) and predictions with outcome incorporating the wind generation curtailed in MWh (*wpi2*, formula n.4), i.e. thwarted outcome. The idea is to understand the extent and direction of the error in wind prediction in the National Grid final forecast. In particular, do prices, which affect wind farm revenues, influence the amount wind farms produce? But also, if the Link was working or not could have an impact on that. For this reason, we consider the following specification:

$$\begin{aligned}(5)\ \ w_{it} = \alpha + \beta Link\ dummy_{it} + \gamma\ (OFGEM + ROC\ Weighted\ Price)_{it} \\ + \delta SSP\ Price\ Elexon_{it} + \tau NPrice\ Constraint\ paid_{it} + \varepsilon_{it}\end{aligned}$$

As dependent variable, w_{it}, we consider the two indexes previously defined (3 and 4). We clustered standard errors for 24 hours. The null hypothesis is that prices and operation of the Link have no influence (in the second case, after allowing for curtailed quantities). By contrast, if there is a connection, this would suggest that wind farms are reacting to market factors in deciding how to produce. For this reason, in addition to the *Link dummy* variable, we include the *Elexon SSP price*, the *Price constraint paid* and the *OFGEM+ROC Weighted Price*. Given that an onshore generator receives 0.9 of the ROC price for its output, while an offshore generator receives 1.5 times for every MWh, following equation (1), including them additively, we need to generate figures separately for onshore and offshore, weighted based on their relative capacities at the time. Therefore, the *OFGEM+ROC weighted variable* is constructed by taking the proportion of plant capacity at that time that is onshore and multiply this by (OFGEM + 0.9ROC) and take the proportion that is offshore and multiply by (OFGEM + 1.5ROC). Since the onshore and offshore capacity is a quarterly variable, for the proportions of capacity we transform that in interpolated values across the quarter. In this case, we consider the overall capacity from Scotland, England and Wales.

Table 2. Variable definition and data sources.

Variable	Description	Level	Source
Constraint Costs	(Logarithm of) the total amount charged in £ per hour for wind power MWh output reduction	Hourly	Renewable Energy Foundation
Price constraint value (£/MWh)	(Logarithm of) the price constraint payment per MWh	Hourly	Renewable Energy Foundation
Link dummy	Dummy variable that takes the value of 1 if the Link was operating, otherwise 0.	Daily	Renewable Energy Foundation
Peak	Dummy variable that takes the value of 1 if the time considered is 5.30-7.30 p.m., otherwise 0.	Hourly	
Total Demand	(Logarithm of) the total demand across all fuels.	Hourly	Gridwatch.co.uk.
Final Forecast Wind Value	(Logarithm of) the Final Forecast Wind Value in MW.	Hourly	Gridwatch.templar.co.uk
Actual Wind Value	Actual Wind value generated by wind farms.	Hourly	Gridwatch.templar.co.uk
N. of Wind Farms constrained	Number of Wind Farms Constrained.	Hourly	Renewable Energy Foundation.
Wind Generation curtailed in MWh	(Logarithm of) the Wind Generation curtailed in MWh	Hourly	Renewable Energy Foundation.
Wind Capacity Scotland	(Logarithm of) the Wind Capacity (onshore and offshore) for Scotland area in MW.	Quarterly	UK Energy National Statistics
Wind Capacity Scotland, England, Wales	Wind Capacity (onshore and offshore) for Scotland, England and Wales areas in MW.	Quarterly	UK Energy National Statistics
Wholesale Price OFGEM	The average wholesale electricity price	Monthly	Ofgem
SSP Price ELEXON	The System Sell Price (SSP) is the 'imbalance price' that is used to settle the difference between contracted generation or consumption and the amount that was generated or consumed in each half-hour trading period.	Hourly	BMReports.com
ROC Price OFGEM	Renewables Obligation Certificate (ROC) is the amount suppliers will need to pay for each ROC they do not present towards compliance with their year obligation.	Yearly	Ofgem
Power cut dummy	Dummy variable that takes the value of 1 if the day considered are August 9th, 10th, 11th2019 when there was a power cut.	Daily	Ofgem; Renewable Energy Foundation.

Table 3. Descriptive statistics.

Variable	Obs.	Mean	Std. Dev.	Min	Max
Constraint Costs	12203	8161.42	23317.68	0	219637
Price constraint value	12203	21.4642	36.1417	0	193
Link dummy	12203	0.5004	0.5000	0	1
Peak	12203	0.1230	0.3285	0	1
Total Demand	12203	30784.70	6428.565	0	48230.33
Final Forecast Wind value	12203	4683.259	2904.187	245	12301
Number of Wind Farms constrained	12203	14.3481	20.7103	0	86
Actual Wind Value	12203	4529.782	2948.141	0	12405
Wind Generation curtailed in MWh	12203	115.0941	331.6289	0	8111
Wholesale Price OFGEM	12203	52.4087	10.2105	37.32	67.69
Percent wrong 1	12203	5.5259	19.8564	-129.3863	100
Percent wrong 2	12203	3.9427	20.2667	-230.0155	100
Wind Capacity Scotland	12203	8700.299	397.9669	7996.811	9170
Wind Capacity Scotland, England, Wales	12203	20901.2	1007.004	19570	22524
Wind Capacity onshore Scotland, England, Wales	12203	12364.81	348.99	11728	12879.55
Wind Capacity offshore Scotland, England, Wales	12203	8899.162	739.519	7842	10303.5
SSP Price Elexon	12203	50.6389	24.1125	-71.26	375
ROC Price OFGEM	12203	47.7645	0.7436	47.22	48.78
OFGEM-ROC Weighted Price	12203	107.3767	9.1711	94.1487	121.6331
Power cut dummy	12203	0.0059	0.0765	0	1

5. Analysis and Results

Before engaging in regression analysis, we check the raw data to confirm the predicted Link effect of reducing payments. Specifically, we focus on four dimensions to the comparison: (a) Are more wind farms constrained, on average, when the link is out of action? (b) How are average prices per MWh affected? (c) How is the amount of wind generation curtailed (in MWh) affected? (d) How are overall payments per hour affected? We observe that (a) indeed, fewer farms on average are constrained when the link is operational; (b) the amount of wind generation curtailed is indeed almost 50% less when the link is operational , but (c) price per MWh is actually slightly lower when the link is operational than when it is not; nevertheless, (d) Overall payments are, as expected, statistically significantly lower when the link is operational, almost 50% less. Note on this last point that because quantities and prices are clearly not independent, the outcome on payments is not the product of the outcomes on prices and quantities. The results are listed in Table 5.

5.1 Impact of the link in operation

Having established that the basic effects of the Link are as expected, we proceed to examine whether and to what extent this remains true once we control for additional factors that impact the constraint framework. Following specification n.2, we examine the role of the Link in cost and price constraint savings and on the wind generation curtailed. We adopt a logarithmic form for the regression having observed that the variables are more nearly lognormally than normally distributed. The results are shown in Table 6, 7 and 8. We carry out estimation both across the whole sample and for the three periods we defined. In columns 1 to 3, we observe the impact of the *Link dummy* for each period and in column 4 for the whole period. In the general model, for all three dependent variables, the *Link dummy* is always negative, meaning that the Link has been a significant factor in cost and price savings. Regarding the control variables, as expected, we find, for all the models, that a greater *Total Demand* reduces both the cost and price of constraint payments. The *Final Forecast Wind Value* represents an important component to consider; an increase in the wind forecast value increases the payments. A positive sign occurs when we consider the *Number of Wind Farms Constrained*, as the number of these constrained farms increases, costs increase as well. Since the *Number of Wind Farms Constrained* variable could be potentially endogenous, we also deployed the same regression using the IV methodology, using as an instrument the *Lagged Number of Wind Farms Constrained* for the previous 24 hours. Using the appropriate test, we detect that our variables are exogenous and so we rely on the OLS specification[9]. We consider also the effect of the *Peak Time* on costs. Finally, we note that inclusion of the dummy for the power cut (not reported) significantly increases costs and price but has no effect on MWh; it does not materially impact on the other coefficients.

In each general model (Table 6, 7 and 8), both costs, prices and wind generation curtailed are lower than at other times.[10] A different result is shown in column 3 (Tables 6 and 7), where the Link dummy takes a positive value. It appears that, in the last period, the price is very different between when the Link was working, and it was not working, in fact higher when it was working. A possible reason for

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[9] After identifying the best instrument and calculating the residuals, we inserted the residuals in a second stage as an additional regressor. This turned out to be not statistically significant, meaning that we have no endogeneity problem. Results are available from the authors upon request.

[10] We check also for multicollinearity using the *VIF Test.*

that is because wind farms have learned how to make money from declaring output even if the Link is working, something we investigate below.

We test for the statistical difference amongst the estimated coefficients comparing the whole period and each specific period results. The *Link dummy* coefficient is statistically different from zero in almost all specifications. For this reason, we show the results for each period and the whole period, but the different periods exhibit several differences. In sum, if we consider the whole period, when the Link is working, the costs, prices and wind generation curtailed are lower.

In order to calculate the magnitude of the Link effect, we exponentially transform the estimated coefficient for the logged variable. Consequently, considering the whole period, we quantify this effect in cost savings as a 30% reduction, a price reduction of 12% and a wind generation curtailed effect of 18%. These effects highlight the importance of the Link for the British Market.

Furthermore, we estimate the costs saved for the whole period, using the following formula:

(6) *Costs saved= (Average Cost per Hour * Total Number of Hours) * Link effect (%)*

Where:
Average Cost per Hour= Average of Cost Constrained in the sample time;
Total Number of Hours= Total Number of hours in which the Link was on and off;
Percentage link effect= 30%.

Using formula (6) we estimate a cost-saving of £29,878,105 or in round figures, £30m over our period of analysis. This result highlights the importance of evaluating the Link for the market in terms of the benefits it creates (when operating). Although these results highlight the positive role of the Link for the British system, we also focus on the result obtained in the last period (column 3 of tables 6, 7 and 8). We believe that this abnormal increase in the last period of costs, prices and wind generation curtailed when the Link is operational needs further investigation. It is also pales rather into insignificance by comparison with the construction cost, estimated at £1.2 billion.[11] Viewed in these terms, the Link is not paying its way. Of course, over time as wind capacity grows, the benefits may be expected to increase, and we may have underestimated it due to the possible presence of "secret"

[11] Source: Iberdrola (Scottish Power, the Scottish partner) https://www.iberdrola.com/about-us/lines-business/flagship-projects/western-link

constraint payments in the form of National Grid making forward energy trades through the market in order to balance the system.[12]

5.2 Do wind farms behave strategically?

Indeed, the results so far propels the analysis towards the second goal of the paper, to detect if the wind farms behave strategically. Normally, it is assumed that since wind is a "free" resource, when wind farms can produce, they will. In other words, the gap between National Grid's prediction and actual wind production should not be related to prices. However, wind farms may choose to exercise caution in declaring production capacity if they are concerned about being unable to meet their target and having to pay penalties. More specifically though, they may have incentives to declare generation plans then be paid to be constrained off (see equation (1)). To investigate this, after constructing the indexes (3 and 4), we examine the relationship between the identified dependent variables and other variables that equation (1) suggests are relevant for the wind farms to have more revenue using specification (5). The results are shown in Tables 9 and 10.

Results reveal a relationship between the extent and direction to which predictions are influenced by price factors that indicate the farms behave strategically, rather than producing when they can. We again split the analysis considering the three different periods (column 1-3) and the period as a whole (column 4). Generally, it seems that the gap between prediction and actual generation is lowered if the Link was working and OFGEM+ROC weighted price and constrained prices increase. A different result is obtained if we consider the 3rd period only, where the Link variable assumes a positive and significant value.

Turning to price predictions, if the wholesale price achieved is high then that gives wind farms an incentive to produce more and so we can expect lower over-prediction, or under-prediction. For the constrained prices, if they constrained off, and the price is high we would expect farms to offer more because in the event that they constrained then they will earn more revenue. On the other hand, it is to be expected that the gap will increase if the SSP prices increase.[13] This is because if they failed to produce what they said that would produce then they have to buy the difference in the short-term market, and so higher is SSP, the lower would be their revenues. All these expectations are borne out

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[12] See again https://www.ref.org.uk/press-releases/249-ref-calls-for-transparency-over-secret-wind-power-constraint-payments

[13] Note that SSP and SBP (system buy price) are now identical and have been so throughout our period of observation.

when we consider our sample as a whole. The OFGEM+ROC weighted price attracts a negative coefficient, meaning generation rises relative to prediction. The higher the SSP price, the lower is generation relative to prediction, so a positive coefficient. Finally, the higher is the constrained price, the higher are both generation and (generation plus thwarted generation) relative to the predicted value. These predictions are largely borne out when we look at the three periods individually, although estimate precision varies somewhat. In particular, it is worth highlighting that the coefficient on the price constraint value consistently achieves negative significance when we use the second alternative dependent variable, which relates more directly to company plans. Again, we include the dummy for the power outage days, for completeness. It has a negative and sometimes significant impact on the proportion wrong, but does not materially alter the other coefficients, so our conclusions remain unchanged.

Table 4. Descriptive statistics for different Link operational period

Variables	**Obs.**	**Mean**	**Std. Dev.**	**Min**	**Max**
Link OFF					
(4/5/2018- 16/10/2018)					
Price constraint value (£/MWh)	3960	22.65	36.42	0	189
Number of wind farms Constrained	3960	17.36	24.39	0	86
MWh wind generation curtailed	3960	147.02	415.91	0	8111
Constraint Cost payments (£/hour)	3960	10483.68	28886.58	0	219636
Link ON					
(17/10/2018- 19/02/2019)					
Price constraint value (£/MWh)	3024	19.08	32.55	0	183
Number of wind farms Constrained	3024	12.45	15.78	0	64
MWh wind generation curtailed	3024	88.70	256.91	0	1820.50
Constraint Cost payments (£/hour)	3024	6164	18014.3	0	138741.5
Link OFF					
(20/02/2019- 23/03/2019)					
Price constraint value (£/MWh)	769	36.82	4.2976	0	156
Number of wind farms Constrained	769	23.90	11.2459	0	76
MWh wind generation curtailed	769	463.61	21.3387	0	1809.57
Constraint Cost payments (£/hour)	769	32685.87	32.62	0	132943
Link ON					
(24/03/2019- 06/04/2019)					
Price constraint value (£/MWh)	335	23.98	34.56	0	98.5
Number of wind farms Constrained	335	13.67	20.11	0	76
MWh wind generation curtailed	335	79.96	252.97	0	1992.90
Constraint Cost payments (£/hour)	335	5804.53	18926.20	0	159395
Link OFF					
(7/04/2019- 02/06/2019)					
Price constraint value (£/MWh)	1368	13.37	30.94	0	183
Number of wind farms Constrained	1368	11.14	19.45	0	74
MWh wind generation curtailed	1368	83.40	255.51	0	1767.60
Constraint Cost payments (£/hour)	1368	5871.30	18076.43	0	130337.5
Link ON					
(3/06/2019-25/09/2019)					
Price constraint value (£/MWh)	2747	22.04	40.31	0	192
Number of wind farms Constrained	2747	10.10	16.98	0	80
MWh wind generation curtailed	2747	68.61	228.90	0	1884.78
Constraint Cost payments (£/hour)	2747	5014.77	16837.88	0	160115

Table 5. T-test for the variables of interest if the Interconnector was operating or not

Variables	**Link**	**Obs.**	**Mean**	**Std. Dev.**	**Mean difference**
Number of wind farms Constrained					
	OFF	6096	17.23	23.75	***
	ON	6107	11.47	16.65	
Hourly Price Constraint (£/MWh)					
	OFF	6096	22.23	35.89	**
	ON	6107	20.69	36.38	
MWh wind generation curtailed					
	OFF	6096	151.08	397.04	***
	ON	6107	79.17	244.62	
Constraint Cost payments (£/hour)					
	OFF	6096	10699.03	27694.51	***
	ON	6107	5626.38	17552.12	

Table 6. Results explaining Constraint Costs as dependent variable.

Variables	(Period 1) ***Costs_log***	(Period 2) ***Costs_log***	(Period 3) ***Costs_log***	(Whole period) ***Costs_log***	(Period 3) ***Costs_log***	(Whole period) ***Costs_log***
Column	1	2	3	4	5	6
Link dummy	-0.6225***	-0.3560***	0.3180***	-0.3634***	0.3041***	-0.3703***
	(0.1279)	(0.0960)	(0.0663)	(0.0544)	(0.0657)	(0.0538)
Peak Time	-0.2588***	-0.2387	-0.1781	-0.2474**	-0.1790	-0.2493***
	(0.0711)	(0.2807)	(0.1184)	(0.0889)	(0.1182)	(0.0885)
Total Demand	-0.7271**	-2.1460***	-0.3066	-0.6434**	-0.2945**	-0.6317**
(log)	(0.3463)	(0.4136)	(0.1919)	(0.2705)	(0.1872)	(0.267)
Final Forecast	1.2875***	2.1834***	1.3124***	1.3219***	1.2841***	1.3133***
Wind Value (log)	(0.0796)	(0.1295)	(0.0897)	(0.0790)	(0.0964)	(0.0804)
N. Wind Farms	0.1001***	0.0901***	0.1119***	0.1045***	0.1124***	0.1047***
Constrained	(0.0027)	(0.0039)	(0.0025)	(0.0021)	0.0025	0.1047***
Power cut dummy			NO	NO	YES	YES
Observations	6926	1103	4076	12105	4076	12105
R-squared	0.45	0.47	0.47	0.47	0.48	0.47

Clustered Standard Errors by hours in parentheses: *** p<0.01, ** p<0.05, * p<0.1

Table 7. Results explaining Price constraint value as dependent variable.

	(Period 1)	(Period 2)	(Period 3)	(Whole period)	(Period 3)	(Whole period)
Variables	***Price_log***	***Price_log***	***Price_log***	***Price_log***	***Price_log***	***Price_log***
Column	1	2	3	4	5	6
Link dummy	-0.3411***	-0.0555	0.2678***	-0.1308***	0.2527***	-0.1383***
	(0.0578)	(0.0713)	(0.0327))	(0.0268)	(0.0329)	(0.0268)
Peak Time	-0.0850**	-0.0238	-0.0896	-0.0765	-0.0905	-0.785***
	(0.0349)	(0.1518)	(0.0654)	(0.0497)	(0.0652)	(0.0493)
Total Demand	-0.2949*	-0.8706***	-0.1423	-0.2946**	-0.1292	-0.2817**
(log)	(0.1470)	(0.2212)	(0.0958)	(0.1296)	(0.0908)	(0.1250)
Final Forecast	0.6499***	0.8551***	0.7036***	0.6487***	0.6730***	0.6391***
Wind Value (log)	(0.0279)	(0.0676)	(0.0437)	(0.0317)	(0.0479)	(0.0327)
N. Wind Farms	0.0380***	0.8551***	0.0443***	0.0405***	0.0448***	0.0406***
Constrained	(0.0010)	(0.0020)	(0.0012)	(0.0008)	(0.0013)	(0.0009)
Power cut dummy			NO	NO	YES	YES
Observations	6926	1103	4076	12105	4076	12105
R-squared	0.36	0.35	0.37	0.37	0.38	0.37

Clustered Standard Errors by hours in parentheses: *** p<0.01, ** p<0.05, * p<0.1

Table 8. Results explaining MWh wind generation curtailed as dependent variable.

Variables	(Period 1) ***MWh _log***	(Period 2) ***MWh _log***	(Period 3) ***MWh _log***	(Whole period) ***MWh _log***	(Period 3) ***MWh _log***	(Whole period) ***MWh _log***
Column	1	2	3	4	5	6
Link dummy	-0.2233***	-0.3302***	-0.2184***	-0.1929***	-0.2197***	-0.1928***
	(0.0810)	(0.0681)	(0.0541)	(0.0445)	(0.0547)	(0.0444)
Wind Capacity	-1.5222**	0.6323	77.8056***	-1.0634**	78.7453***	-1.0622**
Scotland (log)	(0.5750)	(3.4276)	(10.1057)	(0.4401)	(10.6796)	(0.4378)
Peak Time	-0.1807***	-0.2444	-0.0820	-0.1694***	-0.0818	-0.1694***
	(0.0425)	(0.1472)	(0.0632)	(0.0429)	(0.0632)	(0.0403)
Total Demand	-0.4304**	-1.310***	-0.1546	-0.3602**	-0.1564	-0.3603**
(log)	(0.2011)	(0.2297)	(0.0930)	(0.1490)	(0.0935)	(0.1496)
Final Forecast	0.6566***	1.3285***	0.6307***	0.6946***	0.6351***	0.6947***
Wind Value (log)	(0.0513)	(0.0671)	(0.0475)	(0.0487)	(0.0500)	(0.0492)
N. Wind Farms	0.0623***	0.0558***	0.0672***	0.0639***	0.0672***	0.0640***
Constrained	(0.0017)	(0.0021)	(0.0015)	(0.0012)	(0.0014)	(0.0013)
Power cut dummy			NO	NO	YES	YES
Observations	6926	1103	4076	12105	4076	12105
R-squared	0.48	0.51	0.51	0.49	0.51	0.49

Clustered Standard Errors by hours in parentheses: *** p<0.01, ** p<0.05, * p<0.1

Table 9. Results explaining the first percent wrong prediction index (Wpi1) as dependent variable.

Variables	(Period 1) ***Wpi1***	(Period 2) ***Wpi1***	(Period 3) ***Wpi1***	(Whole period) ***Wpi1***	(Period 3) ***Wpi1***	(Whole period) ***Wpi1***
Column	1	2	3	4	5	6
Link dummy	-13.8458***	-5.2452***	1.1995**	-8.3929***	1.3401***	-8.3646***
	(0.5680)	(0.5799)	(0.3938)	(0.3800)	(0.3929)	(0.3806)
OFGEM+ROC Weighted *Price*	-0.6091***	0.3344	-0.02155	-0.3423***	-0.0220	-0.3446***
	(0.0396)	(0.2075)	(0.0939)	(0.0126)	(0.0940)	(0.0127)
SSP Elexon Price	-0.1124**	0.0174	0.1226***	0.1049***	0.1254***	0.1053***
	(0.007)	(0.0389)	(0.0102)	(0.0064)	(0.0101)	(0.0064)
Price Constraint value	-0.0134	0.0156	-0.0285***	-0.0180***	-0.0253***	-0.0175**
	(0.0110)	(0.0099)	(0.0069)	(0.0067)	(0.0068)	(0.0066)
Power cut dummy			NO	NO	YES	YES
Observations	6926	1103	4076	12105	4076	12105
R-squared	0.15	0.03	0.03	0.07	0.03	0.07

Clustered Standard Errors by hours in parentheses: *** p<0.01, ** p<0.05, * p<0.1

Table 10. Results explaining the second percent wrong prediction index (Wpi2) as dependent variable.

Variables	(Period 1) ***Wpi2***	(Period 2) ***Wpi2***	(Period 3) ***Wpi2***	(Whole period) ***Wpi2***	(Period 3) ***Wpi2***	(Whole period) ***Wpi2***
Column	1	2	3	4	5	6
Link dummy	-12.4838***	-3.9639***	1.9610***	-7.2576***	2.0636***	-7.2565***
	(0.6216)	(0.6795)	(0.3709)	(0.4298)	(0.3805)	(0.4311)
OFGEM+ROC Weighted *Price*	-0.6934***	0.6862**	0.0601	-0.3990***	0.0598	-0.3991***
	(0.0393)	(0.2210)	(0.0967)	(0.0098)	(0.0968)	(0.0097)
SSP Elexon Price	0.1324***	0.0613	0.1433***	0.1268***	0.1453***	0.1269***
	(0.0076)	(0.0376)	(0.0096)	(0.0058)	(0.0098)	(0.0060)
Price Constraint value	-0.0877***	-0.0496***	-0.0596***	-0.0769***	-0.0573***	-0.0769***
	(0.0098)	(0.0085)	(0.0054)	(0.0059)	(0.0055)	(0.0060)
Power cut dummy			NO	NO	YES	YES
Observations	6926	1103	4076	12105	4076	12105
R-squared	0.15	0.04	0.05	0.08	0.05	0.08

Clustered Standard Errors by hours in parentheses: *** p<0.01, ** p<0.05, * p<0.1

6. Conclusions and Policy Implications

Our paper contains two important findings concerning the operation of Britain's changing electrical energy system. These concern the benefits of interconnection and the behaviour of wind farms in response to financial imperatives.

Interconnectors are increasingly important mechanisms through which electricity can be transferred across space, reducing the need for additional generation and the potential for power outages. At the same time, *ex post* evaluation of the benefits they create is unusual. As a result of the intermittent operation of the Western Link in Britain, we are able to generate estimates of the current benefits of its operation in terms of the money saved in additional payments. These are significant, but by comparison with the cost of construction, appear distinctly modest. This highlights the need for more investigation of interconnector benefits generally, in order to facilitate interconnectors' role in comparison with other technologies with a similar, and partly complementary, function, such as energy storage. The British case constitutes an example, but the concept is clearly applicable more broadly; Europe relies heavily on interconnection across countries, for example.

At the same time, our results concerning the variable impact of the interconnector across time lead us to question the widely held assumption that wind farms do not behave strategically in response to financial factors, but instead act passively, producing where there is wind available. By comparing expected wind generation with actual generation, we are able to establish that financial factors indeed play a role, and precisely the role that would be expected if they operate according to financial imperatives. In establishing this, we wish particularly to highlight their behaviour in relation to payments where some of them are constrained not to produce in order to maintain the stability of the system. There is a clear link between the higher payments achieved and the gap between predicted and actual generation. Indeed, this calls into question whether they are all operating according to the condition that requires them in effect not to game the system, the Transmission Constraint Licence Condition, introduced in May 2017. Again, this is a matter worthy of further regulatory investigation.

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