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# Strategic behaviour by wind generators: An empirical investigation☆

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ABSTRACT

Renewable generation of electricity is a vital step in reducing dependence on fossil fuels, and wind generation is particularly important in countries such as Britain. A large part of the windfarms are in Scotland but links with England are relatively limited and subject to exogenous failure of an interconnector. As a consequence, for a significant portion of time the system operator imposes constraints on wind generation in Scotland. We investigate the resulting effects on a majority subset of these windfarms operating under a scheme called Renewables Obligation, which involves a subsidy on top of market price. One feature of this scheme is that windfarms each declare a price at which they are willing to be constrained; these prices are used in the selection of windfarms to constrain when necessary. Thus, windfarms are sometimes paid not to produce. We investigate the strategic consequences of this, given that the prices set by windfarms to turn off in practice exceed the opportunity cost, finding significant evidence consistent with windfarm strategic behaviour. Specifically, we observe that in making their final physical declarations of output, the sample windfarms overestimate their final physical notifications of generation, the more so when other circumstances suggest constraints will be required. Following our findings we propose two potential policies to reduce both the extent of over-prediction and the payments made to windfarms to curtail output.



## 1. Introduction

There is a rapid, and continuing, move around the world to decarbonise the electricity system in order to achieve environmental goals. This has been spurred on by unit cost declines in installing generating assets and, in Europe, by the desire to secure a significant degree of independence in energy supplies. Rapid growth in renewable generation assets has been boosted by subsidies but hampered by network transmission constraints given the very different locations of conventional and renewable generation plants. This paper shows that Scotland presents a prime example where generating firms

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have secured favourable deals but appear to have taken strategic advantage of infrastructure constraints and rules in their operations.

In their seminal study of the early workings of the GB electricity generating market when it constituted a strategic duopoly, Green and Newbery (1992) point out that the generators could (and arguably did) offer supply schedules that are substantially above marginal cost. Also “They have additional methods of market manipulation that exploit the constraints on the grid's transmission capacity, since their market power in some of the regional markets is considerably greater than in the country as a whole.” (p. 951). In our case, the concentration of British wind generation in Scotland provides clear constraints on the grid and in all likelihood places particular windfarms at an advantageous position in exploiting these constraints.[1] As we note below, compensation payments to constrain wind generation (that is, payments not to produce) are remarkably more concentrated across firms than are their generating capacities. The effect is exacerbated by the unpenalized significant excess in what are known as final physical notifications (FPNs) made by the windfarms and the relatively high prices that are demanded by windfarms as (over)compensation for them to constrain output. Thus, what is new about our case is the identification of a novel strategic incentive under the British Renewables Obligation (RO) scheme, the incentive to enhance the possibility of being *paid* to curtail output.

To facilitate the rapid deployment of wind power countries have experimented with various mechanisms encouraging companies to bring projects online (see e.g., Fabra and Imelda, 2022, for analysis in Spain). In Britain, three main mechanisms have been involved. Most early and small projects receive Feed-in-Tariffs (FiT); these plants are largely connected into local networks and are not visible to the System Operator (SO) so do not act as strategic players. Up until 2017, the main mechanism for larger generators has been the RO scheme which provides a premium above market price for operators, an essentially fixed sum per MWh produced.[2] This does leave suppliers exposed both to price and volume risk, but provides a predictable premium for 20 years. The most recent windfarms are remunerated under a Contracts for Differences (CfD) scheme which removes price risk but not volume risk. The successful bidders in the *ex ante* CfD auctions do not receive subsidies on top of the price they bid.

Building a sample over 509 days in 2018-19, we examine whether the Scottish RO windfarms seemingly game their announced production levels in the face of an imperfect regulatory framework. Scottish windfarms are a manageable but strategically and economically important subsample of the whole. Specifically, Scotland produced 47% of the British wind-generated electricity in 2019 (source: Renewables Energy Foundation, hereafter REF) but has less than a tenth of the population of England, so much of the power generated needs to be exported to England. The RO subsidy scheme closed to new windfarms by 2018 but even in the most recent year, RO-subsidised Scottish windfarms produced 74% of total Scottish wind output (source: REF). Wind generation varies enormously over time, the links to England are limited, and, in a major respect, subject to exogenous reductions in capacity effecting a capacity reduction of almost 1/3 resulting from downtime of a subsea interconnector called the Western Link. Although the GB network is run as a single transmission grid, these considerations mean that major constraints on the Scottish windfarms are frequently imposed by the SO, with substantial payments made to operators to curtail generation. Whilst the curtailment payments to CfD plants are at their agreed price, payments to the RO plants are different.

Payments for curtailment of RO windfarms are the subject of individual price bids the windfarms make in the final stages prior to actual generation, as discussed in more detail later. If a windfarm is chosen to curtail, it is paid according to its bid. This bidding system is intended to encourage competition and efficiency amongst windfarms, since the SO is more likely to choose firms bidding a lower price in determining which should curtail, subject to technical features of the transmission system. However, in practice, all the bids are routinely above the opportunity cost in terms of foregone revenue. We explore the possible reasons and strategic implications of this, making proposals for changes to the regime.

A plant required to cut output will, for example, turn its rotor blades into the wind so that they cease to rotate and hence cease to generate.[3] By doing so, an RO plant loses revenue represented by the subsidy per MWh it would otherwise receive but crucially does *not* lose revenue relating to their previously negotiated contractual position. Hence, the opportunity cost is the RO subsidy, a fixed amount.[4] However, the average payment per MWh constrained comes out at almost £70 over our period, significantly above the RO price of under £50.[5]

Our analysis involves four steps. First, we explore the SO's behaviour in ordering wind generators to curtail production, thereby triggering a payment to the windfarm as the product of its bid per MWh and the quantity constrained. We anal-

[1] Calculating which plants are in the best position to do this ex-ante is extremely complex and a task for a specialist electrical engineer. We do not seek to identify particular windfarms in our work.

[2] There was a “grace period” meaning that some later plants qualified, https://www.ofgem.gov.uk/environmental-and-social-schemes/renewables-obligation-ro/ro-closure.

[3] Wind turbines have a variety of remote-control measures located in their nacelles to respond to wind changes and measures to reduce generation, for example pitch control or active stall control, hydraulic and mechanical brakes. Pitch control turns the blades out of the wind so that it passes over without creating a turning motion. (Danish Wind Industry Association, www.windpower.org).

[4] Of course, unlike most goods, electricity carries no trace of its origin, so buyers can only measure the amount they receive. If the constraints imposed north of the border lead to a need for increased generation in the south, the SO will use bids to increase supply south of the border to make up the difference. CfD plants are paid their agreed amount per MWh constrained as if they had produced, so do not face a similar incentive structure to the RO plants.

[5] The payment is somewhat higher for offshore windfarms, but these are a very small part of our sample.

yse exogenous factors behind the SO imposing constraints, finding that exogenous variation in transmission capacity has a significant role alongside low demand and high predicted wind generation.

Second, we investigate whether Scottish RO windfarms as a group, in setting their final physical notifications (FPNs) of generation one hour before real time have an impact on the magnitude of constraint required of them.

We then examine whether wind generation exhibits flexibility with respect to the prices and other incentives they face, finding that windfarms can and do exhibit some degree of flexibility, for example that production is higher relative to exogenous forecasts when day-ahead prices are more elevated. This suggests wind generation could indeed be subject to strategic behaviour.

The final step is to analyse strategic modification by windfarms of the declared level (FPN) of Scottish wind production, focusing on the difference between actual and declared wind generation. Declared wind generation is indeed higher relative to actual generation when the exogenous probability of wind curtailment is higher, based on results from the first step. The obvious conclusion is that windfarms overstate their predicted production levels when the probability of constraints is higher, because they then (if chosen to curtail) obtain inflated payments for not producing. This overstatement is not penalised.

Although our case depends upon particular institutional and geographical features, several of the lessons are of much broader interest. For example, the recent rapid growth in renewable generation of electricity has led to significant issues for traditional electrical grids. The geography of renewables- commonly, it is windiest, or sunniest, in an area of a country that is not near traditional power plants nor major demand- creates a problem. Great Britain is a typical example, in this case of wind generation, but other countries such as Germany have similar issues (E. ON-Netz, 2015). Legacy issues can lead to substantial unintended rents to generators. Moreover, it is important not to bake such rents into forthcoming schemes.[6]

A subsea interconnector, the Western Link (hereafter, Link) was developed by National Grid the England and Wales transmission system operator[7] and Scottish Power, an integrated Scottish firm, and put into service to reduce potential wastage of power by reducing curtailments of Scottish wind generation with 90% of RO constraints by MWh being in Scotland.[8] In practice, the Link has not been working well, with long periods over which it was non-operational. We factor this important institutional feature into our analysis in analysing strategic behaviour amongst the Scottish wind generators.

It is well known that thermal electricity generators have the ability to engage in strategic behaviour through capacity withholding, given the common circumstances where the supply schedule is convex whilst demand is virtually unresponsive to price signals in the short term (Bergler et al., 2017; Cabral, 2002; Dechenaux and Kovenock, 2007; Kwoka and Sabodash, 2011). The theoretical literature distinguishes between 'economic withholding' (i.e., a strategy where a supplier offers part of its capacity at an extremely high price thus moving it to the very right of the supply curve) and 'physical withholding' (i.e., capacity is completely taken out of the market) (Joskow and Kahn (2002)). Classic empirical papers on this relating to the British market include Green and Newbery (1992), Harbord and Von Der Fehr (1993) and Wolfram (1998, 1999).

If wind generators produce when they are able, then they simply supply into the market period by period at whatever price the market clears, rather than exploiting the somewhat complex framework of the system. However, the theoretical literature has explored the potential for strategic behaviour amongst wind generators; see Fabra and Llobet (2022) and Ito and Reguant (2016). Moreover, the alternative naïve view assumes that the firms involved operate solely windfarms, whereas many are engaged also in more conventional means of generation, primarily using gas. Acemoglu et al. (2017) engage in some exploration of this issue. What is underdeveloped is empirical analysis of possible strategic behaviour by wind generators; a recent key paper, the closest to ours in concept, is Fabra and Imelda (2022).

Fabra and Imelda (2022) model a particular aspect of strategic behaviour by windfarms empirically, taking advantage of changes in the compensation paid to windfarms in Spain. Spain has experimented with two different schemes for supplementary payment, roughly corresponding to the difference between Britain's CfD scheme which applies to newer windfarms and the RO scheme which applies to the windfarms we analyse. They show that the latter scheme allows windfarms to arbitrage between selling forward contracts then buying in the spot market to make up the difference, thereby creating a strategic incentive. This incentive does not exist in the other case, because of its insurance properties created by paying an agreed fixed price. Our focus is on a different strategic incentive under Britain's RO scheme, the incentive to enhance the possibility of being paid to curtail output.[9]

In Section 2 we set out the key issues regarding the rapid growth in wind power in Scotland in particular. Then in Section 3 we discuss the key features of the system so far as an RO windfarm is concerned and in Section 4 set out our empirical approach given that. We discuss our data sources and engage in some preliminary analysis in Section 5.

[6] Currently, the UK Government is attempting to renegotiate with wind and other plants operating under the RO scheme, because their returns in a period of heightened prices are so much above what they might have anticipated.

[7] There are two relevant and strictly separate branches of National Grid- National Grid Transmission, the England and Wales transmission operator, and National Grid Electricity System Operator (SO), responsible for balancing the Great Britain energy system (i.e., including Scotland), which operates as a single system. Payments systems relating to SO operations are handled by a third party- Elexon.

[8] This percentage refers to our period of analysis, but inspection of 2020 and 2021 data shows the continuing dominance of Scottish wind farms being told to curtail.

[9] The incentive identified by Fabra and Imelda (2022) in their paper may be lessened in the British scheme by the high costs of making futures contracts which cannot later be fulfilled except at the punitive rates charged by the system operator, as explained later, but because the terms of the futures contracts in GB are confidential, that angle cannot be investigated here. Davi-Arderius and Schittekatte (2023) also examine grid constraints in Spain requiring constraints, but in their case due to frequency issues.

Section 6 contains our empirical results whilst section 7 makes a few concluding remarks and discusses potential policy implications. An appendix sets out slightly more formally the revenue function of a windfarm operator.

## 2. The characteristics of wind power in relation to the electricity balancing market

Wind power is a major feature of the British electricity system, but has important characteristics that provide challenges to the modern electrical power system, significantly related to its considerable variability over time. It also receives subsidies in various forms, which have accelerated its very rapid development and deployment. Of the 33% of electricity produced by renewables in GB, 27.5% was produced by onshore wind and 24.3% by offshore wind in 2018 (Dukes, 2019) and this is ramping up rapidly. As is well known, it is essential that electricity supplied into the market balances exactly with demand from the market to the nearest fraction of a second.[10] Hence, several balancing mechanisms are invoked by the SO to achieve this. Our concern is the half-hourly balance mechanism, the main tool used. 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, or the system becomes congested. Traditional fossil fuel plants will offer to pay to reduce output due to the fuel costs saved. But, if windfarms decrease the production for this reason, they lose subsidies; in particular, windfarms on the RO scheme lose the associated RO certificates (ROCs).

The RO programme is a 20-year requirement on conventional generators to purchase ROCs from renewable generators. For each MWh generated, an accredited onshore wind generator currently receives on average 0.95 ROCs/MWh generated. To meet their obligations, conventional generators need to purchase 0.471 ROCs/MWh at the time of writing. The resulting market price of a ROC is around £50 - 55.[11] Therefore, 0.95 of a ROC was worth approximately £49.88/MWh to an onshore wind generator. The effect was roughly to double the achieved revenue per MWh over our period, although the relative impact is greatest at times of low electricity prices. Offshore wind generators receive on average 1.86 ROCs/MWh and so obtain larger subsidies.[12] Around 80% of total GB generated wind power was operated under the RO scheme in 2019 (source: REF) and in our sample, almost 90% of the subsidy was paid to Scottish RO windfarms (source: our calculations based on REF data). In sum, we focus on a very large subset of wind-generated electricity, honing in on Scotland.

## 3. Conceptual framework for wind power delivery

Conceptually, what happens in the market is as follows. There is a first period in which generators including wind generators will sign contracts (which are confidential) to provide power to the demand side at specified prices and volumes (including their own supply business) or will enter the day-ahead or other markets to trade power prior to that power being supplied. A windfarm will continue to receive these payments according to the terms negotiated in the contracts, even if it is unable fully to generate the commitments or if it is constrained. The commitments are summarised in the Energy Contract Volume Notifications (ECVNs) submitted by the windfarm to the SO any time up to the time of actual delivery. In the second period, from 24 hours ahead of delivery until one hour short of delivery, the short-term market (largely APX) operates; both sides of the market, and pure traders, can modify their overall physical positions. By this stage, wind forecasts will have been made.

In the final hour, the third period, operators including wind generators report their “Final Physical Notifications” (FPNs). They also, together with the demand side, report the prices at which they are willing to be constrained not to produce/ take delivery or to increase production, in case this is necessary.[13] In practice windfarms only set prices they are willing to be paid in order to constrain output. If constraints are imposed, each windfarm constrained is paid according to the price it bid. The SO, taking the data received, makes decisions as to whether and where to impose constraints (or command increases). Finally, in the fourth stage, generation matches demand.

RO certificates are awarded to renewable generators according to the measured volumes, not ECVNs. Hence, we distinguish between payments according to ECVN and payments (ROC) according to measured volumes. These mechanisms are set out in detail in Elexon (2020b, p.44). The effect of being constrained is revealed in the following quote from OFGEM (2017, p.7) “Opportunity costs may include, for example, the price of ROCs in the case of renewable generators.”[14]

In the post-output period, Elexon will check the ECVNs against measured volumes, adjusted if necessary for constraints on delivery (balancing services), and will calculate an imbalance volume. It will also calculate an imbalance price, the SBP, related to the actions taken in the balancing market and will book a charge against or payments to the generator as the product of the imbalance volume and the imbalance price.

[10] Storage is extremely limited in Britain.

[11] This is an approximate auction-achieved price from Cornwall Energy estimates; the OFGEM buyout price at time of writing was £50.05 https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-ro-buy-out-price-and-mutualisation-ceilings-2020-21 and rises annually in line with inflation.

[12] For onshore windfarms, weighted average ROC certificates are awarded based on 0.9 or 1 per MWh generated, dependent on when the plant first came into operation. For offshore windfarms, on the other hand, the rates are higher. Within our sample, the rate for the offshore plant is 1.86 per MWh. The table of what is allowed for plants of various vintages can be found at: https://www.ref.org.uk/energy-data/notes-on-the-renewable-obligation.

[13] The latter applies only to operators able to control output, in practice largely gas plant operators and not wind. There are some, limited, demand side operators who may agree to reduce consumption if paid to do so.

[14] See also REF Notes on Wind Farm Constraint Payments (ref.org.uk) which makes the point explicitly.

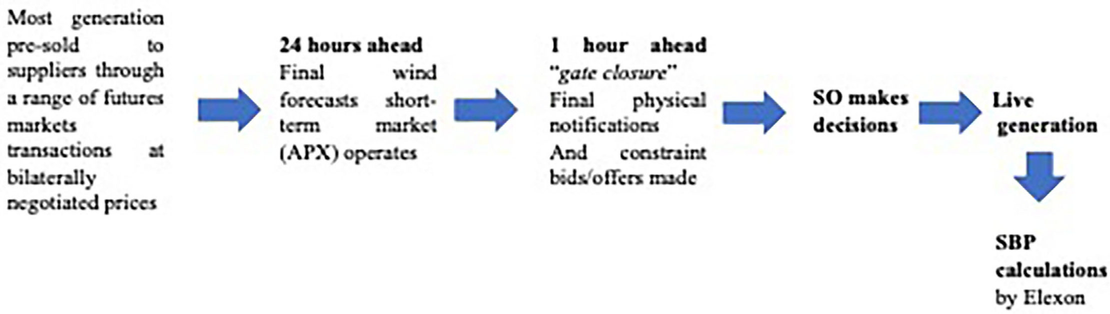


**Fig. 1.** The timeline to live generation and settlement.

Thus, a windfarm under the RO scheme potentially receives income from three sources- (i) its contractual agreements to supply energy,[15] (ii) payments to it, if any, for constraining its output according to its bid to do so and, (iii) based on actual output delivered (*not* output contracted) the money it receives under the RO scheme. Therefore, the opportunity cost of failure to deliver its contracted volume is the loss in RO credits. There is a further factor- if the windfarm has a shortfall on (contracted volume minus the sum of metered volume and constrained volume) in relation to the ECVN, it pays a penalty on that shortfall called the system balance price (SBP), calculated ex-post;[16] normally this is significantly above the contracted prices. Figure 1 illustrates this timeline and a windfarm's sources of income are set out in conceptual detail in the Appendix.

Three significant institutional points should be made. First, the payments for agreeing to be constrained are made on the basis of a pay-as-bid framework, so that a windfarm is more likely to be chosen for constraint if its bid is relatively low compared to others. Nevertheless, in practice, the accepted bids are all comfortably above the opportunity cost (loss in RO income), implying none are lower than this. Second, windfarms (and all others) must "try to adhere to the FPNs" (Elexon, 2020b, p.6). However, and remarkably, there is no penalty for not doing so.[17] Yet, the extent to which balancing services are required is gauged by the difference between FPNs and volumes demanded (Elexon, 2020a, p.16). Third, the network is often constrained in that it has insufficient capacity to move power from Scottish windfarms to English and Welsh consumers; these constraints are particularly severe when the subsea Link interconnector is non-operational- it represents almost 1/3 of transmission capacity between Scotland and England.

## 4. Hypotheses

The key relevant actors are the SO and the windfarms. Balancing, from an SO's viewpoint, is a physical activity to be achieved. The detail of which actors will be called upon in order to achieve the physical target, ensuring the system keeps within a narrow range of hertz (cycles of AC current per second) at all times, is determined shortly prior to delivery. One of the main instruments is to call upon generators to increase or decrease generation. To this end, bids/ offers must be provided by all participating generating (and consuming) parties as to what they are prepared to do, and at what price. They provide these, as explained in the timeline, before gate closure.

Since the SO's objective is to balance demand and supply, we suppose that the higher is predicted generation, the more likely that it will impose curtailment constraints; the higher is anticipated demand, the less likely is curtailment, subject to calendar effects, i.e., day of the week and month of the year. Specifically concerning Scottish windfarms, an additional factor in explaining the degree of constraint required will, we predict, be whether the Link is operating normally. If it is operating, the SO has more flexibility in balancing than if it is not, so will be less likely to constrain Scottish windfarms. These considerations comprise our first prediction. In choosing where and when to impose constraints, the SO has regard to economy in selecting from the bid/ offer schedules generators have provided.

That is

$$Probability\ of\ constraint = \mathrm{f}^1(Final\ forecast,\ Total\ Demand,\ Link\ operational, \text{Day and Month effects}) \tag{1}$$

Here we expect that (i) the higher the final forecast of wind generation, (ii) the lower is demand and (iii) the Link being non-operational will all raise the likelihood of constraints being required. Note that all these are exogenous factors- the final forecast is produced from estimates of wind speeds.[18]

[15] These are confidential bilateral contracts, but we assume they centre on the APX price.

[16] An institution called Elexon determines the SBP, following reporting of the various physical quantities and constraints on the system.

[17] *Information* imbalance volume (different from imbalance volume) is calculated as the modulus of the difference between measured volume and expected metered volume, which is FPN adjusted for any balancing services. The imbalance charge is this multiplied by the *information* imbalance price. However, this price is currently set at zero (Elexon, 2020a, p.32).

[18] A private communication from a National Grid employee confirms this.

Then, concerning the depth of constraints required by the SO from Scottish RO windfarms, we have

$$Scottish\ wind\ generation\ curtailed = \mathrm{f}^2(Final\ forecast,\ Total\ Demand,\ Time\ of\ day,\ Link\ operational,\ FPNs\ Scotland, \text{Day and Month effects}) \quad (2)$$

The same expectations regarding demand and final prediction of wind, as well as whether the link is operational, arise here as in the first equation. These variables are all givens in making the decision on constraints. Regarding Scottish FPNs, we would expect the higher they are, the more likely/ extensive constraints on Scottish wind would be. From the viewpoint of the SO, they are exogenous, being the result of values presented to them by the windfarms and others. Thus again, all explanatory variables may be viewed as exogenous. However, we note that they are not necessarily completely exogenous to the system, in that windfarms may set them bearing possible constraints in mind- something we discuss later. The estimation technique needs to take account here of the large number of zero observations (i.e., unconstrained periods); two econometric approaches suggest themselves and are discussed below.

Turning to windfarms' behaviour, we now examine whether prices influence wind generation patterns. Final forecasts are produced on the assumption that, when wind generation is available, it will happen. We start the investigation of this by running the regression

$$Fina\ l\ for\ ecast - Adjusted\ windgen = \mathrm{f}^3(Daya\ head\ price, RO\ price, E(SBP), Link\ operational) \quad (3)$$

Adjusted wind generation is actual generation plus any constrained generation. Hence, we expect that if windfarms react to prices, and other exogenous factors, then generation will be higher relative to the prediction if the day-ahead price is higher[19] and (though it varies little) the RO certificate price is higher. We expect wind generators to shade their generation down if they expect that the penalty for falling short of contracted generation, in the form of the expected SBP (determined after the event by Elexon), is higher. The challenge is how those expectations are formed, but again will be an exogenous variable so far as individual wind generators are concerned. We simply assume that the wind generators use rational expectations to estimate these. We include whether the Link is operational (again, exogenous) since we consider that when it is not, windfarms may react. This is estimated at aggregate GB level. This is the third estimation.

In effect, the second estimations (Equation (2)) assume the sum of Scottish FPNs, like the other variables, are exogenous (to the SO). However, they may not be exogenous to the system as a whole. We first simply examine the mean value of FPN minus measured generation (adjusted for constrained output, if any). We then move on to testing FPN as part of a potentially simultaneous framework in the fourth estimation. Using aggregate Scottish RO- subsidised windfarm data, we examine

$$FPN\ Scotland\ -\ Adjusted\ wind\ gen\ Scotland = \mathrm{f}^4(Link\ operational, E\ (\text{constraints imposed})) \quad (4)$$

where the expected value of constraints imposed is instrumented by the fitted values from estimation (1). This is the fourth and final estimate.

If Scottish windfarms behave strategically in setting their FPNs (contrary to the purpose of the FPN) then we expect higher reported FPN values relative to measured output (adjusted for any constraint) than if they give their true best estimate, in order to raise the possibility of being constrained. In a best estimate, it is natural to assume that sometimes they will over-predict FPN, sometimes under-predict. Note that one hour beforehand, when FPNs are declared, there will be very limited possibilities for the prediction of output being innocently biased. Therefore, if they are related positively to a raised probability of constraints, this is evidence in favour of strategic behaviour. If FPN Scotland in relation to generation is not exogenous (i.e., FPN Scotland is not determined purely by wind speed), then the question of simultaneity between Equations (4) and (2) arises.

We do not model the firm's choice of price at which it is willing to constrain output. One major problem in doing so is that this price is only reported when constraints are operative.[20]

## 5. Data and basic analysis

We now describe our data sample more completely. We collected hourly data from Gridwatch and Gridwatch Templar on wind generation over 509 days of operation in 2018-19. Half of these days were ones where the Link was operating, half where it was not, thus reducing cross-border capacity between Scotland and England. Using the Renewables Energy Foundation (REF) database, we identified 161 Scottish RO windfarms with a capacity of over 10MW. Not all of these participate actively in the balancing mechanism, particularly many of the smaller ones. From a list of those 107 Scottish RO windfarms that do participate, we obtained aggregate measures of what are called Final Physical Notifications of generation (FPNs) and measured generation from Elexon, which we consolidated by day in order to match up with the data on constraints. This constitutes our sample. Within it, 77 windfarms were subject to constraints at some time over our period, according to REF

[19] Zakeri et al. (2022) estimate that in 2019 natural gas set the wholesale electricity price 84% of the time in the UK, with imported electricity setting the price 15% of the time. Both these are exogenous to the amount of wind generated given the essentially world market for gas. Thus, despite a significant proportion of electricity being generated by wind in Britain, we treat the day-ahead price as exogenous.

[20] That is, the price at which a wind farm is willing to constrain output is not reported when that wind farm is not constrained nor when constraints are not required.

**Table 1**
Variable definitions.

| Variable | Description | Frequency | Source |
|---|---|---|---|
| Actual wind value | Actual wind generation value GB, MWh | Hourly | Gridwatch.Templar.co.uk |
| Adjusted wind gen | Actual wind value+ Wind generation curtailed | Hourly | Generated as sum |
| Constraint imposed | Dummy= 1 when GB constraint payments made | Daily | REF |
| Day-ahead price | Day-ahead price on APX/EPX exchange, £ | Hourly | BM Reports |
| Final forecast (wind value) | Final forecast wind generation value GB MWh | Hourly | Gridwatch.Templar.co.uk |
| FPN Scotland | Final physical notification, Scottish RO plants (bespoke calculation) | Half Hourly | ELEXON |
| SBP price | The imbalance price used to settle the difference between contracted generation and amount generated per MWh (SSP and SBP are identical) | Hourly | BM Reports |
| Scottish wind generation | Generation by RO plants (Bespoke calculation) | Half Hourly | ELEXON |
| Total demand | Total demand GB across all fuels MWh | Hourly | Gridwatch.co.uk |
| Wind farms constrained | Number of wind farms constrained GB | Daily | REF |
| Wind generation curtailed | Wind generation curtailed GB, MWh | Daily | REF |
| Adjusted wind gen Scotland | Actual wind value + wind gen curtailed Scotland, MWh | Daily | Generated |
| Constraint cost Scotland | Total amount paid for wind power curtailed, Scotland, £ | Daily | REF |
| Link operational | Dummy = 1 where interconnector usable | Daily | Several sources confirm it |
| Scottish wind constraints | Constraint payments to Scottish RO plants, £ | Daily | REF |
| Wind farms constrained, Scotland | Number of RO wind farms constrained Scotland | Daily | REF |
| Wind generation curtailed, Scotland | RO wind generation curtailed Scotland, MWh | Daily | REF |
| RO price | Renewables obligation certificate payment £ per measured MWh for each RO MWh not possessed (= value to wind farm) | Annual | OFGEM |

daily data. These constitute the vast bulk, 90%, of volume constraints imposed on RO windfarms in Britain as a whole in our period, according to REF, with Scottish RO windfarms constrained in 279 out of the 300 days when constraints in Britain were required in our period. Some were constrained only rarely, but the average number of days on which a windfarm was constrained is 83.7 and one windfarm was constrained on 213 of the 509 days, nearly 42% of the time. Whether a particular windfarm will be constrained when constraints are required will depend in part on its bid to reduce output, with higher-priced bids less likely to be accepted, but the nature of the network is such that some windfarms are much more likely to be asked to constrain output because of their location in the system.[21]

This data was matched with data on prices on the APX/EPX exchange and on balancing prices from BM Reports, together with windfarm ownership data obtained from RenewableUK (renewableuk.com) and/or The Wind Power (thewindpower.net). The sub-industry (wind generators operating under the RO scheme) is not particularly concentrated given an HHI, based on 2020 output, of 972, although Scottish Power (Iberdrola) and SSE, who also operate the transmission networks in Scotland, are the largest players with almost 20% each. Constraint payments amongst the 77 firm owners receiving them are markedly more concentrated, with an HHI of 2767 in our sample, again with the most significant shares going to Scottish Power and SSE.

For the work on generation relative to forecasts based on predicted wind speeds we were able to make use of hourly data. Some of the data we use, including the payments to Scottish RO plants and constraints on them, also whether the Link was operating, are daily data. Where necessary we consolidated hourly generation data to daily by aggregation of MWh.

Table 1 gives data definitions whilst Table 2 lists basic statistics on the key variables.[22] From the latter we observe that wholesale price varies considerably, on occasion (when demand is very low) it can go negative, but it rises substantially at periods of high demand. The effect of the RO subsidy, which changes annually in April, is almost to double the average revenue windfarms receive per MWh. Note that the mean SBP (balancing) price is no different from the mean wholesale price, but has a significantly greater variance, so that when a windfarm is likely to have a shortage in output relative to its contracted amount the SBP price is likely to be significantly higher than the wholesale price. One factor of particular note is that wind generation by day varies enormously: this high variance is a typical feature of wind generation. Overall, wind on average contributes around 15% to GB demand, with the 107 Scottish RO windfarms we study producing over 45% of overall GB wind generation. Curtailed Scottish generation from these plants amounts to almost 10% of FPNs and given that curtailment constraints are applied in Scotland on over half the days in our sample, they constitute a substantial part of the overall picture. It is notable, given our earlier discussion of the system, that FPNs are on average over-predicting actual wind generation in Scotland (even after correction for constraints).

More revealing features of the data are obtained in Table 3 by engaging in a two-way split of the sample, first into days when the interconnector is operating and when it is not (top panel) and second into days when constraints are imposed

[21] The simple correlation between average bid size and payments over our period is -0.55.

[22] Those variables listed in Table 1 that have been collated from common domain sites are available to interested researchers at https://zenodo.org/record/7716493. The other variables are either available through a (mild) paywall or are bespoke calculations by another party so not available directly here.

**Table 2**
Descriptive statistics.

| Variable | Obs | Mean | Std. Dev. | Min | Max |
|---|---|---|---|---|---|
| *Constraint imposed* | 12203 | 0.548 | | 0 | 1 |
| *Wholesale price* | 12203 | 50.385 | 15.067 | -34.23 | 163.85 |
| *RO price* | 12203 | 47.765 | 0.744 | 47.22 | 48.78 |
| *Final forecast (wind value)* | 12203 | 4683.26 | 2904.19 | 245 | 12301 |
| *SBP price* | 12203 | 50.201 | 22.263 | -71.5 | 375 |
| *Total demand* | 12203 | 30783.7 | 6428.57 | Minimal | 48229.33 |
| *Adjusted wind generation* | 12203 | 4757.33 | 3188.88 | Minimal | 13511.54 |
| *Link operational* | 509 | 0.5005 | | 0 | 1 |
| *Wind generation curtailed, Scotland* | 509 | 5058.40 | 10248.37 | 0 | 52593.4 |
| *Final forecast (wind value)* | 509 | 112278.6 | 63876.9 | 9470 | 272534 |
| *FPN Scotland* | 509 | 51146.72 | 30757.4 | 5193.85 | 127964.4 |
| *FPN Scotland - Adjusted wind gen Scotland* | 509 | 7517.85 | 4187.21 | -519.74 | 18656.64 |

**Table 3**
T-test for the variables of interest (*** significance at 99%, ** 95%, *90%).

| Variables | Link | Obs. | Mean | Std. Dev. | Mean difference |
|---|---|---|---|---|---|
| *Wholesale price* | OFF | 6096 | 52.107 | 13.854 | *** |
| *Wholesale price* | ON | 6107 | 48.665 | 16.005 | |
| *RO price* | OFF | 6096 | 47.570 | 0.651 | *** |
| *RO price* | ON | 6107 | 47.959 | 0.779 | |
| *Final forecast (wind value)* | OFF | 6096 | 4038.58 | 2821.02 | *** |
| *Final forecast (wind value)* | ON | 6107 | 5326.78 | 2842.86 | |
| *SBP price* | OFF | 6096 | 51.886 | 21.23 | *** |
| *SBP price* | ON | 6107 | 48.518 | 23.13 | |
| *Total demand* | OFF | 6096 | 29882.35 | 5664.66 | *** |
| *Total demand* | ON | 6107 | 31683.44 | 6995.28 | |
| *Adjusted wind gen* | OFF | 6096 | 4047.61 | 3076.81 | *** |
| *Adjusted wind gen* | ON | 6107 | 5465.77 | 3141.13 | |
| *Wind generation curtailed, Scotland* | OFF | 254 | 6464.51 | 11934.4 | ** |
| *Wind generation curtailed, Scotland* | ON | 255 | 3657.81 | 8015.16 | |
| *Final forecast (wind value)* | OFF | 254 | 96925.9 | 62393.28 | *** |
| *Final forecast (wind value)* | ON | 255 | 127571.1 | 61744.91 | |
| *FPN Scotland* | OFF | 254 | 45463.6 | 29769.83 | *** |
| *FPN Scotland* | ON | 255 | 56807.56 | 30737.8 | |
| *FPN Scotland - Adjusted wind gen Scotland* | OFF | 254 | 7476.08 | 4367.29 | |
| *FPN Scotland - Adjusted wind gen Scotland* | ON | 255 | 7559.45 | 4007.97 | |

| *Variables* | Wind curtailed | Obs. | Mean | Std. Dev. | Mean difference |
|---|---|---|---|---|---|
| *Wholesale price* | NO | 5511 | 51.532 | 14.920 | *** |
| *Wholesale price* | YES | 6692 | 49.439 | 15.123 | |
| *RO price* | NO | 5511 | 47.896 | 0.773 | *** |
| *RO price* | YES | 6692 | 47.656 | 0.700 | |
| *Final forecast (wind value)* | NO | 5511 | 2982.25 | 1905.08 | *** |
| *Final forecast (wind value)* | YES | 6692 | 6084.08 | 2836.67 | |
| *SBP price* | NO | 5511 | 51.418 | 21.643 | *** |
| *SBP price* | YES | 6692 | 49.199 | 22.714 | |
| *Total demand* | NO | 5511 | 31094.42 | 6474.09 | *** |
| *Total demand* | YES | 6692 | 30527.82 | 6379.96 | |
| *Adjusted wind gen* | NO | 5511 | 2839.18 | 2016.00 | *** |
| *Adjusted wind gen* | YES | 6692 | 6336.96 | 3109.92 | |
| *Final forecast (wind value)* | NO | 230 | 71380.23 | 41268.06 | *** |
| *Final forecast (wind value)* | YES | 279 | 145994.1 | 59400.7 | |
| *FPN Scotland* | NO | 230 | 28088.87 | 15551.52 | *** |
| *FPN Scotland* | YES | 279 | 70154.99 | 26962.79 | |
| *FPN Scotland - Adjusted wind gen Scotland* | NO | 230 | 7167.60 | 4592.55 | * |
| *FPN Scotland - Adjusted wind gen Scotland* | YES | 279 | 7806.58 | 3805.14 | |

on windfarm output and when they are not. As expected, constrained generation is higher when the interconnector is not working- failure of the interconnector means only the overland transmission between Scotland and England operates, reducing capacity by almost 1/3.[23] Significantly, when constraints are imposed, the average amount constrained is almost double when the Link is not working, compared with when it is. In other results, total demand is somewhat higher when the interconnector is on- this is clearly not a factor influenced by the interconnection state, but most probably due to demand

[23] The interconnector's capacity is 2GW whilst overland routes have a total capacity of 4.4GW.

**Table 4**
The Western Link Service History.

| Start Date | End Date | Status | N. of Days |
|---|---|---|---|
| [08/12/2017 | 04/05/2018 | *Low level operation* | 146] |
| 05/05/2018* | 16/10/2018 | *Outage* | 165 |
| 17/10/2018 | 19/02/2019 | *Operating* | 126 |
| 20/02/2019 | 23/03/2019 | *Outage* | 33 |
| 24/03/2019 | 06/04/2019 | *Operating* | 13 |
| 07/04/2019 | 02/06/2019 | *Outage* | 57 |
| 03/06/2019 | 25/09/2019* | *Operating* | 115 |

*Source:* Renewable Energy Foundation and Western Link website.
* Our sample dates from 5/5/2018 to 25/9/2019. The time of day on which an outage occurs is not recorded in our sources.

**Table 5**
Preliminary estimation of probability of constraint (Probit estimation).

| | Coefficient (robust s.e.) | z |
|---|---|---|
| *Final forecast wind value* | 0.0171 (0.0017) | 10.18 |
| *Link operational* | -0.746 (0.1753) | -4.26 |
| *Total demand* | -0.0054 (0.0019) | -2.83 |
| Pseudo R squared | 0.376 | |
| Observations | 509 | |

*Notes:* Test of hypothesis (1) regarding the SO's behaviour. Dependent variable: Probability of constraint being imposed on wind farm generators. Estimation includes day-of-week and month dummies, not reported. The variables Final forecast wind value and Total demand have been divided by 1000 in estimation in order to avoid excessive zeros being reported.

being higher at certain times of the year. Total forecast wind generation is also higher when the interconnector is operating, but again this is not determined by whether the interconnector is working but rather by predicted wind speeds.

The split between periods where Scottish wind is constrained and periods when it is not, the lower panel of Table 3, is also revealing. There is very little difference in overall demand, but unsurprisingly the overall wind generation forecast when constraints are imposed is around twice what it is when they are not. However, the total FPN declared by Scottish windfarms is 2.50 times as much in constrained periods, in other words exacerbating the strong wind forecasts. This hints at something we explore more rigorously later- declared FPNs are clearly not an unbiased predictor of actual generation, instead being an exaggerated amount, but the fact that they are more exaggerated at certain times suggests that they may be being manipulated deliberately by windfarms.

Table 4 lists the dates within our sample period over which the Link was in full operation or out of service. In each case of the latter, a sudden unexpected technical failure caused the Link to fail, the first occurring after a partial operation period prior to our sample. Repair times have been difficult to predict, as well as the various technical failures being the subject of legal disputes between the transmission operator, the switchgear manufacturer, and the cable manufacturer, all of which are potential culprits.

## 6. Empirical results

We test the hypotheses developed above in turn. The first two estimations investigate the SO's behaviour, finding factors that influence whether it imposes constraints on generation and then whether the final product notifications (FPNs) Scottish RO operators make influence the constraints required of them. Finding that the data is consistent with these hypotheses, we then turn to examine wind generator behaviour. Initially we focus on whether wind generators respond to market prices, indicating that they exercise a degree of flexibility in their generating decisions. Finally, we return to the FPN decisions by Scottish RO windfarms, showing that the difference between actual and declared wind generation is higher when the exogenous probability of wind curtailment is higher, so making it more likely that they will benefit from being constrained.

The results of estimating Equation (1) using a probit framework are given in Table 5. As can be seen, and in line with predictions, constraints are less likely (given the day of week and month) if the Link is operational, less likely if demand is high, more likely if the forecast wind value is high.

These results are as expected and encourage us to proceed to Equation (2) in which we consider specifically the level of Scottish (RO) constraints imposed by the SO and the impact of Scottish FPNs in our sample. Due to data limitations, we estimate this equation at the daily level, and we employ alternative approaches to tackling the nature of the constraints data, due to its substantial number of zero observations. As well as providing OLS results, we use a Tobit estimator, and also the PPML procedure (Santos Silva and Tenreyro, 2006) which has previously been used with energy data (Zhao et al., 2013; Costa-Campi et al., 2018). The results of the OLS and Tobit investigations are shown in Table 6. Both give the same qualitative inferences regarding the key factors, namely as expected a negative relationship between total demand and constraint level

**Table 6**
Determinants of Scottish constraint value.

| | *Ols* | | *Tobit estimation* | |
|---|---|---|---|---|
| | Coefficient (robust s.e.) | t | Coefficient (robust s.e.) | z |
| *Final forecast wind value* | -0.0013 (0.010) | 0.13 | -0.031 (0.0056) | -0.56 |
| *Link operational* | -6154.53 (729.03) | -8.44 | -4259.14 (439.80) | -9.68 |
| *Total demand* | -0.0133 (0.0084) | -1.59 | -0.0129 (0.0049) | -2.64 |
| *FPN Scotland* | 0.255 (0.021) | 12.34 | 0.197 (0.0121) | 16.23 |
| Pseudo R squared | 0.601 | | 0.250 | |
| Observations | 509 | | 509 | |

*Notes:* Test of hypothesis (2) regarding the SO's decisions to constrain Scottish RO windfarms. Dependent variable: RO wind generation curtailed Scotland. Estimation includes day-of-week and month dummies, not reported. For Tobit estimation average marginal effects are shown.

**Table 7**
Determinants of difference between forecast generation and actual.

| | Coefficient (robust s.e.) | t |
|---|---|---|
| *Day-ahead price (lagged) + RO price* | -4.7664 (0.6257) | -7.62 |
| *Link operational* | 62.2120 (18.3552) | 3.39 |
| *SBP price* | 6.5971 (0.3376) | 19.54 |
| Adjusted R-squared | 0.146 | |
| Observations | 12178 | |

*Notes:* Test of hypothesis (3) regarding windfarms behaviour in response to prices. Dependent variable: Final forecast - Adjusted generation. Final forecast comes from wind speed forecasts (exogenous), adjusted generation is actual power generated plus any constrained off. Estimation includes hour, day-of-week and month dummies, not reported. Note: Day-ahead price is lagged so as to make it for that day. OLS Clustered SE by day.

(albeit insignificant in the OLS case) and a negative relationship between the interconnector working and constraint level.[24] More importantly, they evidence a very significant positive relationship between Scottish RO FPNs and constraint level, *after taking account of the final forecast value*. A straightforward interpretation is that Scottish FPNs appear to influence decisions regarding the level of constraints imposed. The PPML procedure yields the same qualitative results as the Tobit estimation, but with very different coefficients and we leave it out for space reasons.[25]

We then move on to examine the windfarms' behaviour, firstly whether prices influence wind generation behaviour, as represented in Equation (3). Recall that the day-ahead price and the RO price are known and essentially exogenous to the decisions of windfarms. The SBP is determined ex post, and we assume that windfarms make unbiased estimations of that. Given these assumptions, we treat the decision process as moving from these prices to windfarm decisions on the day. Thus, they will influence the gap between final prediction of wind generation and actual (adjusted) generation. Table 7 illustrates the results, the significant negative coefficient showing that indeed a higher day-ahead price leads to generation being higher in comparison to the final (wind-speed-based) prediction, whereas a higher system buy price, the penalty for a shortfall, leads to it being lower. If the link is operational, actual generation is lower than forecast, which again suggests strategic response to external events, although this last result is somewhat sensitive to precise specification.

We now turn to examine how Scottish windfarms behave in declaring their FPNs, first in terms of mean values relative to adjusted generation, then as to whether behaviour is different when the Link is not operating compared with when it is. We find that the sum of Scottish FPNs, minus measured generation is positive on average, by a daily amount of over 12,500MWh. The mean additional amount in periods when the Link is not working is 13,937MWh, whereas when the Link is working, it is 11,220MWh. Given this result, we may have to consider whether FPNs should be treated as endogenous in testing Equation (2).

To examine this more closely, we investigate the difference between aggregate FPNs and adjusted generation for the Scottish RO windfarms, using whether the Link is operating or not and the fitted probabilities of there being constraints imposed, coming from table 5's estimation.[26] The results of this in terms either of an OLS or IV regression are in Table 8. They show clearly that FPNs are relatively high when the probability of being constrained is high (which includes whether the Link is operational), but given this, there is no additional effect of the Link being operational than when it is not. That is, the effects of the Link being unavailable arise through it increasing the probability of curtailment and amount of wind curtailed, but not otherwise. This latter result suggests we do not see endogeneity of FPNs in Equation (2) as a significant issue.

In sum, our results point to wind generators behaving as expected with respect to prices, and most significantly, seemingly raising their FPN declarations to take advantage of underlying conditions in order to increase the likelihood of being constrained, as well as setting them "optimistically" more generally. They have the scope to do this because there is, remark-

[24] The coefficient values are very different as between the approaches, in line with what was found by Zhao et al. (2013).
[25] Zhao et al. (2013) also found in their use of the method very different coefficients for PPML.
[26] By adjusted generation, we mean actual generation plus the constrained generation.

**Table 8**
Determinants of FPN relative to generation values.

| | *Ols* | | *IV* | |
|---|---|---|---|---|
| | Coefficient (robust s.e.) | t | Coefficient (robust s.e.) | t |
| *Link operational* | 230.22 (406.80) | 0.57 | 98.40 (359.59) | 0.27 |
| *Predicted probability (from eq.1)* | 2141.92 (592.09) | 3.62 | 3378.22 (570.26) | 5.92 |
| Pseudo R squared/ F value | 0.246 | | 35.15 | |
| Observations | 509 | | 509 | |

*Notes:* Test of hypothesis (4) regarding Scottish RO windfarms' behaviour. Dependent variable: FPN Scotland - Adjusted generation Scotland. This is the difference between generation declared one hour before delivery and actual generation adjusted for constraints. Estimation includes day-of-week and month dummies, not reported.

ably, no penalty for false or biased declarations of FPN. Moreover, those firms that operate both windfarms and conventional generation potentially stand to gain by being paid to have windfarms constrained off whilst at the same time providing additional conventional generation to meet demand in England.

## 7 Concluding remarks and policy implications

Given the results of our investigation, which is consistent with Scottish windfarms gaming the system, two policies suggest themselves. First, constraint payments could be limited to a figure slightly above the lost ROC value, thereby economising on payments not to produce whilst still providing some incentive to agree to be constrained in addition to any saving in maintenance due to reduced operation. To see the benefit of this, we perform a straightforward calculation where we substitute a price of £50 per MWh constrained (slightly higher than the opportunity cost) for whatever price was in fact paid. Over our sample period, this leads to a reduction in constraint payments to RO farms of £51.1m, representing over 28.4% of these payments.[27] Of course, this assumes behaviour is unchanged, but since the payments made relate to existing legacy plants' decisions in the very short term, it is likely to give a reasonable picture. It is even possible that it is a lower estimate, because there would be a lesser incentive to want to be constrained. Assuming the Link can be made reliable, or further interconnectors currently at the planning stage are developed, the need for constraints would be reduced in any case.

Second, a straightforward reform to FPN could be instituted whereby a non-zero penalty is introduced for biased declarations of FPN, that is, setting a non-zero *information* imbalance price. For example, over a given period of time, if a windfarm's FPN is consistently too high, a penalty could be imposed. Alternatively, a margin of error could be defined, with a non-zero information imbalance price imposed on a windfarm moving outside that. In fact, the information imbalance volume is already calculated, it is just that this is multiplied by a zero price. Such a reform is in principle straightforward to implement since it arguably does not create a hold-up problem- the mechanism exists for charging, so it is simply a change in price. This would have the incidental benefit of rendering the final hour generation position more accurate, potentially reducing the extent of constraints needed. Calculating the impact is much less straightforward than in the first case, since behaviour is more likely to change.

Broadening the relevant considerations, there are two further points. First, one factor that may be taken into account by investors in choosing where to site a windfarm is the likelihood of it being constrained off, under whatever scheme it operates, so that longer-term planning decisions are potentially influenced adversely (from a societal viewpoint) by the potential for earning (high) constraint payments. Second, as pointed out earlier RO is a legacy scheme, albeit significant and with many years to run. Although it closed to entrants shortly before our sample starts, firm behaviour subject to it provides lessons more generally that in devising a scheme, the potential for firms optimising their behaviour strategically with respect to the scheme must be borne in mind.[28]

## Credit author statement

This paper was jointly and equally written and prepared by Mario Intini and Michael Waterson. We have no funding sources to disclose.

## Data availability

Some of the data was a bespoke creation for the paper; some of the data exists behind a mild paywall. Other than that, the data is in principle available to interested readers on request.

[27] This is £36.6m on an annual basis, assuming our period is typical, but in fact the payments are much greater in some years than others, so an annual figure is somewhat misleading.
[28] The same general lesson might be drawn from the Fabra and Imelda (2022) study.

## Appendix

*The determinants of a windfarm's revenue*

A windfarm company *i* (which may operate a number of windfarms) operating under the RO scheme has the following maximands relating to each period

$$\max_{G_i^a}[G_i^a p^w + G_i^g r^w - \max(0, G_i^a - G_i^g - G_i^{con}).E(p^b)] + \max_{p_i^{con}, G_i^d}[G_i^{con}(p_i^{con}, G_i^d), p_i^{con}, pr(ichosen)] \tag{5}$$

where $\mathrm{G}_i^{\max} \geq G_i^a \geq G_i^g + G_i^{con}$ (the latter inequality in the majority of cases)
$G_i^a \equiv ECVN_i$, the output it has agreed to supply on contract (Energy contract volume notification);
$G_i^g \equiv$ metered output (to grid)
$\mathrm{G}_i^{\max} =$ maximum feasible output, given wind speeds (private knowledge to the wind farm)

$$pr(ichosen) = f(\sum_j G_i^d, p_i^{con}, p_{j\neq i}^{con}, L)$$

and $G_i^d \geq G_i^{con}$ (the output constrained by the SO) where $G_i^d \equiv FPN_i$ (its declaration) and $L$ is a dummy variable depending on whether the Western Link is operating.

Time subscripts have been suppressed but apply to all magnitudes. Subscript *i* is also suppressed where it is obvious.

In words, the windfarm must choose its level of agreed contracted output at the then prevailing wholesale market price,$p^w$ (jointly with the suppliers with whom it contracts), bearing in mind the possibility that, due to insufficient wind, it will not be able to reach that level and will need to pay for the short-term purchases made by the SO to meet its shortfall. The (expected) system balance price (SBP) per MWh it will need to pay for this, $E(p^b)$, will be determined ex post by Balancing Services (Elexon), but given its magnitude, incentivises keeping to the contracted output.[29] It will also receive RO certificates worth $r^w$ in proportion to its *metered* output.

Before gate closure, it is also required to set its final physical notification (FPN) and the (negative) bid price $p_i^{con}$at which it is willing to be constrained. The SO is more likely to decide constraints are needed when the sum of FPNs exceed what is demanded/ acceptable to the network. If it decides constraints are needed, it will accept bids to curtail with regard to location and economy, so a high (negative) bid is less likely to be chosen, other things equal.

Expression (5) and the accompanying definitions incorporate several key factors specific to the detailed implementation of the RO scheme. These are justified in detail in the sub-sections below.

We conceive of the windfarm's optimisation process as having two stages- In the first stage, choosing $G_i^a$, in building up its portfolio of future sales contracts into the future, the firm will need to trade off the benefits of contracting to sell more output against the cost of being unable to meet that output and therefore paying the penalty of facing the higher balancing services price, meaning that it will probably contract with some degree of risk aversion. Therefore, if it expects the balancing price to be high (assuming it can discern a pattern), it will shade its contracting behaviour further below what it anticipates it could produce. However, there is a tradeoff, in that if the market price is high, the benefits of agreeing to sell more are higher. Hence, without needing to write the maximisation process out more formally but noting the signs on the terms incorporating $G_i^a$, we would expect that the higher the market price $p^w$, the greater the volume relative to what would be expected given SO's wind estimates $\sum_G G^f$ (which are likely to be related to $\sum_G G^{\max}$), whereas the higher is $E(p^b)$, the lower the volume compared with expected.

In the second short-term stage leading up to gate closure, it chooses $\mathrm{FPN_i}$ and $p_i^{con}$. Two alternative views regarding $\mathrm{FPN_i}$ are possible. On the first view, FPN is set equal to the expected value of measured volume (after adjusting for any balancing actions it is asked to perform). This is what is implied by the "rules". Alternatively, a more strategic approach to optimising would be that, given the absence of formal constraints on FPN*s* (see below), and the inherent variability of wind, but the increased probability of being asked to constrain if the sum of FPN*s* is high, "optimism" (or strategic action) regarding the declaration is likely and possibly more likely when the probability of curtailment is higher, for example because the Link is not operating. In sum, we expect a gap between FPN and measured output and that this gap may increase when the Link is not operating. Plausibility is added to this possibility by the fact that wind generation in Scotland is moderately concentrated amongst firms and constraint payments are highly concentrated.

Choosing constraint prices is more difficult, because there is a clear tradeoff between setting a higher price and having a lower chance of being chosen to constrain. Of course, a firm needs to consider the opportunity cost, which is essentially the loss of RO certificates, as a plausible lower level for a bid. This applies to all firms, so we would not expect bids below the foregone cost of RO certificates. We are only able to observe bids when constraints are imposed, they are not published otherwise. Those accepted will normally be at the lower end of the distribution of bids, because the balancing services actions

[29] We write the relationship between agreed sales, measured output and constrained amount as a one-way inequality since wind farms seldom sell electricity via balancing operations.

by the SO take economy into account where possible.[30] However, if firms are able to form expectations of the likelihood of constraints being required, this is likely to influence the gap between FPN and measured output, after accounting for any forced constraint.

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[30] That is, assuming there is a single pinch point in moving electricity from north to south, and constraints are required, those firms bidding the lowest prices to curtail production would be chosen above those proposing higher prices, with successively higher-priced firms being brought in until the required degree of curtailment is reached. However, this description simplifies the system's pinch points.