Balancing reserves in a power system with high wind penetration – evidence from Portugal

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***Abstract*—The growth of intermittent renewable power generation has been drawing attention to the design of balancing markets. Portugal is an interesting case study because, while wind generation already accounts for a high fraction of demand (23%), there are still no economic incentives for efficient wind forecast (wind balancing costs are passed to end consumers). We analyze the evolution of the balancing market from 2012 to 2016. Using actual costs provided by the Portuguese TSO, we find wind imbalance costs in the range of 2 to 4 EUR/MWh. These results surprisingly suggest that, even with large wind penetration and socialized imbalance costs, wind forecast errors can have a relatively low cost.**

I. Introduction

Renewable wind power generation has been increasing across the world, already reaching very significant levels in some markets. Portugal is one such case, with wind accounting for 23% of all electricity consumed from 2012 to 2016. The growth of intermittent generation puts more strain on Transmission System Operators (TSO), which must use Balancing Markets to compensate for any deviation between what wind plants were expected to generate and what they actually deliver in real time. The dispatch of secondary or tertiary reserves is typically more expensive than energy contracted in day-ahead markets. Imbalances therefore create an extra-cost, or over-cost, which would be avoided if agents where able to forecast their generation perfectly.

Wind balancing costs have traditionally been paid by the end user, rather than by the wind plants with deviations. However, there are different views on the best market design. Allocating balancing responsibility to wind producers incentivizes them to forecast more accurately. For example, wind generators in Spain have been responsible for their imbalances since 2004, which has led to a continuous improvement in wind forecasting ([1], [2]). On the other hand, balancing responsibility may be disproportionately expensive for small producers with fewer forecasting and financial resources, thus hindering competition. Different countries have followed different rules for allocating balancing responsibility, but European regulators favor a move towards subjecting wind producers to the same market exposure as traditional generators (see, for example, [3]).

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Wind generation in Portugal has been incentivized through guaranteed feed-in tariffs (FiT), which fully isolate wind plants from market price risk (see [4] or [5]). Even though wind plants are formally charged for their imbalance costs in a first stage, the final remuneration they receive compensates for these costs, so that wind producers always receive the set FiT in the end. In other words, wind imbalance costs are socialized, that is, split over final consumers. Portugal is thus an interesting case of a system with large wind penetration, but without price mechanisms to induce low forecasting errors and economic efficiency.

This paper studies the Portuguese Balancing market, using actual observed imbalance quantities and imbalance market prices. We obtain hourly data from the Portuguese TSO (REN) for the period between 2012/Jan/01 and 2016/Dec/31. For this period, the mean absolute imbalance of all wind generation relative to the system load is 3.6%, with deviations reaching more than 20% of load in several hours. Interestingly, we find that the full sample value-weighted average of wind balancing costs is 2.21 EUR/MWh. Hence, our results suggest that wind balancing costs can be relatively low, even at high wind penetration rates, and without the best economic incentives.

These results are consistent with existing studies that evaluate wind balancing costs using observed market prices. [6] reports a cost of 2.8 EUR/MWh for Denmark. [7] find costs close to zero in Denmark, 5.6 EUR/MWh in Austria, and 12.6 EUR/MWh in Poland. [8] find 0.6 EUR/MWh for Finland. [9] find balancing costs in Texas to be in a 2–5 EUR/MWh range. [10] find costs in a range of 1.7–2.5 EUR/MWh for Germany (see this paper for a recent literature review). Most of these studies refer to markets where wind had a low penetration rate (except for Denmark, 17%). Hence, our contribution is to show that the pattern holds even at higher wind shares up to 23%.

[11] show that, while renewable capacity in Germany has been growing, balancing costs have actually been decreasing (which they denote as the "German paradox"). Part of the reason is efficient cooperation by German TSOs ([12]). Our findings support the idea that wind balancing costs can be low, even for a single TSO in a relatively isolated system.

II. Data and market description

Data on all generation, imbalances, and reserves is provided by the Portuguese TSO (REN) for all hours between 2012 and 2016.

A. Wind generation

Wind accounted for 23% of all electricity consumed in Portugal from 2012 to 2016. However, this average masks considerable variation at the hourly frequency. In particular, the last two years of the sample period show some hours with very high wind generation, sometimes even exceeding 100% of load.

B. Imbalances

We have hourly data from REN on the total system imbalances and on wind imbalance. The wind imbalance equals the actual wind generation minus the quantity sold in market. All wind generators are aggregated under a single Balancing Responsible Party (BRP), and therefore only their net imbalance is accounted.

Hourly wind imbalances are reasonably symmetrically distributed, around a full sample average of 32 MWh. However, the tails of the distribution extend out to very large deviations. Over the full sample period, the maximum hourly wind deviation is $+1\,613$ MWh and the minimum is $-1\,497$ MWh. These are large values when compared to the average system load of $5\,594$ MWh over the sample period.

We define as "Other Imbalances" the difference between the total system imbalance and the wind imbalance. This variable thus captures the sum of the imbalances of all other agents in the market, including other generators and consumers.

From the point of view of the system operator, both positive and negative deviations have to be managed. Hence, it is important to compare imbalances in absolute values and relative to total system load. The mean absolute imbalance of wind relative to load is 3.6%, while the mean absolute value of other imbalances relative to load is 2.9%.

C. Reserves

We use hourly data on the quantity of Secondary and Tertiary reserve energy used for upward and downward regulation. Secondary reserve is typically small. However, there is a persistent difference between upward and downward secondary regulation: while downward secondary is typically a small value in the order of 10 MWh, upward secondary always fluctuates around 50 MWh. The fact that upward secondary is relatively stable around this value has a technical/economic explanation related to the design of the Portuguese balancing reserve market.

The rules in place since the beginning of the market require secondary reserve providers to offer a band of reserve split in the ratio of 2/3 for upward and 1/3 for downward regulation. For example, consider a system with a single thermal power plant that is able to vary its output between 200 and 350 MW, and suppose that it was dispatched at 250 MW in the day-ahead market. If this plant wants to sell the entire band (150 MW) in the secondary reserve market, it is required, by economic market rules, to offer 100 MW for upward and 50 MW for downward regulation. At the same time, the TSO, who is mostly focused on the technical conditions of the system, tries to have the secondary band centered at the midpoint, that is, with an equal amount of upward and downward availability. Since the secondary reserve is mobilized automatically by the Automatic Generation Control (AGC), the TSO indirectly controls the secondary band by manually dispatching *tertiary* reserve and thus forcing the AGC to adjust the secondary reserve in the intended direction. In the previous example, the TSO would dispatch 25 MW of *downward tertiary* reserve, forcing the AGC to automatically mobilize 25 MW of *upward secondary* (that is, to increase the generation of the thermal plant by 25 MW).

During 2012–2016 period, the average secondary band offered in the market for upward regulation was 175 MW and for downward regulation was 87.5 MW. The total band was thus, on average, 262.5 MW, with an equilibrium midpoint of 43.75 MW. As explained above, this causes the system to use, on average, approximately 44 MW of upward secondary reserve. In summary, the average 44 MWh of upward secondary reserve results from what we might call the difference between "market equilibrium" and "technical equilibrium".

We also use data on hourly market-clearing prices of upward and downward tertiary reserves. Comparing with the day-ahead market price for the corresponding hour, we find that the series display the expected pattern. Namely, the upward price is above the day-ahead market price, and the downward price is below the day-ahead price (note that the downward price represents a refund from the agent that is reducing its day-ahead-scheduled generation). The full sample average prices are 57 EUR/MWh for upward tertiary, 27 EUR/MWh for downward tertiary, and 45 EUR/MWh for the day-ahead market.

III. Drivers of balancing reserves mobilization

Total system imbalances have to be compensated by the sum of secondary and tertiary reserves, which we denote by "Total Reserves". Since we can only observe imbalances aggregated at the hourly frequency, the most comparable reserves are hourly "Total Net Reserves" (TNR), defined as upward minus downward reserves:

$$\begin{aligned}\text{Total Net Reserves} :=& \\ &(\text{Secondary upward} + \text{Tertiary upward}) \\ &- (\text{Secondary downward} + \text{Tertiary downward}) \quad (1)\end{aligned}$$

Comparing total net reserves and total system imbalances, we find that a very large fraction of reserve usage is explained by total system imbalances. On average, the amount of reserve usage that does not correspond to system imbalance is only 37 MWh. However, there are some hours when this difference becomes very large, from a minimum of $-1\,584$ MWh to a maximum of $-1\,394$ MWh.

We therefore proceed to investigate other determinants of balancing reserves. In addition to imbalances, there are at least two more factors that may drive the use of balancing reserves.

One factor is the change in load. While load evolves as a continuous function of time, the generation that is dispatched in the day-ahead market is a step function constant over each hour. The difference between the two has to be fulfilled with balancing reserves. Hence, we test whether the changes in load relative to the previous and next hour are significant.

A second factor that may drive the use of reserves is the change in trade with neighboring markets. Let "Trade_t" denote the amount of energy exported from Portugal to Spain minus the amount imported into Portugal during hour t. While market agents may trade any desired quantities, if these result in large changes in trade from one hour to the next, the TSO has to smooth the load transition on the interconnection for technical reasons. For example, if a large amount of generation is scheduled to start at the first minute of the coming hour due to an export trade, the TSO will smooth the transition by using upward reserves in the last few minutes of the current hour, and then downward reserves in the first few minutes of the coming hour.

Furthermore, the TSO may use balancing reserves to solve technical grid constraints in real time.

To consider all potential drivers simultaneously, we regress hourly Total Net Reserves (TNR, as defined in 1) on the following variables:

$$\begin{aligned}\text{TNR}_t &= \beta_0 + \beta_1 \text{WindImb}_t + \beta_2 \text{OtherImb}_t \\ &+ \beta_3(\text{Load}_t - \text{Load}_{t-1}) + \beta_4(\text{Load}_{t+1} - \text{Load}_t) \\ &+ \beta_5(\text{Trade}_t - \text{Trade}_{t-1}) + \beta_6(\text{Trade}_{t+1} - \text{Trade}_t) \\ &+ \varepsilon_t \qquad (2)\end{aligned}$$

Table I shows the estimation results. As expected, imbalances have a strong effect on reserves. On average, 1 MWh of unexpected wind generation requires 0.87 MWh of downward reserves. Imbalances from other agents (which in our data come mostly from demand imbalances) have a similar impact. For example, one additional MWh of unexpected demand (which would be registered as -1 in "Other Imbalances") induces, on average, 0.79 MWh of upward reserves. These two imbalances are able to explain a very large fraction, 87%, of the variation in Total Net Reserves.

Changes in load have the expected sign. Namely, if the hourly load increases by 1 MWh relative to the previous hour, the corresponding step-wise increase in day-ahead dispatched generation is smoothed with, on average, 0.045 MWh of downward reserves (presumably during the beginning of the current hour). Likewise, if the load will increase 1 MWh during the next hour, the TSO dispatches 0.012 MWh of upward reserves (presumably in the last minutes of the current hour).

TABLE I
REGRESSION OF BALANCING RESERVES

The dependent variable is Total Net Reserves, as defined in equation (1). Numbers in parenthesis are Newey-West heteroscedasticity and autocorrelation consistent standard errors (HACSE) estimated with 24 lags. Stars denote significance at the 10% (*), 5% (**), or 1% (***) confidence level. Hourly data, 2012/01/01–2016/12/31.

	Model 1	Model 2
Intercept	-35.590^{***}	-35.724^{***}
	(1.374)	(1.374)
Wind Imbalance	-0.869^{***}	-0.868^{***}
	(0.007)	(0.007)
Other Imbalances	-0.788^{***}	-0.790^{***}
	(0.010)	(0.010)
Load(t)-Load(t-1)		-0.045^{***}
		(0.003)
Load(t+1)-Load(t)		0.012^{***}
		(0.003)
Trade(t)-Trade(t-1)		-0.011^{***}
		(0.002)
Trade(t+1)-Trade(t)		0.002
		(0.002)
R^2	0.8675	0.8695
$\bar{R}^2$	0.8675	0.8694
N.obs	43358	43356

Changes in exports and imports have a similar impact. An increase in trade due to, for example, an increase in exports, can be seen as an increase in load for the purpose of interpreting the coefficients in table I.

However, the inclusion of changes in load and in trade has only a tiny effect on the explanatory power of the model (the adjusted R^2 barely changes from 86.75% in model 1 to 86.94% in model 2). Hence, we conclude that, for the purpose of cost allocation, it is reasonable to ignore these other drivers of balancing reserves. In the next section, we will follow the Portuguese TSO procedure and split *total* balancing costs only among wind generators and other agents, even though those total costs may include a (small) amount unrelated to energy imbalances.

IV. BALANCING COSTS OF WIND GENERATION

This section analyzes the total cost of using reserves to balance the system. For the reasons detailed in the previous section, the total system cost is fully allocated to market agents, proportionately to their imbalances.

The Portuguese TSO (REN) computes an hourly imbalance cost or revenue for each agent i through the following formula:

$$V_i = D_i P + K_i E \qquad (3)$$

where V_i (in EUR) is the amount charged to agent i (a positive/negative V_i represents a cost/revenue for the agent), D_i (in MWh) is the imbalance of that agent, P (EUR/MWh) is the electricity price for that specific hour determined in the day-ahead market. E (in EUR) is the total "Extra" cost for balancing the whole system during that hour. This value includes the price spread of secondary and tertiary reserves relative to the day-ahead price, plus the (typically small) cost of solving technical grid constraints. The allocation of E to each agent is determined through:

$$K_i = \frac{|D_i|}{\sum_{j=1}^{I} |D_j|} \tag{4}$$

where I is the total number of balancing responsible parties (BRP) participating in the market. Some small generators are aggregated in a single BRP. In particular, all wind generators are included in the same BRP.

The term K_iE captures the *extra* or *over* cost for agent i due to its imbalance. For example, if wind delivers less energy than contracted in the day ahead market, K_iE will compensate the system for the high cost of having to use upward tertiary reserve. If wind delivers more energy than expected, K_iE will reduce the value paid to wind for that extra energy, in order to compensate the system for the downward tertiary plant that is being paid just to sit idle without generating energy.

Even though wind generators first pay their imbalances cost to the system, they then receive an "out-of-the-market" additional payment, such that, in the end their revenue exactly matches the feed-in-tariff that they were promised. This additional payment is passed through to retail consumers. The imbalance costs of wind are thus "socialized."

We use hourly data provided by REN for the variables mentioned above. We observe that after an initial year with high values, the balancing cost of wind has remained relatively low. The full sample (equal-weighted) average of the wind balancing cost is 3.79 EUR/MWh.

Interestingly, even during periods of very high wind penetration, the balancing costs remain relatively low. Since the amount of wind generation varies through time, we compute a value-weighted average, where the weight for each hour equals the ratio of wind generation in that hour to total wind generation in the sample period. We find that the full sample value-weighted average of the wind balancing cost is 2.21 EUR/MWh.

V. Conclusion

Our results indicate that, even at high penetration rates, system imbalance costs due to wind randomness can be low. The results are surprising due to the lack of economic incentives for wind generators to minimize their imbalances, since wind imbalance costs are effectively paid by final consumers in our market. For future work, it would be interesting to investigate to what extent these low costs are due to good forecasting ability of wind generators or to good management of imbalance reserves by the TSO.

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