Wind balancing costs in a power system with high wind penetration – evidence from Portugal

Pedro M.S. Frade

REN-Rede Elétrica Nacional, Lisboa, Portugal *

and Instituto Superior Técnico, Universidade de Lisboa

pedro.frade@tecnico.ulisboa.pt

João Pedro Pereira †

Nova School of Business and Economics

Universidade Nova de Lisboa

joao.pereira@novasbe.pt

J.J.E. Santana

INESC-ID, Instituto Superior Técnico

Universidade de Lisboa

J.P.S. Catalão

INESC-ID, Instituto Superior Técnico

and C-MAST, University of Beira Interior

and INESC TEC and Faculty of Engineering, University of Porto

April 26, 2019

*The views expressed in this paper are those of the authors and do not necessarily represent the views of REN.

†Corresponding author. Address: Nova SBE, Rua da Holanda 1, 2775-405 Carcavelos, Portugal. Phone: (+351) 213 801 637. Financial support from the following institutions is gratefully acknowledged: Fundação para a Ciência e Tecnologia (UID/ECO/00124/2013

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 wind generation already accounts for a high fraction of demand (23% in 2012–2016), but still there are no economic incentives for efficient wind forecasting (wind balancing costs are passed to end consumers). We analyze the evolution of the balancing market from 2012 to 2016. Using actual market data, we find wind balancing costs around 2 euros per MWh of generated energy. One main reason for these low costs is the existence of a robust transmission grid, which allows for the compensation of positive with negative wind imbalances across the system. Nevertheless, the results suggest that final consumers could save several million euros per year if wind generators were made responsible for the economic cost of their imbalances, in line with other European markets.

1 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 installed capacity growing from 4529 MW in 2012 to 5313 MW in 2016. Wind accounted for 23% of all electricity consumed in Portugal 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 balancing reserves is typically more expensive than energy contracted in day-ahead markets. Imbalances therefore create an extra cost, which could be avoided if agents were able to forecast their generation perfectly.

and Social Sciences DataLab, Project 22209), POR Lisboa (LISBOA-01-0145-FEDER-007722 and Social Sciences DataLab, Project 22209) and POR Norte (Social Sciences DataLab, Project 22209).

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 2007. This has led those generators to minimize expected imbalances by trading in the intraday market (Chaves-Ávila and Fernandes (2015)), and has also led to a continuous improvement in wind forecasting technology (Herrero, Rodilla, and Batlle (2016)).[1] 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.[2]

Wind generation in Portugal has been incentivized through guaranteed feed-in tariffs (FiT), which fully isolate wind plants from market price risk (see Peña, Azevedo, and Ferreira (2014) or Peña, Azevedo, and Ferreira (2017)). While wind generators have to go through a formal market process, where they first have to sell their energy in the power exchange (at a price typically lower than the FiT) and their real-time imbalances are valued (representing a further cost), they then receive an additional remuneration such that, in the end, wind producers always make a revenue equal to the promised FiT. 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

[1] Bueno-Lorenzo, Moreno, and Usaola (2013) suggest further improvements to forecasting incentives in Spain.

[2] Countries where wind is exempted from balancing responsibility include France, Germany until 2011, Ireland, and Portugal. Countries where wind is responsible for imbalance costs include Denmark, Finland, Germany since 2012, the Netherlands, Spain, Sweden, and the U.K. See, for example, Chaves-Ávila, Hakvoort, and Ramos (2014) and table 7 below.

forecasting errors and economic efficiency.

The main goal of this paper is to measure wind balancing costs, using real market data, in a setting of high wind penetration. Furthermore, we want to understand what are the economic and technical factors that influence those costs.

We obtain actual observed imbalance quantities and imbalance market prices from the Portuguese TSO (REN), at the hourly frequency, for the period between 2012/Jan/01 and 2016/Dec/31. Interestingly, we find that wind balancing costs are, on average, only 2.17 euros per each MWh of generated wind energy. In terms of the full distribution, wind balancing costs lie within zero to 12 €/MWh during 90% of the hours in the sample.

These results are consistent with existing studies that measure wind balancing costs using observed market prices. Typical costs reported in the literature (surveyed in section 5, table 7) range from zero to 7 €/MWh. However, most of the studies refer to markets or periods where wind had a low penetration rate. Hence, our contribution is to show that wind balancing costs can be relatively low, even at high wind penetration rates up to 23%. This paper thus alleviates the concern expressed in earlier literature (for example, Vandezande, Meeus, Belmans, Saguan, and Glachant (2010)) that high wind penetration might lead to high balancing costs.

To understand the drivers of balancing costs, this paper does a detailed analysis of the unique Portuguese imbalance pricing method. We show that the particular market design is *not* the reason for low imbalance costs, as in general the pricing system provides inefficient price signals.

We identify several technical factors that help to explain the relatively low wind balancing costs. The most important is the aggregation of all wind generators into a single balance responsible party (BRP), which cancels positive with negative deviations of wind plants across the country. Since the aggregation into a single large BRP requires a robust transmission grid, the results highlight the fact that investments in transmission capacity help to reduce the balancing costs of intermittent renewables.

These results are also related to Hirth and Ziegenhagen (2015), who 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 (Ocker and Ehrhart, 2017). Our findings support the idea that wind balancing costs can be low, even for a single TSO in a relatively isolated system, as long as the transmission capacity within the system is sufficiently robust.

While wind balancing costs are relatively low, we still find that the quantity of imbalances seems too high when compared to similar markets, namely Spain. It would thus seem reasonable to create the proper incentives for wind generators to implement more advanced forecasting technology by making them economically responsible for their imbalances. The results in this paper suggest that this improvement in market design could save consumers several millions of euros per year.

2 The Portuguese balancing market

The Portuguese balancing market is, for the most part, similar to other European markets. However, to the best of our knowledge, the pricing of imbalances is unique.

2.1 Standard market sequence

The Portuguese electricity market is structured in a standard sequence of a day-ahead market, several discrete intraday sessions, and a real-time balancing market. The day-ahead and intraday markets are run jointly with Spain, under the MIBEL designation.[3] The balancing market for Portugal is run

[3]In June 2018, Portugal joined the European Cross-Border Intraday (XBID) Solution, an integrated continuous intraday market. This change is outside our sample period and thus does not affect our results.

in real time by REN, the Portuguese Transmission System Operator (TSO). The balancing market is where the TSO contracts increases or decreases in generation necessary to compensate deviations from the day-ahead and intraday market programs, thus balancing supply and demand of electricity.

REN follows the European Network of Transmission System Operators for Electricity (ENTSO-E) and classifies operating reserves for balancing actions into three categories: primary, secondary, and tertiary reserves. The primary reserve consists of small instantaneous adjustments done independently by each generator. It is not controlled by REN and generators do not get any compensation for it. Hence, this paper focuses on secondary and tertiary reserves.[4]

Secondary reserves, which are activated automatically, must be able to respond within 30 seconds. Secondary reserve providers submit a band of regulation within which they can vary power output. The fixed cost of this secondary band is allocated to all agents that buy energy, proportionately to their consumption. The actual amount of secondary energy that is activated is paid at the tertiary price, as described next.

Tertiary reserves are activated manually and are allowed a longer response time of up to 15 minutes. Tertiary reserve providers are only paid for the actual MWh they deliver, that is, there is no fixed payment for tertiary capacity.[5] Tertiary reserve bids are stacked in the usual merit order. All tertiary and secondary reserves that are activated receive a price per MWh equal to the price of the last tertiary bid that is dispatched (marginal-bid pricing). Tertiary bids are subject to the same price limits as the day-ahead market, namely prices must be between 0 and 180 €/MWh. While an upward tertiary price means a payment from the TSO to the agent, a downward tertiary price means a payment from the agent to the TSO (in fact, a refund

[4]Other markets use alternative designations for reserves, such as, automatic Frequency Restoration Reserves, manual Frequency Restoration Reserves, or Replacement Reserves.

[5]There are however some bilateral contracts with thermal generators to ensure long-term capacity.

of part of the price already received in the day-ahead market).

The TSO measures the imbalance of each wholesale agent. There is a total of 13 Balance Responsible Parties (BRP) in the Portuguese system. Of these, 6 represent thermal generation, corresponding to two coal plants and four natural gas plants. Another 6 BRP represent six different hydrographic regions, with each BRP including several hydropower plants. All wind generators are aggregated under the 13^{th} BRP, and therefore only their net imbalance is accounted. The actual name of this BRP is "Comercializador de Último Recurso" (CUR), which includes, in addition to wind, other generators under guaranteed remuneration schemes. Generation data for Portugal (described in detail in section 3) shows that small hydro, combined heat and power, and biomass, which are dispatchable and typically have very small imbalances, accounted for 43% of the CUR generation during 2012–2016. Regarding the intermittent generators, wind accounted for 54% of the CUR generation, while solar PV represented less than 3%. Hence, we ignore other generators in the CUR and allocate all its imbalances to wind.

2.2 Imbalance pricing system

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

$$V_i = D_i P + K_i R \tag{1}$$

V_i is defined in euros from the point of view of the TSO, that is, $V_i > 0$ represents cash flowing from agent i to the TSO.

The first term in the sum is the value that the imbalanced energy would have in the day-ahead market. More precisely, P (in €/MWh) is the electricity price for that specific hour determined in the day-ahead market. D_i (in MWh) is the imbalance of agent i. It is computed as the difference between: (i) the energy actually generated or consumed during the delivery hour; and (ii), the energy transacted in the day-ahead market, plus in all the intraday auctions up to the delivery hour.

A *long* imbalance is codified as a negative D_i, meaning that BRP i is contributing to generation being higher than load in the overall system. If i is a producer, $D_i < 0$ means that it is generating more than what was programmed; if i is a consumer, $D_i < 0$ means that it is using less energy than programmed. Similarly, a *short* imbalance is codified as $D_i > 0$ (i is generating less or consuming more than the market program). While these definitions may feel counterintuitive at first pass, they allow the same formulas and procedures to be applied directly to both consumers and producers.

The second term in (1), K_iR, penalizes the imbalance relative to its day-ahead value. R (in €) is the extra cost for balancing the whole system during that hour:

$$R := (P - \underline{P})\underline{E} + (\overline{P} - P)\overline{E} \tag{2}$$

where $\underline{E}$ (in MWh) is the total amount of downward regulation energy dispatched by the TSO during the hour, including both secondary and tertiary reserves, $\overline{E}$ (in MWh) is the total amount of upward energy, and $\underline{P}$ and $\overline{P}$ are the corresponding market clearing prices of downward and upward reserves. Note that the TSO may need to use both downward and upward reserves during the same hour, though obviously at different instants.

The allocation of R to each agent is determined through:

$$K_i := \frac{|D_i|}{\sum_{j=1}^{I} |D_j|} \tag{3}$$

where I is the total number of balance responsible parties participating in the market.

The term K_iR is denoted the *balancing cost* of agent i. It can be interpreted as the cost of imperfect forecasting. For example, if wind delivers less energy than contracted, it has to refund the day-ahead value, plus an *additional* K_iR. If wind delivers more energy than expected, the amount paid to wind is reduced by $K_i R$ relative to the day-ahead value, thus representing an *opportunity* cost.[6]

Example (single deviation). Suppose that the only BRP with an imbalance is wind ($i = w$), and that it generated 100 MWh more than programmed, $D_w = -100$ MWh. The TSO thus has to dispatch $\underline{E} = 100$ MWh at a price of, say, $\underline{P} = 30$. Assume $P = 40$. Since $K_w = 1$,

$$V_w = -100 \times 40 + 1 \times [(40 - 30) \times 100] = -4000 + 1000 = -3000 \text{ €}$$

If wind had sold the 100 MWh in the day-ahead market, it would have received 4000 euros. However, now it is only receiving 3000. The balancing cost, $K_w R = 1000$, represents lost revenue, or an opportunity cost. Note that this is a zero-sum mechanism for the TSO because the exact 3000 euros paid to wind are coming from the downward reserve provider. Appendix A.1 shows that this is a general result, that is, the mechanism is always zero-sum for the TSO.

While the previous example shows a case where an imbalance is priced at its marginal cost, the pricing system does not always ensure this result. In fact, the Portuguese system is only guaranteed to behave optimally, in the sense that it prices all imbalances at their true marginal cost, under the conditions of the following proposition.

Proposition 1. *If all agents are imbalanced in the same direction, then each agent pays/receives exactly the marginal cost/value of its deviation, that is,*

$$V_i = \begin{cases} D_i \overline{P} > 0, & \textit{if } D_i > 0, \forall i \in \{1, \ldots, I\}; \\ D_i \underline{P} < 0, & \textit{if } D_i < 0, \forall i \in \{1, \ldots, I\}\ . \end{cases} \tag{4}$$

[6] In the first case, $K_i R$ compensates the system for the higher cost of upward reserves. In the second case, $K_i R$ corresponds to the amount that the downward reserve plant does not transfer to wind, that is, the reserve plant gets paid $K_i R$ just to sit idle without generating energy.

Proof: See appendix A.2.

This means that when all agents deviate in the same direction, the Portuguese pricing system is similar to a single-price system (as described below). However, when there are deviations in both directions, which is often the case, the system no longer behaves optimally, as discussed next.

2.3 Comparison with alternative pricing systems

As described, for example, in Vandezande, Meeus, Belmans, Saguan, and Glachant (2010) or MIT (2016), there are two standard imbalance pricing schemes used in several countries: single-price systems and dual-price systems.[7] Appendix B summarizes the two systems.

The Portuguese imbalance pricing system behaves like a single-price system only in the special case when all BRPs are imbalanced in the same direction (as in proposition 1). When there are imbalances in both directions, the Portuguese system departs from a single-price system. However, contrary to what might be expected, it goes in the *opposite* direction of a dual system, in the sense that the agents causing the imbalance pay even *less* than they would pay under a single-price system. The following example illustrates this effect.

Example (multiple deviations with different signs). Assume again that wind generated 100 MWh more than programmed, $D_w = -100$ MWh, but now suppose that a consumer ($i = c$) exceeded its programmed load by 300 MWh, $D_c = +300$ MWh. The system thus requires a net upward reserve of $\overline{E} = 200$ MWh at a price of, say, $\overline{P} = 50$. Assume again $P = 40$. For

[7] Countries that use one-price systems include Belgium since 2012, Germany, and the Netherlands. Countries that use dual-price systems include Belgium until 2011, Denmark, Finland, France, and Spain. See, for example, Chaves-Ávila (2014) and our table 7.

wind,

$$V_w = -100 \times 40 + \frac{1}{4} \times [(50 - 40) \times 200] = -4000 + 500 = -3500 \text{ €} \quad (5)$$

and for the consumer BRP,

$$V_c = +300 \times 40 + \frac{3}{4} \times [(50 - 40) \times 200] = +12000 + 1500 = +13500 \text{ €} \quad (6)$$

This example is summarized in table 1.

Table 1: Example to compare alternative imbalance pricing systems

The table shows cash flows to the system operator (SO) under three different alternative imbalance pricing mechanisms. A positive value means that cash is flowing from the agent to the SO. The example assumes $\overline{P} = 50$, $\underline{P} = 40$, and the imbalance values $D_c = 300$, $D_w = -100$.

	Portuguese	Single-Price	Dual-Price
Consumer (short, $D_c = +300$ MWh)			
Total cash flow (€)	+13 500	+15 000	> 15 000
Implicit price (€/MWh)	45	50	> 50
Wind (long, $D_w = -100$ MWh)			
Total cash flow (€)	−3 500	−5 000	−4 000
Implicit price (€/MWh)	35	50	40
Upward reserve provider ($\overline{E} = +200$ MWh)			
Total cash flow (€)	−10 000	−10 000	−10 000
Implicit price (€/MWh)	50	50	50
System Operator			
Total cash flow (€)	0	0	> 1 000

As expected, the pricing mechanism is zero-sum for the Portuguese system operator. The total amount collected from the imbalanced parties, 10 000 € in this example, is exactly the amount paid to the upward reserve provider. In this regard, the mechanism behaves like a single-price system. The cost allocation to each BRP, however, deviates from single-price systems.

The consumer BRP is the one causing the whole system to be short. In a single-price system, the imbalance of 300 MWh would be charged at its marginal cost of 50 €/MWh, for a total of 15 000 € ($= D_c\overline{P}$). In a dual-price system, it would be charged a even higher value due to a penalty. In the Portuguese system, however, the BRP that is aggravating the system imbalance pays only 13 500 €. This implies a cost per unit of imbalance of 45 €/MWh, which is actually *less* than the marginal cost the consumer is imposing on the system. As detailed in equation (6), the consumer BRP is only paying $\frac{3}{4}$ of the cost of *net* imbalances.

On the other hand, the excess wind generation of 100 MWh is helping the system to balance. In a single price system, wind would be paid the full value of the injected energy, at the marginal cost of the alternative reserve provider, for a total of 5 000 €. In a dual-price system, it would be partly penalized, and receive only a value corresponding to the day-ahead price, 4 000 €. In the Portuguese system, however, the excess energy is penalized even further, and receives only 3 500 €. As detailed in equation (5), wind still needs to pay $\frac{1}{4}$ of the total system balancing cost. Even though the BRP is helping the system, it receives less than what it could have received in the day-ahead market.

In summary, the Portuguese imbalance pricing system penalizes all deviations from the market program, in the sense that all BRPs are worse-off than if they had perfect forecast and traded the correct amount of energy in the day-ahead market. However, the penalties applied are optimal only in the special case where all BRPs are imbalanced in the same direction. In general, the penalties work in the opposite direction of what might be expected, dampening the cost of BRPs that deviate against system requirements and also dampening the profit of BRPs that deviate in favor of system requirements.

3 Data

Data on all generation, imbalances, and reserves is provided by the Portuguese TSO (REN) for all hours between 2012 and 2016. Table 2 shows descriptive statistics.

Table 2: Generation and Imbalances

Descriptive statistics for total system Load (L), Wind generation (W), Wind Imbalance (WI), total System Imbalance (SI), and the corresponding ratios. All raw variables (L, W, WI, SI) are in MWh. Hourly data, 2012/01/01–2016/12/31.

	L	W	W/L	WI	WI/L	SI	SI/L
Moments							
Mean	5594	1316	0.24	-32	-0.01	-7	0.00
Stdev	971	953	0.18	260	0.05	337	0.06
Percentiles							
Min	3364	11	0.00	-1613	-0.38	-1969	-0.42
5%	4164	169	0.03	-479	-0.09	-546	-0.10
25%	4750	529	0.10	-176	-0.03	-215	-0.04
Median	5597	1083	0.20	-15	0.00	-9	0.00
75%	6333	1931	0.36	121	0.02	192	0.03
95%	7193	3207	0.59	363	0.07	549	0.10
Max	8578	4423	1.04	1497	0.29	1953	0.36
Cross-Correlations							
L	1.00	0.03	-0.22	0.00	0.02	0.10	0.09
W		1.00	0.95	-0.28	-0.28	-0.11	-0.13
W/L			1.00	-0.28	-0.28	-0.14	-0.16
WI				1.00	0.98	0.77	0.78
WI/L					1.00	0.76	0.80
SI						1.00	0.98
SI/L							1.00

The Portuguese total system hourly load varied between 3 364 and 8 578 MWh, with an average value of 5 594 MWh. Wind generation is, on average, 1 316 MWh during each hour of the sample. The average hourly wind penetration (that is, the amount of load fulfilled by wind) is 24%. However, this average masks considerable variation at the hourly frequency, with wind sometimes even exceeding 100% of load. In fact, there is a total of 6 hours when wind generation exceeds system load. The maximum of 104% was at 5 am on 21/Nov/2016, when wind generated 4365 MWh and load was 4202 MWh. The excess generation was compensated by 1476 MWh of upstream pumping in hydro dams (note that other plants, such as coal and run-of-river were still generating). There are four more hours when excess wind is used in upstream pumping, and one additional hour when the excess wind was exported to Spain.

The TSO provided us with hourly data on total system imbalance and wind imbalance. The wind imbalance has a distribution that is reasonably symmetric and centered close to zero, as shown in table 2.[8] More precisely, the full sample average of wind imbalances is −32 MWh, meaning that wind generators, on average, deliver 32 MWh *more* than programmed. There is, however, a large dispersion around this mean, with the standard-deviation being 260 MWh. Furthermore, the tails of the distributions extend out to very large values. Over the full time period, the minimum hourly wind deviation is −1 613 MWh and the maximum is +1 497 MWh. These are large values when compared to the system load. As shown in table 2, the wind imbalance as a fraction of load ranges from −38% to +29%.

Another way of gauging the significance of wind imbalances in Portugal is to compare them with other markets, in particular with Spain, where the wind resource will presumably be reasonably similar. Figure 2 in Herrero, Rodilla, and Batlle (2016) shows that in 2014 (which corresponds to the middle of our sample period), the mean absolute wind forecast error in Spain ranges approximately from 5% to 10% of mean production, depending on the forecast lead time. In contrast, the mean absolute imbalance in Portugal is 194 MWh, which represents 15% of the mean wind generation during our

[8]Since a few hours display very extreme values, we consider as outliers imbalances that are more than three standard-deviations away from the mean. Table 2 describes the data after removing these outliers.

sample period, 2012–2016. The error is thus substantially larger in Portugal. In fact, the level of error in Portugal during 2012–2016 is comparable to the average error in Spain during the earlier 2007–2008 period, the beginning stage of the market. Much of this difference is likely to result from the lack of economic incentives for accurate wind forecasting in Portugal.

Total system imbalances range from $-1\,969$ MWh to $+1\,953$ MWh, and from -42% to $+36\%$ of load. The distribution of system imbalances is somewhat more disperse than the distribution of wind imbalances, but not much more. Together with the high correlation of 0.77 between wind imbalances and total system imbalances, these numbers suggest that wind is a major driver of the whole system imbalance.

Table 3 shows descriptive statistics on the hourly quantity of secondary and tertiary reserve energy used for upward and downward regulation. Secondary reserve is typically used in small amounts, with an average of 8 MWh for downward regulation and 50 MWh for upward regulation. In contrast, tertiary reserve is used in higher quantities, with an average of 167 MWh for downward regulation and 83 MWh for upward regulation. Both directions of tertiary reach much more extreme values than secondary reserve does. There is also an asymmetry in the use of the two types of reserves: upward mobilization is typically higher than downward mobilization for secondary reserve, while the opposite is true for tertiary reserve. This fact has a explanation related to the design of the Portuguese market, as detailed in appendix C.

Table 3 also shows the market-clearing prices of upward and downward tertiary reserves (recall that secondary reserves are also paid at the tertiary price). The full-sample average price of upward regulation is 57 EUR/MWh, while the average price downward regulation is 27 EUR/MWh (recall that the downward price represents a refund from the agent that is reducing its day-ahead-scheduled generation). These values compare with an average day-ahead market price of 45 EUR/MWh. Figure 1 compares the evolution of these three variables. The series display the expected pattern, with the

Table 3: Secondary and Tertiary reserves

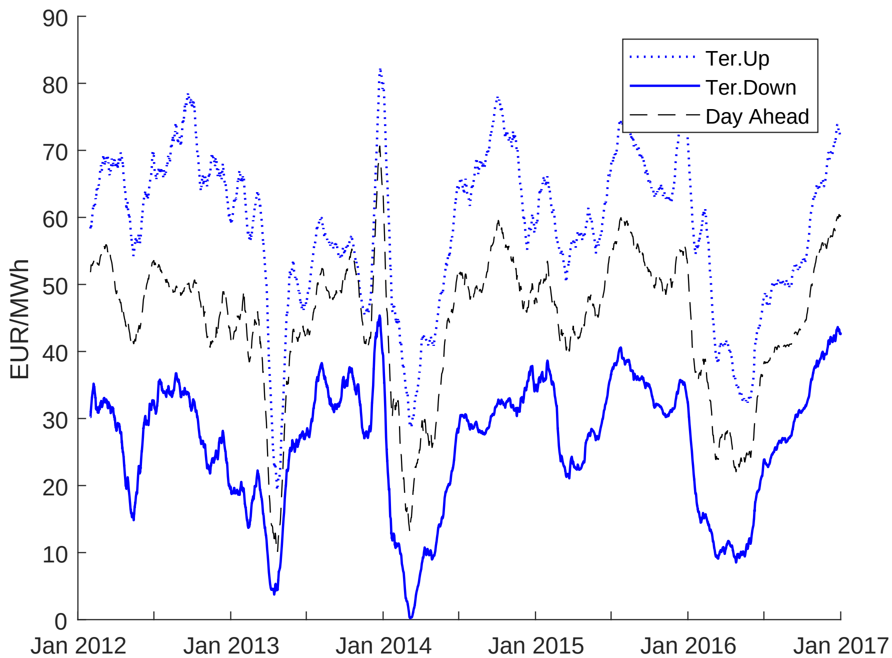
The columns for "Secondary" and "Tertiary" describe the quantity of reserve energy (in MWh) used for upward and downward regulation. The last three columns describe the prices (in EUR/MWh) of tertiary reserves ($\underline{P}, \overline{P}$) and the day-ahead (DA) price. The cross-correlations under "Secondary" and "Tertiary" are between quantities, whereas the cross-correlations under "Prices" are between prices. Hourly data, 2012/01/01–2016/12/31.

	Secondary		Tertiary			Prices		
	Down	Up	Down	Up		Down	Up	DA
Moments								
Mean	8	50	167	83		27	57	45
Stdev	16	41	209	151		16	21	16
Percentiles								
Min	0	0	0	0		0	0	0
5%	0	0	0	0		0	30	12
25%	0	13	0	0		18	45	37
Median	0	44	87	0		29	55	47
75%	10	78	270	112		37	69	56
95%	46	126	584	401		51	95	68
Max	151	271	2129	1568		100	180	112
Cross-Correlations								
Sec. Down	1.00	-0.49	0.01	0.03				
Sec. Up	-0.49	1.00	0.05	-0.04				
Ter. Down			1.00	-0.38	$\underline{P}$	1.00	0.50	0.71
Ter. Up				1.00	$\overline{P}$		1.00	0.62

upward price above the day-ahead, and the downward price below it.

Figure 1: Prices of Tertiary Reserves

Prices of downward and upward tertiary reserves, and day-ahead price. Rolling 30-day averages of hourly values, 2012/01/01–2016/12/31.



4 Drivers of balancing reserves mobilization

As described in section 2, the cost of balancing reserves is allocated to imbalanced agents. However, in addition to imbalances, there may be other causes for the use of reserves. This section compares the importance of the different drivers of reserves.

Since we cannot identify the events that lead the TSO to manually dispatch tertiary reserves in our hourly data, we aggregate secondary with tertiary reserves. Furthermore, since imbalances can be either positive or negative, we focus on net reserves. Hence, the variable of interest is "Total Net Reserves" (TNR), computed for each hour as:

$$\begin{aligned}\text{Total Net Reserves} :=&(\text{Secondary upward} + \text{Tertiary upward})\\ &- (\text{Secondary downward} + \text{Tertiary downward}) \quad (7)\end{aligned}$$

Figure 2 compares total net reserves and total system imbalance. Clearly, a very large fraction of reserve usage is explained by total system imbalance. On average, the amount of reserve usage that does not correspond to system imbalance is only 63 MWh (mean absolute difference between the two series). However, there are some hours when the difference becomes very large, from a minimum of −1 394 MWh to a maximum of +1 584 MWh (not visible in the figure, which plots smooth averages of hourly values over 30-day windows).

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

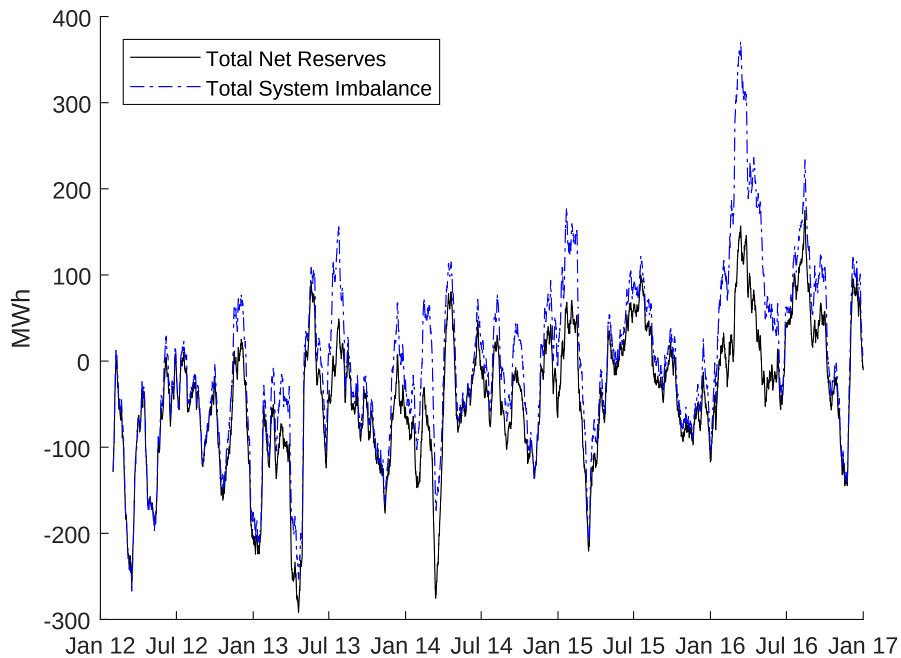
One factor is the change in load. While load evolves as a continuous function of time, the generation that is dispatched in the day-ahead market is a step function constant over each hour. The difference between the two has to be fulfilled with balancing reserves. Hence, we test whether the changes in load relative to the previous and next hour are significant.[9]

A second factor that may drive the use of reserves is the change in trade with neighboring markets (Spain, in this case). While market agents may trade any desired quantities, if these result in large changes in trade from one hour to the next, the TSO manually dispatches reserves to ensure that the system is able to remain balanced during the transition. 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

[9] We assume that the future load is known ahead of time. While this assumption is not strictly true, balancing reserves are dispatched in time frames of a few minutes, and the TSO can forecast load changes for the next few minutes with a high degree of accuracy.

Figure 2: System imbalance and total net reserves

Total Net Reserves (as defined in equation 7) and Total System Imbalance per hour. Rolling 30-day averages of hourly values, 2012/01/01–2016/12/31.



dispatching upward reserves in the last few minutes of the current hour, and then downward reserves in the first few minutes of the coming hour.

To consider all potential drivers simultaneously, we regress hourly Total Net Reserves (TNR, as defined in equation 7) on the following variables:

$$\begin{aligned}\mathrm{TNR}_t = \beta_0 &+ \beta_1 \mathrm{WindImb}_t + \beta_2 \mathrm{OtherImb}_t \\ &+ \beta_3(\mathrm{Load}_t - \mathrm{Load}_{t-1}) + \beta_4(\mathrm{Load}_{t+1} - \mathrm{Load}_t) \\ &+ \beta_5(\mathrm{Trade}_t - \mathrm{Trade}_{t-1}) + \beta_6(\mathrm{Trade}_{t+1} - \mathrm{Trade}_t) + \varepsilon_t \end{aligned} \quad (8)$$

where $\mathrm{WindImb}_t$ is the total wind imbalance (all wind generators are aggregated in a single balance responsible party), $\mathrm{OtherImb}_t$ is the aggregated imbalance of all other agents (computed as the difference between total system imbalance and wind imbalance), and "Trade_t" denotes the amount of energy exported from Portugal to Spain minus the amount imported into Portugal during hour t.

This is a statistical model, i.e., there is still an error term, ε_t, for the following reasons. First, there is the usual possibility of data errors. Second, the TSO may use balancing reserves to solve technical grid constraints in real time, like transmission bottlenecks or generators tripping offline unexpectedly, but we do not have data on these events.

Table 4 shows the estimation results, with the main results in the first two columns. As expected, imbalances have a strong effect on reserves. On average, 1 MWh of wind generation below the market program requires 0.87 MWh of upward reserves (recall that a positive imbalance means that the generator is delivering less than programmed, as defined in section 2). 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.

Table 4: Regression of balancing reserves

Ordinary Least Squares regression of Total Net Reserves (TNR), as defined in equation (8). The last two columns show results for two subsamples, namely the hours when upward reserves are larger (TNR > 0) or smaller (TNR < 0) than downward reserves. 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	Subsamples	
	TNR	TNR	TNR>0	TNR<0
Intercept	-35.590^{***}	-35.724^{***}	40.420^{***}	-73.739^{***}
	(1.374)	(1.374)	(3.050)	(4.056)
Wind Imbalance	0.869^{***}	0.868^{***}	0.691^{***}	0.797^{***}
	(0.007)	(0.007)	(0.016)	(0.013)
Other Imbalances	0.788^{***}	0.790^{***}	0.604^{***}	0.744^{***}
	(0.010)	(0.010)	(0.018)	(0.017)
Load(t)-Load(t-1)		-0.045^{***}	-0.058^{***}	-0.025^{***}
		(0.003)	(0.005)	(0.003)
Load(t+1)-Load(t)		0.012^{***}	0.023^{***}	0.000
		(0.003)	(0.005)	(0.003)
Trade(t)-Trade(t-1)		-0.011^{***}	-0.011^{***}	-0.009^{***}
		(0.002)	(0.003)	(0.002)
Trade(t+1)-Trade(t)		0.002	0.001	0.001
		(0.002)	(0.002)	(0.002)
R^2	0.8675	0.8695	0.6626	0.7843
$\bar{R}^2$	0.8675	0.8694	0.6625	0.7842
N.obs	43358	43356	19514	23841

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).

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 4.

Importantly, 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 among wind generators and other imbalanced agents, even though those total costs may include a (small) amount unrelated to energy imbalances.

Finally, to check whether the explanatory variables have different effects on upward and downward reserves, the last two columns show regression results for two subsets of the data, namely the hours when upward reserves exceed downward reserves (TNR $>$ 0), and then the opposite case (TNR $<$ 0). Note that, say, TNR $>$ 0 for a given hour does *not* mean that only upward reserves are used in that hour. In fact, in 72% of the hours in the sample the system uses both upward and downward reserves. Nevertheless, the regression results suggest that the effect of the explanatory variables, particularly imbalances, is reasonably similar across hours when more upward or more downward reserves are used.

5 Balancing cost of wind power

This section starts by describing the wind balancing cost under the current Portuguese market rules. We then asses the impact of the unique Portuguese pricing system by comparing the current cost with the cost under an hypothetical single-price system, and also with costs reported in the literature for other markets. Finally, we discuss potential factors that explain wind balancing costs.

5.1 Costs under the actual Portuguese system

We use data provided by the TSO on the hourly wind imbalance full value, that is, on the V value defined in equation (1), exactly as computed by REN for the wind balance-responsible party. We separate the series into two subsets, depending on whether the wind imbalance during that hour was long ($D < 0$) or short ($D > 0$).

Table 5 describes the data. The two initial columns describe the full imbalance value per unit of absolute imbalance ($V/|D|$). A short imbalance ($D > 0$) means that wind is not generating all the energy contracted in the market program and therefore has to pay money to the system. The average cost of short imbalances is 57.15 €/MWh_{imb}.[10] In the other direction, a long imbalance ($D < 0$) means that wind is generating more than planned, and therefore receives a payment from the system. The average price received by wind for long imbalances is 29.64 €/MWh_{imb}.

These average prices of short and long imbalances are remarkably close to the average prices of the reserves that would be necessary to compensate wind imbalances: respectively, 57 €/MWh for upward tertiary and 27 €/MWh for downward tertiary (see table 3). These results are somewhat surprising because, as described in section 2, the Portuguese system does not always

[10] We write MWh_{imb} or MWh_{gen} to stress whether the value is per unit of imbalance or generation.

Table 5: Wind imbalance values under the current Portuguese system

Descriptive statistics on hourly wind imbalance values. The columns labeled "Full Value" show the total imbalance value, V_i in equation (1), and the following columns show the penalty term, $K_i R$. The data subsets correspond to the hours when wind has a long ($D < 0$) or short ($D > 0$) imbalance. The last row, "VW Avg", shows a wind-generation value-weighted average. All values are in euros per unit (MWh) of either absolute imbalance ($|D|$) or true wind generation, as denoted in the headings. A positive/negative sign represents a cash inflow/outflow to/from the system operator. Hourly data, 2012/01/01–2016/12/31.

	Full Value		Penalty term				
	(per MWh imb.)		(per MWh imb.)		(per MWh generation)		
	$D < 0$	$D > 0$	$D < 0$	$D > 0$	$D < 0$	$D > 0$	All D
Moments							
Mean	-29.64	57.15	14.75	12.36	2.86	3.43	3.13
Stdev	22.27	21.80	17.68	15.19	4.40	7.98	6.35
Percentiles							
Min	-1532	-155	-1469	-205	-30	-19	-30
5%	-58	23	0	-1	0	0	0
25%	-43	45	5	3	0	0	0
Median	-31	57	12	9	1	1	1
75%	-17	69	21	17	4	3	4
95%	1	91	40	38	11	14	12
Max	255	343	305	303	75	302	302
VW Avg	-25.67	52.16	14.07	13.41	2.17	2.18	2.17

price imbalances at their marginal value. Furthermore, imbalanced parties also have to pay the cost of reserves used for other purposes (as discussed in section 4), which may help explain why the distribution of wind imbalance prices reaches extreme values in a few hours (see the minimum and maximum values in table 5).[11] Nonetheless, these results suggest that the specificities of the Portuguese system have little impact, and in the end the actual price of wind imbalances turns out to be, on average, very close to marginal value.

From the point of view of a wind generator, the relevant balancing cost is the penalty term $K_i R$, as defined in equation (1). The values in table 5 show that shortfalls in generation ($D > 0$) cost, on average, 12.36 €/MWh$_{\mathrm{imb}}$, while excess generation ($D < 0$) has an average opportunity cost of 14.75 €/MWh$_{\mathrm{imb}}$ relative to the alternative of having sold the correct amount in the day-ahead market.[12]

For comparison with other markets, it is more useful to standardize the imbalance surcharge by the amount of wind energy generation, rather than by the amount of imbalance. As shown in table 5, the average penalties for both long and short imbalances decrease substantially when divided by the (large) amount of wind generation, dropping to values close to 3 €/MWh$_{\mathrm{gen}}$.

Furthermore, since the penalty term does not depend on the sign of the imbalance, we pool short with long imbalances. Additionally, since the

[11]The sign flipping in the tails of the distributions may appear counterintuitive, but results from the following. For long imbalances ($D < 0$), the right tail of V may reach positive values in hours with either low day-ahead prices that make the DP term relatively small in $V = DP + KR$, or in hours where the cost of total system regulation, R, is abnormally high due to factors unrelated to imbalances. For short imbalances ($D > 0$), the left tail of V reaches negative values due to R being negative in some hours, as detailed below.

[12]During a few hours, the penalty term $K_i R$ is negative, which must result from $R < 0$. In turn, the total cost of system regulation may be negative due to the following reasons. First, prices may sometimes deviate from "normal" market conditions, that is, prices may not satisfy $\underline{P} < P < \overline{P}$, leading to a negative term in equation (2). Second, since June 2014 there is a market where the Portuguese and Spanish TSOs trade tertiary reserves. While the amount of trading in this market is very small, it sometimes leads to a net revenue that the Portuguese TSO splits among imbalanced agents.

amount of wind generation varies through time due to seasonality and installed capacity, we compute a value-weighted average, where the weight for each hour equals the ratio of wind generation in that hour relative to total wind generation in the sample period. Note that this value-weighted average gives more importance to recent years where wind penetration is higher. The last row of table 5 shows that the full-sample value-weighted average of wind balancing costs is 2.17 €/$\mathrm{MWh}_{\mathrm{gen}}$. This is the main figure in this paper. It indicates that wind creates an extra cost of 2.17 euros per each MWh of electricity generated due to imperfect forecasting. In relative terms, this cost represents approximately 5% of the average day-ahead market price (45 €/MWh).

Finally, since we have a relatively long time-series of balancing costs, it is interesting to analyze how the market has evolved through time. Figure 3 shows the hourly penalty term, for all imbalances, in euros per MWh of wind generation, from 2012 to 2016. We observe that after an initial year with high values, the balancing cost of wind has dropped down significantly. This is consistent with improvements in wind forecasting technology and learning by market agents. Interestingly, the figure shows that even during periods of very high wind penetration, balancing costs remain relatively low.

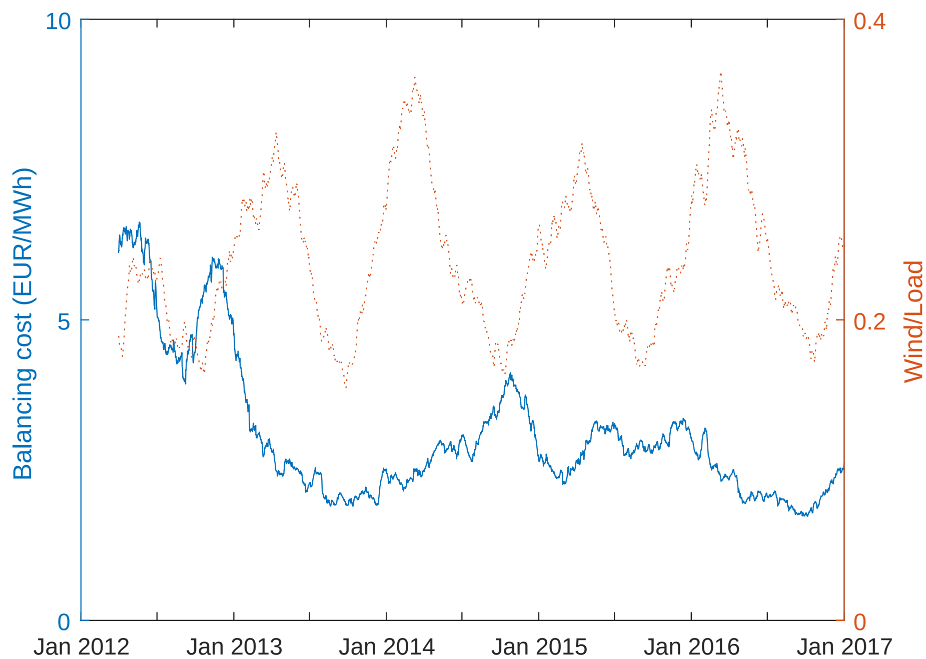
5.2 Costs under a single-price system

The Portuguese imbalance pricing system is different from the standard systems described in the literature. To better understand the impact of the Portuguese mechanism on wind costs, we estimate what the wind balancing costs would be under an hypothetical single-price system. Denote by V_i^* the full imbalance value. Using the single-price formulas from section 2,

$$V_i^* = \begin{cases} D_i \overline{P}, & \text{if system is short (Gen < Load);} \\ D_i \underline{P}, & \text{if system is long (Gen > Load).} \end{cases} \tag{9}$$

Figure 3: Wind balancing cost and penetration

The solid blue line is the wind balancing cost (left axis), measured as the penalty term ($K_i R$, in equation 1) in euros per MWh of wind generation. The red dotted line is the fraction of wind on total system load (right axis). Rolling 90-day averages of hourly values, 2012/01/01–2016/12/31.



Note that now what wind pays/receives depends only on its own imbalance, with the system state determining the unit price. We estimate V_i^* for wind using the observed imbalances (D_i), market clearing tertiary reserve prices ($\underline{P}, \overline{P}$), and total system imbalance. The estimates should obviously be taken only as approximations of what the true costs would be, as market agents might behave differently if the pricing rules were different.

Table 6 shows the full wind imbalance value per unit of absolute imbalance ($V^*/|D|$) in the first columns. Imbalance prices do not reach the extreme values that they did under the Portuguese system (table 5) because they are now naturally limited to the administrative price range for tertiary reserves (0–180 €). Interestingly, we note that the average values (31.44 €/MWh$_{\text{imb}}$ for long and 54.68 €/MWh$_{\text{imb}}$ for short imbalances) remain very similar to the current Portuguese system.

Table 6: Wind imbalance values under single-price system

Descriptive statistics on hourly wind imbalance values. The columns labeled "Full Value" show the total imbalance value, V_i^* in equation (9), and the following columns show the penalty term, C_i^* in equation (10). The data subsets correspond to the hours when wind has a long ($D < 0$) or short ($D > 0$) imbalance. The last row, "VW Avg", shows a wind-generation value-weighted average. All values are in euros per unit (MWh) of either absolute imbalance ($|D|$) or true wind generation, as denoted in the headings. A positive/negative sign represents a cash inflow/outflow to/from the system operator. Hourly data, 2012/01/01–2016/12/31.

	Full Value		Penalty term				
	(per MWh imb.)		(per MWh imb.)		(per MWh generation)		
	$D < 0$	$D > 0$	$D < 0$	$D > 0$	$D < 0$	$D > 0$	All D
Moments							
Mean	-31.44	54.68	12.96	9.86	3.16	3.51	3.32
Stdev	22.50	26.35	19.89	24.27	5.39	11.83	9.01
Percentiles							
Min	-180	0	-147	-90	-38	-111	-111
5%	-73	14	-22	-28	-2	-6	-3
25%	-42	38	3	-2	0	0	0
Median	-30	53	15	9	2	1	1
75%	-18	70	25	21	5	5	5
95%	0	99	42	50	13	21	16
Max	0	180	90	159	93	199	199
VW Avg	-27.56	52.00	12.19	13.21	2.51	2.77	2.61

The balancing cost from the point of view of the wind producer is likewise defined as the opportunity cost relative to having traded the correct amount of energy at the day-ahead price (P):

$$C_i^* := V_i^* - D_i P \tag{10}$$

Contrary to the Portuguese system, now this cost "penalty" can be either positive or negative, even under normal market conditions ($\underline{P} < P < \overline{P}$), because the signed imbalance multiplies a price differential that depends on the system state. For example, if wind generates less than programmed, but that helps a system that is overall long, then the wind "penalty" is negative. The cash flows are still defined with signs from the point of view of the system operator, so a negative penalty represents a cash flow from the system to wind.

Table 6 shows that, even though the support of the penalty distribution would become more symmetric under a single price system, the average value would remain very close to the current system. In particular, the value-weighted average of wind balancing costs would be 2.61 €/MWh$_{\text{gen}}$, which is very close to the current 2.17 €/MWh$_{\text{gen}}$.

In summary, these results suggest that the Portuguese imbalance pricing method is not the reason why wind balancing costs are low.

5.3 Comparison with other markets

To the best of our knowledge, there are only four published papers on wind balancing costs using observed market prices. Table 7 contrasts our findings with the existing literature.

The papers cover several European countries and different time periods. There is also a diversity of imbalance pricing systems: some markets use single pricing, while others prefer dual pricing. Portugal seems to be alone in the socialization of wind imbalance costs, as most other countries make wind generators pay for their imbalance costs.

Wind balancing costs in Portugal, 2.17 €/MWh, are mostly in line with

Table 7: Wind balancing costs in other markets

Papers key: A is Holttinen (2005); B is Obersteiner, Siewierski, and Andersen (2010); C is Holttinen and Koreneff (2012); D is Hirth, Ueckerdt, and Edenhofer (2015). The values under "Wind capacity" refer to the sample used in the paper. W/L is the overall system Wind to Load ratio. P is the average day-ahead price. "Cost" is the wind balancing cost in euros per MWh of wind energy generation. "Payers" are the ultimate payers of wind balancing costs. "(na)" means that we could not find information in the paper.

Paper	Region and Period	Wind capacity	W/L	P	Cost	Payers	Imbalance pricing system
This paper	Portugal, 2012–2016	Total system, 4529–5313 MW	0.23	45	2.17	End consumers	Unique Portuguese system
A	Western Denmark, 2001	Total system, 1930 MW	0.16	23.7	2.3	Wind generators	Two-price system
B	Denmark, Oct2008–Jun2009	63 MW	(na)	(na)	-0.3	(na)	Two-price system
B	Austria, 2008	13 MW	(na)	(na)	6	End consumers pay 10–20%	One-price system
B	Poland, 2008–2009	Year 2008: total system. Year 2009: single 30 MW wind farm.	(na)	(na)	6.9	(na)	Year 2008: two-price system, but not linked to spot price. Year 2009: one-price system
C	Finland, 2004	22 MW	(na)	27.7	0.62	Wind generators	Two-price system. But all imbalances have to pay a fixed price of 0.7 EUR/MWh.
D	Germany, "last three years."	(na)	(na)	(na)	1.7–2.5	(na)	(na)

the other countries in table 7. In most cases, wind balancing costs are below 3 €/MWh. The only two cases with costs above 6 €/MWh are Austria, 2008, and Poland, 2008–2009. Note, however, that most studies present estimates for early periods, when wind forecasting techniques were presumably less developed.

Nevertheless, the results in our paper, together with the results for Western Denmark from Holttinen (2005), encouragingly suggest that wind balancing costs can remain relatively low, even at high penetration rates.

Given that the existing literature covers a limited subset of markets and periods, it is not easy to see the patterns that theory would suggest, neither in terms of the wrong incentives caused by the socialization of wind imbalance costs, nor the effect of different pricing systems. Further research is needed.

5.4 Discussion on cost factors

There are several factors that may help explain the low wind balancing costs in Portugal. First, all wind generators in Portugal are included in the same Balance Responsible Party (BRP), thus reducing the aggregate variability. This setup has the advantage of fostering the entrance of small wind producers, as it exempts them from the cost of having to forecast and trade their individual production. Aggregating all wind into a single BRP requires, however, a strong electrical grid. There must be enough transmission capacity between all relevant points in the network, such that, a wind plant that is generating too little in point A can really be compensated by excess electricity from some other wind plant in point B. The Portuguese transmission grid satisfies this requirement, and thus contributes to lowering wind balancing costs.

A second factor contributing to low wind balancing costs is that most of the current wind farms in Portugal are located in sites with good capacity factors. This helps to reduce the variability costs due to the cubic shape of power curves for typical wind turbines (see, for example, Katzenstein and

Apt (2012)).

A third potential factor is the large capacity of hydropower in Portugal. Hydro dams have zero marginal cost, and therefore are able to underprice thermal balancing reserve providers. Furthermore, there is also a large capacity of upstream pumping, which can act as downward tertiary reserve, again at a more favourable price for the system. There is evidence that hydropower contributes to stabilize day-ahead and intraday prices (see, Pereira, Pesquita, and Rodrigues (2017) for day-ahead prices in Spain, and Kilic and Trujillo-Baute (2014) for NordPool intraday prices), so it seems reasonable to assume a similar effect for balancing markets.

Despite these favorable effects, one should ask whether wind balancing costs could be even lower. Given that wind forecast errors are much larger in Portugal than Spain (as discussed in section 3), the answer is probably yes. This is important because wind balancing costs still amount, in absolute terms, to a significant sum of money. To put it in perspective, considering the total wind generation during the 2012–2016 sample period, the wind surcharge amounts to a total of 124 million euros, or an average of 24.8 million euros per year. This is the amount of money that is effectively transferred from final energy consumers to balancing reserve providers. If wind generators had to actually pay for the cost of their imbalances, they would surely find it economical to invest in better forecasting technology, and thus bring their imbalances closer to the levels of comparable countries.

6 Conclusion and Policy Implications

This paper shows that the cost of wind randomness can be relatively low, even at high wind penetration rates. In Portugal, where wind already accounts for 23% of load, the average wind balancing cost is 2.17€ per each MWh of wind energy generated.

The results are surprising due to the lack of economic incentives for wind generators to minimize their imbalances, that is, wind imbalance costs are effectively paid by final consumers in our market. Even though Portugal uses a unique imbalance pricing system, we have shown that this is not the reason for low imbalance costs. Instead, one important mechanism to reduce wind balancing costs is the aggregation of all wind producers into a single balance-responsible party. Since this aggregation requires an electrical grid with enough transmission capacity, the results imply that in other markets facing high balancing costs for intermittent renewables, it may be economical to invest in upgrades to the transmission grid.

For the specific case of Portugal, even though wind balancing costs are relatively low in "per MWh" terms, the costs still add up to a significant amount of money. At the current stage of market development, we see no reason to keep wind producers immune to the cost of their imbalances. Making wind producers balance responsible would create the proper incentives for better wind forecasting, and save several millions of euros per year for final consumers. It is important to stress that this change in market rules would not imply any change in the revenue of wind producers, which would remain equal to the promised feed-in-tariff. Wind generators would only see a small reduction in net profits due to the lower remaining wind unpredictability. The only agents which would probably lose significant revenues would be balancing reserve providers.

Likewise, it would probably make sense to change from the current Portuguese imbalance pricing system to a standard single or dual-price system, similar to other European markets. If the market evolves in that direction, it would also seem fair to properly account for regulation reserves that are used for other technical purposes that are not related to imbalances (like load and trade smoothing, or indirect AGC control, as described in this paper), and make sure that the corresponding costs are not allocated to imbalanced agents.

References

Bueno-Lorenzo, M., M. Á. Moreno, and J. Usaola, 2013, "Analysis of the imbalance price scheme in the Spanish electricity market: A wind power test case," *Energy policy*, 62, 1010–1019.

Chaves-Ávila, J. P., 2014, "European Short-term Electricity Market Designs under High Penetration of Wind Power," Doctoral Thesis, SETS Joint Doctorate, published by Next Generation Infrastructures Foundation, Delft, the Netherlands.

Chaves-Ávila, J. P., and C. Fernandes, 2015, "The Spanish intraday market design: A successful solution to balance renewable generation?," *Renewable Energy*, 74, 422–432.

Chaves-Ávila, J. P., R. A. Hakvoort, and A. Ramos, 2014, "The impact of European balancing rules on wind power economics and on short-term bidding strategies," *Energy Policy*, 68, 383–393.

Herrero, I., P. Rodilla, and C. Batlle, 2016, "Enhancing intraday price signals in U.S. ISO markets," Working paper, MIT Energy Initiative.

Hirth, L., F. Ueckerdt, and O. Edenhofer, 2015, "Integration costs revisited–An economic framework for wind and solar variability," *Renewable Energy*, 74, 925–939.

Hirth, L., and I. Ziegenhagen, 2015, "Balancing power and variable renewables: Three links," *Renewable and Sustainable Energy Reviews*, 50, 1035–1051.

Holttinen, H., 2005, "Optimal electricity market for wind power," *Energy Policy*, 33(16), 2052–2063.

Holttinen, H., and G. Koreneff, 2012, "Imbalance costs of wind power for a hydro power producer in Finland," *Wind Engineering*, 36(1), 53–67.

Katzenstein, W., and J. Apt, 2012, "The cost of wind power variability," *Energy Policy*, 51, 233–243.

Kilic, M., and E. Trujillo-Baute, 2014, "The Stabilizing Effect of Hydro Reservoir Levels on Intraday Power Prices Under Wind Forecast Errors," *Social Science Research Network Working Paper Series*.

MIT, 2016, "Utility of the Future," http://energy.mit.edu/research/utility-future-study/.

Obersteiner, C., T. Siewierski, and A. Andersen, 2010, "Drivers of imbalance cost of wind power: a comparative analysis," in *Proceedings of the 7th International Conference on the European Energy Market*, pp. 1–9. IEEE.

Ocker, F., and K.-M. Ehrhart, 2017, "The German Paradox in the balancing power markets," *Renewable and Sustainable Energy Reviews*, 67, 892–898.

Peña, I., I. L. Azevedo, and L. A. F. M. Ferreira, 2014, "Economic analysis of the profitability of existing wind parks in Portugal," *Energy Economics*, 45, 353–363.

Peña, I., I. L. Azevedo, and L. A. F. M. Ferreira, 2017, "Lessons from wind policy in Portugal," *Energy Policy*, 103, 193–202.

Pereira, J. P., V. Pesquita, and P. M. M. Rodrigues, 2017, "The effect of hydro and wind generation on the mean and volatility of electricity prices in Spain," *Proceedings of the 14th International Conference on the European Energy Market (IEEE).*

Vandezande, L., L. Meeus, R. Belmans, M. Saguan, and J.-M. Glachant, 2010, "Well-functioning balancing markets: A prerequisite for wind power integration," *Energy Policy*, 38(7), 3146–3154.

Appendix

A Details on the imbalance pricing system

A.1 Zero-sum mechanism

The Portuguese pricing scheme results in a zero-sum mechanism for the TSO. To see this formally, use the definitions for V_i and R_i in (1) and (2), and the fact that $\sum_i K_i = 1$, to verify that the total cash inflow received from imbalanced BRPs, $\sum_i V_i$, equals the net cash outflow paid to reserve providers, $\overline{P}\,\overline{E} - \underline{P}\,\underline{E}$:

$$\begin{aligned} \sum_{i=1}^{I} V_i &= \sum_{i=1}^{I} (D_i P + K_i R) \\ &= P \sum_{i=1}^{I} (D_i) + P(\underline{E} - \overline{E}) - \underline{P}\,\underline{E} + \overline{P}\,\overline{E} \\ &= \overline{P}\,\overline{E} - \underline{P}\,\underline{E} \end{aligned} \tag{A.1}$$

where the last equality results from the fact that the net amount of imbalances must equal the net amount of reserves used, $\sum_{i=1}^{I} D_i = \overline{E} - \underline{E}$.

A.2 Proof of Proposition 1

Proof. Consider first the case $D_i < 0, \forall i \in \{1, \dots, I\}$. We thus have $\underline{E} = \sum_{j=1}^{I} |D_j|$ and $\overline{E} = 0$. From (1),

$$V_i = D_i P + \frac{|D_i|}{\sum_{j=1}^{I} |D_j|}(P - \underline{P}) \sum_{j=1}^{I} |D_j| = D_i \underline{P}$$

which is negative for all i. The corresponding result obtains if all deviations are positive. □

B Typical imbalance pricing systems

Table B.1 compares typical single and dual price systems.

Table B.1: Typical imbalance pricing systems

The table shows cash flows to the system operator (SO) per MWh of absolute imbalance ($|D_i|$). A positive value means that cash is flowing from the balance responsible party (BRP) to the SO. $\overline{P}$ and $\underline{P}$ denote, respectively, the upward and downward reserve prices. In dual-price systems, P is day-ahead price. $\overline{\overline{P}}$ is the upward reserve price aggravated by a penalty, that is, $\overline{\overline{P}} > \overline{P}$. Similarly for the downward price, $\underline{\underline{P}} < \underline{P}$.

	System Imbalance	
BRP Imbalance	Short (Gen<Load)	Long (Gen>Load)
Single-price system		
Short	$+\overline{P}$	$+\underline{P}$
Long	$-\overline{P}$	$-\underline{P}$
Dual-price system		
Short	$+\overline{\overline{P}}$	$+P$
Long	$-P$	$-\underline{\underline{P}}$

Single-price systems are zero-sum mechanisms for the system operator (SO) because negative deviations pay for positive deviations. In most markets, upward and downward reserve prices ($\overline{P}$ and $\underline{P}$ in table B.1) are marginal clearing prices. It is usually considered that single-price systems provide optimal incentives because a balance-responsible party (BRP): (i) pays exactly the marginal cost of its deviation when it aggravates the system imbalance ($\overline{P}$ or $\underline{P}$, depending on the net system state); and (ii), receives exactly the marginal value of its deviation when it contributes to balance the system.

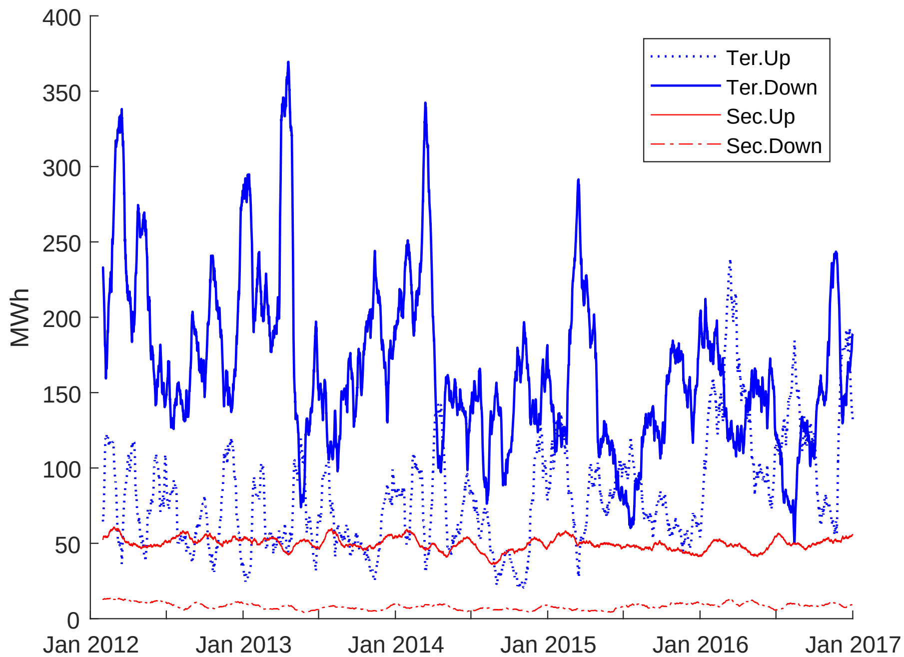
Dual-price systems are non-zero-sum mechanisms for the SO because there are different prices for long and short imbalances. For example, if the whole system is short (programmed generation is insufficient for the actual load), the SO has to dispatch upward reserves at some price $\overline{P}$. However, for a BRP that is short, and thus aggravates the system imbalance, the SO charges a higher price $\overline{\overline{P}}$, which exceeds the marginal cost that the BRP is imposing on the system ($\overline{P} < \overline{\overline{P}}$), that is, $\overline{\overline{P}}$ contains a penalty. On the other hand, a BRP that is long, and thus is helping the system, only receives a lower value (typically the day-ahead price, P), which does not compensate for the full value of the injected energy ($P < \overline{P}$). Hence, a dual-price system penalizes any deviation from the market program more strongly than a single-price system.

C The effect of an asymmetric secondary band

As described in section 3, there is an asymmetry in the use of downward and upward regulation reserves. To better illustrate this fact, figure C.1 shows the time series of secondary and tertiary reserves.

Figure C.1: Secondary and Tertiary Reserves

Secondary and Tertiary reserves used per hour. Rolling 30-day averages of hourly values, 2012/01/01–2016/12/31.



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 around 8 MWh, upward secondary fluctuates around 50 MWh. The fact that upward secondary is relatively stable around this higher value has a technical/economic explanation related to the design of the Portuguese balancing reserve market.

In the beginning of the market in 2007, when intermittent renewables were still small, the major risk for the system was insufficient generation due to, for example, a generator tripping offline or an unexpected increase in load. Additionally, tertiary suppliers had relatively long response times. Hence, market rules were set to 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 thermal power plant that is able to vary its output between 200 and 400 MW, and suppose that it was dispatched at 300 MW in the day-ahead market. If this plant wants to sell the maximum possible band in the secondary reserve market, due to economic market rules, it must offer 100 MW for upward and only 50 MW for downward regulation.

More recently, as intermittent renewables increased, the risk became more symmetric, that is, the probability of too much generation also grew. Additionally, technological developments in some tertiary suppliers, like hydropower plants, now allow them to complement secondary reserves much faster than in the earlier period. Hence, the TSO now prefers to have the secondary band centered at the midpoint, with an equal amount of upward and downward availability. However, the economic market rules in place are still the original ones, requiring generators to offer secondary reserves in the same 2/3–1/3 ratio. 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 requires the system to use, on average, approximately 44 MW of downward tertiary reserve and another 44 MW of upward secondary reserve.

This mechanism induces a constant bias in secondary reserve, leading to the pattern observed in figure C.1. It also contributes to downward tertiary being, on average, higher than upward tertiary mobilization. In summary, the average bias of 44 MWh, in both secondary and tertiary reserves, results from what we might call the difference between "market equilibrium" and "technical equilibrium".