Article

Strategic bidding to increase the market uptake of variable renewable generators in Electricity Markets

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**Abstract:** The 2050 global ambition for a carbon-neutral society is increasing the penetration of the most competitive variable renewable technologies, onshore wind and solar PV. These technologies are known for their near-zero marginal costs but highly variable time-dependent generation. Power systems with major penetrations of variable generation need high balancing flexibility to guarantee their stability by maintaining the equilibrium between demand and supply. Electricity markets were designed for dispatchable technologies. Support schemes are used to incentive and de-risk the investment in variable renewable, since actual market designs are riskier for their active participation. This study presents three strategic bidding strategies for the active participation of variable renewable in electricity markets. The case study examines the levels of active market participation for a wind power producer (WPP) in the Iberian electricity market and the Portuguese balancing markets, where WPPs are financially responsible for imbalances and operate without support schemes in past and actual market designs. Results from the study indicates that the WPP has the potential to increase its market value between 36% and 114% if participating in the tertiary and secondary balancing markets completely adapted to its design, respectively. However, considering the use of strategic bidding in actual market designs, by participating in the secondary reserve, the WPP can increase its market value by 10% when compared with the actual case of perfect foresight.

**Keywords:** balancing markets; imbalance settlement; secondary reserves; market design; RES.Trade; tertiary reserves; variable renewable energy sources; wholesale markets.

1. Introduction

Electricity market (EM) participants are diverse, autonomous entities with distinct objectives and trading strategies [1]. Typically, supply-side agents aim to maximize profits in wholesale markets, while demand-side agents focus on minimizing electricity costs before reselling it to end consumers in the retail market. Most trading strategies involve cooperation, ensuring mutual benefits for both parties [2,3].

Globally, wholesale electricity markets follow three primary models [3]:

1. Auctions – A centralized market where supply and demand agents submit bids, with market prices determined by the intersection of supply and demand curves using a marginal pricing algorithm.
2. Bilateral Contracts – Private agreements between supply and demand agents who negotiate contract terms directly.
3. Hybrid Models – A combination of auction-based trading and bilateral contracts.

Most European Union countries operate under a hybrid market model. In this system, a day-ahead market (DAM) closes at 12:00 p.m. (CET) on the day before trading, followed by intraday markets (IDMs) used for real-time bid adjustments. These intraday markets may function through multiple auction-based sessions, as seen in Iberian (MIBEL), Italian, and German markets, or via continuous intraday trading, as in most of Europe. Additionally, private bilateral contracts and participation in derivatives markets provide risk management tools, enabling agents to secure fixed energy prices over extended time horizons, reducing exposure to spot market volatility. Auxiliary services, as balancing markets (BMs), ensure grid stability by maintaining frequency and voltage, mitigating system imbalances, and enhancing overall network reliability [3-6].

The rapid growth of variable renewable energy sources (vRES), such as wind and solar photovoltaic (PV), has introduced new challenges to electricity markets [7]. However, their intermittent nature increases supply volatility and uncertainty, leading to higher system integration costs, particularly for ancillary services [8,9]. While wind power requires substantial investment, its production costs are nearly zero. Although increased vRES penetration tends to lower spot market prices, it can drive up ancillary service costs, as deviations from expected output require balancing measures. The financial burden of these deviations is typically placed on the responsible market agents through penalties in the imbalance settlement (IS) [9-12]. In extreme cases—such as significant forecasting errors—the penalties imposed on vRES producers can exceed their spot market revenues. However, certain power systems shield vRES producers from these costs, transferring them to consumers instead. This was the case in Portugal under feed-in-tariffs (FiTs) and other guaranteed tariff schemes, which provided financial stability for vRES generation [13-15].

Support schemes are a good option to de-risk investments in renewable energy sources and the volatility of electricity markets if well designed. The most common designs, such as FiTs and contracts for difference (CfDs) contributed to market distortions, such as price cannibalization, negative prices, and tariff deficit. However, with the decreasing levelized costs of energy (LCOE) of vRES and increasing electricity prices in Europa after the 2022 gas crisis, more competitive and well-designed support schemes, such as Financing CfDs and Risk-Sharing Contracts may contribute to de-risking the effect of electricity price volatility [15-17]. Indeed, support schemes contributed for the first time negative grid access prices, reducing real-time pricing retail tariffs to values lower than wholesale prices during the gas crisis [18,19]. However, support schemes are an externality affecting the competition principle of auction-based marginal markets based on the Nash equilibrium [19,20]. So, support schemes cause market distortions by benefiting renewables.

Given the increasing penetration of VRESs, a careful reassessment of electricity market models is necessary to determine their effectiveness in a renewable-dominated landscape [5,6]. Existing market structures were designed when dispatchable power plants dominated generation, limiting incentives for vRES participation unless coordinated with flexible generation assets [21-23]. The growing share of vRESs has led to reduced market liquidity, and despite lower LCOE, economic incentives—such as FiTs—remain essential for ensuring wind farm participation. While solar PV has become economically viable without subsidies, the rising costs of ancillary services highlight the need for market design reforms [5,6,24-25]. Enhancing flexibility mechanisms and appropriately compensating ancillary service providers will be critical to ensuring grid stability and efficiency in high-vRES energy systems [24-26]. vRES have technical capability to provide balancing reserves [26]. They can use strategic bidding with or without support schemes and adapt their behavior to increase their market uptake accordingly [6,11,28-30].

A study on a Wind Power Plant (WPP) operating in the Danish electricity market demonstrated that active participation in both the DAM and Balancing Markets resulted in a 6.5% increase in the overall wind energy value. This finding highlights the potential benefits of flexible and market-aware trading strategies, which not only improve the profitability of vRES but also facilitate their integration into the electricity system. By leveraging multi-market participation, vRES can reduce forecast errors, optimize revenues, and support grid stability, ultimately enhancing their economic sustainability [28].

A profitability assessment of wind power participation in Swedish BMs revealed that the most profitable strategy is engaging in both the DAM and aFRR downward regulation. This combination can generate additional revenue of 35% compared to participation in the DAM alone under perfect production forecasts and 22% when factoring in standard production forecast errors [30].

A study analyzed the participation of WPPs in the DAM and Portuguese BMs across four scenarios. The baseline scenario involved participation solely in the DAM, while Scenario A combined the DAM with automatic Frequency Restoration Reserve (aFRR), and Scenario B combined the DAM with manual Frequency Restoration Reserve (mFRR). Scenario C also integrated the DAM with the mFRR market but reduced the time unit to 15 minutes. The study found that Scenario C was the most favorable, as shorter time units increased flexibility and revenue for WPPs. Scenario A also proved more beneficial than Scenario B, with revenue increases of 4.9% and 2.2%, respectively, compared to the baseline. These findings highlight the role of WPP participation in BMs in reducing dependence on support schemes and fostering their integration as active players in electricity markets [11].

Against this background, this paper evaluates the outputs of vRES in electricity markets without support schemes using strategic bidding. The paper presents a methodology that can be adapted to all vRES technologies based on the probabilistic forecast quantiles and the selection of the best quantile to increase the market uptake of vRES. The presented case study analyzes the extent of active market participation by a WPP in MIBEL and the Portuguese balancing markets, where WPPs bear financial responsibility for imbalances and operate without support schemes under both past and current market designs. The findings indicate that if the WPP fully participates in tertiary and secondary balancing markets tailored to its design, its market value could increase by 35% and 111%, respectively. However, under the current market framework, where strategic bidding is applied, the potential market value increase is limited to 15%.

The remainder of this paper is structured as follows. Section 2 provides an overview of wholesale energy markets and reserve systems, highlighting MIBEL. Section 3 outlines the proposed methodology for strategic participation of vRES in electricity markets. Section 4 presents a case study and evaluates the performance of the developed strategies. Finally, Section 5 summarizes the findings and discusses the implications for future energy markets.

1. Electricity markets

Market participants can trade electricity across five different market types [5]:

1. Spot Markets – Agents submit bids (minimum 0.1 MW) to electricity pools through day-ahead and intraday marginal auctions.
2. Continuous Markets – Trading occurs in real time, with transactions settled up to 15 minutes before delivery.
3. Derivatives Markets – Includes forwards, futures, swaps, and options, allowing hedging against spot price volatility and consumption uncertainty.
4. Non-Organized (Private Bilateral Contracts) – Agents negotiate directly, setting customized terms and conditions outside organized exchanges.
5. Ancillary Services Markets – Managed by Transmission System Operators (TSOs) to ensure system stability by balancing supply and demand deviations.
   1. European electricity markets

In European electricity markets, the day-ahead market closes at noon (CET) the day before real-time operation (12–37 hours ahead). These markets are coupled and use the EU Pan-european Hybrid Electricity Market (EUPHEMIA), a common marginal pricing algorithm that optimizes power flows between different market zones to maximize social welfare [5,31].

Energy trading also occurs in intraday markets, which consist of:

1. Intraday Auctions – Conducted a few hours before real-time operation.
2. Continuous Trading – Operates on a pay-as-bid basis, allowing transactions up to 15 minutes before real-time delivery.

In derivatives markets, agents can enter financial or physical contracts via clearing houses (organized exchanges) or over-the-counter trading to hedge against spot price volatility. For non-standard agreements, private bilateral contracts allow direct negotiations between parties, such as power purchase agreements [3,16].

Since many market participants—such as retailers, energy communities and vRES generators without storage—face real-time deviations from their programmed schedules, TSOs manage balancing markets to ensure system security. Balancing Responsible Parties (BRPs) must cover the costs of their upward or downward balancing deviations, which often result in financial penalties relative to spot market prices [11,32].

European power grids must maintain a stable frequency of 50 Hz, with a secure oscillation range of ±0.1%. If deviations exceed 0.5%, outages and separations of control areas may occur. When deviations reach 0.1%, balancing reserves are automatically activated to restore stability [11,33].

Europe utilizes four main balancing mechanisms to regulate frequency deviations:

1. Frequency Containment Reserve (FCR):
   * First response mechanism, activated within 15 seconds to counteract frequency disturbances.
   * European synchronous grid reserves 3,000 MW for FCR to maintain system stability.
2. Automatic Frequency Restoration Reserve (aFRR):
   * Activated within 30 seconds, replacing FCR.
   * Maintains grid frequency stability for up to 15 minutes.
   * TSOs define a power band for each period, with symmetric band requirements set by ENTSO-E or set by each TSO according its own methodology.
3. Manual Frequency Restoration Reserve (mFRR):
   * Used after aFRR to support extended balancing needs.
   * Addresses medium- and long-term deviations caused by generation or load fluctuations.
   * TSOs activate 15-minute market blocks, allowing generators to bid in auctions.
4. Replacement Reserve (RR):
   * Used for long-term disturbances beyond aFRR and mFRR capabilities.
   * Activated within 15 minutes and remains active for several hours.
   * Typically managed through bilateral agreements between TSOs and providers, rather than real-time market activations.

BMs reserves are traded directly between TSOs and providers. Upward regulation providers receive the up-regulation price, while downward regulation providers pay the down-regulation price. Imbalance settlement costs are assigned to BRPs that deviate from their scheduled dispatch. Typically, upward regulation prices exceed spot prices, while downward regulation prices are lower. In some cases, BRPs may receive compensation instead of penalties, depending on market conditions [11,34,35].

* 1. Portuguese electricity markets

In Portugal and Spain are part of the MIBEL. MIBEL oversees spot, derivatives, and bilateral markets, while ancillary services remain independent for each country and are managed by their respective TSOs. However, certain ancillary services can be traded between TSOs for system balancing.

Portugal follows the European frequency reserve framework for continuous balancing, with the following specifications [11,12,35-37]:

1. FCR:
   * FCR is mandatory and non-remunerated for all technically capable generators connected to the grid.
   * Generators must reserve 5% of their nominal power under stable conditions to support FCR.
   * Portugal contributes to the continental European synchronous grid.
2. aFRR:
   * The Portuguese TSO requires an asymmetrical aFRR power band, where up-regulation capacity is twice the down-regulation capacity.
   * Historically, Portugal's aFRR power band is more used for up-regulation than down-regulation.
   * To align with ENTSO-E guidelines, Portugal’s TSO upscales up-regulation capacity to 60% and downscales down-regulation to 40%.
   * Hourly aFRR capacity auctions are held, allowing all technically capable generators to participate.
   * Generators must offer both up-regulation and down-regulation, with up capacity being twice the down capacity.
   * Due to limited competition, combined cycle gas turbines (CCGTs) dominate the aFRR market.
   * The price of upwards aFRR energy is regulated and set by the national regulator.
3. mFRR:
   * mFRR energy is procured through hourly auctions, with separate bids for upward and downward regulation in marginal markets.
   * Since mFRR is based on hourly auctions, it may not be sufficient for balancing long-term frequency deviations.
4. RR:
   * RRs are activated for long-term system imbalances that cannot be resolved through aFRR or mFRR.
   * RRs can be activated within 15 minutes and remain active for extended periods.

Unlike other reserves, RRs rely on bilateral contracts between TSOs and market participants instead of direct market bidding. Next section presents the strategies for active participation of vRES in electricity markets.

1. Strategic bidding of vRES in electricity markets

The objective of maximizing the producer's revenue is formulated as an optimization problem, which was implemented using Python. In this model, the decision variables represent the volumes traded in the EMs, constrained by market rules and conditions.

The following general constraints are applied:

* The schedule in the EMs is limited by the nominal power of the vRES power plant. The producer cannot sell more energy than what can be physically produced.
* The producer cannot bid more downward balancing capacity than the scheduled injection.
* Bids in the BMs are limited by the request of the TSO.

In this model, the vRES market participation decisions are interconnected through the following concepts:

* Position: The portfolio of vRES that accounts for the bid in the DAM, increasing when selling in the IDM and decreasing when purchasing energy.
* Final offer: The position of the vRES after the capacity market and before the activation of energy bids. This represents the adjusted position based on initial bids and the balancing capacity market.
* Final schedule: After the activation of reserves by the TSO, the final schedule reflects the adjusted energy injection into the grid. It is derived from initial positions from the DAM and IDMs, increasing when upward reserves are activated and decreasing when downward reserves are called upon. This adjustment reflects the energy increased or reduced in response to the TSO's requests.
* Final deviation: The difference between the actual production and the final schedule, which will be settled during the IS period.

These concepts are crucial for understanding how the vRES’s decisions evolve and impact each other across different market stages.

* 1. Ideal Case

In an ideal scenario, the producer has perfect foresight regarding both vRES production and market conditions. With this information, the producer can place bids at the optimal quantile of the distribution to maximize revenue. This participation strategy, based on optimal quantile forecasts of vRES generation, has been discussed in other studies [2,3].

The revenue from the DAM is:

|  |  |
| --- | --- |
|  | (1) |

Where for the hour t:

* is the quantile *j*, with *j* representing the index ranging from 1 to 21.
* is the DAM price.

The deviation between the observed power and the quantile j for the hour t is:

|  |  |
| --- | --- |
|  | (2) |

Since each period *t* corresponds to one delivery hour, the energy volume representing the imbalance, , is the power deviation for that hour as given by equation (2).

Considering the case where vRES only participate in the DAM, after the gate closure of the DAM, any deviations are settled in the IS period. The remuneration during this period depends on the direction of the imbalance, with producers either being penalized or compensated based on whether they over- or under-deliver relative to their bid.

|  |  |
| --- | --- |
|  | (3) |

Where for the hour t:

* is the price paid to the producers with excess generation,
* the price paid by producers with a deficit.

The maximum total remuneration at hour t is given by:

|  |  |
| --- | --- |
|  | (4) |

The optimal quantile for each hour t, which maximizes the total remuneration, corresponds to the quantile with index:

|  |  |
| --- | --- |
|  | (5) |

Considering also the participation of vRES in intraday and balancing markets, the deviation from the DAM schedule (2) can be addressed in other markets, where the remuneration (4) depends on the market conditions and prices.

When participating in the IDMs, the producer can adjust their position after the DAM and before the IS. In the ideal scenario, any deviation can be settled in the market with a higher price in the case of a positive deviation, or a lower price if there is a deficit. The price considered for intraday continuous (IDC) is the DAM price.

Since primary reserve is not procured in markets, only the participation in the secondary and tertiary reserve (TR) were considered.

Participation in the secondary reserve (SR) includes both the capacity and energy markets, as well as the IS process.

In the capacity market, the producer receives for each unit of reserve capacity sold. The offer is constrained by the TSO’s requirements, meaning the producer cannot offer more balancing capacity than the TSO’s needs. Under both the past and current market designs, the bid for downward balancing capacity must be half of the bid for upward balancing capacity.

However, under perfect forecasting, the offer for upward balancing capacity is not limited to available capacity. Producers can bid beyond their available resources and capitalize on potential negative prices in the IS.

The final offer consists of the bid in the DAM and the upward balancing capacity.

|  |  |
| --- | --- |
|  | (6) |

The bid in the energy market must fall within the range set by the offer in the capacity market and is subject to the TSO's requirements. The producer bids at 0 €/MWh for upward regulation and at the DAM price for downward regulation, either receiving or paying the clearing price. The producer receives when providing upward balancing energy and pays when required to provide downward balancing energy.

The remuneration from the energy market is:

|  |  |
| --- | --- |
|  | (7) |

Where for the hour t:

* is the upward secondary balancing energy provided by the vRES.
* represents the downward secondary balancing energy provided by the vRES, which corresponds to the energy withdrawn from the grid when requested by the TSO. The negative sign indicates the payment made by the BRP to the TSO

The final schedule accounts for the vRES’s position (which in the ideal case is the bid in DAM, ) increasing with the upward energy provided and decreasing with the downward energy activated.

|  |  |
| --- | --- |
|  | (8) |

The final deviation to be adjusted in the IS is the difference between actual production and the final schedule.

|  |  |
| --- | --- |
|  | (9) |

Where the observed power at hour *t*.

Remuneration in this market segment depends on the direction of the imbalance and includes a penalty for producers who fail to supply the allocated capacity. The penalty applied to the imbalances for each hour t is calculated as:

|  |  |
| --- | --- |
|  | (10) |

The imbalance price for hour is:

|  |  |
| --- | --- |
|  | (11) |

The producer faces significant penalties if they fail to fulfil their balancing service contracts. If the producer has surplus generation and the imbalance price for a positive deviation is negative, they can voluntarily curtail their excess generation to avoid incurring costs associated with overproduction.

The remuneration from the IS is:

|  |  |
| --- | --- |
|  | (12) |

Revenue from participation in SR is given by the sum of the three market segments:

|  |  |
| --- | --- |
|  | (13) |

The producer can settle deviation (2) in the mFRR market. For negative imbalances, producer can bid the deviation (2) to downward regulation and pay the price . For positive imbalances, the producer can receive .

If the deviation exceeds the needs of the TSO, the remaining imbalance can be adjusted in the IDMs or through IS, with penalties applied as described for the SR.

* 1. Operational Case

Participation in EMs involves inherent uncertainties and limited visibility into market conditions and production levels. Producers often rely on forecasts and bidding strategies to navigate these markets effectively. While minimizing forecasting errors is crucial, some level of uncertainty remains inevitable. Therefore, maintaining operational flexibility and adopting proactive planning are key to managing these challenges and optimizing performance.

The bidding strategy is designed to optimize revenue by dynamically selecting the quantile offered in the DAM based on market conditions. To achieve this, the producer uses the perfect case scenario as a benchmark to identify the average DAM price when the highest quantile is the optimal bid. This threshold price, denoted as *n*, sets the upper limit for bids in the operational mode, ensuring that offers remain competitive while mitigating risk.

The K forecast quantiles are mapped to a price range from 0 €/MWh to *n*, with equal increments between each quantile. The highest quantile is offered when .

The price interval for each of the others quantiles *k* (where k =1,…,K) is given by the following formula:

|  |  |
| --- | --- |
|  | (14) |

Where *k* ranges from 1 to K (for to ).

The quantile is the bid in DAM, if the DAM price for that hour falls within the price interval as described in:

|  |  |
| --- | --- |
|  | (15) |

This dynamic price-responsive strategy ensures effective market participation while aligning bids with expected remuneration.

Deviations from the initial DAM bid are determined by updated forecasts, allowing producers to adjust their bids accordingly. Participation in the SR market is prioritized, as it offers higher remuneration potential from both the capacity and energy markets.

In addition to the previously mentioned constraints, the following rules apply in the balancing capacity market:

* The bid for upward balancing capacity cannot exceed the available capacity or the needs of the TSO.

|  |  |
| --- | --- |
|  | (16) |

Where represents the positive deviation, considering the updated vRES power forecast and the position of the vRES at the time of market.

* The bid for downward balancing capacity cannot exceed the scheduled injection or the needs of the TSO.

|  |  |
| --- | --- |
|  | (17) |

* + 1. Strategies for participation in aFRR market

Seven strategies were simulated, each based on different market designs and varying levels of participation in the SR.

Strategy 1 (S1): it considers the past market design where producers adjust their position in the auction-based intraday (IDA) and bid in the SR market only when the deviation between the forecast (made between 4 and 9 hours before operation) and the DAM bid is positive.

Strategy 2 (S2): it considers the current market design featuring a parallel SR capacity market alongside the IDA. The IDC market is used to make necessary adjustments before the IS. Participation in SR is limited to positive deviations in the IDA.

Strategy 3 (S3): Like S2, this strategy also follows the current market design, but with the aFRR capacity market operating in parallel with the IDC. Participation in SR is restricted to positive deviations.

The deviation is calculated as:

|  |  |
| --- | --- |
|  | (18) |

Where:

​ is the forecasted value 15 minutes before delivery.

​ is the vRES position at the time of the IDC, which can be higher than the bid in DAM if producer sold energy in the IDA, or lower if the producer was a buyer in the IDA.

Figure 1 illustrates the organization and structure of the market across the different strategies.

**A diagram of a company

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**Figure 1:** Market structure for the different strategies

The average remuneration (€/MWh) for the study period is calculated by dividing the total revenue across all hours by the total production for the same period.

|  |  |
| --- | --- |
|  | (19) |

Where:

* is the average remuneration (€/MWh).
* ​ is the total revenue at hour *t*.
* is the observed power production for each hour *t*.
* T is the total number of hours in the dataset (17088 hours).

1. Case study on the active participation of a WPP in EMs

This section presents a case study of a WPP participating in the EMs within the MIBEL framework and the Portuguese BMs during the period of 2009-2010. The analysis assumes that the WPP operates without any support scheme and is fully responsible for managing its imbalances. The objective is to maximize the producer’s remuneration by optimizing market participation strategies. In this section, the dataset, methodology applied, and the developed scenarios are outlined.

* 1. Dataset and statistics

The market data includes hourly prices for DAM, IDMs, positive and negative imbalance prices, as well as hourly prices and requirements for aFRR and mFRR.

Table 1 presents key market price statistics, highlighting significant price differences across various market segments.

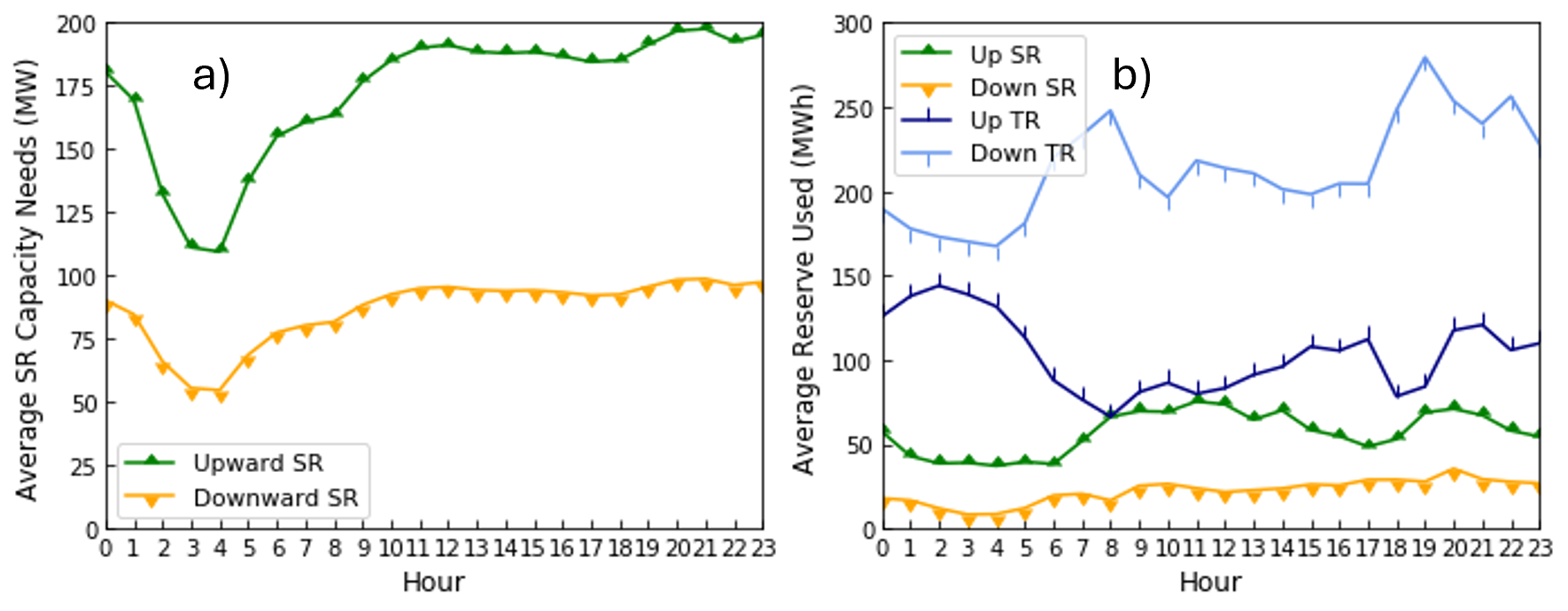
**Table 1:** Key statistics of market prices.

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  | DAM (€/MWh) | IDA (€/MWh) | Secondary Reserve  Capacity (€/MW) | Positive Tertiary Energy (€/MWh) | Negative Tertiary Energy (€/MWh) | Positive Imbalance  Price (€/MWh) | Negative Imbalance  Price  (€/MWh) |
| Min | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -289.51 | -160.44 |
| Max | 180.30 | 112.05 | 180.30 | 181.00 | 100.00 | 225.10 | 381.01 |
| Median | 38.18 | 36.52 | 22.57 | 43.20 | 23.00 | 25.86 | 49.23 |
| Mean | 37.30 | 35.09 | 27.12 | 42.40 | 20.15 | 22.74 | 51.82 |
| SD | 12.17 | 12.62 | 14.54 | 19.66 | 20.92 | 18.02 | 15.49 |

From Table 1 can be verified that positive tertiary energy prices are higher than negative tertiary energy prices, indicating stronger financial incentives for participating in balancing markets. The Portuguese IS is symmetrical, which means the penalty is equal for both positive and negative imbalances [37]. The difference between positive or negative imbalance prices and the DAM price is the penalty. The mean penalty is positive. However, when balancing costs are negative, the penalty can be negative, providing a positive remuneration for BRPs.

Table 1 also presents DAM, IDA, and SR capacity prices, providing further context for the broader market dynamics. The extreme fluctuations in imbalance prices underscore the market's volatility, emphasizing the importance of strategic bidding and accurate forecasting to optimize profitability and manage risks.

Figure 2 illustrates the average hourly values for required aFRR capacity (a) and the energy used for aFRR and mFRR (b).



**Figure 2:** Average hourly values for required aFRR capacity (a) and aFRR and mFRR energy used (b).

In Figure 2 part (a), the upward aFRR capacity requirement is shown to be twice the downward demand, in line with Portuguese legislation. Part (b) highlights that downward tertiary energy is the most used, reflecting the grid's reliance on manual reserves during periods of over generation or lower demand than expected in the programming dispatches.

During the period of the study, the average wind power penetration in Portugal was 16.88% [1]. The wind data originates from an aggregator of wind power plants with a nominal capacity of 250 MW. The dataset contains both observed wind power and wind power forecasts, which include:

* A probabilistic forecast used by the producer when submitting bids to the DAM.
* Two deterministic forecasts are provided in the IDMs: one with a time horizon between 4 and 9 hours depending on the session of IDA (see Figure X), corresponding to the gate closure of the IDA, and another with a 15-minute time horizon, corresponding to the gate closure of the IDC.

Figure 3 illustrates the average hourly values for both observed and forecasted wind power across the 21 quantiles. These interval forecasts range from the 2nd to the 98th percentile of the wind power predictive distribution, corresponding to quantiles Q₁ to Q₂₁ for each trading period.

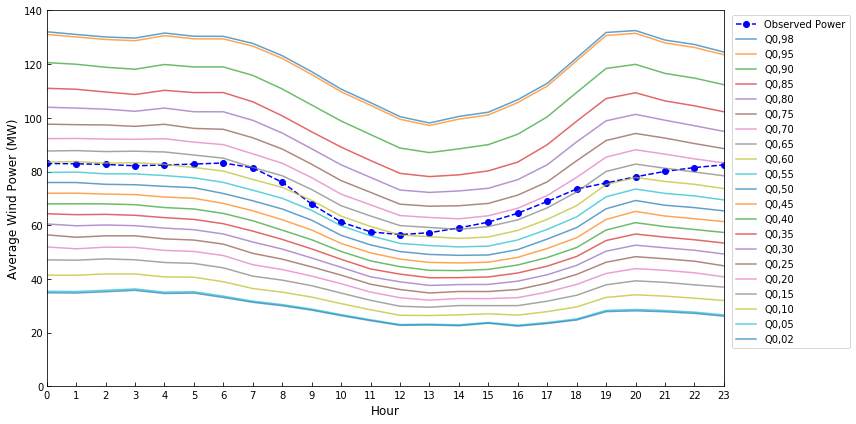
**Figure 3:** Average observed wind power and quantile forecasts per hour of the day.

Figure 4 compares the average hourly values of deterministic forecasts at two different time horizons: between 4 and 9 hours and 15 minutes before real-time operation, against the observed values. It shows that as the forecasting horizon shortens, the deviation from the observed values decreases.

A graph of a number of hours

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**Figure 4:** Average observed wind power and deterministic forecasts per hour of the day.

Table 2 presents key statistics for the forecast deviation (forecast value – observed power) for each forecasting horizon.

**Table 2:** Key statistics for wind power forecasts.

|  |  |  |
| --- | --- | --- |
|  | 4-9h before | 15 min before |
| Min | -143.41 | -23.03 |
| Max | 114.08 | 24.08 |
| Median | 0.45 | 0.27 |
| Mean | -2.03 | 0.02 |
| SD | 22.87 | 2.86 |

Analyzing Figure 4 and Table 2 can be verified the benefits of forecasts closer to real-time operation, being the IDC important to adjust the programming schedules of vRES, reducing imbalances.

* 1. Scenarios

The case study analyses the active participation of the WPP across various markets, aiming to maximize revenue.

Two main cases are considered: (i) an ideal case, where the producer has perfect foresight of market prices and wind power production at the time of delivery, and (ii) an operational case, where the producer relies on forecasts and bidding strategies to navigate uncertainties in the energy markets.

To highlight the evolution and improvements in EMs design, three distinct approaches are explored:

1. Past market design: This approach illustrates the market conditions prior to the introduction of the continuous intraday market. Under this design, the gate closure for the IDA is set a few hours before delivery. According to Portuguese legislation, bids for downward capacity must be half the amount of upward capacity offered in the aFRR market. With increasing competition of WPPs it is assume the price of the reserve energy market instead of the regulated price to CCGTs.

2. Current market design: This design represents the current market, which includes the continuous intraday market with a gate closure 15 minutes before operation. Existing legislation continues to impose restrictions on the procurement of downward capacity. In the simulated period it is assumed that IDC trades have the same price of the DAM trades to overcome the lack of data.

* 1. Results

This section presents the results of the ideal and operational cases. In the ideal case, the WPP has perfect information about its production and market prices. So, it is the case that maximizes the market value of the WPP. The operational case simulates the daily behavior of an active WPP participating in EMs.

* + 1. Ideal case

The outputs of the ideal case are presented in Figure 5.

A graph with different colored rectangular bars

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Figure : Average remuneration for the ideal case in different markets under the past market design.

From Figure 5 can be verified the significant increase of 114% and 84% in the case of the WPP has perfect information when participating in SR, when compared to participating in the DAM, or DAM+IDM, respectively. Furthermore, can be concluded that by participating in the SR, the WPP has the potential to increase their market value by 84% regarding its actual market options. These results indicate the potential benefits of WPPs if electricity markets are designed in adaptation to the stochastic nature of vRES. The WPP perfectly adjusted its position in the IDM for an increase of 16% in its markets value. In the case of participating in the TR, its market value increases to 36%. These results illustrate the high benefit of participating in BMs, mainly in the provision of reserve capacity, as presented in Table 3.

Table : Average hourly values of revenue for the different markets in the ideal case.

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Market Revenue  (k€) | Market | | | |
| DAM | IDM | SR | TR |
| Day-ahead | 2.54 | 3.04 | 1.75 | 3.26 |
| Intraday | - | -0.19 | 0.10 | 0.04 |
| Capacity | - | - | 3.01 | - |
| Energy | - | - | 0.84 | 0.05 |
| Imbalance Settlement | -0.09 | -0.01 | -0.46 | 0.01 |

Analysing Table 3 can be verified that the provision of reserve capacity in SR is the option that provides the higher revenue to the WPPs. Indeed, with increasing levels of vRES, as the main provider of energy, its provision of capacity is important to guarantee the flexibility from the supply-side, avoiding forced curtailments in the case of energy excess.

Table 4 presents the maximum market value of the WPP by introducing the continuous IDM. Analysing Table 4 can be verified that by considering perfect information, the introduction of the IDC only increased the wind market value by 0.41%. However, operationally, the IDC is very important for WPPs adjust their programmed dispatches closer to real-time, as can be verified in Figure 5 and the outputs of the operational case.

Table 5 presents the final results of the ideal case.

Table : Average remuneration for the different market designs in the ideal case.

|  |  |  |
| --- | --- | --- |
| Market Design | **Past** | **Current** |
| Average Remuneration (€/MWh) | 71.41 | 71.70 |

Table : Average hourly values for different market designs in the ide al case.

|  |  |  |
| --- | --- | --- |
| Variables | Market Design | |
| **Past** | **Current** |
| Revenue (k€) | 5.24 | 5.26 |
| DAM traded energy (MWh) | 48.96 | 48.30 |
| IDA traded energy (MWh) | 23.48 | 16.20 |
| IDC traded energy (MWh) | - | 7.98 |
| Allocated Capacity (MW) | 100.90 | 100.43 |
| Activated Reserve (MWh) | 21.04 | 21.10 |
| Imbalances (MWh) | 14.16 | 14.10 |
| Curtailment (MWh) | 3.48 | 3.29 |

Analysing Table 5 can be verified that the mainly difference between the past and current designs is that the IDA energy is now divided between the IDA and IDC. Basically, under perfect information the WPP is gaining from the different prices in IDA and IDC. Naturally, the IDC can reduce imbalances even under perfect information, which is more relevant in the case of the operational case presented in the next section.

* + 1. Operational case

In the operation case it is considered the participation of the WPP in all markets. However, the strategic bidding neglected the TR, because of its competition with SR, being SR more economically advantageous as indicated in section 3.2.1. Figure 6 presents the outcomes of the WPP in the different strategies.

A graph of a number of bars

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Figure : Average remuneration for the operational case in different strategies.

From Figure 6 can be verified the small increase of 18% in the outcomes of the WPP by using different strategic bidding. However, is relevant to notice that S3 increases by 10% the optimal value in the actual marker framework (see IDM output in Figure 5). These results highlight the importance of allowing the participation of vRES, increasing their market value and reducing their imbalances, as presented in Table 6.

Table : Average hourly quantities traded for the different scenarios in the operational mode.

|  |  |  |  |
| --- | --- | --- | --- |
| Variables | Scenario | | |
| S1 | S2 | S3 | |
| DAM traded energy (MWh) | 95.40 | 95.34 | 95.34 | |
| IDA traded energy (MWh) | 34.15 | 21.20 | 20.79 | |
| IDC traded energy (MWh) | - | 23.41 | 15.57 | |
| Capacity allocated (MW) | 10.14 | 10.16 | 17.88 | |
| Upward Reserve Activated (MWh) | 2.86 | 3.72 | 6.49 | |
| Downward Reserve Activated (MWh) | 0.17 | 0.17 | 2.68 | |
| Imbalances (MWh) | 14.64 | 2.31 | 3.53 | |
| Curtailment (MWh) | 3.87 | 2.52 | 5.85 | |

Analysing Table 6 can be verifies the benefit of strategies S2 and S3 from a technical point of view by reducing the imbalances. However, in S2 both imbalances and forced curtailments are lower, being the best strategy from the point of view of the system operator. So, from a technical an economical point of views, S2 and S3 are the best strategies, respectively. Table 7 presents the total revenues from each market.

Table : Total revenue from different markets for the different scenarios under study.

|  |  |  |  |
| --- | --- | --- | --- |
| Total Revenue (M€) | Scenario | | |
| S1 | S2 | S3 |
| DAM | 62.15 | 62.11 | 62.11 |
| IDA | -21.98 | -12.63 | -12.80 |
| IDC | - | -6.28 | -9.54 |
| Upward Capacity | 3.93 | 3.94 | 6.38 |
| Downward Capacity | 1.96 | 1.97 | 3.19 |
| Upward Balancing Energy | 1.90 | 2.51 | 4.65 |
| Downward Balancing Energy | -0.04 | -0.04 | -0.58 |
| Positive Imbalances Cost | 3.17 | 0.44 | 0.83 |
| Negative Imbalances Cost | -5.96 | -0.88 | -0.89 |

Table 7 support previous conclusions. While strategy S3 increases the WPP revenues because of a more significant participation in the SR capacity market, the S2 has lower imbalance costs. In S2 the WPP pays more negative imbalance costs, while in S3 it has more downward balancing energy. So, S3 has more positive imbalances because its reserved capacity is more used for downward regulation.

1. Conclusions

Considering the European targets of increasing penetrations of variable renewables and decommission of fossil-fuel power plants is important to adapt market designs to the behavior of most of their participants (variable renewables). Indeed, security of supply and resilient power systems depend on the balance between demand and supply. Variable renewables shall be incentivized to participate in balancing markets, increasing their market value, decreasing their forced curtailments and the need of de-risking support schemes that contribute to price “cannibalization”, negative prices and market distortions.

This study presents three strategies based on strategic bidding to increase the market value of variable renewables, enabling their market uptake without support schemes. Results from the study proved that by allowing the participation of a WPP in the Portuguese secondary balancing market, it can increase its market value by 10% when compared with the optimal situation without participating in balancing markets. Furthermore, if markets were designed to variable renewables, the WPP has the potential to increase its market value by 84% in the case of perfect foresight and participating in the SR. The outputs of this study highlight the need of adapting electricity market designs to the behavior of variable renewables, incentivizing new investments on them and their active participation in electricity markets without support schemes.

Future work has the goal of testing the market outcomes of variable renewables considering new market designs and their strategic behavior on electricity markets.

**Supplementary Materials:** Python Software

**Author Contributions:** Conceptualization, V.S. and H.A.; methodology, V.S. and H.A.; software, V.S.; validation, V.S. and H.A.; formal analysis, V.S. and H.A.; investigation, V.S. and H.A.; resources, V.S. and H.A.; data curation, V.S. and H.A.; writing—original draft preparation, V.S. and H.A.; writing—review and editing, V.S. and H.A.; visualization, V.S.; supervision, H.A.; project administration, H.A.; funding acquisition, H.A. All authors have read and agreed to the published version of the manuscript.

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**Abbreviations**

|  |  |
| --- | --- |
| aFRR | automatic-activated frequency restoration reserve |
| BM | Balancing market |
| BRP | Balance Responsible Party |
| CCGT | Combined cycle gas turbines |
| CET | Central European Time |
| CfD | contracts for difference |
| DAM | Day-ahead market |
| EM | Electricity market |
| FCR | Frequency controlled reserve |
| FiT | Feed-in tarifs |
| EU | European Union |
| EUPHEMIA | EU Pan-european Hybrid Electricity Market |
| IDA | Auction-based IDM |
| IDC | Continuous IDM |
| IDM | Intraday market |
| IS | Imbalance settlement |
| LCOE | Levelized costs of energy |
| mFRR | manually-activated frequency restoration reserve |
| MIBEL | Iberian market of electricity |
| PV | Photovoltaic |
| RR | Replacement reserves |
| SR | Secondary reserve |
| TR | Tertiary reserve |
| TSO | Transmission System Operator |
| vRES | Variable renewable energy sources |
| WPP | Wind power producer |
| Indices |  |
| j | Probabilistic forecasts quantiles for each hour |
|  | Quantile |
| K | Number of quantiles |
|  | Hours |
| Parameters |  |
|  | Observed power. |
|  | Probabilistic forecast quantiles |
|  | Deterministic forecast hours before delivery in hour t |
|  | Deterministic forecast 15 min before delivery in hour t |
|  | TSO needs for upward balance in the aFRR capacity market |
|  | TSO needs for downward balance in the aFRR capacity market. |
|  | Upward secondary energy requested by TSO. |
|  | Downward secondary energy requested by TSO. |
|  | Upward tertiary energy requested by TSO |
|  | Downward tertiary energy requested by TSO. |
|  | DAM price |
|  | IDA price |
|  | Price received for each unit of balancing capacity in aFRR market |
|  | Price received by BRP with positive imbalances |
|  | Price paid by BRP with negative imbalances |
|  | Price for upward tertiary and secondary energy |
|  | Price for tertiary and secondary energy. |
|  | Price for imbalance for BRP |
|  | Maximum price |
| Variables |  |
|  | Bid in DAM |
|  | Bid in IDA |
|  | Bid in IDC |
|  | Upward capacity allocated |
|  | Downward capacity allocated |
|  | Upward secondary energy activated |
|  | Downward secondary energy activated |
|  | Upward tertiary energy activated |
|  | Downward secondary energy activated |
|  | Energy curtailed |

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