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Strategic Bidding to Increase the Market Value of Variable Renewable Generators in New Electricity Market Designs

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Abstract: Electricity markets with a high share of variable renewable energy require significant balancing reserves to ensure stability by preserving the balance of supply and demand. However, they were originally conceived for dispatchable technologies, which operate with predictable and controllable generation. As a result, adapting market mechanisms to accommodate the characteristics of variable renewables is essential for enhancing grid reliability and efficiency. This work studies the strategic behavior of a wind power producer (WPP) in the Iberian electricity market (MIBEL) and the Portuguese balancing markets (BMs), where wind farms are economically responsible for deviations and do not have support schemes. In addition to exploring current market dynamics, the study proposes new market designs for the balancing markets, with separate procurement of upward and downward secondary balancing capacity, aligning with European Electricity Regulation guidelines. The difference between market designs considers that the wind farm can hourly bid in both (New 1) or only one (New 2) balancing direction. The study considers seven strategies (S1–S7) for the participation of a wind farm in the past (S1), actual (S2 and S3), New 1 (S4) and New 2 (S5–S7) market designs. The results demonstrate that new market designs can increase the wind market value by 2% compared to the optimal scenario and by 31% compared to the operational scenario. Among the tested approaches, New 2 delivers the best operational and economic outcomes. In S7, the wind farm achieves the lowest imbalance and curtailment while maintaining the same remuneration of S4. Additionally, the difference between the optimal and operational remuneration of the WPP under the New 2 design is only 22%, indicating that this design enables the WPP to achieve remuneration levels close to the optimal case.

Keywords: electricity market designs; price arbitrage; probabilistic forecasts; secondary and tertiary reserves; strategic bidding; variable renewable energy sources

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1. Introduction

Globally, wholesale electricity markets work considering three main models: auctions, bilateral contracts, and hybrid approaches that combine elements of both [1–3]. Auctions function as centralized markets where demand and supply participants present bids, with prices established by a marginal pricing algorithm. Bilateral contracts allow demand and supply participants to trade energy directly. Most European Union (EU) countries follow the hybrid model. In this system, the day-ahead market closes at 12:00 p.m. Central European Time (CET) on the day prior to dispatch, pursued by intraday markets, which allow real-time bid adjustments. Some electrical energy markets, such as the MIBEL, Italy, and Germany, use continuous and auction-based intraday sessions, while most of Europe employs continuous intraday trading. Furthermore, bilateral contracts and participation in derivatives markets serve as risk management tools, enabling agents to secure non-volatile energy prices for long periods and thereby reduce their exposure to spot price volatility. Ancillary services play a crucial role in ensuring grid stability by preserving frequency and voltage between secure margins, reducing system imbalances, and improving global network reliability [3–6].

In electricity markets originally designed for dispatchable generation, the increasing share of variable renewable energy sources (vRES), such as wind and solar photovoltaic (PV), necessitates a comprehensive evaluation of whether existing designs remain effective. Since the EU adoption of the First Energy Package in 1996, multiple electricity market reforms have been implemented, the last being the Fifth Energy Package in 2024. It is identified as "Fit for 55" to support its target of reducing net carbon emissions by at least 55% by 2030 relative to 1990 levels [5–10]. Participants in electricity markets represent a heterogeneous group of autonomous actors with varying goals and trading behaviors. On the supply side, market agents typically seek to maximize revenues through wholesale market participation, whereas demand-side agents aim to minimize procurement costs before reselling electricity in the retail segment. Although strategies differ, cooperation among participants is often essential to ensure mutually beneficial outcomes [11–14].

The accelerated integration of vRES has brought significant complexity to market operation. Due to their intermittent and less predictable output, vRES increase the variability and uncertainty of electricity supply, posing challenges particularly for system balancing and ancillary services. While vRES technologies require substantial upfront capital investment, their marginal generation costs are close to zero. As vRES penetration increases, wholesale market prices tend to decline; however, this benefit is offset by the rising costs of ancillary services needed to manage forecast deviations. These deviations typically result in imbalance penalties, which are borne by market participants. In extreme situations—such as large forecast errors—vRES producers may face penalties that exceed their earnings from the spot market [12–17]. Some electricity markets partially shield vRES producers from imbalance-related costs by redistributing them to final consumers. Portugal, for instance, has historically employed feed-in tariffs (FiTs) and other guaranteed remuneration schemes to provide long-term financial certainty for renewable energy investments [6,17,18]. When properly designed, support schemes can be effective in reducing investment risk and shielding vRES deployment from short-term market volatility. Nevertheless, traditional mechanisms such as FiTs and contracts for differences (CfDs) have also introduced market distortions, including price cannibalization, the occurrence of negative prices, and the accumulation of tariff deficits [7,18–20]. As the levelized cost of electricity (LCOE) for vRES continues to decline and electricity prices in Europe surge—particularly in the aftermath of the 2022 gas crisis—more market-aligned and robust support instruments emerge. Instruments such as Financing CfDs and Risk-Sharing Contracts are increasingly used to mitigate exposure to electricity price volatility [21–23]. Notably, these mechanisms have contributed to the occurrence of negative grid access prices for the first time, resulting in real-time retail tariffs that are, in some cases, lower than wholesale market prices [24]. Despite these benefits, support schemes can introduce significant externalities, undermining competitive dynamics in marginal pricing markets that are theoretically grounded in Nash equilibrium conditions [25]. By providing preferential treatment to renewable generators, such mechanisms can distort market outcomes and weaken price signals essential for efficient resource allocation [7,18–20].

The increasing penetration of vRES has also affected market liquidity. Although the falling LCOE improves the economic viability of renewables, financial incentives—such as FiTs—remain important to ensure continued investment in vRES technologies [10,12,21].

However, the price cannibalization effect, particularly for solar PV, and the growing costs of ancillary services emphasize the urgent need for comprehensive market design reforms. These reforms should aim to facilitate the full integration of vRES into wholesale and balancing markets without relying on support schemes [5–9,18–20].

Enhancing flexibility mechanisms and providing appropriate compensation for ancillary service providers will be crucial for maintaining system stability and efficiency in high-vRES scenarios. Importantly, vRES technologies can engage in strategic bidding—both with and without support schemes—and adapt their behavior in response to market signals to enhance their market value [26–35].

A comprehensive literature review on remuneration options for vRES is available in [29]. One study examined the impact of transitioning to a market-based support scheme, revealing that increased exposure to market prices has driven greater price arbitrage by WPPs [30]. The usage of price arbitrage to enhance the market value of vRES has been analyzed in [29–31]. Some studies analyzed the benefits of vRES participating in balancing markets (BMs) [4,5,8,16,27,31–34]. The use of bidding strategies in sequential markets has also been analyzed in the electricity market modeling literature [31–35]. A review on the usage of price arbitrage of vRES in sequential markets including BMs is presented in [31].

In this paper, the performance of vRES in electricity markets without support schemes is assessed by using strategic bidding as the central mechanism. Unlike existing studies, this approach integrates probabilistic generation forecasts into price arbitrage strategies under emerging market designs. This methodology is demonstrated through a case study of a WPP in MIBEL and Portuguese BMs, where WPPs are fully exposed to imbalance costs and do not receive support payments during either stage of MIBEL trading.

Previous results show that, in historical market designs that excluded BM participation, full engagement in tertiary and secondary reserves could have increased the WPP's market value by 36% and 155%, respectively [31]. However, under the current framework—with strategic bidding and vRES participation in BMs—the potential uplift in market value falls to 2% in the ideal scenario and 31% in the operational scenario.

The remainder of this paper is structured as follows: Section 2 presents an overview of European electricity market designs, with a focus on MIBEL. Section 3 outlines the proposed new market design and methodology for the strategic participation of vRES in electricity markets. Section 4 presents a case study and evaluates the effectiveness of the developed strategies. Finally, Section 5 summarizes the findings and discusses their implications for future energy markets.

2. Overview of European Electricity Market Designs

Market participants have the option to trade electricity across five different markets, each serving a specific function within the energy system [3,5]: (i) spot, (ii) continuous, (iii) derivatives, (iv) non-organized bilateral agreements, and (v) ancillary services.

Spot markets allow agents to submit bids of at least 0.1 MW through day-ahead (DAM) and intraday marginal auctions (IDA), where prices are determined based on supply and demand equilibrium using the EU Pan-European Hybrid Electricity Market (EUPHEMIA) [36]. These markets provide short-term trading opportunities and price signals for electricity generation and consumption.

Continuous intraday markets (IDC) facilitate real-time trading, with transactions settled 15 min before delivery. This option enables participants to make last-minute adjustments in response to fluctuations in demand, supply, and grid conditions [37]. Derivatives markets offer financial instruments such as forwards, futures, swaps, and options. These contracts help participants hedge against spot price volatility and uncertainty in energy consumption, providing greater long-term price stability [6].

Non-organized markets consist of private bilateral contracts that allow agents to negotiate directly without using organized exchanges. This flexibility enables them to establish customized terms and conditions for pricing, duration, and delivery, making them suitable for long-term power purchase agreements (PPAs) [22].

Ancillary services markets are managed by Transmission System Operators (TSOs) to ensure grid stability and reliability. These markets procure reserves, frequency regulation, and other balancing services to correct supply–demand deviations of Balance Responsible Parties (BRPs) and maintain system security. Each of these markets plays a crucial role in electricity trading, offering various mechanisms for managing risks, optimizing profitability, and ensuring the stability of the power system. In marginal BMs the clearing process is asymmetrical, i.e., the TSO procurement is completely inelastic, being hourly fixed [38,39]. Imbalance prices are determined within the imbalance settlement (IS) mechanism and are based on deviations from scheduled dispatch. These prices are charged to BRPs according to the cost of the balancing reserves activated to compensate for their imbalances [40].

2.1. Market Design Reforms

In a system originally designed for dispatchable generation, the growing share of vRES requires a thorough assessment to determine whether existing market designs remain effective. Since the adoption of the First Energy Package in 1996, multiple electricity market reforms have been introduced. In 2009, following the Third Energy Package, the European Commission (EC) published the first proposal for regulating the European Internal Market for Electricity (EIME) [41]. During this period, European governments incentivized to invest in non-mature vRES technologies by providing regulated support schemes as FiTs and CfDs, originating market distortions.

In 2016, the EC launched the "Clean Energy for All Europeans" initiative to support the transition to renewable energy and enhance the functionality of the EIME [42]. The following year, the "New EC Proposal" outlined key principles for the EU electricity market, emphasizing competitiveness, consumer focus, flexibility, and non-discrimination to accommodate rising vRES levels in Europe [6,9]. This proposal introduced legislative measures such as a gate-closure of electricity markets closer to the time of delivery, aggregated bidding, a reduction of the market time unit to 15 min, and two key non-discriminatory policies: assigning balancing responsibility and enabling vRES participation in BMs [6,9]. These measures were formally legislated in 2019 as part of the Fourth Energy Package. Regarding BMs, the legislation clearly indicates that there should be a separate procurement of upward and downward capacity [9]. This design is tested in this study to evaluate its potential pros and cons. Furthermore, TSOs are free to develop products to incentivize the participation of vRES in BMs [6,9,39].

In 2024, the Fifth Energy Package, known as "Fit for 55", was enacted to align with the EU's objective of reducing carbon net emissions by at least 55% by 2030 compared to 1990 levels [43]. Building on previous energy reforms and on experience from the 2022 gas crisis, this package introduces key measures aimed at enhancing security of supply, reducing external energy dependency, price volatility and differences between market zones, and fostering competition and rules harmonization within the internal energy market [24]. Now, European governments are incentivizing private investments in vRES considering different market streams, from PPAs, CfDs, and/or their active participation in markets with de-risking mechanisms [10].

2.2. Portuguese Electricity Markets

Portugal and Spain are both part of MIBEL, which oversees spot, continuous derivatives, and bilateral markets. Players can submit up to 24 hourly selling or buying bids with increasing or decreasing prices, respectively. The price-caps of MIBEL are −500 and 3000 EUR/MWh [6,31]. So, price arbitrage and strategic bidding are allowed [29]. Although ancillary services remain nationally operated and are managed by each country's respective TSO, certain services can be exchanged across borders to support system-wide balancing efforts [5,44]. Portugal participates in the European framework for continuous frequency reserves, complying with specific technical and operational requirements for each reserve category [4–6].

For Frequency Containment Reserve (FCR), participation is mandatory and non-remunerated for all technically capable generators connected to the grid. These generators are required to reserve 5% of their nominal power under stable operating conditions to contribute to FCR provision. Portugal is also integrated into the Continental Europe synchronous area, reinforcing its commitment to cross-border frequency stability [4–6].

The automatic Frequency Restoration Reserve (aFRR) in Portugal has historically operated with an asymmetrical power band. As of September 2024, under the previous market design, up-regulation capacity was required to be twice the volume of down-regulation capacity [31]. This asymmetry reflects a system tendency to rely more heavily on upward balancing actions. To comply with ENTSO-E recommendations, the Portuguese TSO adjusted the reserve split, upscaling up-regulation capacity to 60% and downscaling down-regulation to 40%.

AFRR capacity auctions are held hourly, open to all technically qualified generators, with a maximum allowed bid price of EUR 250/MW. Participants must provide both upward and downward regulation capacity, maintaining a 2:1 ratio in favor of up-regulation. However, due to limited market competition, the aFRR segment remains dominated by combined cycle gas turbines (CCGTs). Furthermore, the price of upward aFRR energy is not market-based but is administratively regulated on a quarterly basis by the national energy regulator, using the marginal cost of CCGTs as the reference price [4–6,44].

Since September 2024, the procurement of secondary capacity is symmetrical, such as through bids from market participants, which continues to disincentivize the participation of non-flexible vRES. This measure is a small step forward to encourage the participation of vRES by increasing the downward capacity they can bid [31]. However, as they must bid the same quantity for upward capacity, technically, the participation of vRES in secondary reserves keeps complex and risky. Manual Frequency Restoration Reserve (mFRR) energy is procured through hourly marginal-price auctions, with separate bidding processes for upward and downward regulation. These markets operate under price caps of −1000 EUR/MWh and 10,000 EUR/MWh, respectively. However, because mFRR is structured around hourly intervals, it may be insufficient for correcting prolonged frequency deviations or sustained imbalances [4–6]. To address such long-term imbalances, Replacement Reserves (RRs) are employed. RRs can be activated within 15 min and are designed to remain active over extended durations when neither aFRR nor mFRR is sufficient to restore system balance [4–6,45]. Additionally, extraordinary reserves are procured outside regular market mechanisms. These reserves are based on bilateral agreements between TSOs and market participants, rather than competitive bidding processes [4–6,44]. The IS considers a single penalty and double pricing mechanism with equally distributed penalties, except for BMs participants that pay three times more [31,46].

3. New Market Designs and Strategic Bidding

This section presents a new market design for the secondary capacity market and the respective strategic bidding process.

3.1. New Market Designs

While the secondary capacity market has been designed according to the lack of competition, adapting it to the participation of vRES should surpass this drawback. This work presents two new market designs to procure secondary capacity adapted to the vRES stochastic behavior. To incentivize the participation of vRES, TSOs should separate the procurement of downward and upward secondary capacity. The new designs also provide better price signals for the real-time value of secondary capacity by having double marginal prices, one per direction, instead of a single price for the entire capacity band. Clearly, vRES can easily provide downward capacity according to its programmed schedule. To provide upward capacity, vRES must bid quantity values lower than uncertain forecasts, which is risky [4–6]. Another change to the market design of the secondary capacity consists in having a rolling gate closure, postponing it to after the auction-based intraday (IDA) sessions and in parallel with the sessions of the continuous intraday market (IDC), instead of after the day-ahead market. Currently, vRES must rely on the clearing of IDA and IDC markets to adjust their positions in response to secondary capacity obligations and updated generation forecasts. In proposed market designs, vRES bids for secondary capacity may be automatically adjusted based on the outcomes of the IDC market. This mechanism has the potential to reduce the energy imbalance risk faced by vRES, enhancing their reliability and economic performance in BMs. Furthermore, new designs clear 1 h in 24 rolling sessions instead of 24 h in one single session. This results in a win-win situation for TSOs and vRES because it allows TSOs to define the secondary capacity requirements and vRES to place its bids closer to real-time operation, using more reliable information.

Multiple factors may have contributed to the recent power outage in Spain [46], including (i) the lack of aggregated/hybrid vRES participation in balancing markets; (ii) the absence of fast-frequency reserve services to address low grid inertia; and (iii) the limited deployment of grid-forming inverters by vRES, which, as demonstrated in Ireland, can support coordinated frequency control [4,47]. High solar penetration can also intensify grid stability challenges, contributing to the “duck curve” phenomenon—characterized by reduced grid inertia during daylight hours and steep down and up ramping requirements during sunrise and sunset transitions, respectively [48]. Therefore, vRES can participate effectively in balancing markets without necessarily relying on storage or aggregation, if robust market designs and reliability criteria are applied. Furthermore, the TSO changes to a dynamic procurement of secondary capacity increase the efficiency of the mechanism by adapting reserve procurement to expected needs [49,50]. Thus, by providing market designs that incentivize the participation of vRES, TSOs are increasing competition and reducing the need for fossil fuel participants. In the case of Portugal and countries with the lack of competition for the provision of secondary capacity, changing the market design may open the secondary energy market instead of providing a price defined by the regulator [49]. The only difference between the two new designs is that the first allows hourly bids in both balancing directions, while the second is more disruptive, only allowing bids in one direction, selected by market participants. Table 1 presents the different characteristics of market designs under analysis.

Table 1. Features of the secondary capacity market designs.

Features	Past	Actual	New 1	New 2
Date	By September 2024	Since September 2024	-	-
Direction	Both	Both	Both	One
Gate closure	Day-ahead	Day-ahead	15-min ahead	15-min ahead
Payment	Single marginal	Single marginal	Double marginal	Double marginal
Period	24 h	24 h	1 h	1 h
Procurement	Asymmetrical	Symmetrical	Separated	Separated
size	Asymmetrical	Symmetrical	Dynamic	Dynamic

By analyzing Table 1 from the point of view of vRES, it can be concluded that the actual market design is a small step forward in the active participation of vRES in the secondary reserve. vRES has the technical capability to quickly curtail energy, but it can only provide upward regulation by creating a gap between optimal and operational programming schedules, which is inefficient for a flexible, decarbonized power system [4–6]. The need to curtail vRES means that the system does not have enough flexibility to absorb free-of-cost renewable energy. So, while in the past design players had to bid an asymmetric capacity band where upward capacity doubles downward capacity, practically pushing vRES out of the market, now it is symmetrical. Players that provide upward regulation cannot provide downward regulation at the same time and vice versa, meaning that the maximum usage of the capacity band is 50%, while in the past it was 75%, reducing efficiency [49,50]. From the point of view of the system operation, it means the capacity band increases by 25%, reducing its efficiency. From the point of view of society, costs may also increase by 25%.

The first market design allows vRES to bid quantities in both balancing directions, making it the most flexible. In the second new market design, they can only bid in one direction, potentially increasing the usage of the capacity band to 100%. Against this background, the proposed new market designs can potentially (i) provide incentive for the active participation of vRES, (ii) increase the efficiency of the allocated capacity band, (iii) reduce costs, (iv) provide better price signals according to the balancing needs direction, (v) increase competition, (vi) free up fast response power plants to participate in other markets or ancillary services. The second new market design may be more efficient, although it may not satisfy all TSOs' needs in the case of small competition. However, the separate procurement of upward and downward tertiary reserves is not a problem. So, by allowing the participation of vRES in the secondary market, the increase in competition may surpass this drawback.

3.2. Probabilistic Quantile-Based Forecasts and Price Arbitrage

The provision of reserves by vRES may reduce the need for fast-responsive fossil fuel power plants to provide this service, but it may also curtail some of the renewable production, which is inefficient for decarbonization. Against this background, hybrid vRES complementary solutions with storage capacity are a good approach to balance upward and downward balancing energy with storage [26–28]. Indeed, because of the price "cannibalization" effect in MIBEL during the day, caused by the high solar PV investments in Spain, Portugal already economically incentivizes public solar PV auctions with storage capacity. Furthermore, these solar PV power plants reserved 140 MW of power capacity to support the secondary reserve [31,49–51]. So, they can "charge" or "discharge" storage if they are activated for downward or upward regulation, respectively. Moreover, in spot markets, they can use price arbitrage to decide their participation according to market prices [29,52]. So, they can bid quantities lower or higher than the deterministic forecast when market prices are low or high, respectively. However, while vRES with storage does not face risks with this strategy, vRES without storage risks forecast errors and paying penalties for their deviations. So, as vRES participates in markets considering forecast errors, spot market prices are computed with a certain degree of uncertainty. Indeed, only during real-time operation and after activating balancing reserves is it possible to compute the real wholesale price of electricity. So, in the case of expected energy excess, when spot prices are low, zero, or even negative, vRES may have an economic loss if they do not assume a risk-aversion attitude, considering it better to reduce their bid quantity to avoid economic losses [52]. Contrariwise, when prices are high, vRES may assume a riskier position, bidding higher quantities and using price arbitrage. Marginal markets were designed to receive bids based on marginal costs, but vRES bids based on uncertain forecasts and is significantly penalized if they fail to comply with programmed dispatches [31].

The forecasting methodology employed in this study consists of two components: day-ahead probabilistic quantile-based forecasts and intraday deterministic point forecasts. Both are generated using the K-Nearest Neighbor (KNN) approach, which is trained on historical data from a Numerical Weather Prediction (NWP) model [5,33,53–55]. Day-ahead probabilistic forecasts support price arbitrage strategies in the DAM, while deterministic forecasts are used for quantity arbitrage in the intraday and balancing markets.

The forecasting system operates in real time and is initialized using data from the Global Forecast System (GFS), which provide a set of meteorological variables at an hourly resolution with a forecasting horizon of up to 42 h [5,33]. Probabilistic quantile-based forecasts have demonstrated their effectiveness in managing the trade-off between risk and expected revenues, thereby enhancing the market value of vRES when applied to cross-market arbitrage strategies [31].

In most electricity markets, participants are allowed to submit multiple bids for the same trading period. In MIBEL, supply-side participants may submit up to 24 ascending-price bids per period, enabling a detailed representation of their marginal cost structures. Therefore, in this study, vRES use price arbitrage by using K forecast quantiles $Q_{k,t}$ considering a price range from 0 to n EUR/MWh (the maximum bidding price), with uniform rises among consecutive quantiles. The highest quantile is matched when the DAM market price, C_t^{DAM}, is higher than the maximum price defined by the vRES operator, $C_t^{DAM} \geq n$. The maximum bidding price can be determined based on several criteria, including (i) the LCOE of the vRES technology, (ii) market price dynamics, (iii) strategic bidding behavior, (iv) the market price-cap, and (v) other market-specific strategies. In this study, the maximum bidding price parameter n is derived from market price dynamics, as detailed in [31]. This approach is conceptually like the method used for calculating the water value of pumped hydro storage power plants [26]. The key distinction lies in the methodology. While vRES bids rely on quantile-based generation forecasts, the water value uses a dynamic pricing strategy analogous to the relative reservoir storage level—setting the value to zero when the reservoir is full (100%) and to n when it is empty (0%).

Thus, considering the maximum number of allowed bids, the $Price\ Interval_k$ for each k quantile number from 1 to K (from $Q_{0.02}$ to $Q_{0.98}$) is given by the following formula [31]:

$$Price\ Interval_k = \left[\frac{(k-1)}{K} \cdot n,\ \frac{k}{K} \cdot n\right] \tag{1}$$

Therefore, instead of bidding the whole quantity for their near-zero marginal costs, they may use price arbitrage, defining a price for each quantile. Twenty-one quantiles are considered, from 2% ($Q_{0.02}$) to 98% ($Q_{0.98}$), with a price equal to zero at $Q_{0.02}$, and the maximum bidding price of n at $Q_{0.98}$ [31]. The consecutive quantiles from $Q_{0.02}$ to $Q_{0.98}$ are bid into the DAM, and the bids are accepted up to the $(k-1)$ quantile below the DAM price, C_t^{DAM}, if the bid price falls within the price interval, as expressed in [31]:

$$\frac{(k-1)}{K} \cdot n \leq C_t^{DAM} < \frac{k}{K} \cdot n \tag{2}$$

vRES can use probabilistic quantile-based forecasts to balance between price and risk. When spot prices are low, vRES technologies may assume a risk-aversion preference, bidding low-risk quantiles with the highest probability of having programming schedules lower than their observed power, "charging" storage or curtailing energy to not pay penalties. Contrariwise, when spot prices are high, they may assume a risk-seeking appetite, bidding high-risk quantiles with the highest probability of having programming schedules higher than their observed power, "discharging" storage or buying energy from subsequent markets to avoid paying penalties. Indeed, by using this strategy, vRES technologies are assuming flexibility in spot markets, reducing the spot price volatility and adapting themselves to the system needs according to the price signals. This adaptive, price-receptive strategy optimizes market involvement by positioning bids with anticipated remuneration, enhancing profitability and efficiency. Next section presents the strategies employed by using the quantile-based forecast with price arbitrage.

3.3. Strategic Bidding

The objective of maximizing revenues for vRES producers is framed as an optimization problem, implemented in Python v3.7.3 (the corresponding code is available in the Supplementary Materials). In this formulation, the decision variables correspond to the volumes traded across various electricity markets, subject to regulatory and operational constraints. A set of general constraints is imposed to ensure feasibility. Market schedules are capped by the nominal capacity of the wind power plant, preventing the producer from offering more energy than can be technically delivered. Moreover, the volume of downward balancing capacity bids cannot exceed the scheduled energy injection. Participation in balancing markets is additionally limited by the TSO's reserve activation requests. The model captures the interdependence of vRES participation across market stages through key operational concepts. The position denotes the net energy portfolio of the vRES producer, initially defined by the day-ahead market (DAM) bids and subsequently adjusted by purchases or sales in the intraday market (IDM). The final offer represents this updated position after participation in the secondary capacity market, but before reserve energy activation, thus serving as an intermediate step, reflecting capacity market commitments. The final schedule incorporates reserve activations requested by the TSO, adjusting the scheduled energy to reflect actual grid injections—this increases with upward reserve activations and decreases with downward ones. Finally, the deviation captures the discrepancy between actual energy production and the final schedule, which is settled in the IS mechanism. These interconnected elements are essential for modeling the strategic behavior of vRES across market layers and understanding how decisions at each stage influence overall financial outcomes.

The maximum total revenue, R_t, in the ideal case at hour t is given by

$$R_t = \max_k \left(R_{k,t}^{DAM} + R_{k,t}^{IDA} + R_{k,t}^{IDC} + R_{k,t}^{CAP} + R_{k,t}^{EN} + R_{k,t}^{IS} \right) \tag{3}$$

where

1. $R_{k,t}^{DAM}$, $R_{k,t}^{IS}$ are revenues from the DAM and IS, respectively;
2. $R_{k,t}^{IDA}$, $R_{k,t}^{IDC}$ are revenues from the auction-based and continuous intraday markets, respectively;
3. $R_{k,t}^{CAP}$, $R_{k,t}^{EN}$ are the reserves revenue from capacity and energy markets.

The formulation for the ideal case under perfect market foresight, the operational case, and the complete market remuneration formulation are presented in [31]. The formulation is constrained by MIBEL market regulations, which permit a maximum of 24 price-differentiated bids per period. Additionally, the scheduled dispatch resulting from market clearing must not exceed the installed capacity of the vRES units, nor can it be negative. Consequently, price arbitrage is employed as a response to market price signals within the operational limits of vRES, rather than as a greedy, profit-maximizing, or speculative strategy. This ensures compliance with regulatory constraints while enhancing the economic efficiency of vRES participation.

Seven strategies were developed, the first centered on market design by September 2024. It assumes that an aFRR capacity market operates concurrently with the IDC market. Participation in the secondary reserve (SR) is limited to positive imbalances.

The second and third strategies consider the actual market design. In S2, the bid for upward capacity is limited by the available capacity, whereas the bid for downward capacity is constrained by the current operational position of the vRES. In S3, the upward SR offer is not limited by the available capacity. Unlike in S2, this approach enables the vRES to offer equal capacity for both upward and downward regulation, regardless of the forecasted surplus. This expands the vRES's market participation by allowing higher bids in both directions. However, it also introduces additional risk, as the vRES may need to procure extra energy in IDMs or pay imbalances in IS if its actual generation is insufficient. S4, based on the first new market design (New 1), considers that vRES submits bids in both directions when a positive deviation occurs, offering the expected surplus for upward regulation and the current position for downward regulation. In the case of negative deviations, the vRES purchases the deficit in IDC and bids its new position for downward regulation. The last three strategies considered the second new market design (New 2) and explored varying levels of participation in the SR. In S5 vRES can only bid in one direction at a time. When a positive deviation occurs, it submits bids exclusively for upward capacity, without participating in SR for negative deviations. In S6, for positive deviations, the vRES submits bids for upward regulation. In the case of negative deviations, the vRES procures the shortfall in the IDC and subsequently offers its updated position for downward SR. In S7, when the deviation is positive, the vRES sells the excess in the IDC and offers its updated position for downward regulation. In the case of negative deviations, the vRES procures the shortfall in the IDC and subsequently offers its new position for downward SR. The participation details for these strategies are outlined in Table 2 and illustrated in Figure 1.

Table 2. Strategic bidding of vRES in strategies S1 to S7.

Strategy	Market Design	Deviation in IDC	
		Positive	**Negative**
S1	Past	Bid excess to upward SR	No participation in SR
S2	Actual	Same as S1	Same as S1
S3	Actual	Like S2 but not restricted to available capacity	Same as S1
S4	New 1	Bid to upward and downward SR	Buy deficit in IDC and bid new position to downward SR
S5	New 2	Same as S1	Same as S1
S6	New 2	Same as S1	Same as S4
S7	New 2	Sell excess and bid to downward SR	Same as S4

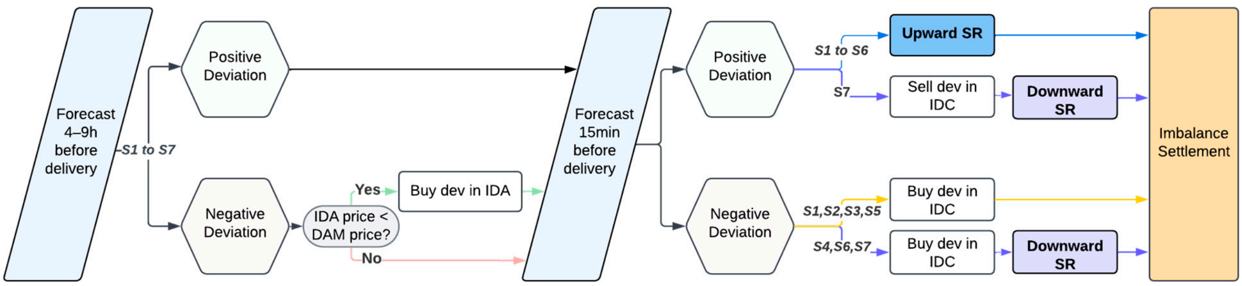

Figure 1. Strategic bidding of vRES in subsequent electricity markets using strategies S1 to S7.

Table 2 and Figure 1 illustrate how vRES producers adapt their bidding strategy based on market price conditions and deviations, aiming to optimize revenues while minimizing imbalance risks.

In these strategies, the deviation 15 min before delivery is calculated by determining the difference between the forecasted value and the vRES position at the time of the IDC.

The deviation is calculated as:

$$E_t^{dev} = E_t^{15\text{min}} - E_t^{position} \tag{4}$$

where
$E_t^{15\text{min}}$ is the forecasted value 15 min before delivery and $E_t^{position}$ is the vRES position at the time of the IDC, which can be higher than the bid in DAM if the producer sold energy in the IDA, or lower if the producer was a buyer in the IDA. The average remuneration, $\overline{R}$ (EUR/MWh), for the study period is calculated by dividing the total revenue across all hours by the total observed production, E_t^{obs}, for the same period $t \in T$ (total number of periods).

$$\overline{R} = \frac{\sum_{t=1}^{T} R_t}{\sum_{t=1}^{T} E_t^{obs}} \tag{5}$$

4. Case Study

This case study analyses a price-taker WPP with 250 MW participating in MIBEL and the Portuguese BMs during the 2009–2010 period, covering a total of 17,088 hourly intervals. The WPP is assumed to operate without any support scheme and to be fully responsible for its imbalance costs. The primary objective is to maximize the plant's remuneration by optimizing its market participation strategy. This section presents the defined scenarios, describes the strategic approaches adopted, and discusses the resulting performance outcomes.

4.1. Scenarios

This case study evaluates the WPP's active participation in multiple markets with a revenue-maximizing behavior. A detailed statistical assessment of the WPP's output, quantile-based forecast accuracy, and pricing strategy is documented in [31].

Two contrasting scenarios frame the analysis: (i) ideal scenario—the producer possesses perfect foresight of both market-clearing prices and wind generation at delivery time; (ii) operational scenario—the producer depends on probabilistic forecasts and strategic bid adjustments to manage uncertainty.

To illustrate how secondary (aFRR) capacity procurement has evolved, we examine four distinct market designs:

1. Past: Asymmetrical bids, where upward doubles downward capacity.
2. Actual: Existing legislation force constraints on the procurement of secondary capacity considering symmetrical bids for upward and downward capacity.
3. New 1: This proposed market design separates the procurement of upward and downward balancing capacity in the secondary market, aligning with the new EIME legislation and European Balancing Guidelines. The secondary capacity market features a gate closure 15 min before delivery, in parallel with IDC.
4. New 2: Similar to New1, but players can only bid in one balancing direction.

4.2. Results

This section presents the results of the employed scenarios, considering the developed strategies in Section 3.3 to the market designs discussed in Section 3.1.

4.2.1. Ideal Case

The outputs of the ideal case considering the participation of the WPP in all markets under the four market designs are presented in Table 3.

Table 3. Average hourly values for different market designs in the ideal case.

Variables	Market Design			
	Past	**Actual**	**New 1**	**New 2**
Remuneration (EUR/MWh)	85.77	104.76	106.75	80.07
DAM trades (MWh)	61.13	56.70	63.82	62.26
IDA trades (MWh)	9.40	8.03	7.45	15.40
IDC trades (MWh)	5.91	5.02	5.01	11.68
Allocated Capacity (MW)	147.23	216.56	176.55	119.10
Activated Reserve (MWh)	24.10	18.75	21.36	12.07
Imbalances (MWh)	20.69	26.81	24.82	18.27
Curtailment (MWh)	3.62	3.27	2.85	1.89

By analyzing Table 3, it is possible to verify that the actual market design significantly improved the potential for the WPP to increase its market value under perfect operational and market foresight. The first new market design slightly improved its remuneration by allowing more flexibility in the bidding process. Furthermore, the second new market design has the worst potential for increasing the market value of the WPP, but it is the one with more technical benefits for the operation of the power system by reducing imbalances and curtailments. Moreover, by reducing curtailments, it also increases the share of vRES in markets, contributing to the society decarbonization.

The actual market design allows us to increase the allocated reserve capacity of the WPP, but not necessarily its activated reserved energy, confirming the reduced efficiency of this design when compared to the others, as described in Section 3.1.

4.2.2. Operational Case

In the operational case, the WPP participates in all markets. However, the strategic bidding approach excludes the tertiary reserve due to its competition with the SR, which was identified as the more economically advantageous option, as discussed in Section 3.3.

Table 4 presents the main outcomes of the operational case.

Table 4. Average hourly values for different strategies in the operational case.

Variables	Strategy						
	S1	**S2**	**S3**	**S4**	**S5**	**S6**	**S7**
Ideal (EUR/MWh)	85.77	104.76	104.76	106.75	80.07	80.07	80.07
Remuneration (EUR/MWh)	42.65	43.94	47.94	63.01	40.71	49.97	62.29
Difference to ideal (%)	−50%	−58%	−54%	−41%	−49%	−38%	−22%
DAM traded energy (MWh)	98.73	100.77	100.77	99.57	99.38	99.38	99.38
IDA traded energy (MWh)	22.39	23.33	23.33	22.78	22.68	22.68	22.68
IDC traded energy (MWh)	16.59	18.47	18.47	15.77	15.80	15.80	28.08
Allocated capacity (MW)	17.05	19.70	50.15	70.32	12.28	38.34	67.98
Activated reserve (MWh)	6.43	5.68	6.18	8.59	6.40	7.87	4.43
Imbalances (MWh)	2.84	2.54	9.11	3.44	2.83	3.21	2.77
Curtailment (MWh)	3.94	3.13	3.16	5.95	4.33	5.33	3.32

By analyzing Table 4, it can be concluded that strategies S4 and S7 result in the highest increase in the market value of the WPP. Furthermore, S7 decreases the WPP market value by only 1% when compared to S4. Moreover, it also decreases the imbalances and curtailments by 19% and 44%, respectively. Against this background, it can be concluded that the second new market design provides practically the same remuneration to WPPs with significantly lower risk. Indeed, in S7, by providing only downward capacity the WPP, there is nearly no risk for practically the same remuneration as in S4. Both strategies increase the WPP market value by more than 30% when compared with the best strategy of the actual market design (S3). So, it can be concluded that the second new market design is the most adapted to the stochastic behavior of the WPP, as it reduces its market value by only 22% compared to the ideal case. The strategies employed considering new market designs have better performance by obtaining remunerations closer to optimal when compared to past and actual market designs.

Analyzing Tables 3 and 4 reveals that the level of vRES participation in reserve markets is substantially higher in the ideal case, mainly because of the non-existent imbalance risk compared to the operational case. Furthermore, while the current market design appears to maximize vRES participation in reserves under ideal conditions, it is the new market designs that achieve higher levels of allocated and activated reserves in the operational scenario with smaller imbalances. These findings indicate that the proposed market designs are better aligned with the stochastic nature of vRES generation, thereby reducing the risks associated with reserve market participation.

Table 5 presents the total revenues from each market.

Table 5. Total revenues for the different strategies in the operational mode.

Total Revenue (M EUR)	**Strategy**						
	S1	**S2**	**S3**	**S4**	**S5**	**S6**	**S7**
DAM	64.22	65.47	65.47	64.74	64.62	64.62	64.62
IDA	−13.66	−14.15	−14.15	−13.86	−13.82	−13.82	−13.82
IDC	−10.30	−10.32	−10.32	−10.76	−10.71	−10.71	−4.75
Upward capacity	6.10	5.23	12.62	6.66	6.68	6.68	0.00
Downward capacity	3.05	5.23	12.62	28.77	0.00	12.29	34.17
Balancing energy	4.32	3.99	4.08	3.65	4.55	3.88	−1.62
Positive imbalances cost	0.65	0.55	0.56	0.86	0.62	0.77	0.64
Negative imbalances cost	−0.90	−0.91	−10.76	−1.03	−0.89	−1.05	−1.15

By analyzing Table 5, it can be concluded that the WPP is using IDMs to buy the energy it needs to comply with reserve schedules most of the time. Furthermore, the DAM keeps the most liquid market being the others used for price and quantity arbitrage. Interestingly, in S3 and S7, the revenue from allocated capacity is more than half of the DAM, significantly contributing to the increase in the market value of the WPP. Indeed, its remuneration for allocated capacity is higher than for activated energy. In S5, only upward capacity has been allocated, and its revenue is higher than for activated energy. Naturally, as in S7 only the downward capacity has been allocated, the revenue from activated energy is negative.

To conclude, New 2 is the best design from an operational point of view. It increases the efficiency of the power system and has the potential to reduce the costs of electrical energy. S7 is the best strategy considering the return/risk ratio of the WPP. This work reinforces the need for adapting designs of balancing markets to the stochastic behavior of vRES towards carbon-neutral societies.

5. Conclusions

Given the European objectives to significantly increase the share of variable renewable energy sources (vRES) and progressively phase out fossil fuel-based generation, electricity market designs must evolve to better reflect the operational characteristics of key actors—especially vRES—and demand-side participants. Maintaining system security and resilience hinges on the ability to continuously balance electricity supply and demand. This study reviews ongoing reforms in European electricity market design, emphasizing the need to integrate vRES more effectively. To improve their market value, minimize curtailment, and reduce dependence on risk-mitigating support schemes—which often lead to price cannibalization, negative pricing, and broader market distortions—vRES should be actively incentivized to engage in balancing markets (BMs).

Against this background, the study introduces two new market designs for the procurement of secondary reserves, tailored to the stochastic nature of variable renewables while also aligned with European balancing reserve guidelines. Both approaches implement the separate procurement of secondary capacity, but they differ in key aspects. The first design (New 1) allows market participants to submit independent bids for upward and downward regulation. In contrast, the second design (New 2) restricts participants to bidding in only one direction at a time, thereby addressing inefficiencies present in both the current framework and New 1, where a single participant cannot be activated for both upward and downward regulation simultaneously. To further explore the impact of market design adaptations, the study examines seven strategic bidding approaches (S1 to S7) aimed at increasing the market value of variable renewables and facilitating their integration without the need for support schemes. These strategies were applied within the Iberian electricity market and Portuguese balancing markets. S1 reflects the past balancing market framework, S2 and S3 represent the current market design, S4 corresponds to New 1, and S5 to S7 pertain to New 2. The results demonstrate that enabling a wind power plant (WPP) to participate in the Portuguese secondary balancing market under an adapted design can increase its market value by 2% compared to the optimal scenario and by 31% relative to the operational scenario. Among the tested designs, New 2 delivers the best operational and economic performance. S7 achieves the lowest imbalance and curtailment levels while maintaining the same remuneration as S4 (New 1). Furthermore, the difference between the optimal and operational revenues of the WPP under New 2 is only 22%, indicating that this market design allows WPPs to achieve near-optimal remuneration when compared to the actual market design with a difference of 54%.

The main limitation of this study is the adoption of the price-taker approach, which is appropriate for analyzing the strategic behavior of market participants without market power. However, it does not fully capture the reality that multiple vRES may adopt similar revenue-maximizing strategies, potentially influencing market outcomes collectively. So, future research will focus on assessing market outcomes for variable renewables under the price-maker approach, analyzing the impact of their price and quantity arbitrage strategies on electricity prices across different markets.

Supplementary Materials: The Python code and only one day of representative wind aggregation data, because of confidentiality reasons, is provided in https://github.com/hugoalgarvio/vRESBids (accessed on 13 March 2025).

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Abbreviations

aFRR	Automatic-activated frequency restoration reserve
BM	Balancing market
BRP	Balance responsible party
CCGT	Combined cycle gas turbine
CET	Central European Time
CfD	Contracts for difference
DAM	Day-ahead market
EU	European Union
EUPHEMIA	EU Pan-European Hybrid Electricity Market
FCR	Frequency containment reserve
FiTs	Feed-in tariffs
GFS	Global forecast system
IDA	Auction-based IDM
IDC	Continuous IDM
IDM	Intraday market
IS	Imbalance settlement
KNN	K-nearest neighbor
LCOE	Levelized costs of energy
mFRR	Manually activated frequency restoration reserve
MIBEL	Iberian market of electricity
NWP	Numerical weather prediction
PPA	Power purchase agreement
PV	Photovoltaic
RR	Replacement reserve
SR	Secondary reserve
TSO	Transmission system operator
vRES	Variable renewable energy source
WPP	Wind power producer
Indices	
k	Quantile number
K	Number of quantiles
t	Hours
T	Total number of hours
Parameters	
C_t^{DAM}	DAM price
$E_t^{15\text{min}}$	Deterministic forecast 15 min before delivery in hour t
E_t^{obs}	Observed energy
$Q_{k,t}$	Probabilistic forecast quantiles
n	Maximum price
Variables	
E_t^{dev}	Deviation
$E_t^{position}$	Programmed dispatch 15 min before real-time operation
$\overline{R}$	Average remuneration
R_t	Hourly total revenue
$R_{k,t}^{CAP}$	Revenue from capacity reserve markets
$R_{k,t}^{DAM}$	DAM revenue
$R_{k,t}^{EN}$	Revenue from energy reserve markets

$R_{k,t}^{IDA}$	IDA revenue
$R_{k,t}^{IDC}$	IDC revenue
$R_{k,t}^{IS}$	IS revenue

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