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Strategies to Incentivize the Participation of Variable Renewable Energy Generators in Balancing Markets

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Abstract: Balancing markets (BMs) play a crucial role in ensuring the real-time equilibrium between electricity demand and supply. The current requirements for participation in BMs often overlook the characteristics and capabilities of variable renewables, limiting their effective integration. The increasing penetration of variable renewables necessitates adjustments in the design of BMs to support the transition toward carbon-neutral power systems. This study examines the levels of active market participation for a wind power producer (WPP) in the Iberian Electricity Market and the Portuguese BMs. In addition to exploring current market dynamics, the study tests one methodology proposed by the Danish Transmission System Operator to support the participation of variable renewables in BMs, the P90, and two new methods based on the full cost balancing concept. These methodologies incentivize WPPs to minimize imbalances by allowing market participation only if imbalances remain within a 10% deadband of annual hours (P90), hourly offers (D90), or both (DP90). The results indicate that participating in the secondary capacity market, particularly for downward capacity, is the most profitable strategy. This participation enhances the value of wind power by over 42%. However, in most methodologies, the WPP failed to deliver nearly 100% of its allocated capacity approximately 1% of the time. In contrast, the D90 approach limited the maximum deviation to 10%, demonstrating the highest reliability among the evaluated methods.

Keywords: balancing markets; balancing reliability requirements; full cost balancing; secondary reserve; variable renewables; wind power

Academic Editor: Tek-Tjing Lie

Received: 24 April 2025
Revised: 22 May 2025
Accepted: 23 May 2025
Published: 27 May 2025

Citation: Algarvio, H.; Sousa, V. Strategies to Incentivize the Participation of Variable Renewable Energy Generators in Balancing Markets. *Energies* **2025**, *18*, 2800. https://doi.org/10.3390/en18112800

1. Introduction

Globally, wholesale electricity markets operate under three primary models: auctions, bilateral contracts, and hybrid models [1–3]. Auctions function as centralized markets where supply and demand agents submit bids, with prices determined through a marginal pricing algorithm. Bilateral contracts enable supply and demand agents to negotiate agreements directly [4]. Hybrid models incorporate elements of both, combining auction-based trading with bilateral contracts.

Most European countries adopt the Internal Market of Electricity (EIME) hybrid model. In this framework, the internal day-ahead market closes at 12:00 p.m. (CET) on the preceding day, followed by intraday markets that allow real-time bid adjustments, considering auction-based intraday sessions, continuous intraday trading, or both [5,6]. Additionally, private bilateral contracts and derivatives markets serve as risk management tools, enabling agents to secure fixed energy prices over extended periods and mitigate exposure to spot market volatility [4]. Ancillary services play a crucial role in maintaining grid stability by regulating frequency and voltage, mitigating system imbalances, and enhancing overall network reliability. The most common are the balancing markets, being three obligated towards EU, the frequency containment reserve (FCR) and the automatic (aFRR) and manual frequency restoration reserves (mFRR), also known as primary, secondary, and tertiary reserves. Some countries also consider the fast frequency reserve (FFR) to support FCR and provide grid inertia [6–8].

The rapid deployment of variable renewable energy sources (vRES)—notably wind and solar PV—has introduced complex challenges to electricity markets [9–11]. Their variable output elevates supply fluctuations and uncertainty, driving up system integration expenses, especially for ancillary services [12–14]. Although vRES installations demand substantial upfront capital, their marginal cost of generation is almost zero. As vRES penetration rises, wholesale spot prices tend to fall, but costs for ancillary services climb due to discrepancies between forecasted and actual output, which must be managed through balancing actions. These imbalance costs are usually passed on to market participants via penalty mechanisms. In severe instances, significant forecast errors can lead to penalties that surpass the vRES producers' spot-market earnings [15–17]. To shield renewable generators, some systems reassign these costs to consumers. Portugal's feed-in tariffs (FITs) and other guaranteed-payment schemes are a prime example—while they have stabilized revenue for vRES, they have also distorted market signals, causing price "cannibalization" and frequent low or negative prices [16–22].

With vRES comprising an ever-larger share of generation, it is imperative to revisit and adapt market designs to function effectively in a renewables-dominated regime [10,11,23,24]. Traditional market designs, built around dispatchable plants, offer little incentive for standalone vRES unless paired with flexible assets or configured as hybrid installations [25–28]. Moreover, increased vRES volumes have eroded market liquidity. Even though vRES boast a low levelized cost of energy (LCOE), mechanisms like FiTs remain vital to attract investment—particularly for wind farms [18–23]. Solar PV has, in many regions, reached subsidy-free competitiveness, yet the climbing costs of ancillary support services underscore the pressing need for market reform [6–8]. Going forward, reinforcing system flexibility and establishing fair compensation for providers of balancing services will be essential to uphold grid reliability and efficiency in high-vRES scenarios. Simultaneously, vRES operators can refine their bidding strategies—with or without state support—to maximize their market returns [23,25,28–31].

Electricity markets, originally designed for dispatchable generation, must be reassessed considering the increasing share of vRES. Since the European Union (EU) adoption of the First Energy Package in 1996, multiple electricity market reforms have been implemented, with the most recent being the Fifth Energy Package in 2024. Known as "Fit for 55", this package aims to reduce net carbon emissions by at least 55% by 2030 relative to 1990 levels [32–34]. Indeed, the legislation for the EIME indicates that markets shall be designed for competitive non-discriminative free fluctuations of prices without externalities [5,6]. While in day-ahead and intraday markets the legislation supports rules harmonization, for balancing purposes it indicates that Transmission System Operators (TSOs) shall adapt balancing markets (BMs) and provide new products to enable the participation of vRES and demand-side players on them [35–37]

This study analyzes the active market participation by a wind power producer (WPP) in the Iberian Electricity Market (MIBEL) and the Portuguese BMs. In addition to examining current market dynamics, it evaluates a methodology proposed by the Danish TSO to enhance the participation of variable renewables in BMs—namely, the P90 approach—alongside two novel methods based on the full cost balancing concept [38,39]. These methodologies incentivize WPPs to minimize imbalances by restricting market participation to instances where imbalances remain within a 10% deadband, assessed based on annual hours (P90), hourly offers (D90), or both criteria combined (DP90).

The remainder of this paper is structured as follows: Section 2 provides a literature review on the participation of vRES in balancing markets, with a focus on MIBEL. Section 4 outlines the proposed new market design and methodology for the strategic participation of vRES in electricity markets. Section 5 presents a case study and evaluates the effectiveness of the developed strategies. Finally, Section 6 summarizes the findings and discusses their implications for future energy markets.

2. Literature Review on the Participation of vRES in Balancing Markets

A comprehensive literature review on various remuneration options for vRES is available in [28]. 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 [29]. A review on the vRES technical capability to provide inertial and frequency response [7,40], on their participation in balancing markets [8], and on their strategic bidding behavior [30] has been presented in the literature. Different control strategies have been considered to allow vRES to provide frequency control [7]. Studies on different market designs of ancillary services have been considered to incentive the participation of vRES [8,32,34,38–45]. Additional research on bidding strategies in sequential markets is significantly discussed in the electricity market modelling literature [6,11,28,30,31,37,42,43,46,47].

A study on a WPP operating in the Danish electricity market proven that strategic participation in the day-ahead market (DAM) and BMs led to a 6.5% raise in the market value of wind power [31]. This output underscores the prospective advantages of adaptable, market-aware exchange strategies. This strategy not only enhance the remuneration of the WPP but also support their seamless integration into the power system. By engaging in multi-market involvement, vRES can mitigate forecast errors, optimize revenue streams, and contribute to grid stability, eventually improving their economic viability.

A study considered the participation of an electric vehicles' aggregator in the Danish reserves considering the P90 requirements [38]. They used the Distributionally Robust Joint Chance Constrained Program to define the bidding strategy of the aggregator. They developed a heuristic based on a grid search approach to support the TSO in adjusting both the P90 reliability requirement and the level of conservativeness, with the objective of maximizing the procurement of reserve capacity from variable resources while minimizing the expected shortfall. The authors concluded that the aggregator mainly could comply with P90 requirements if the radius of the Wasserstein ambiguity is higher than 0.35. However high the radius, higher is the risk aversion of the aggregator, reducing its bided quantity to reserves. From the point of view of the TSO, the violation frequency between [0.05, 0.3] and the radius between [0.1, 0.6] maximize the total flexibility it procures. Furthermore, it has been concluded that the TSO shall define a maximum imbalance limit to reduce the risk of P90.

A remuneration evaluation of a WPP supporting the Swedish BMs identified the most lucrative strategy as the combined engagement in the DAM and secondary downward regulation. This approach was shown to breed extra remuneration of 35% when compared to only DAM participation under perfect information and 22% when considering forecast errors [46].

A study analyzing the involvement of WPPs in the DAM and Portuguese BMs examined four scenarios using the same dataset as the present study. The findings indicated that allowing the participation of WPPs in the tertiary market with 15 min products led to revenue increases of 4.9%. Furthermore, an optimized BM design, along with a newly developed short-term power purchase agreement (PPA) electronic trading platform tailored to WPPs' stochastic behavior, could further enhance their market value by 25%. A comprehensive summary of the obtained results, comparing the conventional deterministic forecasting methodology to the active participation of WPPs in electricity markets, is provided in [11]. Notably, all tested scenarios showed an increase in wind power value relative to the baseline, where only the deterministic forecast was applied to the DAM. These results highlight the importance of WPPs participation in BMs, demonstrating their potential to reduce reliance on support schemes and facilitate their integration as active market players [8].

More recently, stochastic optimization has been widely employed in the literature to optimize the participation of vRES in multiple markets, including balancing markets [48–54]. The study in [48] introduces a two-stage model to optimize the participation of wind producers in the DAM, intraday market (IDM), and BMs. Similarly, the work in [20] proposes a data-driven method for generating meaningful scenarios and applies a two-stage model to optimize the participation of wind and storage technologies in wholesale energy markets. Additionally, a light robust co-optimization of energy and reserves has been considered for the optimal participation of wind farms [52]. A multi-stage model for optimizing the scheduling of conventional and virtual power plants participating in the Italian DAM and ancillary services markets is proposed in [53]. Furthermore, a similar model has been presented for MIBEL, considering also the participation of virtual power plants in the intraday market [54].

The previous studies have highlighted the benefits of strategic bidding behavior of vRES in electricity markets without support schemes. However, existing support schemes reduce the incentive for vRES to participate strategically in BMs, as they remunerate produced energy without applying balancing penalties. In contrast, participation in BMs may require vRES to pay for downward regulation [16–22]. Against this background, BMs should be adapted to attract new investments in vRES without relying on support schemes, while also mitigating the occurrence of near-zero prices.

Table 1 presents the current and projected 2030 levels of vRES deployment in selected power systems, along with the balancing services they currently provide and are expected to offer in the future [7,30,55–66].

Table 1. vRES shares and participation in balancing services in selected power systems.

System	2024 Share (%)	2030 Share (%)	2024 Balancing Services	Future Balancing Services
Denmark	69	80	Down regulation aggregated	P90 to incentivize participation in FRR
Finland	25	44	mFRR and FRR with storage	Same as 2024
Germany	45	80	With storage	Most but not attractive
Great Britain	51	77	With storage	Same as 2024
Ireland	34	80	Most balancing services	Fully RES by 2028
Norway	10	15	-	Down-regulation
Portugal	71	80	FRR with storage	Most balancing services
Spain	40	56	Most balancing services	Priority to hybridized storage solutions
Sweden	26	32	With storage in FFR	Down-regulation or all with storage
Texas	34	23	With storage	Priority to hybridized storage solutions
The Netherlands	45	74	FCR and aFRR	Most balancing services

Table 1 shows that Denmark and Portugal already have high shares of vRES, positioning them as key countries interested in the full market integration of vRES [30,55]. Most power systems aim to increase their vRES shares to near 80% by 2030, except for Finland, Norway, Sweden, Spain, and Texas. Finland, Sweden, and Spain are expected to maintain lower vRES shares due to their substantial hydro and nuclear generation capacities. Norway's predominantly hydro-based power system similarly limits the need for higher vRES integration [7,56]. In Texas, a high share of gas-fired capacity and reserves constrain the expansion of vRES. Moreover, Texas may even experience a decline in vRES share due to a projected 40% increase in electricity demand by 2030, driven by the rapid growth of data centers and AI-related infrastructure [57]. As such, demand growth in Texas may have a more pronounced impact than decarbonization efforts [57].

Among the analyzed systems, only Ireland, Spain, and the Netherlands currently allow vRES to participate in most balancing services [6]. Ireland aims to have its balancing services fully provided by renewable sources by the end of 2027 [58]. Spain facilitates vRES participation due to the early phase-out of support schemes and the resulting need to attract new market-based vRES investments [15,59]. The Netherlands enables aggregated participation, enhancing the reliability of vRES contributions in balancing markets [60].

Multiple factors may have contributed to the recent power outage in Spain, including (i) the lack of aggregated vRES participation in balancing markets, unlike in the Netherlands; (ii) the absence of FFR services to address low grid inertia; and (iii) the limited deployment of grid-forming inverters by vRES, which, as demonstrated in Ireland, support coordinated frequency control [7,58–62]. 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 [62]. Therefore, vRES can participate effectively in balancing markets without necessarily relying on storage or aggregation, provided that robust reliability criteria—such as the proposed D90 requirements—are applied.

In contrast, most power systems currently permit the participation of vRES in BMs only when coupled with storage or through aggregation [6,7]. Active support schemes remain one of the main barriers to incentivizing direct vRES participation in BMs, as they reduce the exposure to market signals. By 2030, all analyzed systems are expected to allow vRES to provide balancing services when aggregated or combined with storage. As a result, hybrid vRES power plants are likely to be prioritized [7,63–66]. However, this approach may prove inefficient if support schemes continue to shield vRES from market dynamics, as is the case in Germany [17].

Norway and Sweden are projected to allow vRES participation solely for downward regulation, reflecting the flexibility of their hydro-dominated systems. Conversely, Denmark, Ireland, Portugal, and Spain anticipate enabling non-aggregated vRES participation in BMs [7,63–66]. In this context, it will be crucial to establish robust and reliable participation criteria that ensure both secure system operation and the economic viability of vRES. Against this background, the present study analyzes the extent of participation of WPPs in balancing markets with new rules to de-risk and support their active participation.

3. Iberian Electricity Markets

Portugal and Spain form MIBEL, which governs Iberian spot, continuous, derivatives, and bilateral markets. Market participants may submit to spot markets up to 24 hourly selling or buying bids with increasing or decreasing prices, respectively, within a price range of -500 to 3000 €/MWh. The MIBEL day-ahead market is integrated into the European Single Day-Ahead Coupling (SDAC) of the EIME and cleared using the EUPHEMIA algorithm, which was designed to maximize social welfare across all participating market areas [67,68].

This framework allows for price arbitrage and strategic bidding. In Iberia, ancillary services remain independently managed by each TSO, although certain services can be exchanged between TSOs to enhance system balancing [41–43,69]. The provision of reserves by vRES can reduce reliance on fast-responsive fossil fuel power plants [7]. However, it may also lead to curtailment of renewable generation, which is counterproductive to decarbonization efforts. In this context, hybrid vRES solutions with integrated storage capacity offer an effective approach to balancing upward and downward regulation energy [25–27].

In MIBEL, price cannibalization—resulting from high solar PV investments in Spain—has led Portugal to implement economic incentives for public solar PV auctions that include batteries [70,71]. Notably, these solar PV power plants have allocated 140 MW of power capacity to support the secondary reserve. This enables them to charge or discharge batteries when activated for downward or upward regulation, respectively [7]. Additionally, in spot markets, they can leverage price arbitrage to optimize participation based on prevailing market prices [28]. This flexibility allows them to bid quantities lower or higher than deterministic forecasts when market prices are low or high, respectively. While vRES with storage can mitigate risks through this strategy, vRES without storage remain exposed to forecast errors and are subject to financial penalties for deviations [43,72]. Consequently, when vRES participate in markets while accounting for forecast uncertainty, spot market prices inherently reflect a certain degree of uncertainty as well [73]. The actual wholesale electricity price can only be determined in real-time operations after balancing reserves have been activated. In scenarios of expected energy excess, where spot prices are low, zero, or even negative, vRES may incur economic losses if they do not adopt a risk-averse bidding strategy. In such cases, reducing bid quantities may be preferable to avoid financial penalties. Conversely, when prices are high, vRES may take on a more aggressive bidding strategy, submitting higher quantities and leveraging price arbitrage. While marginal markets are designed to receive bids based on marginal costs, vRES must bid based on uncertain forecasts, exposing them to significant penalties if they fail to meet their scheduled dispatches [29–31].

Portugal is integrated into the European framework for frequency reserves aimed at continuous system balancing, with distinct operational requirements for each reserve category. Participation in the FCR is compulsory and unpaid for all grid-connected generators that meet technical criteria. These units must allocate 5% of their nominal capacity under stable conditions to FCR, thereby supporting the wider continental European synchronous grid [7,69].

As of September 2024, Portugal's aFRR operated with an asymmetric structure, providing twice as much up-regulation capacity as down-regulation. This configuration reflected the system's higher demand for upward flexibility. To better align with ENTSO-E recommendations, the Portuguese TSO revised capacity shares to 60% for up-regulation and 40% for down-regulation. Hourly auctions for aFRR capacity enable participation from qualified generators, with a bidding ceiling of 250 EUR/MW. Participants must submit symmetric bids, offering both upward and downward regulation but weighted to favor up-regulation at a 2:1 ratio [7,41,43,45]. Due to limited supplier competition, combined-cycle gas turbines (CCGTs) dominate the market, and the Portuguese regulator sets the upward energy price quarterly based on CCGT marginal costs.

In a more recent shift, from September 2024 onward, the aFRR procurement model moved to a symmetric capacity design, requiring equal up- and down-regulation commitments in bids. This change allows vRES to offer more downward flexibility but still obliges them to match it with upward capacity, complicating their technical and financial feasibility in aFRR participation. Nonetheless, this evolution marks progress in integrating vRES into balancing reserve provision.

mFRR, or tertiary reserve, is procured through hourly auctions, with separate markets for upward and downward products. This reserve follows a marginal pricing approach, with allowable prices ranging from −1000 to 10,000 EUR/MWh. However, given its hourly activation granularity, mFRR may fall short in addressing prolonged frequency imbalances. In such cases, replacement reserves (RR) are deployed. These reserves can be activated within 15 min and are sustained for longer durations to restore system balance.

Furthermore, extraordinary reserves are arranged through bilateral contracts between TSOs and providers, bypassing competitive market mechanisms. Any imbalances are financially settled through the imbalance settlement (IS) process, where Balance Responsible Parties (BRPs) are charged penalties for deviations from their scheduled positions. BRPs pay penalties three times higher in deviation from BMs schedules [30].

The next section explores strategic bidding approaches under the new strategies to support the participation of vRES in balancing markets.

4. Mechanisms to Support the Participation of vRES in BMs and Strategic Bidding

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

4.1. Mechanisms to Support the Participation of vRES in BMs

vRES rely on forecasts to determine the amount of energy they will trade in electricity markets. The DAM is the most liquid and serves as a reference for all subsequent market stages. However, this market closes between 12 and 37 h before real-time operation, which hinders the effective participation of vRES. Forecast errors for vRES remain significant until approximately six hours before operation, after which accuracy tends to improve. Participation in the secondary capacity market typically occurs shortly before or after the closure of the DAM, meaning that vRES forecasts are still subject to high uncertainty during this period. Following participation in the day-ahead and secondary reserve markets, vRES can adjust their dispatch schedules in the continuous intraday market (IDC) up to 15 min before real-time operation. Nevertheless, the acceptance of their bids is not guaranteed, potentially preventing them from fulfilling their reserve activation commitments. To address this issue, the Danish TSO introduced the P90 criterion to encourage vRES participation in reserves, considering their high operational uncertainty. To comply with P90 requirements, vRES are allowed to fail reserve activation values up to 10% of the time without incurring penalties. Once this threshold is exceeded, they are no longer eligible to participate in the reserve markets [38,39].

However, the TSO must still ensure that the total amount of reserve contracted from stochastic resources is sufficient to maintain system balance. One of the main shortcomings of the P90 approach is that it does not explicitly limit the amount by which a resource can deviate from its committed reserve [38,39]. As a result, in the event of a substantial shortfall in production, the system operator may lose nearly all the reserve capacity contracted from vRES—an issue that becomes even more critical in countries with limited meteorological diversity [73]. Thus, while the P90 criterion does not guarantee system security, it also significantly increases reserve procurement costs, especially if it accounts for the potential total failure of stochastic reserve providers [38,39]. Furthermore, the Danish TSO already consider a 10% imbalance deadband per period, i.e., 10% of the deviations per period do not pay penalties [39].

Considering the deadband allowance and to overcome the limitations of P90, this article proposes an alternative measure: the D90 criterion. Under D90, stochastic flexibility providers are allowed to deviate by up to 10% of their allocated reserve capacity without paying penalties. Exceeding this threshold results in the revocation of their eligibility to participate in reserve markets. This approach incentivizes more conservative bidding behavior and ensures that the TSO allocates an additional 10% of the reserve contracted from stochastic providers to dispatchable resources, thereby safeguarding system reliability. Moreover, this solution facilitates the adaptation of the current secondary reserve demand formulation, P_t^{Sec}, making it explicitly dependent on the participation of stochastic resources. The new reserve requirement, P_t^{D90}, would thus increase by 10% of the capacity allocated to stochastic providers, P_t^s, with this additional reserve covered by dispatchable units to ensure the power system security:

$$P_t^{D90} = P_t^{Sec} + 0.1 * P_t^s \tag{1}$$

An alternative solution that further strengthens the incentive for stochastic players involves the integration of the two previous measures into a single mechanism, referred to as DP90. Under this approach, stochastic flexibility providers are allowed to deviate up to 10% from their allocated reserve capacity in any given period, and in addition, they may exceed this threshold in up to 10% of the periods over the course of a year. Given the inherent difficulty in predicting when these deviations will occur, this measure does not compromise system security when compared to the P90 approach—especially if Equation (1) is adopted—while offering a more favorable framework for stochastic participants. From the system operator’s perspective, applying the DP90 criterion means that vRES should be considered as operating according to the P90 criterion until more than 10% of the hours show deviations exceeding 10%. Once this threshold is surpassed, vRES are treated under the D90 criterion. In practice, this implies that system operation is as complex as under the P90 assumption whenever none vRES exceeds the 10% deviation limit. The operational complexity then gradually decreases as more vRES units surpass the P90 criterion and start complying with the D90 criterion.

Figure 1 illustrates the maximum imbalances per operational hour for vRES in each methodology.

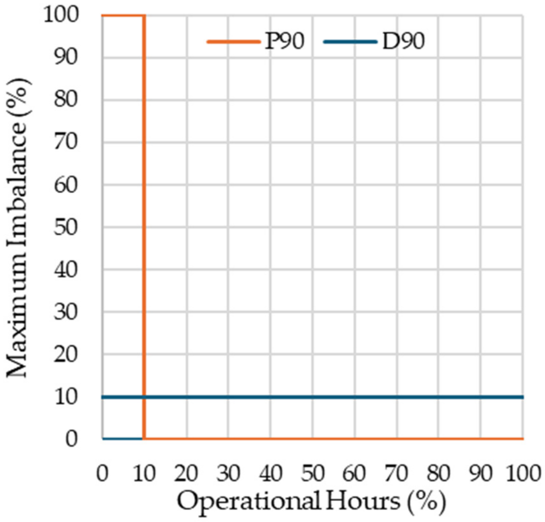

Figure 1. Maximum imbalance percentage per hourly offers across different methodologies.

Figure 1 shows that the maximum total deviations for P90 and D90 are equivalent, while for DP90, they correspond to the sum of both. However, under P90, vRES are allowed to deviate up to their full allocated capacity, whereas D90 restricts deviations to only 10% of the allocated capacity. Consequently, although the annual impact of both methodologies may be similar, the real-time deviation under P90 can be up to ten times greater than that of D90, potentially posing higher operational challenges.

Importantly, these modifications do not alter the design of the secondary reserve mechanism itself but rather influence the system's security of supply and the extent of participation from stochastic resources. Table 2 compares the features of the secondary market rules in Portugal from the point of view of vRES and the TSO.

Table 2. Features of the secondary capacity market rules.

Features	Past	Actual	P90	D90	DP90
Date	By September 2024	Since September 2024	-	-	-
Size	Small	Medium	High	Medium+	High
TSO risk	Medium−	Low	High	Low+	High
vRES incentive	Low	Low+	Medium−	Medium+	High−
vRES risk	High	High−	Medium+	Low+	Low

By analyzing Table 2, it can be concluded that D90 is the more reasonable approach from the point of view all players. It incentivizes vRES participation without compromising the security of supply.

4.2. Strategic Bidding Using Probabilistic Forecasts with Price Arbitrage

The objective function is formulated as an optimization problem, implemented using Python v3.7.3 (code provided in the Supplementary Materials) [30] by selecting the quantile $k \in K$ (maximum number of quantiles) that maximizes the producer's revenue, R_t, at hour t:

$$R_t = \max_k \left(R_{k,t}^{DAM} + R_{k,t}^{IDA} + R_{k,t}^{IDC} + R_{k,t}^{CAP} + R_{k,t}^{EN} + R_{k,t}^{IS} \right) \tag{2}$$

where the following are true:

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 decision variables correspond to the electricity volumes traded across markets, subject to the applicable market regulations and operational constraints [30].

The forecasting framework integrates day-ahead, probabilistic, quantile-based forecasts with intra-day, deterministic point estimates, both derived using a K-Nearest Neighbor (KNN) methodology applied to data from a numerical weather prediction (NWP) model [8,37,73–77]. This real-time forecasting system leverages initial conditions from the Global Forecast System (GFS), which provides hourly meteorological variables with a forecasting horizon of up to 42 h for the training dataset [5,33]. Probabilistic forecasts are employed to optimize price arbitrage in the DAM, whereas deterministic forecasts are used for quantity arbitrage in balancing and/or intraday markets. In the context of multi-market strategies, the use of quantile-based probabilistic forecasts has proven effective in managing the trade-off between price and risk, thereby enhancing the market value of vRES [30]. The probabilistic forecast models for vRES, used across the different market time frames, were developed based on meteorological ensemble outputs derived from NWP models. These forecasts incorporated statistical post-processing techniques applied to the raw NWP data. Synoptic meteorological information was obtained in real-time using the MM5 NWP model, which served as the main forecasting tool. MM5 simulations were executed four times daily, initialized at 0, 6, 12, and 18 UTC, using input data from the GFS provided by the National Centers for Environmental Prediction, with a horizontal resolution of $1^\circ \times 1^\circ$. The MM5 setup employed a two-way nesting configuration with three spatial domains at resolutions of 81, 27, and 9 km, respectively. Adequate parameterizations were applied for the geographic and meteorological characteristics of the study area. A vertical grid structure consisting of 26 irregular sigma layers was implemented for all domains. However, only the high-resolution output from the innermost 9 km domain was used for the analysis presented in this study [30].

Naturally, the higher the forecast accuracy, the better the performance of vRES in BMs. However, the forecasting accuracy of vRES has largely reached its practical limits under current market designs, even with recent advances involving large language models applied to energy-related prediction tasks [76–78]. Therefore, efforts should focus on adapting market designs to better accommodate the stochastic nature of vRES.

The normalized root mean squared error (NRMSE) is used to evaluate the forecast errors of the proposed methodologies used to compute the expected energy, $\hat{E}_t$, with $t \in T$ (total number of periods):

$$NRMSE = 100\% \frac{\sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(\hat{E}_t - E_t\right)^2}}{E_{max}} \tag{3}$$

where E_{max} is the installed capacity, and E_t the observed energy. The value of $\hat{E}_t$ depends on the market time horizon of each forecast to the DAM, IDA, SR, and IDC.

Several general constraints are applied. The schedule, E_t^{dev}, in the electricity markets is limited by the nominal power of vRES, ensuring that the producer does not sell more energy than can be physically generated. Additionally, the producer cannot bid more downward balancing capacity, P_t^{SR-}, than the scheduled injection, $E_t^{position}$. Bids in the BMs are further restricted by the upward, $E_t^{SR_{req}^{up}}$, and downward, $E_t^{SR_{req}^{down}}$, requests of the TSO [30].

$$P_t^{SR+} \leq min\left(E_t^{dev}, E_t^{SR_{req}^{up}}\right) \tag{4}$$

$$P_t^{SR-} \leq min\left(E_t^{position},\ E_t^{SR_{req}^{down}}\right) \tag{5}$$

vRES market participation decisions are interconnected through key concepts. The position represents the vRES portfolio, accounting for bids in the DAM, increasing when selling in IDMs and decreasing when purchasing energy. IDMs consider both auction-based (IDA) and continuous intraday (IDC) markets. The final offer reflects the vRES's position after the reserve capacity market and before the activation of energy bids, representing an adjusted stance based on initial bids and the balancing capacity market. The final schedule incorporates reserve activations by the TSO, adjusting the energy injection into the grid based on DAM and IDM positions. It increases when upward reserves are activated and decreases when downward reserves are called upon. The final deviation is the difference between actual production and the final schedule, which is settled during the IS period. These concepts are crucial for understanding how vRES decisions evolve across different market stages and influence one another, shaping the producer's overall participation and financial performance impact each other across different market stages as presented in Figure 2.

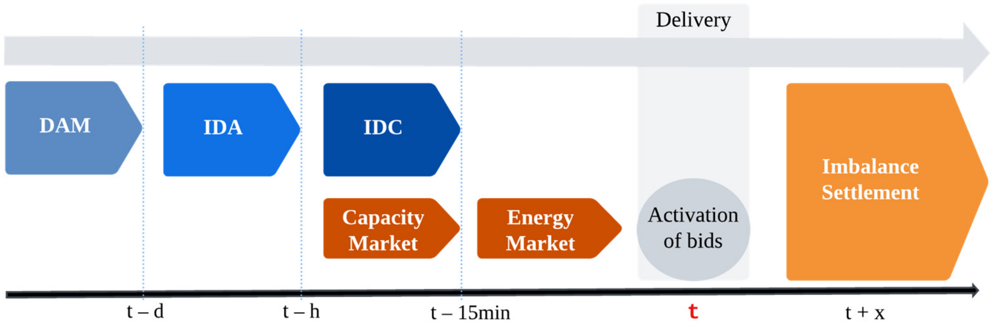

Figure 2. Market structure for vRES strategic behavior (adapted from [30]).

In the ideal case, this study evaluates the methodology proposed by the Danish TSOs, which permits vRES to participate in the aFRR (secondary) capacity market only if their imbalances remain within 10% of the annual operating hours, regardless of the imbalance direction. This approach is referred to as P90. In addition to P90, two alternative methodologies are explored. The first, D90, adopts a similar principle but sets the threshold relative to each WPP's hourly offers, allowing participation only if imbalances remain within a 10% deadband of these offers. The second, DP90, integrates both previous approaches, permitting WPPs to deviate freely within 10% of the annual hours, while imposing a 10% deadband relative to hourly offers during the remaining periods.

The employed operational strategy follows a conservative approach, wherein the bid for upward balancing capacity is limited to the available generation capacity, while the bid for downward capacity is constrained by the vRES current scheduled injection. Given the inherent operational risks, the producer adopts a conservative strategy to minimize significant deviations and ensure compliance with the imbalance thresholds defined by the respective methodologies. Within the current market, when upward regulation bids exceed forecasted generation levels, the risk increases. As adherence to these methodological limits is a prerequisite for participation in the reserve market, an alternative and more risk-averse strategy involves constraining upward regulation bids to levels aligned with the producer's forecast and scheduled position.

To manage positive imbalances in the operational case, the operational strategy is applied depending on the reliability criterion in use. Under P90, positive imbalances are permitted only during periods of high DAM prices, while curtailment is enforced during other hours to avoid unnecessary market exposure. In the D90 approach, curtailment is applied until the accepted value is reached, with a cap set at 10% of the final hourly offer. The DP90 method introduces a hybrid strategy that combines the principles of both P90 and D90, offering greater flexibility and control over imbalances. For negative imbalances, the producer mitigates risk by adjusting its position in the IDC market prior to participating in the reserve market. This involves either decreasing the volume sold or increasing the volume purchased in alignment with the expected deviation.

The complete formulation for the ideal case under perfect market foresight and the operational case is presented in [30]. The average remuneration, $\overline{R}$ (€/MWh), for the study period is computed by dividing the total revenue across all hours by the total observed production:

$$\overline{R} = \frac{\sum_{t=1}^{T} R_t}{\sum_{t=1}^{T} E_t} \tag{6}$$

5. Case Study

This section details a case study involving a 250 MW WPP engaging in electricity markets under the MIBEL framework and Portuguese BMs during the 2009–2010 period.

The WPP is assumed to operate independently, without access to any support schemes, and bears full responsibility for its imbalance management. The primary aim is to enhance the WPP's revenue through optimized market participation strategies. Most of the datasets and statistical analyses used are provided in [30].

5.1. Forecasts and Market Data

This section presents the most relevant data to analyze market dynamic and the level of complexity the WPP face to participate in BMs. Figure 3 presents the DAM price dynamics during the period of 2009–2010.

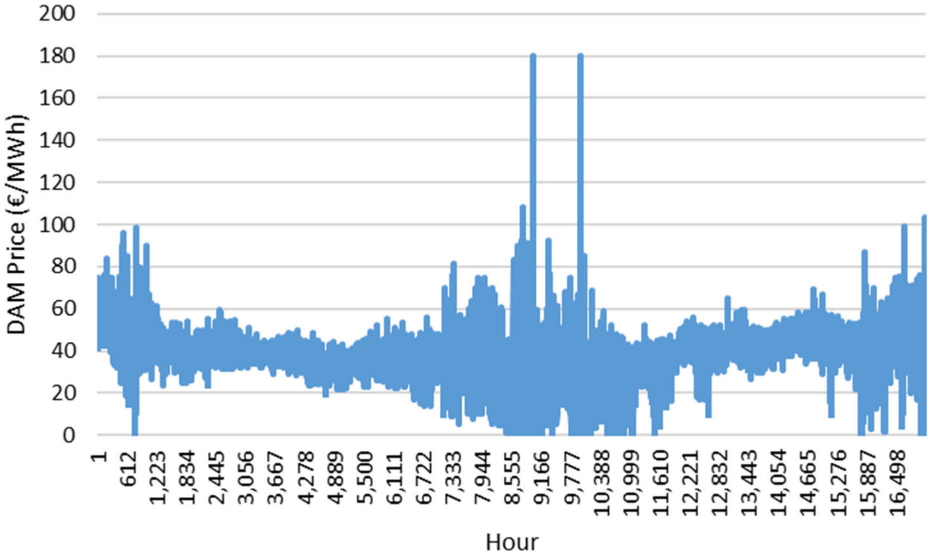

Figure 3. DAM price dynamics during the period of 2009–2010.

Analyzing Figure 3 reveals significant hourly variations and a notable occurrence of zero prices due to high vRES generation, with prices generally higher during the winter months. This pattern is largely attributed to reduced electricity demand during the economic crisis period.

Figure 4 presents the DAM prices dynamic during 2024.

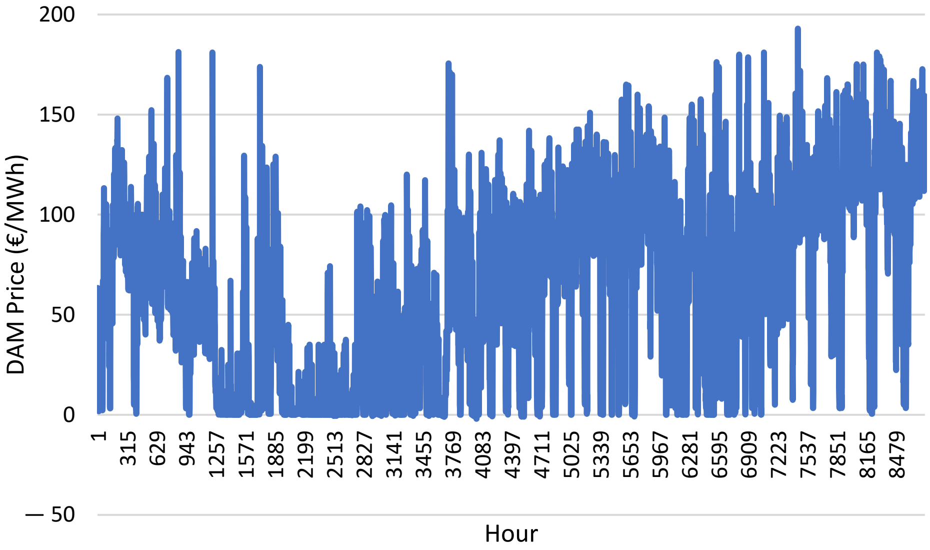

Figure 4. DAM price dynamics during 2024.

Analyzing Figure 4 shows that the incidence near zero prices increased in 2024, with a significantly higher occurrence during daytime hours due to elevated solar PV generation. Market price volatility also rose, driven in part by the increase in the MIBEL price cap from 180.3 to 4000 €/MWh. Prices remained higher during the winter months, primarily due to increased demand. These results show the integration of vRES in BMs is even more critical nowadays.

Figure 5 presents the market price monotone curves in the DAM and IDA and for up- and down-regulation during 2009–2010. Because, in this period, the IDC was not in place, it is considered that the IDC has the same prices of the DAM.

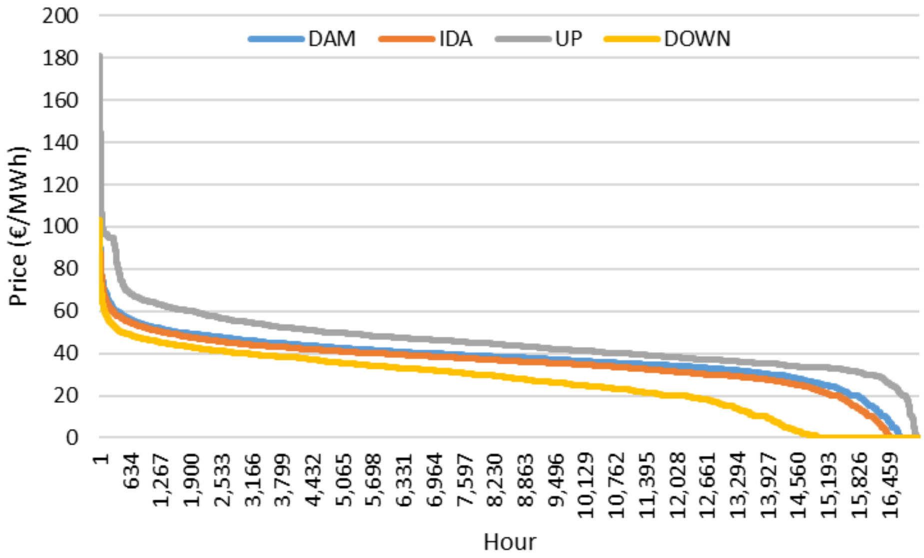

Figure 5. Market price in the DAM and IDA and for up- and down-regulation during 2009–2010.

Figure 5 shows that DAM prices are slightly higher than those in IDA, which incentivizes vRES to submit riskier bids in the DAM, with the possibility of adjusting positions in the IDA. Furthermore, the price difference between down-regulation and DAM prices is greater than that between up-regulation and DAM prices, encouraging vRES participation in down-regulation services.

Figure 6 presents the absolute deviations of the WPP from the deterministic forecasts across the DAM, IDA, and IDC markets.

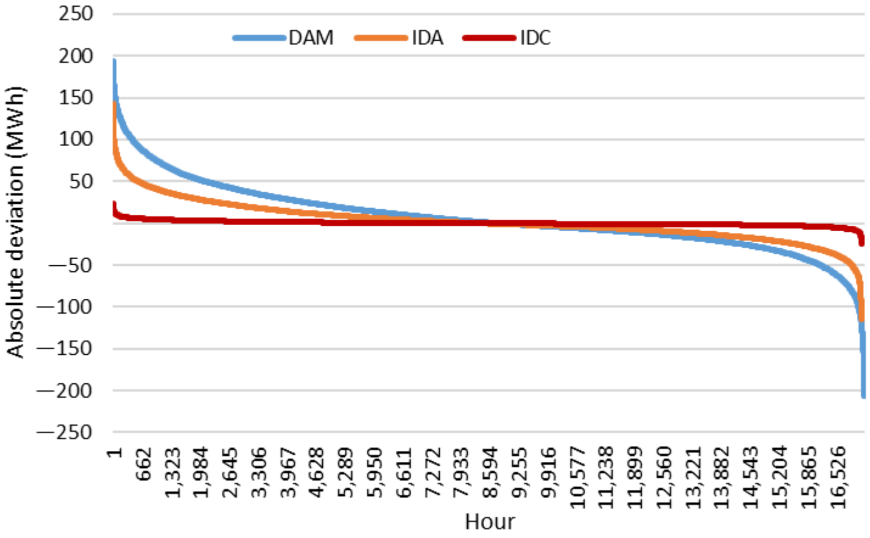

Figure 6. Absolute deviations of the DAM, IDA, and IDC forecasts.

From Figure 6, it is possible to verify significant deviations in the DAM and IDA forecasts. Notably, some deviations approach the full installed capacity of the WPP, highlighting the challenges associated with forecast uncertainty. The NRMSE of DAM, IDA, and IDC forecasts is 15.9%, 9.2%, and 1.1%, respectively.

However, to fully understand the impact of forecast deviations in the capability of the WPP to comply with the BMs' participation criterion, Figure 7 presents the relative deviations of observed production to forecasts across different markets.

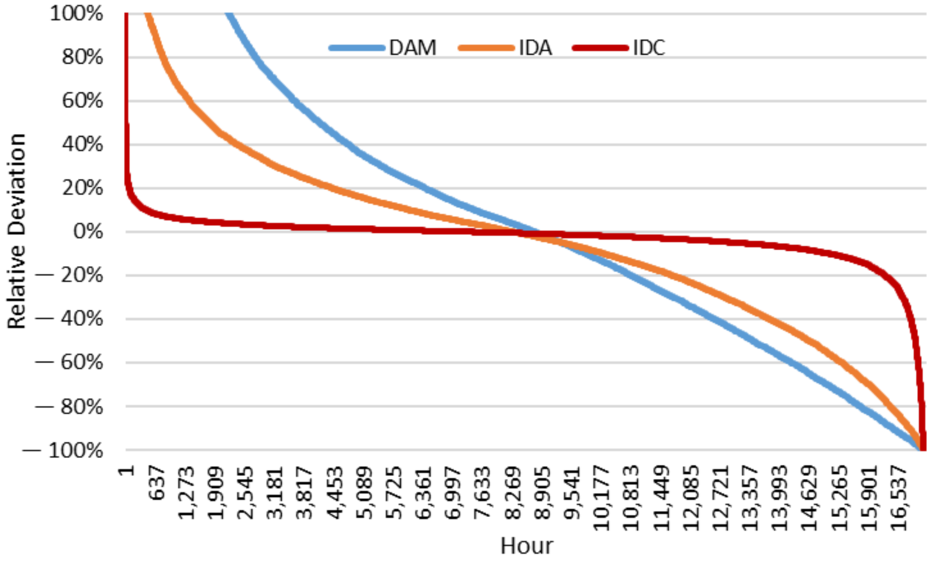

Figure 7. Relative deviations of the DAM, IDA, and IDC forecasts.

Figure 7 shows that only the DP90 criterion can be met when the entire energy forecasted by the IDC deterministic model is traded. This indicates that relying solely on KNN-based deterministic forecasts is insufficient to ensure the WPP effective participation in BMs. Therefore, the proposed strategy leverages KNN-based probabilistic forecasts in combination with price arbitrage to mitigate the risks associated with participation in BMs, as detailed in [30].

5.2. Scenarios

The case study investigates the active participation of a wind power plant (WPP) across multiple electricity markets, with the objective of maximizing revenue. A comprehensive statistical analysis of WPP production, quantile-based forecasting, and pricing strategies is provided in [31].

The analysis considers two primary scenarios: (i) an ideal scenario, where the producer possesses perfect knowledge of both market prices and wind power output at the time of delivery, and (ii) a realistic operational scenario, where decisions are based on forecasts and strategic bidding to address market uncertainties. To evaluate the development and enhancements in the secondary (aFRR) capacity procurement design, four different market configurations are examined. The actual configuration reflects the current regulatory framework, where symmetrical bidding for upward and downward balancing capacity remains in place, with certain restrictions on procurement. Therefore, the results of the baseline and new mechanism (P90, D90, and DP90) simulations are presented to incentivize the participation of vRES in the actual balancing market framework. The baseline scenario reflects the actual BM framework in Portugal, whereas the proposed mechanisms incorporate new criteria designed to incentivize the participation vRES in BMs, as detailed in Section 4.1.

5.3. Results

This section presents the results of the ideal and operational cases using the strategy outlined in Section 4.2, considering the market design described in Section 3 and the new mechanisms presented in Section 4.1.

5.3.1. Ideal Case

The outputs of the ideal case under perfect information, considering the participation of the WPP in all markets under the baseline and new mechanisms approach, are presented in Table 3. It is assumed that the WPP passed the technical requirements to participate in the secondary capacity market under the baseline scenario [7,30].

Table 3. Key results for the new methodologies applied to the current market design under ideal conditions.

Variable	**Balancing Requirement**			
	Baseline	**P90**	**D90**	**DP90**
Average remuneration (EUR/MWh)	104.76	86.05	84.98	95.85
Total reserve capacity allocated (GW)	3700.63	1873.26	2104.73	2401.85
Total reserve activated (GWh)	320.37	386.09	392.47	376.50
Total curtailment (GWh)	55.89	36.87	41.08	17.69
Total positive imbalances (GWh)	28.51	51.26	43.04	84.45
Total negative imbalances (GWh)	427.40	68.61	46.47	115.16
Total positive imbalances cost (M€)	0.72	2.01	1.44	3.03
Total negative imbalances cost (M€)	−23.83	−2.02	−1.64	−3.65

By analyzing Table 3, it can be concluded that it is beneficial for vRES to not be restricted to the technical requirements of the new mechanisms under perfect information because the baseline scenario provides the highest optimal remuneration. In the ideal case, without participation in BMs, the WPP achieves a remuneration of 38.82 EUR/MWh [30]. When perfect information is assumed, remuneration more than doubles through active engagement in BMs. Considering this, it becomes essential to define a methodology that effectively incentivizes the participation of stochastic providers in balancing mechanisms, without compromising power system security.

The technical requirements limit the allocated capacity of the WPP, reducing its remuneration. However, from a sustainable and operational perspective, it may increase the total curtailments and imbalances of the WPP, being a drawback to society and to the TSO. However, it may be confirmed in the operational case.

5.3.2. Operational Case

Table 4 presents the simulation results of the proposed methodologies in the operational case. As shown in Table 4, all scenarios lead to an increase in the WPP's remuneration compared to the optimal case without participation in balancing markets. Specifically, the operational remuneration without engagement in BMs is limited to 29.51 EUR/MWh [37]. The proposed methodologies improve this value by at least 42%. Consequently, the key consideration lies in identifying the methodology that enhances the TSO's confidence in enabling the participation of stochastic providers in BMs.

Table 4. Key results for the new methodologies applied in operational conditions.

Variable	Balancing Requirement			
	Baseline	**P90**	**D90**	**DP90**
Average remuneration (€/MWh)	43.94	43.47	42.02	45.51
Total reserve capacity allocated (GW)	336.58	335.60	276.68	337.73
Total reserve activated (GWh)	97.07	97.58	81.66	97.61
Total curtailment (GWh)	53.44	108.66	90.28	10.72
Total positive imbalances (GWh)	29.32	18.79	51.81	75.73
Total negative imbalances (GWh)	14.01	13.22	10.40	14.06
Total positive imbalances cost (M€)	0.55	0.68	1.55	2.41
Total negative imbalances cost (M€)	−0.91	−0.64	−0.54	−0.65

From the perspective of the WPP, the DP90 methodology yields the highest remuneration due to significantly lower curtailments, making it also preferable from an environmental standpoint. In contrast, P90 results in approximately ten times more curtailment than DP90. D90 represents the most conservative approach, as it reduces the amount of secondary capacity provided and activated by the WPP, consequently lowering its remuneration. Nevertheless, the remuneration gap between the most and least profitable strategies (DP90 and D90, respectively) is only 8%, suggesting that operational performance should be considered when determining the most suitable methodology from a societal perspective.

The baseline scenario is the only case with negative remuneration from imbalances, primarily due to penalty values that are three times higher than those applied to BRPs not providing reserves [30]. While P90 achieves the greatest reduction in total WPP imbalances, this does not necessarily imply greater operational stability. Contrariwise, DP90 more than doubles the total imbalances of the baseline and P90 scenarios.

Therefore, Table 5 presents imbalance statistics for each methodology to assess the degree of uncertainty they introduce regarding the availability of secondary capacity. Table 5 shows that P90 results in the highest single-period deviations, reaching nearly 94% of the WPP's installed capacity. In contrast, the D90 methodology limits maximum deviations to below 10% of installed capacity. From the system operator's perspective, D90 is the most stable option, with a standard deviation of only 5 MWh (approximately 2% of installed capacity). Conversely, DP90 exhibits the highest imbalance variability, with a standard deviation of 5% of installed capacity, making it the least stable approach. From an operational standpoint. D90 emerges as the most predictable and least disruptive methodology when compared to current reserve operation practices. To ensure secure system operation under D90, TSOs would need to procure only 10% additional capacity from dispatchable resources to cover potential shortfalls from stochastic providers, as indicated in Equation (1).

Table 5. Key statistics of imbalances for different methodologies.

Imbalances (MWh)	Baseline	P90	D90	DP90
Min	−20.28	−20.28	−20.28	−20.28
Max	161.91	234.88	24.70	169.75
Median	−0.36	−0.43	0.49	−0.04
Mean	1.08	0.43	2.43	3.61
Standard deviation	7.96	7.90	5.34	12.58

In summary, although P90 may reduce long-term total deviations, it is associated with the highest short-term deviation, being that DP90 is the most volatile methodology. D90, by contrast, offers the most consistent and reliable performance.

Figure 8 presents the imbalance percentage of hourly to verify the level of trust TSOs may have with the reserve offer from stochastic sources across different methodologies.

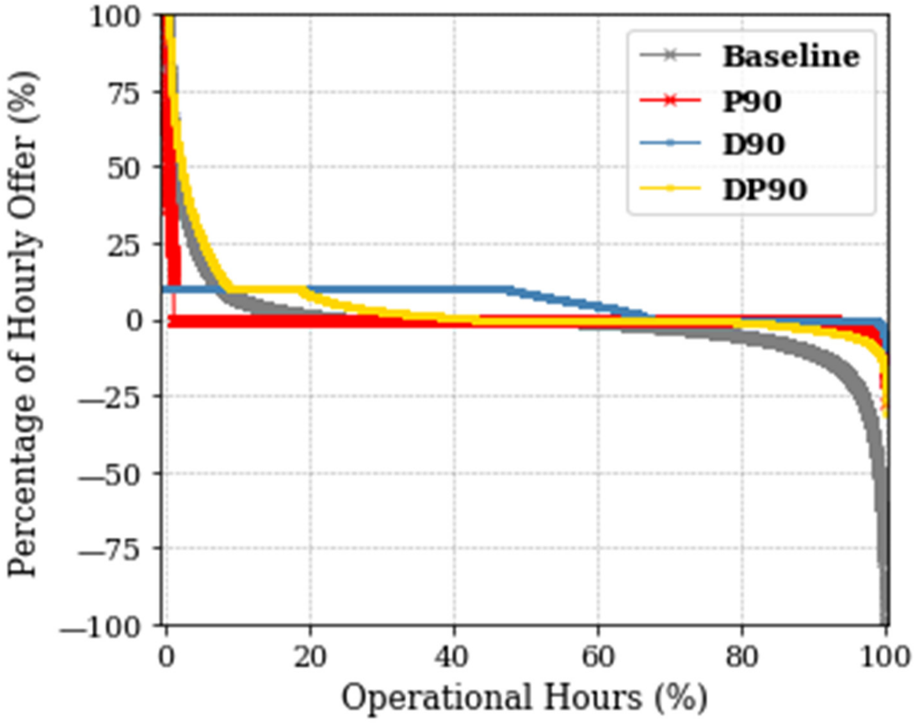

Figure 8. Imbalance percentage of hourly offers across different methodologies.

Figure 8 illustrates that in less than 1% of the time, the WPP failed to deliver nearly 100% of its allocated capacity in the P90 and DP90 methodologies for upward regulation and in the baseline for downward regulation. Given that stochastic players rely heavily on weather forecasts to plan their market participation, forecast errors can lead to widespread non-compliance with activated balancing programs. In this context, the D90 methodology emerges as the most reliable approach for incentivizing the participation of stochastic providers in reserve markets while ensuring power system security. In contrast, alternative methodologies may impose additional costs on TSOs, who must dynamically assess and allocate supplementary secondary capacity to hedge against potential shortfalls [45]. Moreover, these approaches often require the estimation of providers' risk aversion to determine the trustworthy capacity contributions [38].

In conclusion, the methodology selected to incentivize stochastic players must be carefully evaluated, prioritizing secure system operation with a high level of confidence. From the TSO's perspective, D90 offers superior reliability and predictability, making it a favorable choice. However, the D90 methodology may be considered rigid, as it leads to high levels of curtailments and revokes the participation rights of providers that exceed the 10% imbalance threshold. As an alternative, these providers could be allowed to validate or adjust their allocated capacity after the clearing of the IDC market, while covering the associated costs incurred by the TSO for procuring additional capacity from other providers. This approach would preserve system security without permanently excluding participants. Consequently, the design and regulation of balancing markets should evolve to enable both efficient and reliable participation of stochastic providers.

6. Conclusions

As society moves toward decarbonization, it is essential to adapt energy systems to accommodate renewable technologies. Wind and solar PV power, which currently account for the largest shares of installed renewable capacity in Europe, are expected to further increase their shares in the coming years due to continued investment and the progressive phase-out of gas-fired power plants. However, the inherent variability and uncertainty of these resources pose significant challenges for their integration into existing energy markets, which were originally designed to accommodate dispatchable generation technologies. In particular, participation in balancing markets (BMs)—which are critical for maintaining the real-time equilibrium between electricity supply and demand—is constrained by technical requirements such as fast ramping and reliable availability, which are difficult for vRES to meet. This study investigated potential modifications to BMs rules aimed at enabling and incentivizing greater participation of vRES, thereby supporting both system reliability and the transition to carbon-neutral power systems.

In this context, this work proposes and evaluates different methodologies to incentivize the participation of vRES in BMs. The P90 methodology, originally proposed by the Danish TSO, permits deviations in 10% of the reserve operating hours. The D90 approach, newly introduced in this study, allows deviations of up to 10% in all operational hours. The hybrid DP90 methodology combines the constraints of both P90 and D90. These methodologies were assessed based on the participation of a wind power plant (WPP) in the Portuguese BMs, alongside the existing baseline framework for secondary capacity requirements. From the perspective of the WPP, DP90 emerged as the most favorable methodology in terms of aligning with the operational behavior of stochastic generators, as it enhances remuneration while reducing curtailments. However, DP90 also exhibits the highest long-term cumulative deviations and the largest short-term imbalance variability. From a system operation standpoint, D90 is the only methodology that ensures predictability and reliability for TSOs, by limiting deviations to a maximum of 10%, while the other methodologies, including the baseline, may experience deviations nearing 100% during 1% of the time.

The WPP adjusts its strategy to maximize remuneration based on the requirements of the secondary capacity market, occasionally incurring unnecessary deviations under the protection offered by the tested methodologies. Externalities designed to incentivize vRES participation proved to cause price distortions in spot markets, thereby impacting the merit order.

The main limitation of this study is the adoption of a 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. Therefore, future work will assess the efficiency of balancing markets, considering whether it is more effective to adapt their design for better integration of stochastic providers or to implement dedicated mechanisms that specifically incentivize their participation using a price-maker approach. Furthermore, the impact of hybrid vRES solutions will be analyzed in terms of their enhanced reliability when participating in BMs.

Supplementary Materials: The Python code and only one day of representative wind aggregation data, because of confidentiality reasons, are provided at https://github.com/hugoalgarvio/vRESBids (accessed on 24 April 2025).

Author Contributions: Conceptualization, H.A. and V.S.; methodology, H.A. and V.S.; software, V.S.; validation, H.A. and V.S.; formal analysis, H.A. and V.S.; investigation, H.A. and V.S.; resources, H.A. and V.S.; data curation, H.A. and V.S.; writing—original draft preparation, H.A.; writing—review and editing, H.A. and V.S.; 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.

Funding: This work received funding from the EU Horizon 2020 research and innovation program under project TradeRES (grant agreement No. 864276).

Data Availability Statement: All market data used in the simulation are available on the website of the Portuguese TSO at https://mercado.ren.pt/EN/Electr (accessed on 24 April 2025).

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

aFRR	Automatic-activated frequency restoration reserve
BM	Balancing market
BRP	Balance Responsible Party
CCGT	Combined cycle gas turbine
CET	Central European Time
DAM	Day-ahead market
EIME	European Internal Market of Electricity
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
NRMSE	Normalized root mean squared error
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	
E_{max}	Installed capacity
Variables	
E_t	Observed energy
$\hat{E}_t$	Forecasted energy
$E_t^{position}$	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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