Is portfolio bidding profitable?: The case for hybrid photovoltaic-battery power plants

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***Abstract*—Literature suggests that intermittent power producers such as solar photovoltaic (PV) should hybridise with dispatchable power producers to minimise imbalance costs. This paper derives the optimal day-ahead bidding strategies for a stand-alone PV producer, a stand-alone battery, and a hybrid portfolio of both assets, located in the Netherlands. The bidding problem is formulated as a stochastic two-stage problem where the first-stage decision is the day-ahead bid, and the second-stage decision is settling imbalances and trading flexibility in a single-price balancing market. The stochastic variables are the balancing market premiums and PV power plant production, which are assumed to be independent and uncorrelated in the Dutch power market. Results show that both assets maximise profit by deviating from day-ahead forecasts in the same direction. Without regulatory restrictions or additional imbalance penalties, the technologies in the hybridised plant are bid independently and no additional profits are captured through hybridisation.**

***Index Terms*—hybridisation, bidding strategy, balancing market, solar PV, portfolio bidding**

I. Introduction

One of the most significant barriers to the energy transition is increasingly intermittent generation profiles introduced with greater shares of variable renewable energies (VREs) such as wind and solar photovoltaics (PV). Non-dispatchable solar PV can experience great variation in power output over short time horizons, and these fluctuations are difficult to forecast accurately. This unreliable power supply poses a significant challenge to grid system operators tasked with balancing the variable generation profile against demand.

The European energy market schedules power contracts 12–36 hours in advance in the day-ahead market. The following day, in the time approaching the contracted dispatch period, the balancing market is activated to correct deviations between day-ahead commitments and real-time generation outcomes. The balancing market is settled at a single imbalance price. If the contracted plant has fallen *long* by being in surplus, it *is paid* for this energy at the balancing market price, if it has fallen *short* by being in deficit, it must *pay* for its shortfall at the balancing price. This results in a market in which it is beneficial to be in surplus if the balancing price is greater than the day-ahead price, and beneficial to be in deficit if the balancing market price is less than the day-ahead price. In addition, the current market structure presents two aspects which further exacerbate the challenges of VRE intermittency.

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Firstly, the European day-ahead market is currently contracted hourly, despite VREs such as solar PV fluctuating on short, sub-hour timescales. Secondly, by contracting power in the day-ahead market, solar PV plants (and other VREs) are bidding against solar irradiance forecasts with time horizons ranging from 12–36 hours. Naturally, this decreases the accuracy of the forecast compared to short-term forecasts, which in turn increases the uncertainty of settling the day-ahead market and increases the volumes of imbalances in the real-time outcomes.

Currently, European balancing markets are transitioning to 15-minute settlement periods, which could lead to even greater differences between the hourly day-ahead contracts. There has also been a recent shift from dual-price to single-price balancing markets in an attempt to settle imbalances more efficiently, reward plants that are imbalanced in a direction beneficial to the system, and encourage price convergence.

Previous research concluded that for a single-price balancing market, the day-ahead price and balancing price should reach an equilibrium due to arbitrage between markets [1]. Another study found that when the balancing market price differs from the day-ahead price, the optimal strategy to maximise expected profit is to bid at the extreme bounds of generation [2]. This results in VRE bids that are formulated to exploit arbitrage between the day-ahead and balancing markets, regardless of expected generation outcome [3]. Correspondingly, a Nordic study found that without perfect foresight on both real-time generation and balancing market price, a hybrid VRE-battery power plant acting as a price taker in the Nordics profits the most from committing itself to the mFRR market rather than reducing its own imbalance volumes [4].

It is well-known that these issues pose a direct logistical challenge to the *transmission system operator* (TSO). As such, from a system perspective, it is desirable that VREs hybridise with dispatchable energy storage systems like batteries to provide smooth generation profiles accurate to their day-ahead bid. However, despite the system-level benefits of hybridisation, it is hypothesised that there is a market gap between the self-regulated generation profiles the TSOs want and the economically optimal bidding strategy of hybrid PV-battery power plants. This study examines this research challenge by addressing the question: *Is portfolio bidding profitable for hybrid PV-battery power plants?*

The research question is investigated using a two-stage stochastic model, with the first stage representing the day-ahead bid and the second stage representing the real-time outcomes of PV generation and the balancing market price. The case study is a theoretical hybrid PV-battery plant in the Netherlands, using historical Dutch market prices.

The previous research outlined above was conducted at hourly time resolutions. This paper seeks to verify these findings with the stochastic model and expand with two specific contributions:

(1) Assess if the time granularity disparity between the hourly day-ahead market and the 15-minute balancing market influences the extreme bidding behaviour.

(2) Assess the value of hybridisation and portfolio bidding by comparing the bidding strategy of stand-alone PV, a stand-alone battery, and a hybrid PV-battery power plant.

II. Methodology

This study was performed for a site location in the Netherlands for the year 2020, for three different plant configurations:

1) 5 MWp PV power plant
2) 4 MWh, 2 MW, battery energy storage system (BESS)
3) Hybrid PV-battery power plant (1 & 2)

The model assumes that the plant acts exclusively as a *price taker*. In this study, the Dutch balancing market is simplified to always have a single balancing price, though in reality it experiences a dual balancing price in ∼8% of time intervals. In these intervals, the price with the larger absolute balancing premium is assumed. Moreover, it is assumed that the plant can always be activated and is not bound by regulations constraining total imbalance volume.

A. PV generation & market data

The real-time PV power output data was modelled for a 5 MWp synthetic power plant using a comprehensive dataset from Cabauw, Netherlands for 2020 [6, 7]. The dataset includes measurements of global horizontal irradiance, direct normal irradiance, ambient temperature, wind speed, relative humidity, and air pressure. This was used to generate a 15-minute AC power profile, following the methodology presented in [8], with an DC-to-AC ratio of 2.0 and an inverter efficiency of 96%. The hourly solar irradiance forecast was accessed through the European Centre for Medium-Range Weather Forecasts (ECMWF), and the same methodology was applied to generate a forecasted AC power profile for a 5 MWp PV power plant.

The day-ahead prices and imbalance prices were acquired through the public python version of ENTSO-E transparency platform API [1]. Imbalance prices are the imbalance settlement prices that the balancing responsible party pays, and in the Dutch market there is no differences between production and consumption settlement prices [2]

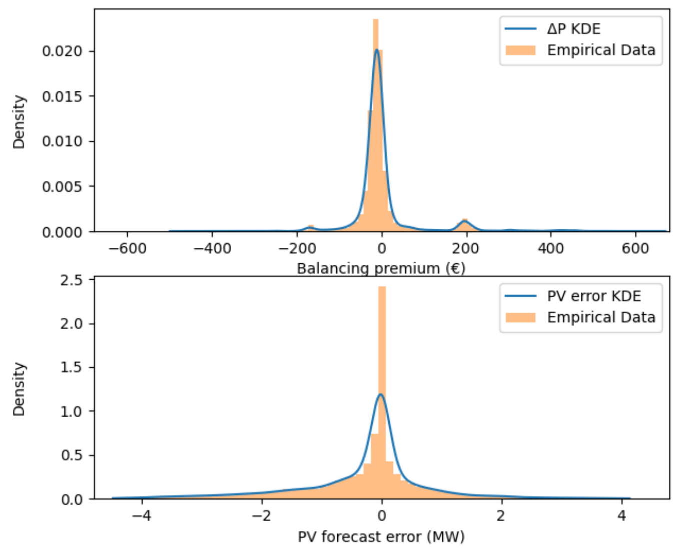

Fig. 1. Kernel density estimation (KDE) of key forecast errors; Balancing premium (€) and PV forecast error (MW).

B. Scenario generation

The two uncertain parameters required for the stochastic model are the real-time PV generation and the balancing premium. The model is run for 10 scenarios of equal probability, with no correlation between the PV forecast error and the balancing premium. It is assumed that the solar PV generation share is too small for irradiance forecast errors to affect the direction of up- or down- regulation in the greater market.

Balancing premium is defined as the difference between the balancing market (BM) price and the day-ahead (DA) price $\Delta P = P_{BM} - P_{DA}$. For real-time PV generation, PV_{RT}^{gen}, the forecast error was sampled between the hourly ECMWF forecast and the real-time generation, $PV_{error} = PV_{RT}(t_{15}) - PV_{fc}(T_h)$. For each error dataset, the Python SciPy Stats package was used to establish a kernel density estimation (KDE), as illustrated in Fig. 1. To generate scenarios, the respective KDEs were randomly sampled n times for n number of scenarios, with each scenario having equal probability $P_n = 1/n$. The randomly sampled $PV_{error}(t_{15})$ is applied to the hourly ECMWF day-ahead PV power forecast for periods between sunrise and sunset and clipped to the upper bound of the maximum PV power plant generating capacity. The sampled ΔP scenarios were applied to the model directly.

C. Model formulation

A two-stage stochastic model was used to determine the optimal day-ahead bidding strategy for each plant configuration, with variables defined in Table I. Decision variables are

[1] https://github.com/EnergieID/entsoe-py/blob/master/README.md

[2] https://www.tennet.eu/node/268

denoted by x. The stochastic variables are ΔP and PV_{RT}^{gen}. The optimisation problem is defined as:

$$\text{Max.} \sum^{T} P_{DA}(t) \cdot x_{DA}(t) \tag{1}$$
$$- \sum^{S} \pi_S(s) \cdot (P_{DA}(t) + \Delta P(t,s)) \cdot (x_{DA}(t) - x_{RT}(t,s))$$

First-stage constraints:

$$x_{DA}(t) = x_{DA}^{PV,del}(t) + x_{DA}^{B,dis}(t) + x_{DA}^{B,ch,G}(t) \tag{2}$$
$$x_{DA}^{PV,del}(t) + x_{DA}^{PV,B,ch}(t) \leq C_{max}^{PV} \tag{3}$$
$$x_{DA}^{B,ch}(t) = x_{DA}^{B,ch,G}(t) + x_{DA}^{PV,B,ch}(t) \tag{4}$$
$$x_{DA}^{B,ch}(t), x_{DA}^{B,dis}(t) \leq C_{powercap.}^{B} \tag{5}$$
$$0 \leq SOC_{DA}(t) \leq C_{Emax}^{B} \tag{6}$$
$$SOC_{DA}(t) = SOC_{DA}(t-1) + x_{DA}^{B,ch}(t) \cdot \eta - x_{DA}^{B,dis}(t)/\eta \tag{7}$$

Second-stage constraints:

$$x_{RT}(t,s) = x_{RT}^{PV,del}(t,s) + x_{RT}^{B,dis}(t,s) + x_{RT}^{B,ch,G}(t,s) \tag{8}$$
$$x_{RT}^{PV,del}(t,s) + x_{RT}^{PV,B,ch}(t,s) \leq PV_{RT}^{gen} \tag{9}$$
$$x_{RT}^{B,ch}(t,s) = x_{RT}^{B,ch,G}(t,s) + x_{RT}^{PV,B,ch}(t,s) \tag{10}$$
$$x_{RT}^{B,ch}(t,s), x_{RT}^{B,dis}(t,s) \leq C_{powercap.}^{B} \tag{11}$$
$$0 \leq SOC_{RT}(t,s) \leq C_{Emax}^{B} \tag{12}$$
$$SOC_{RT}(t,s) = SOC_{RT}(t-1,s) + x_{RT}^{B,ch}(t,s) \cdot \eta - x_{RT}^{B,dis}(t,s)/\eta \tag{13}$$

In addition, initial and final SOC were constrained to $SOC(0), SOC(T) = C_{Emax}^{B}/2$, and the battery was constrained with a binary variable to prohibit simultaneous charging and discharging, forming a mixed-integer linear program (MILP) problem. The model is programmed in Python Pyomo 6.7.3 using the Gurobi solver.

D. Deterministic evaluation model (real-time)

A deterministic model was run to evaluate the bidding strategy. The mathematical formulation remains the same, but x_{DA} is fixed from the results of the bidding model. Uncertainty is removed by replacing stochastic variables ΔP and PV^{gen} with historical real-time data. The model is solved deterministically for the remaining second-stage decision variables. The objective value evaluates performance against real data.

III. Results and Analysis

The results were generated for 6 individual days, one weekday selected per month from July to December, 2020. For each day, the three different configurations were run for the stand-alone PV power plant, the stand-alone battery, and the hybrid PV-battery power plant. The results are presented and analysed according to the research aims from section I:

(1) Verifying the extreme bidding behaviour of a stand-alone PV power plant in a single-price balancing market structure.

TABLE I
NOTATION DEFINITIONS. DECISION VARIABLES IN BOLD FONT.

Symbol	Definition
T, S	Set of time periods T, scenarios S
π_S	Probability of scenario S
System Constraints	
$C_{max.}^{PV}$	Max PV capacity
$C_{powercap.}^{B}$, C_{Emax}^{B}	Max battery power, energy capacity
η	Battery efficiency
Day-Ahead Market Variables (Set T)	
P_{DA}	Day-ahead market price
x_{DA}	Energy dispatched
$x_{DA}^{PV,del}$, $x_{DA}^{PV,B,ch}$	PV power to grid & to battery charge
$x_{DA}^{B,dis}$, $x_{DA}^{B,ch}$, $x_{DA}^{B,ch,G}$	Battery discharge, charge & grid charge
$SOC_{DA}(t)$	Battery state of charge at t
Real-Time (RT) Variables (Set T, S)	
ΔP	Real-time price adjustment
PV_{RT}^{gen}	Available PV generation
x_{RT}	Energy dispatched
$x_{RT}^{PV,del}$, $x_{RT}^{PV,B,ch}$	PV power to grid & to battery charge
$x_{RT}^{B,dis}$, $x_{RT}^{B,ch}$, $x_{RT}^{B,ch,G}$	Battery discharge, charge & grid charge
$SOC_{RT}(t)$	Battery state of charge

(2) Determining if the difference in time granularity between the day-ahead and balancing market impacts bidding strategy.

(3) Assessing the economic value of portfolio bidding for a hybrid PV-battery plant under a single-price balancing market.

Fig. 2 displays the expected balancing premium, the day-ahead price, and the individual bids of the stand-alone plants compared with the hybrid bid, alongside the expected imbalance volume. Since the day-ahead bid is placed at hourly time granularity, the hourly means of expected real-time outcome are indicated to show the foresight perspective of the bidding plant at the time of the day ahead bid placement. Due to its significance, the hours with mean negative hourly expected balancing premium are highlighted in light blue.

A. Stand-alone PV bidding

The results support the hypothesis that risk-neutral PV assets will bid at the extremes in a single-price balancing market, if not subject to additional regulations. Examining Fig. 2 (a) and (c), it can be seen that the PV bid is determined by the expected balancing market premium, not the forecasted PV generation. These extreme bids occur because the bid is settled according to the balancing price, rather than penalised for imbalance volumes, meaning there is opportunity for additional profits in the recourse stage of the balancing market.

This results in a market structure that actively incentivises inaccurate day-ahead bids. An example of this in Fig. 2 is the PV bid at maximum capacity during the night, from 02:00 to 03:00. Although this is often avoided by applying external market regulations, this underlying economic behaviour indicates a market gap between optimal bids to the system and the asset owner. Additionally, the extreme bidding strategy can potentially expose risk-neutral VRE bidding assets to greater risks if the expected balancing premium is incorrect.

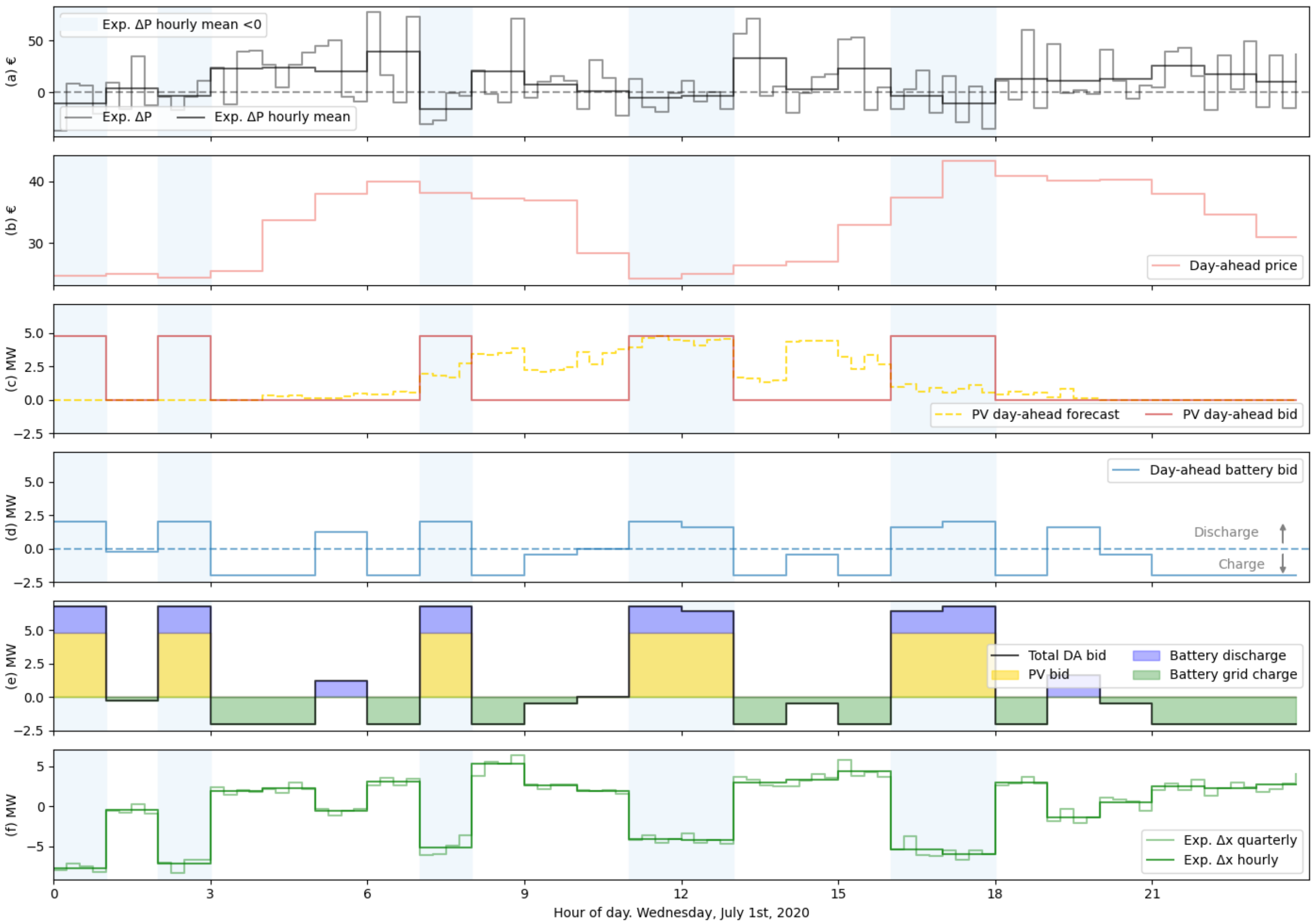

Fig. 2. July 1st, 2020, Cabauw, Netherlands. (a) Quarterly and hourly mean expected balancing premium, as a weighted average of all balancing premium scenarios (€). (b) Day-ahead price (€). (c) Day-ahead bid of the stand-alone PV plant, and quarterly day-ahead PV forecast as a weighted average of all PV scenarios (MW). (d) Day-ahead bid of the stand-alone battery power plant (MW). (e) Day-ahead bid of the hybrid PV-battery power plant (MW). (f) Quarterly and hourly mean expected imbalance volume, as a weighted average of all real-time generation scenarios (MW). Imbalance volume is defined as real-time generation - day-ahead bid (MW). Negative imbalance volume represents shortfall, positive imbalance volume represent production surplus.

B. *Stand-alone battery bidding*

Batteries are generally expected to exploit price arbitrage in the day-ahead market, which dampens price spikes. As such, the expected day-ahead bid would inversely follow the day-ahead price, Fig. 2 (b). However, Fig. 2 (d) shows the stand-alone battery following the same economic incentive as the PV bid and also bidding according to the expected balancing premium. Again, this bid is optimal for the battery operator, to exploit arbitrage between the day-ahead and balancing markets, but suboptimal from a system perspective.

Furthermore, this is interesting due to the dispatchable nature of the plant, showing that under an unregulated, single-price balancing market, all plants are incentivised to bid in the same direction. This confirms the theoretical finding from [1] that the price-taker assumption would no longer be valid and, due to inter-market arbitrage, the day-ahead price and the balancing price will eventually reach an equilibrium. This further confirms the market gap requiring regulatory intervention or policies to discourage extreme bidding.

C. *Impact of time granularity of bidding intervals*

The results indicate that the day-ahead bids are dependent on the hourly mean of the expected balancing premium despite the 15-minute settlement periods of the balancing market. This suggests that the time granularity difference between the day-ahead bid and the real-time balancing market periods does not fundamentally affect the extreme bidding behaviour in a single-price balancing market.

However, the time granularity difference likely increases the bidding plant's exposure to risk. The day-ahead bid is dependent on the hourly mean, which means direction can be influenced by a quarterly price spike in one scenario. In the event that the spike doesn't occur, the expected balancing premium would be wrong, and the plant will have submitted an extreme bid in a non-profitable direction.

D. *Portfolio bidding*

Finally, the value of hybridisation was assessed by analysing the hybrid plant portfolio bidding strategy. Fig. 2 shows that

TABLE II
FINANCIAL RESULTS FROM ONE DAY OF EACH MONTH, FOR STAND-ALONE PV, STAND-ALONE BATTERY, AND HYBRID PV-BATTERY POWER PLANTS.

	Stand-alone			Portfolio
July	**PV**	**Battery**	**Sum**	**Hybrid**
Expected profit (€)	1903	1955	3858	3857
DA profit (€)	2191	-40	2151	2150
Expected RT profit (€)	-288	1995	1707	1707
Actual profit (€)	1585	1855	3440	3440
Actual RT profit (€)	-605	1896	1291	1290
Profit difference (€)	-318	-99	-417	-417
August				
Expected profit (€)	2171	2300	4471	4471
DA profit (€)	1796	-220	1576	1576
Expected RT profit (€)	375	2520	2895	2895
Actual profit (€)	1934	2091	4025	4025
Actual RT profit (€)	138	2311	2449	2449
Profit difference (€)	-237	-209	-446	-446
September				
Expected profit (€)	2263	2058	4321	4321
DA profit (€)	1791	-122	1669	1669
Expected RT profit (€)	472	2180	2652	2652
Actual profit (€)	2302	3148	5450	5450
Actual RT profit (€)	511	3270	3781	3781
Profit difference (€)	39	1090	1129	1129
October				
Expected profit (€)	707	2126	2833	2833
DA profit (€)	1961	-188	1773	1772
Expected RT profit (€)	-1254	2314	1060	1060
Actual profit (€)	202	417	619	619
Actual RT profit (€)	-1759	606	-1153	-1153
Profit difference (€)	-505	-1708	-2213	-2214
November				
Expected profit (€)	1436	1791	3227	3227
DA profit (€)	2585	3	2588	2589
Expected RT profit (€)	-1150	1788	638	638
Actual profit (€)	1882	1939	3821	3821
Actual RT profit (€)	-704	1936	1232	1232
Profit difference (€)	446	148	594	594
December				
Expected profit (€)	705	2025	2730	2730
DA profit (€)	2644	59	2703	2702
Expected RT profit (€)	-1939	1966	27	28
Actual profit (€)	768	1564	2332	2333
Actual RT profit (€)	-1875	1506	-369	-370
Profit difference (€)	63	-461	-398	-397

the hybrid PV-battery day-ahead bid is a simple sum of the stand-alone PV and battery bids, indicating no strategic benefit to hybridisation in a single-price balancing market, compared with co-ownership and individual bids. This finding is confirmed by Table II, in which each metric for the hybrid plant is the sum of the results from the stand-alone PV and stand-alone battery plants, save for small discrepancies that have been verified to be rounding errors. Despite the system interest in smooth, regulated profiles, accurate to the day-ahead bid, the single-price balancing market doesn't incentivise hybrid plants to self-regulate imbalance, nor to reduce intermittency of generation. This confirms the market gap created by single-price balancing markets.

IV. CONCLUSION

The results imply a market gap induced by the the single-price balancing market structure, which fails to incentivise hybrid power plants to self-regulate imbalances or reduce volatility of generation. This gap is attributed to economic motivation to bid to extremes against the expected balancing premium. Although economically rational for the bidder, this behaviour increases market volatility and balancing market costs. In hybrid portfolio bidding, the hybridised technologies bid according to their individual strategy, with no additional value in hybridised operation. This contradicts the common assumption that hybridisation of VREs with storage is economically advantageous due to reduced imbalance penalties.

Furthermore, the current transition to 15-minute settlement periods does not appear to aid this market inefficiency. The results suggest that the differences in time granularity between the day-ahead and balancing markets may also expose bidders to additional risks under uncertainty.

Further research should be conducted in the case of dual-price balancing markets, which are likely to exhibit more strategic behaviour based on previous research. Additionally, the scenario generation from this study assumed no correlation between PV forecast and balancing premium scenarios. Further research should investigate if these results are impacted by correlated PV forecast error and balancing premium direction. In addition, since day-ahead bids are so heavily reliant on the expected balancing premium, the quality of balancing price modelling should be improved. Future studies should aim at identifying market mechanisms to align economic incentives with system reliability objectives, particularly under increasing generation shares of VREs.

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