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Grid Connection Sizing of Hybrid PV-Battery Systems: Navigating Market Volatility and Infrastructure Constraints

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Abstract

The increasing share of intermittent renewable energy generation amplifies power price volatility, raising the need for storage technologies such as battery energy storage systems (BESS). However, limited transmission infrastructure, particularly constrained grid connections, poses a major barrier to the deployment of both BESS and further renewable generation. Co-locating BESS with wind and solar assets can increase grid connection utilization and lower project costs. This study examines the effects of grid connection rationing on hybrid PV-BESS systems, accounting for weather-induced generation uncertainty and price fluctuations. Findings indicate that PV and BESS margins exhibit a strong negative correlation, leading to risk diversification. Grid withdrawal constraints substantially reduce contribution margins and increase risk exposure by lowering the diversification effect. In contrast, hybrid PV-BESS systems can reduce their grid injection capacity by up to 60% of their nameplate capacity without significantly affecting contribution margins or risk, as peak solar generation coincides with low power prices. A market premium payment diminishes the diversification benefits of hybrid PV-BESS systems and encourages greater grid connections by inflating the value of generation during low-price periods. These findings suggest that the central features of the German EEG innovation tender scheme for hybrid BESS systems - grid withdrawal constraints and a market premium - created an unnecessary excess burden for taxpayers.

Keywords: PV-battery storage, Grid constraints, Renewable integration, Diversification, Risk mitigation

JEL classification: C61, C63, D81, L51, Q41, Q42

The contents of this paper reflect the opinions of its author only.

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1. Introduction

The rapid integration of wind and solar power has become central for decarbonizing energy systems globally. However, the inherent intermittency and regional distribution of these renewable energy sources (RES) can create challenges in power systems. Energy storage technologies play a pivotal role in addressing these challenges. While long-term storage, such as hydrogen, addresses seasonal imbalances, battery energy storage systems (BESS) are well suited for providing short-term flexibility, which is essential in power systems with high shares of intermittent RES (Ruhnau and Qvist, 2022).

BESS can offer temporal and spatial flexibility to the power system (Czock et al., 2023). By storing electricity, they shift supply and demand over time, helping to reduce power price volatility. In Europe, price volatility has surged in recent years due to rising and fluctuating commodity prices and a growing share of wind and solar generation. Spatial flexibility is needed to integrate intermittent renewable generation on all voltage levels as curtailment rates increase and grid connection processes become an emerging bottleneck for the energy transition.

The time required to secure a grid connection has increased over the last decade, and grid connection costs have risen substantially (IEA, 2023; Wind Europe, 2024; Gorman et al., 2025). In Germany, legislators decided to limit the grid injection of new residential PV installations to 60 percent of their installed capacity, effectively reducing the available grid connection capacity. Given the increasing competition for scarce grid connection capacity, co-locating BESS with renewable generation — so-called hybrid systems — offers cost-saving opportunities, as they enable a more effective grid access utilization (Schleifer et al., 2023; Chinaris et al., 2025).[1] A co-location also saves costs in planning and construction, reduces energy losses, and enhances the energy value of renewable production (Gorman et al., 2020).

Despite their critical role in the energy transition, battery investments remain in their early stages in many countries. Beyond profitability concerns, regulatory uncertainties and energy market risks are significant barriers to investments in BESS (Côté and Salm, 2022; Jayaraj et al., 2024). Therefore,

[1] The term hybrid BESS system defines assets that combine solar or wind assets and a BESS while maintaining locational and operational linkages, as suggested by Murphy et al. (2021).

many European countries introduced support schemes to enable storage investments in "standalone" and “hybrid” configurations (Paolacci et al., 2024). In Germany, the government has introduced the so-called "EEG innovation tender" to incentivize investments of up to 8 GW of hybrid BESS capacity by 2029. The support scheme pays a market premium on every MWh fed into the grid. This subsidy is tied to grid connection restrictions, as the BESS can only charge from the renewable generation asset, not the grid. Similar requirements exist internationally. For instance, the federal Investment Tax Credit for solar generation assets in the U.S. has historically limited grid charging of battery storage when paired with renewable generation (Kim et al., 2024).

In theory, efficiently designed grid connection rationing or grid connection charges can steer socially optimal market entry decisions for new intermittent renewable energy sources (Newbery and Biggar, 2024; Simshauser and Newbery, 2024). However, the impact of grid connection restrictions on contribution margins of hybrid PV-BESS systems has not yet been quantified. We also lack an understanding of the impact of these restrictions on the related risk of contribution margins, which are crucial for BESS investments. Moreover, the interaction between grid connection sizing and a market premium payment, such as in the German EEG innovation tender scheme, is unclear. To contribute to addressing these gaps, this paper asks: *How do grid connection restrictions and market premium payments affect contribution margins and revenue risks of hybrid PV-BESS systems?*

The analysis is based on a techno-economic mixed-integer linear programming (MIP) model applied to a German case study, simulating the optimal dispatch of a hybrid PV-BESS system against multiple stochastically derived, exogenous price samples. By systematically varying the grid connection configuration, the analysis derives the change in contribution margins resulting from incremental constraints on grid access. This framework enables investors to identify the optimal grid withdrawal and injection capacities by comparing the risk-return profiles of grid cost-adjusted contribution margins. The findings show that hybrid PV-BESS systems exhibit strong diversification effects, significantly reducing contribution margin risk compared to standalone PV or BESS assets. In the absence of regulatory requirements, investors would not reduce the grid withdrawal capacity, as charging restrictions reduce contribution margins significantly and increase associated risks by lowering the diversification of PV and BESS assets. In contrast, grid injection capacities of hybrid

PV-BESS systems can be significantly reduced without impacting margins, as high grid connection utilization levels typically coincide with low power prices. A market premium alters the price signals faced by investors. It incentivizes higher grid injection capacities as power generation during low-price periods becomes more valuable. As the market premium varies with the market value of RES, the diversification benefit of combining PV and storage is reduced. It effectively mutes the negative correlation between PV revenues and BESS arbitrage. The findings are robust for different asset configurations and benchmark years. Policymakers and network operators may need to reconsider support schemes for hybrid PV-BESS systems. Current grid connection restrictions focus on the wrong side of the grid - instead of grid withdrawal restrictions, grid injection could be limited at lower costs. Additionally, market premia could inadvertently incentivize project developers to increase grid connection capacities and raise their financing costs. Subsidy payments from the EEG innovation tender could have been reduced by 50% in 2024 with a more efficient policy design while reaching the same contribution margins.

The structure of this paper is as follows. Section 2 reviews the relevant literature. Section 3 outlines the model framework and describes the numerical assumptions employed in the case study. The results are presented in Section 4, followed by a discussion of their implications in Section 5. Section 6 concludes the paper.

2. Literature review

Several studies have analyzed the value of BESS from a system-oriented and microeconomic perspective. This review focuses on the relevant microeconomic literature on utility-scale storage systems, which takes the perspective of an investor to understand how market developments or regulatory elements impact storage value and the operational dispatch.[2]

The value of standalone storage systems for investors has been investigated intensively. Mercier et al. (2023) analyze the value of storage arbitrage on day-ahead markets across Europe. They find that storage value has increased between 2000 and 2021 and that an additional storage duration beyond four hours has a low marginal benefit. Many studies show that the storage value increases when

[2]Insights from system-level analyses are presented and referenced in Section 5. Zhang et al. (2022) provide a comprehensive literature review of hybrid PV-BESS systems with a strong focus on residential applications.

an asset participates in multiple markets. However, the focus most commonly lies on operational strategies for the participation in day-ahead and ancillary service markets, e.g., aFRR or mFRR markets (e.g., Merten et al., 2020; Nitsch et al., 2021; Hu et al., 2022; Mohamed et al., 2023). Despite their increasing role in storage business cases, intraday markets are less often included in analyses (some examples are Kraft et al., 2023; Collath et al., 2023). Recently, hybrid system configurations coupling intermittent RES and BESS have gained increasing attention. Significant focus has been put on the value of different asset configurations under different price profiles (Schleifer et al., 2022). Keles and Dehler-Holland (2022) investigate the profitability of hybrid PV-BESS systems in Germany and evaluate different storage durations. The analysis reveals that the most profitable storage configuration has a duration of two hours. Similarly, Schreiber et al. (2022) formulate a techno-economic dispatch model for hybrid PV-BESS systems with an application to Germany. To the best of the author's knowledge, they are the only study with an application to the German EEG innovation tender scheme. However, they do not investigate the impact of the respective regulatory features, nor include intraday markets in the analysis.

Another strand of literature analyzes the interaction of hybrid storage systems with the grid. Gorman et al. (2022) analyze the value of hybrid storage systems considering locational prices in the U.S. They show a locational value of storage, which does not necessarily align with the value of the renewable resource in hybrid systems. Similarly, Kim et al. (2024) examine the value of hybrid PV-BESS asset configurations in congested regions in the U.S. They find that the value of hybrid BESS systems varies significantly depending on the renewable share in the regional market. Motivated by the U.S. Investment Tax Credit scheme, both studies analyze binary charging restrictions. The grid connection dimensioning of utility-scale hybrid storage applications has received little attention, as most analyses on the interaction between batteries and grid connection have been limited to residential applications (e.g., Cuenca et al., 2023). Chinaris et al. (2025) are one of the few studies analyzing the impact of utility-scale hybrid storage applications on the utilization of the grid infrastructure. They highlight that grid connection utilization increases when batteries are included in hybrid setups, but exclusively focus on grid injection. None of the studies mentioned above includes multiple markets or investigates varying grid connection capacities and their impact on the investment risk.

Most research that includes elements of uncertainty in its analysis focuses on developing optimal trading strategies to maximize revenue.[3] Literature on the investment risk perspective is scarce, especially for hybrid PV-BESS systems (Hsi and Shieh, 2024). The survey by Côté and Salm (2022) shows that this research gap is especially severe, as investors reveal a strong aversion towards energy market risk. Yu and Foggo (2017) investigate the stochastic valuation of storage from an investor's perspective but do not consider the combination with renewable assets. Some papers analyze the option value and diversification effect of batteries coupled with PV assets, but only focus on residential applications (Parra and Patel, 2019; Andreolli et al., 2022; Ma et al., 2022). Sinsel et al. (2019) are among the few studies that analyze the diversification effect of utility-scale batteries and renewable energy sources from an investor perspective. The paper applies the Modern Portfolio Theory (MPT) and compares a technological (wind, solar, and storage) with a geographical (different generation profiles) diversification.[4] They find that technological diversification reduces risk more effectively than geographical diversification. The paper does not analyze hybrid PV-BESS systems but focuses on general portfolio compositions.

Previous research has proposed using feed-in tariffs to promote energy storage (Krajačić et al., 2011). Feed-in tariffs are widely applied to PV systems coupled with BESS, primarily in residential applications (see Bayod-Rújula et al. (2017) for a review). Therefore, most literature focuses on residential PV-BESS systems when analyzing the impact of feed-in tariffs (e.g., Hassan et al., 2017; Parra and Patel, 2016). To the best of the author's knowledge, feed-in tariffs or market premium schemes for utility-scale hybrid PV-BESS systems and their impact on risk and grid connection have not been analyzed.

Existing research has separately addressed BESS valuation, grid connection challenges, or risk assessment. However, a critical gap remains in understanding their confluence for utility-scale hybrid

[3]See Yang et al. (2022) for a review of operational BESS energy management modeling approaches in renewable energy systems.

[4]See deLlano Paz et al. (2017) for a review of applications of MPT in the field of energy planning and electricity production. Recent examples of MPT applications focusing mainly on wind and solar complementarity can be found in Castro et al. (2022), Li et al. (2024), and Prol et al. (2024).

PV-BESS projects from an investor's standpoint. Specifically, literature is scarce that systematically quantifies how varying grid connection capacities for withdrawal and injection interact with contribution margins, associated risks, and the influence of policy instruments like market premia. Therefore, the main contributions of this study are as follows: First, the paper develops and applies a methodology to quantify the weather-related contribution margin risk for hybrid PV-BESS systems participating in day-ahead and intraday markets. Second, this study provides a systematic microeconomic analysis of how different grid connection configurations affect the contribution margins and risk profiles of these hybrid systems. This is particularly important as most literature on the grid connection of hybrid systems has focused primarily on grid injection or residential applications and has neglected their interactions with risk. Third, this paper offers novel insights into the role of market premium payments, such as those in the German EEG innovation tender scheme, in shaping the economics and risks of utility-scale hybrid PV-BESS systems. The paper analyzes explicitly how a market premium influences the grid connection sizing and the inherent diversification benefits of hybrid assets. Finally, by integrating these elements — grid connection sizing (injection and withdrawal), detailed risk assessment from an investor perspective, and the impact of market premium payments — this paper is the first to comprehensively analyze the interplay of these critical factors for utility-scale hybrid PV-BESS systems, with direct implications for policy design, such as the EEG innovation tender scheme.

3. Methodology

To answer the research question, this study applies a model framework similar to Schlund and Theile (2022) (see Figure 1). A techno-economic MIP problem is formulated to jointly optimize a hybrid PV-BESS system and estimate its optimal dispatch and contribution margins.[5] The dispatch is optimized for exogenous PV generation profiles and corresponding electricity prices.

[5] As the primary analysis focuses on BESS coupled with a PV asset, this section refers to hybrid PV-BESS systems. Still, the methodology also allows for the analysis of hybrid Wind-BESS systems.

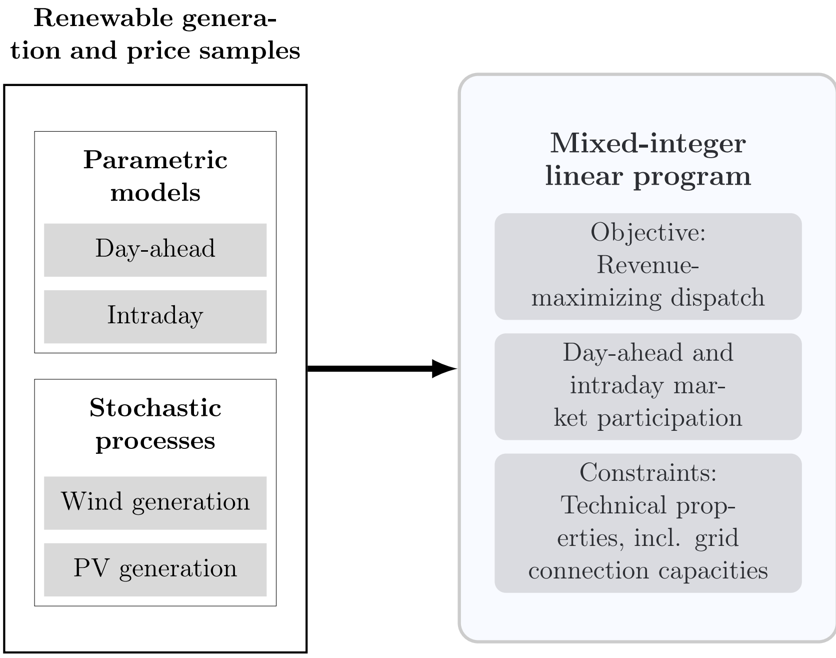

Figure 1: Model framework for the analysis (Own illustration based on Schlund and Theile, 2022).

In contrast to other valuations of hybrid PV-BESS systems, the model considers day-ahead and intraday markets. Other sources of revenue, like ancillary service markets, are not included in the analysis, as previous studies have shown their limited importance for BESS revenues (Keles and Dehler-Holland, 2022). The dispatch is optimized for different asset configurations with varying grid withdrawal and injection constraints to derive the change in contribution margins from incremental grid connection constraints and enable investors to identify cost-optimal grid connection capacities. Additionally, the cases differ depending on whether they receive market premia payments. Exogenous generation and price patterns are derived from stochastic models for renewable energy feed-in and related forecast errors. Two parametric models for day-ahead and intraday markets capture the relationship between wind and solar generation and electricity prices based on the benchmark year 2024. Therefore, the analysis accounts for the interdependency of renewable energy generation and electricity prices, which is crucial for evaluating RES, given the concurrent operation of the plant under evaluation and all other renewable assets selling electricity simultaneously. The model focuses on weather-induced uncertainties, which are an important driver for the value of renewable assets and storage (Mathews et al., 2023).[6] The stochastic nature of the analysis allows for the assessment of related risks and distributions of contribution margins by examining the arithmetic mean values and coefficients of variation (CoV). The CoV, also known as the relative standard deviation, measures the spread of a data set by relating the standard deviation to the mean of the distribution.

3.1. Mixed-integer linear program for hybrid BESS operation

To assess the hybrid PV-BESS system, a techno-economic dispatch model is formulated as a MIP problem. The model is formulated similarly to Mercier et al. (2023) or Schreiber et al. (2022) with adjustments to account for the market participation in intraday and day-ahead markets, the variation of grid access configurations, and market premium payments. The optimization considers the viewpoint of a price-taking power producer managing a renewable generation asset (e.g., solar power generation) coupled with a BESS, aiming to maximize profit. The power producer has access to the day-ahead and the intraday electricity markets. The model is solved for a full year at a quarter-hourly resolution, employing a rolling horizon approach in which the asset is optimized on a daily basis. This approach is especially suited for storage systems with storage durations of up to four hours. The model assumes that the operator has perfect foresight for the next day, given that day-ahead electricity prices and renewable production can be accurately forecasted (Ziel et al., 2015). Section 5 discusses this assumption and its impact on the findings of this paper.

The techno-economic dispatch model maximizes the total gross margin π from arbitrage and power sales over all simulated periods $t \in T$ (1).

$$\max \pi = \sum_{t}^{T} R_t - C_t \tag{1}$$

The revenue R_t in (2) represents the income from spot market sales of the battery $q_{m,t}^{-}$, and the PV asset q_t^{FeedIn}. The battery can sell the stored electricity on the different markets $m \in M$. In this paper, these markets represent the intraday $p_{ID,t}^{-}$ and day-ahead market $p_{DA,t}^{-}$. The electricity from the PV asset is sold at a price p_t^{PV}. Note that, depending on the investigated case, a market

[6] Other sources of risk, such as fuel prices, affect the contribution margins of BESS. These factors are partially addressed in the robustness test for the benchmark year 2019, presented in Section 4.5. However, a comprehensive analysis of other risk sources is beyond the scope of this paper.

premium p_t^{MP} is added to the respective market prices. Therefore, the prices for charging $p_{m,t}^{+}$ and discharging $p_{m,t}^{-}$ might differ between cases.

$$R_t = \sum_{m}^{M} p_{m,t}^{-} q_{m,t}^{-} + p_t^{PV} q_t^{FeedIn} \quad \forall t \in T \tag{2}$$

The cost of charging the battery C_t from the grid depends on the market:

$$C_t = \sum_{m}^{M} p_{m,t}^{+} q_{m,t}^{+} + c_{cycle} * N_t^{cycle} \quad \forall t \in T \tag{3}$$

Additionally, the cost function includes the penalty term $c_{cycle} * N_t^{cycle}$, which accounts for battery degradation based on the total number of cycles (Grimaldi et al., 2025). One equivalent full cycle is defined as the amount of energy throughput (charge or discharge) equivalent to one complete charge-discharge cycle at the battery's maximum energy capacity $\overline{SOC}$ (4). The costs for one cycle are based on the cycle-based degradation and replacement costs of the energy storage. Note that this (virtual) penalty term is not considered when displaying the total contribution margin.

$$N_t^{cycle} = \frac{(\sum_m^M q_{m,t}^{+} + q_t^{+,PV}) * \eta^{BESS} + \sum_m^M q_{m,t}^{-} / \eta^{BESS}}{2 * \overline{SOC}} \tag{4}$$

The model includes several constraints to ensure the system operates within its physical and operational limits. The energy balance constraint (5) ensures that the total renewable energy production q_t^{PV} equals the power sold q_t^{FeedIn}, charged $q_t^{+,PV}$, or curtailed q_t^{curt} at any given time.

$$q_t^{FeedIn} + q_t^{+,PV} + q_t^{curt} = q_t^{PV} \quad \forall t \in T \tag{5}$$

The state of charge (SOC_t) is based on the charging and discharging activities, summarized as Δ_t^{SOC}. For the initial time step ($t = 0$), the SOC_t is set based on the current charging and discharging, i.e., the battery starts empty. For subsequent time steps ($t > 0$), the SOC equals the previous SOC plus the net effect of charging and discharging.

$$SOC_t = \begin{cases} \Delta_t^{SOC} & t = 0 \\ SOC_{t-1} + \Delta_t^{SOC} & \forall t > 0 \end{cases} \tag{6}$$

The net effect of charging and discharging (Δ_t^{SOC}) accounts for the battery's efficiency (η^{BESS}) and is defined as

$$\Delta_t^{SOC} = (\sum_m^M q_{m,t}^{+} + q_t^{+,PV}) * \eta^{BESS} - (\sum_m^M q_{m,t}^{-})/\eta^{BESS} \quad \forall t \in T \tag{7}$$

Several capacity constraints ensure that charging and discharging activities remain within their respective limits. The battery's state of charge cannot exceed its maximum energy capacity. The battery import capacity constraint ensures that the total power used for charging from all sources (day-ahead market, intraday market, and renewable energy system) does not exceed the maximum charging power capacity ($\overline{q^{BESS}}$). Similarly, the battery export capacity constraint ensures that the total power discharged to the day-ahead and intraday markets does not exceed the maximum discharging power capacity.

$$0 \leq SOC_t \leq \overline{SOC} \quad \forall t \in T \tag{8}$$

$$0 \leq \sum_m^M q_{m,t}^{+} + q_t^{+,PV} \leq \overline{q^{BESS}} \quad \forall t \in T \tag{9}$$

$$0 \leq \sum_m^M q_{m,t}^{-} \leq \overline{q^{BESS}} \quad \forall t \in T \tag{10}$$

The grid connection capacity constraints ensure that the total power injected into or withdrawn from the grid does not exceed the grid connection's maximum capacity in the respective direction ($\overline{q^{+,grid}}$, $\overline{q^{-,grid}}$). For the analysis of different grid connection configurations, the respective maximum capacities vary. In the base case, the grid withdrawal capacity equals the BESS capacity, and the grid injection capacity is assumed to equal the cumulative nameplate capacity of the hybrid PV-BESS system.

$$\sum_m^M q_{m,t}^{-} + q_t^{FeedIn} \leq \overline{q^{-,grid}} \quad \forall t \in T \tag{11}$$

$$\sum_m^M q_{m,t}^{+} \leq \overline{q^{+,grid}} \quad \forall t \in T \tag{12}$$

Two conditional (Big-M) constraints (13)-(14) ensure the battery cannot charge and discharge simultaneously using a binary variable I_t^+. Therefore, the model includes an arbitrarily high scalar M. If the binary variable is 1, charging is possible, while discharging is not, and vice versa. To correctly bound the integer constraints, the artificial scalar M is set to be above $\overline{q^{BESS}}$, while it is kept small enough to ensure computational efficiency.

$$\sum_{m}^{M} q_{m,t}^{+} + q_t^{+,PV} \leq I_t^+ * M \quad \forall t \in T \tag{13}$$

$$\sum_{m}^{M} q_{m,t}^{-} \leq (1 - I_t^+) * M \quad \forall t \in T \tag{14}$$

Finally, all variables except for the binary variables are non-negative.

$$0 \leq q_{m,t}^{-}, q_{m,t}^{+}, SOC_t, q_t^{FeedIn}, q_t^{+,PV}, q_t^{curt} \quad \forall t, m \in T, M \tag{15}$$

In some cases, the hybrid PV-BESS system receives a market premium, which is calculated according to the German EEG innovation tender regulation (Verordnung zu den Innovationsausschreibungen, InnAusV) and the Renewable Energies Act (Erneuerbaren Energien Gesetz, EEG). Therefore, the market premium is calculated yearly, as the difference between a strike price ($\overline{p}$) and the average market value of the system-wide PV generation (p^{PV}). The payment of market premia is only applicable if the day-ahead market price in an hour is greater than zero.[7]

$$p_t^{MP} = \begin{cases} \overline{p} - p^{PV} & \text{if} \quad p_{DA,t} > 0 \\ 0 & \text{else} \end{cases} \quad \forall t \in T \tag{16}$$

In cases where grid charging is possible and the hybrid PV-BESS system receives a market premium, it is ensured that the subsidy is only paid for electricity production from the renewable generation asset. In these cases, a new variable $q_{m,t}^{-,PV}$ is introduced, which is compensated with a market

[7]Details can be found in §9 InnAusV, and §23a Appendix 1 (2) EEG.

premium in addition to the respective market price. The constraint (17) restricts $q_{m,t}^{-,PV}$ such that the market premium is only paid for electricity production from the renewable generation asset.

$$\sum_{t}^{T}\sum_{m}^{M} q_{m,t}^{-,PV} \leq \sum_{t}^{T} q_t^{+,PV} \tag{17}$$

3.2. Synthetic renewable generation and electricity price time series

The price patterns for the techno-economic optimization are derived from two parametric models that predict day-ahead and intraday electricity market prices based on stochastic samples of renewable electricity generation forecasts and their corresponding forecast errors.

To model the renewable electricity generation samples, this paper follows the approach of Wagner (2014) and Keles and Dehler-Holland (2022). This approach models wind and solar generation as their respective capacity factors (CF_t^{tech} where $tech \in \{PV, Wind\}$) rather than the underlying wind speed and solar radiation. The capacity factors are logit-transformed to normalize the time series.

The core idea for the solar generation sampling is to capture the primary stochasticity in the daily maximum solar generation while treating the intraday quarter-hourly profile as deterministic. For each day $d \in D$, the maximum normalized value is identified.

$$\overline{CF}_d^{PV} = logit(\max_{t \in d}(CF_t^{PV})) \tag{18}$$

This daily maximum series is deseasonalized to handle yearly variations by subtracting a trigonometric function of the form:

$$\eta_d^{PV} = a_1 \cos(2\pi a_2 d + a_3) + a_4 \sin(2\pi a_5 d + a_6) + a_7 \tag{19}$$

An AR(2) process is fitted to the deseasonalized series ($\hat{\overline{CF}}_d^{PV}$) to capture the temporal autocorrelation:

$$\hat{\overline{CF}}_d^{PV} = \gamma_0 + \gamma_1 \hat{\overline{CF}}_{d-1}^{PV} + \gamma_2 \hat{\overline{CF}}_{d-2}^{PV} + \epsilon_d \tag{20}$$

The wind generation sampling is constructed similarly to the solar generation process. However, the process is based on the complete quarter-hourly time series instead of the daily maximum.

In line with the solar sample generation process, the logit-transformed capacity factors for wind are deseasonalized with the help of a trigonometric function. As proposed by Wagner (2014), an AR(3) model is fitted to the residual time series. The stochastic wind and solar capacity factor simulation is performed by running the respective auto-regressive models forward, using randomly drawn residuals based on the fitted distribution. The simulated series are then re-transformed by adding the seasonal component and reverting the initial transformation (logit-transformation and reverting the daily profile in the case of PV). Finally, the resulting wind and solar capacity factor samples are multiplied by the benchmark year's overall available wind capacity to obtain the final simulated production series. Appendix A presents a statistical analysis of the simulated wind and solar generation forecast series.

The deviation of the actual generation from the renewable generation forecasts, i.e., the forecast errors of wind and solar generation, is modeled according to Wang et al. (2018). A Gaussian Mixture Model based on conditional distributions replicates the dependency of the distribution of forecast errors on the forecast levels. Note that while these models do not incorporate autocorrelation features, the underlying process of the forecast values exhibits autocorrelation characteristics.

Two parametric models capture the relationship between wind and solar generation and electricity prices. Following Schlund and Theile (2022), the first parametric model establishes a link between day-ahead electricity prices p_t^{DA} (the dependent variable) and the forecasted residual load q_t^{res} (the independent variable). Equation (21) presents the corresponding model formulation. Employing a third-degree polynomial captures the non-linear relationship between day-ahead prices and residual load. The functional relationship is not merely a reflection of the merit order; it also implicitly incorporates demand-side price elasticity and accounts for scarcity (Elberg and Hagspiel, 2015). The model is estimated monthly to consider the seasonal effects of renewable generation, demand, and fuel prices.

$$p_t^{DA} = \alpha_0 + \alpha_1 q_t^{res} + \alpha_2 (q_t^{res})^2 + \alpha_3 (q_t^{res})^3 + \epsilon_t \tag{21}$$

The second parametric model explores the relationship between intraday prices p_t^{ID}, which serve as the dependent variable, and the day-ahead prices p_t^{DA}, along with forecast errors from PV (FE_t^{PV})

and wind generation (FE_t^{Wind}), which are the independent variables outlined in equation (22). The forecast errors reflect deviations between actual and predicted outputs for wind and solar generation, while all other influencing factors are held constant. To account for the non-linear relationship and varying impacts of forecast errors on intraday prices, a second-degree polynomial model is employed that differentiates between the forecast errors of PV and wind generation (Kulakov and Ziel, 2021). This functional relationship implicitly incorporates several influencing factors on intraday prices, including scarcity and ramp-up constraints (Pape et al., 2016).

$$p_t^{ID} = \beta_0 + \beta_1 p_t^{DA} + \beta_2 FE_t^{PV} + \beta_3 (FE_t^{PV})^2 + \beta_4 FE_t^{Wind} + \beta_5 (FE_t^{Wind})^2 + \epsilon_t \tag{22}$$

The parametric models capture the functional relation between renewable generation, forecast errors, and electricity market prices. Using stochastic wind and solar generation forecast and realization profiles, synthetic electricity price time series are constructed based on these parametric models.

3.3. Case study design and data

The models are calibrated with historical data from the German electricity market and with technical parameters for the hybrid PV-BESS system. The power system data covers the period from 2015 to 2024. Data on forecasted and realized values for electricity generation and demand are obtained from the German government's data publication platform (BNetzA, 2025b).[8] All data is in quarter-hourly resolution and MWh. Electricity prices, including day-ahead and intraday market prices, are sourced from EPEX Spot. As the German intraday market is continuous, prices vary until settlement. In line with the proposals of Kulakov and Ziel (2021), the model uses the volume-weighted average price of all intraday trades for each quarter-hour period. The parametric models for the electricity prices are fitted to the benchmark year 2024, thereby avoiding distortions arising from the atypical market dynamics in 2020 and 2022. No significant regulatory change affected the intraday and day-ahead market in the benchmark year. The wind and solar generation samples used to derive the corresponding electricity prices are based on the full temporal span of

[8]The realized and forecasted generation data are post-grid stability measures, i.e., re-dispatch. As TSOs' actions influence both parameters, the bias is expected to be negligible.

the dataset. The simulation is run in quarter-hourly resolution over a one-year horizon, using 100 samples presented in Section 4.1.

The parameterization of the hybrid PV-BESS system is informed by existing literature and aligns with the German innovation tender regulation. The assumed parameters represent a typical battery; in practice, the technical and economic characteristics may be more complex and differ based on various factors, such as the cable lengths and the inverter type. The hybrid PV-BESS system is assumed to be AC-coupled and to have a PV-to-BESS ratio of 3:1, which is the standard configuration required under the EEG innovation tender scheme (Figgener et al., 2022). The PV system's generation profile perfectly correlates with the overall PV generation in the market. In other words, the model does not differentiate between the site-specific production and the overall production in Germany. Section 5 discusses the impact of this assumption. The storage duration of the BESS is two hours, which is the required and usual size for hybrid PV-BESS systems in the EEG innovation tender scheme and has been found to be the optimal system configuration (Figgener et al., 2022; Keles and Dehler-Holland, 2022). The round-trip efficiency is assumed to be 85%. Data on degradation for the parametrization of the cycle penalty term is sourced from Grimaldi et al. (2025). In the base case, the hybrid PV-BESS system neither faces grid connection constraints nor receives a market premium. This case serves as a benchmark for comparison with other configurations. Subsequently, the grid connection configurations are changed, and a market premium is introduced. The simulation includes various (partially) asymmetric grid connection capacities, all of which comply with the grid code requirements in Germany. Note that while the physical grid connection capacity might be symmetric, the commercial grid connection depends on the grid connection agreement with the network operator.[9] To compare the profitability of the different grid connection configurations, this paper considers grid connection charges. In Germany, these charges vary by region and voltage level. They are currently debated among regulators and the industry (see Appendix D for an in-depth discussion of German connection charges). The analysis assumes a grid connection charge of 152 EUR/kW, corresponding to an annualized cost of 15 EUR/kW. This value reflects the average high-voltage connection charge applied by major German DSOs and

[9] The technical requirements for connecting batteries to the German power grid are outlined in standards such as VDE-AR-N 4110 and VDE-AR-N 4120. IRENA (2022) provides an overview of international grid codes.

aligns with recent proposals from the Federal Network Agency (Bundesnetzagentur, BNetzA). In Germany, connection charges apply only to grid withdrawal, and no cost figures are available for grid injection capacity (ACER, 2023). Therefore, investors have limited incentives to choose grid connection capacities below the installed nameplate capacity.[10] As an approximation, this analysis assumes the grid connection costs for injection capacity to be similar to connection charges for grid withdrawal, aligning with the principle of symmetric network tariff design (Morell-Dameto et al., 2023; Morell et al., 2021). Table 1 presents all input parameters, along with the cost parameters used for calculating annuities.

Table 1: Input parameters for the hybrid PV-BESS system (own assumptions based on Keles and Dehler-Holland (2022) and Fraunhofer ISE (2024)).

Parameter	Unit	PV system	BESS
Capacity	[MW]	3	1
Storage duration	[h]	-	2
Storage round-trip efficiency	[%]	-	85
Cycle penalty	[EUR/cycle]	-	19.5
Economic lifetime	[a]	30	15
CAPEX	[EUR/kW]	550	720
Fixed OPEX	[EUR/kW/a]	13	20
Interest rate	[% p.a.]	5.3	10
Grid withdrawal capacity	[MW]	[0, 0.25, 0.5, 0.75, 1]	
Grid injection capacity	[MW]	[0.25, 0.5, 0.75, 1, 1.5, 2, 3]	

4. Results

This section presents the results of the techno-economic dispatch model for the case study. The analysis isolates the impact of key features of hybrid PV-BESS systems, such as grid connection restrictions and market premium payments, by examining them separately. First, the section introduces the renewable generation samples and corresponding electricity prices. Then, it presents the base case results, assuming no grid restrictions (neither for withdrawal nor injection) and no market premium payments. This base case illustrates the distribution of contribution margins, their

[10] Note that some incentives may result from savings due to inverter capacity reduction. In Germany, utility-scale PV systems usually have a DC-to-AC ratio between 1.1 and 1.3, meaning the PV array's DC capacity is 10% to 30% higher than the inverter's AC capacity. However, these considerations are not in the scope of this paper, as they are highly project-specific (Cossu et al., 2021).

interdependencies, and the risk diversification potential of PV and BESS assets. Subsequently, the impact of grid withdrawal and injection limits on the techno-economic dispatch and associated margins is analyzed. Next, the effect of market premia is examined. Finally, sensitivity analyses and robustness tests are conducted, considering a co-location with wind and a different benchmark year (2019).

4.1. Electricity market price samples

Following the methodology outlined in Section 3.2, the analysis is based on 100 samples of quarter-hourly renewable generation profiles and corresponding day-ahead and intraday market prices spanning over one year. The model outcomes for the renewable electricity generation samples and the regression analysis of the parametric price models are provided in Appendix A and Appendix B. This section focuses specifically on the simulated price samples. Table 2 presents descriptive statistics comparing 2024 prices with the simulated time series.

Table 2: Price statistics of actual prices and samples in EUR/MWh.

	Day-ahead		Intraday	
	Actual (2024)	Sample mean	Actual (2024)	Sample mean
Mean	79	75	81	79
Std.	53	50	84	53
Min.	-135	-301	-868	-349
5%	0	-3	-5	-8
50%	80	79	80	81
95%	143	144	151	153
Max.	936	389	2902	435
Spread	111	93	228	130

It is worth noting that wind speeds and solar radiation levels in Germany in 2024 were close to their long-term average over the past decade (Bär and Kaspar, 2025). The sample space effectively replicates historical weather variability and produces realistic price patterns. The samples' mean price levels align well with observed market prices. While the model adequately replicates the volatility observed in the day-ahead market, it underestimates intraday market volatility, primarily due to limitations in capturing extreme price fluctuations in the distributional tails. Nonetheless, the generated samples provide a robust and meaningful range for the analysis.

Figure 2 displays the range of price duration curves and average hourly profiles of the day-ahead price samples, illustrating the weather-driven price dispersion. Price variability is most pronounced during periods of high and low residual load, resulting in greater dispersion at both ends of the price duration curve. Conversely, moderate residual load conditions yield smaller price differentials. The visualizations also confirm the negative correlation between renewable generation and electricity prices, underscoring the merit-order effect.

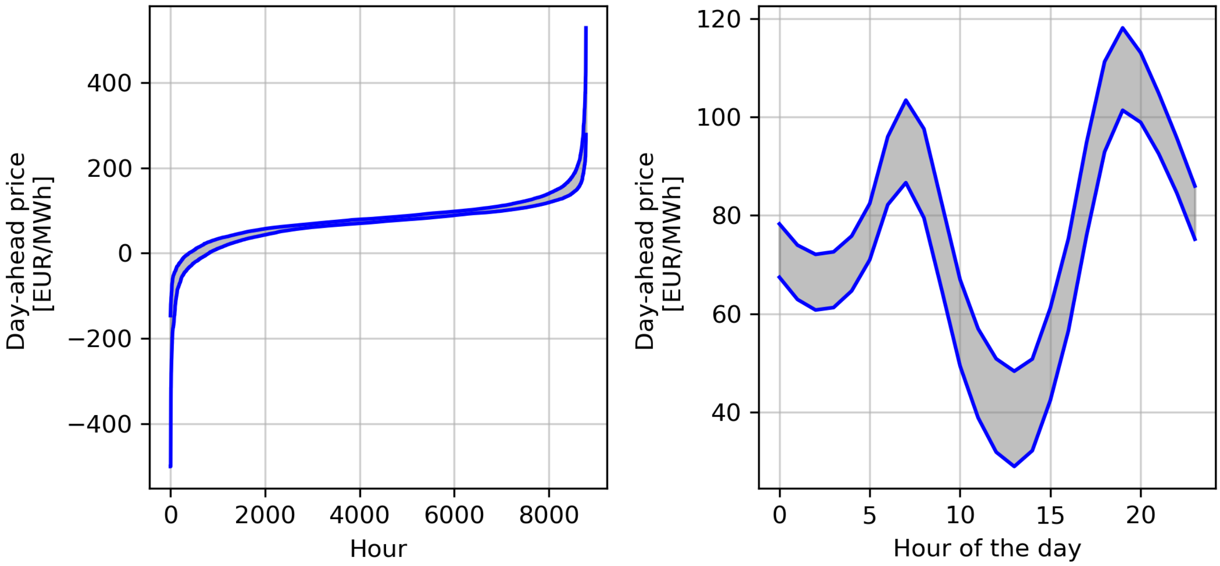

Figure 2: Price duration curve (left) and average hourly profile (right) of day-ahead price samples. The upper and lower limits of the samples are shown.

This effect becomes even more evident in the average daily price profile. Price dispersion peaks at noon, coinciding with the PV generation maximum. During these hours, uncertainty from both PV and wind generation compounds, whereas only wind generation contributes to price variability at night. Consequently, the relative price variance is highest during periods of PV production. This time-variable price variance influences the potential for arbitrage and associated risk mitigation.

4.2. Base case

In the base case, the hybrid PV-BESS system faces no grid connection restrictions and receives no market premium payments. This configuration serves as a benchmark for the comparison with other asset configurations and cases with market premium payments. The primary evaluation metrics are the mean contribution margins and the corresponding CoV. To highlight the individual contributions of each asset to the overall margin of the hybrid system, the analysis separates the margins of the BESS and the PV asset, where applicable. All energy flows between the two assets are valued at the opportunity costs of selling the electricity to the grid.[11]

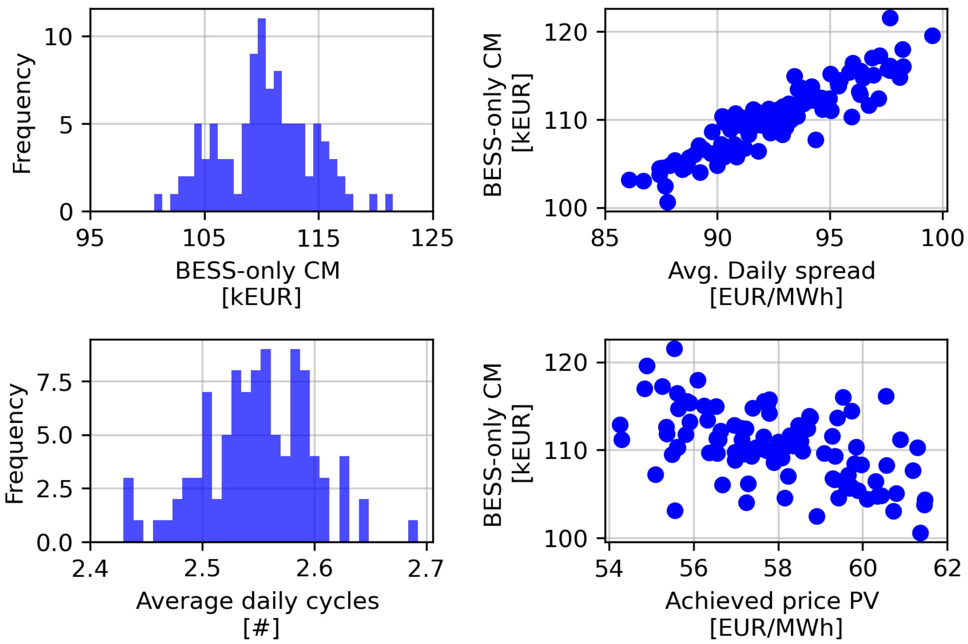

Figure 3: Distribution of margins and cycles in the base case, and relevant correlations.

Figure 3 illustrates the distribution and correlations of BESS margins in the base case. The average BESS margin is 110 kEUR, with a standard deviation of 4 kEUR.[12] The daily cycles are distributed around 2.5 cycles per day. Typically, the BESS charges at night (when demand is low) and at noon (when solar production peaks), while it discharges during the morning and evening peaks (cf. Fig 2). The BESS margins correlate strongly with the average daily spread, defined as the difference between the highest and lowest prices within a day. Thus, the daily spread is a reliable proxy for BESS margins when no operational constraints exist. Furthermore, the BESS margins negatively correlate with the PV asset's achieved price. In other words, the BESS margins increase when PV margins decrease and vice versa. During periods of high PV production, electricity prices tend to drop, causing PV margins to fall if the price reduction outweighs the production increase.

[11]In times of negative prices, it is assumed that the PV asset would otherwise be curtailed.

[12]BESS margins are commonly stated in relative terms. Since the BESS capacity is set to 1 MW, 110 kEUR translates to 110 EUR/kW.

Simultaneously, the BESS can charge at lower prices, resulting in higher margins. This negative correlation creates a strong diversification effect for hybrid PV-BESS systems, significantly reducing their risk compared to the individual assets. Table 3 presents the respective contribution margins and their CoV. The contribution margin of the hybrid PV-BESS system has a CoV that is roughly 40 % lower than the average contribution margin variance of the individual assets.

Table 3: Contribution margin statistics for the respective assets in the base case.

	Unit	Hybrid PV-BESS	PV-only	BESS-only
Mean	[kEUR]	225.84	115.47	110.37
Std.	[kEUR]	5.02	4.66	4.04
Min.	[kEUR]	211.55	102.29	100.61
Max.	[kEUR]	238.17	125.28	121.54
CoV	[%]	2.22	4.04	3.66

It is important to note that a physical co-location of the assets is not a prerequisite for risk diversification. However, co-location may still be advantageous due to project cost savings in planning and constructing hybrid systems. Appendix C offers an excursion on how investors could consider the negative correlation of PV and BESS margins when choosing the optimal PV-to-BESS ratio based on Modern Portfolio Theory.

4.3. Impact of grid connection restrictions

This section presents the change in contribution margins and risks of hybrid PV-BESS systems under different grid connection configurations. For this assessment, the maximum grid injection and withdrawal capacities are varied in equations (11) and (12), respectively. The analysis considers 35 distinct grid connection configurations derived from the capacities listed in Table 1, while holding the nominal capacities of the PV (3 MW) and the BESS (1 MW / 2 MWh) asset constant. Figure 4 illustrates the *grid restriction-induced contribution margin change* (upper panels) alongside changes in contribution margin variance (lower panels).

Restricting the BESS from charging from the grid significantly impacts its contribution margin. Figure 4 (upper left panel) demonstrates a substantial and non-linear reduction in the mean contribution margin of the hybrid system as withdrawal capacity decreases. A complete prohibition on grid charging (0 MW withdrawal capacity) reduces the system's average annual contribution

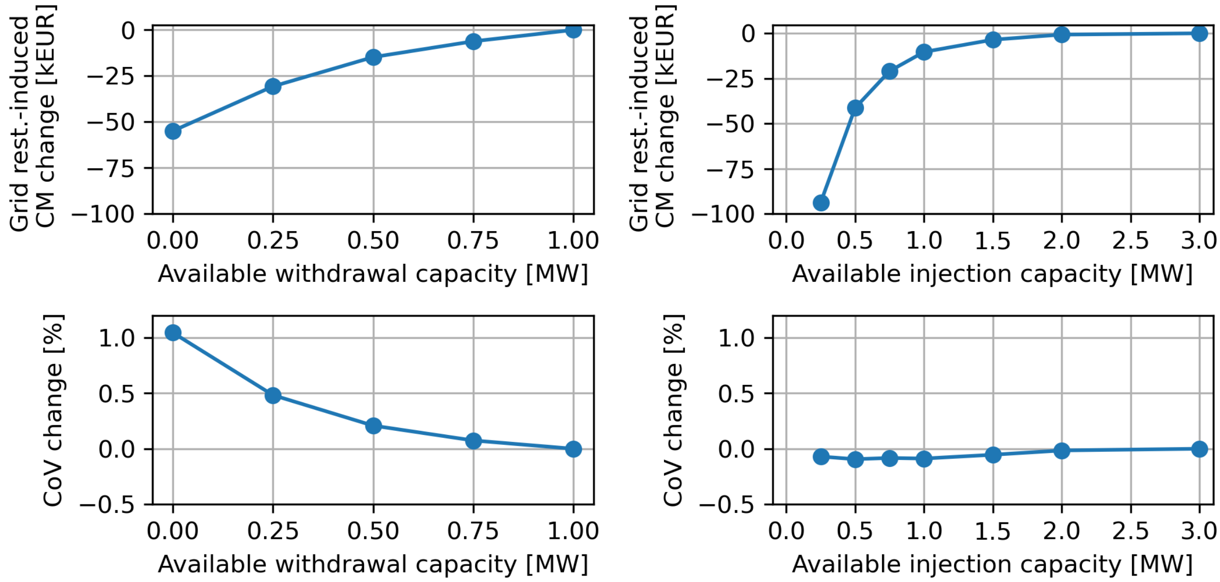

Figure 4: Grid restriction-induced contribution margin change and related changes in contribution margin variance.

margin by approximately 55 kEUR, representing a 25% decrease in the total hybrid system margin and a 50% reduction relative to the standalone BESS margin in the unconstrained base case. The primary economic driver for this loss is the inability to engage in price arbitrage between low-price periods (e.g., overnight) and high-price periods (e.g., the morning peak), significantly reducing the frequency and profitability of BESS cycling. Furthermore, withdrawal restrictions prevent the BESS from charging at negative prices. The effect of partial charging restrictions on revenue is non-linear, as they create an asymmetry in the storage duration. For example, with a grid withdrawal restriction of 50%, a two-hour BESS needs four hours to fully charge the storage while maintaining a two-hour duration for discharging. However, the marginal loss rises as the BESS requires longer charging periods (e.g., eight hours for a 25% grid withdrawal reduction), resulting in higher average charging prices. These findings align with Mercier et al. (2023), who report low marginal benefits from extending storage duration beyond four to six hours. Besides reducing absolute contribution margins, the charging restriction also exacerbates their variance (lower left panel of Figure 4). Reducing the grid withdrawal capacity increases the contribution margin's CoV, which rises by nearly one percentage point under a full charging restriction. This heightened risk exposure stems from the diminished operational flexibility of the BESS, which weakens the negative correlation between

PV generation revenue and BESS arbitrage margins. Two main factors explain this effect. First, unrestricted hybrid PV-BESS systems can exploit negative prices by curtailing PV output and charging the BESS from the grid, effectively getting paid to store electricity. Under withdrawal restrictions, the BESS must absorb otherwise curtailed PV production, losing the chance to benefit from negative prices. Second, limited grid charging reduces the BESS's ability to monetize low PV capture prices. Without grid access, the BESS can only charge from concurrent PV production, while grid-connected systems can charge at full capacity whenever it is most profitable. Consequently, charging restrictions reduce total contribution margins and increase their risk.

In contrast to grid withdrawal constraints, limiting the grid injection capacity has a markedly smaller effect on the hybrid system's economics, especially for capacities above the BESS's nameplate capacity. Figure 4 (upper right panel) reveals that the asset's mean contribution margin remains largely unaffected even with significant reductions in the grid injection capacity. For instance, restricting the injection capacity to 1 MW – one-fourth of the system's combined nameplate capacity – results in a contribution margin loss of only about five percent compared to the unconstrained case. The underlying economic reason is that curtailment of electricity feed-in predominantly occurs during periods of peak PV generation, which frequently coincides with low, or even negative, wholesale electricity prices due to the merit-order effect. Consequently, the opportunity cost of curtailed energy is low. The CoV of contribution margins is virtually unaffected by injection capacity restrictions (Figure 4, lower right panel). In the unconstrained case, the BESS typically charges during these high-PV, low-price periods anyway, meaning moderate curtailment does not substantially alter the system's overall dispatch pattern or risk structure.

Determining the optimal grid connection requires investors to balance the absolute contribution margin (net of grid connection costs) and the associated risks.[13] Figure 5 illustrates the mean-variance relationship of the *grid cost-adjusted contribution margins* across all investigated grid connection configurations. These margins represent the respective contribution margins net of grid connection costs, calculated using the annuitized grid connection charges (cf. Section 3.3). Figure 5

[13] Due to the microeconomic nature of this analysis, "optimality" is assessed from the investor's perspective. Potential implications for system-level efficiency and optimality are addressed in Section 5.

highlights the dominant configurations, i.e., the set of configurations that offer the highest expected grid cost-adjusted contribution margin for a given level of risk (standard deviation).

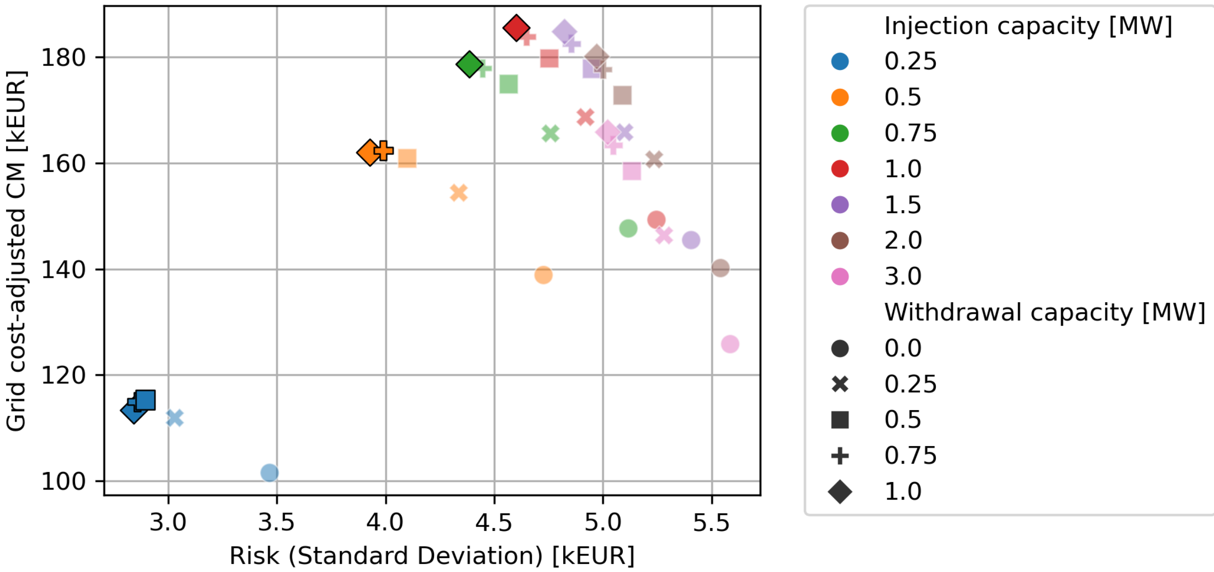

Figure 5: Mean-Variance relation of grid cost-adjusted contribution margins for the different asset configurations. Colors: Various injection capacities; Shapes: Various withdrawal capacities.

For most grid injection capacities, the highest margins are achieved when the grid withdrawal capacity equals the BESS capacity, effectively eliminating charging restrictions. This is indicated by the diamond markers representing the highest values per color on the y-axis. Reducing the grid withdrawal capacity significantly lowers the contribution margin and increases the risk (shifting points down and to the right), rendering such configurations sub-optimal from a risk-adjusted perspective. Conversely, limiting injection becomes attractive once investors consider connection costs. Increasing injection capacity up to the BESS capacity (1 MW) raises grid cost-adjusted contribution margins, as the marginal benefit of avoiding lost revenue outweighs the marginal cost of providing that capacity. Specifically, an injection capacity of 1 MW – one-fourth of the hybrid system's total nominal capacity – yields the highest grid cost-adjusted contribution margin across all asset configurations. Investors would select the optimal grid connection capacities from the set of dominant configurations based on their individual risk preferences. Following the approach of Sinsel et al. (2019), this paper assumes that investors choose the configuration based on the highest

Conditional Value at Risk (CVaR) at the 10% quantile.[14] Under the assumed cost structure, combining unrestricted withdrawal (1 MW) with restricted injection (1 MW) yields the highest CVaR, confirming its optimality for risk-averse investors.

Notably, the sensitivity analysis in Appendix E demonstrates that while the precise optimal grid connection capacities depend on the level of the grid connection charges, unrestricted or minimally restricted withdrawal capacity remains the most profitable option across a plausible range of costs. In contrast, substantial injection capacity reductions are consistently favored. The results robustly indicate an asymmetry: Restricting grid injection is more cost-effective and carries lower risk implications than restricting grid withdrawal for hybrid PV-BESS systems.

4.4. Impact of market premia

Feed-in tariffs, such as a market premium, are a widely implemented policy instrument to support renewable electricity generation. The German EEG innovation tender scheme applies a market premium payment to hybrid PV-BESS systems. This section examines the impact of market premia on contribution margins and financial risks of hybrid PV-BESS systems and assesses their effect on optimal grid connection sizing. As outlined in Section 3, the market premium is determined according to the EEG innovation tender regulation. The subsidy represents a yearly fixed feed-in tariff calculated as the difference between a predefined strike price and the market value of the system-wide PV generation in Germany. This study assumes a strike price of 85 EUR/MWh, consistent with recent EEG innovation tender results. For reference, the average market value of PV generation in Germany in 2024 was 46 EUR/MWh.[15] The market value for solar PV generation is derived from the respective renewable generation and price samples. Furthermore, following current German regulations, market premium payments for hybrid PV-BESS systems are only granted when day-ahead market prices are non-negative. Notably, this exception does not apply to the majority of PV assets operating in Germany.

Table 4 (second column) presents the contribution margin statistics of hybrid PV-BESS systems with market premium payments but without grid connection constraints. The market premium

[14]The findings would not differ when using either the CVaR of the worst 5% quantile or the maximum ratio between the average CM and its standard deviation as a selection criterion for the optimal configuration.

[15]Data on average market values can be found in German TSOs (2025). Previous auction results of the EEG innovation tender are listed in BNetzA (2025a).

increases the total contribution margin of the hybrid PV-BESS system, as the strike price exceeds the average market value of PV generation. This increase primarily results from the higher effective price (market price + market premium) for PV production. The average market premium in the sample space is 44 EUR/MWh, around 75% of the asset-specific market value of PV production (58 EUR/MWh).[16] The contribution margin of the BESS also rises, albeit to a small extent. The BESS benefits from market premium payments on electricity generation that would otherwise be curtailed.

Table 4: Contribution margins for hybrid battery systems under different scenarios.

		Base case	Market premium	Wind co-location	Base Case (2019)	Market premium (2019)
Hybrid	Mean [kEUR]	225.84	316.70	446.43	113.47	245.46
	Std [kEUR]	5.02	10.14	13.24	2.58	8.14
	CoV [%]	2.22	3.20	2.96	2.27	3.32
RES-only	Mean [kEUR]	115.47	202.71	336.13	89.60	220.44
	Std	4.66	6.14	12.76	2.08	6.83
	CoV [%]	4.04	3.03	3.80	2.32	3.10
BESS-only	Mean [kEUR]	110.37	113.99	110.30	23.87	25.03
	Std [kEUR]	4.04	4.82	4.04	1.62	1.88
	CoV [%]	3.66	4.22	3.66	6.81	7.52

Market premia aim to mitigate the risk of renewable assets' contribution margins by reducing market value exposure. When market values decline, the market premium compensates with higher payments, and vice versa, thereby stabilizing revenue streams. As shown in Table 4, introducing a market premium reduces the variance of PV contribution margins by one percentage point relative to the base case. However, the overall contribution margin variance of the hybrid PV-BESS system increases. The reasons for this effect are twofold: First, the market premium increases the contribution margin variance of the BESS, as it can discharge some energy (the energy that was previously charged from the PV asset) at a higher price. Therefore, the BESS benefits twice from low market values, as it can charge at lower prices and discharge at higher prices, leading to a greater variance. Second, market premia weaken the diversification effect between PV and BESS margins in the hybrid system. Since the market premia already hedge the PV asset's market value

[16] Note that the market value of the asset under investigation includes curtailment at negative prices, as incentivized by the EEG innovation tender regulation. In contrast, the majority of Germany's system-wide PV production has limited incentives to curtail during periods of negative prices, leading to a lower system-wide market value.

exposure, the correlation between PV and BESS margins declines. A key factor contributing to this outcome is the structure of the German EEG regulation, which bases the market premium on the system-wide market value of PV generation rather than the asset-specific market value. This misalignment weakens the risk-mitigating function of the market premium, as subsidy payments diverge from the actual dispatch of assets. As a result, instead of lowering the financial risk as intended, the market premium amplifies the contribution margin exposure for hybrid systems. This effect contrasts with the stabilizing influence of market premia on margins for standalone renewable generation assets.

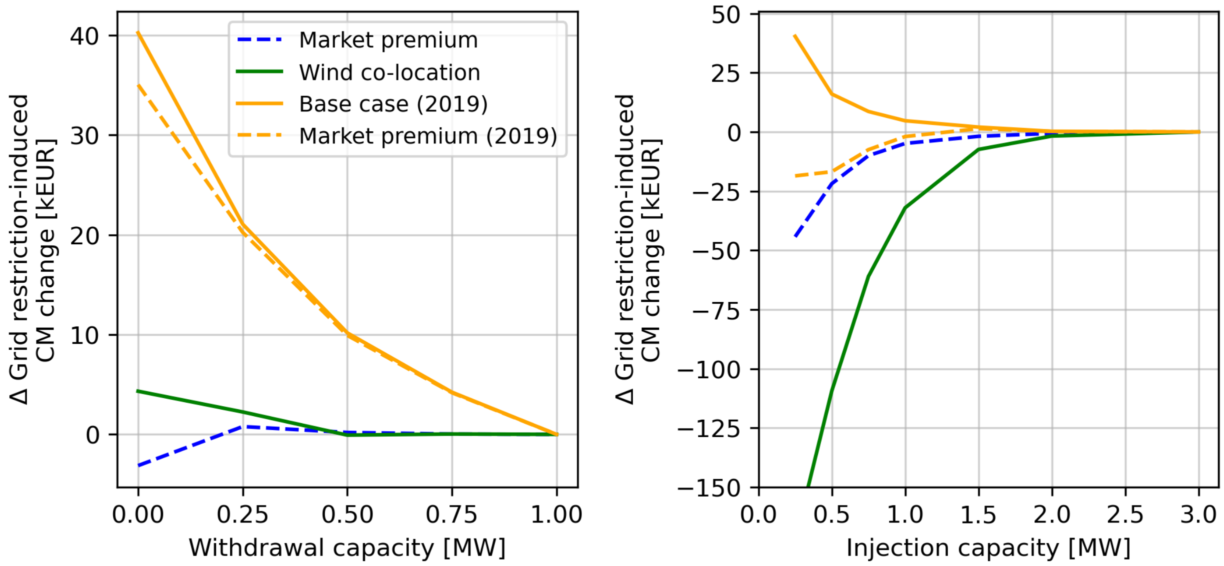

Figure 6: Difference in the grid restriction-induced contribution margin change relative to the base case for different scenarios (represented by the different lines).

Besides their impact on risk and absolute contribution margins, market premia interact with grid connection constraints. Figure 6 illustrates how different scenarios, including the case with market premium payments, influence the grid restriction-induced contribution margin change, relative to the base case shown in Figure 4. A positive difference ($\Delta > 0$) indicates a lower grid restriction-induced contribution margin change than in the base case, i.e., losses from grid restrictions are less severe, and vice versa. The left panel of Figure 6 reveals that receiving a market premium has little effect on the grid restriction-induced contribution margin change. The small difference suggests that grid withdrawal constraints reduce contribution margins similarly, regardless of whether market premium payments are received. The BESS operates comparably in both cases, as its behavior remains unaffected by the subsidy payment. By contrast, grid injection capacity constraints respond differently. Market premia increase the grid restriction-induced contribution margin loss (right panel). Ceteris paribus, investors are likely to opt for larger grid connection capacities when market premia are available. Based on the CVaR, investors would favor a system design with the same withdrawal capacity as in the base case (1 MW) but a higher injection capacity of 1.5 MW. The extent of this effect depends on the available grid injection capacity – the difference in contribution margin change increases with lower grid connection capacities. When grid connection capacity is scarce and associated costs are high, market premia may incentivize greater grid connection capacities than in cases with lower connection costs. This effect is even more pronounced for standalone renewable assets. Appendix F presents the grid restriction-induced contribution margin change of standalone PV and wind assets for cases with and without market premium payments. The analysis shows that wind assets face higher contribution margin changes than PV assets. Furthermore, PV is more sensitive to market premium payments than wind.

4.5. Impact of different asset configurations and robustness tests

The contribution margins of hybrid PV-BESS systems are sensitive to the asset configuration and electricity price dynamics, particularly under grid connection constraints. To illustrate these dependencies, this section extends the analysis to hybrid Wind-BESS systems, offering a comparative perspective relative to PV co-located systems. Furthermore, Appendix G explores how varying PV-to-BESS capacity ratios and extended storage durations change the impact of charging restrictions. Finally, this section concludes with a robustness test using an alternative benchmark year to support the paper's main findings.

4.5.1. Wind co-location

While BESS assets are most commonly co-located with PV assets, integration with wind generation is also feasible. This section examines the implications of substituting PV with wind in hybrid configurations and evaluates the impact on contribution margins. Table 4 (central column) presents the contribution margin statistics of a hybrid Wind-BESS system without grid connection constraints or market premium payments. In this configuration, BESS profitability remains invariant to the co-located renewable source, as the optimal storage dispatch is (almost) independent of the generation profile. However, wind assets achieve substantially higher contribution margins than PV, driven by their superior capacity and value factors.[17] The contribution margin's CoV is greater for hybrid Wind-BESS systems due to a weaker correlation between the respective technologies, implying that PV-BESS configurations offer stronger diversification benefits.

The nature of the co-located renewable asset also influences the grid restriction-induced contribution margin change, thereby altering the optimal grid configuration for investors (see Figure 6). The contribution margin loss induced by grid injection restrictions is significantly higher for hybrid Wind-BESS systems (indicated by the negative values in the right panel), reflecting the higher value factor and reduced price cannibalization associated with wind generation. Wind's higher and more consistent capacity factors (cf. Table A.6 and A.7) exacerbate losses under limited grid injection capacity. Conversely, the contribution margin change induced by grid withdrawal constraints is slightly lower than in hybrid PV-BESS systems. The wind asset's steadier generation profile enables a higher utilization rate of the BESS, leading to higher revenues, particularly in cases where complete charging restrictions are in place. These asymmetries imply that investors would choose a different grid connection configuration when co-locating a battery with wind instead of PV. Under current German grid connection charges, a hybrid Wind-BESS configuration with a 1.5 MW injection and a 1 MW withdrawal capacity yields the highest CVaR. Compared to PV co-located systems, Wind-BESS configurations require greater injection capacity. The core result remains robust despite the distinct grid configuration under wind co-location: Investors would favor restricting grid injection capacity over limiting withdrawal.

4.5.2. A different underlying benchmark year for price patterns

The contribution margins of hybrid PV-BESS systems are sensitive to the underlying electricity price pattern. Consequently, the grid restriction-induced contribution margin changes vary with the price levels and the price volatility. This section conducts a sensitivity analysis using an alternative benchmark year for the sample generation process to assess the robustness of this paper's main findings. Specifically, the parametric models (21) and (22) are recalibrated using data from 2019

[17]Note that wind assets also have significantly higher CAPEX than PV assets.

instead of 2024. Table 5 compares the key characteristics of the resulting price samples. In 2019, fuel prices and installed solar capacity were lower than in 2024, resulting in a price structure characterized by a lower average level and reduced volatility, which is reflected in substantially lower day-ahead price spreads. Despite these changes, the average achieved price for solar generation in 2019 was only 20% lower than in 2024 due to a higher solar value factor driven by lower PV penetration. It is important to note that the average grid connection charge in 2019 was also around 40% lower. Previous studies have shown that distributed generation from renewable energy sources is a significant cost driver for network operators (Just and Wetzel, 2020). These dynamics underscore the dual role of renewable electricity generation in shaping both market outcomes and grid economics. On the one hand, increased renewable penetration raises price volatility and, in turn, enhances storage arbitrage potential. On the other hand, higher shares of distributed generation impose additional costs on the grid, raising connection charges and network tariffs.

Table 5: Metrics for the average price samples for the benchmark years 2024 and 2019.

	Unit	2024	2019
Day-ahead price	EUR/MWh	74.83	38.02
Day-ahead spread	EUR/MWh	92.70	24.50
Intraday spread	EUR/MWh	129.28	39.46
(System-wide) Achieved price PV	EUR/MWh	40.97	32.90
(System-wide) Value factor PV	%	55	87
(Annualized) Grid connection charge	EUR/kW	15	9

The hybrid PV-BESS system's contribution margin in Table 4 reflects the differences in PV market value and the less favorable conditions for arbitrage in 2019, leading to a substantial decline in absolute contribution margins. These findings are consistent with earlier results by Keles and Dehler-Holland (2022), who report a lack of profitability for hybrid PV-BESS systems under 2019 market conditions.[18] Given the variation in absolute contribution margins, the grid restriction-induced contribution margin change differs between the benchmark years (see Figure 6). Lower price levels and a reduced number of negative prices in 2019 diminish the losses from charging restrictions (left panel), making withdrawal constraints potentially more favorable. The contribution

[18] In fact, the contribution margins reported by Keles and Dehler-Holland (2022) closely align with the 2019 base case in this study.

margin loss induced by grid injection restrictions is also sensitive to the underlying benchmark year but diverges notably only at smaller injection capacities. This resemblance indicates that substantial reductions in grid injection capacity remain feasible even under different price environments. Including a market premium payment alters this finding. Given that the market premium was higher under the lower price conditions in 2019, the effective price is similar for the two benchmark years. Therefore, the grid restriction-induced contribution margin change shifts to a similar level as for the case with market premium payments in 2024. The results suggest that the effect of market premia on grid connection configurations becomes more pronounced in low-price environments with reduced market values for renewable generation. In such cases, investors are increasingly incentivized to opt for greater grid connections than in cases without market premium payments. Based on these results and the grid connection charges of 2019, investors would opt for a grid connection configuration with a withdrawal capacity of 0.75 MW and an injection capacity of 1 MW in the absence of a market premium. With a market premium, they would increase the injection capacity to 1.5 MW, while maintaining the same withdrawal capacity. This suggests that, irrespective of the benchmark year, investors tend to limit grid injection more than grid withdrawal. Therefore, regardless of the benchmark year, investors would restrict grid injection to a greater extent than grid withdrawal.

5. Discussion

This study presents an economic framework for determining how grid connection restrictions impact contribution margins of hybrid PV-BESS projects in the presence of risk from variable renewable generation. The analysis provides practical insights into balancing infrastructure costs and risk exposure by quantifying grid cost-adjusted contribution margins and assessing the role of market premia. The results show that the grid injection capacity can be substantially reduced without impacting contribution margins or risk exposure. Conversely, restricting grid withdrawal capacity inflicts significant losses and worsens the risk profile. This asymmetry arises because peak grid injections typically coincide with periods of low prices, while grid withdrawal enables storage to capitalize on price spreads during off-peak hours. The analysis reveals that market premia, such as those in Germany's EEG innovation tender scheme, change the incentives for investors: By increasing the value of generation during low-price periods, the market premium raises the losses from grid injection restrictions, making greater grid injection capacities more profitable. Moreover, the market premium design reduces the diversification benefit of combining PV and BESS, as it mutes the negative correlation between PV revenues and BESS arbitrage that typically stabilizes hybrid asset returns. This effect undermines one of the central advantages of hybrid BESS systems – risk mitigation.

5.1. Implications for the EEG innovation tender scheme

This paper presents a detailed quantitative analysis of two central features of the German EEG innovation tender scheme: the mandatory grid withdrawal constraints (i.e., BESS can only charge from the co-located RES) and the payment of a market premium. The findings suggest that the restriction of grid charging imposes a significant economic penalty on hybrid PV-BESS projects; in 2024 market conditions, this is estimated to be around 50% of the potential standalone BESS contribution margin. Consequently, without these charging restrictions, projects could achieve their target profitability with substantially lower subsidy payments. Extrapolating this indicative saving to the targeted 8 GW of hybrid capacity under the scheme (assuming a similar PV-to-BESS ratio and market conditions) could translate to potential national savings of around 108 mEUR per year. As subsidies are granted for 20 years, the total savings could be up to 2.2 billion EUR (around 61 % of the total subsidies given under this scheme).[19] It is crucial to acknowledge that these figures are illustrative and sensitive to the specific benchmark year and market dynamics; for instance, the 2019 sensitivity showed smaller, though still significant, impacts. Nevertheless, with the continued expansion of RES and a corresponding increase in the frequency and depth of negative prices, the economic burden of such charging restrictions is more likely to escalate than to diminish in the near term. Furthermore, the combination of charging restrictions and the specific design of the market premium not only affects the profitability of hybrid PV-BESS systems but also exacerbates their weather-induced revenue risk. This amplified risk profile could inadvertently increase project financing costs, thereby paradoxically increasing the perceived need for subsidies. While market

[19] While the absolute subsidy savings mainly depend on the impact of charging restrictions, their relative share of the total subsidy payments is highly reliant on the market value of PV.

premia aim to de-risk investments, their effectiveness is diminished when they simultaneously increase exposure to other risk factors or counteract natural hedging mechanisms inherent in hybrid systems. It should be noted that the market premium also mitigates other risks, such as those from a lower absolute price level or regulatory interventions. Should long-term assessments confirm a persistent financing gap necessitating public support, alternative support mechanisms — perhaps decoupled from the per-MWh production, such as availability payments or targeted CAPEX subsidies — might offer more cost-effective means for promoting investment than the current market premium structures. Examples of such policy instruments are the PERTE scheme in Spain and the Cap-and-Floor scheme in the UK (Paolacci et al., 2024). Therefore, German policymakers are encouraged to reconsider the current design of the EEG innovation tender scheme, particularly the efficacy and economic impact of mandatory charging restrictions and the structure of the market premium.

5.2. Potential system implications

Beyond the specific context of the German EEG innovation tender, the microeconomic insights derived from this study offer broader implications for system-level planning and regulatory design. The results of the microeconomic optimization should align with the system-optimal outcome if price signals (from the market and the grid) are efficient and the price-taker assumption holds (i.e., the dispatch of individual hybrid PV-BESS assets does not significantly alter market prices or grid costs). In particular, the selection of grid connection capacity reflects a trade-off between the grid access costs and the temporal market value of storage and renewable generation.

Regulatory charging restrictions for hybrid PV-BESS systems are likely welfare-detrimental, as they diverge from the microeconomic optimal grid connection configuration. These restrictions prevent storage from fully utilizing its temporal system value to the electricity market, which increases with the level of RES penetration, as it mitigates the merit-order and cannibalization effects (López Prol and Schill, 2021). This role as an economic buffer will become critical as negative prices become more frequent and structural in systems with high shares of wind and solar. However, where peak-related grid costs exceed the market value of generation, enforcing or incentivizing grid injection limitations may enhance welfare. In fact, this paper's findings show that for a wide range of grid connection costs, the optimal grid connection capacity (in both directions) is largely determined by the size of the battery. Implementing efficient grid connection charges for grid injection and withdrawal capacity will be critical for aligning private investment decisions with system-level welfare. These charges should reflect the marginal costs of providing a grid connection to new projects. Alternatively, efficiently designed grid access rationing may achieve similar allocative outcomes (Newbery and Biggar, 2024). Recent policy proposals in Germany, such as regional grid connection charges and capacity-based injection restrictions, are consistent with the findings of this paper. Nevertheless, there remains a need to assess whether a unified policy instrument for all market participants, relying solely on price signals or capacity restrictions, can more effectively coordinate decentralized investment decisions.

Previous system-level analyses have shown that the co-location of storage with PV generation can offer spatial flexibility to the power system (Czock et al., 2023; Manocha et al., 2025). In addition to mitigating local and transmission-level congestion, storage investments reduce price risk and offer a diversification value to risk-averse system planners (Diaz et al., 2019; Möbius et al., 2023). These findings imply a strategic co-location value of storage systems for system planners. This paper confirms that hybrid PV-BESS systems can significantly reduce injection capacity with minimal private economic losses, implying a potential for cost-effective grid relief. Moreover, hybrid PV-BESS systems demonstrate greater risk diversification and more favorable cost profiles for curtailing grid injection than Wind-BESS configurations. These features suggest that co-location incentives — particularly those favoring PV — could enhance system efficiency by reducing congestion management costs and the overall system risk. A policy that explicitly links battery deployment to solar generation sites may thus deliver system-wide benefits. Such approaches would align with the suggestions of Czock et al. (2023).

Given the current scale of BESS deployment in Germany, the price-taker assumption for hybrid PV-BESS systems remains valid. However, as BESS deployment scales, system-level interactions will become increasingly relevant. Additionally, a rigorous application of grid connection pricing for injection and withdrawal capacities across all market participants and asset types would alter price signals and likely reduce negative prices driven by excess generation from RES. In such cases, grid connection restrictions would also influence grid congestion and overall system dynamics. Future research should employ system-wide equilibrium models to capture these feedback loops and grid impacts.

5.3. Assessment of model assumptions

Several model assumptions merit further reflection. Recent changes in the European electricity market design, particularly the anticipated shift to 15-minute resolution in the day-ahead market coupling, further amplify the need for flexibility and responsiveness in asset dispatch. Finer market granularity enhances the ability of storage assets to capture short-term price fluctuations. However, interactions with intraday markets are likely, and current price patterns resulting from restricted market participation are expected to change (Knaut and Paschmann, 2019). Future modeling should explicitly incorporate 15-minute day-ahead market granularity to refine the revenue impact. Moreover, the modeling framework assumes that the hybrid PV-BESS system's generation profile aligns perfectly with the system-level PV output. However, fleet-wide capacity factors tend to be more stable than capacity factors of individual assets. This difference arises from geographic diversification and smoothing effects from aggregation. Consequently, project-specific exposure to curtailment risks, negative prices, and forecast errors may be subject to bias. Therefore, fleet-level analysis may understate the impact of grid connection restrictions on renewable assets' contribution margins. However, as BESS can mitigate localized peaks more effectively than system-wide averages suggest, the effect on hybrid PV-BESS systems remains unclear. Future work should differentiate between fleet-level and project-specific generation profiles. The assumption of perfect foresight in the dispatch model likely overestimates the revenue potential of BESS, particularly in intraday markets, which are subject to greater uncertainty than day-ahead markets. According to the paper by Keles and Dehler-Holland (2022), imperfect foresight reduces monthly returns by approximately 20%. Although this assumption applies to all analyzed cases, it may benefit those cases without grid connection restrictions more, given the higher degrees of freedom in trading. On the other hand, excluding ancillary service markets, such as aFRR and mFRR, from the modeling framework might underestimate potential value streams that are more accessible with unrestricted grid connections.

Therefore, grid connection constraints below BESSs' nameplate capacity may limit the participation of hybrid PV-BESS systems in these markets.

6. Conclusion

Integrating large shares of renewable electricity generation, like wind and solar, requires energy storage to manage intermittency and ensure system stability efficiently. Hybrid battery projects, which are co-located with renewable generation, offer a promising option to reduce grid congestion by optimizing grid usage. However, investment decisions in storage are sensitive to revenue risks, especially in volatile power markets.

This paper evaluates the contribution margins of hybrid PV-BESS systems under different grid connection configurations and support schemes. The analysis reveals that hybrid PV-BESS configurations yield significant diversification effects, thereby reducing contribution margin variance compared to standalone assets. Hybrid systems hedge against weather-induced price volatility and fluctuating renewable generation. The results demonstrate that restricting grid withdrawal capacity (charging from the grid) significantly reduces contribution margins and increases risk exposure. In contrast, grid injection capacity can be substantially limited, resulting in only minor losses. This asymmetry arises because peak grid injection often coincides with periods of low prices, while withdrawal restrictions eliminate valuable arbitrage opportunities during off-peak hours. Moreover, the analysis reveals that market premia incentivize larger grid connections by increasing the value of generation during low-price periods. In contrast to the subsidy's intention, a market premium increases the contribution margin variance of hybrid PV-BESS systems by weakening the diversification and the correlation of PV and BESS margins.

The study finds that the grid connection design for hybrid PV-BESS systems depends strongly on grid connection costs and policy design. Current charging restrictions and market premium structures in the German EEG innovation tender scheme could misalign private incentives with system efficiency. Policymakers and regulators should reconsider the structure of hybrid PV-BESS support schemes. Efficient grid connection charges, which account for both injection and withdrawal, combined with production-independent subsidies, could better align investor behavior with system-level efficiency.

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Appendix A. Synthetic RES generation and forecast error samples

This section reports the outcomes of the stochastic modeling processes applied to wind and solar power generation. Detailed statistics on the forecasts for wind and solar generation are presented in Table A.7 and A.6. The columns labeled 'Min.' and 'Max.' denote the years with the minimum and maximum average generation, respectively, highlighting the inter-annual variability in renewable output. The stochastic process effectively replicates the average production levels and their associated volatility, while also capturing the observed range between annual generation volumes.

Table A.6: Summary of PV capacity factor samples and actual data in [%].

	Actuals			Samples		
	Min.	Mean	Max.	Min.	Mean	Max.
Mean	9	10	11	9	10	11
Std.	14	15	17	14	15	17
CoV	152	153	152	152	154	154
Min.	0	0	0	0	0	0
Max.	59	69	67	59	77	81

Table A.7: Summary of Wind capacity factors samples and actual data in [%].

	Actuals			Samples		
	Min.	Mean	Max.	Min.	Mean	Max.
Mean	17	20	23	17	20	23
Std.	13	16	18	14	16	17
CoV	78	79	77	84	78	75
Min.	1	0	0	1	1	0
Max.	73	86	78	88	86	89

To evaluate the performance of the stochastic model in replicating forecast errors, Table A.8 presents standard forecast accuracy metrics, specifically the Mean Absolute Error (MAE) and Mean Absolute Percentage Error (MAPE). These metrics are benchmarked against observed historical data. The results indicate that the Gaussian Mixture Models (GMMs) effectively capture both the magnitude and distribution of absolute and relative forecast deviations.

Table A.8: Summary of forecast errors metrics for wind and solar.

	Wind				PV			
	MAE [MWh]		MAPE [%]		MAE [MWh]		MAPE [%]	
	Actual	Samples	Actual	Samples	Actual	Samples	Actual	Samples
Mean	267	277	14	13	98	106	10	13
Min.	224	258	13	11	82	89	8	13
Max.	298	299	16	14	143	124	14	14

Appendix B. Regression results

Figure B.7 presents the in-sample forecast based on the regression estimates for the day-ahead market for the year 2024.

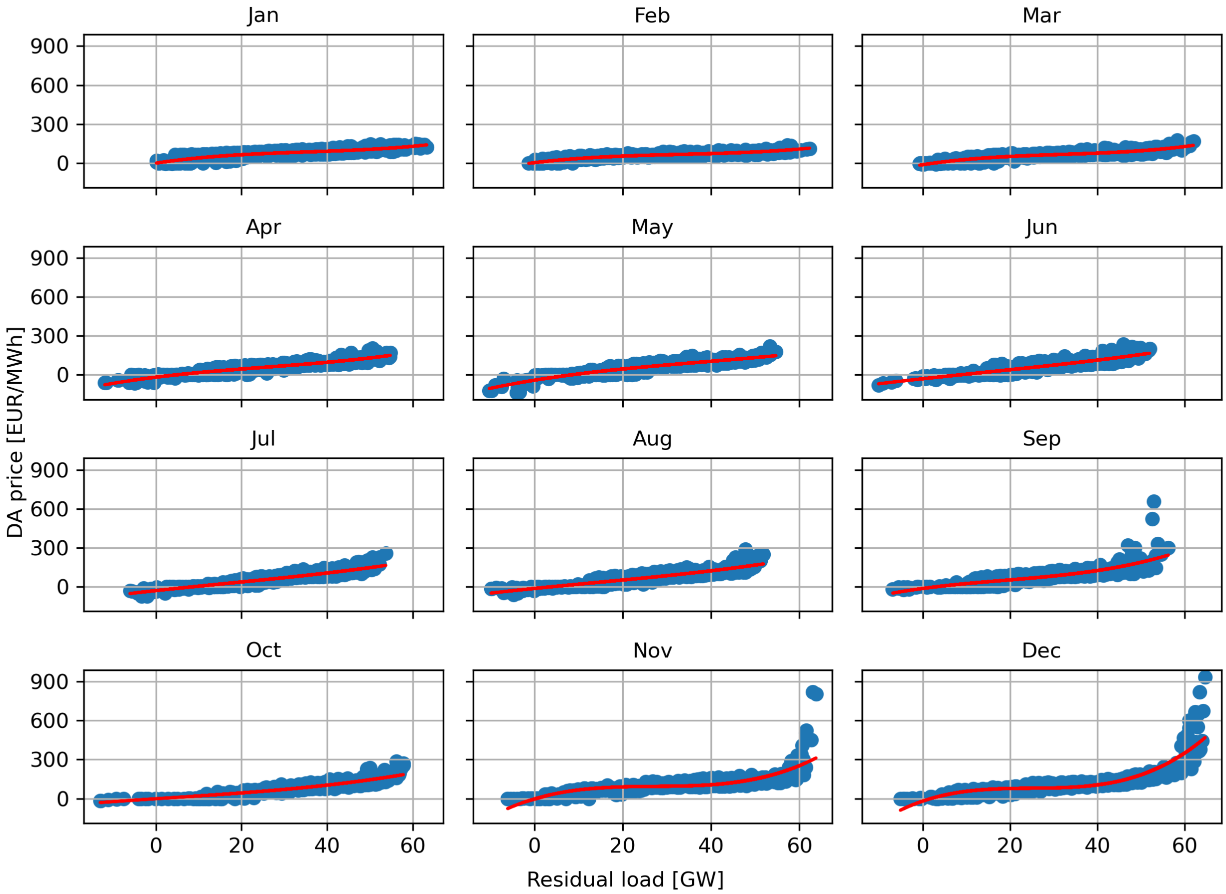

Figure B.7: Day-ahead regression results by month.

The results for the intraday market regression are reported in Table B.9. In this context, forecast errors are defined as the difference between realized and forecasted generation, where positive values indicate excess supply, which have a negative effect on intraday prices. The estimated coefficients are broadly consistent with the magnitudes reported in earlier literature, such as Kulakov and Ziel (2021). The intercept reflects the observed intraday price premium in 2024, which may be attributed to the presence of a forward or risk premium (Obermüller, 2017) or to unobserved factors such as unplanned outages, which have a price-increasing effect on the intraday market.

PV forecast errors exert a stronger influence on intraday prices than wind forecast errors. This differential impact may stem from the temporal patterns of PV forecast errors, which typically occur during midday ramps — periods when flexible thermal generation units are either offline or undergoing their own ramping processes, thus limiting system flexibility. The existence of threshold effects related to the share of demand met by renewable energy sources is shown by Kiesel and Paraschiv (2017).

Table B.9: ID regression results.

	Coefficients	Standard Errors	t-values	p-values
β_0	2.45	0.522	4.696	0.000
$\beta_1(p_t^{DA})$	1.07	0.006	167.119	0.000
$\beta_2(FE_t^{PV})$	-2.66	0.118	-22.654	0.000
$\beta_3(FE_t^{PV})^2$	0.15	0.012	12.289	0.000
$\beta_4(FE_t^{Wind})$	-1.96	0.070	-27.917	0.000
$\beta_5(FE_t^{Wind})^2$	-0.02	0.006	-3.598	0.000

Appendix C. An application of Modern Portfolio Theory to hybrid PV-BESS assets

Given the negative correlation between PV and BESS margins, Modern Portfolio Theory (MPT) can be used to determine the optimal ratio between the PV and BESS assets. MPT suggests that investors can optimize their portfolios to achieve the highest expected return for a given level of risk, emphasizing the importance of diversification. Combining assets with varying but correlated returns, such as renewable generation assets and batteries, minimizes overall portfolio risk. MPT introduces the concept of an efficient frontier, representing the set of portfolios that offer the best risk-return trade-offs. To construct the efficient frontier, the returns for each technology are calculated by dividing the respective contribution margins by the corresponding annuities, based on the cost data in Table 1. Given these returns, the average, standard deviation, and covariance matrix are computed. Varying the financial weights of the technologies, while ensuring their sum equals one, yields different portfolio combinations. Portfolio returns and standard deviations are then determined using standard portfolio theory formulas. The efficient frontier comprises all portfolios that maximize expected return for a given level of risk. The capital allocation line is based on the optimal portfolio determined by the Sharpe ratio. The Sharpe ratio measures the risk-adjusted return of an investment by comparing its excess return over a risk-free rate to the standard deviation of its returns. The calculation assumes a risk-free rate of 2.41% based on the interest rate for a 10-year German government bond (European Central Bank, 2025). Finally, the physical weights of each technology are derived by scaling the financial weights by their respective annuities. Unlike financial weights, the physical weights represent the share of each respective technology in megawatts (MW). Figure C.8 shows the efficient frontier for the hybrid PV-BESS systems in the base case and the corresponding physical weights of the technologies. The selection of the optimal portfolio depends on the risk aversion of investors.

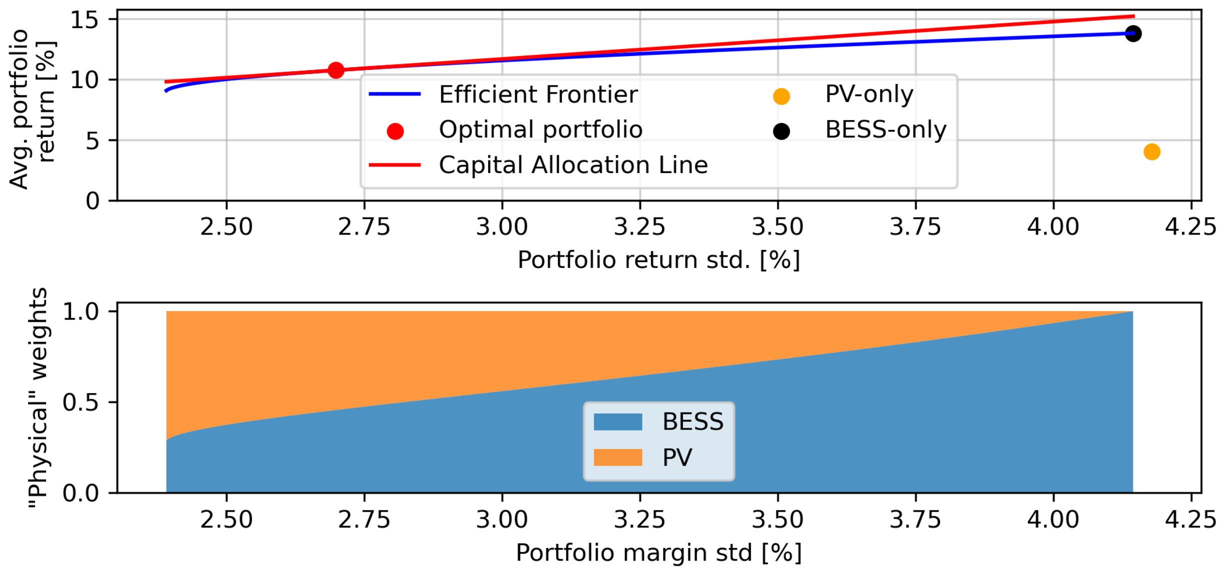

Figure C.8: Efficient frontier of hybrid PV-BESS system and analysis of respective weights.

The optimal portfolio, based on the Sharpe ratio, and the respective standalone assets are highlighted. The optimal hybrid PV-BESS system has a PV-to-BESS ratio of 1.2:1. For a total system capacity of 4 MW in the base case, this translates to a configuration of 2.2 MW PV and 1.8 MW battery capacity. As investors' risk appetite increases, the share of batteries in the portfolios along the efficient frontier rises. In contrast to a standalone BESS, a standalone PV asset (PV-only) is not part of the efficient frontier. PV-only assets deliver comparatively low returns while exhibiting a high risk. Therefore, an investment in a standalone PV asset would not be profitable in this case study.

It is important to note that the financial performance of each asset depends on the underlying electricity price structure (cf. Section 4.5). Investment decisions require an assessment of expected price trajectories over the full asset's operational lifetime. Nevertheless, the proposed methodology offers a robust framework that is applicable over extended horizons. Moreover, investment and financing costs play a major role in determining the optimal portfolio. Future research could enhance the approach with different technology options, such as wind or electrolysis, and consider a broader market portfolio as an alternative investment.

Appendix D. Grid connection charges in Germany

Efficiently designed network tariffs play a critical role in guiding investment decisions and supporting market design, particularly in power systems operating under uniform pricing regimes (Jeddi and Sitzmann, 2021; Arnold et al., 2022). Such tariffs include grid connection charges —upfront, one-time payments required for new grid connections — which are intended to signal grid-related costs and steer investments accordingly (Jeddi and Sitzmann, 2019). In Germany, the regulatory framework surrounding grid connection charges for batteries is currently under legal and regulatory scrutiny. Historically, BESS assets have been subject to the same principles as other consumers, with charges based on the system's grid withdrawal capacity and the applicable capacity tariff at the corresponding voltage level of the DSO or TSO. However, a recent court decision classified this practice as discriminatory, prompting the BNetzA to refer the matter to the Federal Court of Justice (OLG Düsseldorf, 2024). In its subsequent position paper, the BNetzA reaffirmed the general appropriateness of applying grid connection charges to BESS based on capacity tariffs (BNetzA, 2024). The paper proposes a tiered system for TSOs, consisting of five levels, with the highest tier reflecting the full capacity charge and the lowest set at 20% of that amount. The applicable tier is to be determined by the locational value of the connection, reflecting grid congestion levels and the need for expansion. This locational differentiation aims to incentivize siting in grid-favorable areas. Based on the current proposal and the published capacity tariffs of German TSOs, the current proposal would imply a cost of approximately EUR 20–100 per kW for BESS connections to the extra-high voltage grid. This range corresponds to roughly 3–13% of the capital expenditure (CAPEX) for a two-hour duration BESS. It is important to note that capacity charges vary substantially across voltage levels and among DSOs. As a significant share of planned BESS installations are expected to connect at the high-voltage level via DSOs, the average grid connection charge for this voltage level is calculated based on published figures from the four largest DSOs in Germany, as reported by the BNetzA. The resulting average charge is presented in Table D.10.[20] The resulting average connection charge for the high-voltage grid is 133 EUR/kW, or an annuity of 15 EUR/kW.

Table D.10: Overview of BKZ for 2025 and (annuity) in EUR/kW.

	TSO	DSO average (High-voltage)	DSO average (Medium-voltage)
Full capacity charge (100%)	103 (10)	139 (14)	152 (15)
Reduced capacity charge (20%)	21 (2)	18 (3)	30 (3)

Appendix E. Optimal grid connection capacities under various marginal grid connection costs

This sensitivity analysis investigates how the optimal configuration of grid access for hybrid PV-BESS systems responds to variations in the connection costs for grid injection and withdrawal capacity. The analysis is based on identifying the configuration that maximizes the CVaR. Figure E.9 presents the results, illustrating the optimal levels of grid withdrawal (left panel) and injection (right panel) capacity across a range of grid connection costs. The findings indicate that a complete restriction on grid charging is suboptimal under moderate marginal withdrawal costs. In contrast, limiting grid injection capacity is optimal even when grid connection costs are moderate. The analysis reveals a notable interaction between the connection costs of grid injection and

[20] The four largest DSOs by overhead line length—excluding the German railroad network—are identified as Westnetz GmbH, Avacon Netz GmbH, Bayernwerk Netz GmbH, and Netze BW GmbH.

withdrawal capacity. Under asymmetric charging schemes, an increase in grid injection costs leads to a reduction in both the optimal grid injection and withdrawal capacities. Higher injection costs diminish the economic value of feeding electricity to the grid, which in turn reduces the value for grid-based charging. As a result, the battery charges more from the PV asset. Furthermore, lower grid withdrawal capacity constrains the system's ability to capitalize on short-duration price spikes. This dynamic underscores the importance of considering not only absolute grid connection costs but also their interactions when designing grid charging schemes for hybrid renewable systems.

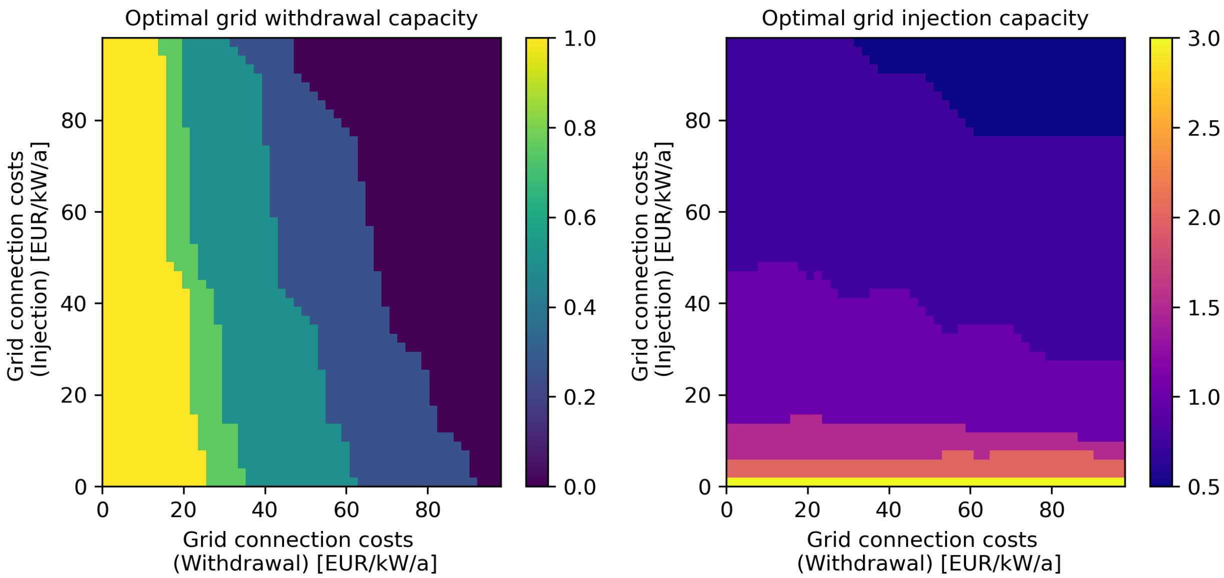

Figure E.9: Optimal grid connection configurations depending on the marginal grid connection costs.

Appendix F. The impact of market premia on standalone wind and PV assets

This section presents the impact of grid injection restrictions on contribution margins of standalone renewable energy assets, distinguishing between cases with and without market premium payments. The analysis compares solar and wind generation to evaluate how their respective characteristics influence sensitivity to grid constraints. PV assets exhibit a lower contribution margin reduction than wind assets. This outcome is primarily driven by two factors: the generally lower market value of PV generation and the less frequent occurrence of high-capacity utilization. As a result, restricting grid access imposes a comparatively smaller economic loss on PV systems. Market premium payments increase the loss from grid injection restrictions for both technologies. However, the magnitude of this effect differs. The increase is less pronounced for wind assets, reflecting their typically lower market premia. In contrast, PV assets experience a stronger sensitivity, as market premia are higher.

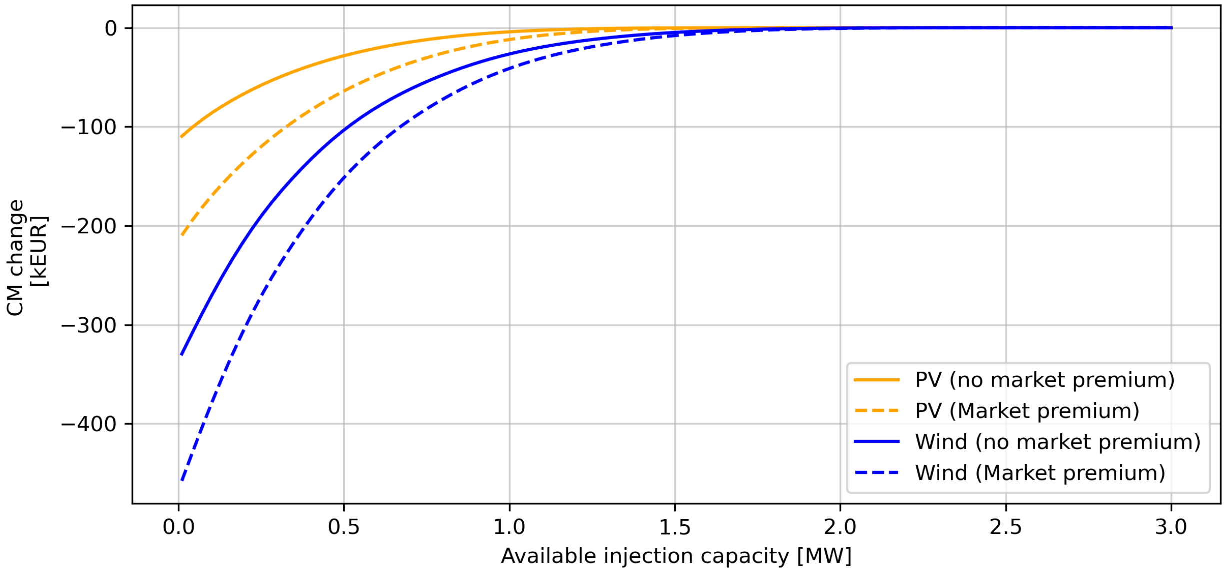

Figure F.10: Contribution margin changes for different RES assets with and without market premium payments.

Appendix G. Sensitivity analysis of different storage durations and PV-to-BESS ratios

Given the significance of charging restrictions for hybrid PV-BESS systems in the German EEG innovation tender scheme, this section examines how different asset configurations influence their impact. Notably, all analyzed cases exclude market premia.

Table G.11 presents contribution margin statistics for storage durations of two and four hours in the base case and for configurations with grid charging restrictions. The findings reveal three key insights. First, doubling the storage duration does not result in a proportional increase in contribution margin, indicating diminishing marginal benefits of additional storage — consistent with previous studies (e.g., Mercier et al., 2023). Second, the relative risk of contribution margins remains nearly unchanged for systems with two- and four-hour storage durations, particularly in the base case. This suggests that longer storage durations do not significantly influence risk. Third, the effect of charging restrictions on average contribution margins increases in absolute terms as storage durations increase.

Table G.11: Impact of different storage durations on the absolute contribution margin.

	2h duration Grid charging	No grid charging	Difference [%]	4h duration Grid charging	No grid charging	Difference [%]
Mean [kEUR]	225.84	170.83	-24.36	273.11	196.23	-28.15
Std. [kEUR]	5.02	5.58	+11.21	6.14	6.05	-1.56
CoV [%]	2.22	3.27	+47.03	2.25	3.08	+37.01

Beyond storage duration, PV-to-BESS ratios also shape the impact of charging restrictions. Figure G.11 illustrates how contribution margins vary with installed BESS capacity. In the base case, where the grid connection is not constrained, the contribution margin increases linearly with installed BESS capacity. The relative contribution margin remains constant when grid charging is permitted, as grid injection capacity scales with the combined PV-BESS capacity. However, in cases with charging restrictions, the contribution margin increase follows a concave pattern. A higher PV-to-BESS ratio limits the amount of PV generation available for charging. Yet, even for very high ratios (1:1), revenue continues to increase, as the BESS can discharge more stored electricity at the highest price.

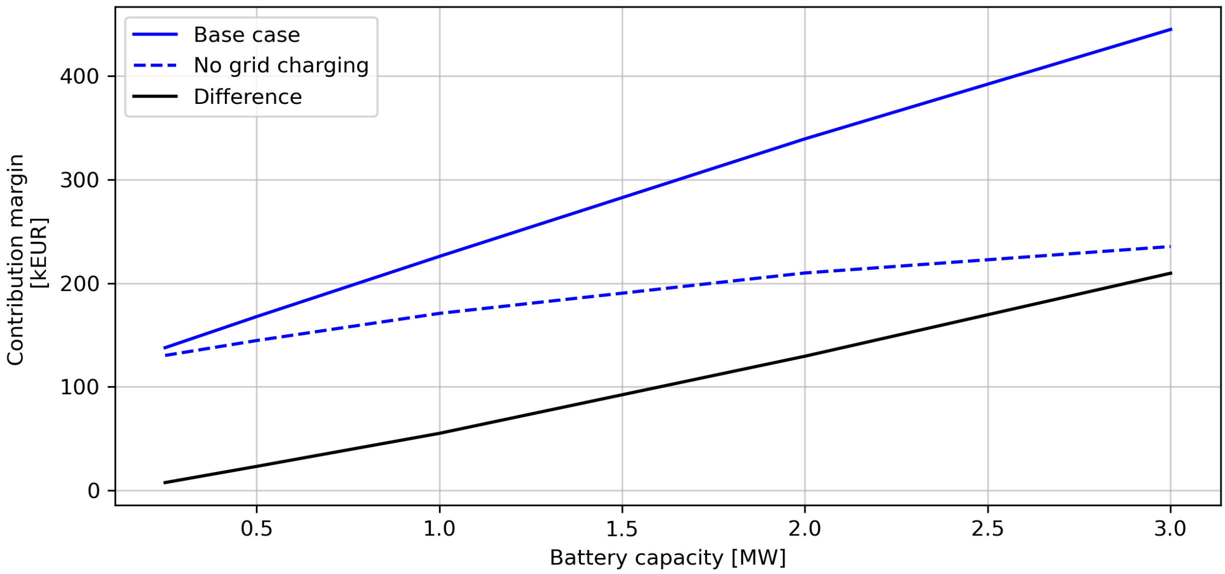

Figure G.11: Contribution margins for different PV-BESS ratios.

Nonetheless, the marginal benefit of this increased flexibility declines. Consequently, the impact of charging restrictions intensifies with the PV-to-BESS ratio, meaning the restrictions imposed by the EEG innovation tender regulation become more severe as the ratio increases. The findings indicate that investors would favor smaller PV-to-BESS ratios.