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From Model Optimality to Market Reality: Do Electricity Markets Support Renewable Investments?

EPRG Working Paper **EPRG 2521**

Cambridge Working Paper in Economics **CWPE 2558**

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JEL Classification Q41, D47, Q42, H23, Q47

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Publication	Sep 2025
Financial Support	The Schöller Foundation

From Model Optimality to Market Reality: Do Electricity Markets Support Renewable Investments?

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Highlights:

1. Evaluating a subsidy-free market for renewables expansion in Germany
2. PV face challenges due to cannibalization and infra-marginal generation
3. Onshore wind has the potential to be self-financing
4. Future investments will likely need continued subsidies to remain profitable
5. Market reforms and instruments are crucial for stabilizing market values

Abstract

This study investigates the future market values of photovoltaics and wind energy in Germany to assess their economic profitability without financial interventions. Using an open-source optimization model benchmarked against 2019–2024 data, we model the wholesale electricity market under the official expansion scenarios with projected carbon and gas price trajectories. Results show that despite higher wholesale electricity prices compared to pre-crisis levels, low capture prices, particularly for photovoltaics, may deter its future profitability. Contrary to that, onshore wind achieves higher capture prices, suggesting greater potential for self-financing under higher carbon and gas prices. However, market dynamics still pose risks, including price cannibalization and infra-marginal effects during generation oversupply periods. Policy interventions, including market design reforms and long-term instruments are critical to ensure stable revenues and align market conditions with renewable energy expansion goals.

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1. Introduction

The transition to a climate-neutral energy system is one of the most pressing global challenges. It is scientifically well-established that achieving net-zero CO_2 emissions is technically feasible and affordable. This is evident globally [1], in the United States [2], China [3], Europe [4], and in Germany [5]. These studies are largely based on ex-ante fundamental capacity expansion models, where a central planner optimizes cost-minimal (or welfare-maximal) investments (e.g., in power plants) along the decarbonization pathway, assuming market participants will reach long-term equilibria and recover their investment costs.

While optimization models effectively identify cost-minimal transition pathways, they often fail to reflect economic realities. In practice, investment decisions are often made by private actors, relying on undistorted market signals rather than centralized planning. Consequently, optimal investment pathways from a system-cost perspective may not align with actual economic incentives. This study examines whether market signals provide sufficient incentives for investments in renewable technologies—ensuring their levelized costs are covered—or if state intervention (e.g., subsidies or market design adjustments) is necessary.

Several studies highlight challenges in systems with a high share of renewable energy sources (RES). Empirical evidence suggests that increasing renewable penetration leads to lower average wholesale electricity prices—the so-called merit-order effect [6, 7, 8, 9, 10]—as well as a rise in hours with low or even negative prices [11, 12, 13]. This, in turn, reduces the market value[2] of renewables [14, 15, 16]. The expectation of persistently low and volatile electricity prices, along with potential distortions from renewable subsidies, has raised concerns about electricity supply security, investment incentives, and market design [17, 18, 19, 20]. On one hand, low electricity prices may fail to incentivize essential investments, jeopardizing supply security. On the other, high electricity prices may prompt political intervention to shield consumers and industries from rising energy costs. Additionally, price volatility encourages investments in energy storage.

From a neoclassical economic perspective, efficient decarbonization could be achieved through a carbon tax (as proposed by Pigou [21] for taxing externalities associated with market inefficiencies) or a cap-and-trade system (inspired by [22], later developed by [23]). However, setting an optimal carbon price that accurately reflects the social cost of carbon is

[2] The revenues that renewables can generate when they feed into the system

challenging. Effective carbon pricing would need to be globally coordinated and span all economic sectors, which has proven elusive, likely due to political failure, coordination failure, and public mistrust, among many other factors. Non-market-based policies—such as subsidies for renewables and storage, or mandated prohibitions on certain technologies (e.g., coal and nuclear power)—have significantly distorted wholesale electricity prices, potentially leading to suboptimal investment decisions. Previous studies already demonstrate adverse and unintended investment effects via market interventions, ultimately undermining the profitability of other system components and reducing incentives for their investment (i.e., storage or gas plants) [24, 25, 26, 27, 28, 29, 30].

This research bridges two seemingly contradictory strands of literature: one emphasizing the technical feasibility of deep decarbonization, and the other highlighting the economic challenges posed by high shares of intermittent renewables and near-zero electricity prices. By developing a detailed open-source optimization model of the German wholesale electricity market, this paper assesses whether current electricity markets and policy frameworks provide adequate incentives for renewable energy investments on the path to net zero, and highlights where market design may fall short in ensuring sufficient long-term investment signals.

This study contributes to the literature on capture prices and cannibalization in several novel ways. First, while much of the existing work relies on long-term equilibrium models, our analysis explicitly accounts for short-run volatility and revenue risk, which are central to actual investment decisions. Second, we link capture price dynamics directly to current and emerging policy frameworks, demonstrating how market design shapes revenue adequacy for renewables. Finally, we employ a detailed open-source optimization model calibrated to recent years of price volatility, thereby extending the empirical foundation beyond the relatively stable pre-crisis period. Together, these contributions sharpen the understanding of how renewable investments interact with market dynamics during the transition to net zero

Specifically, we evaluate Germany's official investment plan for 2037 using multi-weather datasets to account for weather variability. By modeling wholesale electricity spot market as the hourly intersection of supply and demand curves, we assess the economic feasibility of the decarbonization transition under different plausible commodities price scenarios. This approach provides insights into investment adequacy, the necessity for subsidies, the extent to which the energy transition can be translated into an economic reality and informs policies to ensure a cost-effective and economically sustainable transition. While focused on Germany—the largest electricity market in Europe—the findings are relevant for other countries pursuing deep decarbonization as the energy transition challenges are global.

2. Background

The wholesale electricity market consists of several trading layers. Long-term contracts are settled in forward and futures markets. Closer to real-time, electricity is traded on the day-ahead (spot) market, which plays a central role in price formation by matching supply and demand for each hour of the next day. In addition, intraday markets allow for balancing closer to delivery and ancillary services markets ensure system stability in real-time.

The spot market is particularly relevant to this study. It reflects the short-run opportunity market for generators, since it is the most liquid and price-relevant trading venue in the wholesale electricity system [31]. Consequently, spot market outcomes serve as key investment signals, and understanding them is essential for assessing the feasibility of market-based decarbonization. While electricity could be traded in other market venues, the central role of the day-ahead market in price formation makes it the most interesting to study.

In liberalized electricity markets, various modeling approaches have been developed, differing in the market interrelationships they capture and the techniques used to capture them. Several methods have been applied to model spot markets, including machine learning, statistical, stochastic, regression-based, optimization as well as simulation methods [32, 33, 34, 35].

From a microeconomic perspective, modeling individual firm decisions in electricity markets is highly complex, requiring detailed knowledge of stakeholder behavior at the micro level [36]. For instance, interrelations between firms in three German markets—the control reserve market, the energy-only market, and the district heating market—have been studied using an agent-based model with firm-specific bidding strategies [37]. Similarly, [14] used a partial equilibrium model to analyse the declining market value of renewables as penetration levels increase. Other studies have applied optimization models to investigate cross-sectoral interactions and their impact on wholesale electricity prices [38], the effect of sector coupling on renewable market values [39], and the potential for CO_2 pricing to mitigate the market value decline of renewables [40].

In the last years renewables have experienced a substantial increase so that thinking about future system configurations and market design becomes essential. Previous literature has extensively studied electricity market design for a fully renewable power system. Ritter et al. provided a comprehensive overview of challenges and solutions for electricity market design for 100% renewable energy [41], while Mallapragada et al. discussed the pricing challenges of the future decarbonized electricity markets [42]. Haertel and Korpas examined the impact of cross-sectoral flexibility (e.g., heat, industry) on price formation in low-carbon power systems [38]. More recently, Tarel et al. studied the price formulation in systems with only renewables and storage [43] and Brown et al. explored how demand elasticity impacts price formulation without fuel costs [44]. Antweiler and Muesgens investigated electricity market equilibria based solely on renewables and storage, with empirical evidence from Germany and ERCOT [45].

While the previous studies substantially contributed to the understanding of electricity market dynamics, they often come with limitations. First, they typically include a limited selection of generation technologies and rely on data from relatively stable commodity price periods (i.e., pre-crisis period), thus overlooking the recent surge in price volatility. Second, many of these studies focus on long-term market equilibrium outcomes, demonstrating that energy-only markets can function with high shares of renewables in the long run (e.g., 2050). However, investment decisions are taken in the present and are highly sensitive to short-run price volatility and revenue risk. By abstracting from these dynamics, equilibrium studies may underestimate the challenges investors face in securing stable revenues during the transition. This study addresses these gaps by developing a detailed open-source optimization model of the German spot market, that explicitly captures short-run volatility. The goal is to assess whether current market signals are sufficient to incentivize new investments under conditions of high renewable penetration, or whether state intervention remains necessary.

3. Model & Data

3.1Model Setup

We use multi-year weather and demand data spanning 2019 to 2024, covering the periods before, during, and after the 2022 energy crisis. In this section, we schematically show how the model setup is constructed. Data assumptions on costs and technical parameters, as well as the mathematical formulation is discussed in Appendix A. The model is developed using the open PyPSA framework [46] and is publicly available online under an open licence.

Price formation in the wholesale electricity market follows the well-known merit-order, where prices are determined by the intersection of supply and demand bids based on the ordered marginal costs of generators. Bids and asks in the wholesale market are submitted before the execution of deliveries for the following day. Under the assumption of rationality and profit maximization, market participants would not be willing to supply electricity below marginal costs (as they would make a marginal loss). As wholesale electricity demand is highly inelastic [47, 48], the optimal economic dispatch at the lowest possible cost replicates the price-clearing mechanism of wholesale electricity markets.

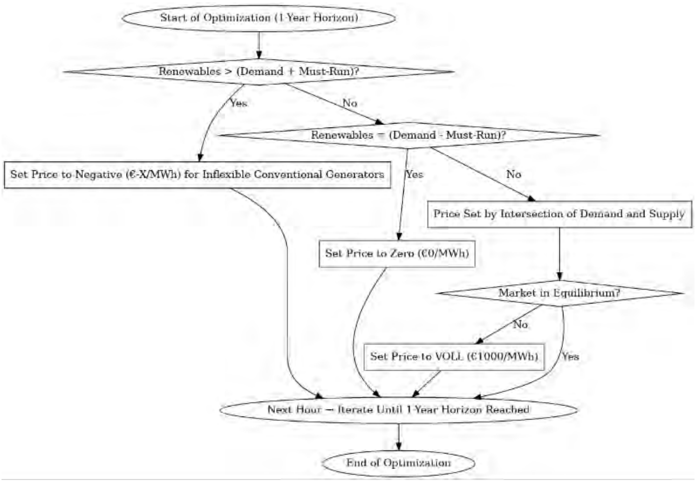


Figure 1: Optimization Flowchart for a Single Bidding Zone Electricity Market

Nevertheless, the share of negative electricity prices continues to grow. Negative prices in electricity markets happen due to one of two reasons; (i) must-run constraints that prevent shutdown and start-up costs for inflexible conventional generators (e.g., coal and nuclear) [49], or (ii) intermittent renewables feed-in exceeds demand [11]. We define must-run capacities to capture the inflexibility of conventional assets (see Table A. 1) and compute hourly renewable generation to assess whether clearing prices would turn negative.

The frequency of negative price hours is expected to increase in the future due to the increase in intermittent renewables feed-in [50]. However, the severity of these negative price events is likely to decline as inflexible generation sources are gradually phased out (e.g., coal, lignite, and nuclear) [51]. In practice, this implies that negative clearing prices may occur more frequently, the downward price spikes will be less extreme because the system will depend less on plants that are costly to ramp down. Negative prices are typically set by firms that prefer to bid at a loss rather than curtail output [52], yet detailed information on such bidding behaviour is scarce. To capture this realistically, the model assumes that negative price values follow the historical average of hourly negative prices from the same weather year, rather than projecting increasingly extreme values. Conversely, if the generation stack cannot meet demand, we assume a high value of lost load at 1000 €/MWh. The model's logic is illustrated in Figure 1.

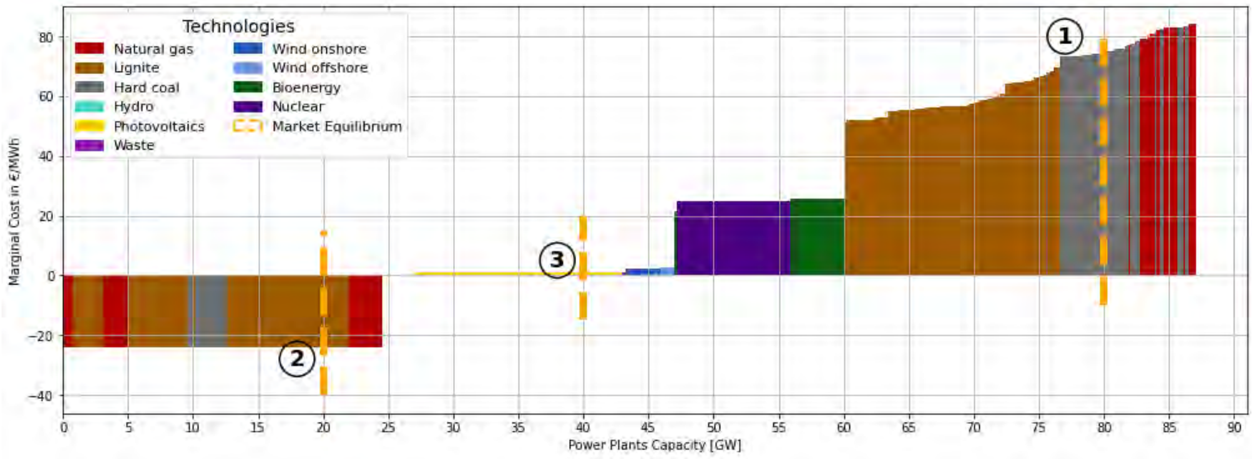


Figure 2: Market clearing and RES market-based revenue computation mechanism - schematic example of merit order. The three circles represents the three cases of equilibrium with different participation from renewables.

The three cases of how renewable assets generate in a market are shown in Figure 2. The first case (circle 1) is when renewables participate in the market, yet do not satisfy the demand on their own. In this case, market clearing is set by another non-renewable generation asset, and thus renewables profit is defined as the difference between the market clearing price and their near-zero marginal costs. The second case (circle 2) is when renewables solely satisfy the demand. in this case, market clearing price is set by renewables and as such, renewables do not make any profit. Here, it is important to differentiate where the market equilibrium is reached, as renewables have near-zero marginal cost, yet differ in their marginal costs (see Table A. 1). The last case (circle 3) is when must-run inflexible non-renewable generation assets bid with negative prices. In this case, renewables do not earn positive revenue from the market itself but continue to offer their capacities at negative prices to get state subsidies [29]. We argue that this behavior, while not involving direct payments to the regulator, underscores the competitiveness of RES within the current market conditions, an approach that is widely acknowledged in literature [53, 54].

3.2Model Quality

Before assessing the feasibility of renewable generation technologies in Germany's future energy system, we evaluate the quality of our model by comparing its outputs against observed real-world values. For this validation, we utilize daily closing commodity prices for coal, natural gas, and oil from financial market platforms [55] as well as wholesale electricity spot prices and EU ETS prices from an online data platform [56], as shown in Figure 3.

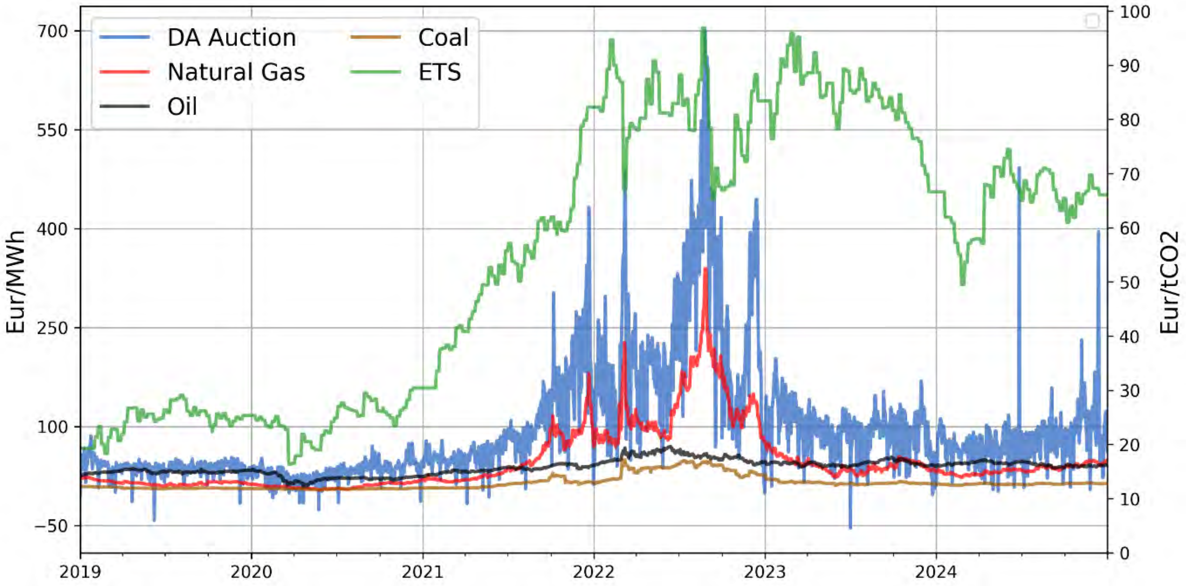


Figure 3: Commodity price developments in Germany. The graph shows the daily average German day-ahead spot price of electricity in €/MWh (DA Auction), the daily closing values of the Dutch TTF natural gas, coal (API2), and crude oil WTI one-month ahead future price €/MWh, and the daily closing values of the EU ETS (right axis)

Our model validation spans six years (2019–2024), covering the period before, during, and after the 2022 energy crisis. Table 1 summarizes the model's key outputs against actual spot prices in Germany, while Figure 4 shows the comparison between the actual spot prices and the output of our model.

Table 1: Summary of benchmarking our model

Period	Average Electricity Price in €/MWh	Correlation (Within 1-99% percentile)	STD in €/MWh	RMSE in €/MWh (Within 1-99% percentile)	MAE in €/MWh (Within 1-99% percentile)	R^2 (Within 1-99% percentile)
2019	Model: 35.62 Real: 37.67	0.88 (0.85)	Model: 12.6 Real: 15.5	5.96 €/MWh (5.49) €/MWh	4.45 €/MWh (4.24) €/MWh	0.75 (0.66)
2020	Model: 31.39 Real: 30.47	0.90 (0.89)	Model: 13.5 Real: 17.5	6.44 €/MWh (6.57) €/MWh	4.71 €/MWh (4.87) €/MWh	0.79 (0.72)
2021	Model: 87.65 Real: 96.85	0.96 (0.95)	Model: 64.2 Real: 73.7	21.4 €/MWh (21.58) €/MWh	13.25 €/MWh (13.13) €/MWh	0.90 (0.87)
2022	Model: 172.17 Real: 235.44	0.65 (0.68)	Model: 89.7 Real: 142.8	116.04 €/MWh (93.97) €/MWh	75.47 €/MWh (65.7) €/MWh	0.18 (0.17)
2023	Model: 92.82 Real: 95.18	0.93 (0.92)	Model: 42.4 Real: 47.6	13.95 €/MWh (13.21) €/MWh	10.67 €/MWh (10.21) €/MWh	0.85 (0.84)
2024	Model: 80.16 Real: 79.57	0.74 (0.86)	Model: 41.4 Real: 64.5	28.57 €/MWh (15.28) €/MWh	12.55 €/MWh (10.71) €/MWh	0.54 (0.74)

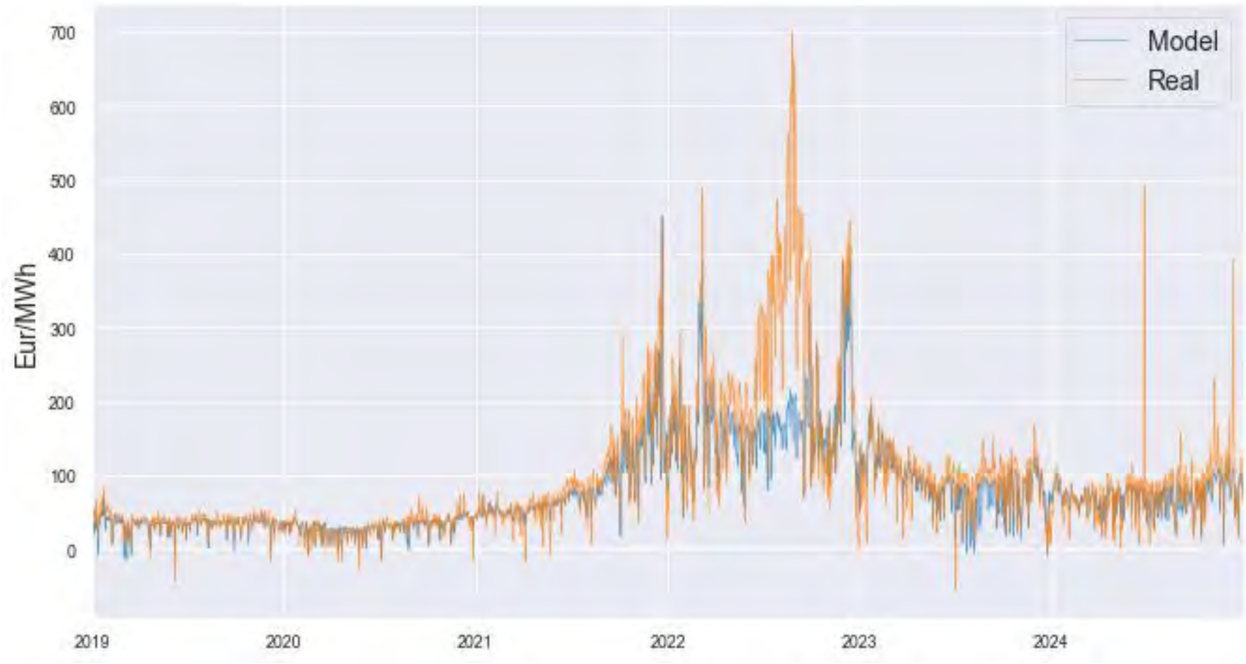


Figure 4: Comparison of DA spot prices and model results for the year 2019–2024. Correlation= 0. 90

It is important to note that electricity prices during the crisis period were significantly higher than in both the pre-crisis (by a factor of 6–7) and post-crisis periods (by a factor of 2–3). This explains the relatively higher model errors observed for this period, a finding consistent with other studies in the literature [57, 58, 59]. Another reason behind this can also be the market power of firms [60] or the expensive cost of congestion management [61]. Nevertheless, compared to other electricity market simulation models for Germany, the model demonstrates excellent accuracy.

For instance, Ringler et al. modeled hourly electricity prices in Germany for 2014 and found a mean absolute error (MAE) of 2.99 €/MWh and root mean square error (RMSE) of 5.10 €/MWh [62]. Ziel and Weron reported MAE values between 5.05 and 8.11 €/MWh for the period 2010-2016 [63]. Eising et al. modeled the electricity prices in 2015 and found a MAE of 4.02 €/MWh and RMSE of 8.27 €/MWh [59]. Qussous et al. reported MAE and RMSE values of 7.89 €/MWh and 11.21 €/MWh, respectively, for the period 2016–2019, with 2019-specific values of 6.69 €/MWh (MAE) and 10.91 €/MWh (RMSE) [37]. Mendes et al. modeled hourly electricity prices in Germany for multiple years (2017-2020) and found a MAE of 7.27 €/MWh and RMSE of 11.33 €/MWh [64]. Loizidis et al. reported RMSE values for 2019 ranging between 7.01 and 26.41 €/MWh [57], and Nitsch et al. estimated an average electricity price of 39.2 €/MWh [65].

While our model yields more accurate results than these studies, it is crucial to consider the significantly larger price spread during our study period, further reinforcing the robustness of our approach. For example, the price spread[3] in 2019 and 2020 was approximately 30 €/MWh, increasing to 80 €/MWh in 2021, and peaking at 187 €/MWh in 2022. Qussous et al. reported an RMSE of 8.43 €/MWh and an MAE of 5.36 €/MWh for 2020 [66], while Ghelasi and Ziel achieve a MAE of 4.72 €/MWh [67]. Another study reported MAE values between 30.56 and 36.08 €/MWh for the period June 1, 2021, to May 31, 2022 [68], whereas our model achieves a lower MAE of 24.86 €/MWh for the same timeframe. Altogether, we judge the model to be applicable for studying the future development in the German energy system.

3.3Economic indicators of renewables profitability

Capture prices represent the market value that a project achieves in a market. In the context of electricity markets, capture prices reflect the average price per MWh received by a renewable energy producer for electricity sold in the market, as this determines its financial value through its ability to generate revenue. Unlike fixed electricity tariffs, capture prices fluctuate based on real-time market conditions, meaning that renewable energy generators may earn different amounts for each unit of electricity they produce depending on the hourly clearing price. The following formula is used to compute the capture price:

$$Capture\ price\ [€/\text{MWh}] = \frac{\sum_{h=1}^{j}(E_h\ [MWh] *\ P_h[€/\text{MWh}])}{\sum_{h=1}^{j}(E_h)\ \ [MWh]}$$

Where E is the electricity sold by a technology at hour h, P denotes the clearing price at hour h, and j corresponds to the total number of hours in the examined period (1 year in our study). The capture price is the market value of a technology in €/MWh.

3.4Policy scenarios description

The future of energy systems is highly uncertain. To address this, our study adopts the future scenarios outlined in Germany's official Network Development Plan (NDP) [69]. The NDP provides insights into the necessary reinforcements and expansions of Germany's energy system in the coming years. It is developed by the country's four transmission system operators—50Hertz, Amprion, TenneT, and TransnetBW—who create various projections of the future energy landscape. The Federal Network Agency (BNetzA) subsequently reviews, approves, and publishes the NDP on a bi-annual basis.

Electricity markets serve as the primary source of revenue in an undistorted market, making it crucial to identify key price-driving factors. The main determinants of future

[3] Price spread is defined as the difference between the highest and lowest spot prices on an average annual basis.

electricity prices include gas and EU ETS allowance prices, renewable energy expansion, and rising electricity demand [9, 70, 71, 72, 73]. While other factors, such as nuclear and coal phase-outs, have historically influenced German electricity prices, they will become irrelevant in the long-term future due to their scheduled phase-out.

A major source of uncertainty is the future price of CO_2 allowances in the EU ETS. Currently, these prices range between 70 and 90 €/tCO_2. The IEA [74] projects that CO_2 allowance prices in the EU ETS could exceed 200 \$/tCO_2 (~179 €/tCO_2) under net-zero scenarios. Similarly, [75] forecasts prices of around 220 €/tCO_2 by 2050. However, EU ETS prices could also decline in response to phase-outs and decarbonization efforts. Several studies [76, 77, 78] predict a future price range of 50–100 €/tCO_2, while [79] estimates prices between 70 and 275 €/tCO_2, depending on emission reduction targets. Given these uncertainties, our study assesses EU ETS prices within a broad range of 25–300 €/tCO_2.

Natural gas prices also play a crucial role, particularly for Germany. As illustrated in Figure 3, natural gas prices exhibit a strong correlation with electricity prices. Despite extreme volatility during the 2021/22 energy crisis, European gas prices have already dropped below 40 €/MWh, with further stabilization expected by 2025 [80]. Recent forecasts suggest that gas prices will remain below 50 €/MWh in the long run [74, 75, 81]. In our study, we analyze natural gas price sensitivities within the range of 10–60 €/MWh.

To ensure consistency, factors such as future demand growth and renewable energy expansion are based on the three NDP scenarios, as summarized in Table 2, while demand and intermittent renewable generation profiles are based on the profiles from 2019–2024. Here, it is important to note that the most recent European Resource Adequacy Assessment report mentions that significant adequacy risks will be observed in the longer term in Germany resulting in high price spikes in some hours of the year [82]. To avoid the distortion due to those hours with high clearing prices, we indirectly introduce a price cap on electricity prices by assuming the natural gas capacities are high enough to satisfy the demand without the risk of facing extremely high prices.

The justification behind this assumption stems from the fact that many wholesale markets cap energy prices and employ capacity mechanisms to avoid high prices and provide adequate investment signals for investments [30, 42]. For instance, in Germany, over the period 2019-2024, spot price exceeded the 1000 €/MWh mark only for 3 hours. Moreover, in a future market with capacities similar to the ones shown in Table 2, natural gas capacities will always be the marginal generator setting the clearing price in hours of scarcity. We explore the direction of keeping the capacities as in Table 2 and impose a price cap at 1000 €/MWh in Supplementary Material S1.

Table 2: Overview of the key figures in the respective scenarios

Technology	2037-A	2037-B	2037-C
Natural gas/hydrogen [GW][4]	52.9	52.9	52.9
PHS [GW]	11.7	11.7	11.7
Onshore wind [GW]	105	158.5	158.5
Offshore wind [GW]	54.5	60.4	60.4
Photovoltaics [GW]	280	345	380
Biomass [GW]	5	5	5
Hydro [GW]	4.6	4.6	4.6
Other non-renewable [GW]	1.1	1.1	1.1
Other renewable [GW]	1	1	1
Batteries [GW] (small/large-scale)	40/18	55/32	60/36
Electricity Consumption [TWh]	773.9	938.1	1,002.3

By analysing these scenarios, this study aims to assess the profitability of renewable energy technologies in Germany's future energy system. By assessing a wide range of uncertainties around future electricity prices, this research will evaluate the investment profitability of renewables and highlight the necessary support schemes for realizing the German energy transition.

4. Results and Discussion

In our analysis, we show the results for the reference-year 2021. The deviation due to weather years and demand profiles is in the Supplementary Material S1.

4.1Future Development of Wholesale electricity prices

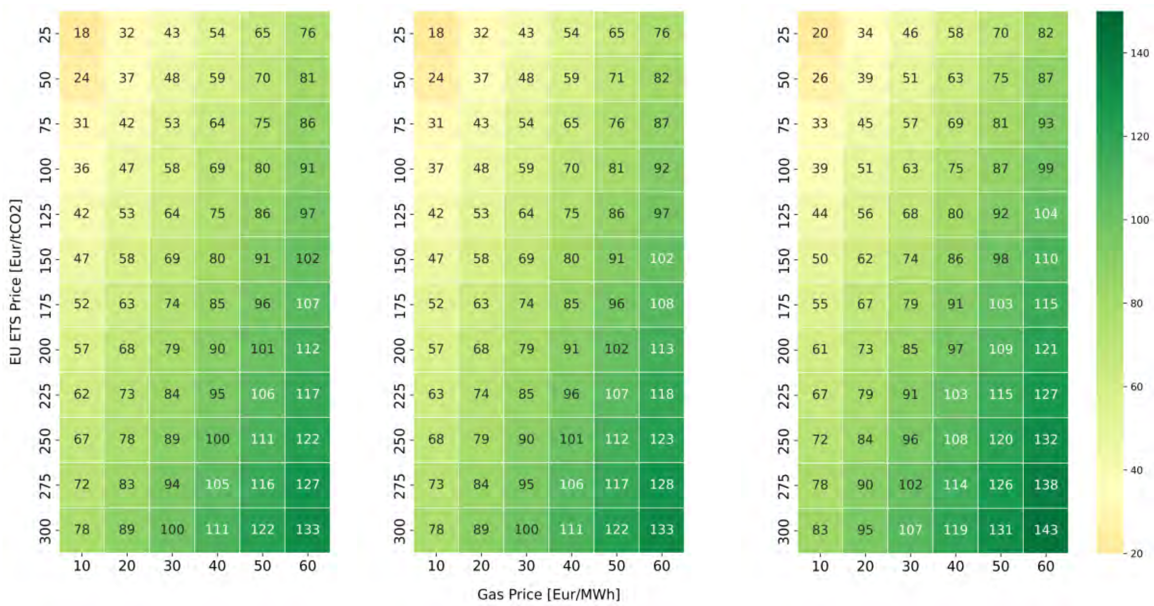
In an electricity market without coal or nuclear as in our case, gas-fired power plants dominate price setting, making natural gas and ETS prices critical drivers of wholesale electricity prices.

Across all scenarios, the wholesale price exhibits a strong upward trend with rising ETS and gas prices as shown in Figure 5. For instance, in Scenario A, the wholesale price climbs from more than 50 €/MWh at an ETS price of 25 €/tCO_2 and gas price of 40 €/MWh, to 98.2 €/MWh at an ETS price of 250 €/tCO_2 under the same gas price. This underscores the substantial impact of carbon pricing on electricity market dynamics.

[4] For the sake of transparency, we do not include hydrogen usage in gas-fired power plants in our study. However, following the same assumptions as in the NEP, we assume fuel prices for natural gas and hydrogen are identical [72]: "For the 2037/2045 (2025) NDP, analogous to the 2037/2045 (2023) NDP, it is assumed that the total costs of natural gas and hydrogen will be at a similar level in 2037."

Gas prices exert an even stronger influence on wholesale electricity prices. At an ETS price of 100 €/tCO_2, the wholesale price rises from 35.7 €/MWh when gas is 10 €/MWh to 89.5 €/MWh at 60 €/MWh. Even with ETS prices as low as 25 €/tCO_2, wholesale electricity prices are higher than pre-crisis period with higher gas prices. This steep increase reflects the pivotal role of gas-fired plants, as their fuel costs set the marginal price when renewable output is insufficient to meet demand.

While the massive renewable energy expansion is expected to depresses wholesale prices, the higher ETS and natural gas prices overweigh this effect resulting in generally higher wholesale prices. Under low gas and ETS prices (lower than 100 €/tCO_2 and 20 €/MWh), average wholesale prices are matching levels that were previously seen in pre-crisis period. However, this phenomenon is even more with higher commodity prices. For instance, with gas prices north of 30 €/MWh, wholesale prices are at least double those of pre-crisis period.



(a) Scenario A *(b) Scenario B* *(c) Scenario C*

Figure 5: Development of wholesale electricity price in the three scenarios with EU ETS prices (€/tCO_2) on the y axis, gas prices (€/MWh) on the x axis, and average electricity prices on the color bar.

This can be further explained from observing the hourly price distribution as shown in Figure 6. While renewables temporarily depress wholesale prices during the day hours, mainly due to the massive photovoltaics capacity, driving closing prices to zero and often to negative values. However, the hourly prices skyrocket after those (sunny) hours, resulting in greater price volatility and showing consistently higher price spikes. This trend is also visible in the morning hours, yet to a lower extent due to lower demand levels. In those hours, wind capacities take care of the majority of the demand, yet, gas capacities are needed to cover the residual demand.

Moreover, despite the greater added capacities of renewables between the three scenarios, Figure 6 shows the impact of higher electrification levels on the price spreads and the average electricity prices. This is especially evident in scenario C, where a high level of electrification accompanied result in a greater spread of high spot prices along the year. Another aspect that is evident across the three scenarios is the seasonal changes of spot prices. In summer, the average electricity prices and spikes are lower than in winter due to the greater solar capacities. Consequently, the frequency of hours with negative electricity prices is greater. Conversely, winter months result in higher electricity prices, resulting in a lower frequency of negative prices and higher price spreads.

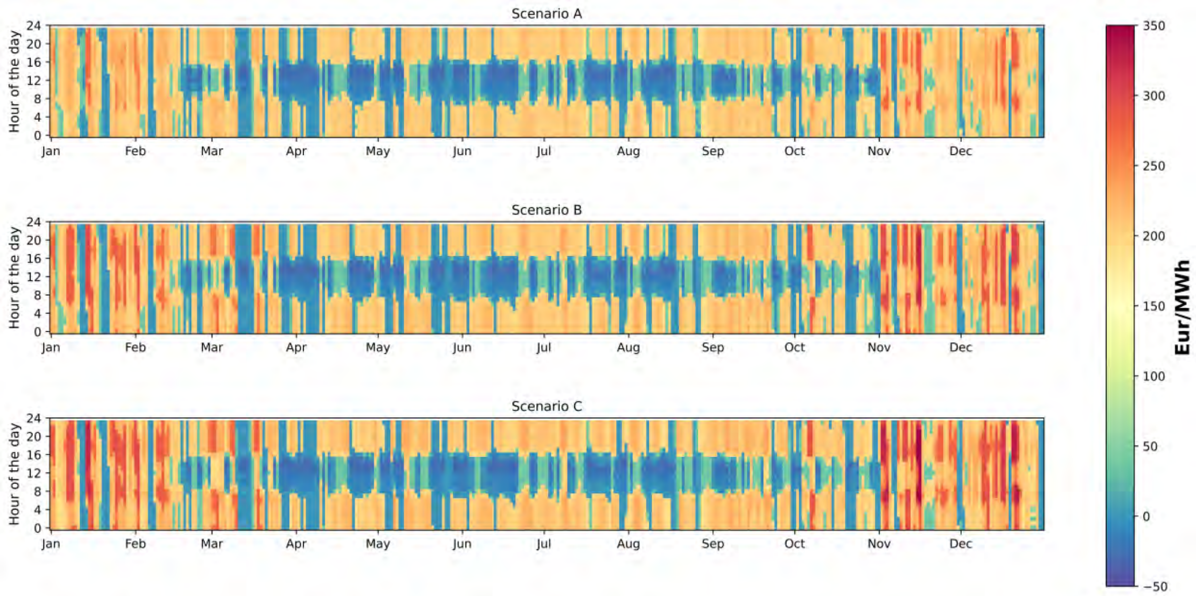


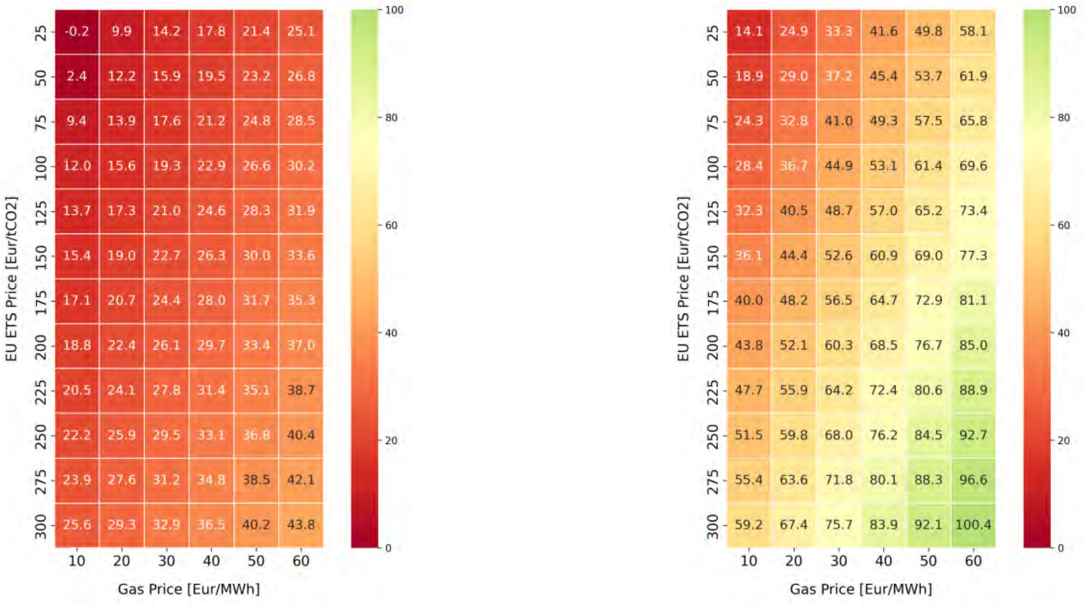
Figure 6: Hourly closing electricity prices in the three scenarios. The x axis shows the months of the year, the y axis shows the hour of the day, and the color bar shows the hourly wholesale electricity price.

Moreover, while it is true that renewables push the prices down to very low values (zero or negative), this is only evident for around 2300-2500 hours a year due to their intermittency as shown in Figure 6. On the other hand, in the three scenarios, natural gas represents a small fraction of the total generation mix (23%-24%). However, they will still often be the price-setting technology for more than 5250 hours a year. As a result, the wholesale electricity prices in the future are expected to be on higher compared to the pre-crisis era, despite the massive renewable energy expansion. This underscores the need for strategic interventions to mitigate this impact.

4.2Market value of renewables

Here, we show the results for scenario A, which represents the most conservative expansion scenario amongst the three scenarios. Extra results on the other two scenarios are in the Supplementary Material S2. Nonetheless, the following facts hold true in all scenarios.

Future capacities of renewables are heavily influenced by the commodity prices as shown in Figure 7.



(a) (b)

Figure 7: Market value in €/MWh for scenario A of (a): Photovoltaics, (b): Onshore wind, with EU ETS prices (€/tCO_2) on the y axis, gas prices (€/MWh) on the x axis, and , and market values on the color bar.

Photovoltaics face challenges with very low capture prices. The overall low market value of photovoltaics is largely explained by the massive build-up of capacity, which leads to an oversupply during sunny hours. During these hours, electricity prices are often infra-marginal (as previously seen in Figure 6). At such hours with low price levels, no profitable dispatch is possible (either generating with no market-based revenue when prices are zero or paying to dispatch when prices turn negative), regardless of their generation levels.

For instance, under conditions of low commodity prices, the market value of photovoltaics can even become negative. A notable example is when the CO_2 price is 25 €/tCO_2 and the gas price is 10 €/MWh, where investments achieve a negative market value of -0.2 €/MWh. This means that photovoltaics assets are mainly generating at hours with low or negative prices and are incentivized to do so to earn market premiums and subsidies. Conversely, in a scenario with the highest CO_2 price of 300 €/tCO_2 and a gas price of 60 €/MWh, photovoltaics market value reaches 43.8 €/MWh. This stark contrast highlights the sensitivity of market values to both gas and CO_2 prices.

Wind energy enjoys higher market values compared to photovoltaics but is still subject to fluctuations driven by the interplay of gas prices and CO_2 allowance prices. For example, in scenarios with low commodity prices, the market value of onshore wind energy remains relatively modest. When the CO_2 price is 25 €/tCO_2 and the gas price is 10 €/MWh, the market value of wind is only 14.1 €/MWh. On the other hand, onshore wind becomes more valuable as fossil-based generation becomes costlier due to higher gas and CO_2 prices. For instance, under favourable conditions with a CO_2 price of 300 €/tCO_2 and a gas price of 60 €/MWh, wind achieves a much higher market value of around 100 €/MWh.

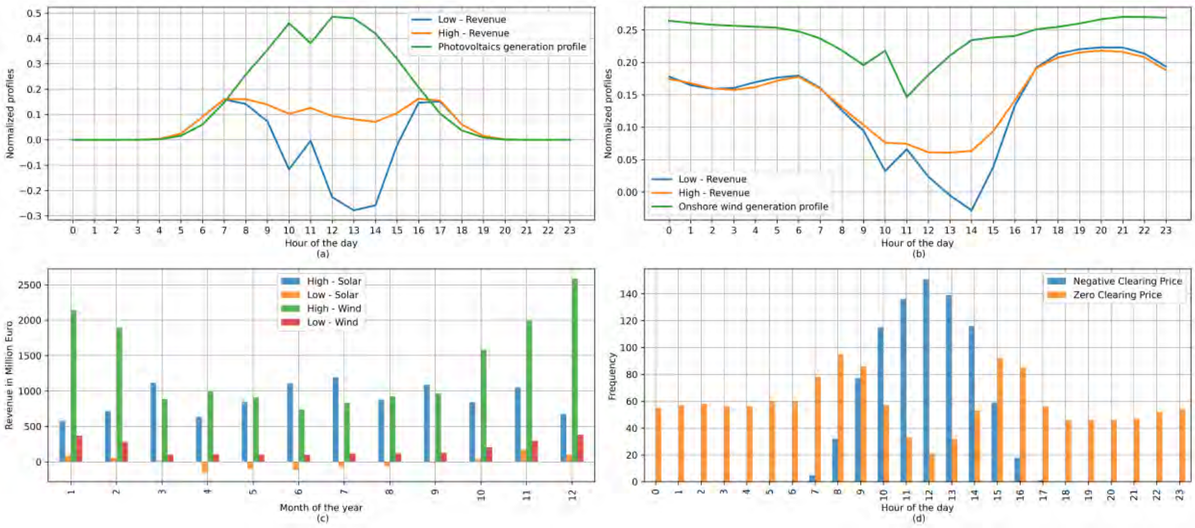


Figure 8: Market value analysis for the case of high and low commodity prices. (a): Average hourly market value and generation profiles for Photovoltaics. (b): Average hourly market value and generation profiles for onshore wind. (c): Monthly market-based revenue for the four cases. (d): Frequency distribution of hours with negative and zero clearing prices.

The other reason affecting the capture prices is explained through Figure 8. Photovoltaics generate electricity for around 4,950 hours a year. Under low commodity price conditions, over 849 hours clear at negative prices and more than 1,400 hours at near-zero prices. The remaining 2,672 hours see clearing prices with a maximum of 40 €/MWh and an average of 30.4 €/MWh. In contrast, while 849 hours still clear at negative prices in the high commodity price case, only around 900 hours are priced near zero. The remaining 3,203 hours reach a significantly higher maximum clearing price of 281 €/MWh, with an average of 172 €/MWh. It is during these high-price hours that photovoltaics generate the bulk of their market value, effectively offsetting periods with negative or near-zero prices. This effect is clearly shown in Figure 8-a, where the normalized market-based revenue profile under high commodity prices is substantially greater than in the low-price case.

On the other hand, onshore wind benefits from a more consistent output profile compared to photovoltaics, as it is not restricted to daylight hours (Figure 8-b). However, periods of high wind generation can lead to price drops in the market, particularly during times of low demand. As a result, excess wind coupled with high infeed of photovoltaics with low demand resulted in wind generating low market-based revenues in times of high photovoltaics generation (Figure 8-c).

While the impact of commodity prices is the same on onshore wind, the prices in hours where wind is generating are, on average, higher than the case of photovoltaics, resulting in better capture prices even with low commodity prices. Moreover, the negative clearing prices are only evident at daytime (Figure 8-d), accordingly affecting the market-based revenue stream for their investments.

Another aspect that is evident in Figure 8 is the price cannibalization of renewables. This is evident for both photovoltaics and onshore wind, yet differs in the range of its impact. For instance, during sunny hours, photovoltaics revenue profiles suffer from low values, resulting in a self-cannibalization effect, where the oversupply of photovoltaics is causing a sharp drop in the wholesale clearing price, hence affecting its own market value during time of oversupply (Figure 8-a). For the case of onshore wind, their revenue profiles during mid-day are drastically lower than during night (Figure 8-b), mainly as oversupply from photovoltaics either depress prices to zero or negative prices (Figure 8-d), or decrease positive closing prices by pushing the expensive generation unit out of market (merit-order-effect). In both cases, onshore wind revenue profiles are negatively affected, where photovoltaics supply cannibalizes onshore wind market values. This is also evident seasonally, where wind revenues in months with better photovoltaics generation (summer) are lower than cold months (Figure 8-c).

5. Policy Discussion: Current and future prospects of renewables market value

Tracking renewables capture prices is an essential task in evaluating project's profitability. Given the ambitious plans to expand renewable energy capacities, it is evident that the market value of renewables investments will face significant downward pressure, a finding that is consistent with literature [14, 40, 59, 10, 27]. Nonetheless, our analysis shows that wholesale electricity prices remain relatively high, exceeding pre-crisis levels even with the substantial increase in renewable energy generation. This result aligns with what is widely seen in the literature [9, 59, 76, 83].

For the owners of renewable energy assets, this constant decline in market value introduces future price risks. Mitigating these risks will require financial instruments that ensure stable revenues and support project development. Our results indicate that the maximum capture prices for photovoltaics could reach 43.8 €/MWh, while onshore wind achieves up to 100.4 €/MWh. Comparing these values to the recent capture prices[5] observed in the German market (as presented in Table 3), it becomes evident that future investments in photovoltaics will likely need continued subsidies to remain profitable. Conversely, onshore wind projects show higher capture prices, suggesting that they may require less financial support, as their market revenues could potentially recover investment costs.

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[5] Calculated using Eq. 1 described in section 2.4

Table 3: Capture prices of photovoltaics and onshore wind from 2019-2024.

	2019	2020	2021	2022	2023	2024
Photovoltaics capture price €/MWh	34.9	24.7	76.2	224	72.1	47
Onshore wind capture price €/MWh	32.3	24.5	79.8	167.3	77.8	64.5

To further assess renewables feasibility, the market capture prices from our study are compared with current estimates of the levelized cost of electricity (LCOE) for each technology, which is understood as the low-bound revenue required for an economical plant operation (long-term equilibrium). The latest Fraunhofer ISE study on LCOE in Germany in 2024 revealed that utility-scale photovoltaics have a current LCOE of 41–68 €/MWh, with long-term projections expected to drop down between 31–62 €/MWh, while current onshore wind LCOE falls between 43–92 €/MWh [84], with expectation to fall between 38–83 €/MWh in the future [84]. Similarly, IRENA identifies 2023 LCOE in Germany at 46-100 €/MWh for photovoltaics and 28–66 €/MWh for onshore wind [85]. These comparisons highlight that while onshore wind capture prices often exceed or align with their LCOE, photovoltaics capture prices may fall short, emphasizing the need for continued financial support in the form of subsidies or market mechanisms for investments.

Historically, Germany has supported renewable energy projects through feed-in-tariff (FiT) premiums, which guaranteed long-term fixed or minimum remuneration [86, 13]. FiT payments, funded through the RES Act levy (a levy on electricity consumption), covered the difference between FiT tariffs and day-ahead market prices.

Diverse support schemes can provide a critical buffer in a volatile market to ensure the realization of the announced national expansion plans and reduce the uncertainty around the electricity market prices [87, 88]. Tenders (or auctions) are widely utilized to encourage cost reduction and competition. However, studies suggest that the observed cost declines are driven more by falling renewable technology costs and locational advantages than by competition itself [89].

Currently, RES capacities receive remuneration provided they are dispatched during negative clearing prices, decoupling the generation from market prices (also referred to as produce-and-forget). Research showed that avoiding such subsidies will prohibit negative price bidding by RES [29]. Our results showed that current electricity markets alone are unlikely to generate adequate price signals to drive investments in future renewables capacity. Policymakers should adjust market design to ensure sufficient long-term investment incentives. A recent key regulatory change in the RES Act (EEG) was introduced to the remuneration during periods of negative day-ahead market prices. Under the new rule, subsidy payments will be suspended for any negative price periods in the day-ahead market for new renewables assets. Moreover, existing installations already awarded RES Act (EEG) contracts can voluntarily opt for this revised scheme and, in return, receive an increased subsidy of 6 €/MWh during eligible hours.

Our analysis showed that produce-and-forget bidding strategies highly affect the capture prices. This new reform is expected to discourage renewables from bidding into the market during negative price periods, especially when marginal market-based revenues fall below zero. Generators will now have a stronger economic incentive to curtail production during times of oversupply, aligning bidding behaviour more closely with system needs.

The results showed that future electricity prices will be volatile with high daily price spreads. As such, stabilizing revenues of renewable energy assets will be key to ensure enough investment and mitigate future price risks. In this context, long-term Power Purchase Agreements (PPAs) are emerging as an increasingly attractive alternative to stabilize revenues, allowing developers to sell electricity at fixed prices and hedge against price fluctuations [90]. In Germany the PPA market is significantly growing over recent years yet remains nascent [91]. Contracts for differences (CfDs), have been used to shield developers from market price volatility by compensating the difference between a strike price and the market price [92, 93]. Nevertheless, CfDs can reduce price competition and future power price uncertainty is particularly challenging for renewable project investors [94].. The volatile electricity prices, along with the low capture prices and high daily price spreads would incentivize energy storage solutions [9]. Co-location of storage flexibility would enable project developers to capitalize on high price spreads and volatility, boosting capture prices and enhancing the economic profitability of renewable projects.

6. Conclusion

This study analysed the development of future market values for wind and solar energy in Germany, focusing on the necessity of support mechanisms to meet the ambitious renewable energy expansion targets. Using an open-source optimization model validated against real-world data for 2019–2024, we modelled Germany’s future day-ahead electricity market based on the government’s 2037 expansion plans and projected carbon and gas price trajectories.

Our findings indicate that future wholesale electricity prices will remain elevated compared to pre-crisis levels, largely due to gas power plants being the marginal generator for over 5000 hours a year. Nevertheless, the economic profitability of renewables faces challenges. Photovoltaics suffer from low capture prices caused by cannibalization effects and frequent infra-marginal pricing due to significant capacity build-up. Conversely, onshore wind demonstrates better capture prices and could achieve financial self-sufficiency with higher carbon and gas prices.

The findings highlight that low capture prices, particularly for photovoltaics, can significantly deter private investment unless proper market interventions are implemented. This conclusion challenges a notion that is widely spread in literature, aligning with Brown and Reichenberg [40] in asserting that declining market values stem from policy choices rather than a natural property of RES with higher market shares. Although Brown and Reichenberg [40] find that a higher carbon price can improve the market value, we argue that this finding is not universally true. Under the current market design, negative prices will counteract the benefits of a high carbon price. As such, dropping market values in high shares of renewables could be alleviated by market interventions without the need for subsidies. Market design reforms could help stabilize market-based revenues, enabling profitable investment in renewables while supporting the planned capacity expansion goals.

Our results provide important insights for policymakers and market designers. Nevertheless, the modelling framework abstracts from several real-world aspects, including cross-border electricity flows, network constraints, and demand elasticity. Stronger cross-border interconnections could moderately improve wind capture prices relative to solar, since wind patterns are less correlated across time and space in Europe [95]. Within Germany, regional imbalances between production and consumption create network congestion, which may cause price distortions and reduce renewable capture prices [51]. Wholesale electricity demand has a high price-inelastic degree (reflecting limited exposure to real-time prices) [47, 48, 30]. Advanced technologies such as vehicle-to-grid and demand response could increase elasticity [44, 96]. Nevertheless, this requires a significant offtake in smart meters rollout, which remains heavily underdeveloped in Germany [97].

Other research questions warrant further investigation. Greater battery capacities can reduce price spreads and spikes, compressing revenue opportunities with market depth. This is known as “storage adequacy”, which is also raised by other researchers [42, 43, 45]. Another trend that is observed in our study is the spread of negative prices across consecutive days. In such cases, it would be interesting to study bidding strategies to maximize assets profitability. Future research should investigate these areas to provide a more robust understanding of future electricity market dynamics.

Data Availability

All data used in the paper is properly cited. The code for model and analysis to reproduce the study's results are publicly available at https://github.com/AnasAbuzayed/market_value and archived on Zenodo under https://doi.org/10.5281/zenodo.16394138.

Acknowledgment

This research was supported by The Schöller Foundation. The Author would like to thank Mario Liebensteiner and Gregor Zöttl (University of Erlangen Nuremberg) as well as David Newberry (University of Cambridge) for their insightful comments and discussions on an earlier draft of this manuscript.

Appendix A: Mathematical formulation of the model & data inputs

The model assumes a benevolent global social planner seeking minimal generation costs and optimal resource allocation under perfect competition market assumption. The solution to the optimization problem leads to time-dependent markets prices equal to the variable cost of the marginal generator. The market equilibrium where the generation stack is covering the demand is defined in the following system of equations.

$$\min_{\substack{\text{Ɛ}_{g,n,i},\varepsilon_{g,n,t,i} \\ \text{ꭓ}_{g,n,t,i},B_{\mathcal{L},\text{Ü},i} \\ \text{Ƕ}_{s,n,t,i}}} \sum \begin{pmatrix} o_g \cdot \varepsilon_{g,t} \\ + \kappa \cdot \nu_t \\ + o_s \cdot [q_{s,t}]^+ \end{pmatrix} \tag{1}$$

s.t.

$$\partial_t = \sum \varepsilon_{g,t} + \sum \text{Ƕ}_{s,t} + \sum \nu_t \tag{2}$$

$$0 \leq \varepsilon_{g,n,t} \leq \tilde{\omega}_{g,n,t} \quad \forall \text{ g in renewables} \tag{3}$$

$$0 \leq \varepsilon_{g,t} \leq \text{Ɛ}_g \cdot \text{ꭓ}_g \quad \forall \text{ g in conventionals} \tag{4}$$

$$0 \leq [q_{s,t}]^{\pm} \leq E_s \quad \forall \text{ s in storage units} \tag{5}$$

$$0 \leq \frac{[q_{s,t}]^{\pm} \cdot \eta_s}{E_s} \leq \Gamma_s \quad \forall \text{ s in storage units} \tag{6}$$

The objective function is the sum of three terms 1) the dispatch of generation capacity (ε) at a certain and time (t) for each generation technology (g) and their marginal cost (o) per unit of generation; 2) the positive dispatch (q^+) of storage technologies (s) at a certain time (t) with their associated marginal cost (o), and 3) The unmet demand (v) at a certain time (t) along with a high penalty cost (κ).

The market is cleared for each time step using a nodal energy balance. Equation 2 states that the demand at every hour equals the summation of 1) the dispatch of generation capacity *(ε)* at a certain time *(t)* for all generation technologies *(g); 2)* the dispatch (q) of storage technologies (s) at a certain time *(t);* and 3) the load shedding *(v)* at a certain time *(t)*.

The generation of intermittent renewable technologies is constrained by weather profiles that dictate their real-time availability (Equation 3). This same principle applies to hydro generation, which is subject to water availability but benefits from longer storage durations, representing its inherent flexibility. Generation of thermal power plants (ε) at time (t) is constrained by their available installed capacity (Ɛ) and availability factor (ҳ) as shown in Equation 4.

The energy storage constraints in Equation 5 ensure that the energy charged or discharged (q) of each storage technology (s) at each time(t) does not exceed the storage capacity of the storage unit (E). Moreover, both charging and discharging along with the storage unit efficiency (η) are bound to the storage capacity (E) by the number of charging hours at nominal power (Γ) as in Equation 6.

Existing generation capacities for different energy carriers are sourced from the Open Power System Data (OPSD) platform [98], which includes data on approximately 750 power plants in Germany, along with their thermal efficiencies and power capacities. The historical hourly load and intermittent generation profiles for renewables from the years 2019-2024 are extracted from SMARD [99].

Must-run capacities of conventional power plants in wholesale electricity markets are in line with values reported in [100]. Moreover, availability factors are incorporated to account for planned and unplanned outages of power plants. The marginal cost of each power plant is defined as the fuel price added to the CO_2 emissions allowance and the variable operation and maintenance cost. The variable operation and maintenance cost (VOM) and fuel cost assumptions are sourced from [101]. For energy storage, we assume a 4-hour capacity at nominal power for pumped hydro storage (PHS) and a 2-hour capacity for battery storage. The model cost inputs are summarized in Table A. 1.

Table A. 1: Model assumptions

Technology	VOM [€/MWh]	Fuel cost [€/MWh$_{fuel}$]	Must-run Capacity [%]	Availability Factor [%]	Emissions factor [tCO_2/MWh_{fuel}]
Bioenergy	2.1	9	0	90%	0
Hard coal	2.9	8.73[6]	30%	85%	0.354
Lignite	2.9	4	30%	85%	0.334
Nuclear	8	5.5	35%	80%	0
Waste	1	0	0	100%	0
Photovoltaics	1	0	0	100%	0
Wind onshore	2.3	0	0	100%	0
Wind offshore	2.7	0	0	100%	0
Hydro	0	0	0	100%	0
Oil	3	76.5[6]	25%	85%	0.248
Natural gas	4	42[6,7]	20%	90%	0.187
Geothermal	1	0	0	100%	0
PHS	1	0	0	100%	0

Future capacity expansion are extracted from the official NDP of Germany [69] as discussed in Section 3 as an input to the model. Here, we increase the power plants' cumulative capacities to match the future capacities. For trading with neighboring grids, we adapt the historical import/export profiles extracted from [99] exactly by a factor that equals the increase of total future demand over the historical demand. While this approach is simplistic, the official NDP sheds no light on future import/export balance in any kind in their report. Importantly, while the whole European power systems are transforming their power systems with higher levels of intermittent renewable generation, the value of flexibility from interconnection becomes limited [102]. Finally, a major constraint may be that interconnection between similar weather systems can significantly reduce the capabilities of interconnection flexibility yet remain crucial for technical aspects [103].

[6] For benchmarking and assessing model quality, we use the daily closing prices from the financial market platform investing.com [46]

[7] For future scenarios, gas price is a model input to capture the uncertainty around its future trajectories

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