Mitigating negative electricity prices - Batteries or flexibility in wind and solar?

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Abstract— **This paper analyses the influence of battery storage systems and high shares of price-inelastic generation on electricity prices. Within the last years, negative wholesale electricity prices have become a relevant topic in many electricity systems around the world. We develop a linear cost minimization model to analyze the relationship between price-inelastic generation and battery storage. We parameterize the model with three different scenarios which describe the German electricity market in the year 2030. Our model shows that both additional storage capacities and more flexible renewable generation are necessary to avoid high volatility in electricity prices and thereby reduce the number of hours with negative electricity prices.**

Index Terms-- **Flexibility, Intermittent energy, Renewable energy, Surplus energy**

I. INTRODUCTION

Negative electricity prices have become increasingly common on electricity wholesale markets around the world. These negative prices are largely driven by the inflexibility of both consumers and generators. On the consumer side, price inelasticity stems from several factors, including the lack of real-time metering in many regions. In Germany, for instance, approximately 277 TWh of the total 480 TWh annual electricity consumption (2022) stem from consumers who are not equipped with real-time meters [1]. As a result, these consumers have no incentive to respond to price fluctuations, which primarily affects private households and the commercial sector. Industrial consumers, who account for about 203 TWh, are generally metered in real-time but face technical and regulatory barriers that limit their ability to adjust consumption. These include constraints imposed by industrial processes and grid fee structures that incentivize stable consumption patterns.

On the generation side, flexibility is influenced by technical, economic, and regulatory factors. Technical constraints include minimum generation levels, start-up costs and ramp-up limitations. Economically, generators may have income from other markets (e.g., heat production or ancillary services) that influence the decision on whether to produce. Finally, regulatory factors, such as different subsidy schemes, also play a significant role. Subsidies do not only affect renewable generators, they are also being discussed for newly built hydrogen power plants.

This paper presents an energy system model designed to explore the impact of battery storage systems and varying levels of inflexible (price-inelastic) generation (e.g. subsidized renewables and combined heat and power plants needed to cover heat demand) on (negative) electricity prices. As negative electricity prices make it more difficult to expand renewable energies, as they reduce the profitability of these plants, they are generally viewed critically. The study compares electricity prices across different scenarios.

The paper is structured as follows: Section II provides a literature overview about the influences of renewable energy sources on power markets. Section III presents the methodology of the conducted study. In section IV a validation of the model compared the historical data for 2023 is presented. Section V describes the modelling results for different scenarios for the year 2030 and section VI summarizes and discusses the insights.

II. LITERATUR REVIEW

The following section introduces the existing literature on the effects of renewable energy sources on power markets. It addresses both the increasingly frequent occurrence of negative prices and the value of flexibility.

The general effects of increasing shares of renewable energy sources on electricity markets are well discussed. Several studies show that increasing shares of electricity generation from renewable energy sources influence electricity prices [2] - [5]. With variable generation costs of nearly zero € / MWh renewable energy sources like wind and solar lower wholesale electricity market prices down to their variable generation costs

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when available. In contrast to this well discussed short-term merit order effect it can be shown that in the long-term the merit order effect is zero [6]. This effect is clearly evident in the case of low and medium market penetration of renewable energy sources. However, with large shares of generation from renewable energy sources the variance in electricity prices increases [7].

Beyond that, negative prices appear on electricity markets (e.g. in Germany and in the Southwest Power Pool region in the United States) and illustrate the issue associated with subsidized electricity generators [8], [9]. As a result, the ability to react flexibly to price signals is increasingly gaining economic value [10]. This can be shown for electricity consumption as well as generation [11], [12].

III. METHODOLOGY

The following section describes the developed dispatch model as well as its limitations and the study setup.

A. *Model description*

We develop a linear dispatch model minimizing total costs of electricity supply. A general description of this approach is given in [13]. The model covers one year in hourly resolution. Within one year 52 weeks are separately optimized. This is done to limit the "perfect foresight" to only one week and avoid the model to use battery storages as seasonal storage technology. The model contains four different sets. First, the hours of one year (t), second, conventional generation technologies (c), third, renewable generation technologies (r) and fourth storage technologies (s). The model includes three different kinds of conventional generators. First, gas turbines as peak load technology which is characterized by high flexibility but also high variable generation costs. Second, combined cycle gas turbine (CCGT) plants, which are characterized by a high level of 'must-run', as it is assumed that these power plants provide a constant heat demand. CCGT is assumed to face the lower variable generation costs (for electricity) compared to gas turbines due to the high overall efficiency and a high level of cost recovery from the provision of heat. Third, there are steam power plants in the system. These are characterized by high start-up costs as well as high variable generation costs resulting from fuel costs and high carbon emissions. Moreover, all conventional power plants are restricted by an individual ramping constraint that limits the change in generation from one hour to another. Furthermore, all conventional power plants are subject to a minimum partial load, which describes a share of the running capacity that must generate electricity, and partial load costs (plc), which describes the share of the variable generation costs that arise for capacities that are running but not generating electricity.

The renewable generation technologies contain wind (further separated into offshore and onshore), solar power, biomass and hydro power (run-of river (RoR)). Offshore wind farms are assumed to be completely flexible and to operate without subsidies. This means that the generation is reacting to prices, reducing output when prices fall below marginal generation costs. Onshore wind is separated in two groups. First, a flexible share which marginal generation costs varying between scenarios, and second, an inflexible share which generates electricity which generates as much electricity as possible. Solar power is divided into three different groups. Compared to onshore wind, there is one additional group of flexible solar generators in order. This allows to differentiate between levels of subsidized (or not-subsidized) flexible solar generators. This differentiation allows to consider the inhomogeneity of solar plants. On one hand there are large plants that are operated professionally and on the other hand there are small private operated solar plants. As these are subsidized differently, they are also implemented differently. As for onshore wind there is also an inflexible share. Biomass and RoR are assumed to be technically completely controllable.

The model includes two kinds of storage technologies. Pumped storage and battery storages. These storage technologies are included with a generation (or demand) capacity and an energy-to-power ratio. The model also includes a capability to shift load from one hour to another. This capability is included like storage technologies, with a power in MW and an energy-to-power ratio. Furthermore, the model includes a 'must-run' capacity for ancillary services' provision which must be covered by conventional generators. In the event that uncontrollable generation exceeds demand, curtailment is possible, but this is associated with high curtailment costs. The following TABLE I shows an excerpt of parameters used.

TABLE I. PARAMETERS

Formula character	**Description**	**Unit**
	Sets	
t	Hours of the year	
c	Conventional generation technologies	
r	Renewable generation technologies	
	Variables	
TC	Total system costs	€
CURT (t)	Curtailment in hour t	MWh
GEN (t,c)	Generation in hour t from technology c	MWh
RUN (t,c)	Running capacity in hour t of technology c	MW
START_UP (t,c)	Started capacity in hour t	MW
RES (t,r)	Generation in hour t from technology r	MWh
	Parameters	
curt_cost	Curtailment costs	€ / MWh
vc_c (c)	Variable generation costs	€ / MWh
plc (c)	Partial load cost factor	
sc (c)	Start-up costs	€ / MW
vc_r (r)	Variable generation costs	€ / MWh

The objective is to minimize the total system costs (TC), described in (1).

$$
\begin{aligned}
TC = \sum_{t} (CURT_t \cdot \text{curt\_cost} \\
&+ \sum_{c} \big(GEN_{t,c} \cdot vc\_c_c \\
&+ \big(RUN_{t,c} - GEN_{t,c}\big) \cdot vc_{c_c} \\
&\cdot plc_c + START\_UP_{t,c} \cdot sc_c\big) \\
&+ \sum_{r} RES_{t,r} \cdot vc\_r_r)
\end{aligned}
\tag{1}
$$

The TC function adds up the system costs in all hours and consists of three parts. The first part sums the hourly curtailment costs. The second part adds up all cost associated with conventional generation in one hour. This includes the generation costs, the costs for running but not generating capacities, and start-up costs. The third part describes generation costs from renewable generators. These can be negative due to negative marginal generation costs of some technologies.

Furthermore, contains several constrains describing conventional and renewable generation technologies, storage technologies and load shifting. The complete model (written in GAMS), empirical parameters and the used study framework in python can be found online in a GitHub repository (https://github.com/BTU-EnerEcon/avoiding_negative_prices).

B. *Model limitations*

The presented model faces different limitations. First, conventional generation technologies are simplified to three different kinds of generators. Moreover, these technologies are described with linearized startup and partial load constraints. Second, we exclude international power exchange as well as reserve capacities and we abstract from all grid related constraints. And third, our deterministic model includes a perfect foresight ignoring the uncertainty of demand and availability of renewable energy sources. We strive to limit this by optimizing one week at a time.

C. *Study setup and scenario description*

Our dispatch optimization model is used to visualize the effects of different levels of flexible generation as well as storage expansion. The marginal generation costs are used as shadow price to describe electricity prices. We use the model to calculate prices in three different scenarios for the year 2030. We investigate the distribution of the calculated prices as well as the total number of hours with negative electricity price. The three scenarios for 2030 are:

- Business-as-usual 2030 (BAU-2030)
- Flexible Batteries (Flex-Bat)
- Flexible Renewables (Flex-Res)

in addition, we calculate a “Business-as-usual 2023” scenario which is used to validate the model by comparing the calculated prices with historical day-ahead prices in 2023. The 2023 scenario is parameterized based on [14] - [18].

The three 2030 scenarios assume a change in the generation portfolio, in particular a general shift from steam power plants to CCGT and gas turbines as well as an increase of installed generation capacities from renewable energy sources (i.e. generation from wind offshore and wind onshore and solar) following the expansion targets of the German government [19]. These include 30 GW wind offshore capacities, 115 GW wind onshore and 215 GW solar capacities by 2030. The scenarios assume different levels of (in-)flexible generation from the mentioned renewable energy sources. The generation capacities for biomass and RoR are not increased. The marginal generation costs for biomass vary between a strong negative value and zero € / MWh. The strong negative marginal generation costs shall reproduce the highly inflexible behavior that can be seen today. RoR faces marginal generation costs of zero € / MWh. The pumped storage capacities are not increased. Furthermore, these scenarios include a significant increase in battery storage capacities. The power-to-energy ratio is increased to three hours in all scenarios as well as the inverter. There is also an increase in variable generation costs for conventional power plants as well as an increased annual demand of 700 TWh. For all scenarios the availability factors for renewable generation technologies are calculated based on [20], [21]. Weather conditions are assumed to be as in 2012 which is a representative weather year used for the official grid expansion planning in Germany [22]. Furthermore, the scenarios include an increase in demand response (shiftable load increases from 100 MW to 2 GW) and a decrease in conventional “must-run” capacity for ancillary services provision. Our model excludes international power exchange. As we focus on negative electricity prices we assume that in times where generation from renewable energy sources exceed demand there is no potential to export electricity.

The “Business-as-usual 2030” scenario assumes a high share of inflexible renewable generators. This inflexibility results from subsidies that lead to negative variable generation costs for onshore wind and solar generators as well as an uncontrollable share of these generation capacities. The battery storage inverter power is increased to 15 GW.

The “Flexible Batteries” scenario assumes the same structure of generation technologies as the “BAU-2030” scenario. It deviates from the “BAU-2030” scenario in the batterie storage inverter capacity, which is significantly increased to 160 GW.

The “Flexible Renewables” scenario in contrast assume high-flexible renewable generators. All wind turbines (offshore and onshore) have zero variable generation costs and are fully flexible. Solar capacities are also assumed to be completely flexible but there still is a subsidized share, which is assumed to face negative variable generation costs. Moreover, biomass generation is assumed to have marginal generation costs of zero € / MWh to represent complete flexibility of this technology. As in the “BAU-2023” scenario 15 GW of battery storage inverter capacity are assumed.

IV. VALIDATION

This section presents the comparison of the historical situation on the German electricity market[1] in 2023 and the scenario “BAU-2023” results. First, the distribution of hourly electricity prices in both settings is presented. As the developed model is quite simple and we use weather data not from 2023 we do not expect the calculated prices to match the historical ones exactly. Thus, we compare the distribution of prices as well as extreme price events. Fig. 1 presents boxplots of realized prices in 2023 and calculated prices for the “BAU-2023” scenario.

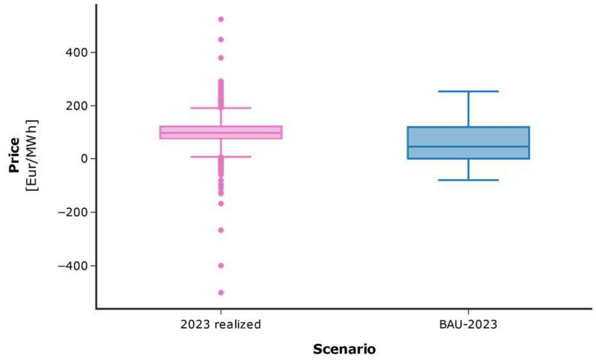

Figure 1. Distribution of prices in 2023 and the “BAU-2023” scenario

The figure shows that our model generally underestimates electricity prices, but at the same time shows a higher variance in prices. In 2023 the distribution realized prices ranks from approx. 75 € / MWh (first quartile) to 122 € / MWh (third quartile) while the median price was at 98 € / MWh. In contrast, the modeled “BAU-2023” scenario has 50 % of the mass between zero and 92 € / MWh (first and third quartile), with the median price being 68 € / MWh. The historical median is close to the modelled value but the distance from first to third quartile is nearly doubled in the modelled scenario. Furthermore, the model does not replicate the extreme price events 2023 faced. Neither the highest prices above 400 € / MWh nor the lowest at - 500 € / MWh are reproduced. However, both the realization and the model have a significant share of negative prices.

Fig. 2 visualizes the number of hours with negative electricity prices in 2023 and in the “BAU-2023” scenario. For the whole year, the amount of negative price hours is relatively similar between model and reality. The model-based “BAU-2023” scenario calculated 240 hours with negative electricity price while the German market faced in 2023 301 hours with negative price. In the details, our model overestimates the number of hours with a negative price at the beginning of the year. Only towards the end of the year the historical data exceeds the model results. Especially the strong increase after Christmas 2023 is not represented in the model result, presumably due to differences in the assumed weather year.

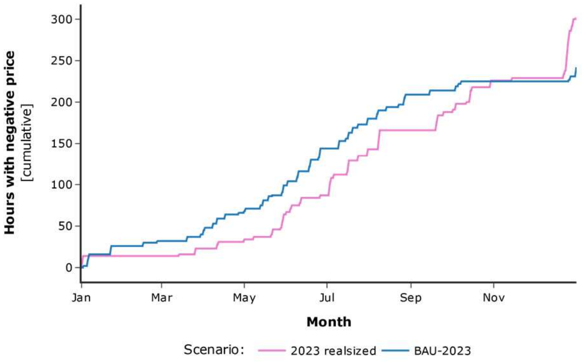

Figure 2. Number of hours with negative electricity price

In summary, it can be said that the model tends to underestimate prices but also underestimates extreme events. However, the amount of negative price hours does not differ by an order of magnitude.

V. EMPIRICAL RESULTS

The following section presents the three 2030 scenarios’ results. Analogue to section IV, the distribution of prices and the number of hours with negative prices are investigated. All prices are rounded to whole Euros.

In general, the results indicate a greater variance of prices compared to 2023 (historically and “BAU-2023” scenario). Fig. 3 shows boxplots of the calculated prices for the three scenarios.

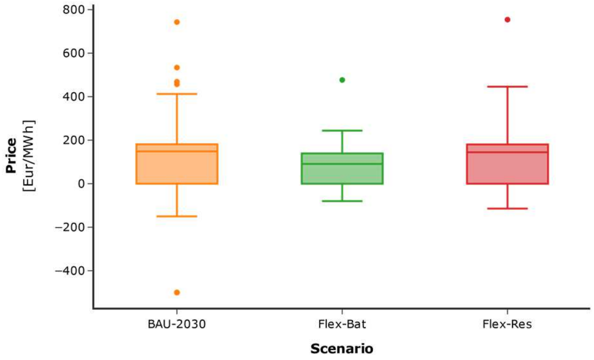

Figure 3. Distribution of prices in the three 2030 scenarios

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[1] Data used is EPEX day-ahead hourly wholesale electricity prices from [23].

The “BAU-2030” scenario shows the greatest variance in prices. In contrast to the “BAU-2023” scenario this includes extreme price events. There is one hour with a particularly high price (more than 743 € / MWh) and one hour with a minimum price of - 500 € / MWh. The interquartile range in this scenario ranges from zero to 181 € / MWh. The median price increases to 149 € / MWh compared to the historical situation.

The variance in prices is lowest in the scenario “Flex-Bat”. The prices vary between zero and 139 € / MWh (first and third quartile). The median price is also the lowest value in all three scenarios. It is 91 € / MWh, almost the same as in 2023. This reduction in price volatility is the result of increased storage technologies. The storages are charged in hours with high availability of electricity from renewable energy sources and increase the demand (and also the price) in this hours. In hours with low availability of renewable electricity generation storages are discharged and feed electricity back to the grid and replace expensive generation from conventional technologies.

The “Flex-Res” scenario also shows a higher variance in prices compared to the previous scenario but in the same order of magnitude compared to the “BAU-2030” scenario. The quartiles range from zero to 180 € / MWh (first and third quartile) and the median price is 145 € / MWh. However, more flexible renewable generators cannot protect against high prices in hours with low availability of wind and solar. This is shown by the high median price and the hour with the highest price in all compared scenarios.

The following Fig 4 illustrates the number of hours with negative price in all three scenarios for 2030.

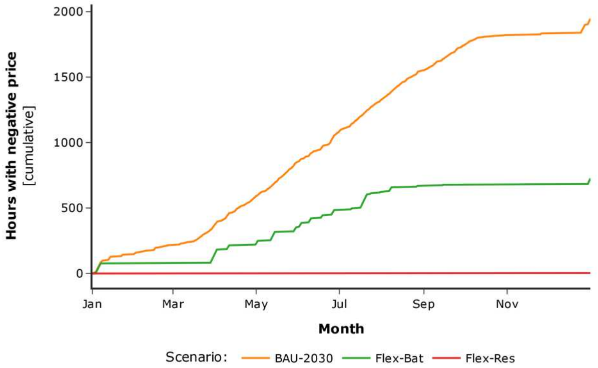

Figure 4. Number of hours with negative price

There are almost 2,000 hours with negative prices in the “BAU-2030” scenario. The figure also indicates that although the “Flex-Bat” scenario can prevent strong negative prices, it cannot fundamentally prevent the price from becoming negative. This is due to the limited capacity of storages. In good conditions for generation from renewable energy sources, these are regularly completely full. In contrast, the “Flex-Res” scenario just has three hours (less than 0.1 % of the year) with negative prices.

The following TABLE II summarizes the model results.

TABLE II. MODEL KEY-RESULTS

	BAU-2030	**Flex-Bat**	**Flex-Res**
First quartile price [€/MWh]	0	0	0
Median price [€/MWh]	149	91	145
Third quartile price [€/MWh]	181	139	180
Hours with negative price	1940	722	3

These results illustrate the demand for flexibility in the German electricity market. Without additional storage capacities and less inflexible generation from renewable energy sources electricity prices will become more and more volatile including events with extreme high and low prices. While a focus on battery storage systems can curb this volatility, batteries are not able to completely absorb the surpluses from renewable energy sources if the latter remain as inflexible as they currently are.

VI. CONCLUSION AND DISCUSSION

Historical data as well as the presented model results confirm that increasing capacities of renewable generation technologies necessitate greater flexibility within the electricity system. This flexibility is crucial to mitigate higher volatility in electricity prices, including a rising number of hours with negative prices. Without additional flexibility in the system, the number of negative prices is likely to increase greatly, in our base case the model calculates close to 2.000 h per year. However, our results also illustrate that different kinds of flexibility can reduce volatility in electricity prices and avoid negative electricity prices. Increasing storage capacities can charge during low residual demand hours and then even help to cover times with high residual demand. In combination, storages thus allow the integration of more electricity from renewable energy sources to the system. In contrast, more flexible and price sensitive generation from renewable sources is even better suited to mitigate negative electricity prices, but comes without the additional benefits.

Due to the simplifications made in the model, it makes sense to repeat this investigation with a more comprehensive energy system model. In this follow-up study, conventional generation technologies can be modeled with more precision including cold and warm startup cost as well as efficiency losses due to partial load. Also, demand response as well as more different storage technologies can be integrated with more complexity.

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