Solar Infeed During Low Demand Hours – A Problem?

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***Abstract*—This paper addresses negative electricity prices resulting from the integration of renewable energy sources into power systems. We show that a significant share of renewable capacity, particularly solar and wind, are unresponsive to negative prices. The study presents two scenarios for future excess generation in the German electricity system: a business-as-usual scenario and a scenario with enhanced demand-side flexibility. Results show that without increased demand flexibility, the system could face excess generation, i.e. supply exceeding demand at the lowest price currently allowed (- 500 E/MWh), of up to 15 GW by 2027, with negative prices causing significant market disruption. Conversely, the extended demand flexibility scenario could mitigate these issues significantly. The findings underscore the necessity for demand-side flexibility and efficient curtailment of RES output.

***Index Terms*-- Flexibility, Intermittent Generation, Renewable Energy Sources, Negative Electricity Prices**

I. INTRODUCTION

The majority of debates on the integration of renewable energy sources (RES) in power systems focus on security of supply, i.e. how to match supply and demand during periods of cold weather (increased demand for heating), low sunlight (little solar generation and increased demand for lighting), and low wind (low wind generation). In contrast, little attention has been given to potential problems on the "right side" of the load duration curve, i.e. during events of low demand but high infeed from RES. During these times, there is more electricity available than needed. Increasingly, electricity turns from a "good" with positive prices to a "bad" with negative prices, i.e., market participants must be paid to get rid of electricity, either by consuming more or by producing less. Our paper sheds light on this currently under-researched aspect of negative prices.

Before we analyze the causes and consequences of negative prices in greater detail, it is important to clarify that negative electricity prices in itself are not necessarily problematic. On the contrary, negative prices can be an efficient market clearing signal. For example, an industrial consumer face costs to reschedule consumption to times of excess supply. On the supply side, plants may be willing to pay to avoid future start-up costs. In both cases, negative prices can be a welfare-maximizing, efficient market outcome. However, two problems may arise. First, the reaction to price signals may be distorted on both sides of the market. RES with a fixed feed-in tariff are an example on the supply side. In its purest form, i.e. when every produced kWh of electricity receives the tariff payment, the incentive to reduce production in a feed-in tariff is zero–even if the wholesale price drops towards minus infinity. An example on the demand side are household consumers, which in most jurisdictions still face flat, i.e. time-invariant, electricity tariffs. Again, the incentive to increase consumption is zero–even if the price falls towards minus infinity. The second problem when prices turn negative is that the market may not clear at all because supply and demand are not sufficiently price-responsive to intersect. This problem becomes worse when a limit on prices is imposed.

To highlight the empirical significance of negative price events, Figure 1. presents the cumulative number of hours with negative day-ahead electricity price in Germany in the years from 2020 to 2024. A lighter blue is referencing an earlier year.

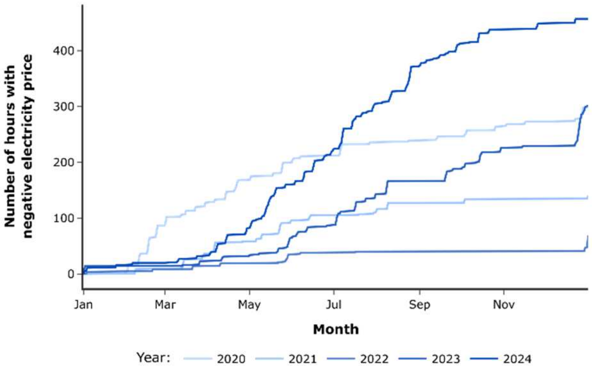

Figure 1. Cumulative amount of negative prices in the German day-ahead market by year

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The figure shows a clear trend of increasing times with negative electricity prices over the years. The exception is the year 2020, which already had numerous negative price hours, especially in the first quarter. This effect is an artefact of the COVID-19 pandemic which caused a massive decrease in electricity consumption.

The following Figure 2. shows that the reaction of RES to negative price events is limited. The figure shows the ratio of what solar and wind did produce in a quarter hour with negative prices (numerator) and the amount they could have produced in that hour (based on the forecasted weather conditions) in the denominator. The quarter hourly resolution is chosen to map the feed-in of renewables in as much detail as possible, even though all four quarters of an hour have the same price in the day-ahead market.[1] The reduction in feed-in varies slightly even within an hour. The figure shows that there is a limited reaction of wind power to negative prices (when prices fall below -100 €/MWh, about half the potential wind generation remains in the market, but the other half is curtailed). At the same time, solar power shows nearly no reaction to negative prices.

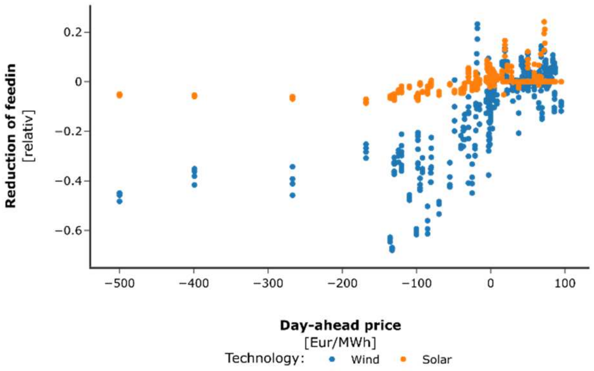

Figure 2. Wholesale prices and relative reduction of feed-in for solar and wind, covering all hours from days with at least one hour having a price below -100 €/MWh in the German day-ahead market in the year 2023

It is straightforward that ever increasing amounts of RES capacity will stress the system if so little potential generation reacts to price signals. In particular, the market will not clear even if the price drops to -500 €/MWh, which currently is the lowest price allowed in the German day-ahead market.

Our paper analysis in two scenarios how many such events can be expected in the German electricity market in the upcoming years, and how much "excess electricity" at prices of - 500 €/MWh the system will face. The first scenario is a business as usual scenario, the second is a scenario with increased flexibility on the demand side, brought about by large-scale power-to-heat systems and battery storage. This paper is based on a recent study the authors did together with the Scientific Advisory and Project Board of 50HertzTransmission GmbH ([1], work package 1). In particular, the methodology presented in that report is also used here in this paper. At the same time, this paper deviates in three aspects: First, the scenarios are defined differently. While [1] focused on the price reaction of RES generation, our work here focuses on other sources of flexibility. Second, this also changes the results and the conclusions. Especially, all insights on the contribution of large flexible loads to reduce excess electricity generation are new. Third, this paper is written in English and in more technical language, to reach the scientific community.

Although not as intensively discussed as the "left side" of the load duration curve negative wholesale prices are a topic for more than ten years. As early as 2013, [2] discussed negative electricity prices as a result of strong generation from renewable energy sources and presented an arithmetic Lévy model describing the German electricity sector. The influences of different subsidy schemes are also examined and identified as an important influence on flexibility and thus on negative prices [3]. And also, at present negative electricity prices and future estimations on negative electricity prices are discussed. The ongoing expansion of generation capacities from renewable energy sources and the increasing frequency of negative prices make this topic relevant today. While [4] discusses negative electricity prices on general level [5] presented a statistical model to interpret current electricity prices and estimate future prices on the German electricity market.

The paper is structured as follows: Section II provides a literature overview about negative electricity prices. Section III presents the methodology of the conducted study. In section IV, the calculated data is discussed. Section V describes the results for different scenarios for the year 2030 and section VI summarizes and discusses the insights.

II. METHODOLOGY

The following section describes the methodology used to quantify duration and severity of excess generation in the system.

First, we focus on the generation at hours with price being - 500 €/MWh. This generation comprises solar infeed (s_t), wind infeed (w_t), biomass & hydro production (bh_t), as well as the production from all other remaining must-run capacity (mr_t).[2] Both solar infeed and wind infeed can react to negative price events by curtailing the forecasted output with a technology specific curtailment factor which is assumed to be constant through the year.

$$s_t|(p_t = -500€/\mathrm{MWh}) = cs \cdot sb_t \tag{2}$$

and

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[1] The German EPEX day-ahead market will introduce quarter hourly price notations in 2025. However, for our data, all EPEX day-ahead auction price results were hourly.

[2] The model could easily accommodate international power exchange, but we abstract from it under the assumption that Germany cannot export excess electricity as neighboring countries are also filled to capacity based on their own renewable infeed.

$$w_t|(p_t = -500€/\mathrm{MWh}) = cw \cdot wb_t \quad (3)$$

Curtailment of biomass & hydro production is left for future research, historically reactions of biomass have been negligible.

Demand comprises both an inflexible basic component db_t and a flexible component which is added as a result of the price drop to - 500 €/MWh. We further differentiate between small flexibility sources on the demand side (e.g. smart EV charging) and large flexibility sources (e.g. grid scale electric heating and batteries). The demand increase due to small flex is referred to as ds_t, large flex is dl_t. We do not consider energy restrictions for increased demand. The assumed potentials for small and large flex can therefore be called up in any hour, regardless of the previous hours.

$$d_t|(p_t = -500€/\mathrm{MWh}) = db_t + ds_t + dl_t \quad (1)$$

Now, we define excess generation X_t in hour t as the amount of electricity (in MWh) by which supply exceeds demand in the day-ahead market even at a price of - 500 €/MWh, given the assumptions. For all hours of a given year, we calculate this number by taking the generation that would remain despite the price being - 500 €/MWh and subtract the demand.

$$\begin{aligned} X_t|(p_t = -500€/\mathrm{MWh}) & \quad (4) \\ = cs \cdot sb_t + cw \cdot wb_t + bh_t + mr_t & \\ - (db_t + ds_t + dl_t) & \end{aligned}$$

What we are interested in is

a. the number of hours with positive X_t, i.e. the frequency of having excess supply on the day-ahead market, and

b. the size of X_t, i.e. the GWh/h of excess supply. In our analysis of distribution of X_t values of a year, we calculate both the 99 % and the 95 % percentile, i.e., the X_t where only 1 % (or 5 % respectively) of the hours of a whole year have higher values. Not focusing on the highest value of X_t in a year increases the robustness of our results.

Before we parameterize the model, it should be briefly discussed what excess supply, i.e. a positive X_t, implies. First, the day-ahead market is not in equilibrium, as the equilibrium requires supply and demand to be equal. Second, the price would have to be even lower than - 500 €/MWh to reach an equilibrium, either to incentivize additional demand or to drive more supply out of the market. Third, in this particular case EPEX applies a tie-breaking rule, and supply is awarded pro-rata. Fourth, any uncleared production on the day-ahead market can still be traded on the intraday market before physical delivery. Hence, while there may well be technical problems resulting from too much physical supply in real time operation, they are not necessarily emerging when the day-ahead market has too much electricity. Neither intraday trading nor technical problems are explicitly part of this study.

III. DATA

We parameterize the model with data of the German market. Our analysis covers the medium-term future, i.e. the years from 2025 to 2030. All data and calculations are made available on github at https://github.com/BTU-EnerEcon/solar_excess.

Base demand db_t is parameterized based on realized demand in the year 2023, with data taken from SMARD [6]. Hence, all future years from 2025 to 2030 are assumed to have the same base demand in the respective hour of the year.

Small flexibility on the demand side, i.e. ds_t, is parameterized based on [7].

Large demand flexibility is the crucial parameter varying between the two scenarios. In both scenarios, we define “large” as single load of more than 1 MW. The potential is subdivided in electricity storages and other loads.

A high *electricity storage* potential is observed in large electric batteries including both non-flow and redox-flow systems, due to their low investment costs and high efficiency. By the end of 2024, grid-connected large batteries could store 2.2 GWh and charge and discharge at 1.7 GW [8], [9], with rapid growth rates. Grid connection inquiries are at a historically high level of 226 GW [10] only for the four German Transmission System Operators, but only a portion of these inquiries is likely to be realized.

Compressed Air Energy Storage (CAES) systems are attractive in terms of investment costs and technology readiness. However, CAES has lower efficiencies compared to batteries, and the necessary caverns may have competitive alternative uses as hydrogen storage. Liquid Air Energy Storage (LAES) is a scalable technology with relatively low investment costs, but like CAES, it also has significantly lower efficiencies than batteries. If the continuous price decline of battery cells persists, substantial market shares for CAES and LAES technologies are not anticipated.

Pumped Hydrogen Energy Storage (PHES) can be competitive with batteries; however, since existing PHES systems are already operating in the electricity markets, they cannot be counted as additional demand flexibility. Significant shares of new installations are not expected in Germany. We do not expect other technologies to provide much to large demand flex before 2030 as they are either not available at a high technology readiness level or remain too expensive, such as gravity batteries and various types of electricity-heat-electricity storage. Additionally, some storage options are generally unsuitable for Germany's geographical conditions, particularly due to the lack of deep-sea areas, such as buoyancy energy storage or underwater pumped hydro energy storage spheres.

The conversion of hydrogen to electricity is not expected to occur in significant quantities before 2030; therefore, until that time, hydrogen electrolysis is considered as a load rather than a form of electricity storage.

The flexibility potential of *other loads* is mainly seen in power-to-heat options. This means both heat pumps and electrically powered boilers (e-boilers). Heat pumps are preferred in terms of efficiency but they have relatively high investment costs and complex installation requirements especially due to the integration of a heat source. E-boilers have much lower investment costs and installation complexity. For economic operation, heat pumps and e-boilers must be competitive with conventional gas boilers. For a theoretical mean electricity price of 50 €/MWh (end customer, ancillary costs inclusive), a gas price of 40 €/MWh and a CO_2 price of 100 €/t the heat pump needs at least about 1000 full load hours while the e-boiler can be cost-efficient above 200 full load hours.

Large *other heat loads*, particularly those exceeding 1 MW, are primarily found in the district heating and industry sectors. On a summer day, the overall heat load reaches 5 to 6 GW for district heating and exceeds 10 GW for industry. This load can be augmented by heat storage systems. With theoretical heat storage capacities designed for the load of a single summer day (4 hours of charging and 20 hours of discharging), the potential load in district heating systems across Germany could increase to 35 GW. Storage solutions for even longer durations are commercially available, and the cost contributions of these storages to overall heat generation costs are manageable. This highlights the significant flexibility potential of power-to-heat systems. Currently, the main barrier to power-to-heat implementation is regulatory aspects, particularly network fees, which render flexible operation with fewer than 1,000 full-load hours economically unattractive."

Additional flexible loads, each with a potential ranging from 1 GW to 10 GW, can be observed in refrigeration plants (load shifting), power-to-gas (hydrogen), the substitution of industrial power stations by purchasing electricity, and the load shifting of industrial electricity demands.

Consequently, our assumptions for large flexibility, dl_t, vary between the two scenarios. The business as usual scenario (BAU) assumes 8.9 GW in 2030 while the extended demand flexibility scenario (EDF) assumes 30 GW in 2030. Note that this is the only difference between the two scenarios.

On the supply side, bh_t and mr_t are parameterized based on the electricity generation in 2023 [6]. bh_t is assumed to generate equal to the historical generation while mr_t is assumed to decline from 6.9 GW in 2023 to 6.2 GW in 2030.

Furthermore, the generation of solar and wind are crucial. First, we parameterize the potential infeed (sb_t and wb_t) using forecasts for installed capacity, multiplied with availability factors (based on [11], [12]) for the weather year 2012, which is often used in the literature as a "representative weather year" (source: [7]). This gives the maximal hourly in-feed. Second, we also need to estimate the share of curtailed generation when prices drop to - 500 €/MWh, i.e. cs and cw in the methodology section. For these, we assume that the inflexible share of solar generation capacity decreases to 60 % in 2030 and the inflexible share of wind generation decreases to 6 % in 2030. These assumptions are based on [1].

IV. EMPIRICAL RESULTS

The following section presents the results. The calculated excess generation as well as the cumulative number of hours with excess generation are discussed.

The following Figure 3. shows the development of excess generation (95 % percentile) over the years investigated in both scenarios. A key take-away from the analysis is that without additional flexibility, the German electricity system may face excess generation up to 15 GW in 2027. In the following years, the excess generation remains roughly constant at a level of approx. 14 GW. In contrast, the EDF scenario faces no excess generation after 2027 and strongly decreased excess generation until 2027.

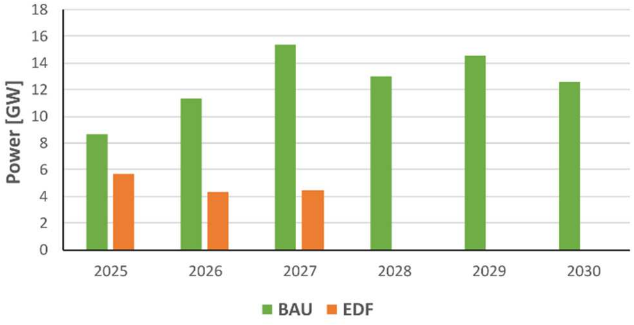

Figure 3. Power of excess generation (95 % percentile) in the scenarios

The following Figure 4. in contrast illustrates the difference between the 95 % and 99 % percentile. It shows the calculated excess generation in the BAU Scenario. The 95 % values are still a conservative estimate in the sense that 5 % of the hours per year are expected to have even higher excess. Cutting off only 1 %, i.e. looking at the 99 % percentile, the excess reaches a maximum of 30 GW in 2027 and then remains almost stable between 25 GW and 30 GW until 2030.

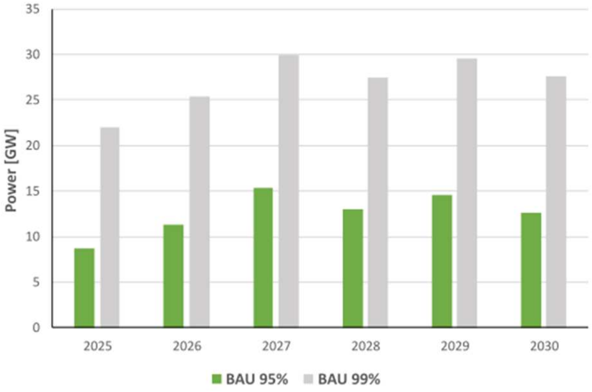

Figure 4. Power of excess generation (95 % and 99 % values) in the BAU Scenario

The following Figure 5. presents the cumulative amount of hours with excess generation in the BAU Scenario for the years from 2025 to 2030. It illustrates the maximum of excess generation in 2027 and the following decrease. In the maximum there are more than 1,000 hours with excess generation. In contrast the years 2025 and 2030 show similar hours with excess generation (842 hours in 2025 and 900 hours in 2030).

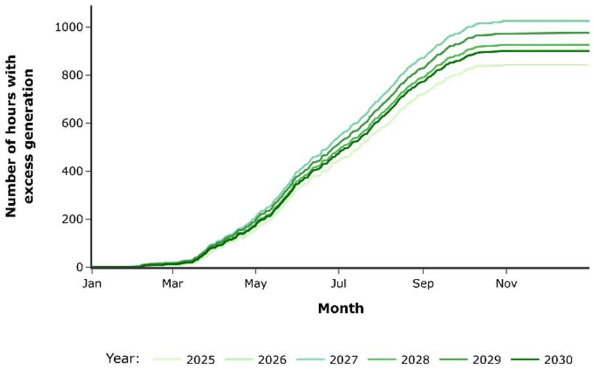

Figure 5. Cumulative amount of hours with excess generation in the BAU Scenario

Figure 6. shows the same information as Figure 5, but for the EDF Scenario. In this Scenario the maximum is reached in 2025 while the increasing capacity of large demand flexibilities absorbs an increasing share of potential excess generation in the following years. The maximum is here approx. 700 hours in 2025 and then it decreases to approx. 200 hours in 2030. This seems to be a contradiction to Figure 3 where no excess generation is shown after 2027. The difference between these two figures is that Figure 3. shows the 95 % values while Figure 5. and Figure 6. sum up all hours with excess generation.

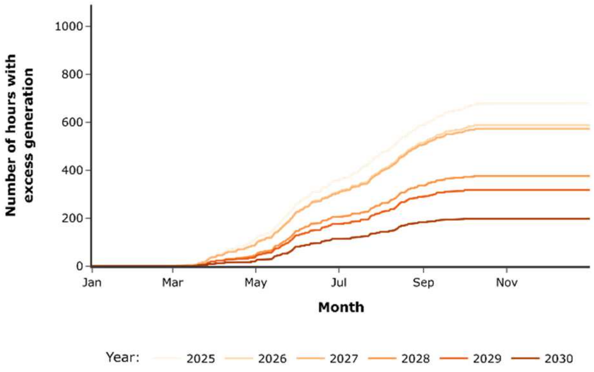

Figure 6. Cumulative amount of hours with excess generation in the EDF Scenario

V. CONCLUSION AND DISCUSSION

Our results show that both the frequency of hours and the amount of excess generation per hour offered on the day-ahead market will increase in the upcoming years when a business as usual scenario manifests. The resulting negative electricity prices will stress the system in several regards. First, the day-ahead market cannot completely clear when there is excess supply at the lowest possible price. Consequently, some generators cannot sell the desired amount of electricity on the day-ahead market. Second, when these inequalities cannot be balanced before real time, this may even result in technical problems in the grid. Third, when inflexible renewable generation is supported with a fixed feed-in tariff, required subsidies can rise considerably as the generation is now paid twice: once to the producer (in the form of the feed-in tariff) and once to the off-taker at a market price of – 500 €/MWh.

While the business-as-usual scenario shows what can happen without further intervention, rising awareness and a recent surge towards large scale storage and flexibility options open the door to a less bleak scenario. We model such an alternative development in the extended demand flexibility scenario, where we assume a strong expansion of flexible loads based on existing technical potentials for different demand technologies. Under this assumption, from 2027 onwards no excess is observed at the 95 % percentile and the 99 % percentile of excess generation decrease to approx. 1 GW in 2030.

This expansion in demand side flexibility requires changes in the regulatory framework. For example, the structure of grid tariffs is a one barrier to more flexibility from electricity consumers. Furthermore, 15-min-metering should be rolled out much faster to incentivize demand response in households. Furthermore, incentivizing RES to curtail electricity output also reduces the problem considerably.

VI. ACKNOWLEDGEMENTS

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