Assessing price effects of RES infeed and its regional distribution in nodal markets: A case study for Germany

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Abstract:

The market-based dispatch of generation units in Germany's bidding zone often leads to congestions in the transmission system, resulting in a significant dependency on redispatch. In contrast, a nodal pricing regime internalises grid capacity in the market resulting in different Locational Marginal Prices (LMPs) in case of congestions. Based on the results of a linear formulated optimisation problem, our paper investigates in multiple scenarios how the regional distribution of RES capacities would impact LMPs in Germany. Our results show that congestions exist in all modelled scenarios which result in diverging LMPs. Using statistical instruments, we identify wind infeed to have the most significant impact on diverging LMPs. In most scenarios, the probability of diverging LMPs increases significantly the higher the wind infeed becomes. Even the anticipated grid extension measures for future scenario years are not sufficient to fully eradicate this effect. The PV infeed has only little impact on price divergences. We conclude that spatial incentives allowing for investments at sites where they add the highest value to the system become increasingly important and appropriate market designs should be discussed further.

Keywords: market design, nodal pricing, redispatch, spatial incentives

1 Introduction and Motivation

Replacing fossil fuel-based technologies in the electricity system with renewable energy sources (RES) is crucial for reducing greenhouse gas (GHG) emissions and thus limiting the impacts of human-made climate change. However, the increasing share of weather-dependent RES in electricity generation entails new challenges in maintaining the security of supply, i.a. in terms of transmission adequacy. We believe that, next to technical concepts, market designs are an important lever that can contribute to ensuring the system's security in an economically efficient way.

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In Germany, the transmission system developed alongside large scale conventional power plants, which historically were located closer to regions with high electrical loads. Nowadays, it needs to deal with an increasingly different regional distribution of generation and load. While particularly wind turbines are overwhelmingly erected at windy sites, e.g. in Northern or Eastern parts of Germany as well as offshore, industrial and densely populated areas are rather located in the South and West. The market-based dispatch of generators then often induces congestions in transmission lines that Transmission System Operators (TSOs) need to resolve, e.g. by altering the power plants' dispatch to achieve a technically implementable load flow (redispatch). Several grid extension measures will be deployed in the upcoming years to reduce the congestions in the system. In the short term, however, the phase-out of the remaining nuclear power plants further reduces the Southern generation capacities and therefore might worsen the already existing north-to-south-congestions in the German transmission network.

The strongly increased congestion management costs are not internalised in Germany's electricity market design that builds upon a single bidding zone assuming electrical networks to be copper plates with unlimited transmission capacity. Instead, existing costs of congestion management measures are indirectly paid through network tariffs by all consumers. In contrast to zonal pricing, a nodal-based market design internalises costs for congestion management as transmission capacity becomes subject to the market. If a line is congested, a nodal-based market design results in different regional electricity prices [1].

The debate around nodal pricing or a split of the German bidding zone to better reflect congestions in the transmission system is highly politicised. Several high-level commitments have been made to maintain Germany's uniform bidding zone [2]. However, the EU Agency for the Cooperation of Energy Regulators (ACER) has, pursuant to the Capacity Allocation and Congestion Management (CACM) Regulation, to assess the efficiency of the current bidding zone configuration [3]. As ACER's assessment revealed inefficiencies in some of the current bidding zone configurations, it requested European TSOs to conduct a Bidding Zone Review (BZR), which could result in the reconfiguration of some of the existing bidding zones.

Our paper does not aim at arguing in favour of a certain market design or a split of bidding zones but rather contributing to the discussion about the spatial granularity of electricity markets by analysing the impacts the regional distribution of RES has on LMPs and discussing some conclusions that can be drawn from them. We show for different scenarios, today and in the future, what LMPs could look like and analyse the main determining factors for price divergences across Germany. The underlying model was implemented in Python using the free software toolbox PyPSA (Python for Power System Analysis) [4]. The input data we use relies entirely on publicly available and open-source data.

In this paper, modelling nodal and zonal prices is used to quantify the impacts of congestions on prices and how the current regional distribution of RES capacities contributes to it. Hence, it focuses solely on issues regarding the electrical power system while neglecting the socio-economic consequences such a change in electricity market design would have.

2 Overview of Zonal and Nodal Electricity Markets

The electrical energy fed into the electricity grid is an entirely homogeneous commodity, meaning that there is, no physical difference between electrical energy coming from different power plants [5]. In a market for a completely homogeneous good, only one price is formed under the condition of freedom of arbitrage [6]. However, due to electricity's specific characteristics, electricity markets differ significantly from other commodity markets. First, electricity has a different value over time as large volumes cannot be easily stored. Second, electricity has a different value over space as electricity can only flow in the limits the transmission components physically allow. Third, demand and generation must match each other at all times to ensure the security of supply. Hence, not only the electrical energy is a scarce resource, but transmission capacity and flexibility are scarce resources as well and traded in several markets until the actual delivery takes place in real-time [7].

However, the delivery of electricity depends on a power grid that can transport the electrical energy from power plants to consumers. While the physical electricity flow prefers, in accordance with the laws of Ohm and Kirchhoff, the way with the lowest resistance, the commercial electricity flow can differ from that. In a grid without any congestion, often referred to as a copper plate, different physical and commercial flows do not really lead to a difference: If the same amount of electricity is bought and sold as physically consumed, no shortage will appear, and every consumer gets supplied independently from the location of the generator the electricity was bought from.

In a zonal market design, bidding zone internal congestions are neglected in the market. The market assumes that the electricity can be supplied independently from the location of power plants and consumers. Each system operator is responsible for ensuring the network safety in its control area and hence for avoiding any congestions violating the (n-1)-redundancy criterion. The (n-1)-redundancy criterion prescribes that after an occurrence of a contingency, the remaining elements are capable of accommodating the new operational situation without violating operational security limits [8].

If the (n-1)-redundancy-criterion would be violated by the market result, TSOs have to apply remedial actions (RA) to maintain the system's security. RA incorporate non-costly measures, such as changing the network's topology through closing or opening specific circuits, as well as costly measures like countertrade or redispatch measures with the aim of relieving certain network elements.

With redispatch measures, TSOs intervene in the dispatch that previously arose in the electricity market. In that case, TSOs request one or more power plants before a bottleneck to reduce their generation (negative redispatch) and one or more power plants behind the bottleneck to increase their generation (positive redispatch). Instead of using generation capacities to handle congestions, TSOs can also use controllable loads. The equivalent of a positive redispatch is then reducing the demand of a load behind a bottleneck. Hence, redispatch, in theory, does not change the balance of the system as the TSO needs to activate the same power as somewhere else was reduced.

While the zonal market model neglects internal congestions, it takes into account the congestions at the borders between adjacent bidding zones. The maximal transfer capacities are either explicitly or implicitly reflected in the market. If the transfer capacities between two zones are not sufficient, the prices in both zones will diverge.

In comparison to zonal markets, a nodal design internalises all transmission capacities into the market. Generally, the clearing process to determine the price works similarly as in a zonal market: The price is set by the last (most expensive) power plant needed to satisfy the demand. However, in contrast to zonal prices, no larger area is aggregated and considered as a zone with uniform prices. Instead, the market operator executes a locationally sensitive clearing process that determines a certain node's price [9].

As long as no congestion between nodes occurs, the nodes' prices converge. However, once congestions among nodes appear, prices will diverge. If one sticks to zonal markets' terminology, every node can be considered its own zone and power exchanges with all neighbouring nodes as inter-zonal trade.

The main advantage of a nodal market is that it makes redispatch obsolete. If internal congestions appear in a zonal market, the price would still be the same at every node. However, physical constraints remain the same in both market designs, and the zonal market's result could not have been implemented while ensuring the system's security. Instead, TSOs had to apply RAs, like requesting a power plant with higher marginal costs than the market price to provide positive redispatch power. The costs for this RA would not have been visible in the electricity market. Hence, by merely comparing market prices, the zonal model indicates lower costs than the nodal model. But still, the costs for physically providing the electrical power behind congestions have to be paid. In a zonal model, these costs are paid by all network users through the transmission tariffs.

In contrast, a nodal pricing system already internalises these costs and make them visible to the electricity market. Thus, a nodal approach allows using the existing transmission infrastructure in the best possible way as operation constraints are already reflected in the market [10]. Therefore, it is largely undisputed among economists that nodal prices increase electricity markets' static efficiency and reduce overall generation costs [9]. In [11], the authors compare zonal and nodal markets by more than 40 developed criteria and identified amongst others locational investment incentives and market power as important aspects.

In both nodal and zonal set-ups, market actors react to the profit opportunities the market provides. Since a zonal market model has a uniform price that applies to the entire bidding zone, the market price itself does not incentivize locationally sensitive investments. The regional distribution of investments in a zonal market is rather determined by the cost structure at a given location. For example, the levelized costs of electricity of a wind turbine are particularly impacted by the wind conditions. In Germany, this leads to a disproportional deployment of wind turbines at windy Northern sites, which could then result in increased congestions in the electricity grids. In a nodal market, not only the cost structure depends on the site, but also the revenue potentials of produced energy gets a spatial component as the electricity price can differ across nodes. For example, structurally higher electricity prices at a certain node can outweigh lower production costs at another node resulting in higher profit opportunities for the investor. Vice versa, large (industrial) consumers get incentives to invest at locations with lower electricity prices. Hence, nodal markets add the capabilities of the transmission system as a criterion for investment decisions of market actors and can lead to economically more efficient investment decisions [12]. However, there are several drivers (politics, availability of land/resources and acceptance) which influence investment decisions and which might outweigh the signal of locational prices.

Although nodal pricing disaggregates the electricity market to increase its spatial granularity and better reflect the real costs of providing electricity at a specific location than zonal markets, they entail some disadvantages. Investment uncertainties could increase as the prices at a single node can be heavily impacted by a newly deployed transmission line or generator. The credibility and stability of LMPs are hence difficult to foresee and may prevent market actors from taking investment decisions. Some argue that locational market power can be more pervasive in nodal than in zonal markets so that most regulators respond with price caps in order to prevent the abuse of market power. This may result in an increased missing-money-problem and under-investment [9] However, in practice, there are several options to detect and mitigate the abuse of market power. Furthermore, the existence of market power is rather independent of the choice of the market design as it is mainly driven by the physical constellation of the existing resources and grid infrastructure. The transition from an existing zonal system towards a nodal market entails implementation costs. In [13], the authors estimate that the annual benefits arising from a nodal pricing regime typically recover the one-time implementation costs already within one year of operation. The switch to a nodal system would, however, massively impact existing power plants. Generators historically located at a node where electricity is cheap will face reduced opportunities to obtain contribution margins.

All in all, a nodal market design incorporates not only cross-border congestions but any congestions occurring in the system. While price signals in zonal markets fail to reflect scarcity situations in some grid regions, nodal regimes reveal them through a price signal. As a result, electricity prices can vary significantly across different regions of a congested network. A switch from a zonal to a nodal regime can economically heavily affect existing players, and market power could become more pervasive.

3 Methodology and assumptions

The underlying methodology of this paper bases on a linearly formulated optimisation problem of the German electricity system with an hourly resolution, including generation, load, storage and transmission capabilities. The model minimises the sum of marginal system costs while respecting constraints, such as always ensuring balance of generation and load and not overloading transmission lines. The electrical flows are simplified considered by applying a DC load flow approach. The model was formulated with the free software toolbox PyPSA [4]. The objective function minimises the total costs of the considered system components, which are the sum of the marginal costs $c_{n,u,t}$ times the dispatch of generators $g_{n,u,t}$ over all nodes n, all units u and all snapshots t.

$$\mathrm{f}_{(g_{n,u,t})} = \min \sum_{n,u,t} c_{n,u,t} * g_{n,u,t} \tag{3-1}$$

The objective function is limited by several constraints. The electricity demand $d_{n,t}$ at each bus n must be met at each time t by the sum of the local dispatch of generators $g_{n,u,t}$, the local dispatch of storage units $h_{n,s,t}$ and the power flows $f_{l,t}$ of incoming lines which we assume to transmit power without any losses in the model. Hence, the following equation implements Kirchhoff's Current Law and ensures energy conservation:

$$\sum_{u} g_{n,u,t} + \sum_{s} h_{n,s,t} + \sum_{l} f_{l,t} = d_{n,t} \qquad \forall\, n,t \qquad \text{(3-2)}$$

More constraints that we are not discussing in detail here ensure that the dispatch of generators and storages, as well as the loading of lines, do not exceed their respective physical limits. Detailed information on PyPSA's standard constraints can be found in [4].

The model's underlying data is mostly retrieved from DIW Berlin's Reference Data Set representing the status of the German electricity system in 2015 [14]. It covers a total of 450 nodes and 724 transmission lines on the 380 kV and 220 kV levels. This database is updated with our own assumptions to represent the year 2020 as a reference scenario. Additionally, we simulate scenarios for the years 2023, 2025 and 2030 to investigate the impacts of grid extension measures, phase-out of conventional generation capacities, and further RES deployment. Figure 1 visualises the assumed transmission network in the respective scenarios.

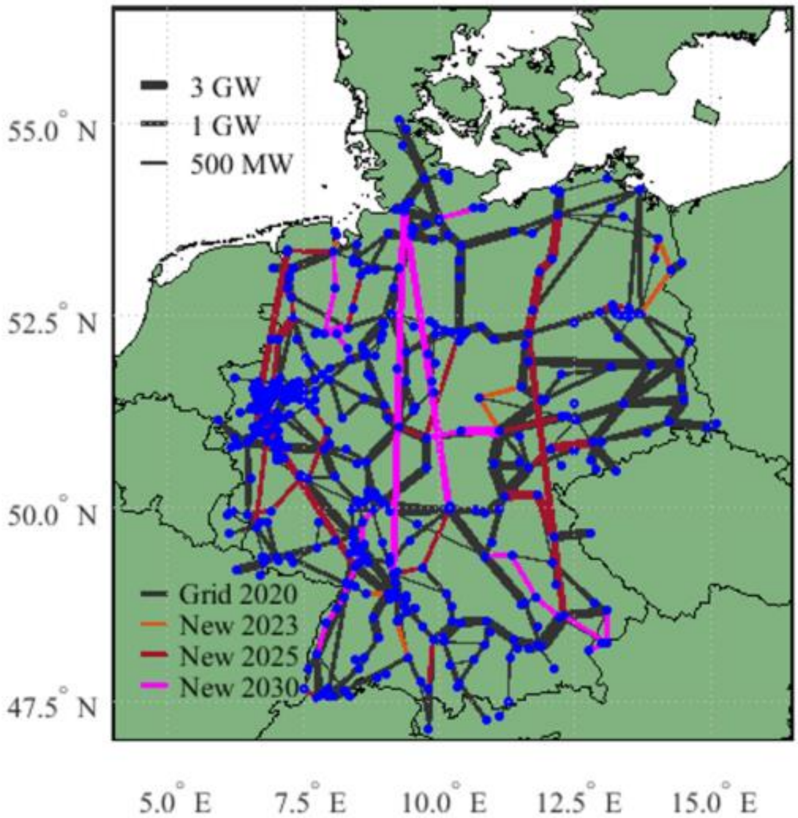

Figure 1: Overview of the assumed transmission network in respective scenarios

The considered power plants are also derived from DIW Berlin's reference data set and updated with the power plant list of Bundesnetzagentur. Figure 2 shows the distribution of different carriers and at which nodes they feed into the grid.

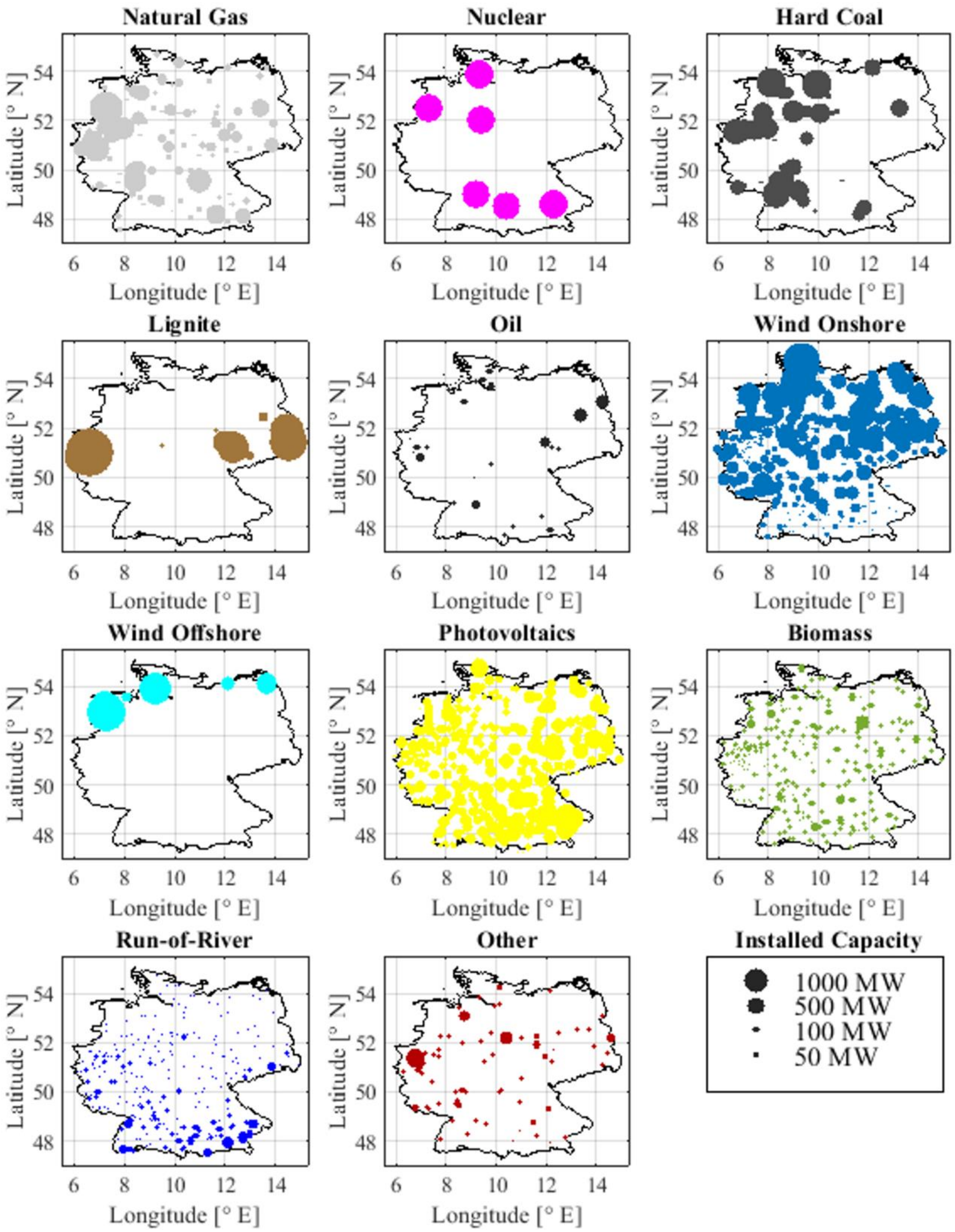

Figure 2: Installed generation capacities per technology in the 2020 scenario

The total capacity installed we assume per carrier in different scenarios is visible in Figure 3. The installed capacities for 2025 and 2030 are derived from Scenario C of The Power Grid Development Plan 2030 (Netzentwicklungsplan Strom – NEP) [15]. The installed capacity of renewables in 2023 is derived by a linear interpolation between the installed capacities in

2020 and those assumed in the 2025 scenario of the NEP. To meet the total installed capacity per carrier in a given scenario we assume in our base case that future RES capacities will be deployed with the same regional distribution as in the past. The installed capacity per carrier and node of the given input data is scaled accordingly. As the coal phase-out law was issued after the referred NEP had been published, coal capacities are adjusted in line with the law, and nuclear capacities are fully phased out.

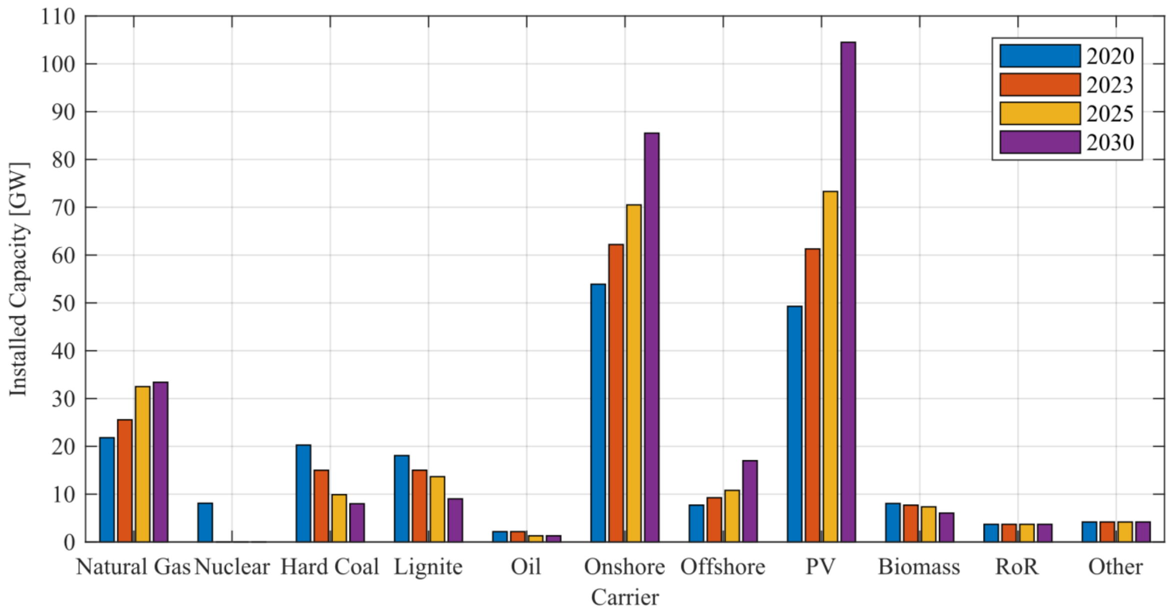

Figure 3: Assumed installed capacity per carrier and year

Nodal-based profiles for wind turbines are calculated through ERA5 wind data derived from Copernicus Climate Data Store [16]. To each node in the transmission system, we assigned the wind profile of the closest virtual measuring point of the ERA5 data set in 2019. For the profiles of PV and nodal load profiles, we rely on the data shipped with DIW Berlin's reference data set. For import and export, we set the limitations of the yearly tradeable energy to the energy exchange of DIW Berlin's reference data set and model it exogenously.

All in all, we had to make many assumptions and simplifications for building the model. Every assumption, and particularly those for the scenarios in 2025 and 2030, is subject to uncertainty. The development of installed capacities per carrier, as well as their regional distribution, is of high importance for the model. Whereas it is quite clear when respective nuclear and lignite power plants will leave the system, a hard coal generator's specific phase-out is less predictable due to the tender system in the coal phase-out law. Also, the development of natural gas power plants and their regional distribution is crucial to the model. The exact development of transmission lines and their respective thermal limits are subject to assumptions that are based on publicly available information. Due to the DC Load Flow modelling approach, the (n-1)-criterion is only considered by statically reducing each transmission line's nominal capacity. The model can also be improved by considering cross-border trade endogenously, which requires including components of foreign electricity systems into the model.

4 Results

Running the model with our assumptions provides us with marginal prices for every node and hour. It is not this paper's aim to forecast future electricity prices but to analyse regional differences as they would occur if nodal pricing was introduced. Hence, we are focusing here on the distribution of nodal prices and analyse the main determining factors for divergences.

LMPs only diverge if congestions on connecting transmission lines exist. Hence, a totally congestion-free electricity system would show the same prices at every node and the standard deviation, as an indicator to easily express their variability, would equal zero. Figure 4 shows the standard deviation of nodal prices as a duration curve in the 5000 hours with the highest variations and in different scenarios. The remaining 3760 hours are cropped out of this figure for visibility reasons as the prices hardly diverge anymore.

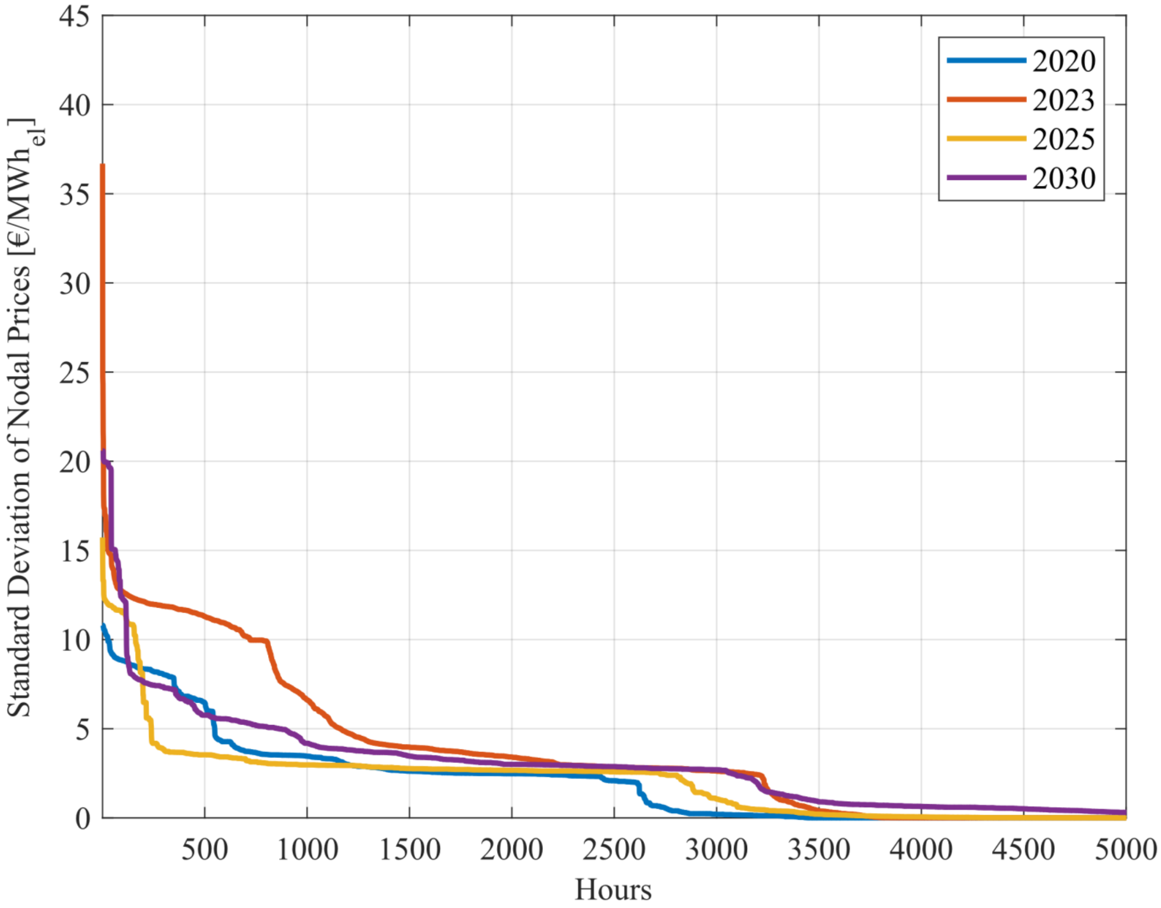

Figure 4: Duration curve of the standard deviation of nodal prices in 5000 hours and different years

Snapshots in which the standard deviation does not equal zero show that some nodes are facing different prices than others. At these snapshots, congestions in the transmission system occur. In a zonal market, these would reflect situations in that TSOs need to carry out RA, e.g. activation of redispatch measures. Snapshots with a high standard deviation indicate situations in that a power plant with significant higher marginal costs needs to be activated, although much cheaper generation power would have been available behind a congested part of the transmission system.

Our results show that congestions in the transmission system occur in all scenarios – however, to a different extent. The most significant divergences are visible in the 2023 scenario. This does not surprise, since considerable changes in the installed generation capacity (particularly the phase-out of the remaining nuclear power plants), but only little improvements in the transmission system are assumed.

Also, the decrease of snapshots with a standard deviation and the generally lower absolute value of the standard deviation between the 2023 and 2025 scenario is explainable. We assume many transmission projects to become operational between both scenarios, including Südostlink, which we assumed to be operational in 2025.[4] More surprisingly, the number of snapshots with price divergences increase between the 2025 and 2030 scenario. Given the assumed development of generation capacities, the remaining planned grid development projects between 2025 and 2030 seem insufficient to reduce the necessity of redispatch measures further.

4.1 Determining Factors for Price Divergences

When we analyse the absolute value of prices at snapshots with a high standard deviation, we found out that the prices at many nodes are relatively low. This raises the question of what the generation mix at snapshots with high price deviations across regions look like and if a pattern can be recognized that is statistically significant. Pearson's Correlation Coefficient *r* is a value to measure and assess the correlation of two data sets and is calculated by the covariance of the two variables, divided by the product of their standard deviations:

$$r = \frac{\sum_{i=1}^{n}(x_i - \overline{x})\,(y_i - \overline{y})}{\sqrt{\sum_{i=1}^{n}(x_i - \overline{x})^2} * \sqrt{\sum_{i=1}^{n}(y_i - \overline{y})^2}} \qquad (4\text{-}1)$$

According to Cohen, a significant statistical correlation between two variables exists if the absolute value of Pearson's Correlation Coefficient $|r|$ exceeds 0.5. A moderate correlation occurs if $|r|$ lies above 0.3 and a little correlation above 0.1 [17].

Figure 5 visualises the correlation of standard deviations of nodal prices with the main price-determining factors we found. It shows, besides the single data points of the standard deviation and price-determining factors, the linear regression curve for each of the subplots as well as Pearson's Correlation coefficient *r*. Using Cohen's interpretation, one can see that the model's results show a significant statistical correlation between the standard deviations of nodal prices and wind infeed both from onshore and offshore turbines. The correlation between the standard deviations of prices and the electrical load is closely below the 0.1 threshold for little significance. PV infeed has almost no influence on regional different nodal prices as the absolute value of its correlation coefficient is even further below 0.1.

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[4]According to recent announcements made after we finished our simulations, some grid extension measures will become operational later than assumed here. Hence, some price-converging effects might be realised later than we assumed for this paper.

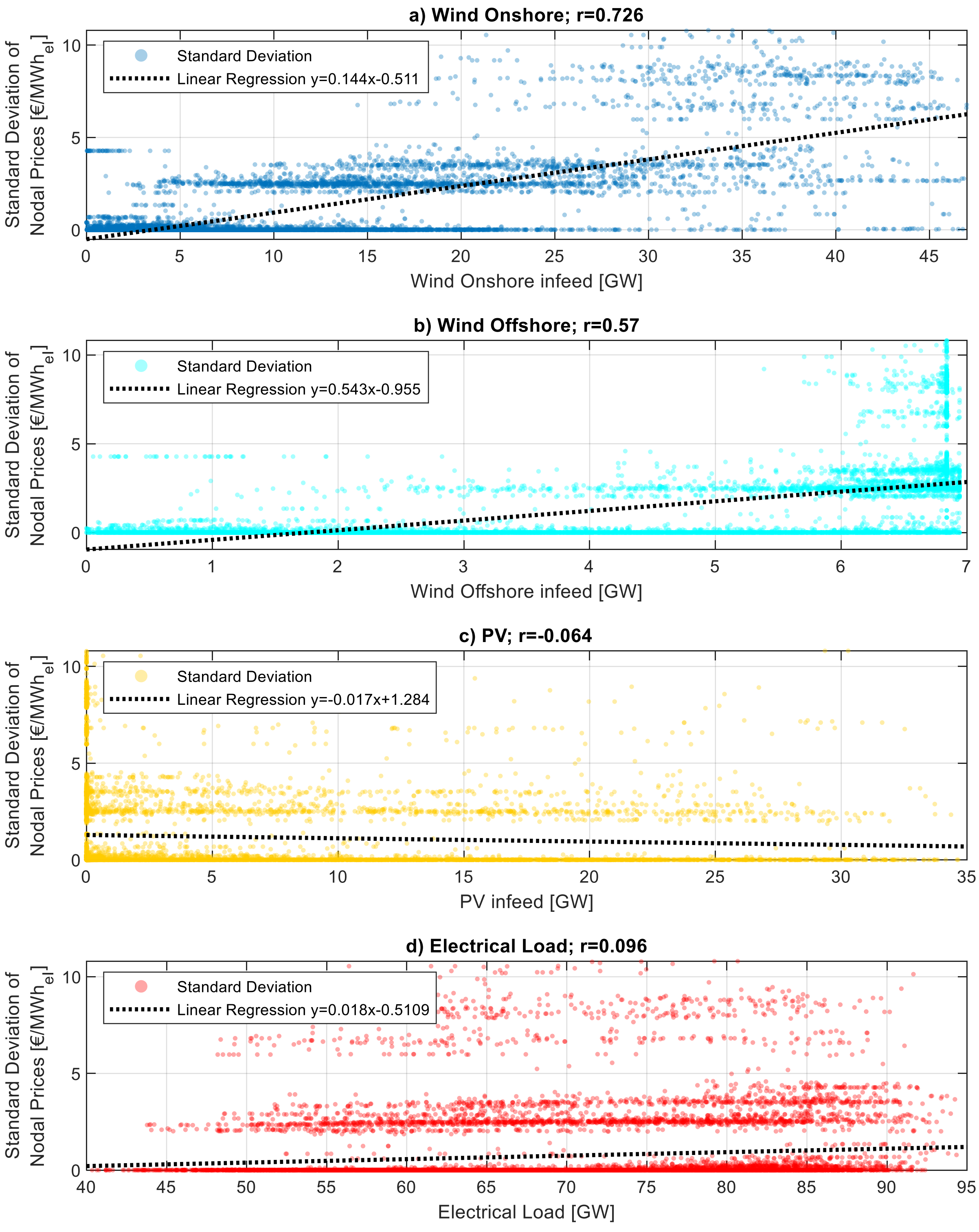

Figure 5: Correlation between the standard deviation of nodal prices and the infeed of a) Onshore Wind, b) Offshore Wind, c) PV, and d) electrical load for 2020

Combining the information on the significance of the correlation with the regression curve shows that the higher the wind infeed is, the higher the standard deviations of nodal prices. A similar correlation can also be detected for electrical load – the significance is, however, way lower than with wind. One can conclude that high wind infeed increases the probability of different regional prices drastically. This effect gets reinforced if it coincides with a high electrical load. The strong correlation also gives an explanation for the effects we see when we look at the absolute prices, where it is visible that a high standard deviation of nodal prices coincides with relatively low prices compared to their mean prices. Thus, wind infeed benefits both lower overall prices as well as higher regional price differences.

The significance of the correlation between price differences and the identified influencing parameters differs across the considered scenarios. Figure 6 shows how the absolute value of Pearson's Correlation Coefficient develops over the considered years.

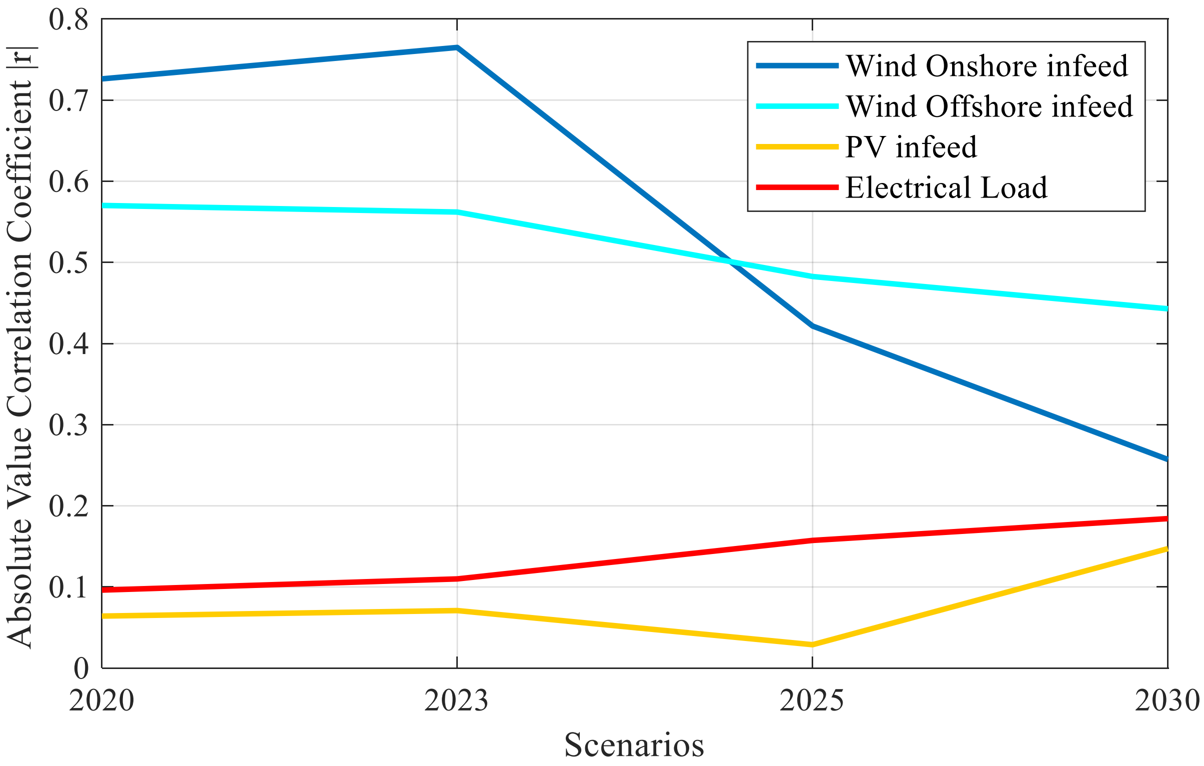

Figure 6: Development of Pearson's Correlation Coefficient between the standard deviations of nodal prices and influencing variables

Figure 6 confirms that wind infeed is the most determining factor influencing regional differences in nodal prices. The vast significance that both onshore and offshore wind infeed have in the 2020 and 2023 scenarios decreases sharply as of the 2025 scenario. From then onwards, offshore wind remains to have a moderate significance. Onshore wind's moderate significance in the 2025 scenario decreases to little significance in 2030. The main reason for this development lies in the assumed to be operational grid extension measures.

It is also interesting that the significance of the influence wind onshore infeed has on price differences rises from the 2020 scenario to the 2023 scenario, whereas the offshore infeed's significance slightly decreases. The reason for this observation might be that we assume more wind capacities to be installed onshore than offshore between both scenarios. Since nuclear power plants are not operational from the 2023 scenario onwards, the lack of generators with comparably low marginal costs increases the price differences between different nodes and hence the standard deviation in cases of congestions.

Given the assumed development of the grid, wind infeed, particularly offshore, will remain to influence nodal price differences in the 2030 scenarios when most of the so far planned grid extension measures became operational. For a zonal market, this means they remain to have an influence on the necessity for RA.

Further, Figure 6 shows that the statistical correlation between price differences and the electrical load becomes more significant over the scenarios. The increasing statistical correlation is benefitted by the ongoing phase-out of conventional power plants, which leads to a scarcity of available generation capacity in some parts of the system at snapshots with a higher electrical load. With ongoing sector coupling efforts resulting in higher electricity demand, the impact of load on diverging LMPs will probably even further increase.

Remarkably, the statistical correlation of price differences and PV infeed alters. After dropping from 2023 to its lowest value in the 2025 scenario, it rises again and exceeds the 0.1 threshold in 2030, meaning that there is little significance according to the definition of Cohen. However, one should keep in mind that Pearson's Correlation Coefficient, as well as the slope of the linear regression curve for PV in Figure 5, are negative values (Figure 6 shows absolute values). Both values indicate that the higher the PV infeed is, the fewer price differences occur (however, hardly measurable in the 2020, 2023 and 2025 scenarios and in the 2030 scenario only with little significance). The reason for the jump of Pearson's Correlation Coefficient for PV from the 2025 to the 2030 scenario may lie in the massive deployment of new solar panels, increasing the capacity from 73.3 GW in the 2025 scenario to 104.5 GW in the 2030 scenario. Another conducted correlation analysis shows that high PV infeed often coincides with high electrical loads ($|r|=0.405$). At these snapshots, PV infeed contributes to less diverging LMPs. The regional distribution of PV benefits, particularly in the 2030 scenario, the system's ability to supply every node without congestions.

5 Conclusion

There is no perfect market design – both nodal and zonal market designs have their merits and shortfalls. The simulation results we derived with our simplified model show that in relevant time periods LMPs would differ across Germany if nodal pricing was introduced. While areas in the North with a higher RES penetration face lower prices, prices in Southern regions increased in our model. The statistical correlation analyses show that the main determining factor for the occurrence of different regional prices in a nodal pricing scheme is the infeed of wind turbines. Transmission lines connecting nodes with high installed wind capacity with other areas, particularly southwards, are often congested. Even if the situation improves with the continuous commission of new or reinforced transmission lines, they are not sufficient in our model to entirely resolve congestions in the German transmission system. If ambitious sector-coupling efforts are implemented, the rising electrical load may induce further price deviations, whereas the installed PV capacity has only little influence on price deviations.

We conclude that with today's transmission capabilities in Germany, a regionally imbalanced distribution of RES generation would strongly impact price divergences in a nodal pricing system. In today's market design, TSOs regularly resolve these congestions with RAs like redispatch measures that account for significant system costs. In a nodal market design, the costs of redispatch are internalised to the electricity market, resulting in a market environment contributing to a cost-optimal coverage of load while respecting transmission limits.

With rising ambitions towards carbon-neutral electricity production and sector coupling efforts, flexibility becomes increasingly important to the system. Flexibility options that build their business case on the volatility of electricity prices cannot be easily allocated in zonal markets due to the aggregation of locational system conditions into one averaged price signal. In a nodal market scheme, regional different price signals could incentivise investments at sites contributing to the overall economic welfare and stand in accordance with the needs of the transmission system [18].

Furthermore, our model shows that if renewables were built with a different regional distribution, particularly more wind turbines in the South, they would contribute to more convergence of LMPs, respectively less need for congestion management. A market-based incentive for building wind turbines at less windy sites is not given in a zonal market with a uniform price. Nodal price signals could potentially offset disadvantageous wind conditions at a node by higher revenue potentials per produced MWh. Studies have also shown for the demand side that passing spatially resolved electricity price signals leads to loads being placed at low-cost grid nodes [19]. Besides incentivising demand-side flexibility through spatial electricity price signals, further options, like the design of network tariffs, which we do not discuss in this paper, can be important levers to unlock flexibility [20].

On the other hand, investment uncertainties could increase as newly deployed transmission lines or power plants significantly impact LMPs and, thus, operators' potential revenues. The stability and credibility of nodal prices are difficult to foresee for market actors and hence result in higher investments uncertainties that will be priced in with higher risk margins. One might argue that Germany's plans to massively reinforce the transmission system may lead to investment challenges if nodal pricing was introduced although regional information in terms of price signals for investments in generation, storage, demand as well as grid infrastructure would be revealed. However, the question of resource adequacy is an issue in zonal and nodal systems. There are many examples of markets based on a zonal market design that have identified the need for additional (regional) capacity mechanisms. In a nodal market, market participants can hedge locational price risk using Financial Transmission Rights, which are instruments that offset differences between LMPs at defined locations. These well-known instruments are very important features in nodal markets, though adding some level of complexity to the market.

A decarbonised power system requires, besides sufficient renewable generation capacity, adequate grid capacities and flexibility options for ensuring a spatially and temporally balanced system. Both zonal and nodal markets have advantages and disadvantages, and further research is needed to find market schemes that ensure efficient and effective price signals for both the short-term dispatch as well as long-term investments, i.a. to ensure adequate spatial incentives for flexibility options.

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