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One price fits all? Wind power expansion under uniform and nodal pricing in Germany

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Abstract

This paper evaluates investment incentives for wind power under uniform and nodal pricing. An electricity system model is developed, which allows for investments into wind power while considering transmission grid constraints in detail. Targeting equally high wind capacities under nodal and uniform pricing until 2030, locations of new wind power plants shift towards sites with lower wind yield under nodal prices. The wind energy fed into the grid, though, is higher under nodal pricing since curtailment is cut to a third. Grid-optimal wind locations require higher subsidy payments but decrease yearly variable supply costs by 1.5% in 2030. However, distributional effects are an obstacle to implementing nodal pricing, where about 75% of German demand faces electricity costs increase of about 5%. For mitigating distorted investment signals of uniform pricing, implementing investment restrictions within grid expansion areas prove to be more promising than a latitude-dependent generator-component in the grid tariff design.

Keywords: Nodal pricing, Market design, Energy System Modeling, Renewable Energies, Market Values.
JEL Classification: Q42, Q48, C61, D47.

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1. Introduction

1.1. Motivation

For lowering greenhouse gas emissions intensity within the European power sector, wind power capacities have increased significantly over recent years. As the share of intermittent generators rises, their location becomes increasingly important. On the one hand, spatially distributed locations can flatten the skittish nature of their in-feed (balancing effects) and hence relieve the need for dispatchable generation capacities. On the other hand, sites with high wind yield usually do not coincide with main load centers (cf. Borenstein (2012)). A high concentration of wind power plants at productive but remote sites imposes challenges to the grid. The siting of wind power plants is thus often a trade-off between high wind yield and grid congestion. This trade-off becomes more critical with increasing market shares of renewable energy sources (RES).

This article considers Germany as a case study. Germany is a pioneer in the expansion of wind power plants. In 2019, 25% of the electricity demand was covered by wind energy, and further expansion is a clear political goal. The typical pattern that remote locations offer better wind conditions applies also to Germany: Wind yield peaks in Northern Germany on the shore of the North and Baltic Seas. Demand for electricity, however, is highest in the densely populated and industry-rich areas of Southern and Western Germany. As a direct consequence, there have been increasing problems with the integration of RES generation into the grid in recent years.[1] In the current market design, the electricity price is uniform throughout Germany and does not take grid bottlenecks into account. As a result, scheduled generation[2] may be adjusted after market-clearing to align with grid restrictions, often referred to as redispatch.[3] Both redispatch volumes and costs have risen over recent years. For minimizing electricity supply costs, coordinating wind power expansion with grid bottlenecks is crucial.

In liberalized electricity systems, grid expansion is subject to regulatory decisions whereas wind power plants are built by private investors. Due to long approval and construction periods, grid expansion projects are fixed for the long term, usually before the decision

[1] Government decisions on phasing-out coal and nuclear power plants further exacerbate the problem, since these plants are usually located close to load centers.

[2] The dispatch of power plants is usually scheduled on wholesale markets before delivery, namely day-ahead and intraday markets.

[3] Within redispatch, usually remote intermittent RES are curtailed and replaced by ramping up conventional power plants close to load to overcome congestion.

to invest in new generation capacity is taken.[4] In Germany, as in many other European countries, the expansion of wind power is subsidised by the government. In addition to the revenue on the electricity market, wind turbines receive a market premium for electricity fed into the grid. The level of the market premium is determined in capacity-based pay-as-bid auctions. New wind power projects bid according to their expected revenue, which consist of expected electricity prices, expected wind yield at the respective location and the correlation between wind availability and electricity price. Incentives for spatial diversification are only set by regionally different wind in-feed patterns and resulting balancing effects (cf. Schmidt et al. (2013)). However, wind yield at respective sites dominate balancing effects under uniform pricing due to high correlation of in-feed patterns (cf. Eising et al. (2020)). As a result, wind power investors rather seek to maximize wind feed-in. Hence, wind power has been mainly deployed at high wind-yield sites in Northern Germany.

There is a broad consensus among economists on how to efficiently coordinate wind power expansion with grid constraints. The expansion of intermittent electricity generation exerts negative externalities on the electricity grid. Pricing of externalities is the economically desirable instrument to overcome their detrimental effects (cf. e.g., Hogan (1999), Borenstein (2012) or Wagner (2019)). While uniform prices fail to reflect grid externalities, nodal pricing regimes internalise them in market prices, which reflect both generation costs and grid constraints (cf. Weibelzahl (2017)). If, for example, the wind power feed-in in Northern Germany is too high to be integrated into the grid, low electricity prices arise there. If such situations occur frequently, the electricity price level drops and investments become unprofitable. This mechanism creates dynamic incentives in nodal price regimes for an efficient coordination of investments in wind energy with the existing grid (cf. Green (2007)).[5]

In order to counteract problems with the grid integration of wind energy under uniform pricing, the amendment to the Renewable Support Scheme in 2017 (*Erneuerbaren-Energien-Gesetz 2017*) introduced the so-called grid expansion area (*Netzausbaugebiet*). In this area, an investment restriction prevents excessive expansion of wind turbines at windy but grid-critical locations. Another instrument to coordinate wind power investments with grid

[4] Höffler and Wambach (2013) argue that an early commitment to grid extension is also welfare-optimal as long as the investment costs of the companies do not represent private information. The investment costs for wind power plants are transparent such that an early commitment to grid expansion is economically desirable.

[5] This applies also to demand side or flexibility investments: building energy-intensive industries becomes more attractive in regions with lower electricity prices, flexibility is increasingly built into regions with large electricity price fluctuations.

restrictions under uniform pricing are spatially differentiated grid tariffs for generators (e.g., Haucap and Pagel (2014) or Grimm et al. (2019)). They can be designed to internalize the electricity generation's external effects on grid congestion under uniform pricing and hence positively affect social welfare (e.g. Agency for Cooperation of Energy Regulators (ACER) (2015) and Daxhelet and Smeers (2007)). Several European countries have introduced spatially differentiated g(enerator)-components in their grid tariff scheme, e.g., Sweden, the UK and Norway (cf. ENTSO-E (2019)). While perfectly defined (node-specific) g(enerator)-components can replicate the efficient investment signals, a more simple approach eases information gathering for investors and tariff setting for regulators. Since distorted signals of uniform prices develop mainly along the North-South axis (cf. Obermüller (2017)), we follow the Swedish grid tariff design and assess latitude-dependent g-components in this paper (THEMA (2019)).

The paper at hand quantifies the effects of nodal and uniform prices on the spatial distribution of wind power expansion, welfare losses stemming from distorted incentives set by uniform prices as well as distributional effects, which result from introducing nodal prices. Further, this paper evaluates to which extent welfare losses resulting from inefficient wind power siting can be mitigated by complementing uniform pricing with latitude-dependent g-components in grid tariffs or grid expansion areas.

1.2. Related Literature

The paper at hand is based on two strands of literature:

The first strand uses the concept of market values to evaluate the worth of power generation facilities. In recent years, several articles have used market values to analyze efficient RES expansion paths. Joskow (2011) introduces market values to evaluate intermittent power generators. Among others, Grubb (1991), Jägemann (2014) and Hirth (2013) discuss how RES market penetration affects their market value. Higher penetration of RES undermine their market value due to cannibalization effects (e.g., Prol et al. (2020)). With increasing wind capacities, the electricity price drops in hours with high intermittent in-feed, especially when there is a high degree of simultaneity, lowering the market revenue of wind power plants. Grothe and Müsgens (2013), Elberg and Hagspiel (2015) and most recently Eising et al. (2020) use market values to shed light on the optimal distribution of wind power plants in Germany. However, these articles only consider the current uniform pricing market design. Accordingly, the market values only reflect the correlation of local wind in-feed with the uniform price signal and do not cover grid restrictions. Consequently, the problem of coordination between RES deployment and grid bottlenecks is not tackled.

The second strand examines the trade-off between grid expansion and investment or analyzes nodal market designs as a theoretically efficient instrument to solve this coordination problem. Lamy et al. (2016) examines the trade-off between grid expansion and investments in wind power plants at less productive locations. Their results show that building new wind power plants close to load is economically desirable. Opportunity costs of choosing sites with lower wind-yield are lower than avoided grid expansion costs. In a scenario comparison for Germany, though, Böing et al. (2017) find the opposite. Grid expansion imposes fewer costs than an increased deployment of wind power plants in the low-wind south of Germany. In an early work on nodal prices, Green (2007) uses a 13-node model to investigate the welfare effects of switching from uniform to nodal prices in England/Wales. He finds that, in a static setting, the introduction of nodal prices avoids welfare losses of 1.5% concerning spot market revenues of electricity producers. He suggests that the efficient dynamic incentive effects of nodal prices should significantly increase welfare gains. Leuthold et al. (2008) conducts a similar, static investigation of uniform and nodal market designs for Germany and finds comparable welfare effects. They also emphasize the advantages of nodal prices in a dynamic context. Pechan (2017) sheds light on the dynamic incentives of nodal pricing. Using a simplified 6-node model, she investigates the effects of uniform and nodal pricing on the siting of wind turbines. The spatial distribution of wind turbines changes significantly if the siting of wind power plants considers negative grid externalities. Closest to this article, Obermüller (2017) combines the two strands of literature. He uses a static dispatch model to examine the market values of wind power plants under uniform and nodal pricing in Germany for 2014. He derives diverging market values and concludes that uniform prices set inefficient investment incentives for wind power plants. Yet, a dynamic evaluation to quantify the resulting inefficiencies is missing.
The prevailing literature on evaluating spatially differentiated grid tariffs or grid expansion areas to mitigate inefficient investment signals of uniform pricing is scarce. Lück and Moser (2019) assess the German grid expansion area and its impact on redispatch volumes but do not evaluate its benefits from an economic perspective. Numerically evaluating spatially differentiated g-components, Bertsch et al. (2016b) and Grimm et al. (2019) find only small positive effects of their implementation on congestion costs and welfare.

1.3. Contribution and Structure

The paper at hand sheds light on the dynamic coordination of wind power investments for given grid expansion under nodal and uniform pricing. Our contribution is fourfold: First, an electricity system model is developed. The model allows for investments into power

plants, while considering a detailed depiction of transmission grid constraints in a closed form solution. For isolating the effects of the spatial distribution of wind power plants, this paper considers only endogenous investments into wind power, while conventional power plants follow an exogenous path. Existing dynamic modelling approaches either decouple investment decisions and grid modelling, and approximate an equilibrium solution by iterative model runs (e.g., Bertsch et al. (2016a), Fürsch et al. (2013), Hagspiel et al. (2014) or most recently Fraunholz et al. (2020)) or use highly aggregated grid depictions with only few nodes or zones (e.g., Grimm et al. (2016b)). For accurately addressing the spatial distribution of wind power plants and its impact on grid congestion, the model considers a 380 node-depiction of the German transmission grid. To the best of our knowledge, existing highly spatially resolved models are static and abstract from investments in power plant capacities (e.g., Obermüller (2017) or Breuer and Moser (2014)). Second, the efficient expansion of wind power plants in Germany is derived using nodal pricing. Third, inefficiencies implied by the current uniform pricing market design are quantified. In order to do that, we compare market values of wind power plants under nodal and uniform pricing, derive necessary subsidies as well as the resulting welfare losses and distributional effects. Fourth, this paper investigates latitude-dependent g-components as well as grid expansion areas to remedy welfare losses due to inefficient siting of wind power plants under uniform pricing.
Our main findings are as follows:
First, building the same amount of wind capacities at grid-friendly sites rather than at sites with maximal wind yield increases the amount of wind energy fed into the grid. The reduced need for curtailment overcompensates losses in wind yield.
Second, we quantify distorted signals of uniform prices for siting of wind power and their consequences. Sites which require low (or even no) subsidies have low system values and hence increase redispatch and curtailment. In general, uniform prices lower subsidies for wind power but lead to yearly welfare losses amounting to 1.5% of variable supply costs in 2030 due to inefficient wind power expansion.
Third, latitude-dependent g-components fall short in reflecting distortions of uniform pricing adequately. Their potential in mitigating inefficient wind power expansion remains limited. A single grid expansion area, as currently implemented in Germany, outperforms latitude-dependent g-components. Yet, a further differentiation into multiple grid expansion areas can significantly enhance these positive effects.
Fourth, spatially differentiated signals of nodal prices for wind power investments lead to distributional effects. Consumers in Northern Germany representing about 25% of German

demand would benefit from up to 30% lower nodal electricity prices compared to uniform prices in 2030. In contrast, electricity prices in Western and Southern Germany would increase by about 5% under nodal prices. As a result, electricity consumers in the load centers in Western and South-Western Germany would bear higher costs while electricity generators in Northern Germany face declining revenue and vice versa.

The remainder of this paper is structured as follows: Section 2 introduces the model, the input data and central assumptions. The differences in investment locations, electricity generation, market values as well as welfare and distributional implications triggered by switching from uniform to nodal pricing regime are explained in section 3. Latitude-dependent g-components and grid expansion areas as complementary measures to mitigate distorted investment signals of uniform pricing are analyzed in section 4. Section 5 provides a critical discussion of applied methodology and section 6 concludes.

2. Methodology, Input Data and Scenario Design

The paper at hand uses the notation presented in Table A.4. For distinguishing exogenous parameters and endogenous optimization variables, the latter are written in capital letters.

2.1. Investment and Dispatch Model

Within this paper, the novel investment and dispatch model SPIDER (Spatial Planning and Investments of Distributed Energy Resources) is developed, which considers a detailed depiction of the German transmission grid. It is based on the power market model DIMENSION[6]. SPIDER is a partial equilibrium model of the European power sector. By assuming perfect markets and no transaction costs, the profit maximization of firms corresponds to a cost minimization of a central planner. The competition of profit-maximizing symmetric firms constitutes the dual optimization problem to a central planners' cost minimization. The central planner invests into new power plants and dispatches generation capacities such that the net present value of the variable (VC) and fixed costs (FC) is minimized, where β represents the discount factor.

[6]DIMENSION was used in numerous analyses, e.g., in Bertsch et al. (2016a) and Peter (2019). For a thorough introduction to DIMENSION and its characteristics, the reader is referred to Richter (2011).

The objective is hence:

$$min!\ TC = \sum_{y \in Y} \beta(y) \cdot [VC(y) + FC(y)].$$

Installed electricity generation capacities (CAP) are modeled endogenously: The model invests in new generation capacities (CAP_{add}) and decommissions capacities (CAP_{sub}), which are not profitable. For a realistic depiction of European energy markets, existing as well as under construction capacities ($cap_{add,min}$) and decommissioning due to end-of-lifetime or technology bans ($cap_{sub,min}$) are given exogenously. These parameters serve as lower bounds for building or decommissioning capacities, respectively. The fixed costs per year comprise the annualized investment costs (δ) plus fixed operation and maintenance costs (σ) per installed capacity. The following equations describe these interrelations.

$$\begin{aligned} CAP(y,m,i) &= CAP(y-1,m,i) + CAP_{add}(y,m,i) - CAP_{sub}(y,m,i) \\ CAP_{add}(y,m,i) &\geq cap_{add,min}(y,m,i) \\ CAP_{sub}(y,m,i) &\geq cap_{sub,min}(y,m,i) \\ &\forall y \in Y, \forall m \in M, \forall i \in I \end{aligned}$$

$$\begin{aligned} FC(y) = &\sum_{m \in M, i \in I} CAP(y,m,i) \cdot \sigma(i) \\ &+ \sum_{y1 : y - y1 < econ\_lifetime(i)} CAP_{add}(y1,m,i) \cdot \delta(y,i) \end{aligned}$$

Electricity generation (GEN) in each market and timestep (t) has to level the (inelastic) demand (d) minus the trade balance ($TRADE\_BAL$), which depicts the net imports of trade flows ($TRADE$) from other markets. Availability of power plants ($avail \cdot CAP$), which, e.g., considers maintenance shutdowns limit their generation. Trade flows between markets are limited by interconnection capacities ($linecap$). Yearly total variable costs (VC) result from the generation per technology times the technology-specific variable operation costs (γ), which mainly comprise costs for burnt fuel and required CO_2 allowances.

$$\sum_{i \in I} GEN(y,t,m,i) = d(y,t,m) - TRADE\_BAL(y,t,m)$$
$$GEN(y,t,m,i) \leq avail(y,t,i) \cdot CAP(y,m,i)$$
$$TRADE\_BAL(y,t,m) = \sum_{n} [(1 - l(n,m)) \cdot TRADE(y,t,n,m) - TRADE(y,t,m,n)]$$
$$TRADE(y,t,m,n) \leq linecap(y,m,n)$$
$$\forall y \in Y, \forall m,n \in M \;\; \& \;\; m \neq n, \forall i \in I$$
$$VC(y) = \sum_{m \in M, i \in I, t \in T} GEN(y,t,m,i) \cdot \gamma(y,i)$$

The presented equations constitute the backbone of SPIDER. Beyond that, the model features, e.g., constraints to depict the utilization of storage as well as constraints on energy potentials, e.g., for biomass.

2.2. Grid modelling

Within this paper, the inner-German transmission grid infrastructure is considered within a linear optimal power flow problem (LOPF). Non-linear AC power flow restrictions are approximated via linear DC power flow constraints. While this approach is consistent with Kirchhoff's current as well as voltage law, it neglects grid losses (cf. van den Bergh et al. (2014)). For implementing DC power flow, the cycle-based Kirchhoff formulation is used. In an extensive comparison of different LOPF formulations, Hörsch et al. (2018) identifies this approach as favorable concerning model run times, particularly in the context of generation investment optimization problems.

Kirchhoff's current law is implemented directly via mapping active power injections in each market m (which equal the trade balance $TRADE\_BAL$) on line power flows ($FLOW$) via the incidence matrix $\kappa(m,l)$, i.e.:

$$TRADE\_BAL(y,t,m) = \sum_{l \in L} \kappa(m,l) \cdot FLOW(y,t,l)$$
$$, \kappa(m,l) = \begin{cases} 1 & \text{if line } l \text{ ends in bus } m, \\ -1 & \text{if line } l \text{ starts at bus m } m, \\ 0 & \text{else} \end{cases}$$

The transmission grid is assumed to be a directed graph. With $|L|$ representing the number of lines and $|N|$ the number of nodes, the graph is uniquely determined by $|C| = |L| - |N| - 1$

linear independent cycles. To fulfill Kirchhoff's voltage law, power flows ($FLOW$) times line reactances (x) along each of these cycles have to sum up to zero. Thereby, the model considers interactions of electricity generation and power flows endogenously. The cycle matrix ($\phi(l,c)$) assigns lines to the respective cycles.

$$\sum_{l \in L} \phi(l,c) \cdot x(y,l) \cdot FLOW(y,t,l) = 0$$

$$, \phi(l,c) = \begin{cases} 1 & \text{if line } l \text{ is element of cycle } c, \\ -1 & \text{if reversed line } l \text{ is element of cycle } c, \\ 0 & \text{else} \end{cases}$$

$$\forall c \in C, \forall y \in Y$$

Investments in transmission grid lines are not considered endogenously but are exogenous assumptions. Incorporating a detailed depiction of grid constraints as well as endogenous investments into generation is computationally challenging. Thus, the model underlies several limitations to keep it tractable: To avoid mixed-integer optimization, ramping and minimum load constraints are approximated. The model does not depict combined heat and power plants. Further, the model abstracts from uncertainty and assumes perfect foresight. Further, the model is able to use representative days to reduce the temporal dimension of the optimization problem.

2.3. Assumptions and Data

Scope and Transmission Grid

The regional focus of the model is Germany with a spatial resolution at transmission grid node level, i.e., 220 kV to 380 kV voltage levels. For the depiction of the transmission grid, grid information from multiple sources is combined, e.g., Matke et al. (2016) and 50Hertz et al. (2019). Grid extensions follow the latest version of the German grid development plan (cf. Bundesnetzagentur (2019)). The model covers Germany and its neighboring countries, depicted as one node without inner-country grid restrictions. Interconnectors to as well as between neighboring countries are approximated via Net Transfer Capacities based on ENTSO-E (2018). Overall, the model incorporates 380 nodes and 606 connecting lines within Germany. The regional scope and the depiction of the German transmission network is visulized in Appendix B.

The temporal scope covers the years 2019, 2020, 2025 and 2030, represented by 12 representative days in an hourly resolution. The representative days are derived using k-medoids clustering concerning residual load (cf. Kotzur et al. (2018)).
The technological scope comprises the most common conventional and renewable power plant types, as well as pumped storage. Table C.5 provides an overview of the considered technologies, including their techno-economic parameters. Endogenous investments are only allowed for onshore wind power plants in Germany. The capacity development of all other technologies is exogenous. It follows the *National Trends* scenario in ENTSO-E (2018) and *Scenario B* in 50Hertz et al. (2019). The development of power plant capacities follows political announcements. For instance, the phase-out of German lignite and coal power plants is implemented according to the latest public information. The German coal power plant fleet is decommissioned in order of the installation year to comply with target capacities for coal power plants. The exogenous development of conventional generation capacities is sufficient to meet demand at any time, i.e., we assume that the electricity market design triggers sufficient investments into backup power plants such as open-cycle gas turbines. Appendix C discloses further assumptions on demand development per country, investment costs as well as fuel prices.

Input data: Time-series and Regionalization
Demand time-series are based on hourly national demand in 2014, according to ENTSO-E (2020). The German demand is distributed to the nodes similar to the approach in 50Hertz et al. (2019). Based on sectoral demand shares on federal state level (cf. Energiebilanzen (2020)), household demand is broken down to nodes via population shares. For regionalizing industry and commercial demand, regional data on gross value added is used for the respective sectors (cf. EUROSTAT (2020)).
For modeling intermittent renewable in-feed of photovoltaics and wind power, data provided by Pfenninger and Staffell (2016a) and Pfenninger and Staffell (2016b) is used for Germany and its neighbors. Since this paper investigates wind power expansion, we use regional in-feed within Germany based on Henckes et al. (2017), which applies a novel meteorological reanalysis model to derive wind speeds for several vertical layers and in high spatial resolution (6kmx6km). The derived wind speeds were transformed into in-feed time-series, calibrated to historical in-feeds of wind parks.

Existing power plant capacities, as well as their distribution across Germany, are derived from data of the German regulator Bundesnetzagentur.[7] Power plants are distributed via their postcodes to the nearest transmission grid node. The future distribution of offshore wind farms and solar power plants is in line with 50Hertz et al. (2019).
Figure 1 shows the regionally differentiated capacity factors for onshore wind power plants as well as the initial distribution of wind power plants across Germany in 2019.

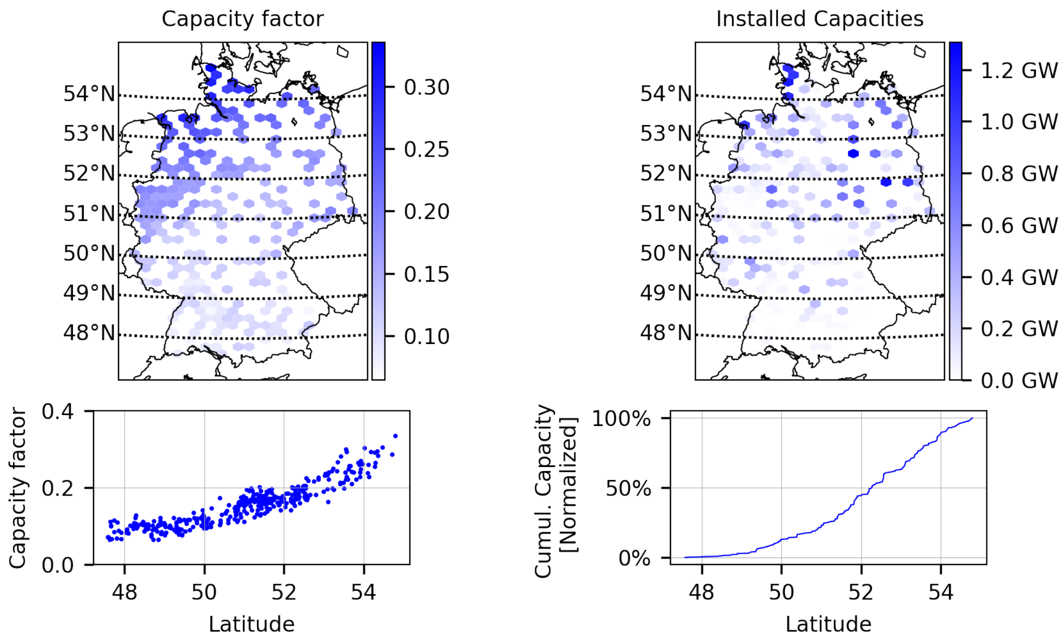

Figure 1: Regional capacity factors of wind power plants (left) and spatial distribution of wind power plants in 2019 (right).

Capacity factors of wind power plants in Northern Germany range from 25% up to 35%. Towards the south, capacity factors decrease gradually. Though, wind yield in Western Germany stays above a capacity factor of 20% until the 51st parallel, followed by a sharp decrease in the Southern direction. In Southern Germany, most sites offer only around 10% to 15%. As a result, about 75% of existing capacity are located above the 51 parallel. Yet, wind power capacities are low in densely populated Western Germany although the above average wind conditions.

[7] Conventional power plants are based on the power plant list (Bundesnetzagentur (2020a), Renewables on *Marktstammdatenregister* (Bundesnetzagentur (2020b)).

2.4. Scenario Setup

The paper at hand analyzes investment decisions into wind power plants under different market designs. Besides the uniform price market design, a nodal pricing regime is set up to derive efficient locations for new wind power plants. Under nodal pricing, each transmission grid node constitutes a market and grid constraints are taken into consideration within the price formation. Uniform pricing considers only nation-wide electricity markets where prices do not reflect inner-German grid bottlenecks. Like Germany, several European countries use uniform pricing.[8] Modeling-wise, the only difference between the nodal and uniform pricing regime is the consideration of grid constraints within Germany. While the transmission grid constraints are modelled via DC power flow (cf. section 2.2) for the nodal pricing regime, these constraints are turned off under uniform pricing. Inner-German power flows are hence not restricted under uniform pricing. We consider two scenarios:

- *Nodal*, where invest and dispatch is derived under nodal pricing.
- *Uniform*, where invest and dispatch is derived under uniform pricing. The scheduled dispatch after market clearing, however, might violate physical grid restrictions and hence necessitates curative redispatch measures. The subsequent redispatch is assumed to derive the cost-efficient dispatch decision under the given power plant fleet.[9]

Additionally, section 4 evaluates the effects of complementing uniform pricing with either latitude-dependent g-components or grid expansion areas. Both instruments are proposed to mitigate inefficient investment signals of uniform pricing.
For both nodal and uniform pricing, we assume a homogeneous RES expansion target. The overarching target of Germany is to reach a 65% share of RES generation with regard to gross electricity demand according to the government coalition agreement in 2018. For meeting this target, RES capacities are extended linearly according to announced capacity targets - i.e., 20 GW of Wind Offshore in 2030 - or capacities stated in the Grid Extension Plan (cf. scenario B in 50Hertz et al. (2019)). Table 1 shows the assumed RES expansion in Germany.

[8]Exemptions are e.g. Norway, Sweden and Italy where the electricity market is split into bidding zones.

[9]Within this run, the cost-efficient dispatch decision is derived including optimal trade flows. In reality, market clearing under uniform pricing pre-determine trade flows which renders system optimal trade in redispatch impossible. Cross-border redispatch is only viable based on bilateral contracts.

Table 1: Development of Installed RES Capacities in Germany, based on 50Hertz et al. (2019)

[GW]	2019	2020	2025	2030
Wind Onshore	53.4	55.9	68.7	81.5
Wind Offshore	7.5	8.7	14.3	20.0
Photovoltaics	49.2	53.0	72.1	91.3

The expansion of photovoltaics as well as offshore wind power plants is exogenous, the spatial distribution of new capacities follows the development in the latest grid extension plan (50Hertz et al. (2019)). For the expansion of onshore wind power plants, we require the model to expand capacities by 2.56 GW per year. The assumptions on RES expansion is in line with the goal of the German government to provide 65% of gross electricity demand via RES power plants.

In order to avoid an unrealistic concentration of new wind power plants, upper bounds for yearly expansion at each transmission node based on area-corrected historical expansion rates (data retrieved from Bundesnetzagentur (2020b)) are implemented. There are two reasons for defining the wind onshore target with regard to capacity instead of energy feed-in: First, the current auction design in Germany is capacity based. The government auctions off a pre-defined amount of capacity to be built. Second, a capacity target ensures that investment costs are the same under uniform and nodal pricing. Resulting changes in total costs are only due to different incentives to coordinate wind power investments and the grid topology.

3. Implications of wind power expansion under nodal and uniform pricing

The subsequent section compares the spatial distribution of wind power plants investments under nodal and uniform pricing. Further, the implications on electricity generation, market values, subsidies as well as welfare and distributional effects are shown.

3.1. Siting of Wind Power and Implications for Wind In-feed

In both market settings, uniform and nodal pricing, the gross wind capacity expansion equals 2.56 GW per year. Besides regional investment bounds, e.g., due to acceptance and potential, the market-based incentives for the spatial distribution between both settings differ: Under uniform pricing, new wind power plants are usually built where the best wind conditions prevail. Only different in-feed patterns and resulting balancing effects trigger a spatial differentiation. Under nodal pricing, market revenue reflects costs resulting from grid congestion. Hence, nodal pricing incentivizes grid-friendly locations. Figure 2 visualizes the impact of market design on the siting of wind power plants until 2030.

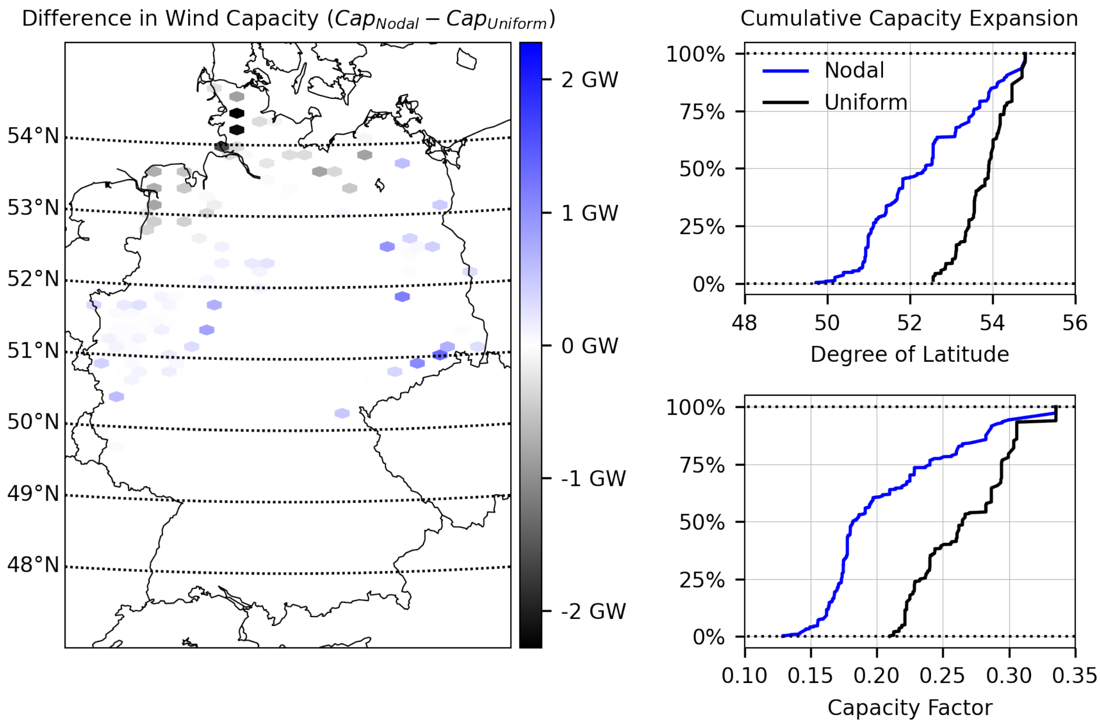

Figure 2: Difference in Spatial Distribution of Wind Capacities in 2030 (left) and cumulative wind expansion by latitude and capacity factor (right)

Under uniform pricing, wind power expansion concentrates on Northern Germany. Sites above the 53rd parallel cover approximately 90% of wind power expansion. Under nodal pricing, the investment pattern differs in two aspects: First, wind energy investments spread over more nodes than under uniform pricing. Second, locations for new wind power plants move southwards. Nodal pricing leads to a decrease of capacity additions at windy sites above the 53rd parallel. Instead, sites at latitudes between 51 and 53 attract about 75% of new wind power plants. As a result, capacity factors of newly installed wind power decrease: While wind power is exclusively expanded at sites with a capacity factor of at least 20% under uniform pricing, only about 40% of new wind power plants reach an equally high factor under nodal pricing. Uniform pricing set rather low incentives for spatial diversification, wind yield and wind power investments are strongly correlated. Nodal pricing triggers spatial diversification. Wind power expansion spreads to mediocre wind yield sites in Western and

Eastern Germany. These sites are either close to load or own comparatively low existing wind capacities (cf. figure 1). Both aspects ease the grid integration of wind power. In Southern Germany, nodal pricing does not trigger additional investments. On the one hand, gains through grid relief do not compensate for the lower capacity factors in Southern Germany, since the main grid bottlenecks are between Northern and Central Germany.[10] On the other hand, high proportions of photovoltaic and hydropower plants within Germany and particularly in the neighboring countries of Austria and Switzerland further decrease the profitability of wind power plants in Southern Germany.

As a consequence of different investment patterns, feed-in of wind power plants as well as curtailment volumes change. Figure 3 depicts the spatial generation pattern of wind power plants and the development of actual in-feed as well as curtailment. As discussed in section 2.4, this analysis assumes capacity-based RES expansion targets. Hence, installed wind capacities are equal under nodal and uniform pricing.

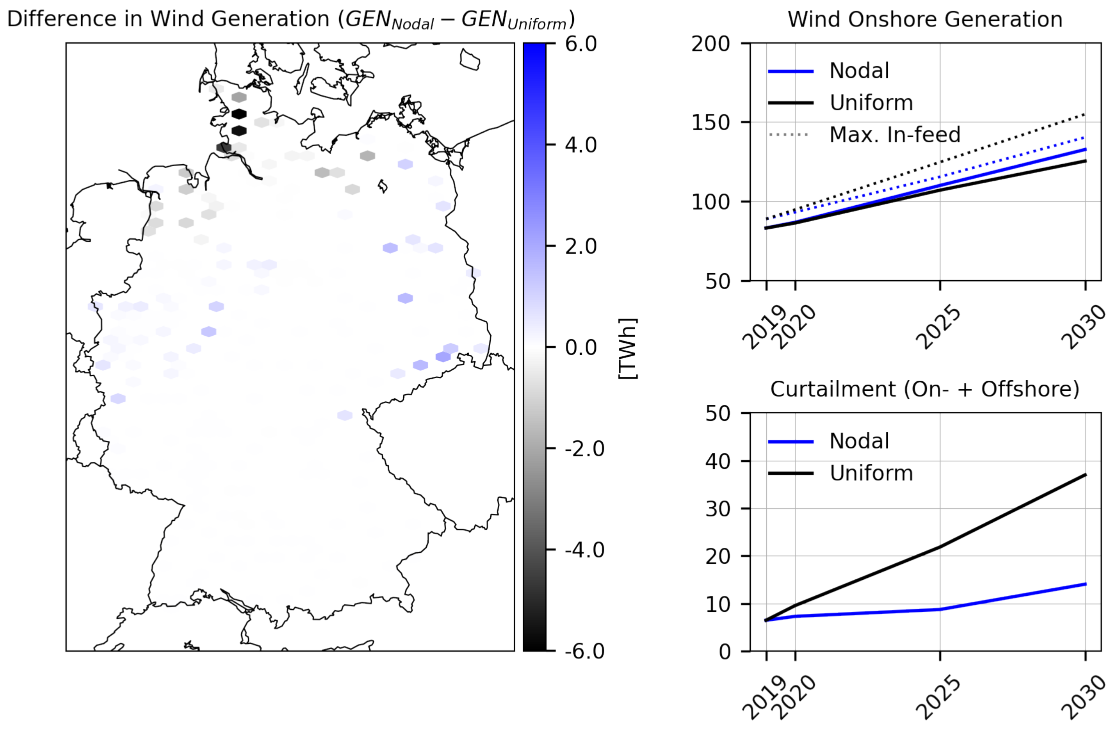

Figure 3: Difference in Spatial Distribution of Wind Generation in 2030 (left) and development of wind generation and curtailment (right)

[10]The high wind capacities of Germany's Northern neighbor reinforces these bottleneck.

First, the southward shift of capacity additions goes hand in hand with a shift of generation in the same direction. Second, the internalization of grid costs under nodal prices reduces grid congestion significantly. Both existing and newly installed wind power plants are capable of feeding a higher proportion of potential generation into the grid. Consequently, overall wind power curtailment in 2030 is cut to a third under nodal prices compared to uniform pricing. All in all, the decrease of curtailment overcompensates lower wind yield potentials, and thus more wind energy is fed into the grid in the nodal pricing setting.

3.2. Regional Electricity Prices

Wind power investments strongly interact with electricity prices under nodal pricing. Nodal prices joint with total wind yield and its temporal pattern set spatially differentiated signals for wind power expansion. Though, wind power investments depress nodal prices locally if the grid is congested (cannibalization effect). Figure 4 illustrates uniform and nodal electricity prices in 2030.

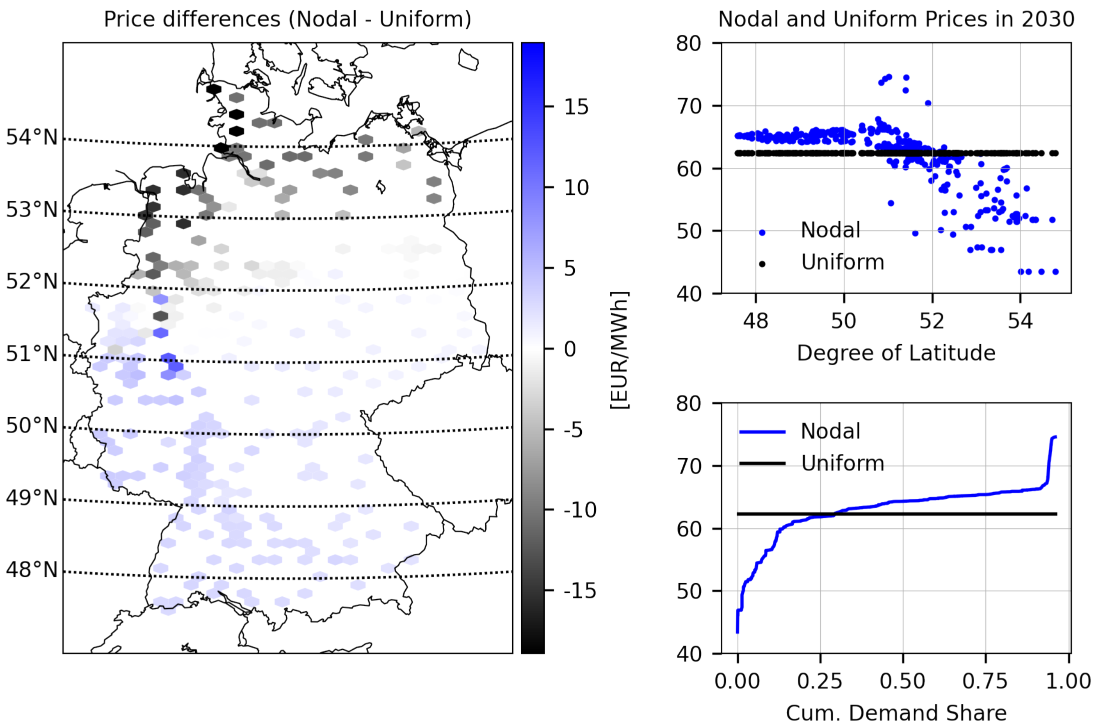

Figure 4: Difference between weighted-average nodal and uniform prices (left) as well as nodal and uniform prices over latitude and cumulative demand (right). Uniform prices include redispatch costs of 1.5 EUR/MWh.

Given the assumptions on power plant phase-outs, fuel and carbon prices, the weighted average of Germany-wide uniform electricity prices rises to slightly above 61 EUR/MWh in 2030 compared to about 38 EUR/MWh in 2019. Nodal electricity prices differ between regions. Average nodal electricity prices in Northern Germany are significantly lower than the uniform price, falling as low as 43 EUR/MWh at single nodes. About 25% of German electricity consumption would benefit from lower prices, whereas the rest would face higher electricity prices.[11] The majority of demand faces a price increase of about 5%. However, electricity prices at single nodes increase up to 75 EUR/MWh. These price peaks occur mostly in Western Germany where demand is high, RES capacities low, and conventional capacity is short due to phase-outs of lignite power plants. Further, Western Germany is not as well connected to wind-rich Northern Germany as Southern Germany, whose interconnection enhances due to three new DC lines after 2025. Nodal prices in Southern Germany also profit from high shares of PV and Hydro, including flexible Pumped Hydro. Additionally, imports from nuclear and hydropower dominated neighbors in the South, namely France, Switzerland and Austria, reduce price peaks in Southern Germany.

Nodal prices change trade flows between Germany and its neighbors. Grid bottlenecks are not visible under uniform prices. Consequently, high wind feed-in in Northern Germany leads to a low electricity price throughout Germany, which triggers exports to all neighboring countries, even to the south. If the wind in-feed in Northern Germany does not comply with grid constraints, power plants in Southern Germany need to ramp up for delivering scheduled exports. In such situations, however, electricity imports from neighboring countries in the south would be favorable. Nodal prices reflect grid congestion issues and hence prevent inefficient incentives for cross-border trade. Net trade indicates that inefficient trade flow incentives of uniform prices will become more problematic with higher RES shares in German electricity generation (see Appendix D).

3.3. Market Values and Subsidies

This paper uses the concept of market values to reflect the electricity market revenue of power plants.[12] In contrast to nodal pricing, market values under uniform pricing fail to reflect the actual value of power plants. To evaluate whether market values under uniform pricing set distorted incentives, we derive system values of wind power plants in the uniform

[11] In contrast to uniform prices, nodal prices already reflect grid congestion costs. Hence, we include redispatch costs of 1.5 EUR/MWh (see section 3.4) in uniform electricity prices.

[12] In our definition, market values reflect revenue under the respective market design per capacity.

market design from an optimal nodal dispatch given invest decisions derived under uniform pricing. Under nodal pricing, market and system values are equal. Figure 5 depicts the market and system values of wind power plants in 2030 under uniform and nodal pricing.

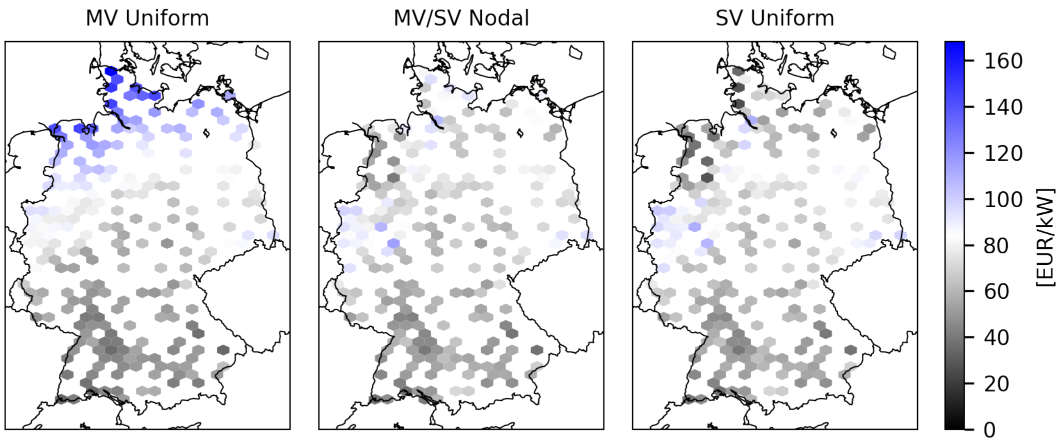

Figure 5: Market (MV) and system values (SV) under uniform and nodal pricing in 2030.

Market values under uniform pricing strongly correlate with wind conditions. Market values peak in Northern Germany close to the shore, where the best wind conditions prevail despite there is already a lot of wind power installed. Since the market area is large and grid restrictions are not visible in uniform prices, high local wind power investments are possible before market prices would drop due to cannibalization effects. Market values in a nodal dispatch run given investments under uniform pricing reflect the corresponding system values. In contrast to market values, the system values are low in Northern Germany. The difference between market and system values indicates that uniform prices send distorted signals for the siting of wind power plants. Market revenue triggers high investments in Northern Germany, although the actual system values are low due to grid bottlenecks. Under nodal prices, though, market values at Northern Germany's shores are significantly lower than under uniform pricing. Wind power plants in Western Germany close to load with mediocre wind yield become more valuable than under uniform pricing. As a result, wind power expansion is spatially wide-spread.

To further assess the incentives set by uniform and nodal pricing, the subsequent paragraph compares the distribution of market values and the system values of wind power investments. We further derive the required subsidies from the difference between fixed costs of wind power plants and market values divided by the actual in-feed.[13] Figure 6 depicts the distribution of market and system values of newly built wind power plants and the required subsidies with boxplots.[14]

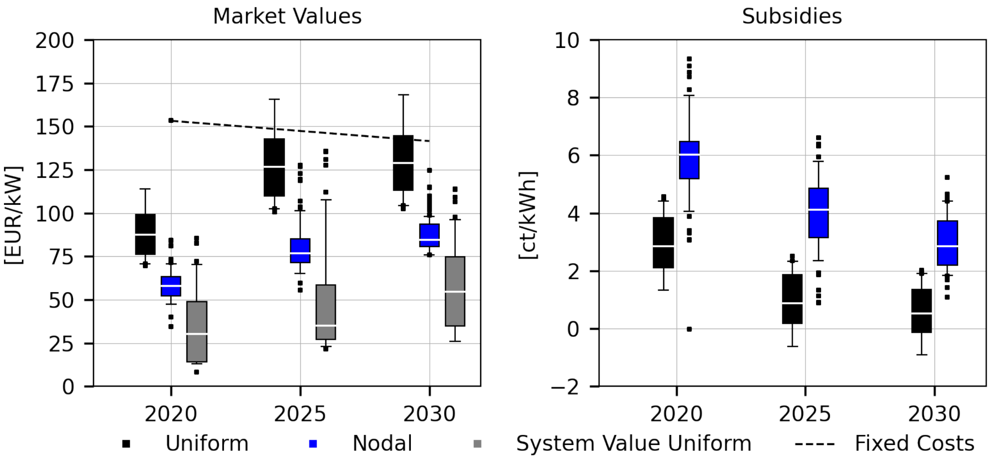

Figure 6: Boxplots of market and system values as well as required subsidies for wind power investments.

Under uniform pricing, market values of wind power investments exceed 75 EUR/MW and even the best sites are not profitable without subsidies. Required subsidies range from about 1.5 up to just below 5 ct/kWh.[15] Until 2025, market values increase due to rising electricity market prices as a result of higher fuel and carbon prices as well as the Nuclear phase-out until the end of 2022. At the same time, fixed costs decrease due to the assumed learning rates in investment costs (cf. Appendix C). Consequently, almost 25% of wind power capacity additions become economically feasible without subsidies, while most of the residual sites require subsidies 0 to 2 ct/kWh.[16] Between 2025 and 2030, market values and subsidies remain relatively constant under uniform pricing.

[13]In line with real auctions, we indicate the subsidies in terms of electricity production (ct/kWh).

[14]Boxplots visualize the range of values. The boxes represent the 25 and 75% percentiles, the whiskers the 5 and 95% percentiles. The line within the boxes represents the median, outliers are scattered.

[15]Historical auction tenders in 2017 are in the same range. At the moment, auctions are not competitive due to issues in approval processes and subsidies are close to the regulated maximum bid of 6.2 ct/kWh.

[16]Uniform prices do not not reflect negative grid externalities of wind power investments. Wind power plant investments are cross-subsidized by electricity consumers, which have to bear these externalities, i.e., redispatch costs, via higher grid tariffs.

Market values under nodal pricing are significantly lower than under uniform pricing. Wind power cannibalizes itself and lowers market revenue at sites with high wind power installations due to grid bottlenecks. As a result of soaring electricity market prices as well as grid expansion, nodal market values increase steadily from 2020 to 2030. Subsidies under nodal pricing are about double as high as under uniform prices. However, the higher subsidies under nodal pricing include grid integration costs. If negative externalities of wind power plants on the grid are considered for wind power plant additions under uniform pricing, their system value is significantly lower than the respective market value.

To evaluate whether market prices set efficient signals for the siting of new wind power plants, figure 7 visualizes the required subsidies over system values under uniform and nodal pricing. Under nodal pricing, subsidies naturally reflect system values and stimulate an efficient siting of wind power. Under uniform pricing, though, particularly sites, where little subsidies are needed, have low system values. Hence, uniform prices set inefficient incentives: productive but grid-hostile sites are tendered first in auctions under uniform pricing.

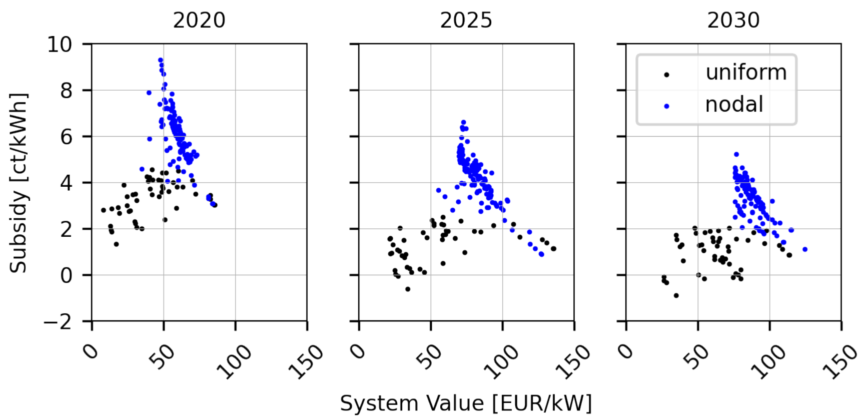

Figure 7: Required subsidies vs. system values of newly built wind power plants under nodal and uniform pricing.

Summing up, uniform prices do not reflect negative externalities of wind power plants to grid congestion. Grid congestion costs are not reflected in market revenue under uniform prices. Hence, investments into wind power are close to profitability and require only comparatively low direct subsidies. Wind power plants though receive indirect subsidies as their integration is in-transparently borne by consumers via grid charges. Auctions that minimize subsidy costs under uniform prices lead to inefficient wind power expansion. Nodal prices internalize negative grid externalities. As a result, subsidies double compared to uniform prices, but wind power expansion shifts to system-optimal sites.

3.4. System Costs

Comparing the system costs provides insights into welfare losses due to inefficient siting of wind power plants. Average electricity supply costs reflect the total variable costs of electricity supply divided by aggregate electricity demand. Table 2 compares variable supply costs for the two scenarios.

Table 2: Average variable electricity supply costs.

[EUR/MWh]	2019	2020	2025	2030
Uniform	17.5	18.3	23.8	22.8
incl. redispatch costs	0.6	0.9	1.3	1.5
Nodal	17.5	18.3	23.6	22.4
Delta Uniform - Nodal	0.0	0.04	0.24	0.34

The average variable supply costs increase until 2025 for both scenarios driven by increasing fuel and carbon prices as well as the phase-out of nuclear power plants in Germany. After 2025, costs decrease since the expansion of intermittent RES with low variable costs overcompensates the slight increase in fuel prices after 2025.

Supply costs in *Uniform* reflect the costs after (optimal) redispatch. The development of redispatch costs is given separately. Despite grid expansion, redispatch costs increase from 0.6 EUR/MWh in 2019 to 1.5 EUR/MWh until 2030 due to distorted investment signals of uniform pricing.

The difference between *Nodal* and *Uniform* reflects the lower bound of welfare losses implied by distorted wind power investment signals under uniform pricing.[17] Consequently, there is no cost difference in 2019. Until 2025, the additional costs per year due to sub-optimal siting of new wind power plants increase to about 0.24 EUR/MWh. Due to grid expansion, particularly the installation of DC lines between Northern and Southern Germany in 2026, the increase in electricity supply costs slows down afterward. It reaches 0.34 EUR/MWh

[17]We assume cost-optimal redispatch with optimal trade flows between countries. Therefore, the neighbouring countries partly bear the costs caused by inner-German bottlenecks. In reality, though, market clearing under uniform pricing predetermines cross-border trade. Hence, optimal trade flows are usually not feasible since cross-border redispatch is limited to bilateral contracts.

in 2030, which corresponds to an annual cost increase of 1.5% compared to the least-costs electricity supply under nodal pricing. If we only consider the direct costs of wind power generation, an efficient siting of wind power plants and thus higher wind in-feed, the average levelized costs of electricity generation of new wind power plants decreases to 79.8 EUR/MWh in 2030, which is about 15% lower than the average cost of 93.3 EUR/MWh under uniform prices.

4. Evaluation of G-Components and Grid Expansion Areas

As shown in section 3, uniform pricing sets inefficient signals for the siting of new wind power plants. This section analyzes two instruments to reduce these distorting effects of uniform prices: first, spatially differentiated grid tariffs, i.e., latitude-dependent g(eneration)-components and second, grid expansion areas. Both instruments are already implemented in European power market designs: For instance, Sweden charges energy-based g-components, which linearly increase with the latitude. Germany restricts wind power expansion within a grid expansion area, which is dynamically adjusted and usually covers Germany's most Northern federal states.

4.1. Configuration

g-components

This paper considers capacity based g-components. These spatially differentiated grid charges can be considered a grid connection fee, which depicts grid externalities of wind power at the respective sites. Optimally, the g-component reflects the distorting signals of uniform prices and thus equals the difference in market values between uniform and nodal pricing. We derive g-components by regressing this difference on the latitude and consider two designs: G-components, which either linearly (*Lin. g-comp.*) or cubically (*Cub. g-comp.*) depend on the latitude. Figure 8 visualizes the development of the derived g-components.

The difference in market values is (slightly) negative in Southern Germany (below the 50th parallel). Uniform prices underestimate the system value of Southern Wind power plants. In contrast, sites in Northern Germany largely exhibit strong distortions (above the 52nd parallel). The market revenue of wind power plants at these sites is higher than their system value. The distorting signals of uniform pricing do not develop linearly with the latitude but increase convexly. Thus, linear g-components are particularly far off for sites with high wind

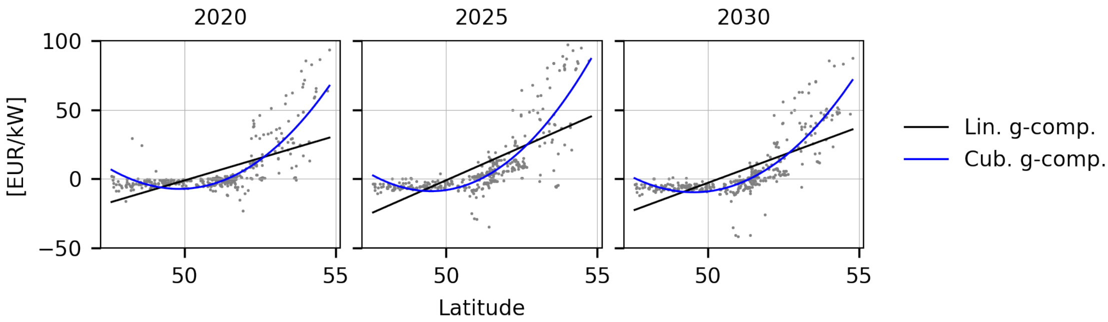

Figure 8: Derivation of latitude-dependent g-components from the differences in market values between *Uniform* and *Nodal*.

yields in Northern Germany. Cubical g-components better reflect the non-linear correlation of market value distortions and latitude, in particular above the 52nd parallel.

Grid expansion areas

Further, this paper considers two designs of grid expansion areas, in which an annual investment limit restricts the wind power expansion. First - close to the currently implemented design[18] - this paper evaluates a single grid expansion area (*GEA1*), which covers the three coastal states of Mecklenburg-Western Pomerania (MP), Schleswig-Holstein (SH) and Lower Saxony (LS) as well as the city-states of Hamburg and Bremen). Appendix E visualizes their geographical situation. Second, we subdivide this region into three grid expansion areas (*GEA3*) to assess whether further differentiation would be beneficial. The three grid expansion areas are in line with the three aforementioned federal states. The investment limit for wind power expansion within the defined grid expansion areas equals the efficient investments under nodal pricing and is given in table 3.

The investment limit in *GEA1* equals the sum of the three limits in *GEA3*. Until 2030, the investment limit rises, in particular for the most Northern state of SH, due to grid investments, which improve the connection between Northern and Southern Germany. The subsequent section discusses the impact of complementing uniform prices with the aforementioned additional instrument.

[18]The specific configuration is subject to bi-annual reviews. From 2017 to 2020, the grid expansion area limited wind power expansion within MP, SH and the Northern part of LS including the city-states of Hamburg and Bremen to 902 MW per year (cf. Lück and Moser (2019)). From 2020 on, the annual limit decreases to 786 MW and changes the spatial configuration by including also the Southern part of LS while excluding MP.

Table 3: Yearly investments limit [MW/a] for the two designs of grid expansion areas.

Variation name	2020	2025	2030
GEA1	646	889	1289
GEA3	LS: 436 SH: 33 MP: 177	LS: 457 SH: 220 MP: 212	LS: 441 SH: 670 MP: 178

4.2. Effects on Siting, In-Feed and System Costs

Siting of Wind Power Plants

For understanding the effects on the siting of wind power plants, figure 9 depicts the spatial distribution of wind power if uniform pricing is complemented with the four aforementioned instruments compared to the two pure market designs *Nodal* and *Uniform*.

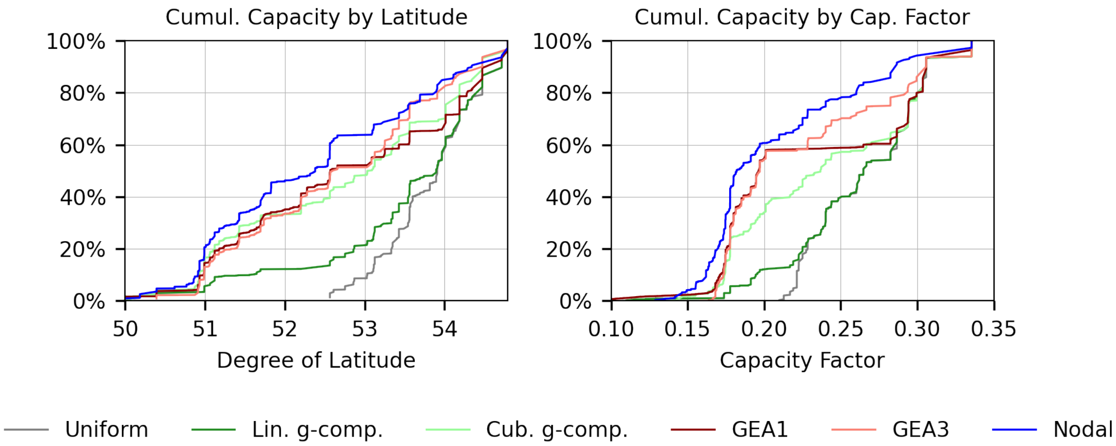

Figure 9: Cumulative wind power expansion by latitude (left) and capacity factor (right) until 2030.

The investment pattern with linear g-components is very similar to *Uniform*. The high distortions for very productive sites are not sufficiently internalized so that expansion in the very North of Germany hardly changes. About 50% of the installed capacity is still allocated above the 54th degree of latitude. The siting of the remaining half of investments shifts a bit southward. Cubical g-components address the distorting signals more accurately and shift the investment pattern with regard to latitude closer to the *Nodal* pattern. Looking at the investments concerning the capacity factors reveals that still very productive sites are preferred. But below the few very windy sites, cubical g-components significantly trigger investments at sites with lower capacity factors.

Under a single grid expansion area (*GEA1*), the sites with the highest capacity factors are still utilized, while the expansion stagnates between capacity factors of 20% and roughly 27%. This is intuitive: The best sites are still exploited while the investment limit prohibits to develop less attractive sites within the grid expansion area. Splitting the single grid expansion into three parts (*GEA3*) prevents such a clear cut. However, the very best wind conditions, which are also subject to the highest distortions, are still exploited. Yet, the investment pattern under *GEA3* comes close to the outcomes of nodal pricing.

Feed-In and Curtailment

Figure 10 depicts the impact on potential and realized in-feed as well as curtailment resulting from the changed investment pattern, i.e., it shows the difference to *Nodal*.

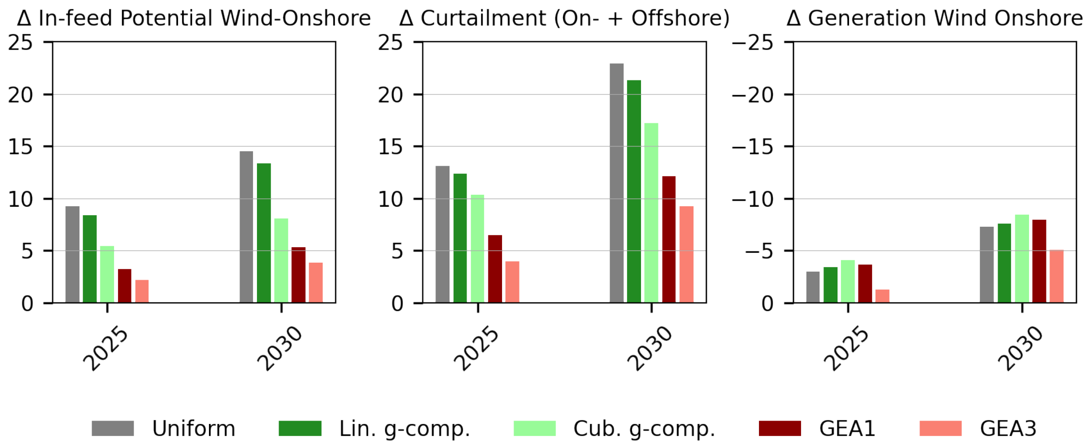

Figure 10: Change in in-feed potential, curtailment and realized generation compared to *Nodal*.

Under all considered market designs, the in-feed potential is higher than under nodal pricing since wind power plants are built at sites with higher capacity factors. All of the instruments also decrease curtailment compared to *Uniform*. The actual wind power in-feed is the difference between generation potential and curtailment. Compared to *Uniform*, only *GEA3* performs better and allows for higher wind power feed-in, while all other instruments slightly lower the realized compared to *Uniform*. For evaluating the efficiency of the instruments, though, wind power in-feed is not decisive. Lower grid congestion could improve the overall working of the electricity system, e.g., by allowing an efficient dispatch of conventional power plants. In particular, grid expansion areas significantly lower curtailment by prohibiting excessive wind power expansion at very productive but grid-critical sites. For evaluating whether the considered instruments avoid welfare losses through inefficient siting of wind power, the next section analyzes system costs.

System Costs

Figure 11 depicts the discounted increase of variable supply costs compared to the efficient benchmark (*Nodal*) for the considered market designs.

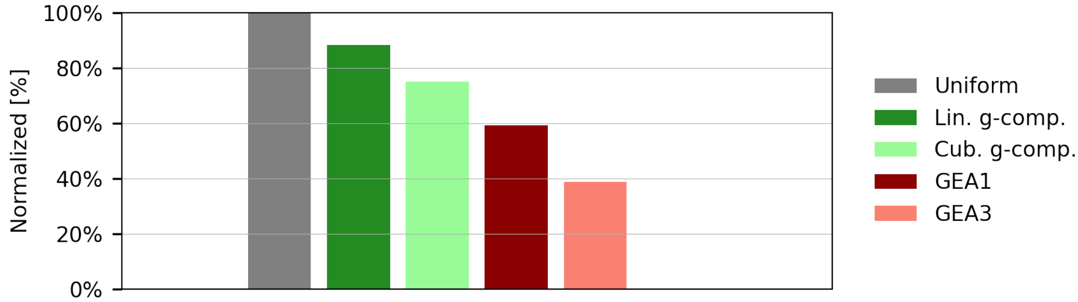

Figure 11: Normalized increase of discounted additional supply costs compared to *Nodal*

Linear g-components reduce the costs increase due to uniform pricing by about 15%. Cubical g-components better reflect high distorting signals for productive sites in Northern Germany and hence drive additional costs down by about 20%. Both designs of grid expansion areas perform better than latitude-dependent g-components. A single grid expansion area (*GEA1*) cuts the welfare losses implied by uniform pricing to 60%. Yet, a further differentiation into multiple grid expansion areas (*GEA3*) leads to a significant additional welfare gain, reducing additional costs to 40% compared to pure uniform pricing.

Summing up, this paper evaluates selected designs of g-components and grid expansion areas. In general, the bandwidth of design options for these instruments is broad. Nonetheless, this paper finds that latitude-dependent g-components do not adequately reflect the distortions of uniform prices in Germany. Hence, such grid charges struggle to mitigate adverse effects from inefficient investment signals under uniform pricing. In particular, linearly dependent g-components are hardly beneficial. Grid expansion areas are superior in addressing these inefficiencies. In particular, a well-considered differentiation into several areas, which account for inter-dependencies of wind power expansion and grid congestion, can significantly lower welfare losses.

5. Discussion of the Methodology

This article relies on several strong assumptions, e.g., perfect foresight, no transaction costs, exogenous siting of new conventional power plants and inelastic exogenous demand.

First, future nodal prices are sensitive to other firms' actions or grid expansion decisions, while uniform prices are robust due to the market size. Ceteris paribus, investors would adjust their risk premia according to the higher risk. Second, nodal prices increase transaction costs for actors (e.g., Breuer and Moser (2014)), particularly for setting up a new market environment and corresponding regulations. Third, demand reacts to power prices, particularly in the long-term, e.g., via the siting of new industrial plants or investments into energy efficiency. The siting of conventional plants also depends on expected revenue under different market designs. All of the aspects mentioned above affect welfare gains or distributional effects of implementing nodal markets.

This paper quantifies the distorting effects of uniform pricing for the isolated problem of coordinating wind power investments with (given) grid restrictions. The derived welfare loss is rather a conservative estimation since lock-in effects in redispatch, e.g., due to scheduled trades or ramping constraints of power plants, are neglected. Widening the scope, allocating flexibility options and incentivizing optimal grid expansion is crucial for an efficient integration of RES into electricity systems. In particular, interactions between regulated grid expansion and electricity generation competition among firms are neglected.

Whether nodal prices raise market power issues (cf. Weibelzahl (2017)), or market power stems from physical realities, i.e., grid bottlenecks, and market design only determines where it unfolds (cf. Hogan (1999) or Bertsch (2015)) is beyond the scope of this paper. Zonal prices, i.e., splitting the uniform pricing market into several bidding zones, are an alternative for spatially differentiated prices (cf. Grimm et al. (2016a)). Besides spatially differentiated investment incentives, zonal pricing mitigates the inherent weakness of uniform prices to set distorted incentives for cross-border trade due to the single price signal for all neighbors. Our results suggest that a division into a Northern, a Southern and a Western zone might appropriately reflect grid congestion issues. Yet, zone configuration based on nodal prices has to be interpreted with caution and requires a more sophisticated approach. (e.g., Ambrosius et al. (2020)) Further, the interactions of the discussed policy measures on incentives for grid expansion must be considered (e.g., Ruderer and Zöttl (2018)).

6. Conclusion

We set up a power system model that allows for investments in electricity generators, i.e., wind power plants, and incorporates a detailed DC power flow depiction of the German transmission grid. Applying the model, this paper investigates the siting of wind power plants in Germany under nodal and uniform pricing until 2030 and its implications on the electricity system, welfare and distributional effects.

Uniform prices fail to incentivize spatial diversification of wind power expansion. Investments in wind power strongly concentrate on high wind yield sites. Since uniform prices do not reflect negative externalities on the grid, wind power expansion requires low direct subsidies and is partly even profitable without subsidies. The large market size forecloses significant cannibalization effects. Hence, wind capacities at productive but grid-hostile sites have a competitive edge in subsidy minimizing auctions, i.e., low subsidy requirements correlate strongly to low system values under uniform pricing.

Nodal pricing as the efficient benchmark shifts investments closer to load centers at the expense of lower potential wind yield. However, curtailment is cut to a third so that more wind energy is actually fed into the grid under nodal pricing when installed capacities are equal in both market designs. By harmonizing wind power expansion with grid restrictions, variable generation costs in 2030 under nodal pricing are 1.5% lower than under uniform prices only due to system-optimal wind power expansion. However, distributional effects might pose political challenges to the introduction of spatially differentiated electricity prices. Only about 25% of German electricity demand would profit from lower wholesale electricity prices, while wholesale electricity prices would increase by about 5% for densely populated and industry rich regions such as Western Germany.

If introducing nodal or zonal pricing render politically impossible due to distributional effects, additional instruments like spatially differentiated, i.e. latitude-dependent, g(enerator)-components in grid tariffs or grid expansion areas to incentivize grid-friendly siting of wind power are worth considering. This paper finds that both instruments are effective in partly mitigating the inefficient investment signals of uniform prices but their design matters. G-components, which increase linearly with the latitude, are not able to depict the distortions of uniform prices at the very productive Northern sites adequately. Cubical g-components address these distortions more accurately. However, grid expansion areas are more effective in mitigating distorted signals of uniform pricing for wind power investments. Differentiating a large grid expansion area as in the current German market design into several areas could significantly enhance the efficiency gains. Grid expansion areas though are technology-specific investment restrictions, while g-components could be generalized to include other generators such as gas power plants. Beyond generation, nodal pricing incentivizes an efficient allocation of demand and discloses information on grid bottlenecks.

Future research could extend the model to shed light on efficient integration of flexibility, such as power-to-heat applications or electrolysis plants. Implementing the grid topology of neighboring states would allow investigating inefficiencies stemming from limited possibilities for cross-border redispatch. Further, the optimal layout of price zones could be investigated by clustering nodes to price zones. Finally, including endogenous grid investments in the model allows for analyzing efficient incentives for coordinating power plant and grid investments.

Appendix A. Notation

Throughout the paper at hand, the notation presented in Table A.4 is used. To distinguish (exogenous) parameters and optimization variables, the latter are written in capital letters.

Table A.4: Sets, Parameters and Variables

Sets		
$i \in I$		Electricity generation and storage technologies
$m, n \in M$		Markets
$l \in L$		Transmission Grid Lines
$c \in C$		Linear independent cycles of modelled grid
$y, y1 \in Y$		Years
$t \in T$		Representative timesteps
Parameters		
$d(y,t,m)$	[MWh]	Electricity demand
$avail(y,t,m,i)$	[-]	Availability of electricity generation technology
$linecap(y,m,n)$	[MW]	Available transmission capacity
$\beta(y)$	[-]	Discount factor
$\delta(y,i)$	[EUR/MW]	Annualized investment cost
$\sigma(i)$	[EUR/MW]	Fixed operation and maintenance cost
$\gamma(y,i)$	[EUR/MWh]	Variable generation cost
$cap_{add,min}(y,m,i)$	[MW]	Capacities under construction
$cap_{sub,min}(y,m,i)$	[MW]	Decommissioning of capacity due to lifetime or policy bans
$l(m,n)$	[-]	Relative transmission Losses
$\kappa(m,l)$	[-]	Incidence matrix
$\phi(l,c)$	[-]	Cycle matrix
Variables		
$CAP(y,m,i)$	[MW]	Electricity generation capacity
$GEN(y,t,m,i)$	[MWh]	Electricity generation
$CAP_{add}(y,m,i)$	[MW]	Investments in electricity generation capacity
$CAP_{sub}(y,m,i)$	[MW]	Decommissioning of electricity generation capacity
$TRADE(y,t,m,n)$	[MWh]	Electricity trade from m to n
$TRADE\_BAL(y,t,m)$	[MWh]	Net trade balance of m
$FLOW(y,t,l)$	[MWh]	Power flow along line l
TC	[EUR]	Total costs
$FC(y)$ / $VC(y)$	[EUR]	Yearly fixed or variable costs

Appendix B. Regional Scope: Germany's Transmission Network and Neighbors

Figure B.12 visualizes the regional scope. Within Germany, this paper considers a detailed depiction of the transmission network. Connections to neighbors are approximated via Net Trade Capacities (NTC).

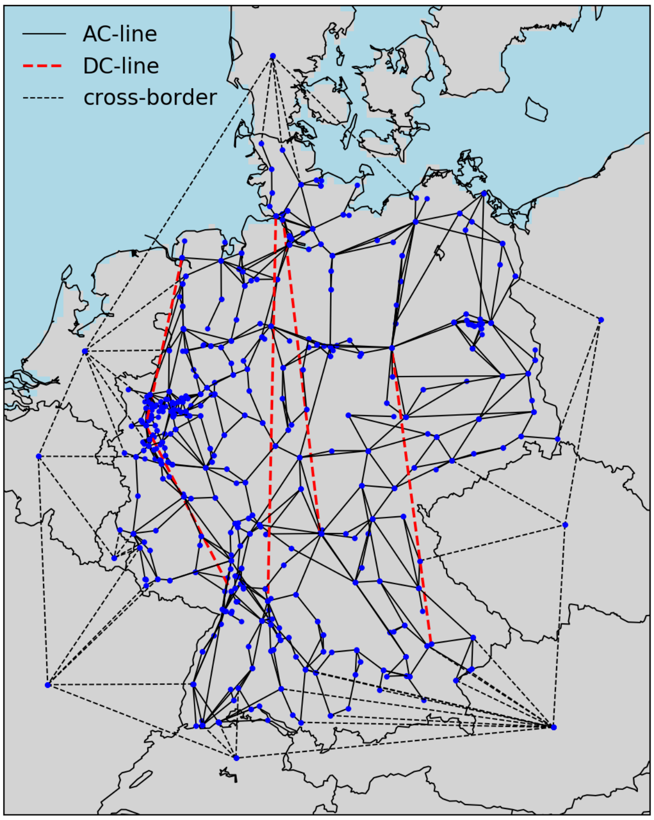

Figure B.12: Regional scope and considered grid topology in 2030.

Appendix C. Assumptions on Invest Costs, Demand and Fuel Prices

Table C.5: Considered Technologies, assumptions based on scenario *Stated Policies* in World Energy Outlook 2019 (IEA (2019)) and Knaut et al. (2016)

Technologies	Efficiency	Fixed Operation Costs (EUR/kW/a)
Nuclear	0.33	85
Lignite	0.4	45
Coal	0.45	45
Combined Cycle Gas Turbines (CCGT)	0.5	25
Open Cycle Gas Turbines (OCGT)	0.38	15
Oil	0.4	7
Biomass	0.3	150
PV	1	17
Wind Onshore	1	12
Wind Offshore	1	93
Hydro	1	11.5
Pumped Storage	0.78	11.5

Table C.6: Development of Invest Costs [EUR/kW] for Onshore Wind Power Plants based on The Boston Consulting Group and Prognos (2018)

Technology	2020	2025	2030
Wind Onshore	1200	1150	1100

Table C.7: Development of Fuel and Carbon Prices [EUR/MWh_{th}], based on scenario *Stated Policies* in World Energy Outlook 2019 (IEA (2019))

Fuel	2019	2020	2025	2030
Uranium	3.0	3.0	3.0	3.0
Lignite	3.9	4.2	5.6	5.6
Coal	7.9	8.1	9.1	9.3
Natural Gas	13.6	15.2	23.2	23.2
Oil	33.1	34.7	42.3	45.9
Biomass	21.0	22.0	22.5	23.0
Carbon [EUR/tCO2]	24.9	26.2	35.5	38.8

Table C.8: Development of Demand [TWh], based on scenario *National Trends* in TYNDP 2020 (ENTSO-E (2018)) and *Scenario B* in German grid development plan (50Hertz et al. (2019))

Country	2019	2020	2025	2030
AT	67	69	77	79
BE	85	85	87	91
CH	62	62	62	61
CZ	63	65	73	78
DE	530	529	528	544
DK	35	38	52	46
FR	456	463	496	486
NL	114	114	114	119
PL	156	160	181	182

Appendix D. Trade Flows

The modeled trade flows underlie three simplifications which are necessary to keep the model tractable: First, the age structure of national power plants fleets is not considered. Second, interconnectors are depicted as NTC constraints without power flow restrictions. Third, other countries than German neighbours are not in the scope of this paper. Due to these shortcomings, the derived trade flows are not realistic. The derived patterns among the three scenarios, however, shed light on the impact of market design on electricity trade between Germany and its neighbours. Figure D.13 visualizes German net imports in the years 2020 and 2030.

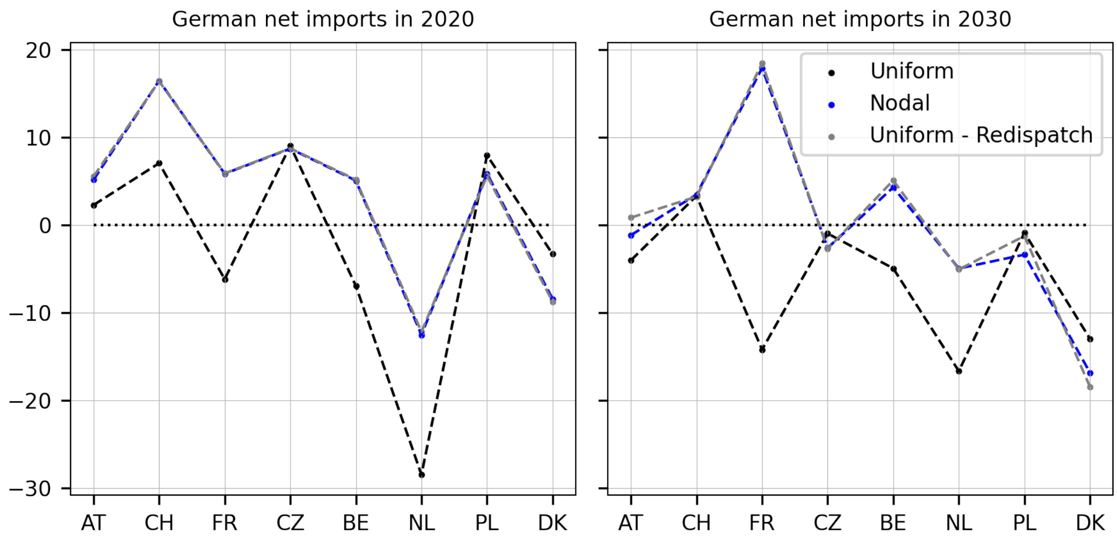

Figure D.13: Trade between Germany and its neighbour countries in 2020 and 2030.

In general, uniform prices trigger higher exports in all directions. Nodal prices incentivize, in particular in Southern and Western Germany, higher imports while exports to Denmark increase. The difference in trade between nodal and uniform prices can be observed best at the example of France. Instead of significant net export under uniform pricing, optimal dispatch under nodal pricing requires high net imports in 2030.

Appendix E. North-German Federal States

Figure E.14 visualizes the three most Northern federal states of Germany.

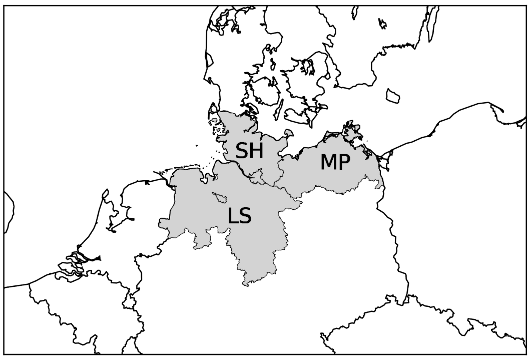

Figure E.14: The area of the federal states of Mecklenburg-Western Pomerania (MP), Schleswig-Holstein (SH) and Lower Saxony (LS).

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