

# On the long-term efficiency of market splitting in Germany

Christoph Fraunholz<sup>a,\*</sup>, Dirk Hladik<sup>b</sup>, Dogan Keles<sup>a,c</sup>, Dominik Möst<sup>b</sup>, Wolf Fichtner<sup>a</sup>

<sup>a</sup> Karlsruhe Institute of Technology, Chair of Energy Economics, Hertzstraße 16, 76187 Karlsruhe, Germany

<sup>b</sup> Technische Universität Dresden, Chair of Energy Economics, Münchner Platz 3, 01069 Dresden, Germany

<sup>c</sup> Technical University of Denmark, Energy System Analysis Section, Akademivej Building 358, 2800 Kgs. Lyngby, Denmark

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## ABSTRACT

In Europe, the ongoing renewable expansion and delays in the planned grid extension have intensified the discussion about an adequate electricity market design. Against this background, we jointly apply an agent-based electricity market model and an optimal power flow model to investigate the long-term impacts of splitting the German market area into two price zones. Our approach allows capturing long-term investment and short-term market behavior under imperfect information. We find strong impacts of a German market splitting on electricity prices, expansion planning of generators and required congestion management. While the congestion volumes decrease significantly under a market split in the short term, the optimal zonal configuration for 2020 becomes outdated over time due to dynamic effects like grid extension, renewable expansion and new power plant investments. Policymakers and regulators should therefore regularly re-assess bidding zone configurations. Yet, this stands in contrast to the major objective of price zones to create stable locational investment incentives.

## 1. Introduction

Driven by the massive expansion of renewable electricity generation as well as political phase-out decisions of technologies such as nuclear or coal-fired generation, the design of the European electricity markets is in a state of constant evolution. An aspect of particular relevance in this respect is the design of the day-ahead markets and the closely related congestion management. Currently, following the concept of zonal pricing, the day-ahead market clearing of the interconnected European electricity system is carried out without considering any grid constraints within a price zone, which in most cases corresponds to a whole country. Only in a subsequent step, congestion management measures, such as redispatching and curtailment of generation from renewable energy sources (RES), are used if the market outcome is not realizable due to intra-zonal congestion. Due to recent and upcoming trends, congestion management becomes increasingly important in Germany:

- Large generation capacities, mainly located in Southern Germany, are dropping out of the market until 2022 due to the political decision of phasing-out nuclear power. Moreover, the German *Kommission für Wachstum, Strukturwandel und Beschäftigung* (commonly called *Kohlekommission*) has recently agreed on a phase-out of coal-fired generation until 2038, which will particularly affect regions

in the West (Rhineland) and East (Lusatia, Central German district) of the country ([Bundesministerium für Wirtschaft und Energie, 2019](#)).

- Electricity generation from wind power has increased significantly over the past years and is expected to continue to do so. However, these generation capacities are to a large extent located in Northern Germany.
- Low wholesale electricity prices provide poor incentives for investments in additional conventional generation capacity or utility-scale storage units.
- While these developments result in a shift of generation capacity to Northern Germany, the industrial load centers with a rather inflexible demand structure are mainly located in Western and Southern Germany. In the past years, this locational mismatch between generation and consumption has already led to an increasing number of hours where the market result had to be corrected by redispatching and curtailment of RES ([Bundesnetzagentur and Bundeskartellamt, 2019](#)). Moreover, Poland and the Czech Republic have already installed phase shifters to reduce loop flows from Northern Germany to Southern Germany through their domestic grid.
- Although new high-voltage direct current (HVDC) lines are supposed to solve these issues to a large extent, their completion is likely to be delayed by a few years.

\* Corresponding author.

E-mail address: [christoph.fraunholz@kit.edu](mailto:christoph.fraunholz@kit.edu) (C. Fraunholz).

Nomenclature			
<i>Parameters</i>		$p^{\text{ren}}$	renewable power plant
$\Delta t$	time step length [h]	$p^{\text{stor}}$	storage power plant
$\eta$	efficiency [MWh <sub>el</sub> /MWh <sub>th</sub> ]	$s$	scenario
$\bar{c}^{\text{var}}$	average variable costs [EUR/MWh <sub>el</sub> ]	$y$	year
$c^{\text{add}}$	specific costs of artificial load [EUR/MWh <sub>el</sub> ]	<i>Variables</i>	
$c^{\text{curt}}$	specific costs of curtailment [EUR/MWh <sub>el</sub> ]	$\Delta p$	relative day-ahead price difference [-]
$c^{\text{O\&M}}$	operation and maintenance costs [EUR/MWh <sub>el</sub> ]	$\Delta p^{\text{sorted}}$	sorted day-ahead price difference [EUR/MWh <sub>el</sub> ]
$c^{\text{var,max}}$	maximum variable costs [EUR/MWh <sub>el</sub> ]	$\lambda$	locational marginal price [EUR/MWh <sub>el</sub> ]
$c^{\text{var,rev}}$	reverted variable costs [EUR/MWh <sub>el</sub> ]	$\bar{p}$	average day-ahead price [EUR/MWh <sub>el</sub> ]
$c^{\text{var}}$	variable costs [EUR/MWh <sub>el</sub> ]	$b$	bid price [EUR/MWh <sub>el</sub> ]
$c^{\text{voll}}$	specific costs of lost load [EUR/MWh <sub>el</sub> ]	$b^{\text{min}}$	bid price for minimal load [EUR/MWh <sub>el</sub> ]
$e^{\text{fuel}}$	emission factor [t <sub>CO<sub>2</sub></sub> /MWh <sub>th</sub> ]	$b^{\text{rest}}$	bid price for rest load [EUR/MWh <sub>el</sub> ]
$l^{\text{gross}}$	gross load [MWh <sub>el</sub> ]	$C^{\text{cong}}$	total costs of congestion management [EUR]
$l^{\text{net}}$	net/residual load [MWh <sub>el</sub> ]	$C^{\text{curt}}$	total costs of curtailment [EUR]
$p^{\text{CO}_2}$	CO <sub>2</sub> price [EUR/t <sub>CO<sub>2</sub></sub> ]	$C^{\text{inf}}$	total infeasibility costs [EUR]
$p^{\text{fuel}}$	fuel price [EUR/MWh <sub>th</sub> ]	$C^{\text{redispatch}}$	total costs of redispatching [EUR]
<i>Sets and Indices</i>		$c^{\text{start}}$	specific start up costs [EUR/MWh <sub>el</sub> ]
$e$	transmission line	$f^{\text{AC}}$	net flow AC [MWh <sub>el</sub> ]
$h$	hour	$f^{\text{DC}}$	net flow DC [MWh <sub>el</sub> ]
$h^{\text{off}}$	offline hour	$g$	electricity generation [MWh <sub>el</sub> ]
$h^{\text{on}}$	online hour	$g^{\text{market}}$	market-dispatched electricity generation [MWh <sub>el</sub> ]
$m$	market area	$l^{\text{add}}$	artificially added load [MWh <sub>el</sub> ]
$n$	grid node	$l^{\text{charge}}$	storage charging demand [MWh <sub>el</sub> ]
$p$	power plant	$l^{\text{dump}}$	dumped load [MWh <sub>el</sub> ]
$p^{\text{con}}$	conventional power plant	$t^{\text{off}}$	offline time [h]
		$t^{\text{on}}$	online time [h]

Apart from resulting in additional costs for congestion management, these trends might also endanger security of supply in (Southern) Germany in the upcoming years. Regional price signals could help to counteract these risks by incentivizing investments in generation capacity or avoiding decommissioning of further power plants by adequately indicating regional scarcity.

In this context, nodal pricing is often considered to be the theoretically first best solution as prices in this market design directly reflect not only marginal generation costs but also bottleneck costs (Stoft, 1997). This concept is currently for instance used in the PJM market area of the USA and in New Zealand (Pettersen et al., 2011). However, a short-term implementation of nodal pricing in Germany or even Europe is unlikely (Trepper et al., 2015).

Alternatively, country price zones can be split up into multiple zones, such as those in the Nordic electricity market (Norway, Sweden, Finland, Denmark) (THEMA Consulting Group, 2013), resulting in diverging electricity prices and therefore regional investment incentives. With regard to Germany, this solution might be quicker and easier to implement than a nodal pricing approach. However, the current German government is strongly in favor of staying with a single German price zone and has recently even changed the legislation (*Stromnetzzugangsverordnung – StromNZV*) accordingly (Bundesministerium für Wirtschaft und Energie, 2017). Nevertheless, the topic remains highly relevant not only from an academic and political perspective, but also for generation companies and grid operators.

While the short-term impacts of dividing the German price zone have already been extensively analyzed by different authors (Burstedde, 2012; Breuer et al., 2013; Breuer and Moser, 2014; Trepper et al., 2015; Egerer et al., 2016; Plancke et al., 2016), the only investigations of the long-term impacts to date have been carried out by Grimm et al. (2016a, b, 2017, 2018) and Ambrosius et al. (2019). Yet, as Grimm et al. (2016b) point out, the consideration of these long-term effects is an essential aspect for the political discussion on concrete splitting of zones.

Against this background, we use an innovative modeling framework consisting of an agent-based electricity market simulation model (PowerACE) and an optimal power flow model (ELMOD) to investigate the long-term impacts of splitting the German price zone. Contrary to the method used in Ambrosius et al. (2019), this new approach allows to consider multiple time periods with regard to generation and storage expansion planning and is therefore able to capture the real-world long-term dynamics appropriately.

Our results focus on the German day-ahead market, required congestion management measures as well as associated system costs and distributional effects under a zonal split as compared to the status quo of a single German price zone. Despite the explicit focus on Germany, the obtained results are also relevant for other regions using multiple price zones within a country, such as the Nordic electricity market or Italy.

The remainder of the paper is structured as follows. In Section 2, we briefly review the relevant literature and derive the research gap our paper aims to fill. Section 3 introduces the proposed modeling framework and explains important methodological aspects in details. We then describe the most relevant input data as well as the scenario definition in Section 4. In Section 5, we present possible long-term impacts of splitting the German price zone. Ultimately, Section 6 provides a summary and an outlook on future work.

## 2. Literature review and research gap

In the following, an overview of the previous literature relevant for this article is provided. Firstly, we briefly review existing methods for bidding zone delimitation. Secondly, the focus is set on the short-term impacts of reconfiguring the European price zones and splitting the German price zone in particular. Thirdly, we summarize literature on the long-term impacts of such market design changes. Ultimately, we outline the research gap that this paper aims to fill.

Regarding the bidding zone configuration method, four main approaches can be distinguished. Firstly, the zonal delimitation is based on historical real-world grid congestion (Egerer et al., 2016; Plancke et al., 2016). Secondly, splitting a price zone can be conducted along the main bottlenecks of the transmission grid for a future reference year (Trepper et al., 2015). Thirdly, nodal electricity prices are clustered, e. g., by using genetic algorithms (Breuer et al., 2013; Breuer and Moser, 2014). Fourthly, a new bidding zone configuration is determined model-endogenously (Grimm et al., 2017; Ambrosius et al., 2019). In the paper at hand, we assume the regulator to base his decision on the division of the German price zone on knowledge available to him at the time of decision-making. For this reason, nodal prices of the year 2020 are clustered using a fuzzy c-means algorithm, rather than applying a model-endogenous approach (see Section 3).

Reconfiguring European bidding zones brings along a number of short-term impacts, which have already been extensively analyzed in several studies to date. The relevant contributions are shortly presented in the next paragraphs.

Burstedde (2012) compares a nodal pricing approach and a zonal configuration based on the clustering of nodal prices on a European level for the scenario years 2015 and 2020. Both variants are then contrasted with the current situation of nationwide price zones in terms of generation and redispatching costs. While the costs of redispatching are significantly reduced when the current zones are reconfigured and even more so under the nodal pricing approach, the rise of generation costs almost entirely compensates this effect.

Breuer et al. (2013) and Breuer and Moser (2014) apply genetic algorithms for the scenario years 2016 and 2018 in order to deduce an optimal zonal configuration on a European level from nodal prices. They investigate different numbers of zones and ultimately conclude that reconfiguring the European price zones into 10 to 15 new zones, the costs of redispatching would decrease more than the costs of generation would rise as compared to the reference case. However, also in these studies, the savings are very low in relation to the total traded electricity volume.

Trepper et al. (2015) investigate a splitting of the German price zone based on the most heavily congested lines for the scenario year 2020. With trading capacities of 10.2–15.3 GW, the redispatching volumes decrease significantly and average price differences of 1.55–3.56 EUR/MWh<sub>el</sub> between the two new zones occur. Moreover, the authors find decreasing producer rents and increasing consumer rents in Northern Germany, while the opposite is true for Southern Germany.

Egerer et al. (2016) analyze a splitting of the German price zone for the years 2012 and 2015 without taking into account the German neighboring countries. With a trading capacity of 8 GW, only small average price differences of 0.40 EUR/MWh<sub>el</sub> (2012) and 1.70 EUR/MWh<sub>el</sub> (2015) between the two German zones arise. Redispatching volumes decrease slightly in 2012 and more significantly in 2015.

Plancke et al. (2016) apply a European spot market model to a scenario for the year 2020 and examine the European impact of a splitting of the German price zone. Assuming a trading capacity of 8 GW, the average price differences between the two zones amount to 5.16 EUR/MWh<sub>el</sub>. While the greatest changes in consumer rents and producer rents can be observed in Germany, to a lesser extent, many neighboring countries are also affected. Since the authors don't use an additional grid model, no analyses on the changes in redispatching volumes and costs are carried out.

All of the studies mentioned so far focus on the static short-term perspective without taking into account dynamic long-term aspects, such as the impact on investments in new generation capacity. The literature tackling these particular issues, as presented in the following, is substantially less extensive to date.

Applying an integrated generation investment, spot market and redispatching model to a small-scale test network, Grimm et al. (2016b) provide a theoretical analysis of potential long-term welfare effects of splitting up price zones under consideration of investment behavior. In

their work, they explicitly point out that for the political discussion regarding concrete splitting of zones, the consideration of such long-term impacts is essential for decision making.

This aspect is further investigated in a number of additional contributions (Grimm et al., 2016a, 2017; 2018; Ambrosius et al., 2019), all of which apply multilevel equilibrium models considering both the electricity market and the electrical grid.

In Grimm et al. (2016a), a model with decision levels for line expansion, generation capacity expansion and spot market including redispatching is introduced, formally analyzed and applied to a small-scale case study. Grimm et al. (2018) then extend this model and investigate different market design changes including market splitting for a strongly simplified representation of the German electricity system and a single future year (2035). The division of the German price zone is conducted in a simplified fashion along the borders of some German federal states. The authors find that the locational price signals occurring under market splitting induce a more efficient allocation of conventional power plants. This, in turn, reduces the need for grid expansion. Moreover, the choice of appropriate transfer capacities between the two German zones proves to be crucial.

The first decision level of Grimm et al. (2016a) is modified in Grimm et al. (2017) in order to model-endogenously derive an optimal specification of price zones instead of deciding on line investments. While Grimm et al. (2017) focus on solution algorithms and highly-aggregated test cases, Ambrosius et al. (2019) use an again slightly modified version of this model to derive an optimal delimitation of the German price zone under consideration of anticipated generation capacity expansion as well as spot market trading and redispatching. A novelty of this contribution is the model-endogenous determination of the transfer capacities between the different German price zones. The extended model is applied to a strongly simplified representation of the German electricity system in a single future year (2035). Ambrosius et al. (2019) find that under two or three price zones in Germany, the major part of the theoretically achievable welfare gains is already realized, while increasing the amount of zones further brings little additional benefit.

The above-mentioned contributions are the first in the literature to present important insights in potential long-term impacts of splitting the German price zone in two or multiple zones. Yet, despite modeling different decision levels, Ambrosius et al. (2019) assume perfect anticipation of the regulator in terms of generation expansion planning, spot market trading and redispatching. Moreover, the long-term effects of splitting the German price zones are only analyzed for a single future year and under strong simplifications, particularly in terms of grid resolution. We therefore propose an alternative modeling framework, which extends the work of Ambrosius et al. (2019) in three important aspects.

Firstly, in our approach, the regulator decides on an optimal delimitation of the German price zone prior to the decisions of the companies on investments in new generation and storage units, i.e., under imperfect information. In a real-world setting, this is exactly the situation a regulator would be confronted with when deciding on a new price zone configuration. Not having any information on the reactions of the generation companies, he could only base his decision on information available to date.

Secondly, our proposed modeling framework includes an agent-based multi-period simulation covering 2020 through 2050 as well as Germany and all neighboring countries. This approach allows to capture long-term investment and short-term market behavior under imperfect information while adequately accounting for both intertemporal effects and cross-border effects.

Thirdly, the applied optimal power flow model considers the entire German transmission grid and auxiliary nodes in the neighboring countries rather than using a strongly simplified representation of the grid. Therefore, cross-border effects in terms of required congestion management measures and persistent intra-zonal congestion can also be

considered.

For these reasons, the novel approach presented in the following is very well suited to capture dynamic long-term impacts of a zonal split in Germany in a closer-to-real-world fashion than any other publication available to date.

### 3. Methodology

Any approach that aims to investigate all relevant long-term aspects of a zonal split in Germany needs to cover the decisions of different actors. Firstly, a regulator deciding on the actual zonal split, secondly, the long-term investment and short-term market decisions of the different generation firms, and thirdly, the required congestion management measures carried out by the transmission system operator (TSO).

We tackle this challenge by jointly applying two established energy-related models, namely the optimal power flow model ELMOD and the electricity market simulation model PowerACE. In Section 3.1, we describe the interaction of the two models and outline the advantages of our modeling framework. Sections 3.2–3.5 then explain in detail, how the different decision levels are modeled in ELMOD and PowerACE.

#### 3.1. Overview of the modeling framework

The timeline of the different decision levels in the combined application of ELMOD and PowerACE is presented in Fig. 1. In order to outline the differences between our modeling approach and that of Ambrosius et al. (2019), we use the same style for our illustration as they do.

In a first step (bottom-left box), the regulator decides on an optimal splitting of the German price zone and corresponding transfer capacities. For this purpose, hourly nodal prices that are simulated with ELMOD for the base year 2020 are clustered in two zones (see Section 3.2 for details). Contrary to Ambrosius et al. (2019), the zonal delimitation is independent of the subsequent decisions on expansion planning and (re)dispatch, since a regulator wouldn't have a priori knowledge on these decisions in a real-world setting.

Next,  $|Y|$  periods are simulated, each denoting one year at hourly resolution. For each period, the simulation covers three steps. Firstly, using the information on the new zonal delimitation, the day-ahead market is simulated with PowerACE (for details see Section 3.3). Secondly, the hourly dispatch originating from the market simulation serves as input to determine required congestion management measures with ELMOD (for details see Section 3.4). These two steps correspond to the top-right box in Fig. 1. Thirdly, the different companies create their individual generation and storage expansion plan for the subsequent periods (bottom-right box). Contrary to Ambrosius et al. (2019), these decisions are not directly related to the (re)dispatch of the following periods, but the companies rather prepare future price forecasts and generate their expansion plans accordingly. This approach is again closer to a real-world setting, since real companies only have limited knowledge on the future developments of the day-ahead markets. Moreover, multiple years are simulated and therefore also multiple investment decisions are taken, which makes it possible to better grasp the long-term dynamics of a zonal split. For details on the investment planning, see Section 3.5.

In the subsequent Sections 3.2–3.5, we describe the different decision levels in more detail. Additionally, Appendix A provides a brief general introduction to the models.

#### 3.2. Zonal configuration and transfer capacities

As a first step when investigating the impacts of market splitting in Germany, we need to carry out an adequate reconfiguration of the bidding zone which is both stable and has low intra-zonal congestion. Stable in this context means that considering all hours of a base year, the

final zonal configuration is predominant to other configurations.

In electricity systems, the nodal price or locational marginal price (LMP) of a given grid node represents the marginal cost of delivering an additional unit of electricity to this specific node. The LMP includes information on both marginal generation costs and the physical aspects of the transmission grid. Using the standard objective function of minimizing total generation costs, we apply ELMOD to calculate the LMP  $\lambda_n$  at every node  $n \in N$  which corresponds to the dual variable of the energy balance as shown later in Eq. (2).

If the grid is congested between two nodes, the LMPs of these nodes diverge. In contrast, nodes with identical or similar LMPs are typically not affected by congestion between each other. These properties of LMPs imply that clustering nodes with similar LMPs is a promising approach in order to determine stable zones with low intra-zonal congestion. Therefore, in order to split the German market area into two bidding zones, we apply a fuzzy c-means clustering algorithm (Dunn, 1973; Bezdek, 1981; Hong et al., 2002) to the LMPs of all German grid nodes over 8760 hours of the base year 2020.

The major challenge when clustering the LMPs is to avoid fragmented zones, meaning that some nodes are clustered in the same zone but are not physically connected. A proven solution for similar scientific network questions is the application of spatial clustering which is based on graph theory (e.g., von Luxburg, 2007). Spatial clustering of an electricity network uses a Laplacian matrix  $L$  which considers the relation between two nodes  $n_i, n_j \in N$  as well as lines/edges  $e \in E$  within graph  $G = (N, E)$ . This procedure has previously been applied by Metzdorf (2016).

After determining the new bidding zone configuration for Germany, we calculate the trading capacities between the two bidding zones based on the transmission capacities on the border lines of the zones for 2020. Thereby, DC-lines are counted at full and AC-lines at one third of their capacity to account for uncertainties regarding the state of the grid at a given point in time. For the subsequent years, we take into account additional capacities on the basis of the network development plans.

#### 3.3. Day-ahead market simulation

Splitting the German market area into two price zones has a direct impact on the outcomes of the day-ahead markets, both in the short-term and the long-term. Using the zonal split determined with ELMOD, we can now apply PowerACE to quantify these effects as explained hereafter.

The PowerACE model is structured into different market areas  $m \in M$ , in each of which multiple supply traders, i.e., utility companies, are active on the day-ahead market. The simulation of the day-ahead market consists of four steps, which are briefly outlined in the following.

**Price forecast.** According to the economic theory, market participants are willing to sell electricity at their marginal generation costs. However, starting up a power plant leads to additional costs due to higher fuel consumption and a reduced lifetime caused by material stress. In order to account for these costs and prepare bids accordingly, it is important for the supply traders to estimate, if and how long a specific power plant will be in the market on the following simulation day. Thus, in a first step, all supply traders prepare a price forecast for all hours  $h \in H$  of the following day. The basic approach for this price forecast is an extended merit-order model, i.e., a cost-minimal power plant dispatch serving the expected hourly residual loads in the respective market area is determined under consideration of both variable and start-up costs.<sup>1</sup> The major output of the price forecast are the expected running hours for all power plants on the following simulation day.

**Bidding.** Using the information from the price forecast, the different

<sup>1</sup> Formally, this step requires to solve a mixed-integer optimization problem. However, to save computational resources, a heuristic approach is applied, such that only close-to-optimal solutions can be guaranteed.

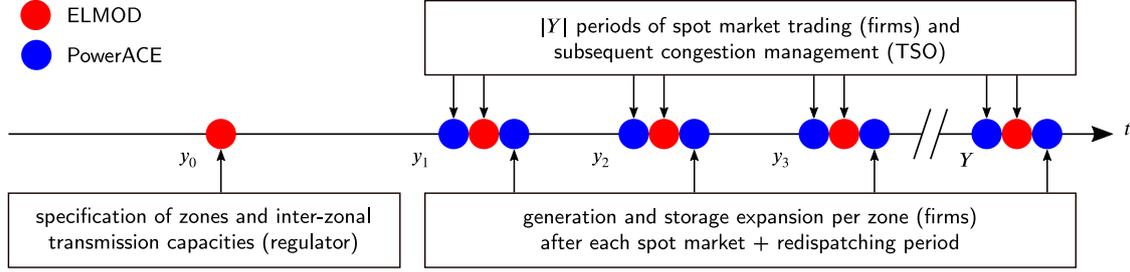


Fig. 1. Timeline of the combined application of the models ELMOD and PowerACE (based on a similar illustration in Ambrosius et al., 2019).

supply traders now prepare bids for all of their own power plants and each hour  $h$  of the following day. These bids consist of volume (MWh), price (EUR/MWh) and type (buy or sell). While the bid volume for each power plant is determined considering an exogenously given availability factor and a potential obligation to provide balancing power, the bid price depends both on the type of the power plant and whether the power plant is expected to run in the respective hour or not. An overview of the bidding strategies is provided in Appendix B.

**Market clearing.** All bids prepared in the previous step are then submitted to the market coupling operator. In the market clearing process, supply and demand bids are matched across all market areas, such that welfare is maximized subject to the limited interconnector capacities between the different market areas. For a formal description and details of the market coupling and clearing, see Ringler et al. (2017). As a result, the information, which bids have been partly or fully accepted is returned to the different supply traders.

**Dispatch.** All supply traders now calculate their individual hourly load curve, which is the sum of their hourly bids that have been accepted. In the final step of the day-ahead market simulation, the different traders determine a cost-minimal dispatch of their individual power plant fleet, which serves their hourly load curve under consideration of both variable and start-up costs<sup>1</sup>.

### 3.4. Congestion management

Using the hourly dispatch of all power plants as obtained from the day-ahead market simulation with PowerACE, we can now determine the impact of splitting the German market area on the required congestion management measures using ELMOD. In the ELMOD version applied in this contribution, the congestion management comprises redispatching of conventional power plants and curtailment of renewable energy production. The integration of these instruments into ELMOD is briefly described in the following.

As shown in Eq. (1), ELMOD has a linear objective function in which the total costs of congestion management  $C_{\text{total}}^{\text{cong}}$  across all market areas  $m \in \mathbf{M}$  are minimized.

$$\text{minimize } C_{\text{total}}^{\text{cong}} = \sum_{m \in \mathbf{M}} (C_m^{\text{redisp}} + C_m^{\text{curt}}) \quad (1)$$

where

$$C_m^{\text{redisp}} = \text{total redispatching costs in market area } m$$

$$C_m^{\text{curt}} = \text{total curtailment costs in market area } m$$

The main restriction of ELMOD is the energy balance presented in Eq. (2), which needs to be fulfilled at every transmission grid node  $n$  and in every hour  $h$ . Please note:

- The power plant set  $P_n$  at node  $n$  comprises subsets for conventional power plants  $P_n^{\text{con}}$ , storage plants  $P_n^{\text{stor}}$  and renewable power plants  $P_n^{\text{ren}}$ .
- The gross load  $l_{n,h}^{\text{gross}}$  is exogenously set and assumed fully price-inelastic.
- The neighboring countries of Germany are represented with one aggregated grid node and additional auxiliary nodes to capture interconnector behavior.

$$l_{n,h}^{\text{gross}} + \sum_{p \in P_n^{\text{stor}}} f_{p,h}^{\text{charge}} = \sum_{p \in P_n} g_{p,h} + f_{n,h}^{\text{AC}} + f_{n,h}^{\text{DC}} \quad \forall n \in \mathbf{N}, h \in \mathbf{H} \quad (2)$$

where

$$l_{n,h}^{\text{gross}} = \text{gross load at node } n \text{ in hour } h$$

$$f_{p,h}^{\text{charge}} = \text{storage charging of unit } p \text{ in hour } h \text{ (decision variable)}$$

$$g_{p,h} = \text{electricity generation of power plant } p \text{ in hour } h \text{ (decision variable)}$$

$$f_{n,h}^{\text{AC}} = \text{net input of the AC lines at node } n \text{ in hour } h$$

$$f_{n,h}^{\text{DC}} = \text{net input of the DC lines at node } n \text{ in hour } h$$

The redispatching costs  $C_m^{\text{redisp}}$  of all market areas  $m \in \mathbf{M}$  are determined based on the deviations between the hourly market-dispatched power plant generation  $g_{p,h}^{\text{market}}$  with  $p \in P_m^{\text{con}}$  and the endogenous generation variables  $g_{p,h}$  of ELMOD, which are multiplied by the marginal costs of the respective power plant  $c_p^{\text{var}}$  as shown in Eq. (3).

$$C_m^{\text{redisp}} = \sum_{p \in P_m^{\text{con}}} \sum_{h \in \mathbf{H}} (g_{p,h} - g_{p,h}^{\text{market}}) \cdot c_p^{\text{var}} \quad \forall m \in \mathbf{M} \quad (3)$$

It is important to note that for computational performance reasons start-up costs are considered in the market simulation with PowerACE, but not in the grid model ELMOD. Consequently,  $g_{p,h}^{\text{market}}$  could be re-optimized without an actual grid congestion need. In order to avoid this, Eq. (3) needs to be reformulated such that both positive and negative redispatching of conventional power plants are penalized. For details on the reformulation, please refer to Appendix C.

If the redispatching capacities of the conventional power plants are not sufficient to find a feasible solution, curtailment of the market-dispatched renewable generation  $g_{p,h}^{\text{market}}$  with  $p \in P_m^{\text{ren}}$  is deployed by the model, i.e.,  $g_{p,h}^{\text{market}}$  is reduced to  $g_{p,h}$ . The differences between  $g_{p,h}^{\text{market}}$  and  $g_{p,h}$  lead to curtailment costs  $C_m^{\text{curt}}$ , which are integrated into ELMOD

**Table 1**  
Model resolution of PowerACE and ELMOD.

Type	PowerACE	ELMOD	
	All countries	Germany	Other countries
Temporal resolution	2020–2050 (yearly) at 8760 h/a	2025/2035 at 8760 h/a	
Transmission grid	interconnectors	full representation	aggregated grid nodes
Conventional power plants	unit level	unit level	technology aggregated
Electricity demand	hourly, market area	hourly, grid node	hourly, aggregated grid node
Renewable feed-in	hourly, market area	hourly, grid node	hourly, aggregated grid node

as shown in Eqs. (4) and (5).<sup>2</sup>

$$C_m^{\text{curt}} = \sum_{p \in P_m^{\text{ren}}} \sum_{h \in H} (g_{p,h}^{\text{market}} - g_{p,h}) \cdot c^{\text{curt}} \quad \forall m \in M \quad (4)$$

$$g_{p,h} \leq g_{p,h}^{\text{market}} \quad \forall p \in P^{\text{ren}}, h \in H \quad (5)$$

Although most of the grid congestion events can be relieved by redispatching and curtailment measures, it is reasonable to use additional auxiliary variables for dumped load  $l_{n,h}^{\text{dump}}$  and artificially added load  $l_{n,h}^{\text{add}}$  to guarantee a feasible solution. For details on the integration of these variables, please refer to [Appendix C](#).

Finally, it is important to mention that the neighboring countries of Germany are only represented in a simplified fashion. Therefore, the focus of the congestion management measures is on Germany with the neighboring countries being used for redispatching only if the German power plant capacities are not sufficient (see also [Appendix C](#)).

### 3.5. Investment planning

The potential impact on investment incentives is an essential aspect when evaluating the long-term efficiency of splitting the German market area. For this purpose, the different utility companies modeled as agents in PowerACE can perform long-term decisions on investments in new conventional power plant and storage capacities at the end of each simulation year. Contrary to the common approach of expansion planning with the objective of minimizing total future system costs, an actor's perspective is taken. Consequently, investments are only carried out if expected to be profitable by the investor agents. The applied investment planning algorithm is introduced and described in detail in [Fraunholz et al. \(2019\)](#). A brief overview of the basic principles is given in the following.

The decisions of the different investors are primarily based on their expectations regarding future electricity prices. As these, vice versa, are influenced by the investment decisions of all investors in all interconnected market areas, a complex game with multiple possible strategies opens up. To find a stable outcome for this game, a Nash-equilibrium needs to be determined.

Therefore, the investment planning algorithm terminates when all planned investments are profitable and at the same time none of the investors is able to improve his expected payoff by carrying out further

<sup>2</sup> The curtailment costs for renewable generation are an artificial penalty, because generation costs are already included in the market dispatch and additional costs for the system will only occur for the positive redispatching which is needed to balance the system. Nevertheless, these penalty costs can be explained by the Renewable Energy Directive (2009/28/EC) which claims priority access to the grid for renewable generation in real time. Furthermore, renewable generation is often subsidized by feed-in tariffs or premiums which add to the generation costs of the market ([Bjørndal et al., 2018](#)). Therefore, the curtailment costs of renewable generation  $c^{\text{curt}}$  are orientated at the maximum penalty costs for negative redispatching in Germany in the respective year. Using this approach, curtailment is only carried out if the available redispatching capacities are not sufficient to relieve the grid congestion – similarly to the real-world process.

or less investments, i.e., there is no incentive for any investor to unilaterally deviate from the equilibrium outcome. The eleven different market areas<sup>3</sup> are defined as the players interacting with each other and the planned investments are then distributed among the investors within each market area. This is achieved by first randomizing and then iterating over the different investors after each investment being carried out.<sup>4</sup> Following this approach, it is possible to consider the mutual impact of investments in one market area on the electricity prices and consequently investments in the interconnected market areas.

After the investment planning in PowerACE has been carried out, the grid nodes of ELMOD are sorted per market area in descending order beginning with the node where most old power plant capacity has been decommissioned. The new investments in the respective market area are then allocated to the sorted list of grid nodes. Please note that it may also occur that more capacity is newly built than decommissioned in a given market area. In this case, the ratio between total newly installed capacity and total decommissioned capacity in the given zone is computed. The installed capacity at each node is then increased by this factor.

## 4. Data and scenario setup

As cross-border effects have a strong impact on the splitting of market areas, we model Germany and all neighboring countries plus Italy in our analysis. The time horizon covers 2020 through 2050 at hourly resolution. While we carry out a continuous simulation over the whole time period in PowerACE, we only investigate selected years in terms of required congestion management with ELMOD. An overview of the model resolutions is provided in [Table 1](#) and further details are described in the following. Please note that all (future) prices and costs are calculated in real values to exclude the effect of inflation.

Both models – PowerACE and ELMOD – use consistent data on the power plant fleets in the year 2020 which has been compiled using information from [Bundesnetzagentur \(2017\)](#) for Germany and [S&P Global Platts \(2015\)](#) for the other countries. In PowerACE, this data is used on unit level for all countries, while ELMOD applies technology aggregated data for the neighboring countries. Based on their individual commissioning year, the existing power plants are gradually decommissioned over the time horizon until 2050 after reaching the end of their technical lifetime. This is exemplary shown on a technology aggregated level for the German market area in [Fig. 2](#). In Germany, the phase-out of all nuclear power plants until 2022 as well as of all coal-fired power plants until 2038 is implemented, following the suggestions of the German [Kohlekommission \(Bundesministerium für Wirtschaft und Energie, 2019\)](#).

Fossil fuel prices are based on the EU Reference Scenario ([European Commission, 2016](#)), while the CO<sub>2</sub> price development path is taken from the same source, yet scaled to reach 150 EUR/t<sub>CO<sub>2</sub></sub> in 2050. Historical electricity demand profiles of 2015 obtained from [ENTSO-E \(2017\)](#) are

<sup>3</sup> Germany in two price zones and all of its neighboring countries plus Italy.

<sup>4</sup> If the investors within each market area are differently parameterized, it would also be possible to have the single investors instead of the market areas play against each other. However, since the focus of our paper is not on market power issues, we choose the more basic approach of defining the market areas as players.

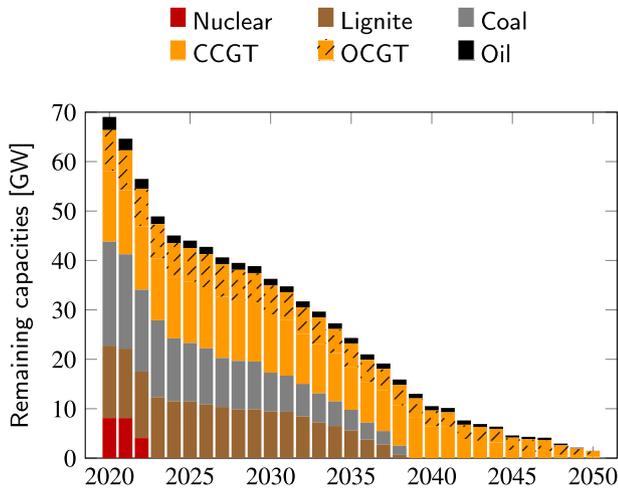


Fig. 2. Assumed conventional power plant capacities in Germany without additional new investments (Bundesnetzagentur, 2017, and own assumptions). Abbreviations: CCGT—combined cycle gas turbine, OCGT—open cycle gas turbine.

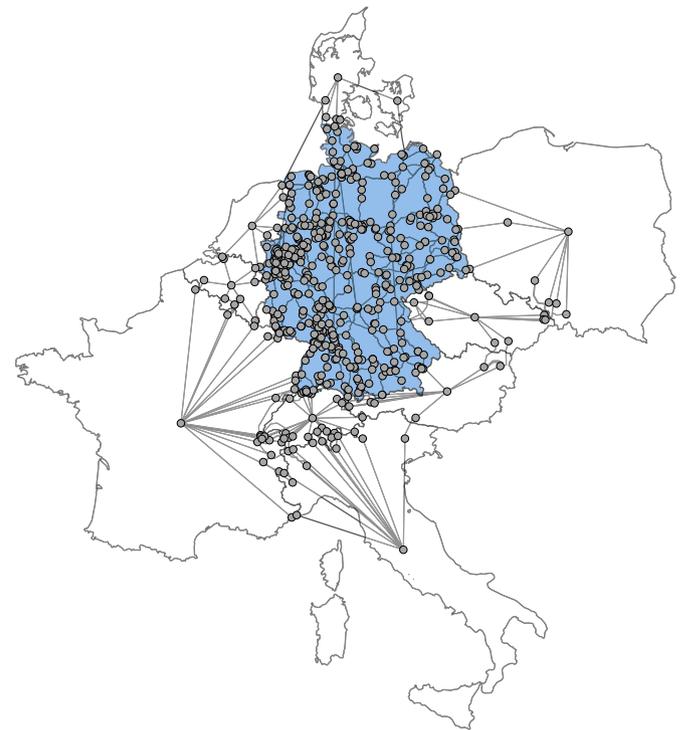


Fig. 4. Simulated market areas and corresponding level of detail of the grid model.

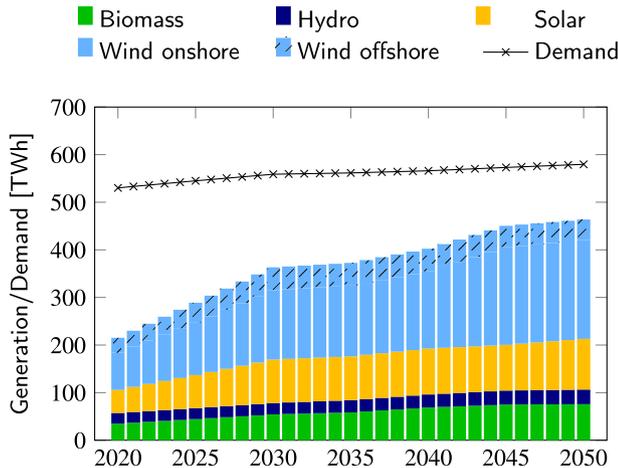


Fig. 3. Assumed annual renewable electricity generation and gross electricity demand in Germany (European Commission, 2016, and own assumptions).

used and scaled to the yearly demand according to European Commission (2016). Electricity generation from renewables is based on historical profiles of 2015 (ENTSO-E, 2017), which are scaled such that an overall renewable share in relation to electricity demand of 80% in 2050 is reached. Fig. 3 illustrates the assumed composition of the renewable electricity generation in Germany as well as the total yearly gross electricity demand.<sup>5</sup> Despite the potential impact of market splitting on regional incentives to flexibilize load, demand side management is out of the scope of this paper and not taken into account.

In ELMOD, the transmission grid is modeled on a nodal level for Germany while aggregated artificial grid nodes are defined for the

neighboring countries (see Fig. 4). Future grid extension is based on the Ten-Year Network Development Plan (ENTSO-E, 2016). However, given the current status of the different HVDC projects in Germany, we assume a delay of five years compared to the official plans.

For the German market area, the power plant fleet, hourly renewable feed-in and hourly electricity demand are regionalized and then assigned to the respective grid nodes in ELMOD. The regionalization of renewable power plants is based on data from Bundesnetzagentur (2019). For the electricity demand, a load share for each node is calculated based on gross domestic product and population per NUTS-3 area. Please note that the shares of renewable feed-in by technology and electricity demand at each node are assumed constant over the whole simulation period, i.e., today’s yearly generation and demand are scaled to the respective future values.

For the day-ahead market simulation in PowerACE, the exchange of electricity between Germany and its neighboring countries is limited by fixed maximum transfer capacities obtained from ENTSO-E (2016), while – similarly to the real-world market clearing process – intra-zonal grid constraints are not considered.

The agents in PowerACE can invest in different conventional power plants as well as utility-scale storage technologies. An overview of these investment options with their respective techno-economic characteristics is provided in Appendix D. Accounting for the political situation in the different market areas, investments in lignite- or coal-fired power plants are only eligible in the Czech Republic and Poland.

In order to analyze the long-term impacts of splitting the German price zone, two different scenarios need to be investigated. Table 2 summarizes the main characteristics of these scenarios. In scenario REF, which serves as a benchmark, the German market area consists of only one countrywide price zone (DE). Consequently, no intra-zonal transmission grid constraints are considered in the day-ahead market simulation with PowerACE. However, these constraints become relevant in the subsequent step, when calculating the required congestion management measures in ELMOD based on the market outcome of PowerACE. Contrary, in scenario SPLIT, a division of the German market area in a Northern price zone (DEN) and a Southern price zone (DES) is

<sup>5</sup> In reality, driven by sector coupling, the electricity demand may increase much stronger than we assumed. This is particularly true in the period after 2040. However, the grid would then likely also be further extended. Since no data on grid extension after 2035 is currently publicly available, we use relatively conservative assumptions regarding demand growth and renewable expansion. In future research, more ambitious scenarios should therefore also be investigated.

**Table 2**  
Overview of the investigated scenarios.

Scenario	German market area	Day-ahead market clearing	Congestion management
REF	one countrywide price zone (DE)	no consideration of any intra-zonal transmission grid constraints	consideration of intra-zonal transmission grid constraints
SPLIT	two price zones (DEN/DES)	limited static transfer capacity between German price zones	consideration of intra-zonal transmission grid constraints

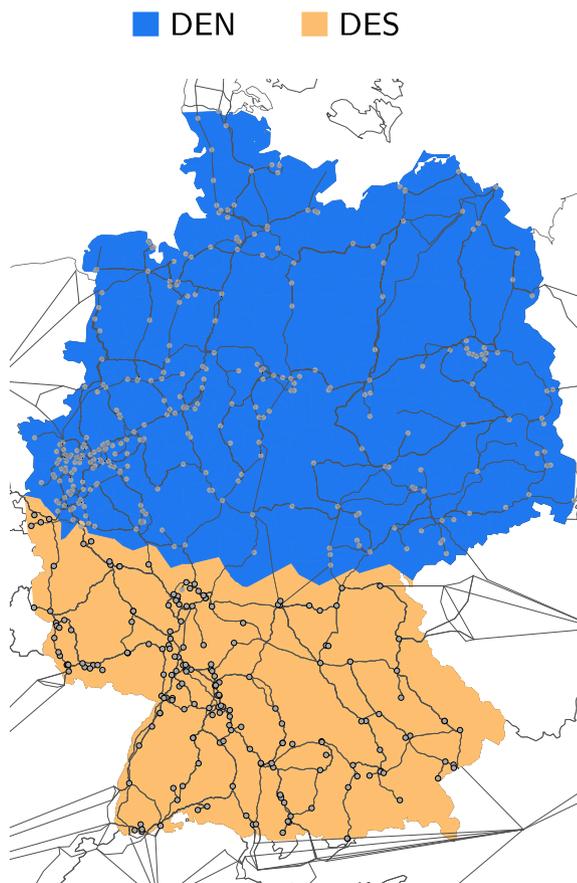
investigated.

The splitting of the German market area is assumed to take place in 2020. In order to implement the market splitting, we apply a limited static transfer capacity between the two German price zones for the day-ahead market simulation in PowerACE. This transmission limit is adjusted over time to account for grid extension within Germany (see Section 5.1). For the calculation of required congestion management in ELMOD, we consider the full German transmission grid in the same way as for the scenario REF.

## 5. Results and discussion

### 5.1. Zonal configuration and transfer capacities

Before delving into the long-term impacts of splitting the German market area, let us start with a brief look at the zonal delimitation resulting from the clustering of nodal prices (Fig. 5). While the regionalized electricity demand (cf. Section 4) is split roughly evenly between DEN and DES, we can see that the majority of conventional power plants, in particular lignite-fired capacities with low variable costs, is located in DEN. Regarding renewable electricity generation, we can



**Fig. 5.** Optimal delimitation of the German bidding zone resulting from the clustering of nodal prices.

**Table 3**

Conventional power plant capacity, renewable feed-in and electricity demand in Germany for the base year 2020 and the respective shares in DEN and DES as resulting from the bidding zone delimitation (Bundesnetzagentur, 2017; European Commission, 2016; and own assumptions/calculations). Abbreviations: CCGT—combined cycle gas turbine, OCGT—open cycle gas turbine.

Technology type	Capacity/Generation/ Demand	Share in DEN	Share in DES
Nuclear	8.1 GW	51%	49%
Lignite	14.7 GW	98%	2%
Coal	21.0 GW	63%	37%
CCGT	14.2 GW	71%	29%
OCGT	8.3 GW	72%	28%
Oil	2.7 GW	82%	18%
Pumped storage	6.4 GW	38%	62%
Biomass	33.9 TWh	64%	36%
Hydro	22.5 TWh	20%	80%
Solar	48.5 TWh	49%	51%
Wind onshore	78.2 TWh	87%	13%
Wind offshore	31.3 TWh	100%	0%
Electricity demand	530.3 TWh	58%	42%

state that solar is split evenly, whereas wind power is predominantly located in DEN and hydro power in DES. For details, please refer to Table 3.

In Table 4 we show the corresponding assumed total net transfer capacities, which are an important driver for the day-ahead market simulation and generation expansion planning. We calculate the capacities based on the transmission capacities on the border lines of the zones in the respective year as described in Section 3.2. As previously mentioned, we assume a delay of five years for the different HVDC projects compared to the official plans.

### 5.2. Day-ahead market impacts

Let us now move on to the short-term and long-term day-ahead market impacts of splitting the German market area.

We can see that in both scenarios REF and SPLIT, the average day-ahead prices  $\bar{p}$  in Germany increase significantly throughout the simulation period despite the high shares of renewable electricity generation (Fig. 6a). This trend can mainly be attributed to the assumed strong increase in CO<sub>2</sub> prices, more frequent and costly start-ups of conventional power plants as well as some scarcity hours with prices of 3000 EUR/MWh<sub>el</sub>.

In order to isolate the price impact resulting from the split of the German market area, we transform the mean prices  $\bar{p}$  to relative price differences for further analysis (Fig. 6b). For this purpose, we define the German mean day-ahead price in scenario REF as a reference and then compute the relative price differences  $\Delta p_{s,m}$  in scenario  $s$  and market area  $m$  as  $\Delta p_{s,m} = \bar{p}_{s,m} / \bar{p}_{REF,DE} - 100\%$ . Consequently, by definition, the relative price differences of REF–DE are always at 0% throughout the simulation period.

We can see from Fig. 6b that initially, in 2020, the average prices in DEN are only around 2% (corresponds to 0.87 EUR/MWh<sub>el</sub>) lower, but those in DES almost 16% (7.23 EUR/MWh<sub>el</sub>) higher than in the single German price zone.<sup>6</sup> Between 2020 and 2035, the relative price

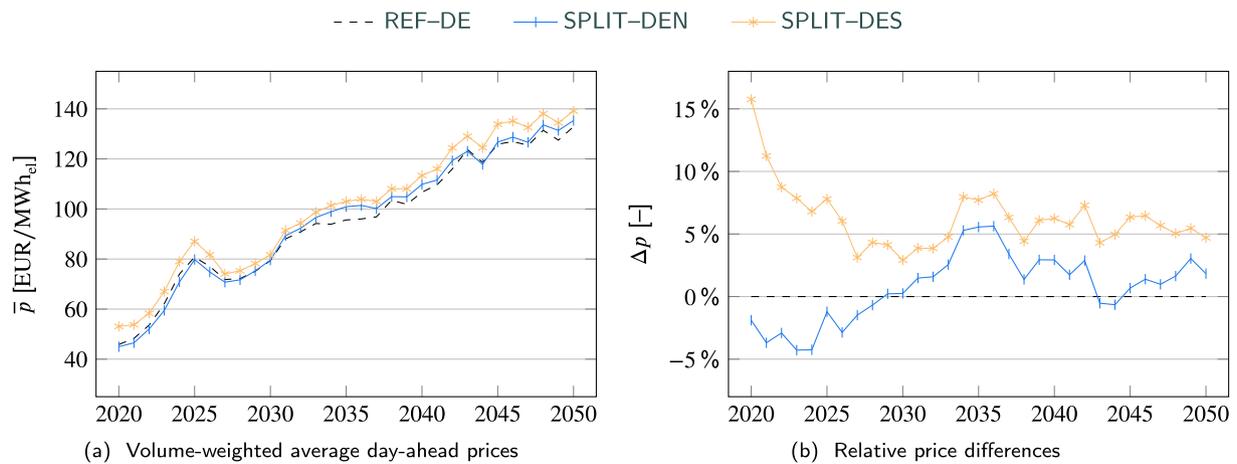
<sup>6</sup> These price differences between the two German price zones are higher than those found in the literature (cf. Section 2). However, previous studies are difficult to compare to ours due to varying scenario years and substantially different assumptions, e.g., regarding the power plant fleets. In additional sensitivities with higher (lower) net transfer capacities of 10 GW (6 GW), we find the price differences to decrease (increase) to 4.96 EUR/MWh<sub>el</sub> (12.37 EUR/MWh<sub>el</sub>). These results stand well in line with those of Plancke et al. (2016). Splitting the German market area already in 2015 instead of 2020, we obtain an average price difference of 2.35 EUR/MWh<sub>el</sub>, which is comparable to that found by Egerer et al. (2016) for 2015 (1.70 EUR/MWh<sub>el</sub>).

**Table 4**

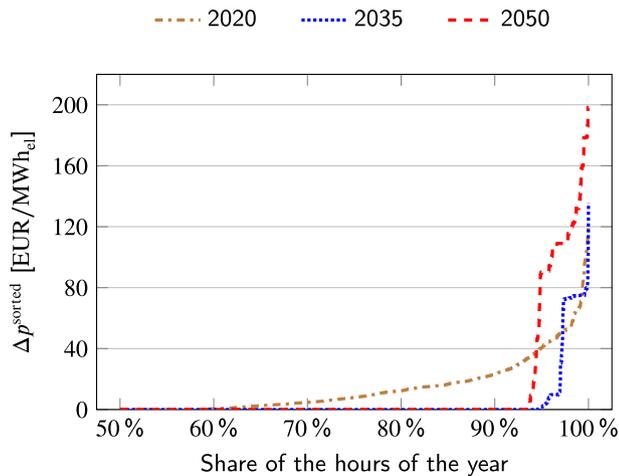
New high-voltage direct current (HVDC) lines and assumed total net transfer capacity (NTC) of all lines between DEN and DES (both directions) in scenario SPLIT (ENTSO-E, 2016, and own assumptions).

Years	New HVDC lines	Total NTC
2020–2026	Ultranet	8 GW
2027–2028	Suedlink	12 GW
2029	SuedOstLink	14 GW
2030–2034	A-North	16 GW
2035–2050	DC21/DC23	18 GW

their absolute magnitude increases sharply between 2035 and 2050. The reasons for this finding are twofold. Firstly, towards 2050, renewables are increasingly often price-setting in DEN with their marginal cost of 0 EUR/MWh<sub>el</sub>, while conventional capacity is still needed in DES due to a lack of transmission capacity between the two German price zones. Secondly, the general level of the day-ahead prices rises strongly over the course of the simulation as previously explained. Situations with higher prices in DEN than in DES occur in well below 1% of the hours throughout the simulation period and are therefore not further discussed.



**Fig. 6.** Simulated development of the day-ahead prices (real values) in absolute (a) and relative (b) terms for both scenarios REF and SPLIT.



**Fig. 7.** Simulated sorted day-ahead price differences (real values) between DES and DEN in scenario SPLIT.

differences between DEN and DES continuously decline, which is mainly driven by the grid extension and the resulting increase in transfer capacities between the two German price zones (cf. Table 4). However, due to the ongoing strong expansion of renewables (cf. Fig. 3) and no additional grid extension after 2035, the relative price differences rise again slightly in the second part of the simulation period (2035–2050).

This result is also reflected in Fig. 7 showing the sorted hourly price differences between DES and DEN. While the share of hours with positive price differences (i.e., higher prices in DES than in DEN) declines strongly from around 40% to less than 10% between 2020 and 2035,

Fig. 6b also illustrates that in the medium to long term, the price level in both DEN and DES is slightly higher than in REF-DE. Given the completely different setup regarding location of (new) power plants (discussed below, cf. Fig. 8), grid extension (cf. Table 4) and renewable expansion (cf. Fig. 3) as compared to the base year 2020, the assumed zonal configuration has become outdated by 2035. Moreover, the limited transfer capacity between the two German price zones leads to a less efficient market outcome than under a single German price zone. The major reason for this finding is that the additional restrictions at the market clearing stage lead to more electricity generation by peak load units with high variable costs, while at the same time the market-based curtailment of renewables with zero variable costs increases under a zonal split (discussed in Section 5.3, cf. Fig. 9c).

The bidding zone delimitation and the related price divergence between DEN and DES also has an impact on the respective investment incentives for conventional power plants and utility-scale storage units.<sup>7</sup> In Fig. 8, the simulated development of the conventional power plant and utility-scale storage capacities in the two price zones DEN and DES is depicted for both scenarios REF and SPLIT.<sup>8</sup>

As compared to scenario REF, significantly more investments are carried out in the price zone DES in scenario SPLIT, while the opposite is true for the price zone DEN. This is a direct outcome of the investment planning module presented in Section 3.5. Due to the higher electricity price forecasts in DES, investments in DES are often preferred over DEN in scenario SPLIT. Contrary, in scenario REF, new power plants are distributed equally between DEN and DES.

The generally slightly higher price level in scenario SPLIT also leads

<sup>7</sup> The expansion of renewable generation capacities is not modeled endogenously, instead the renewable feed-in is based on exogenously defined hourly profiles (see Section 4).

<sup>8</sup> In scenario REF, new capacities in Germany are distributed evenly between the two zones DEN and DES to allow for a comparison with scenario SPLIT.

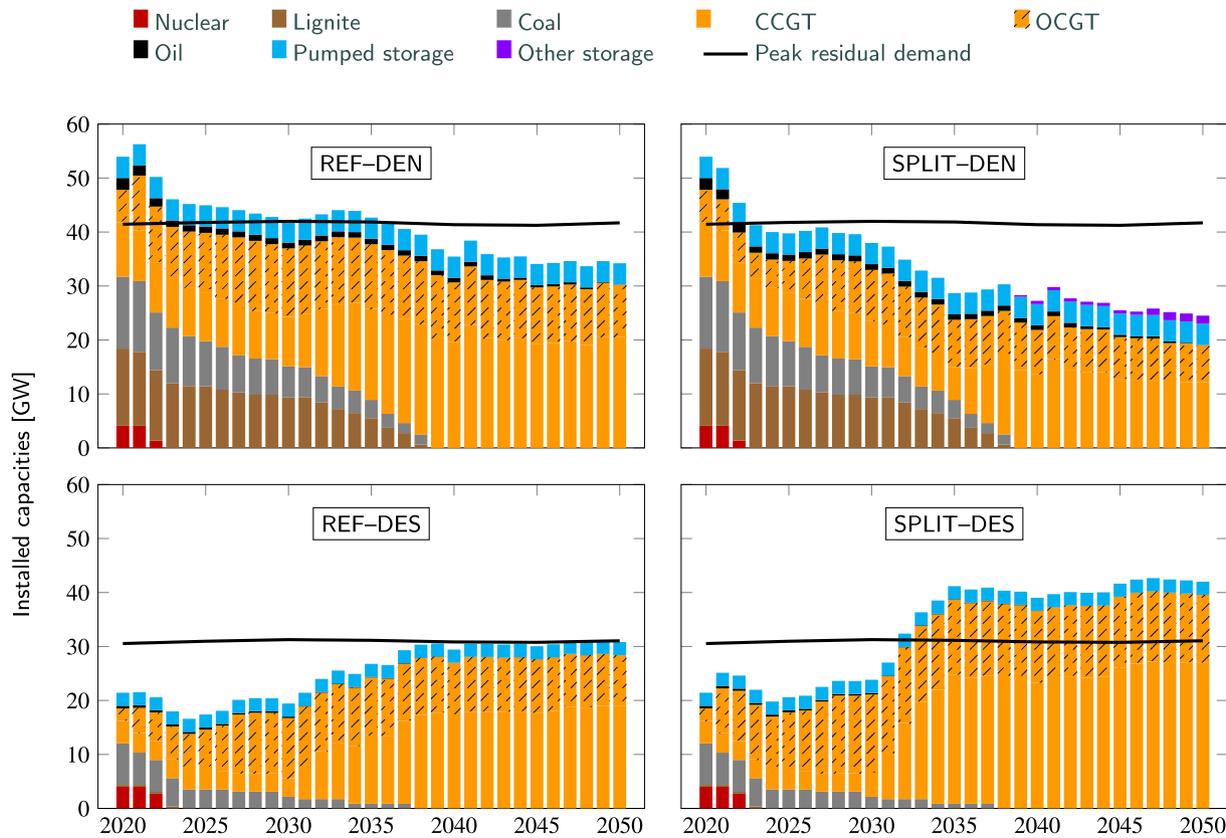


Fig. 8. Simulated development of the conventional power plant and utility-scale storage capacities in Germany for both scenarios REF and SPLIT. Abbreviations: CCGT—combined cycle gas turbine, OCGT—open cycle gas turbine.

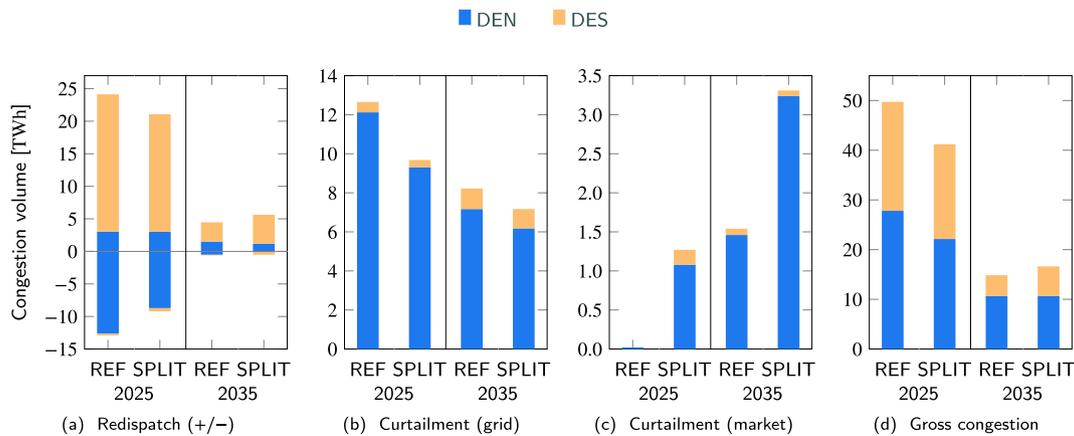


Fig. 9. Required congestion management measures by category for both scenarios REF and SPLIT. As is common practice, the gross congestion volume (d) is calculated as the absolute sum of categories (a)–(c).

to the cumulated new capacity across both price zones being a bit higher than in scenario REF. Moreover, while storage investments are not profitable in scenario REF, some investments in these technologies are carried out in scenario SPLIT and price zone DEN. Given the high amount of renewable electricity generation in DEN as well as the limited transfer capacities to DES in scenario SPLIT, this finding is quite straightforward.

### 5.3. Congestion management

The day-ahead market results described in the previous section have an immediate impact on the required congestion management measures.

The volumes of these measures are presented by category and for both scenarios REF and SPLIT in Fig. 9.

We can see that in 2025 the redispatching volumes decrease as a result of the zonal split (Fig. 9a). More specifically, by considering potential grid congestion between DEN and DES already at the market clearing stage, negative redispatching in DEN and positive redispatching in DES can be reduced. However, as discussed before, the different setup as compared to the base year 2020 leads to the assumed zonal configuration becoming outdated by 2035, which ultimately causes an increase of positive redispatching volumes in DES.

As expected, splitting the German market area leads to a reduction of grid-related curtailment in both 2025 and 2035 (Fig. 9b). This is

particularly relevant for DEN due to the large amount of wind power installed. However, the positive effect is overcompensated in 2035 by additional market-related curtailment (Fig. 9c), which results from the strong increase in renewable electricity generation and the limited net transfer capacities between DEN and DES. In consequence, we can observe a negative total effect of the market splitting on required curtailment of renewables in 2035.

Summing up redispatching and curtailment measures, we end up with the gross congestion volume<sup>9</sup> (Fig. 9d), which decreases under a zonal split in 2025, yet increases in 2035 due to the outdated and therefore inadequate zonal configuration. These findings show that policymakers and regulators should regularly re-assess and potentially adjust bidding zone configurations.

#### 5.4. System costs and distributional effects

Using the results from Sections 5.2 and 5.3, we can now derive a number of economic indicators, which are summarized in Table 5. A brief description of our major findings is provided in the following.

The price differences between DEN and DES (cf. Fig. 6b) lead to a decrease of the wholesale costs of electricity generation in DEN and an increase in DES (2025) under a zonal split, before increasing in both DEN and DES (2035). In contrast, volumes and costs of redispatching are lower for scenario SPLIT in 2025, but then rise in 2035 since the previously optimal zonal configuration has become outdated for several reasons, as mentioned before. In consequence, we find the total system costs to be higher in both 2025 and 2035 if the German market area is split into two zones.

Since we have assumed the electricity demand to be completely static, the increase in system costs is identical with the reduction of the consumer rents. In scenario SPLIT, producers in DES benefit from higher prices as compared to scenario REF. Thus, the producer rents in DES increase in 2025, while the opposite is true for DEN, in total leading to a reduction of the producer rents. In 2035, a substantial increase of the producer rents in DES can be observed due to the preferred allocation of new generation capacity in DES as well as higher prices as compared to scenario REF. In DEN, a lot less generation capacity is installed in scenario SPLIT, leading to a decrease of the producer rents. Since the effect in DES is much stronger than in DEN, we find an overall increase of the producer rents in Germany in 2035.

Apart from affecting the system costs, the price differences between DEN and DES also lead to higher congestion rents under a zonal split. Since the prices in both zones converge to a certain extent (cf. Fig. 6b), this effect is less pronounced in 2035 than 2025.

We can ultimately conclude that splitting the German market area in two zones has strong distributional effects. DES benefits from a significant increase of the producer rents, which overcompensates the corresponding reduction of the consumer rents, resulting in a positive welfare effect. Yet, the opposite effect occurs in DEN. Overall, we find a negative welfare effect for Germany. Finally, it is important to mention that we take a purely German perspective in our analysis, while other neighboring countries may benefit from a German market splitting. However, given our simplified representation of the neighboring countries, we are unable to derive profound results in this regard.

## 6. Conclusion and policy implications

Using an innovative modeling framework consisting of an agent-based electricity market simulation model (PowerACE) and an optimal power flow model (ELMOD) we investigated the long-term impacts of splitting the German price zone in a multi-period setting with different

decision levels. We found strong impacts of a market splitting on day-ahead electricity prices, investment planning of generation companies, required congestion management and, ultimately, system costs and social welfare.

After splitting the German market area into a Northern price zone (DEN) and a Southern price zone (DES) in 2020, the day-ahead prices in both zones initially diverge significantly with higher prices in DES and lower prices in DEN. The price differences then decline between 2020 and 2035, which is mainly driven by grid extension, and rise again slightly between 2035 and 2050 due to the ongoing strong expansion of renewables without additional grid extension. Since the limited transfer capacity between the two German price zones leads to a less efficient market outcome, we found the price level in both DEN and DES to be slightly higher than under a single German price zone in the medium to long term.

The higher electricity prices in DES than DEN also have an immediate impact on investment incentives, leading to much more new power plants being built in DES than DEN as compared to the reference case of a single German price zone.

The required congestion management decreases in 2025 under a zonal split, however, we found it to be higher in 2035, since the bidding zone delimitation has become outdated given the completely different setup regarding location of (new) power plants, grid extension and renewable expansion as compared to the base year 2020.

These results are also reflected in system costs, which rise under a zonal split in both 2025 and 2035, mainly due to significantly higher wholesale prices for electricity. In terms of social welfare, the generation companies in DES benefit from substantial increases in producer rents, which overcompensate the reduction of consumer rents. In contrast, the generation companies in DEN suffer from lower producer rents (mainly 2025), which are then supplemented by a strong decrease in consumer rents in 2035. Overall, we found a negative welfare effect in Germany under a zonal split. However, it is important to mention that we took a purely German perspective in our analysis, while other neighboring countries may benefit from the German market splitting.

Our findings are particularly crucial for policymakers and regulators in the field of electricity market design, but also for generation companies and grid operators. Optimization approaches with perfect anticipation of future decisions by different players as previously applied in the literature typically lead to positive welfare effects of market splitting. This is rather straightforward, given the perfect foresight and single-period character of these models. In contrast, our multi-period approach with imperfect information of the different players showed that a zonal delimitation optimal from today's perspective may become outdated over time in a dynamic environment with grid extension, renewable expansion and investments in new power plants.

Therefore, we recommend that policymakers and regulators should regularly re-assess and potentially adjust bidding zone configurations. However, one major objective of price zones is to provide locational investment incentives. These would be reduced, if investors could not rely on stable price zones. In consequence, adequately setting up stable bidding zones remains a major challenge, which is reflected by most of the European electricity market still being organized in countrywide price zones. Importantly, our results are not only valid for Germany, but also highly relevant for any other region using multiple price zones within a country, such as the Nordic electricity market or Italy.

We are well aware that despite providing important insights on the long-term impacts of splitting price zones, our work could be substantially extended to get a more complete picture on this issue. Regarding the day-ahead market simulation, much depends on the appropriate choice of the transfer capacities between the different zones, which is a difficult task. In reality, flow-based market coupling is already in place in Central Western Europe, which automatically accounts for and at least partly solves this issue. Our day-ahead market simulation could therefore be extended to a flow-based market coupling approach.

Moreover, we have assumed exogenous expansion of renewables.

<sup>9</sup> Please note that it is common practice to count all congestion management measures in positive terms, i.e., also negative redispatching contributes to an increase of the gross congestion volume.

**Table 5**

Effects of the market splitting on economic indicators in Germany in million EUR (real values). All values show the respective deltas between the scenarios SPLIT and REF.

ID/Calculation	Indicator	Year 2025 [10 <sup>6</sup> EUR]			Year 2035 [10 <sup>6</sup> EUR]		
		DEN	DES	DEN + DES	DEN	DES	DEN + DES
A	Δ Wholesale costs	- 308	+ 1440	+ 1132	+ 1732	+ 1735	+ 3467
B	Δ Redispatching costs	+ 243	- 360	- 117	+ 10	+ 88	+ 98
$C = A + B$	Δ System costs	- 65	+ 1080	+ 1015	+ 1742	+ 1824	+ 3566
$D = - C$	Δ Consumer rents	+ 65	- 1080	- 1015	- 1742	- 1824	- 3566
E	Δ Producer rents	- 1207	+ 1115	- 92	- 280	+ 2093	+ 1813
F	Δ Congestion rents	+ 298	+ 380	+ 677	+ 198	+ 180	+ 378
$G = D + E + F$	Δ Total welfare	- 844	+ 414	- 430	- 1824	+ 450	- 1374

However, the different electricity price levels in DES and DEN might not only affect investments in conventional power plants, but also lead to more renewables being placed in Southern Germany despite better wind locations in Northern Germany. Our approach could therefore also be extended in this direction and account for model-endogenous renewable expansion. The same applies for the electricity demand, which we have assumed to be exogenously given and fully static. Yet, market splitting and the related price differences might create regional incentives to flexibilize load.

In future research, it would also be possible to use a more detailed representation of the grid in the German neighboring countries than we did in our paper. Like this, the welfare effects in all these countries could be investigated rather than only in Germany. Such an analysis would likely bring interesting insights on why Germany is reluctant to split its market area, while some neighboring countries are rather in favor of this measure.

Lastly, we have assumed the regulator to decide on the zonal delimitation based purely on information available to him at the time of decision-making. Alternatively, some kind of iterative procedure could be implemented, in which the regulator tries to anticipate the future status of the electricity system and the behavior of the market participants as a result of his zonal split. The regulator could then adjust the

initial zonal delimitation accordingly. Carrying out this iteration multiple times, we would then likely end up with similar results as in the literature, where perfect anticipation of future decisions is often assumed. However, given the high degree of uncertainty that a regulator deciding on a zonal delimitation is confronted with, we expect our results to be closer to the real-world setting than models with perfect anticipation of all players' decisions.

#### Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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## A. Model descriptions

### A.1. Optimal power flow model ELMOD

ELMOD is a linear optimization model for the analysis of interactions between electricity generation and transmission grid. Originally developed at TU Dresden (Leuthold et al., 2008), ELMOD has already been used for numerous system analyses (e.g., Kunz et al., 2011; Kunz, 2013). In ELMOD, the European transmission grid as well as power plants and electricity demand are regionally modeled on a grid node level. The load flow is approximated by a direct current (DC) approach. The objective of the standard model version is to minimize total generation costs. In this contribution, however, costs for congestion management are minimized instead, since the electricity generation of the different power plants results from the market simulation with PowerACE and is an exogenous input for ELMOD. The constraints of ELMOD include maintaining the energy balance for each point in time and grid node as well as further equations regarding restrictions of the load flow and the dispatch of generation and storage units. An overview of the detailed mathematical formulations can be found in Leuthold et al. (2012). ELMOD is formulated in the General Algebraic Modeling System (GAMS) and solved with the commercial CPLEX solver.

### A.2. Electricity market simulation model PowerACE

The agent-based simulation model PowerACE has been developed at Karlsruhe Institute of Technology and has already been applied for various energy system analyses (e.g., Bublitz et al., 2017; Genoese, 2010; Keles et al., 2016; Ringler et al., 2017). In PowerACE, major wholesale electricity markets and the associated market participants such as utility companies, regulators and consumers are modeled. The agents representing electricity suppliers can decide on the daily scheduling of their power plants and storage units as well as on the construction of new power plants and utility-scale storages. Thus, the short-term and long-term decision levels are considered jointly and their interactions can be investigated. Ultimately, the development of the markets emerges from the simulated behavior of all agents.

## B. Day-ahead market simulation

The different supply traders prepare bids  $b_{p,h}$  for all of their own power plants  $p$  and each hour  $h$  of the following simulation day. The respective bid

price depends both on the type of the power plant and whether the power plant is expected to run in the respective hour (i.e.,  $h \in \mathbf{H}_p^{\text{on}} \subseteq \mathbf{H}$ ) or expected not to run (i.e.,  $h \in \mathbf{H}_p^{\text{off}} \subseteq \mathbf{H}$ ). All bidding prices for the different cases are briefly described in the following and formally summarized in Table 6.

**Table 6**

Overview of power plants' hourly bidding prices  $b_{p,h}$  depending on the type of the power plant and the expected online hours.

Case (1):	Power plant $p$ (base-/medium-/peak-load) is in the market in all hours $h$ $b_{p,h} = c_p^{\text{var}} \quad \forall h \in \mathbf{H}_p^{\text{on}} = \mathbf{H}$
Case (2):	Power plant $p$ (base-load) is in the market in some hours $h$ $b_{p,h} = c_p^{\text{var}} \quad \forall h \in \mathbf{H}_p^{\text{on}} \subseteq \mathbf{H}$ $b_{p,h}^{\text{min}} = c_p^{\text{var}} - c_p^{\text{start}} / t_p^{\text{off}} \quad \forall h \in \mathbf{H}_p^{\text{off}} \subseteq \mathbf{H}$ $b_{p,h}^{\text{rest}} = c_p^{\text{var}} \quad \forall h \in \mathbf{H}_p^{\text{off}} \subseteq \mathbf{H}$
Case (3):	Power plant $p$ (medium-/peak-load) is in the market in some hours $h$ $b_{p,h} = c_p^{\text{var}} + c_p^{\text{start}} / t_p^{\text{on}} \quad \forall h \in \mathbf{H}_p^{\text{on}} \subseteq \mathbf{H}$ $b_{p,h} = c_p^{\text{var}} + c_p^{\text{start}} / \Delta t \quad \forall h \in \mathbf{H}_p^{\text{off}} \subseteq \mathbf{H}$

Case (1). If a power plant of any type (base-, medium- or peak-load) is expected to be in the market in all hours, i.e.,  $\mathbf{H}_p^{\text{on}} = \mathbf{H}$ , the hourly bids  $b_{p,h}$  only consist of the variable costs  $c_p^{\text{var}}$ , which are determined by the fuel price  $p_p^{\text{fuel}}$ , the power plant's net electrical efficiency  $\eta_p$ , the price of CO<sub>2</sub> emission allowances  $p^{\text{CO}_2}$ , the CO<sub>2</sub> emission factor of the fuel  $e^{\text{fuel}}$  and the costs for operation and maintenance  $c_p^{\text{O\&M}}$  as shown in Eq. (6).

$$c_p^{\text{var}} = \frac{p_p^{\text{fuel}} + p^{\text{CO}_2} \cdot e^{\text{fuel}}}{\eta_p} + c_p^{\text{O\&M}} \quad (6)$$

Case (2). If a base-load power plant is expected to be in the market only in some hours or never, i.e.,  $\mathbf{H}_p^{\text{off}} \neq \emptyset$ , variable costs are bid for the expected running hours  $\mathbf{H}_p^{\text{on}}$  and two different bids are created for each hour  $h \in \mathbf{H}_p^{\text{off}}$  – the minimum running load of the power plant is bid at variable costs minus avoided start-up costs  $c_p^{\text{start}}$ , while the remaining load is bid at variable costs. The avoided start-up costs are evenly distributed among the expected offline time  $t_p^{\text{off}}$ . The economic reasoning behind this strategy is, that base-load power plants are expected to temporarily accept market prices below their marginal generation costs in order to avoid start-up costs in subsequent hours.

Case (3). If a medium- or peak-load power plant is expected to be in the market only in some hours or never, the hourly bids consist of variable costs and start-up costs. If the online time  $t_p^{\text{on}}$  is longer than one hour, start-up costs are distributed evenly.

Further price-inelastic bids for demand, renewable feed-in and pumped storage units are prepared by a single trader per market area, respectively. For details on the determination of the bid volumes for pumped storage plants, please refer to Fraunholz et al. (2017).

### C. Congestion management

For computational performance reasons start-up costs are considered in the market simulation with PowerACE, but not in the grid model ELMOD. Consequently, redispatching might be carried out without an actual grid congestion need. In the following, we describe how this issue can be avoided by reformulating Eq. (3). Thereby, the following crucial conditions need to be satisfied:

- Both, positive and negative redispatching have to be penalized to avoid redispatching without a grid congestion need.
- Positive redispatching should be carried out with the lowest-variable-cost power plants able to resolve the grid congestion.
- Negative redispatching should be carried out with the highest-variable-cost power plants running according to the day-ahead market outcome.
- Redispatching measures should preferably be carried out within Germany rather than in neighboring countries.

As a first step, we define the reverted variable costs  $c_p^{\text{var,rev}}$  of a German conventional power plant  $p \in \mathbf{P}_{\text{DE}}^{\text{con}}$  as shown in Eq. (7), where  $\bar{c}_{\text{DE}}^{\text{var}}$  denotes the average variable costs of the German conventional power plant fleet.

$$c_p^{\text{var,rev}} = \left( \frac{\bar{c}_{\text{DE}}^{\text{var}}}{c_p^{\text{var}}} \right) \cdot \bar{c}_{\text{DE}}^{\text{var}} \quad \forall p \in \mathbf{P}_{\text{DE}}^{\text{con}} \quad (7)$$

We can now calculate the total costs for redispatching in Germany  $C_{\text{DE}}^{\text{redisp}}$  according to Eq. (8). In this formulation, positive redispatching is penalized with the respective variable costs, whereas negative redispatching is penalized with the respective reverted variable costs. Like this, cost-minimal redispatching is carried out, yet only if required for grid congestion reasons.

$$C_{\text{DE}}^{\text{redisp}} = \sum_{p \in \mathbf{P}_{\text{DE}}^{\text{con}}} \sum_{h \in \mathbf{H}} \left( \max(g_{p,h} - g_{p,h}^{\text{market}}, 0) \cdot c_p^{\text{var}} - \min(g_{p,h} - g_{p,h}^{\text{market}}, 0) \cdot c_p^{\text{var,rev}} \right) \quad (8)$$

As previously mentioned, the neighboring countries of Germany are considered via interconnectors and aggregated auxiliary grid nodes. Moreover, the focus of this analysis is on the congestion management capabilities of Germany. For these reasons, contrary to redispatching in Germany, both positive and negative redispatching in neighboring countries are penalized at the maximum variable costs of the German conventional power plants  $c_{\text{DE}}^{\text{var,max}} = \max_{p \in \mathbf{P}_{\text{DE}}^{\text{con}}} c_p^{\text{var}}$  as shown in Eq. (9). Using this approach, redispatching is always preferably carried out in Germany.

$$C_m^{\text{redisp}} = \sum_{p \in \mathbf{P}_m^{\text{con}}} \sum_{h \in \mathbf{H}} |g_{p,h} - g_{p,h}^{\text{market}}| \cdot c_{\text{DE}}^{\text{var,max}} \quad \forall m \in \mathbf{M} \setminus \{\text{DE}\} \quad (9)$$

In reality, if a power plant has to conduct negative redispatching, the saved marginal costs have to be paid back to the TSO. To account for this practice, the final redispatching costs are determined by subtracting the artificial negative redispatching costs from the positive redispatching costs

subsequently to the cost minimization with ELMOD.

Although most of the grid congestion events can be relieved by redispatching and curtailment measures, situations in which the load cannot be served by the available generation units under grid restrictions may occur. In these cases, part of the load can be dumped through  $l_{n,h}^{\text{dump}}$  at a high penalty of  $c^{\text{voll}} = 10\,000$  EUR/MWh<sub>el</sub><sup>10</sup>. Contrary, the artificially added load  $l_{n,h}^{\text{add}}$  is implemented for modelling reasons only in order to ensure a feasible solution and is also strongly penalized with specific costs of  $c^{\text{add}} = 10\,000$  EUR/MWh<sub>el</sub>. If  $l_{n,h}^{\text{add}}$  volumes arise, it may reveal model failures. Both penalty costs sum up to  $C_m^{\text{inf}}$  as shown in Eq. (10). The objective function of ELMOD as introduced in Eq. (1) now needs to be extended to the version shown in Eq. (11). Moreover, the energy balance shown in Eq. (2) has to account for the introduced auxiliary variables, leading us to Eq. (12).

$$C_m^{\text{inf}} = \sum_{n \in N} \sum_{h \in H} (c^{\text{add}} \cdot l_{n,h}^{\text{add}} + c^{\text{voll}} \cdot l_{n,h}^{\text{dump}}) \quad \forall m \in M \quad (10)$$

$$\text{minimize } C_{\text{total}}^{\text{cong}} = \sum_{m \in M} (C_m^{\text{redisp}} + C_m^{\text{curt}} + C_m^{\text{inf}}) \quad (11)$$

$$l_{n,h}^{\text{gross}} + \sum_{p \in P_n^{\text{prior}}} l_{p,h}^{\text{charge}} + l_{n,h}^{\text{add}} - l_{n,h}^{\text{dump}} = \sum_{p \in P_n} g_{p,h} + f_{n,h}^{\text{AC}} + f_{n,h}^{\text{DC}} \quad \forall n \in N, h \in H \quad (12)$$

## D. Input data

An overview of the techno-economic characteristics of the different investment options modeled in PowerACE is provided in Tables 7 and 8.

**Table 7**

Conventional power plant investment options modeled in PowerACE with their respective techno-economic characteristics (Schröder et al., 2013; Louwen et al., 2018, and own assumptions).

Technology	Block size [MW <sub>el</sub> ]	CCS	Net efficiency <sup>a</sup> [%]	Lifetime [a]	Building time [a]	Specific investment (2015–2050) <sup>b</sup> [EUR/kW <sub>el</sub> ]	O&M costs fixed [EUR/kW <sub>el</sub> a]	O&M costs var. <sup>b</sup> [EUR/MWh <sub>el</sub> ]
Coal	600	no	45–48	40	4	1800	60	6
		yes	36–41			3143–2677		30
Lignite	800	no	43–47	40	4	1500	30	7
		yes	30–33			3840–3324		34
CCGT	400	no	60–62	30	4	800	20	5
		yes	49–52			1216–1078		18
OCGT	400	no	40–42	30	2	400	15	3

*Abbreviations:* CCGT—combined cycle gas turbine, CCS—carbon capture and storage, OCGT—open cycle gas turbine, O&M—operation and maintenance.

<sup>a</sup> Resulting from technological learning, the net efficiency is assumed to increase over time. Since conventional power plants can generally be regarded as mature technologies, it is further assumed that only the specific investments of the CCS-technologies are declining.

<sup>b</sup> Including variable costs for carbon capture, transport and storage, where applicable.

**Table 8**

Electricity storage investment options modeled in PowerACE with their respective techno-economic characteristics (Louwen et al., 2018; Siemens Gamesa, 2019, and own assumptions).

Technology	Block size [MW <sub>el</sub> ]	Storage capacity <sup>a</sup> [MWh <sub>el</sub> ]	Round-trip efficiency <sup>b</sup> [%]	Lifetime <sup>b</sup> [a]	Building time [a]	Specific investment (2015–2050) <sup>b</sup> $\frac{\text{EUR}}{\text{kW}_{\text{el}}}$	O&M costs fixed <sup>b</sup> $\frac{\text{EUR}}{\text{kW}_{\text{el}} \text{a}}$
Li-ion battery	300	1200	85–95	20–30	2	3149–572	63–11
		3000				7643–1388	153–28
RF battery	300	3000	75–85	20–30	2	4206–892	84–18
A-CAES	300	3000	60–75	30	2	1095	22
ETES	300	1200	50–60	40	2	600	12
		3000				672	13

*Abbreviations:* A-CAES—adiabatic compressed air energy storage, ETES—electric thermal energy storage, O&M—operation and maintenance, RF battery—redox-flow battery.

<sup>a</sup> For RF batteries and A-CAES, a substantial share of the investment expenses is related to the converter units. Consequently, for economic reasons, only higher storage capacities of 3000 MWh<sub>el</sub> are eligible as investment options for these technologies.

<sup>b</sup> Resulting from technological learning, round-trip efficiency and lifetime are assumed to increase over time for the emerging storage technologies. Analogously, specific investments and fixed costs for O&M are assumed to decline.

<sup>10</sup> The Value of Lost Load (VoLL) is defined as the willingness to pay of electricity consumers to avoid a disruption of their electricity supply. The determination of the VoLL is non-trivial and depends on several customer-specific factors as well as the respective point in time. Therefore, we assume an average value, which is chosen high enough to only consider load shedding as a last resort when carrying out congestion management.

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