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Merchant transmission in single-price electricity markets with cost-based redispatch

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ABSTRACT

Transmission expansion is a complex problem in energy market design and research has not yet provided a market-based solution that is superior to a (partly) regulated approach. Furthermore, markets with a single market clearing price lack regional incentives for system friendly generation or transmission capacity expansion. In this paper, we propose a market design for transmission expansion that can be implemented in single-price markets with cost-based redispatch and we describe its properties. We show that our market solution is incentive compatible, satisfies the 'beneficiary pays' requirement and leads to a welfare optimal grid expansion otherwise achieved by an integrated optimization approach of a benevolent grid operator. We apply the mechanism to the German electricity system in 2018, 2019 and 2030 as an example and show that transmission capacity expansion is greatly reduced using the mechanism instead of a no-congestion regulation. We also test the robustness of the approach to erroneous generation capacity expectations and find that the impact on economic results is limited. Finally, we extend our approach to include congestion reducing generation capacity investment and discuss the strategic effects on a 6-node reference grid.

1. Introduction

As electricity systems evolve, their transmission capacity needs to be adapted to a changing generation infrastructure and changing consumption patterns (Orfanos et al., 2012). This is especially true today as renewable generation resources with intermittent generation are added to the system, often in the geographical periphery. Furthermore, new consumption patterns can be expected due to an electrification of the overall energy demand (Tröndle et al., 2020). Such changes become immediately apparent in markets that implement locational marginal pricing: Local scarcity or abundance is signaled through varying nodal prices and investment is encouraged where it is needed in the system (Schweppe et al., 2013). However, in markets with a single market clearing price, such changes are not equally reflected in the market results and spatial effects are ignored altogether (Weibelzahl, 2017). While increasing consumption might increase the clearing price and more renewables might decrease the price through the merit order effect in single-price electricity markets (Sensfuß et al., 2008), there are no spatial market signals that encourage system-friendly investment in generation capacity in specific regions or signals that reflect the value of specific transmission capacity. This causes problems as generation capacity investment and consumption patterns can diverge in a way that causes the market results in the single-price market to be no longer feasible in regards to the existing grid infrastructure leading to congestion. In such cases, most member states of the European Union apply so-called redispatch. Redispatch is performed by the transmission system operators (TSOs) which are unbundled from the generation side. They, therefore, plan their grids without definitive knowledge on generation capacity expansion (Meletiou et al., 2018). Redispatch is a change of the generation schedule from the economic dispatch to a dispatch that satisfies all system constraints. The performed mechanism is called cost-based redispatch if compensation is based on audited marginal costs of generation (Nüßler, 2012). This is true for instance in Germany. Besides the marginal costs, there are a few other components that factor into the compensation (see Staudt et al. (2018b) for details). Other EU member states use different procurement strategies such as France or the Netherlands (Poplavskaya et al., 2020). However, for this paper, we consider cost-based redispatch as it is the best reflection of welfare gains from transmission expansion for the system. For a power plant increasing its generation, cost-based redispatch would mean that its marginal costs of operation are covered. A power plant that decreases its generation, is allowed to keep the revenue awarded by the market but needs to reimburse the saved marginal costs of

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operation to the TSO. Therefore, a frictionless optimal cost-based redispatch eventually leads to a market result that would have been reached through a locational marginal pricing dispatch. The approach is similar to what was used in the Californian zonal market design. It similarly allows for inc–dec gaming (Alaywan et al., 2004) but not to the same extent (Staudt et al., 2018b). However, the costs for cost-based redispatch have useful properties. They can be used to incentivize an optimal expansion of transmission line capacity as we show in Section 3. These incentives can be used to create a merchant transmission investment market that incentivizes market participants to invest in the same transmission lines that would be expanded through an integrated approach taking both generation expansion and future consumption patterns into account. This way, decentralized decisions lead to an optimal overall transmission system expansion. Such a design reduces grid expansion to an economically reasonable minimum and eliminates the need for costly regulatory processes that currently determine the transmission grid capacity expansion. In the following sections, we introduce this market design and apply it to a model of the German electricity system. Using this example, we show the reduction of grid expansion compared to the current no-congestion regulation policy and determine the risk taken by investors in regards to wrongly anticipated generation expansion. The market design may be expanded beyond transmission capacity investment to congestion reducing generation capacity investment, which would, however, make it more complex and might allow for strategic gaming opportunities. We demonstrate this design including a compensation for well-positioned generation capacity on a 6-node network from Chao and Peck (1998). The presented mechanism introduces spatial market signals in single-price markets where the revenue awarded by the market is otherwise independent of location. It is, therefore, an alternative for markets that do not plan to introduce nodal pricing. However, in a static situation with no generation investment, the optimality of the transmission expansion incentives are equally optimal for markets that implement nodal pricing.

2. Transmission expansion planning

Transmission capacity expansion planning is a complex problem both from an economical as well as from a computational perspective (De La Torre et al., 2008). Therefore, it is often considered as an integrated problem and numerous models have been suggested to optimally expand transmission grids (Latorre et al., 2003). However, transmission grid expansion also has economic implications. In markets with nodal pricing, it causes feedback effects that make it difficult to anticipate the reaction of market participants (Sauma and Oren, 2009). Rising prices at low price nodes might cause new investments whereas additional demand might arise at previously higher priced nodes. Many authors have considered this problem but to this day there are in essence two economic approaches for the expansion of transmission capacity: (1) A regulated approach (Matschoss et al., 2019) and (2) a merchant transmission approach based on financial transmission rights (FTRs) (Hogan, 1999).

The regulated approach is based on an integrated perspective of the market. The TSOs or ISOs anticipate the future development of generation capacity and consumption and propose the expansion of the grid. This is often done in accordance with a regulatory body such as the BNetzA in Germany (Matschoss et al., 2019). If the current transmission system is insufficient and grid constraints are not considered at market clearing, congestion occurs which causes additional system costs. While in single-price markets, the cost for congestion is often socialized and everybody thus benefits from grid expansion, this is different in markets with nodal pricing where congestion has no explicit costs but causes higher nodal prices which result in congestion rent. This causes different incentives for market participants in regards to grid expansion even if an expansion would increase the total welfare (Sauma and Oren, 2009). With Order No. 1000, FERC has in essence adopted a *beneficiary pays* approach (Joskow, 2019). Such a design is difficult to uphold in practice (Schulte and Fletcher, 2020). However, this problem of nodal pricing systems is of no concern for this paper as the market incentives for transmission capacity expansion are more aligned in single-price electricity markets with cost-based redispatch as we discuss in the next section. Other regulation as for example in Germany, essentially requires TSOs to avoid congestion altogether (Weber et al., 2013). It has long been argued that such a policy is economically unreasonable (Lévêque, 2007), but such regulation establishing a *copper plate* electricity market within a bidding zone is still implemented in many European countries. Furthermore, the regulated approach that considers transmission systems to be natural monopolies often implements a revenue-cap regulation that guarantees a rate of return on equity (Kuosmanen and Nguyen, 2020). This incentivizes TSOs to inflate the need for transmission grid expansion whenever possible. Some scientists have, therefore, petitioned to change the design such that short-term redispatch is a valid alternative to long-term grid expansion if it is cost optimal (Kemfert et al., 2016). Our presented design takes this into consideration.

The so far suggested merchant approach is based on FTRs that cause payments to their owners in case of congestion on the corresponding transmission line based on the price differences between connected nodes (Kristiansen and Rosellón, 2006). These FTRs can be traded to hedge against price differences between system nodes. The payments for FTRs are based on the congestion rent that occurs because consumers at higher priced nodes pay more for the electricity at their node than the generators at lower priced nodes receive. This approach can, therefore, only be implemented in markets that employ a nodal pricing market design. One major drawback of the design is that the payments for FTRs might be insufficient to cover the investment costs for the line expansion (Rubio-Oderiz and Perez-Arriaga, 2000). Various authors have, therefore, proposed mixed designs between a merchant transmission investment based on FTRs and the regulatory approach with the most notable publication by Hogan et al. (2010). However, FTRs do not incentivize welfare optimal expansion. This is apparent when considering that congestion rent can only be paid if a transmission line is congested. Therefore, a merchant transmission approach based on FTRs would never cause any line to be built such that there is no more congestion even if it would be beneficial from a welfare perspective (Barmack et al., 2003).

Using redispatch as an indicator has been previously proposed in (Barmack et al., 2003) and in (Franken et al., 2018). In this paper, we are further adding to these approaches by proposing a market mechanism that is suited to use the costs for redispatch as a welfare optimal incentive for transmission capacity expansion. In the next section, we are laying the theoretical foundation.

3. Economics of redispatch

To demonstrate the economics of redispatch, we use the exemplary situation in Fig. 1 which can easily be generalized. Node 1 can be thought of as the grid with infinite generation capacity ($c_1 = \infty$) and no load ($d_1 = 0$). Node 2 is a local node with limited generation capacity $c_2 = C$ and some positive demand d_2. For simplicity, we assume that the local generation capacity is sufficient to cover the local demand ($C > D = d_2$). The transmission capacity from node 1 to node 2 is limited to a capacity of t_{12}. This reflects the limited transmission capacity to any one node in the grid. The marginal cost of generation at node 1 and at node 2 are linearly increasing with the parameters α at node 1 and β at node 2. This is a natural assumption as marginal cost of generation increase with increasing demand. Fig. 2 depicts this situation from an economic perspective. The increasing curve shows the increasing marginal generation costs at node 1 which has the slope of α. The decreasing curve shows the marginal generation cost that is avoided at node 2 through the transmission of generation from node 1 to node 2 with a slope of $-\beta$ starting at βD which is the marginal cost of the most expensive increment if all demand was covered at node 2. In a

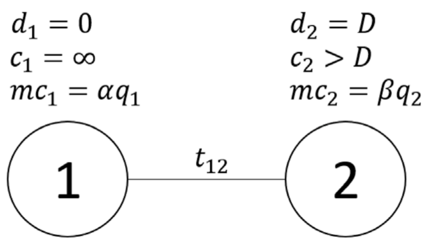


Fig. 1. Two node example of an electricity market.

system without transmission constraints, the generation at node 1 and node 2 would be such that the marginal cost at both nodes would be equal and the market would produce one market clearing price where the two curves intersect. It is the underlying assumption of single-price electricity markets that this optimum can always be reached with the given transmission infrastructure, which often refered to as the *copper plate* assumption. In Fig. 2, this optimal generation is $q_1^* = \frac{\beta D}{\alpha+\beta}$ and consequently $q_2^* = D - q_1^* = \frac{\alpha D}{\alpha+\beta}$. Now, we assume that the transmission capacity is lower than the generation at node 1 such that $t_{12} < q_1^*$. Therefore, the generation from node 1 cannot be fully transmitted to node 2. In a nodal system, this would be considered at market clearing and the generation at node 1 would be restricted to t_{12}. However, in a system with a single clearing price, redispatch needs to be performed in the amount of $q^{\Delta} = \frac{\beta D}{\alpha+\beta} - t_{12}$. In an ideal cost-based redispatch, the most expensive power plants that are still dispatched through the single-price market clearing decrease their generation. In the example of Fig. 1, this means that the generation with the highest marginal cost is ramped down until $q_1 = t_{12}$. The marginal cost they are reimbursing c^r_{down} is exactly the integral of the marginal cost curve of node 1 between t_{12} and q_1^* and, therefore, $c^r_{down} = \int_{t_{12}}^{q_1^*} mc_1(q_1)dq_1$. In Fig. 2, this is the dashed area below the marginal cost curve of node 1. Mathematically, it is easier to express this with linear marginal cost functions as we assume here but it can easily be transferred to the type of step-wise merit order supply curves that usually represent electricity markets. Now, we move on to the cost of increasing generation at node 2 to replace the ramped down capacity of node 1. The increasing generation needs to come from node 2. The elegance of the model in Fig. 2 is that the integral of the avoided marginal cost curve at node 2 in the same interval between t_{12} and q_1^* is the cost of ramping up power plants at node 2 c^r_{up} and it is thus $c^r_{up} = \int_{t_{12}}^{q_1^*} \beta D - mc_2(q_1)dq_1$. In Fig. 2, the sum of the checkered and dashed area represent these costs. Finally, we can calculate the cost of redispatch as $c^r = c^r_{up} - c^r_{down}$. This cost is shown in Fig. 2 as the checkered area. Besides being the cost of redispatch, this area is equivalent to the lost welfare due to the grid constraint of t_{12}. The checkered area above the single market clearing price p^* is the lost consumer surplus as the more expensive power plants are activated. The checkered area below p^* is lost producer surplus in theory. If the ramped-down power plants were to reimburse their entire market revenue, then they would lose the producer surplus they gained. However, as redispatch costs are socialized, the lost producer surplus is borne by consumers as well. This implies two things: (1) The congestion costs of an ideal cost-based redispatch are exactly equivalent to the lost welfare of a binding grid constraint and (2) this welfare loss is fully covered by consumers. Both properties qualify cost-based redispatch as a well-suited incentive for grid expansion.

4. Cost-based redispatch and transmission expansion

Given that redispatch costs of a cost-based redispatch are equivalent to the lost welfare induced by the transmission constraint, it is the correct incentive for its expansion. Compensating investors with the avoided costs of the cost-based redispatch exactly mirrors the welfare gain of the system achieved through the expansion. This also solves the problem of insufficient compensation through the mechanism that

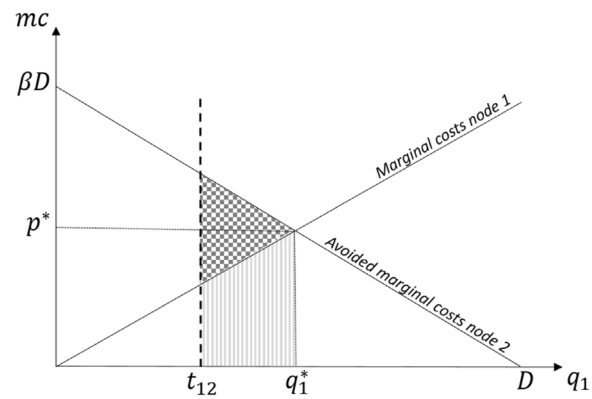


Fig. 2. Redispatch economics for the model in Fig. 1.

persists by using a merchant transmission approach with FTRs: If the compensation for a transmission line investment through avoided redispatch cost is not sufficient to cover the investment, then the welfare gain induced by this transmission line investment does not warrant the construction of the line. This facilitates the planning of transmission grid expansions as individual investors are free to decide whether they expect a grid expansion to be beneficial. If their forecasts of the development of generation and consumption are wrong, they incur a financial loss. Under the current regulation in Europe, the consumers bear the risk of incorrect forecasts by TSOs and wrongly approved grid expansions. The alignment of financial incentives for investors with a welfare optimal grid expansion can be further described by looking at the optimization function of a potential merchant transmission investor with revenue π and investment costs $\gamma = \sum_{l \in N_l} \tau_l^{exp} \cdot p_l^{exp}$ as the sum of the cost of investment over all lines l with τ_l^{exp} being the added capacity and p_l^{exp} being the cost of adding that capacity. Redispatch costs are, using a more general expression, $c^r = \sum_{t \in T}^{T} \sum_{i \in N_b} \sum_{j \in J_i} p_{i,j} \cdot q^{\Delta}_{i,j,t}$ the sum over the increased capacity multiplied with the marginal cost of generation minus the sum of the reduced capacity both denoted as $q^{\Delta}_{i,j,t}$ multiplied with its marginal cost of generation over all nodes i, generation units j at node i and time intervals t. Furthermore, we denote $c^{r,old}$ as the total redispatch cost before a grid expansion and $c^{r,new}$ as the redispatch costs after. Let T be the period over which the investment is considered and t one timestep in that period. Then, the investor intends to maximize its profits represented by revenue created through avoided redispatch minus the investment costs.

$$
\begin{aligned}
& max \sum_{T} \pi_t - \gamma_t \\
\Longleftrightarrow\ & max \sum_{t \in T} (c_t^{r,old} - c_t^{r,new}) - \gamma_t \\
\Longleftrightarrow\ & min \sum_{t \in T} (-c_t^{r,old} + c_t^{r,new}) + \gamma_t \\
\Longleftrightarrow\ & min \sum_{t \in T} (c_t^{r,new} + \gamma_t) - c_t^{r,old}
\end{aligned}
$$

Because the costs of redispatch before a line expansion $c^{r,old}$ are unaffected by the actions of the investor, its objective is to minimize the sum of redispatch costs and its investment as shown above, which is precisely the objective of an integrated optimization performed by a benevolent integrated system operator. This shows that using cost-based redispatch costs as the incentive for grid expansion provides optimal incentives from a welfare perspective without relying on central optimization. Investments that would lead to a negative outcome would not be undertaken such that $c_t^{r,new} = c_t^{r,old}$ and $\gamma_t = 0$. Therefore, reimbursing investors with saved redispatch costs leads to a welfare optimal grid expansion through decentralized decisions under the assumption of perfect foresight. Such a coordination can be best performed through a market which we describe in the remainder of this paper.

Furthermore, the fact that redispatch costs are currently socialized, causes the incentives of all market participants on the consumer side to be aligned from a financial standpoint. All customers are (equally) interested in a welfare optimizing grid expansion, no matter where in the system they are located depending on the redispatch cost distribution mechanism. At the same time, any generator should be agnostic to an expansion at least under an assumed optimal mechanism without friction.[1] In such a mechanism, redispatched power plants do not benefit from the cost-based redispatch. They are only reimbursed for costs that incur due to the redispatch which means that their profit is zero. Generators which are ordered to decrease their generation during the redispatch have the same profits as before as they need to reimburse any marginal generation costs. This does of course not include local opposition against transmission expansion, for example due to fear of impaired views of the landscape or environmental concerns.

Given these characteristics, we propose a three-stage market mechanism as depicted in Fig. 3. The first stage is the project identification. This step can be performed by any stakeholder in the market. It could be the regulator, consumers, investors or the TSOs among others. The more important task in this step is the project prioritization, which is performed by the regulator. As different projects influence each other because any addition of transmission capacity changes the nature of redispatch in the system, it is important to decide in which sequence projects are implemented. This question is not treated in this paper, but further research on how to schedule different expansion projects in the system is important in this context. We come back to discussing this in our exemplary case on the 6-node network in Section 6.

Once a project is identified and prioritized, it moves to the second stage of the market mechanism. In this stage, possible investors offer the time period during which they require to receive the saved redispatch costs induced by the project. This auction can easily be implemented as a Vickrey auction (Ausubel et al., 2006), ensuring incentive compatibility. More complex auctions that include several projects are possible and are subject of further investigation into the subject (see Stern and Turvey (2003) as a reference). The winner of the auction would then receive the saved redispatch costs for the time period of the bid of the runner-up. Note that this compensation does not include the operation of the newly constructed transmission capacity. Any additional grid capacity would be operated by the TSO which is responsible for the grid area where the expansion is performed. This TSO would be reimbursed through a regulated compensation as before. Only the investment is covered through the proposed mechanism. It needs to be discussed who would own the transmission capacity after the compensation period is over. It could be public property or it could be moved into the TSOs assets as compensation for the operation of the grid.

Finally, in the third stage, the winner of the auction in the second stage is compensated periodically once the project is finalized. Depending on the time resolution in which redispatch is performed e.g., in timesteps of 15 min, the necessary redispatch and its cost are calculated once with and once without the newly constructed transmission capacity. The difference in redispatch costs is paid to the investor. Note that additional transmission capacity may even cause higher redispatch costs due to the Braess paradox (Blumsack, 2006). In this case, the grid expansion investor would have to pay for the additional redispatch costs caused by the project because otherwise incentive-alignment would not be ensured. If this was not the case, an investor would then have an incentive of adding lines that cause congestion which can then be mitigated and compensated through other grid expansion projects. If different projects receive payments, they are compensated in the sequence of their approval i.e., every project is considered based on the known topology of the grid at the time when the project is auctioned. These payments are made for the period awarded in the auction. Once this period runs out, the customers profit from the installed grid capacity. Note that the customers only benefit from this system. Without the expansion, they would have to pay for the necessary redispatch. With the mechanism, they pay the same to the transmission capacity investor but only until the compensation period runs out. We now move on to simulating the mechanism on the German transmission grid.

5. Simulation on German transmission grid

In this section, we simulate the presented market mechanism using a representation of the German electricity system based on the ELMOD-DE model[2] (Egerer, 2016). We simulate the years 2018 and 2019 to show the short-term outcomes of the mechanism. We then simulate the year 2030 based on the current outlook for the transmission system of the German regulatory body BNetzA (Bundesnetzagentur, 2017). For the year 2030, we assume different regional investment paths in renewable generation capacity besides the base case. This allows us to better understand the consequences of investment decisions based on erroneous generation capacity expansion expectations. This perspective is important in order to judge the uncertainty associated with transmission expansion decisions. If in the long run an expanded line is not needed to reduce redispatch, this investment would not pay off. As transmission lines are usually depreciated over 40 years, a correct outlook is particularly important (Kemfert et al., 2016). The optimization problem of reducing redispatch while expanding the transmission grid economically to be solved by an investor is given in Eq. (1). Note that as shown before, this optimization problem is equivalent to the optimization problem of a benevolent integrated transmission system operator that intends to minimize its cost of transmission expansion without being able to expand generation capacity because the solution to this problem leads to the highest possible profit. We consider the more general case including the possibility of adding congestion reducing generation capacity in Section 6.

$$
\begin{aligned}
\min \quad & \sum_{t\in T}\sum_{i\in N_b}\sum_{j\in J_i} p_{i,j}\cdot q^{\Delta}_{i,j,t}\cdot a+\sum_{l\in N_l}\tau_l^{exp}\cdot p_l^{exp}\cdot y^{-1}\\
\text{s.t.} \quad & \sum_{i\in N_b}\sum_{j\in J_i} q^{\Delta}_{i,j,t}=0, \forall t\in T\\
& q_{i,j,t}+q^{\Delta}_{i,j,t}\le c_{i,j,t}, \forall i\in N_b, \forall j\in J_i, \forall t\in T\\
& q_{i,j,t}+q^{\Delta}_{i,j,t}\ge 0, \forall i\in N_b, \forall j\in J_i, \forall t\in T\\
& |\sum_{i\in N_b\setminus\{|N_b|\}} H_{(l,i)}\cdot(\sum_{j\in J_i}(q_{i,j,t}+q^{\Delta}_{i,j,t})-d_{i,t})|\\
& \quad \le(\tau_l+\tau_l^{exp}), \forall t\in T, \forall l\in N_l
\end{aligned}
\tag{1}
$$

$p_{i,j}$	Marginal cost of unit j at node i
$q^{\Delta}_{i,j,t}$	Redispatch at node i of unit j at time t
τ_l^{exp}	Expansion of line l
p_l^{exp}	Cost of expansion of line l per MW and period
$q_{i,j,t}$	Generation at node i of unit j at time t
$c_{i,j,t}$	Capacity of production unit j at node i (at time t for renewables)
H	Matrix of power distribution factors
$d_{i,t}$	Demand at node i at time t
τ_l	Transmission capacity of line l
N_b	Set of buses (nodes)
N_l	Set of lines
T	Set of considered timesteps
J_i	Set of generation units at node i
$N_b\setminus\{|N_b|\}$	Set of nodes without the slack node
y	Depreciation period
a	Weight of time period t within a year

[1] There are different redispatch regulations that include other payments than marginal generation costs (Staudt et al., 2018b).

[2] http://www.diw.de/elmod.

Fig. 3. Stages of merchant transmission expansion market mechanism.

The model includes 317 nodes and 472 lines. The entire transmission system is depicted in Fig. 4. Parallel lines that have the same start and end node are aggregated into one line. Line impedance is assumed to be equal for all lines. The model is limited to the German electricity system and cross-border connections are ignored. The original model from 2013 is updated with current generation capacities for all nodes based on the reports of the German regulatory body BNetzA (Bundesnetzagentur, 2019a). The capacities are allocated to the geographically closest transmission node. National wind and solar power generation and load data for 2018 and 2019 are provided by the BNetzA (Bundesnetzagentur, 2018) in an hourly resolution. The national load is distributed to the nodes based on the GDP of that region relative to the national GDP. This is a common approach (Leuthold et al., 2008). The wind and solar generation are distributed to the nodes based on the regionally installed capacity of wind and solar, respectively. This is the same approach that is used for the original ELMOD-DE model (Egerer, 2016). For 2030, the wind and solar generation data is scaled with the envisioned installed respective capacity in 2030 based on Bundesnetzagentur (2017) using the generation data from 2019. The generation is then distributed to the respective nodes by installed renewable generation capacity as for the years 2018 and 2019 thus assuming that the relative expansion is equivalent to the relative current capacity. In order to reduce the computational complexity, we use average days in the calculation. For each month of the year, an average generation day for wind and solar is calculated as the average generation over all days. This is reasonable for our use case as the optimal expansion is rather based on average system states than few peak events. We do the same for the consumption data. Here, we also distinguish weekdays and weekends leading to a total of 24 representative days for the year and, therefore, 576 timesteps in total considering an hourly resolution. It is important to note that averaging reduces the peaks in the system. Therefore, the optimal expansion that we determine later is already based on average values. The factor a in the optimization problem describes the weight of a specific timestep (i.e., how often it is repeated in a year). We ignore ramping constraints and idle time constraints of thermal power plants. The marginal costs of generation for conventional power are based on Leuthold et al. (2008). The marginal generation cost of wind and solar generation are assumed to be zero (Staudt et al., 2018a), the demand is assumed to be inelastic (Weidlich and Veit, 2008). The costs for a line expansion are based on the distance between two nodes calculated using the coordinates of the nodes and the haversine formula and on the cost values from Gunkel and Möst (2014). A line addition is assumed to give an additional capacity of 1.7 GW (Ekici, 2012). To reduce the computational complexity, the problem is formulated as a linear program rather than a mixed integer linear program meaning that the costs for a line expansion are relative to the added capacity. This means that small expansions that are usually not necessarily possible are still performed in the model. Such small expansions might, however, be facilitated through technological advances such as dynamic line rating (Foss and Maraio, 1990).

The current status of the system in the years 2018, 2019 and 2030 is shown in Table 1. The values show that congestion is being reduced

Table 1
Status quo of market outcomes in different years.

Status Quo	Redispatch	Redispatch cost	System costs single-price	System costs nodal
2018	5.1 TWh	0.76 bn	8.2 bn	8.9 bn
2019	4.6 TWh	0.74 bn	6.9 bn	7.6 bn
2030	2.9 TWh	0.37 bn	1.3 bn	1.6 bn

Table 2
Redispatch assuming expansions in a welfare optimizing market environment.

Base year	Optimal expansion	Opt. exp. redispatch	Opt. exp. yearly costs
2018	14.3 GW	3.8 TWh	0.02 bn
2019	14.7 GW	3.2 TWh	0.02 bn
2030	15.7 GW	1.8 TWh	0.03 bn

through a change in the generation structure alone. The amount of redispatch per year is reduced from 2018 to 2030. While the empirical amount of redispatch was slightly higher in 2018 (Bundesnetzagentur, 2019b), this can be attributed to the fact that we are smoothing out peaks through averaging the days for each month. The numbers also show that the total system costs are slightly higher for a system with a single-price and redispatch compared to a nodal pricing system. This is explained by the additional consumer surplus that generators reducing their infeed in the redispatch process get to keep. The system and redispatch costs decrease from 2018 to 2030. This can be explained by the additional renewable generation capacity in the generation mix. We are assuming the same generation costs for 2030 as for 2018. We do so, because our intention is not to give a realistic picture of the power market in 2030 (this is done, for example, in Boldt et al. (2012)) but to provide insights into the proposed market mechanism.

Table 2 shows the optimal expansion, the resulting remaining redispatch and the associated costs for each of the analyzed years individually. It shows that redispatch does not have to be reduced dramatically to reduce its costs. While redispatch is reduced by only 25%–38%, the costs of redispatch are reduced by over 90% for each considered year. This holds an important message. There is a need for a mechanism that differentiates between costly and cheap redispatch when transmission grid expansions are considered. The presented market mechanism balances expansion and redispatch costs such that they are socially optimal. One notable finding is that even the costs of redispatch do not necessarily imply a higher or lower welfare optimal grid expansion. The numbers show that the optimal grid expansion for 2030 is higher than for 2018 and 2019 even though the projected costs of redispatch are much lower. This comes from the fact that the gradient in costs between intermittent renewable generation and local conventional generation is high and thus justifies an increased grid expansion.

If we consider that the grid is expanded sequentially as new information becomes available, we have to simulate the expansion consecutively by updating the transmission capacity after each year. Table 3 shows the corresponding results. The table shows the optimal expansion in every year as well as the total costs of the expansion both for the

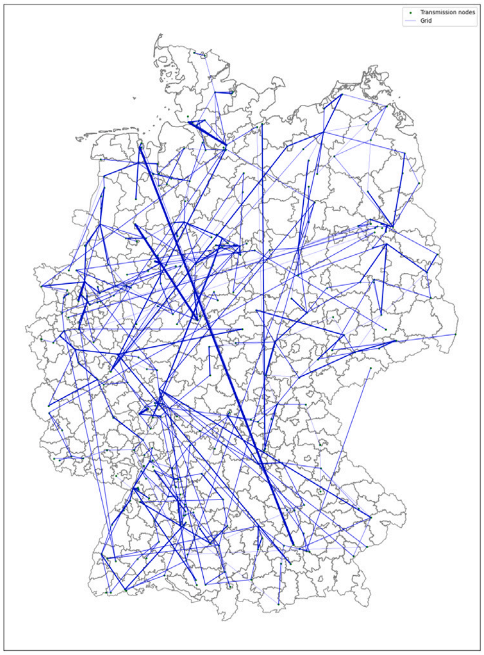


Fig. 4. Model of the German transmission grid.

Table 3
Expansion and Compensation Base Scenario.

Year	Opt. expansion	Opt. Exp. costs	Max. expansion	Compensation
2018	14.3 GW	0.36 bn	21.7 GW	–
2019	1.2 GW	0.02 bn	0.9 GW	2018: 0.73 bn
2030	3.9 GW	0.22 bn	5.8 GW	2018: 0.28 bn 2019: 0.02 bn

described market-based approach and for a no-congestion regulatory approach (max. expansion). The results show that the expansion in 2018 would be around 50% higher under a no-congestion regime. This is true even though generation and consumption peaks have already been averaged. Consequently, the expansion in 2019 is slightly lower for the no-congestion regulation as most expansion is already performed in 2018. For 2030, the no-congestion expansion is again about 50% higher. Finally, the table also shows the compensation for the optimal expansion using the market-based design in consecutive years. As you can see, the cost of the optimal expansion in 2018 is already covered in 2019. The 2019 expansion is also compensated for the entire investment in one year based on the 2030 results. Fig. 5(a) shows the grid expansion if consecutive actions are taken based on the proposed market mechanism in the years 2018, 2019 and 2030. Note that the thickness of lines in Fig. 5 is 1/20 of the thickness in Fig. 4 in order to allow for a better visibility of small expansion. The expansion in Fig. 5(a) is optimal under the assumption that market actors assume the current congestion situation in each of these years to persist and invest correspondingly. Fig. 5(b) shows the **additional** expansion in the system if the regulatory intention is that no congestion should occur. Please note again that we use average consumption and generation data for each month of the year which in itself does already smooth peak situations. Therefore, the difference in Fig. 5(b) is such that it addresses commonly occurring congestion which should, however, still not be reduced from an economic perspective. In comparison to the expansion costs shown in Table 3, an expansion to avoid congestion altogether would increase the expansion costs to 0.64 billion Euros in 2018, 0.05 billion in 2019 and 0.37 billion in 2030.

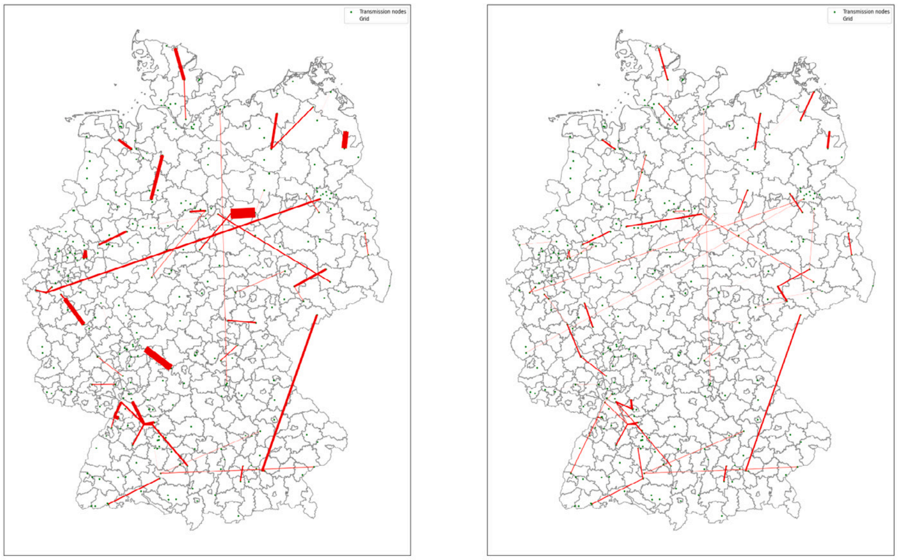
Finally, we evaluate the effects of erroneous forecasts of generation expansion by investors on the payback for transmission expansion investments. To do so, we simulate an expansion for the year 2030 without previous investments in 2018 and 2019. The optimal expansion then amounts to 0.5 billion Euros. This investment is based on the expected distribution of generation capacity in 2030. In this simulation, we assume a constant conventional generation capacity but an increase in solar and wind generation capacity proportional to the currently installed renewable generation capacity meaning that the distribution of total wind and solar generation capacity over all transmission grid nodes remains unchanged. Again, we do not claim this to be an adequate forecast of the generation capacity in 2030 nor is this the objective of this analysis. It is rather our intention to show possible consequences of implementing the proposed market mechanism. We then assume two additional different distributions of newly installed generation capacity from wind and solar. One is that the newly installed capacity is equally distributed over all nodes. The other assumed distribution is inversely proportional to the current distribution in the way that newly installed capacity is placed at nodes with currently very little wind and solar PV capacity. Both assumptions are unlikely for obvious reasons. Certain geographical areas are more favorable for wind and solar generation, which is why the majority of generation capacity is installed at the corresponding nodes. Therefore, this analysis can be regarded as a worst case for transmission capacity investors. In reality, the future expansion of renewables is much easier to anticipate. Table 4 shows the results of the analysis. In the base case, the investors would receive 0.37 billion Euros in the year 2030 for their investment. Note that this is the yearly payout such that we would expect the payouts to cover the 0.5 billion Euros of investment easily over the course of up to 40 years. However, even with the less beneficial future distributions of renewable generation capacity expansion, the investors could still easily cover their investment. While the payout in case of an inversely proportional generation capacity expansion is only about a third of the payout for the expected expansion, it is still sufficient to cover the investment over the course of the depreciation period. Furthermore, it has to be noted that a grid capacity expansion today with subsequent inversely proportional expansion would still lead to payouts under the current distribution of generation capacity for many years before 2030. However, investors certainly need to plan for such contingencies and adapt their bidding correspondingly. However, these are individual managerial decisions and should be left to the individual. It is important to note that such risk is currently borne by consumers and would be moved to investors using the proposed market mechanism.

Table 4
Compensation for expansion based current capacity distribution.

Renewable expansion scenario	Compensation
Expected distribution	0.37 bn
Equal capacity expansion	0.20 bn
Inversely proportional expansion	0.12 bn

6. Reducing congestion through generation expansion

In the previous sections, we discuss payments to investors of transmission capacity for redispatch reducing investments. However, similar payments are conceivable for investors of generation capacity. The dilemma of single-price electricity markets is the lack of regional investment incentives. A new power plant or renewable generation capacity are not necessarily installed where they are most valuable for the system because there are no economic incentives for an operator to consider system-optimal siting of generation capacity. The described incentive of paying out saved redispatch costs to welfare increasing infrastructure can be transferred to generation capacity. If generation capacity is specifically sited such that it reduces network congestion, the reduced congestion costs could be paid out to the operator or



(a) Expansion market-based approach

(b) Additional expansion no-congestion regulation

Fig. 5. Comparison between a market-based transmission grid expansion and a no-congestion regulated approach.

investor. This would even give incentives to bid into the market below marginal costs in order to be in the market to benefit from the payments for reducing congestion. In order to evaluate and discuss such a system, we simulate the approach using an adapted version of the 6-node example grid from Chao and Peck (1998). The system and its properties are shown in Fig. 6.

We slightly modify the original example to allow for more congestion to be reduced. Throughout the system, all demand is located at node 4 with 400 MWh. The cheapest supply is located on the opposite side at node 3 with a generation capacity of 400 MW and marginal costs of generation of 10$/MWh. Additional supply of 400 MW is available at node 4 at a cost of 80 $/MWh and there is one other small generator at node 4 who can generate 10 MW at 9$ per MWh. This ensures that the demand can always be covered regardless of the congestion in the grid.

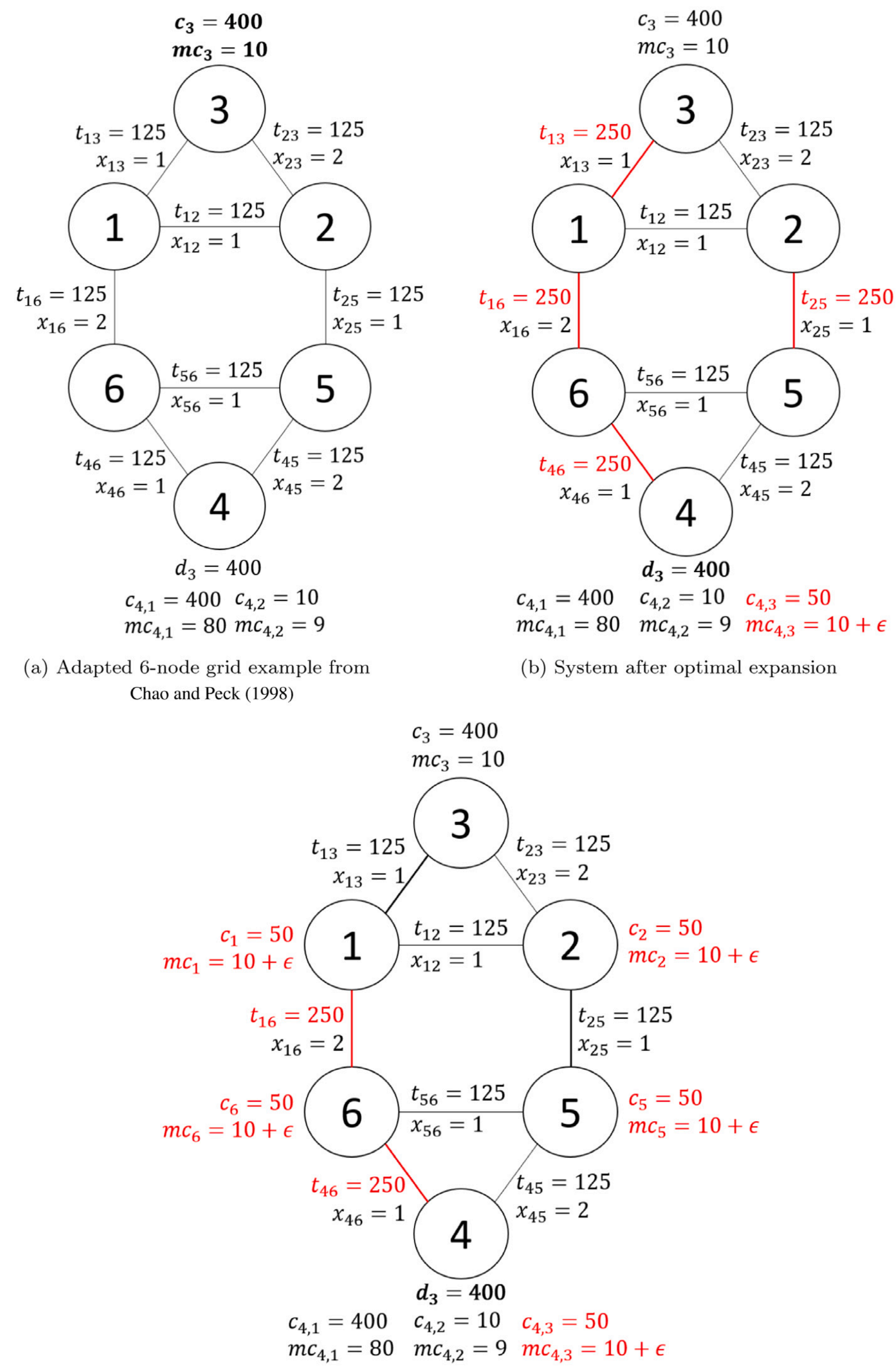
We now design the system expansion options. Note that these options are obviously only examples and a variety of other options is possible. Neither are the expansion costs necessarily correct. This serves as an illustration of the market design rather than a realistic example of an actual electricity market. Every transmission line capacity can be doubled to 250 MW. Such an expansion has a cost of 1000 $. Additionally, a generation unit can be installed at every node with a generation capacity of 50 MW also for a cost of 1000 $. The marginal cost of additional generation for this capacity mc_a is set to the current single market price p_s plus an increment ϵ such that $mc_a = p_s + \epsilon$. This is done in order to ensure that an addition of this capacity is not already welfare increasing without considering congestion and would theoretically be out of the market. For both investments, we assume a depreciation period of 20 time steps and an interest rate of zero such that the depreciation occurs constantly over the time horizon. Note that in both cases, the investment decision is binary.

Given the described system and options, we first optimize the system using a welfare maximizing nodal pricing formulation. This gives us the optimal expansion under a nodal pricing market design with optimal grid expansion. The formulation is given in Eq. (2).

$$
\begin{aligned}
\min \quad & \sum_{i \in N_b} \sum_{j \in J_i^{exp}} p_{i,j} \cdot qi,j + \sum_{l \in N_l} p_l^{exp} \cdot x_l^{exp} \cdot y^{-1} + \sum_{i \in N_b} \sum_{j \in J_i^{exp}} p_{i,j}^{exp} \cdot g_{i,j}^{exp} \\
\text{s.t.} \quad & \sum_{i \in N_b} \sum_{j \in J_i^{exp}} q_{i,j} = \sum_{i \in N_b} d_i \\
& q_{i,j} \leq c_{i,j} \cdot g_{i,j}^{exp}, \forall i \in N_b, \forall j \in J_i^{exp} \\
& q_{i,j} \geq 0, \forall i \in N_b, \forall j \in J_i^{exp} \\
& \left| \sum_{i \in N_b \setminus \{|N_b|\}} H_{(l,i)} \cdot \left(\sum_{j \in J_i} (q_{i,j} - d_i) \right) \right| \\
& \leq (\tau_l + \tau_l^{exp} \cdot x_l), \forall l \in N_l
\end{aligned}
\tag{2}
$$

x_l^{exp}	Binary decision variable for line expansion
p_l^{exp}	Cost of expanding line l
$g_{i,j}^{exp}$	Binary decision variable for generation expansion
$p_{i,j}^{exp}$	Cost of expanding generation capacity $c_{i,j}$, 0 for existing units
J_i^{exp}	Set of generation units at node i including possible expansions

Once we have a welfare optimal result, we implement the redispatch compensation-based market design. The expansion options are implemented consecutively in the order of their anticipated amortization period from shortest to longest. This way, we cannot only demonstrate the mechanism but also test whether a sequence of measures given a decision rule for prioritizing also reaches optimality. To determine which expansion is executed next, we calculate the amortization time for each measure. We calculate the redispatch cost for the status quo and then individually calculate it for adding any of the possible measures. If generation capacity is evaluated, its marginal cost of production are virtually set to slightly below the market price such that $mc_a = p_s - \epsilon$ to ensure that the capacity enters the market. The incurred loss of 2ϵ caused by offering capacity below the marginal cost is considered in the amortization time. The amortization time is then calculated as the ratio of the sum of the expansion cost c_i^e of measure i and the cost caused by offering capacity below the marginal cost of generation c_i^{marg} if the measure is generation expansion and the saved redispatch through measure i r_i^s per period such that $t_a = \frac{c_i^e + c_i^{marg}}{r_i^s}$. We then add



(a) Adapted 6-node grid example from Chao and Peck (1998)

(b) System after optimal expansion

(c) System after sequential market expansion

Fig. 6. Combining congestion reducing transmission and generation expansion.

the measure with the lowest amortization time t_a that is both positive and lower than the depreciation period (the amortization period can be negative if a measure makes additional redispatch necessary). We then add the expansion measure with the lowest amortization time and move on to the next round until no measure can further decrease the redispatch. This sequence is described in Algorithm 1.

The results of both, the nodal optimization and the sequential market approach are shown in Table 5, the resulting systems are shown in Fig. 6(b) for the optimal nodal solution and Fig. 6(c) for the sequential solution based on saved redispatch cost compensation. The results reveal that the market mechanism with the sequential execution of expansion measures does not lead to the welfare optimal solution. This shows that individual measures are not necessarily welfare optimal and that expansion bundles should always be possible in order to come to an optimal solution. In other words, investors should be able to bid multiple projects into the mechanism at once. Note that the initial expansion of the generation capacity at node 4 has a lower amortization time than the overall optimal nodal expansion as shown in Table 5. Therefore, it is possible that this expansion would be performed individually. However, as this generation expansion is part of the optimal expansion set, the remaining expansions can still be performed achieving an optimal social welfare. This optimal bundle leads to a lower amortization period than the remaining choices for

Table 5
Sequential and optimal transmission and generation expansion in the 6 node example network.

Expansion step	Expansion measure	Remaining redispatch	Investor payments	Amortization period
0	Initialization	13550	0	0
1	Generation Node 4	10050	3500	0.29
2	Generation Node 5	9425	625	1.60
3	Transmission Line 4–6	6675	2750	0.36
4	Generation Node 6	3113	3563	0.28
5	Generation Node 2	467	2646	0.38
6	Transmission Line 1–3	238	229	4.36
7	Generation Node 1	0	238	4.21
Optimal	See Fig. 6(b)	0	13550	0.37

the sequential market-based mechanism. The market would thus lead to an optimal expansion if expansion bundles were possible.

Finally, we want to discuss the difficulty of using the proposed market mechanism for generation resources instead of transmission capacity. To do so, we assume that the operator of the cheapest 10 MW of generation capacity at node 4 is also the investor into the congestion reducing measures in the optimally expanded system of Fig. 6(b). This operator now has the option to exacerbate congestion in order to achieve an additional profit. If the operator withholds the 10 MW of cheap capacity at node 4 from the , then the resulting redispatch cost is 437.5 \$. If the capacity is not withheld, there is no congestion. However, the virtual redispatch cost without the newly added capacity when the 10 MW are withheld is 14,250 \$ compared to 13,550 \$ if the capacity is in the market. Therefore, if the capacity is not withheld, the saved redispatch payment to the operator equals 13,550 \$. If it is withheld, the operator receives 13,812.5 \$. The profit the operator would make by offering the capacity in the market is 10 \$ because the market price is 10 \$ and the marginal generation costs of the cheap capacity is 9 \$ with 10 MW capacity. Therefore, the operator would knowingly increase congestion in the system reducing the system's efficiency. A similar behavior is not possible when investors only invest in transmission capacity as it is controlled by regulated TSOs.

Data: Network, Generation capacity, Demand
Main: Main
expansion = True;
while *expansion* **do**
  marketResult = SinglePriceMeritOrder();
  redispatchOrig = Redispatch(marketResult);
  for *(t = 1 to len(ExpOptions))* **do**
    if *ExpOptions[t].type == generation* **then**
      ExpOptions[t].marginalCost = marketResult.price - ϵ
    end
    redispatchExpansion[t] = Redispatch(ExpOptions[t]);
    amortizationTime[t] = $\frac{investCost[t]+reducedMarginalCost[t]}{redispatchOrig-redispatchExpansion[t]}$;
    if $amortizationTime[t] < 0$ **then**
      amortizationTime[t] = deprecPeriod + 1;
    end
  end
  if $min(amortizationTime) \leq deprecPeriod$ **then**
    performExpansion(amortizationTime);
  else
    expansion = False;
  end
end

Algorithm 1: Market-based capacity expansion algorithm

In conclusion, this section has four essential takeaways. First, using the proposed market mechanism for merchant transmission reduces grid expansion when compared to a no-congestion policy as redispatch is accepted as a valid alternative. Second, the risk that investors take through investing in transmission capacity is limited and can be managed through their bidding behavior. Even an expansion that is contrary to the expectations, which is unlikely for renewable generation, does not necessarily eliminate payments. Third, projects should always be allowed to be composed of multiple measures in order to achieve a welfare optimal expansion and the optimal prioritization of projects is subject to future research. And last, including congestion payments to investors in generation capacity is problematic from a market perspective as it allows for strategic behaviour if the operators own further resources in the system. In the next section, we discuss shortcomings of the proposed mechanism and necessary further research.

7. Discussion

In this paper, we describe a market mechanism that incentivizes welfare optimal grid expansion that can be applied to single-price electricity markets with cost-based redispatch. As mentioned several times in the previous chapters, there are further aspects to consider before implementing this mechanism. In this section, we briefly discuss these aspects as well as limitations of our results.

One of the major open issues regarding the market mechanism is the sequence in which projects are prioritized. The idea is that projects can be proposed by anyone. The beauty of the mechanism is that any investor is always only paid what consumers would pay anyway if the expansion did not occur and the corresponding risk is borne by the investors. However, to achieve a welfare optimal expansion, it matters which expansion project is performed first and this prioritization impacts the profitability of other projects. Therefore, the regulator has to decide on the sequence of projects. As shown in the 6-node example of the last section, a prioritization of individual projects based on the shortest bid amortization times is not optimal. However, if projects including several measures are permitted, the mechanism will lead to a welfare optimal expansion by prioritizing according to amortization time, always assuming that the optimal expansion is among the proposed projects at all. However, contrary to our example, bids in reality would be greatly influenced by expectations and it is, therefore, much more complicated to prioritize correctly. This remains an open question for further research.

Another problematic aspect is the incentive for lobbying activities by investors. Once first projects are implemented, investors in transmission grid capacity have an incentive to steer generation capacity expansion such that it benefits their project. They could fund lobbying activities that block generation expansion projects in certain locations and lobby for other, possibly less valuable projects from a welfare perspective, to increase the payback for their investment. One could argue that this only persist until the end of the payback period. However, diverging interests across the system could make generation expansion a difficult task. This is a similar problem as for systems with nodal pricing, where generation expansion at certain nodes causes local prices to fall and similar approaches would have to be undertaken to overcome such lobbying.

At their core, both described problems are related to the optimal system expansion overall. It is important to note that the described market mechanism while being optimal in theory does not necessarily ensure an optimal system expansion in practice. Given any spatially distributed pattern of demand and supply, it leads to an optimal grid expansion serving this pattern. However, the transmission system expansion only reacts to exogenous generation capacity expansion. This is worth a discussion because the integrated optimal expansion of the power system is neither correctly incentivized in nodal price systems nor in single-price systems. In nodal price systems, generation and consumption are incentivized to move to specific nodes with preferential prices. However, there is no market mechanism that would balance this movement with transmission expansion which might sometimes be the preferential option. In single-price electricity markets there is currently no spatial incentive at all. Neither transmission expansion, nor generation and consumption are incentivized to consider system optimality. The proposed market mechanism, therefore, increases the system expansion optimality somewhat even though it does not necessarily lead to an optimal integrated expansion or siting of supply, demand and transmission capacity. However, it does incentivize an optimal expansion of transmission capacity as a reaction to an exogenously given, spatially distributed supply and demand.

As discussed for nodal pricing, the proposed mechanism can only be directly applied to single-price market zones. Whenever a price differential due to congestion occurs, there is no longer an explicit congestion cost that could be distributed to investors. Therefore, the proposed mechanism does not directly solve the problem of cross-border capacity investment in the European Union (as discussed for example in Olmos et al. (2018)). However, there might be an indirect effect. Given that investors are compensated for congestion in the transmission grid of a zone, this might incentivize them to try to increase this congestion. We already discussed that they cannot be allowed to invest in generation capacity. They can however increase congestion by increasing cross-border capacity to other market zones. The increased power flows from other low-priced market zones could increase congestion within the zone they invested in. However, it remains to be shown that this is still welfare optimal.

Furthermore, an important aspect to consider is the decommissioning of power plants. The proposed mechanism is intended to react to future developments of generation and demand. If generation capacity is expanded or demand shifts, the payments to the investors change either to or against their benefit. It is the task of the investors to correctly anticipate the development and factor in the risk into their bids. However, it is possible that regional, uneconomical power plants are no longer necessary due to transmission grid expansion. Usually, the regulator would hinder these power plants from being decommissioned. However, if such power plants were decommissioned as a reaction to new transmission capacity, then local virtual redispatch might no longer be possible or lead to prohibitively high payments. This in turn would result in large payments to transmission investors that are no longer justified by the market. Therefore, the available generation capacity needs to form a lower bound at construction of any new transmission capacity and only newly constructed generation capacity or new demand can be considered in calculating the avoided redispatch.

As shown in the example for generation expansion as a congestion reducing measure, strategic incentives between generation capacity operators and the capacity expansion market for congestion arise. This is similarly true for collusion between transmission capacity investors and generation operators. If operators are aware of new generation capacity expansion projects, they could pass on this knowledge to transmission investors, allowing them to bid on transmission capacity that no one else considers. Therefore, the unbundling regulation between system operators and generators needs to be strictly enforced, preventing any kind of gaming on the market.

Finally, it is unclear which agents would be active on such a market and whether it is possible to ensure sufficient competition between investors. Mostly, it is unclear whether the uncertainty of future generation and demand leads to high risks and, therefore, high capital costs for investment. However, as shown in the case study of the German system, even a grossly incorrect prediction might not considerably impact the return on an investment. The regulator might also reduce the risk by giving certain guarantees but this would have to be further evaluated in practice. Finally, it has to be noted that the risk of unprofitable investment is equally present today but is fully borne by consumers. The new mechanism provides profit opportunities to investors but also shifts the risk away from consumers.

Regarding the case studies, we want to emphasize that these are not meant to provide an outlook on the German transmission system or simulate the actual cost structure on electricity markets. Both examples, the case study for the German transmission system and the 6-node network, are meant to demonstrate the mechanics of the proposed market mechanism. It needs to be emphasized that such a market leads to a welfare optimal expansion only under the assumption that other spatial price components (e.g., LMPs) are not introduced. While in systems with spatial price components or with a market-based redispatch, cost-based redispatch is still the economically correct incentive for grid expansion, differing nodal prices, for instance, are already a welfare optimal signal for location specific generation and consumption investments. Both mechanisms cannot be combined as the incentive structure for customers would then no longer be aligned. Further research should focus on an optimal scheduling of expansion projects and regulation in which the transmission expansion market can be embedded.

8. Conclusion

In this study, we introduce a market mechanism that leads to the welfare optimal expansion of transmission capacity in systems with a single-price electricity market using cost-based redispatch. We introduce the market mechanism along the economics of cost-based redispatch and show that the resulting incentives coincide with a welfare optimal expansion of a benevolent transmission system operator. To demonstrate the mechanics of the market mechanism, we apply it to the German transmission system in the years 2018, 2019 and 2030. For the latter, we assume future generation capacities based on current federal scenarios. We show that by applying the mechanism, the expansion in transmission grid capacity is reduced by roughly 30%. Furthermore, the example helps us to show that an erroneous expectation of future generation capacity expansion poses limited risk. Additionally, we apply the market mechanism to a known 6-node example to assess the possibility of compensating beneficially sited generation capacity using the mechanism. However, using the example, we can show that including generation capacity can lead to adverse strategic incentives. Furthermore, using the example, we can demonstrate that expansion projects need to allow for composite expansion projects as welfare optimality can otherwise not be guaranteed. The presented study leaves several routes for further research, most notably the analysis of an optimal prioritization sequence for the regulator to choose between different proposed transmission capacity expansion projects. The presented market design and the results of this study are a contribution to include spatial investment incentives in markets with a single electricity market clearing price experiencing congestion. They are, therefore, an important advancement in times of increasing investment in spatially distributed intermittent renewable generation capacity.

CRediT authorship contribution statement

Philipp Staudt: Conceptualization, Methodology, Validation, Formal analysis, Data curation, Writing - original draft, Writing - review & editing, Visualization. **Shmuel S. Oren:** Conceptualization, Methodology, Writing - review & editing.

Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.eneco.2021.105610.

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