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A welfare analysis of electricity transmission planning in Germany[☆]

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HIGHLIGHTS

- Analyze planning and regulatory regimes for electricity transmission in Germany.
- Modeling setup to analyze transmission planning process NEP (*Netzentwicklungsplan*).
- The NEP suggests excessive network expansion.
- Alternative integrated generation-transmission optimization enhances welfare.
- Transmission investment needs should be reconsidered.

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ABSTRACT

We analyze the electricity transmission planning process in Germany (*Netzentwicklungsplan*), which separates transmission expansion decisions from generation dispatch. We employ an economic modeling approach to analyze two different network planning settings. In the first setting, there is no trade-off between transmission network development and generation dispatch, as is currently the case in Germany. A second setting alternatively allows for such a trade-off, and thus represents a welfare superior way of transmission network planning. Applications with the two model variants are carried out for the German electricity system in 2035. The results illustrate overinvestment in transmission capacity and decreased welfare associated with the *Netzentwicklungsplan*.

1. Introduction

The German energy transition (*Energiewende*) is a cornerstone of the national energy policy with the main aim to steadily increase the share of renewable energy in the electricity sector to 40–45% in 2020, 55–60% in 2030 and at least 80% by 2050. Wind power and photovoltaics are the most important renewable energy sources due to the limited potential of other renewable sources like biomass or hydro power. However, these sources are characterized by differing regional potentials, thus implying a significant change in the spatial generation pattern in Germany. Hence, the German energy transition requires both an expansion and a reshaping of the current transmission network to specifically accommodate the integration of increasing renewable energy sources.

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The German transmission system follows a TSO approach,[3] with its grids owned by four different TSOs. With the amendment of the electricity law (*EnWG*) in 2011, a structured and coordinated network planning approach was implemented, and TSOs are obliged to annually prepare a network development plan *Netzentwicklungsplan* (*NEP*). The planning approach starts with the development of the scenario framework by the TSOs. It includes generation and demand forecasts and scenarios for two future years, 10 and 20 years ahead. Subsequently, the scenario framework is publicly consulted and finally approved by the federal network regulator Bundesnetzagentur (BNetzA). Based on generation and demand forecast and scenarios, the TSOs perform model calculations and develop an initial draft of the *NEP*, which specifies the detailed expansion needs of the German transmission network. The initial draft is then again published for consultation with stakeholders, and finally approved by BNetzA. The entire planning process is repeated biennially for a time horizon of 10–20 years.[4]

Unlike many other international electricity market cases,[5] the *NEP* is determined by a program that is independent from generation-power market dispatch. The basic logic is reasoned by the European market design which differentiates between the management of international and national congestion issues.[6] It basically means that TSOs first determine the generation commitment and dispatch subject to restrictions on international trade between different bidding zones.[7] Given the national generation commitments, the future network usage is determined and network expansion needs are identified in a second step that ensures the feasibility of the generation dispatch. A cost-benefit analysis of individual line expansions with alternative congestion management options, like redispatch of generation and/or temporary reduction of renewable generation, is not performed. Therefore, the *NEP* ensures the feasibility of the least-cost generation dispatch, thus implying a network expansion towards a congestion-free transmission network.

The separated generation and network planning approach of the *NEP* (meaning the non-consideration of alternative congestion management options) is reasoned by the fact that network planning is mainly performed by abstracting from uncertainties about future developments. Therefore, alternative congestion management approaches are often seen as alternatives to deal with inherent uncertainties (e.g. short-term changes on generation dispatch due to unplanned outages) or deviations from network planning assumptions, which could not be captured in the *NEP* transmission planning process. Hence, congestion management is currently rather an alternative of last resort to deal with short-term network infeasibilities than a decision-relevant alternative to network expansion within the network planning approach. However, from an economic point of view it is still questionable if the transmission network and planned expansion should aim at a congestion-free transmission network and what are the associated costs and benefits of individual network expansions. In the German discussion and *NEP* process, a quantification of the expansion costs and system benefits could guide the regulator to approve or deny specific expansion projects.[8]

From a theoretical perspective, congestion management can be seen as a substitute for transmission expansion. Thus, the optimal level of network expansion is defined by the minimum level of both congestion management and network expansion cost. As transmission expansion cost increase and congestion management costs decline in the amount of new built transmission capacity a cost-minimal combination should include both options rather than just one option. More practically speaking, resolving a temporary congestion on a single line and in a single hour during a year through congestion management might come at lower cost than expanding the single line. Thus, optimal transmission expansion should not totally eliminate congestion in the transmission network (Stoft, 2006), but rather optimally balance both substitutes.[9]

The above somewhat crude naïve intuition should be formally confronted with a welfare-benchmark analysis that evaluates efficiency losses associated with the proposed *NEP* specific network expansions. Such a model should first carry out a transition from the current German uniform-pricing scheme to a nodal-pricing regime so as to be able to gauge the shadow value of network congestion, and be able to evaluate welfare efficiency in expanding transmission links (as in Hogan et al. (2010)).[10] This also implies a counterfactual where a hypothetical ISO maximizes welfare in an integrated transmission generation-dispatch power-flow model. The basic idea is then to compare the network expansions proposed under *NEP* with the welfare-benchmark case simulations derived from this modeling strategy.[11] In the academic literature, several studies investigate optimal transmission expansion, especially in the context of increasing renewable generation shares.

[3] There are basically in practice two institutional regimes in electricity transmission: the transmission-system-operator (TSO) regime, where system operation and ownership of the grid are integrated into a single company, and the independent-system-operator (ISO) regime, where the ISO takes care of system-operation grid while ownership remains within the transmission company (Transco). The ISO regime is popular in many countries throughout the Americas (Argentina, Chile, Brazil and Mexico), US states (Texas, California, New York, New England, Pennsylvania-New Jersey-Maryland (PJM) and Mid-West), Canadian provinces (Ontario, Alberta), Australia, and even some European countries (Ireland and Switzerland). Most of Europe is characterized by TSOs that own networks, plan the grid's expansion, and carry out the operation of the system (including generation dispatch).

[4] Once the *NEP* determines the plan for transmission expansion, the TSOs' role is to implement such projects and charge prices subject to regulatory constraints. Cost-plus regulation is used to regulate capacity-expansion costs, while revenue-cap regulation is, in turn, applied to O&M costs. DENA-Verteilnetzstudie (2012) supports the cost-plus regime for transmission investment costs, but Weber et al. (2013) argue that such regime incents TSOs tend to inflate costs and not to expand network capacity where it is most needed; namely, in a north-to-south corridor to bring into the populated southern consumption areas large amounts of wind power generated in the north.

[5] See Rosellón et al. (2011), Rosellón and Weigt (2011), and Schill et al. (2015).

[6] International transmission between two bidding zones is handled by explicit and implicit capacity auctions prior or during the spot market clearing. Contrarily, national congestion is mostly resolved after spot market clearing using curative congestion management approaches like redispatch, network topology adjustments, and/or reduction of renewable supply.

[7] In 2015, bidding zones are mostly defined by administrative or national borders and do not necessarily match with regional congestion pattern. With the adoption of the Network Code on Capacity Allocation and Congestion Management (NC CACM) in 2014 a review of the current bidding zones has been initiated.

[8] A cost-benefit-analysis is performed for instance within the European ten-year-network-planning approach (TYNDP) by ENTSO-E and provides an assessment of expected benefits of expansion projects. A similar analysis is recently implemented in the German *NEP* 2025, but only applied to selected expansion projects.

[9] For further analyses on optimal transmission expansion planning see: de Oliveira et al. (2005), Sauma and Oren (2006, 2009).

[10] One step in that direction is made by Kunz et al. (2014). One important output of such transitional model would be the determination of FTRs that, among other things, might be used to model transmission point-to-point outputs in a welfare maximizing bi-level model (see Hogan et al. (2010) and Rosellón and Weigt (2011)). Jenabi et al. (2013) further propose a bi-level model for optimal transmission network expansion by the transmission company, anticipating investment of competitive generation companies.

[11] Grimm et al. (2015) propose a model to analyze the long-run impact of regulation on transmission line expansion and investment by private firms in generation capacity. Investment decisions are carried out under expectation of an energy-only market and cost-based redispatch. Outcomes are as well compared with a first-best benchmark of integrated planner problem. They find excessive network expansion due to the energy-only assumption, while market-splitting might ameliorate excessive transmission investment. Trepper et al. (2015) further analyze market-splitting in Germany.

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Baringo and Conejo (2012) build a model to identify the optimal wind projects to be developed and the required network reinforcements, together with an array of subsidies to promote independent wind power investment. van der Weijde et al. (2012) present a stochastic two-stage optimization model to analyze transmission planning under uncertainty, and show that ignoring risk in planning transmission for renewables might yield decisions that have lower expected costs than traditional deterministic planning methods. Kunz (2013) analyzes the German approach to congestion management and finds that congestion and associated costs increase due to higher renewable generation shares. In the same line, Schroeder et al. (2013) develop an optimization model and analyze the future level of congestion with different scenarios for transmission expansions. It is pointed out that increasing renewable generation requires a reshaping of the national transmission network. Egerer and Schill (2015) analyze future transmission and generation expansion needs in the German electricity system using an integrated investment and dispatch model. Their results indicate that transmission expansion can be partly substituted by a system-optimal placing of generation investments.

In this paper, we analyze the impacts of different network planning approaches on annual welfare and transmission investments. We apply two model settings. One a "separated" setting where there is no trade-off between transmission expansion and generation dispatch; a modeling set-up similar to the one used for the *NEP*. A second "integrated" setting further allows for such a trade-off, and thus represents a welfare superior way of transmission capacity expansion. Calculations with the two models are carried out and compared so as to gauge the amount of overinvestment in capacity associated with the current regime. We show that an integrated approach to network expansion planning considerably reduces the necessary network expansion as opposed to the currently practiced separated approach.

This paper is organized as follows. We develop, in Section 2, a modeling setup to compare the German separated transmission-planning regime with a benchmark model that integrates the decisions of transmission expansion and generation (re)dispatch. Results are presented and discussed in Section 3. Section 4 concludes with some final remarks and proposes further research.

2. Model and data

To quantify the required network expansion of the German electricity system, we employ a quantitative techno-economic modeling approach. The model comprises a zonal representation of the German and a national representation of the European power system that is optimized for an entire year. We consider two different planning settings with respect to their consideration of dispatch decisions and investment cost in the transmission planning cost, analyzing the impacts on investment needs and system costs. The focus of this analysis is to challenge the existing incentives for transmission investment within the current regime in Germany, which separates generation capacity dispatch from network capacity expansion decisions.

2.1. Model

The modeling approach is described by Eq. (1)–(13). The nomenclature is provided in Table 1. The model determines the cost-minimal generation dispatch, $G_{i,n,t}$, and network expansion, P_l, given a fixed price-inelastic demand, $q_{n,t}$, and an hourly renewable generation profile, $r_{n,t}^{max}$. The balance of generation, demand, and injections to or withdrawals from the transmission network is ensured by the nodal energy balance (2). Dispatchable conventional generation capacities are characterized by their marginal generation costs, $mc_{i,n}$, and are restricted by their maximum generation capacity (4). Furthermore, pumped-hydro storage plants allow for an intertemporal shift of energy between different hours (5) and are limited by their corresponding reservoir (6), generation (7), and pumping (8) capacities. Renewable generation, $R_{n,t}$, is considered to be a non-dispatchable generation source characterized by an hourly generation capacity $r_{n,t}^{max}$, but can be curtailed (9,10) with cost c^{curt}. The transmission network is reflected by a Power-Transfer-Distribution-Matrix, $ptdf_{l,n}$, that determines the impact of a nodal injection or withdrawal on transmission flows. Transmission flows are approximated by DC load-flow approach and are restricted by a maximum transmission consisting of the initial capacity, cap_l, and the extended capacity, P_l (11,12). In contrast to physical flows, transfers between countries, $T_{c,cc,t}$, are defined in (3) and are limited by the net transfer capacity (13) corresponding to the current European congestion management approach for international links

Table 1
Nomenclature.

Sets and indices	
i	Technology
l	Transmission line
n	Node
t	Hour
$c(cc)$	Country
Parameters	
c^{curt}	Curtailment cost of renewable power generation
c_l^{inv}	Annualized investment cost of transmission line l
cap_l	Initial transmission capacity of transmission line l
$g_{i,n}^{max}$	Maximum generation capacity of technology i at node n
$mc_{i,n}$	Marginal cost of technology i at node n
$ntc_{c,cc}$	Net transfer capacity between country c and cc
$ptdf_{l,n}$	Power-transfer-distribution matrix
$r_{n,t}^{max}$	Renewable generation capacity at node n in hour t
$q_{n,t}$	Hourly demand at node n in hour t
v_n^{max}, w_n^{max}, l_n^{max}	Maximum generation, pumping, reservoir capacity of pump-hydro storage at node n
Variables	
$C_{n,t}$	Renewable curtailment at node n in hour t
$G_{i,n,t}$	Generation of technology i at node n in hour t
P_l	Capacity expansion of transmission line l
$R_{n,t}$	Renewable power produced at node n in hour t
$T_{c,cc,t}$	Commercial transfer between country c and cc in hour t
$V_{n,t}$, $W_{n,t}$, $L_{n,t}$	Generation, pumping, reservoir level of pump-hydro storage at node n in hour t
$Y_{n,t}$	Net injection at node n in hour t

$$\min \sum_{i,n,t} mc_{i,n} G_{i,n,t} + \sum_{n,t} c^{curt} C_{n,t} + \sum_{l} c_l^{inv} P_l \tag{1}$$

$$\sum_{i} G_{i,n,t} + R_{n,t} + V_{n,t} - W_{n,t} - q_{n,t} + Y_{n,t} = 0 \quad \forall\, n,\, t \tag{2}$$

$$\sum_{n \in c} \left[\sum_{i} G_{i,n,t} + R_{n,t} + V_{n,t} - W_{n,t} - q_{n,t} \right] + \sum_{cc} [T_{cc,c,t} - T_{c,cc,t}] = 0 \quad \forall\, c,\, t \tag{3}$$

$$0 \le G_{i,n,t} \le g_{i,n}^{max} \;\forall\, i,\, n,\, t \tag{4}$$

$$L_{n,t-1} - V_{n,t} + 0.\,75 * W_{n,t} = L_{n,t} \;\forall\, n,\, t \tag{5}$$

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$$0 \le L_{n,t} \le l_n^{max}\ \forall\ n,\ t \tag{6}$$

$$0 \le V_{n,t} \le v_n^{max}\ \forall\ n,\ t \tag{7}$$

$$0 \le W_{n,t} \le w_n^{max}\ \forall\ n,\ t \tag{8}$$

$$R_{n,t} = r_{n,t}^{max} - C_{n,t}\ \forall\ n,\ t \tag{9}$$

$$0 \le C_{n,t} \le r_{n,t}^{max}\ \forall\ n,\ t \tag{10}$$

$$0 \le \left| \sum_n ptdf_{l,n} Y_{n,t} \right| \le cap_l + P_l\ \forall\ l,\ t \tag{11}$$

$$P_l \ge 0 \forall l \tag{12}$$

$$0 \le T_{c,cc,t} \le ntc_{c,cc}\ \forall\ c,\ cc \tag{13}$$

As we aim at total economic implications on the German system in terms of e.g. annual welfare changes, we consequently have to abstract from important complexities of the transmission network problem. We firstly abstract from lumpy investment decisions and assume continuous expansion of transmission lines.[12] Secondly, we assume that load-flow patterns are independent from the undertaken network expansion in order to circumvent arising non-linearities.[13] Including both complexities would require either a reduction of expansion project to selected candidate projects or a reduction of the hourly time scale to specific hours to reduce the computational burden. The model is coded and solved in GAMS using CPLEX.

2.2. Data

The application of the model focuses on the German power system and its projected development through 2035 concurrent with the current transmission planning process by the German transmission system operators. Therefore, the underlying dataset comprises the current projections of the German power system for 2035 (50Hertz et al., 2014b) as approved by BNetzA, the federal network agency (BNetzA, 2014). These data are also used for the 2015 version of the national network development plan *NEP*. The dataset includes the expected development of generation capacities, the status of individual power plants, as well as projections on fuel and CO_2 prices, net transfer capacities, and national load. As seen in Table 2, renewable capacities in Germany are expected to increase significantly while conventional capacities decline. In order to capture the international exchanges with neighboring countries, European countries are considered on a national detail level with their estimated capacities and load based on ENTSO-E (2014a). Transfer capacities between countries are taken from ENTSO-E (2014b).

Table 2
Projected development of German electricity capacities.Source: BNetzA (2014), p. III.

In GW	**2013**	**2035**
Nuclear	12.1	0.0
Lignite	21.2	9.1
Coal	25.9	11.1
Gas	26.7	32.7
Renewables		
Hydro	3.9	4.2
Wind onshore	33.8	88.8
Wind offshore	0.5	18.5
Biomass	6.2	8.4
Solar	36.3	59.9
Pumped-hydro storage	6.4	12.5
Other	9.2	2.4

In order to adequately capture the German power system and its interactions with neighboring European countries in a common framework, we employ an aggregated representation of the detailed European transmission network. The detailed topology of the current European transmission network as well as the specification of the spatial distribution of renewable capacities and load is described in detail in Egerer et al. (2014). Herein, national load is distributed to individual network nodes using regional data on gross domestic product as well as regional population. Existing and planned generation units are reflected on a detailed plant level including their geographical location and are assigned to the nearest network node. The detailed dataset provides the basis for the following aggregation of the transmission network as well as the generation capacities and load.

The spatial aggregation approach builds upon the detailed European transmission network and assigns nodes to typical congestion zones following the zonal definition in DENA (2010). A comparable approach is used in Trepper et al. (2015). This approach ensures an adequate representation of typical flow patterns and loop-flow effects across Europe. For Germany, we define 21 zones and consider 170 cross-zonal transmission lines. Other European countries are reflected on a national basis abstracting from any inner-national congestion issues.

Transmission investment cost are considered as annualized cost assuming 1.4 million EUR/km investment cost for a double 380 kV transmission line (50Hertz et al., 2012), 5% interest rate, and 40 years lifetime. The length of the transmission lines reflects the distance between zones instead of individual lines to account for further investment needs within zones.

2.3. Scenarios

The described modeling approach allows us to quantify the implications of different network planning settings on resulting network investments and economic indicators. Herein, the consideration of transmission investment cost within the *NEP* approach is of particular interest. The current *NEP* approach separates the dispatch of generation capacity from the determination of network expansion needs. As the spot market pricing in Germany relies on a uniform pricing approach, generation dispatch is determined without considering internal network restrictions. If congestion in the German transmission network occurs, it is managed by the TSOs using curative congestion management options (e.g. BNetzA and BKartA (2014), p. 54f). Thus, TSOs currently have an incentive to optimize transmission investments to

[12] The inclusion of lumpy investment decisions requires binary variables to account for the status of transmission expansion projects. The advantage of this approach is a detailed consideration of individual line projects and their value within the system. However, the computational effort increases and would require a reduction of complexity in other model aspects, e.g. the time horizon of the model. Alguacil et al. (2003) provide a linearized formulation of the transmission expansion problem.

[13] In general, network expansion has an impact on the distribution of line flows in a meshed network. To capture the impact of network expansion on the flow pattern, an obvious option is to endogenize network expansion within the line flow determination. This would however lead to a non-linear model specification which limits the solvability in larger model settings. Alternatively, the non-linearities could be reformulated through disjunctive constraints yielding a linear model (Alguacil et al., 2003). However, such an linearized approach often requires a selection of network expansion projects to improve solvability. As our analysis explicitly focuses on a yearly representation of the power system and relies on an aggregated network representation without a selection of expansion projects, we abstract from the impact on line flow distribution.

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Table 3
Investment cost and added capacity in the separated and integrated scenario.

	Separated	Integrated
Transmission investment cost in bn. EUR	15.4	8.5
Capacity added in GW	88.5	48.6

ensure the feasibility of the generation dispatch of the uniform pricing market and the trade-off between congestion management, like redispatch of generation, and transmission expansion is not explicitly taken into account. Therefore, we define two scenarios which differ in the consideration of transmission network investment costs within the objective function.

The first scenario, *separated*, captures the characteristics of the current *NEP* approach by disregarding the cost of (or assuming costless) network expansion within the described model. Within the formulated optimization problem the network investment costs c_l^{inv} are set to zero in the objective function (1). This scenario basically implies that network expansion is optimized solely to implement a cost-minimal generation dispatch within Germany.

A counterfactual second scenario, *integrated*, optimizes both generation dispatch and network expansion with their associated costs. Consequently, network investment costs c_l^{inv} are now explicitly considered in the objective function (1) and the system is optimized to minimize generation dispatch and network investment costs.

Both scenarios have in common that they solely focus on transmission investments. Generation investments are based on current projections of the German electricity system and are exogenously defined. Furthermore, both scenarios and the general model design assume a market design which allows for regional or nodal prices and is therefore different from the current uniformly price German market design. We discuss the transferability of the received results to the German market design in the following section.

3. Results and discussion

Table 3 depicts the cost and capacity results of the two considered scenarios. In general, the significant increase of renewable generation capacities in Germany requires a reshaping of the existing transmission network in order to balance regional generation surpluses and deficits. As the main share of renewable wind generation is expected to be located in the northern part of the country (while load is mostly located in the western and southern parts), north to south transmission capacity particularly needs to be increased. Under a separated planning framework, as currently done in Germany, investment costs sum up to 15.4 bn. EUR relating to an increase of transmission capacity by 88.5 GW.[14] In an integrated optimization setting, total investment cost amount to 8.5 bn. EUR corresponding to an additional capacity of 48.6 GW. Thus, investment needs could be significantly reduced, up to 45%, through an integrated optimization of generation dispatch and transmission investments.

Fig. 1 illustrates the optimized transmission investment needs between the different regions in Germany for the two considered scenarios. In both scenarios, significant investments are required to integrate the increasing shares of renewable generation and to allow for an instantaneous regional balancing of generation and load. Due to the strong increase of wind generation capacity in northern Germany, additional transmission capacity on the north-south axis is of particular importance in both scenarios in order to supply load centers in the western and southern parts of Germany. However, the scenarios differ in the amount of investment needed, which are lower in the integrated setting.

The savings in transmission investment needs basically stem from the fact that a change in the spatial generation pattern to circumvent congestion is less costly than expanding the corresponding transmission line. This effect consequently reduces the transmission needs, in particular during those few hours when renewable wind generation is high. As seen in Fig. 1, network expansion in the northeastern part of Germany is reduced to a large extent if transmission costs are considered. Due to the dominant wind capacity in this region, the temporary reduction of peak wind generation leads to significantly lower expansion needs to adjacent regions. Thus, integrating the energy generated during these few hours by expanding the transmission network comes at higher cost than replacing it with other generation technologies. Furthermore, this effect also occurs between different conventional generation technologies, leading to reduced investment needs.

Table 4 depicts the welfare distribution in Germany for the two considered cases. As we assume a fixed demand, consumer surplus is defined as the annual sum of hourly demand valued with the difference of value of lost load (VoLL) of 4000 EUR/MWh and the calculated spot prices. Producer surplus comprises the profits from selling energy at market prices less electricity generation costs. Finally, the surplus of the transmission operator accounts for congestion revenues[15] and annualized investment cost in the different scenarios. Congestion revenues are defined as the annual sum of hourly regional transmission flows valued with the regional price difference. The sum of the three surpluses is defined as the total welfare of the German power system for an entire year. Through an integrated evaluation of costs and benefits of transmission capacity investments, total welfare can be increased by 1.3 bn. EUR or 0.1%.

Due to the integrated assessment of generation dispatch and network investments, we implicitly allow for regional price differences on the spot market. On the one hand, this leads to higher cost for consumers and, thus, a smaller surplus. On the other hand, producers gain higher profits for the same reasoning. Furthermore, the TSO faces congestion rents of 1.5 bn. EUR in the integrated case, which overcompensates the annualized investments cost of 0.6 bn. EUR. In combination with the lower amount of transmission investments, the increase in surplus of producers and TSOs exceeds the reduction in consumer's surplus yielding an increase of total welfare. Moreover, if the surplus of the TSO is entirely redistributed to consumers through network charges, consumers are left with higher surplus in the integrated setting than in the separated case. Therefore, an integrated evaluation of cost for investments and benefits of added transmission capacity reduces the amount of transmission investments while enhancing the welfare of the entire system.

In our optimization, the benefits of added transmission capacity are determined within the spot market dispatch, which allows for regional price differences. Alternatively, benefits could also be defined as a reduction in the usage of congestion management measures, which are implemented by the TSO due to a uniformly priced spot market. This approach is more consistent with current European market organization. However, as shown in Kunz (2013), this would mainly impact the distribution of surplus between

[14] The German network development plan of 2014 (50Hertz et al., 2014a) identifies an investment volume of approximately 23 bn. EUR. Due to computational restrictions, the German transmission network is simplified, thus the calculated investment costs are underestimated.

[15] Congestion revenues stemming from international trade are excluded in both scenarios.

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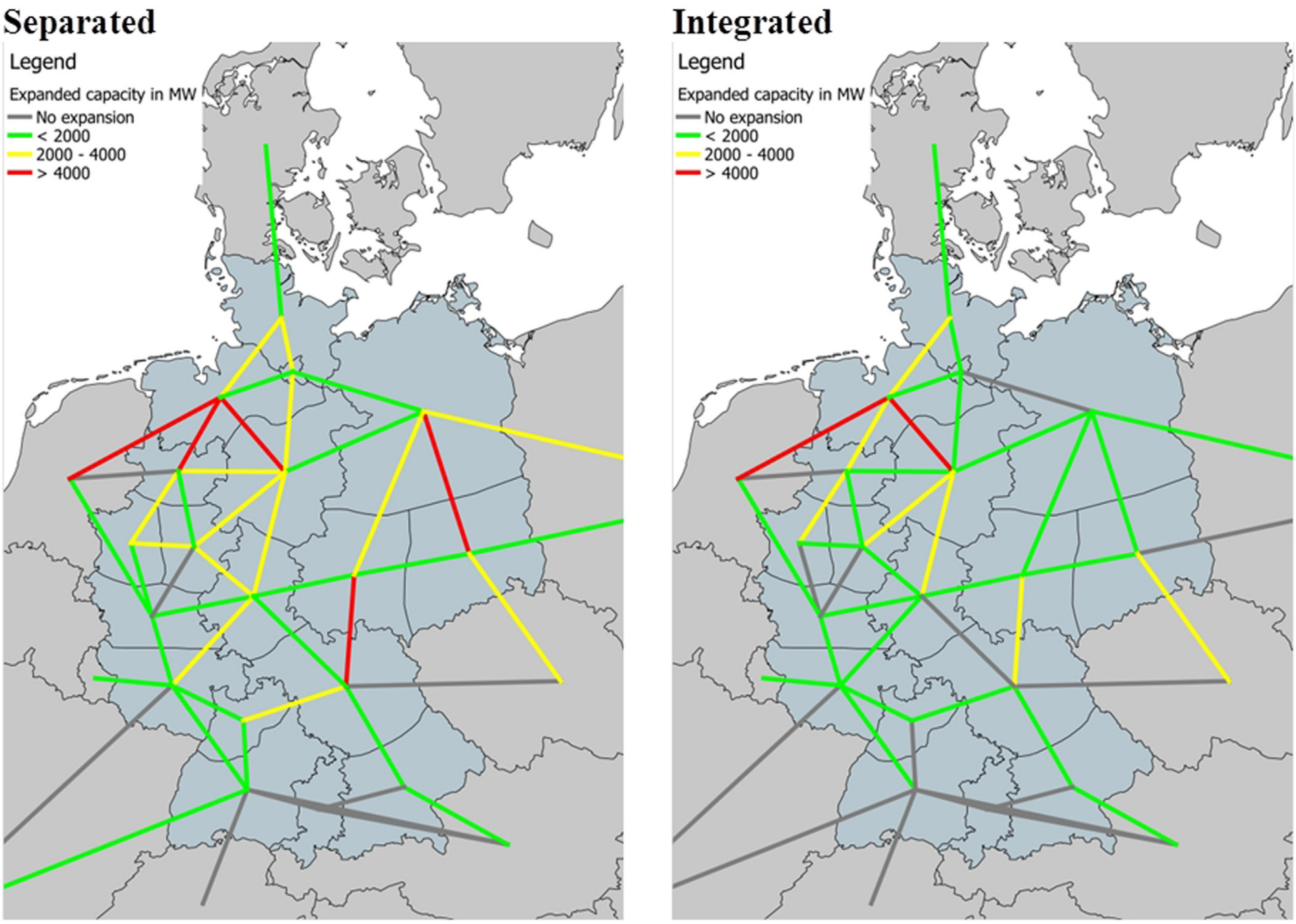

Fig. 1. Transmission capacity investments in Germany for 2035 in the separated and integrated scenario.

Table 4
Consumer, producer, and TSO surplus in the separated and integrated scenario.

In bn. EUR	**Separated**	**Integrated**	**Change**
Consumer surplus	2147.0	2145.5	−**1.5**
Producer surplus	10.6	11.5	+**0.9**
TSO surplus	−1.0	0.9	+**1.9**
Of which			
TSO congestion rent	*0.0*	*1.5*	*+**1.5***
TSO annualized investment	*1.0*	*0.6*	*−**0.4***
Total welfare in bn. EUR	**2156.6**	**2157.9**	+**1.3**

market participants. The efficiency of the generation dispatch and, therefore, the total welfare would remain unaffected. Therefore, the welfare benefits would also accrue in a system with a uniformly priced spot market and curative congestion management.

As with most model-based applications, assumptions and simplifications are made that must be taken into account when interpreting the results. Firstly, the model abstracts from lumpy transmission investment, which is a characteristic of electricity transmission networks. Due to the assumption of continuous transmission investment in our application, the results typically underestimate required transmission expansion and, consequently, cost. Secondly, the physical flow pattern remains unchanged and does not account for additional network investments. Thus, we account for higher transmission capacity on an expanded transmission line, but neglect the reductive effect on parallel flows. Therefore, transmission investments are less effective in our modeling framework, which tends to overestimate total investments. Moreover, the generation dispatch abstracts from unit commitment decisions, which certainly overvalues the flexibility of generation. Additionally, the model is based on a spatially aggregated dataset in order to allow for the representation of an entire year. Thus, the spatial aggregation abstracts from any inner-zonal transmission needs and, therefore, tends to underestimate the absolute amount of required transmission expansions. Based on these assumptions and simplifications, our results tend to underestimate the absolute amount of required transmission investments for both presented cases, whereas the qualitative difference between the cases remains unaffected.

4. Conclusions

Our analysis of the German *NEP* shows that German TSOs have excessive network expansion plans as compared to a model that integrates both transmission expansion decisions and generation dispatch. The amount of overinvestment was measured in an economic model for Germany, where we constructed a counterfactual setting with nodal prices. The results of our indicative application show that investment needs could be significantly reduced up to 45%, and welfare enhanced by 1.3 bn. EUR (+0.1%), through an integrated optimization of generation dispatch and transmission investments. As our application is based on several simplifications, the quantitative results are rather indicative but the qualitative

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dimension of the results nevertheless suggests a significant scope for improving the network planning. Considering the costs and benefits of transmission expansion in the determination of transmission investment needs avoids inefficient over-investments in network infrastructure, thus enhancing the welfare of the entire system. If investment costs are disregarded in this process, the network is designed to be congestion-free in all considered hours. This planning approach is in particular questionable in systems with high shares of renewable generation and, consequently, high temporary generation peaks in specific regions, as it may require significant investments in transmission infrastructure.

The policy implications of our analysis are clear: integrating generation dispatch and network expansion requires less investment, while increasing overall welfare. Thus, network planning approaches should be complemented by alternative congestion management approaches, like redispatch of renewable and conventional generation. However, the welfare implications of our analysis rely on a perfectly competitive electricity market under perfect information as well as other assumptions. In practice, market participants may for example react to institutional changes by altering their bidding strategy. Furthermore, the separation between transmission investment and line management decisions might deliver other kind of benefits and costs not investigated in this paper. Also, as hinted in our analysis, it is not just the separation between generation and grid investment decisions that determines the incentives for market participants; it is also the transmission-tariff regulatory scheme. The use of cost-plus regulation for grid investments suggests that German TSOs have further incentives to strategically determine capacity expansions and inflate costs.

Regarding the welfare redistribution, less network investment is necessary but congestion rents for the TSO increases and also profits for generators. Therefore, total welfare might augment at the expenses of consumers. This result is questionable as reduced investment in transmission goes against two pillars of EU energy policy: favor towards renewables and lower energy costs for end users. However, if TSO's surplus is entirely redistributed to consumers through network charges, consumers could be left with greater surplus in the integrated case than in the separated case. An integrated evaluation of cost for investments and benefits of added transmission capacity could then effectively achieve an optimal sizing of transmission capacity investments, while simultaneously enhancing consumer surplus in the system.

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