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How to benefit from a common European electricity market design☆

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ABSTRACT

The realization of an Internal Electricity Market in Europe is currently, on the one hand, progressing, in particular thanks to the wide-spread implementation of market coupling solutions for cross-border congestion management. On the other hand, diverging national market designs pose a threat to the continuation of this process. Given the challenges to electricity market design in a multi-regional context, we analyze how different design aspects, namely cross-border congestion management and capacity mechanisms, affect welfare and generation adequacy in Europe. In doing so, we rely on an agent-based simulation model for electricity wholesale markets which we apply within several numerical, computational case studies for the region of Central Western Europe (2012–2030). Our results confirm the benefits of market coupling in terms of welfare as well as generation adequacy. Furthermore, we find indications that coordinating market designs across regions supports these targets. Therefore, we recommend that European energy policy forms a stable, transparent regulatory framework with cross-border market coupling as an integral component. In this context, energy policy targets should be clearly defined and operationalized, which also needs to consider potential conflicts between them. Finally, electricity market designs need to be coordinated among states to benefit most from a common European market.

1. Introduction

Creating an Internal Electricity Market (IEM) in Europe on the wholesale level is a long-term goal of the European Commission. A harmonized and competitive European electricity market is expected to provide improvements in terms of efficiency, end-user prices, standards of service, security of supply and sustainability (European Parliament and the Council of the European Union, 2009). Transforming formerly regulated, nationalized electricity systems is a complex task and requires the design of various measures and their practical implementation. The plurality of energy policy targets – usually concerning *security of supply*, *economic efficiency* and *environmental impact* – and the predominance of national competencies challenge this process in particular. Overall, cross-border congestion management plays a pivotal role as does the cooperation of relevant bodies, i.e., market operators, grid operators, regulators and politicians (Knops et al., 2001).

Currently, the realization of the IEM is at a critical crossroads (Glachant and Ruester, 2014). On the one hand, there is significant progress, first and foremost, with regard to congestion management between European electricity markets, but also, for instance, on the level of harmonizing different operational processes across member states. On the other hand, there is substantial headwind because of the way how electricity generation from renewable energy sources (RES) and capacity mechanisms in several countries (e.g., France, Germany, Great Britain) are promoted. It is not necessarily the measures themselves that entail a potential risk of slowing down European market integration, but rather the prevalence of uncoordinated national steps. Against this background, it is necessary to evaluate the current and future impact of coupling markets in Europe considering the actual specifics and imperfections of electricity markets. In order to support the creation of an IEM, electricity market design in Europe needs to take into account different levels of interactions between regions, markets and targets.

There is a large body of literature related to coupled electricity markets in general as well as with a specific focus on Europe. First, there is extensive empirical research on the state of the European market integration with a large consensus that there is measurable progress, though it is still a long way from being completed (e.g., Zachmann, 2008; Bunn and Gianfreda, 2010; Menezes and Houllier, 2015). Empirical approaches are suitable for analyzing historical developments, but less for evaluating future market design changes. Second, theoretical as well as numerical work has shown the relative benefits of different approaches to congestion management (e.g.,

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Hobbs et al., 2005; Ehrenmann and Neuhoff, 2009; Neuhoff et al., 2013). While these studies lay the foundations for designing cross-border congestion management, they are often restricted to relatively short evaluation periods ignoring the dynamics of electricity markets over time. Our approach is to be attributed to a third stream which comprises studies explicitly addressing electricity market design issues and target criteria concerning the development of coupled electricity systems. For instance, Boffa et al. (2010) estimate how Italian electricity end-users might benefit from an improved interconnection between the Northern and Southern price zone. The authors find that increasing interconnection capacity, even in small-scale increments, can lead to substantial end-user savings. Cepeda and Finon (2011) analyze the impact of different market designs (e.g., energy-only market, central capacity market) on generation adequacy for a stylized system of coupled electricity markets. Their findings emphasize, amongst others, the merits of harmonizing market designs in coupled systems. Similarly, Ochoa and van Ackere (2015) study interdependencies between France and Great Britain as well as Colombia and Ecuador under varying market design options. They find that the potential welfare benefits of market coupling heavily depend on the complementarities between the coupled markets. For the Finnish electricity market, Ochoa and Gore (2015) analyze potential benefits and risks of an integration with the Russian market. The identified effects on welfare and reliability are strongly determined by the respective market characteristics and policy measures.

Despite existing research, several aspects in the field of cross-border electricity market design are still only scarcely studied. In particular, we identify the need to consider economic efficiency and security of supply under certain market designs in a more integrated and consistent fashion. Market design choices on the wholesale level include selecting cross-border congestion management schemes as well as remuneration instruments (e.g., capacity mechanisms). In this regard, it is essential to highlight potential conflicts between the different targets and market participants in order to point out particular design challenges. Moreover, specific agent decisions over time and market imperfections are important drivers of the development of electricity systems, which equally require a greater attention. The objective of market design is exactly to set a regulatory framework in a way that the market participants' behavior supports achieving energy policy targets. Therefore, the influence of design changes on agent actions (e.g., investments) in imperfect markets like liberalized electricity markets should be considered in an explicit way for certain analyses. Furthermore, conducting numerical studies for detailed real-world cases can help to transfer theoretical findings to the European electricity system. This paper aims to reduce these research gaps and ultimately intends to contribute to the shaping of the European market integration process. While certain aspects in this context, such as the general effect of market coupling on security of supply and economic welfare, have already been studied in isolation, we also see a need for a more comprehensive evaluation considering potential interactions between them. As a result, we hope to derive more balanced recommendations for a future European electricity market design.

Concerning our general research approach, we rely on numerical, computational simulations. Electricity markets can be considered as complex, adaptive systems with heterogeneous participants, various imperfections and out-of-equilibrium dynamics (Tesfatsion, 2006; Miller and Page, 2007). In particular, market areas in Europe are not isolated but interconnected via a physical and economic coupling (Knops et al., 2001). Furthermore, it is vital to analyze the evolution of electricity systems over time in order to consider changes to the market structure (Arango and Larsen, 2011). For instance, imperfect foresight makes the forecast of fundamental price drivers a complex task within the investment valuation process. The approach of agent-based computational economics (ACE) is based on a detailed and explicit representation of agents in an economic system, of their interactions and of an emergent evolution on the macro level (Tesfatsion, 2006). In this paper, we make use of this methodological concept by developing an electricity market simulation model and by applying it to several case studies for Central Western Europe (CWE). Thereby, we study the impact of different market design constellations on security of supply and economic welfare by varying the interconnection network configuration as well as by simulating an asymmetric market design across the considered market areas.

This paper is structured the following way. Section 2 provides relevant background on the design of electricity markets in Europe and on how economic efficiency and generation adequacy can be operationalized. In Section 3, we formally present our methodological approach in the form of an agent-based simulation model for wholesale electricity markets. Our simulation design and relevant input data are illustrated in Section 4. In Section 5, we give an overview of our model results with regard to the potential development of the CWE Market Coupling under various scenarios. Finally, Section 6 concludes with implications for the European electricity market.

2. Background

2.1. Electricity market design in Europe

The architecture and operation of liberalized electricity markets is generally determined by an explicit regulatory framework. Ideally, this electricity market design sets basic incentives for market participants in a way that energy policy objectives are achieved indirectly through the behavior of all parties involved.

In Europe, the long-term goal of creating the IEM requires a European-wide market design of some kind. After the liberalization of the energy sector in the 1990s, electricity markets in Europe have been structured according to different design principles (Stoft, 2002; Wilson, 2002). Notably, a differentiation can be made with respect to the nature of the producers' remuneration in electricity markets. Given that consumers demand a certain amount of electrical energy at a particular point in time, generators typically receive payments depending on the delivered electricity volume, which should cover the respective generation costs. In perfect energy-only markets, investments in new generation capacity are signaled through rising electricity prices in times of scarcity. If these prices materialize in the market, they allow the recovery of fixed operational costs and capital costs. However, given various imperfections in electricity markets (Stoft, 2002; Joskow and Tirole, 2007), the design of electricity markets is an intricate task and the practical functioning of energy-only markets is hard to verify. This is also why so-called capacity mechanisms are often discussed as an additional instrument to ensure security of supply by avoiding plant closures and incentivizing the construction of new plants, respectively (Joskow, 2008). The rise in electricity generated from RES increases concerns that imperfect energy-only markets are not fully suited to provide adequate incentives for market participants (Cramton and Ockenfels, 2011). Traditionally, electricity markets in Europe follow an energy-only design; however, the last years have seen a rising discussion and implementation of different kinds of capacity mechanisms, for instance, in France (MEDDE, 2015), Germany (BMWi, 2016) and Great Britain (DECC, 2015).

Furthermore, electricity markets in Europe follow a zonal design and, hence, neglect intra-zonal congestion. Traditionally, zones are defined according to national borders. As a result, market prices are equal for all market participants in the respective zone and, as such, do not exhibit any locational component but only reflect the marginal generation costs and marginal utility, respectively.[1] At the same time, national electricity markets in Europe are not isolated but intercon-

[1] In case schedules for injection and consumption based on energy market results lead to congested lines, grid operators need to perform curative measures, for instance, through a redispatch of units (Holmberg and Lazarczyk, 2012). These costs are distributed ex post among electricity consumers as part of the grid charges.

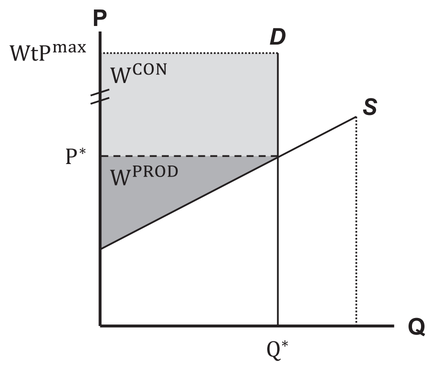

Fig. 1. Market clearing in electricity spot markets.

nected through physical lines and economic arrangements. While the interconnection lines between the countries in Europe had been viewed traditionally as back-up in critical situations, there has been a considerable change in this regard in recent years. The overall goal of the three European Energy Packages is to create a European electricity market with non-discriminatory freedom of competition and a maximum of cross-border trade which, ultimately, should result in efficiency gains and higher security of supply (European Parliament and the Council of the European Union, 1996, 2003, 2009).

In contrast to national electricity markets, congestion on interconnectors, i.e., inter-zonal congestion, is managed in a preventive way by determining the available capacity as well as by allocating it to market participants. Different approaches to cross-border congestion management are available (Knops et al., 2001) with implicit auctions in the form of market coupling having become the approach of choice in Europe (European Parliament and the Council of the European Union 2009). By means of implicit auctions markets for electricity and interconnection capacity are integrated and cleared simultaneously. Due to the zonal design electricity prices in Europe reflect locational signals on the level of price zones.

Market coupling in Europe has started for the day-ahead market. In November 2006, the *Trilateral Market Coupling* between France, Belgium and the Netherlands was the first implementation of its kind in Europe. In November 2010, the coupling was extended to include the German-Austrian market area (*CWE Market Coupling*). At the beginning of 2016, the market coupling solution, now called *Multi-Regional Coupling*, covered 23 countries or more than 90% of Europe's electricity consumption (EPEX SPOT, 2016). In order to couple the different market areas and to account for different bid types, the clearing algorithm used by the electricity exchange EPEX SPOT for determining day-ahead zonal prices and cross-border commercial flows has equally been adjusted. Additionally, in May 2015, the calculation of cross-border capacities in CWE was switched to a flow-based approach allowing an improved consideration of physical flow characteristics in electricity grids compared to the previously used concept of net transfer capacities (NTC).[2]

2.2. Operationalizing energy policy objectives

In liberalized electricity markets with a design as in Europe, energy policy targets are not managed explicitly but expected to be fulfilled implicitly through the behavior of market participants. Therefore, it is all the more important to operationalize these concepts in a consistent manner in order to evaluate the status quo in electricity systems as well as the impact of different electricity market design options. In this paper, we will focus on the operationalization of long-term security of supply and economic efficiency, both on the wholesale level.

2.2.1. Generation adequacy

The notion of *adequacy*, i.e., the general ability of an electricity system to provide sufficient capacity to serve demand, is long-term oriented and rather abstract when compared to a system's *security* (Stoft, 2002; Roques, 2008). As a result, there are quite different views on how adequacy can be guaranteed, in particular on the question of whether an energy-only approach is sufficient or additional explicit regulatory measures are required in order to provide incentives for market participants (Oren, 2003; Joskow, 2006). Generation adequacy, meaning the provision of an adequate amount of generation capacity to serve electricity demand in the system under consideration at any point in time, is often the focus of discussions regarding capacity mechanisms.

In this paper, we measure generation adequacy with the help of *loss-of-load events* (Billinton and Li, 1994). In general, a loss-of-load event occurs when in a certain time step demand is not expected to be fully met. A standard metric for generation adequacy is the *loss-of-load expectation* (LOLE), which represents the expected absolute number of loss-of-load events in a certain period. Due to its forward-looking nature, measuring generation adequacy involves using a computational model for the electricity system of interest.

2.2.2. Economic efficiency

Supplying end users with electricity based on market transactions has different economic effects on the considered system and on the respective market participants. Microeconomic welfare analysis provides an analytical framework to study the economic efficiency of certain electricity market design options.

In electricity spot markets without scarcity, the market clearing price P^* and volume Q^* are determined by the intersection of the aggregated demand and supply curves creating non-negative consumer rents W^{CON} and producer rents W^{PROD} in the short term. Fig. 1 shows the market clearing situation for an illustrative time step given a price-inelastic demand D and an aggregated supply curve S.

In order to illustrate the specific welfare effects of market coupling, we use a simple, stylized example with two electricity markets A and B under perfect market conditions in this section. Initially, Fig. 2 shows the market clearing without interconnection capacity. In the case at hand, market A exhibits a lower price than market B.

Introducing a theoretically unlimited interconnection capacity yields a full integration of the two markets. By increasing generation in A and exporting $Q^{ex}_{A\to B}$ from A to B,[3] market prices in both markets equal (Fig. 3 left). This is the optimum in terms of welfare creation resulting in a welfare gain $W^{WG,MC}$ compared to the case without interconnection (Fig. 3 right). The distribution of welfare gain is asymmetric, i.e., consumers and producers in the two market areas are affected in different ways depending on the shapes of the supply and demand curves.

However, interconnection capacity is usually limited to $Q^{ex,max}_{A\to B}$ and situations can occur when the interconnector is fully utilized, i.e., $Q^{ex}_{A\to B}=Q^{ex,max}_{A\to B}$ holds. The interconnection capacity is now scarce and has a non-zero economic value. Since the capacity is insufficient to create a full price convergence, the property rights owner with regard to the utilization of the interconnector can make an arbitrage profit by buying energy in A and selling it at a higher price in B. The price difference and the exchange volume determine the congestion rent W^{CR} accruing to the rights holder (Fig. 4 left). Furthermore, there is also a welfare increase but below the social optimum shown above (Fig. 4 right).

From a microeconomic perspective, market coupling increases

[2] Initial experiences from a test phase confirm positive impacts of the flow-based approach on transmission capacity utilization, price convergence and economic welfare (ACER and CEER, 2015).

[3] In this paper, we define $Q^{ex}_{A\to B}$ to be non-negative and $Q^{ex}_{A\to B}>0 \Rightarrow Q^{ex}_{B\to A}=0$. A flow in the opposite direction, i.e., from B to A, is represented analogously by $Q^{ex}_{B\to A}>0$ and $Q^{ex}_{A\to B}=0$.

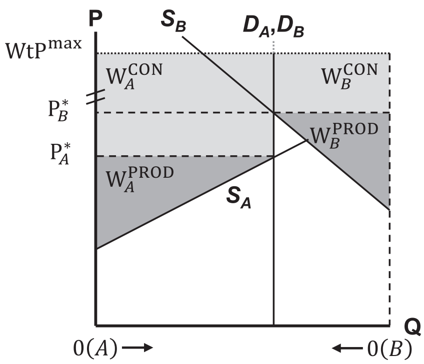

Fig. 2. Welfare without interconnection capacity.

2014). The transition to a liberalized and more decentralized architecture is profoundly changing the operation of electricity systems. In response to these developments, ACE as a recognized modeling approach for complex, socio-technical problems in general (Bonabeau, 2002) has been applied as well to study electricity systems and markets (Ventosa et al., 2005). The field of energy system analysis has seen several applications of ACE techniques mainly for a dynamic, bottom-up analysis of wholesale electricity markets (Weidlich and Veit, 2008; Guerci et al., 2010).[4]

In ACE models, the structure of the underlying system is emulated by creating software agents and dedicated modules for agent interactions. Therefore, the basic setup requires the definition of specific behavioral agent models. In addition, potential interactions can be determined by introducing respective platforms and rules (e.g., on marketplaces). By letting software agents decide, (inter)act and learn accordingly, the idea of agent-based models is to ultimately observe an emergent system behavior.

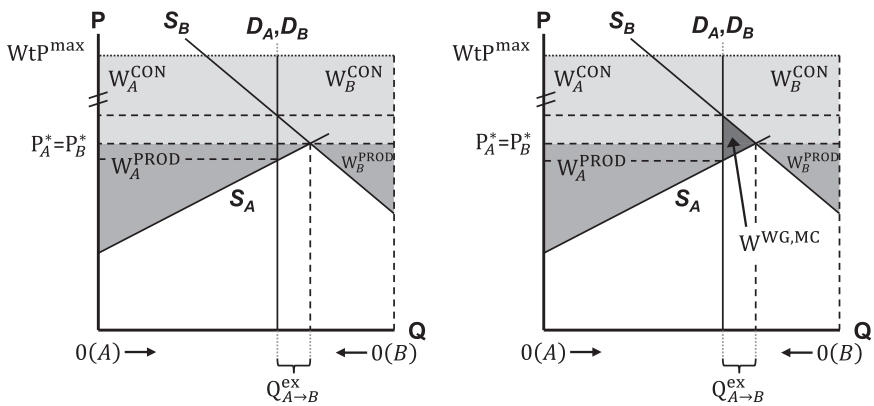

Fig. 3. Welfare with unlimited interconnection capacity.

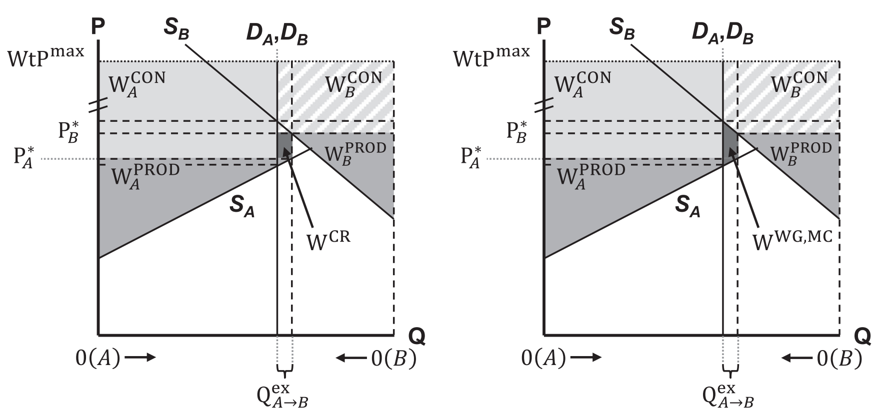

Fig. 4. Welfare with limited interconnection capacity.

short-term welfare in the coupled electricity system due to a more cost-efficient utilization of generation capacities. Furthermore, interconnections can provide potential capacity in scarcity situations. Thus, market coupling is expected to have an additional beneficial effect on generation adequacy. The flip side is that any changes in a specific market area, ranging from individual agent decisions to regulatory interventions, are likely to affect connected market areas to some extent as well. Such interactions can lead to external effects which need to be considered when designing electricity markets.

3. Methodology

3.1. Agent-based modeling and simulation

In the last decades, different computational models have been developed in order to analyze electricity systems in detail (Ventosa et al., 2005; Foley et al., 2010; Möst and Keles, 2010; Pfenninger et al.,

3.2. Overview of the baseline model

In our work, we build on the *PowerACE* model, an agent-based, bottom-up, discrete-event simulation model for wholesale electricity markets, which was originally developed for the German electricity market. Detailed descriptions of the different concepts and their implementations can be found in Sensfuß (2007), Weidlich (2008) and Genoese (2010). The basic principle of the PowerACE model

[4] More recently, there has been an increase in agent-based modeling of decentralized electricity systems focusing, for instance, on demand response, distributed generation, distribution grid modeling as well as local markets (Ringler et al., 2016).

includes representing major submarkets for electricity on the wholesale level and the relevant participants, for instance, large generation companies and market operators, as software entities. The modeled entities can be composed of different agent types (e.g., electricity generator, trader) which assume respective roles in the electricity market and require a specific agent model to be formulated explicitly. Similarly, the operation of the simulated markets needs to be modeled adequately by implementing appropriate clearing algorithms.

Given their practical relevance, the PowerACE model focuses on the simulation of spot markets for electricity.[5] In each time step of the simulation, the spot market operator clears the market by intersecting the aggregated demand and supply curves which are constructed from the agents' bids. Conventional power plants are offered on the spot market on a plant-by-plant basis,[6] the other determinants of supply and demand on an aggregated level. Thus, market prices are determined by the merit order and residual demand in the respective time step. Besides the short-term bidding behavior, investment decisions with regard to conventional power plants are the other main agent actions. The combination of the different temporal dimensions allows simulating the development of electricity systems over multi-year horizons. Final model results include, amongst others, hourly spot market prices and the evolution of the power plant fleet.

Since its origination, the model's validity has been demonstrated by several dedicated exercises. Comparisons between simulated electricity prices and historical data for the years 2001 and 2004 (Genoese, 2010), 2005 and 2006 (Möst and Genoese, 2009), 2009 and 2010 (Genoese, 2013) and 2011 (Bublitz et al., 2014) yield satisfactory results and have finally encouraged the model's application in the field of energy economics. In this paper, we also subject our extended model to a similar validation process (cf. Section 3.4).

In the past, the model was used for various studies of the German electricity market. For instance, Sensfuß et al. (2008) analyze the merit order effect of RES on spot market prices, Möst and Genoese (2009) explore the existence as well as the exercise of market power and Genoese et al. (2010) study fundamental drivers of price spreads in electricity spot markets. Furthermore, different design options for electricity markets are evaluated in Keles et al. (2016).

3.3. Formalization of the model extensions

3.3.1. Overview of the extended model

For this paper, we adhere to the basic concepts of the baseline model but develop several extensions. Eventually, the extended model comprises new modules for an implicit auction of cross-border interconnection capacities, for a strategic reserve, for quantifying the considered policy targets and for a stochastic simulation. As such, the model is generally suited to measure aspects of economic welfare and generation adequacy in coupled electricity systems with differing market designs. The main steps of a single simulation run, shown schematically in Fig. 5, include the model's initialization, the repeated hourly execution of a market coupling considering limited interconnection capacities (cf. Section 3.3.2) and an annual investment planning made by generator agents. Welfare and generation adequacy are measured in each time step of the simulation based on the respective spot market results (cf. Section 3.3.3).

[5] The model simulates a single spot market which covers the total electricity demand of the considered market area and whose procedural rules follow broadly the organization of day-ahead markets in Europe as daily auctions with hourly delivery periods (EPEX SPOT, 2015). Since we implicitly assume that no intraday deviations occur, the terms "spot market" and "day-ahead market" can be used interchangeably in the context of the model.

[6] One of the model's main features is the high level of detail concerning the considered techno-economic parameters of power plants (cf. also Appendix A). Conventional plants are modeled individually and can differ with respect to fuel type, conversion technology, net capacity, electrical efficiency, technical lifetime, operation and maintenance costs, start-up costs and capital expenditures. In combination with the high temporal resolution, a realistic simulation of the short-term bidding and dispatch as well as of the long-term deployment of power plants can be obtained.

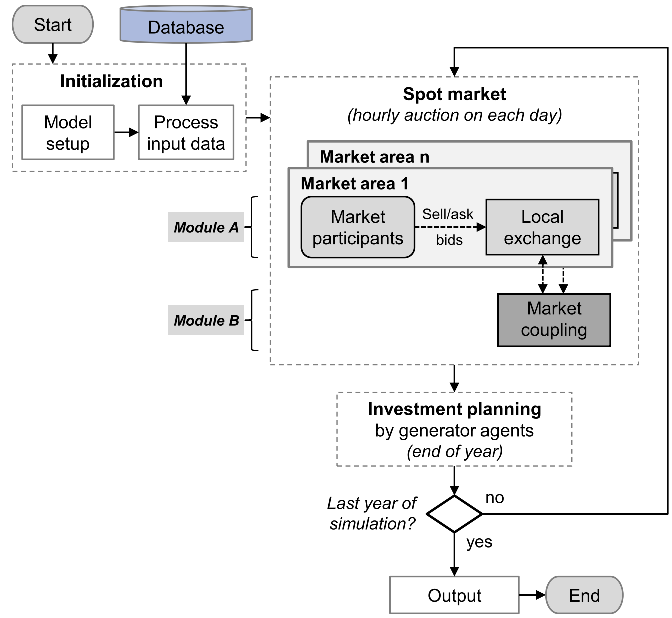

Fig. 5. Main simulation steps.

3.3.2. Coupling of spot markets using implicit auctions

Following the implementation of the market coupling solution in CWE, the daily clearing of spot markets in the simulation model involves two distinct stages. First, all electricity supply and demand traders submit their spot market bids on the local exchange (module A in Fig. 5). According to economic theory, market participants are willing to sell electricity at marginal costs and to purchase electricity equal to the marginal utility, respectively. Electricity trading agents in the model follow this principle by submitting corresponding spot market bids which consider various techno-economic parameters (cf. Appendix A). We assume that auctions are held for hourly contracts and only simple price-volume bids are allowed.

Second, after a central market coupling entity has received all bids, it uses a clearing algorithm to determine electricity prices and cross-border commercial flows (module B in Fig. 5). The objective for the clearing institution is to maximize the economic welfare in the coupled system given the energy bids from all market areas and the available interconnection capacities. The latter are provided to the operator in the form of NTC. Formally, in our work, the mathematical problem is trimmed to a linear maximization program in each time step of the simulation (Eq. (1)). Constraints include a limitation of the bid acceptance rates (Eq. (2) and Eq. (3)), the fulfillment of the supply-demand balance in each market area (Eq. (4)) and a restriction of interconnector flows to the given maximum (Eq. (5))[7]:

$$\max_{q_d, q_s} \sum_{m \in \mathcal{M}} \left(\sum_{d \in \mathcal{D}_m} (P_d^{bid} \bullet Q_d^{bid} \bullet q_d) + \sum_{s \in \mathcal{S}_m} (P_s^{bid} \bullet Q_s^{bid} \bullet q_s) \right) \tag{1}$$

subject to

$$0 \le q_d \le 1 \quad \forall d \in \quad \mathcal{D}_m, \forall\ m \in \mathcal{M} \tag{2}$$

$$0 \le q_s \le 1 \quad \forall s \in \quad \mathcal{S}_m, \forall\ m \in \mathcal{M} \tag{3}$$

[7] In the following equations, time indices for hour h of simulation year y are omitted for better readability.

$$\sum_{d\in\mathcal{D}_m}(Q_d^{bid}\bullet q_d)+\sum_{s\in\mathcal{S}_m}(Q_s^{bid}\bullet q_s)+\sum_{m'\in\mathcal{M}'_m}(Q_{m'\to m'}^{ex})-\sum_{m'\in\mathcal{M}'_m}(Q_{m'\to m}^{ex})=0 \quad \forall m\in\mathcal{M} \tag{4}$$

$$Q_{m_1\to m_2}^{ex}\le Q_{m_1\to m_2}^{ex,max} \quad \forall \quad m_1,\, m_2\in\mathcal{M} \tag{5}$$

where

(Decision variables)
- q bid acceptance rate $[-]$
- $Q_{m_1\to m_2}^{ex}$ flow from market aream_1 to market area m_2 $[MWh]$

(Parameters)
- P^{bid} bid price $[EUR/MWh]$
- Q^{bid} bid volume $[MWh]$
- $Q_{m_1\to m_2}^{ex,max}$ maximum flow from market area m_1 to market area m_2 $[MWh]$

(Indices)
- d demand bid
- s supply bid
- m market area

(Sets)
- $\mathcal{M}$ totality of simulated market areas
- $\mathcal{M}'_m$ market areas connected to market area m
- $\mathcal{D}_m$ demand bids submitted in market area m
- $\mathcal{S}_m$ supply bids submitted in market area m

After the market coupling is successfully performed, the operator publishes the results and sends relevant information to the trading agents. As long as the last day of the respective simulation year is not reached, the simulation continues by executing the spot market for the following day. Otherwise, the current simulation year is completed by the power generators' investment planning (Genoese et al., 2012; Keles et al., 2016).

Overall, the proposed modeling approach covers various techno-economic aspects of the complex decision-making process of electricity market participants (e.g., estimating marginal generation costs on a plant-by-plant basis). As their actions determine the system behavior in the end, representing agent decisions in detail can help to explore relationships in electricity markets and to gain new insights.

3.3.3. Evaluating the development of electricity systems

For the quantification of economic welfare and generation adequacy an ex-post perspective is adopted, i.e., the evaluation is based on the relevant simulated market results and agent decisions. Total welfare effects comprise, on the one hand, short-term rents for consumers, producers as well as holders of interconnection rights and, on the other hand, long-term fixed operational costs as well as investments. For instance, the total welfare for all producers, i.e., operators of conventional power plants, in year y and market area m is set by the following equation:

$$W_{y,m}^{PROD}=\sum_{h\in\mathcal{H}_y}\left(\sum_{j\in\mathcal{J}_m}\left(\left(P_{h,y,m}^{*}-\bar{c}_{h,y,j}\right)\bullet Q_{h,y,j}^{sold}\right)\right)-\sum_{j\in\mathcal{J}_m}\left(C_{y,j}^{O\&M,fix}-C_{y,j}^{invest}\right) \tag{6}$$

where

- $\mathcal{H}_y$ set of all hours in simulation year y ($|\mathcal{H}_y|$=8760)
- $\mathcal{J}$ set of power plants
- P^* hourly spot market price $[EUR/MWh]$
- $\bar{c}$ average realized hourly generation costs $[EUR/MWh]$
- Q^{sold} sold energy volume in spot market $[MWh]$
- $C^{O\&M,fix}$ fixed operation and maintenance costs $[EUR]$
- C^{invest} investments $[EUR]$

The results for consumers are determined in the same manner, yet, there are no long-term costs assumed. Congestion rents accruing to the holders of interconnection rights are set in each time step by the product of the price difference between the interconnected market areas and the corresponding commercial exchange flow determined by the market coupling. No fixed costs for the operation of the market coupling process are taken into account.

$$W_y^{CR}=\sum_{h\in\mathcal{H}_y}\left(\sum_{m\in\mathcal{M}}\left(\sum_{m'\in\mathcal{M}'_m}\left(|p_{h,y,m}^{*}-p_{h,y,m'}^{*}|\bullet Q_{m\to m'}^{ex}\right)\right)\right) \tag{7}$$

Finally, in case RES generation needs to be curtailed because it exceeds total electricity demand in the respective time step, we assume a deadweight loss amounting to the curtailed energy volume times an average feed-in tariff received by RES plant operators despite of being curtailed.

A loss-of-load event occurs when demand cannot be met by the available generation capacity or other remedying factors. The assessment in each hour h of simulation year y and in each market area m is carried out according to the following relationship determining the amount of energy-not-served with all items representing aggregated energy volumes after the market clearing:

$$Q_{h,y,m}^{ENS}=Q_{h,y,m}^{D}-Q_{h,y,m}^{S}-Q_{h,y,m}^{S,RES}-Q_{h,y,m}^{PS}-Q_{h,y,m}^{EX}-Q_{h,y,m}^{IC} \tag{8}$$

where

- Q^{ENS} energy-not-served
- Q^{D} demand
- Q^{S} conventional generation
- $Q^{S,RES}$ RES generation
- Q^{PS} generation (+) / consumption (−) by pumped storage units
- Q^{EX} import (+) / export (−)[8]
- Q^{IC} activation volume of interruptible load contracts

If $Q_{h,y,m}^{ENS}>0$[9] holds, a loss-of-load event is registered. Yearly deterministic values for the LOLE in the respective simulation run are calculated as follows[10]:

$$LOLE_{y,m}=\sum_{h\in\mathcal{H}_y}[Q_{h,y,m}^{ENS}>0] \tag{9}$$

3.3.4. Activation of strategic reserve

In the model different market design options can be tested and compared. In this paper, we supplement the energy market by a capacity mechanism in the form of a strategic reserve which is contracted from existing power plants in an exclusive manner and to be called only in scarcity situations.[11] For that purpose, the model features an additional agent for the operation of the strategic reserve. In each time step, the operator evaluates whether the condition for the activation of the contracted reserve in the implementing market area m_1 ($Q_{h,y,m_1}^{ENS}>0$) is fulfilled. Subsequently, a potential cross-border activation is checked by the operator. For a directly interconnected market area m_2, this is feasible if after market clearing $Q_{h,y,m_2}^{ENS}>0$, $Q_{m_1\to m_2}^{ex}<Q_{m_1\to m_2}^{ex,max}$ and reserve capacities are not yet exhausted. Both national and cross-border activation as well as the contracting of the strategic reserve affect welfare and generation adequacy,[12] which are quantified corre-

[8] Sum of endogenous market coupling flows and exogenous flows to and from market areas not explicitly covered by the simulation model.

[9] Owing to the supply-demand constraints in the market coupling algorithm (Eq. (4)), $Q_{h,y,m}^{ENS}$ is always non-negative.

[10] The Iverson bracket converts a Boolean expression to 1 if true and to 0 if false, respectively.

[11] Details regarding the implementation of a strategic reserve can be found in Neuhoff et al. (2015) and Meyer and Gore (2015).

[12] In particular, $Q_{h,y,m}^{ENS}$ is reduced by the activation volume of the strategic reserve $Q_{h,y,m}^{SR}$.

spondingly.

3.4. Validation of the extended model

In order to establish a model's quality in the context of the respective research question, energy system analysis typically foresees a model testing including different levels of validation and verification (Jakeman et al., 2006). Operational validation provides for comparing the model output with the equivalent from the empirical domain which was explicitly not used as model input to generate the results (Sargent, 2013).

In addition to the validations of the baseline model for the German market area in the years 2001, 2004, 2005–2006 and 2009–2011 (cf. Section 3.2), we apply the validation procedure to the extended model by comparing simulated and historical day-ahead market prices for Germany, France, Belgium and the Netherlands in the period 2012–2014 where data availability in the required resolution is acceptable. For instance, for the year 2014, we find deviations with regard to the mean electricity price between 0.8% (Germany)[13] and 6.1% (Belgium) as well as coefficients of correlation between historical and simulated prices ranging from 0.67 (France) to 0.78 (Germany). Furthermore, the market coupling in the simulation yields a similar share of hours per year with a certain price difference (e.g., EUR 1 per MWh) between two market areas when compared to empirical data.

On average, the validation indicators for the extended model slightly outperform the existing validations of the PowerACE model. This observation is to some degree attributable to the additional endogenous simulation of commercial electricity exchange flows between the market areas. Supplementary quantitative and graphical measures of the model validation are included in Appendix B. Altogether, we judge the model to be applicable for studying the future development of welfare and generation adequacy effects in coupled electricity systems.

4. Simulation design and input data

In this paper, we apply the developed agent-based simulation model for wholesale electricity markets within several case studies. Geographically, we focus on the simulation of the CWE region consisting of the market areas Germany, France, Belgium and the Netherlands.[14] It was also this region[15] which was covered by the CWE Market Coupling, at the time of its introduction a major step towards European market integration.

We set the time frame of each simulation run to 2012–2030. On the one hand, this allows comparing simulation results for the first years with historical data and conducting a model validation (cf. Section 3.4). On the other hand, the simulation period is large enough to consider investment decisions. The cap at 2030[16] is set in order to limit data uncertainty and program execution time.

Concerning the general market design, we assume in the *base case* an energy-only remuneration for power plants across all market areas. Despite the already realized and planned introduction of capacity mechanisms in Europe, we focus in this case study on energy-only markets in order to emphasize effects and interactions stemming from the coupling of electricity spot markets. Analogous to the microeconomic considerations in Section 2.2, in each time step of the base case's simulation, the market coupling is performed for three distinct interconnection scenarios, namely, without any interconnection (*isolated*), with the actual limited capacity values (*market coupling*) and in an unlimited interconnection setting (*unlimited*).

Table 1
Overview of analyzed case studies and interconnection scenarios.

	Interconnection scenario		
Case study	isolated	market coupling	unlimited
Base case	1a	1b	1c
Without ALEGrO		2	
With strategic reserve		3	

With regard to the interconnection capacities, we rely on published NTC values. The interconnection network is held constant during the simulation. The only exception in the base case is provided by a new interconnector between Germany and Belgium (ALEGrO), which is assumed to start its operation in 2019. The potential effects of this new interconnector are analyzed in a separate case study (*without ALEGrO*).

In a third case study, a strategic reserve (cf. Section 3.3.4) is introduced in one market area, namely in Germany (*with strategic reserve*). This constellation can be seen as a stylized example for an asymmetric market design in a coupled electricity system. The respective analysis will focus on the potential effects of a strategic reserve on the implementing market area and, if the reserve can be activated across borders, on the whole system.

Table 1 summarizes how the defined case studies and interconnection scenarios are combined in this paper. Eventually, five separate simulation runs are made and compared pairwise as indicated in the table.

Computing each case study requires the definition of various types of exogenous input data. As far as available, time series data in the model has an hourly resolution. For historical data, official sources are used, while scenario data is based on various existing external studies. An overview of sources for key input data is given in Appendix C.

5. Results and discussion

5.1. Welfare and generation adequacy

In this section, we show the base case's results with regard to the impact of the NTC-based market coupling solution on economic welfare and generation adequacy in the simulated CWE region.

First, we compare how total welfare changes under different interconnection scenarios. The expected short-term welfare-enhancing effect of increasing interconnection capacities (cf. Section 2.2) is confirmed by the simulation results as shown in Fig. 6; while comparing the isolated interconnection scenario (simulation run 1a) and a market coupling with limited interconnection capacity (simulation run 1b) reveals welfare losses in each year of the simulation until 2030, the unlimited scenario (simulation run 1c) leads to welfare gains for the overall system. The welfare effects stem from a better utilization of the respective lowest-cost power plants in the coupled system and from avoiding loss-of-load events in scarce situations through electricity imports.

However, there is a large difference with regard to the respective effect size. Cumulated potential welfare gains in the unlimited case amount to EUR 5.0 billion (or EUR 0.3 billion per year), potential welfare losses in the isolated case to EUR 33.3 billion (or EUR 1.8 billion per year). This large spread is due to the fact that in the isolated

[13] We also performed a statistical validation procedure to test the model's non-validity (Sargent, 2013). For that purpose, we use the developed stochastic simulation framework (cf. Appendix D) to determine mean electricity prices and compare them with historical values based on a two-tailed, one-sample *t*-test. For instance, for 2014 and Germany, the test statistic leads with a significance level of 95%, to support the null hypothesis, i.e., that the model is not invalid.

[14] We follow the definition by the European Regulators' Group for Electricity and Gas (2010), which in 2006 created seven *Regional Initiatives* in Europe with the CWE region forming one of them.

[15] Including Austria as part of the common price zone with Germany.

[16] The cap only refers to the clearing of the spot market in the model, though the planning horizon within the investment appraisal can reach beyond 2030 in order to have equally long horizons every time the investment simulation module is executed.

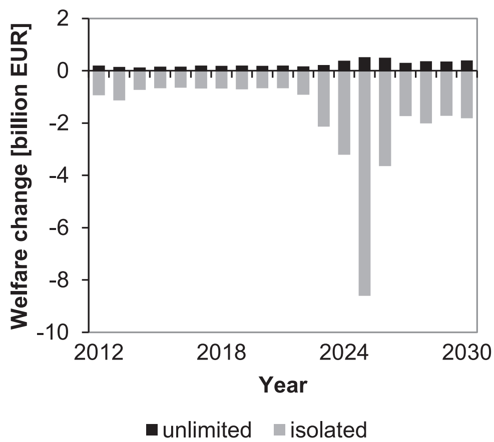

Fig. 6. Yearly welfare changes between limited market coupling and alternative interconnection scenarios.

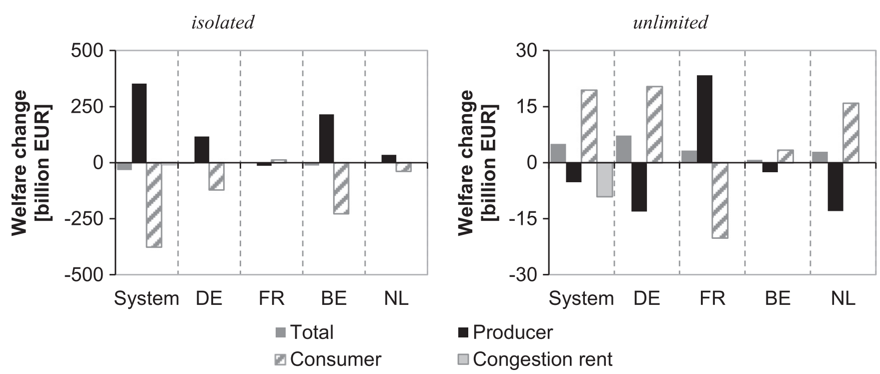

Fig. 7. Distribution of welfare changes among market areas and participants between limited market coupling and alternative interconnection scenarios.

Table 2
LOLE in the simulated system and per market area for the different interconnection scenarios.

	System			**Germany**		**France**		**Belgium**		**Netherlands**	
Year	**isolated**	**coupling**	**unlimited**	**isolated**	**coupling**	**isolated**	**coupling**	**isolated**	**coupling**	**isolated**	**coupling**
2012	4	0	0	0	0	0	0	4	0	0	0
2013	43	0	0	0	0	0	0	43	0	0	0
2014	12	0	0	0	0	0	0	12	0	0	0
2015	17	0	0	0	0	0	0	17	0	0	0
2016	14	0	0	0	0	0	0	14	0	0	0
2017	10	0	0	0	0	0	0	10	0	0	0
2018	14	0	0	0	0	0	0	14	0	0	0
2019	10	0	0	0	0	0	0	10	0	0	0
2020	11	0	0	0	0	0	0	9	0	2	0
2021	11	0	0	0	0	0	0	9	0	2	0
2022	47	1	0	3	0	0	0	45	0	2	1
2023	248	2	4	16	2	0	0	248	0	6	0
2024	415	7	4	36	6	0	0	414	1	7	1
2025	1627	15	11	47	11	0	0	1624	5	8	3
2026	418	16	7	48	8	0	0	402	3	15	8
2027	113	4	4	19	2	0	0	93	0	20	3
2028	159	10	6	23	3	0	0	121	1	56	8
2029	80	7	6	23	4	1	0	20	0	63	5
2030	93	8	7	23	5	1	0	34	1	66	4

case, we observe a high number of loss-of-load events, particularly in the Belgian market area (see below). In these deficit situations, demand cannot be fully satisfied and neither producer nor consumer rents do materialize for the energy-not-served because a matching between demand and supply is only feasible as long as generation capacities are available. Correspondingly, the largest welfare effects can be found in the years where supply is scarcest (2024–2026).

Second, we analyze the distribution of the observed cumulated welfare changes among market areas and participants (Fig. 7). In general, consumers can profit from exchanging electricity between market areas when market clearing prices are reduced as well as when more demand can be met. The latter is, in this paper, equal to avoiding loss-of-load events. Producers can benefit from a market coupling in those cases when prices in the respective market area rise due to higher exports. However, since in a time step with a loss-of-load event market prices are artificially set by the operator to the maximum price allowed (in the present case EUR 3,000 per MWh), a lower number of loss-of-load events has generally a negative effect on producer rents for the benefit of consumers. The overall simulation results suggest that consumers benefit on the wholesale level from the initial introduction of a market coupling as well as from increasing interconnection capacity; the welfare situation for producers worsens when seen for the whole system.

A regional analysis reveals the same trend for all market areas, except for France. Compared to the other market areas, France has a relatively low level of electricity prices because of its large nuclear power plant fleet with low variable generation costs which, in contrast to other market areas (e.g., Germany, Belgium), is not expected to be phased out until the end of the simulation horizon. As a consequence, market coupling generally raises wholesale prices in the French price

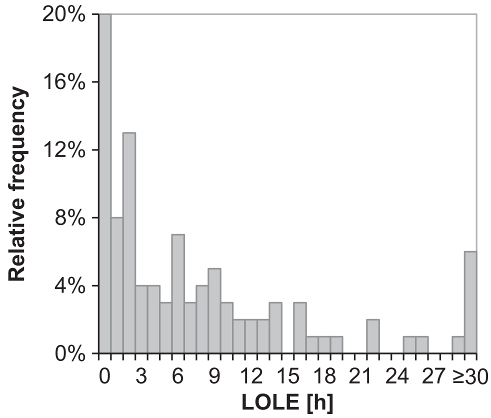

Fig. 8. Histogram of LOLE values for Germany in 2030.

zone, which is detrimental to local consumers. Moreover, we can observe the net welfare effect in each market area to be positive, i.e., market coupling to be welfare-enhancing in all price zones. The cumulated effect compared to the isolated case (simulation run 1a) is strongest for Belgium (EUR 12.9 billion) and weakest for France (EUR 1.8 billion). In the other control case with unlimited capacity (simulation run 1c), Germany would profit most (EUR 7.3 billion) and Belgium least (EUR 0.8 billion).

Third, we focus in our evaluation on the effect of the simulated CWE Market Coupling on generation adequacy. As expected, introducing a market coupling increases generation adequacy in the total system as well as in each market area. Belgium can profit by far the most from the option to import electricity from neighboring countries. While in the isolated case (simulation run 1a), the LOLE in Belgium attains a maximum of 1,624 h in 2025, this value is reduced to 5 h under the actual market coupling (simulation run 1b). In combination with the welfare analysis above, we can show that energy policy targets can be conflicting in certain situations. Specifically, French consumers profit in the simulation from a higher generation adequacy attained by the market coupling, however, the sum of consumer rents decreases compared to the isolated case. Hence, they do not value the reduced number of loss-of-load events as high as the welfare losses due to an increase in electricity prices. This outcome is in part due to price caps in electricity markets which prevent the actual value of lost load from being considered in the market clearing. Additional improvements for the system in terms of generation adequacy can be observed when comparing the unlimited capacity scenario (simulation run 1c) with the limited market coupling. Yearly LOLE values for the different zones and scenarios are presented in Table 2.

In the market coupling scenario (simulation run 1b), there are no loss-of-load events in the system until 2022. Afterwards, the results show a general trend of a slight increase of the LOLE in the simulated energy-only markets. When comparing the modeled LOLE values with today's regulatory standards of at most 3 h per year in France and Belgium as well as 4 h per year in the Netherlands, there is no violation to be observed in France during the whole simulation period, one in Belgium (2025) and three in the Netherlands (2026, 2028 and 2029). There are no guidelines for Germany, which exhibits in the result dataset the LOLE maximum of 11 h in 2025, or the CWE region.

As expected, the simulation results are sensitive to the different types of input data and parameters. One part of the sensitivity analysis is formed by a stochastic simulation, which considers the variation of several input time series, namely of the electricity demand, the fluctuating feed-in from wind and photovoltaic plants as well as the availability of conventional power plants (cf. Appendix D). The stochastic simulation yields N independent simulations of the spot market (cf. Fig. 5) in one particular simulation year. Fig. 8 shows with$N = 100$ the histogram of the simulated LOLE values for Germany in the year 2030. We observe a range from 0 to 52 with an expected value of 8.3[17] and a mode of 0. Not only does the analysis illustrate a clear sensitivity of the results, but the approach also highlights that energy policy targets should rather be defined in a probabilistic manner. Similarly, there is a trade-off between the expected value and the potential “worst case” with respect to the LOLE.

Furthermore, simulation results depend on the chosen values of certain model parameters. For instance, price forecasts play, as expected, a major role when power plant operators value their investment projects which can be shown in our modeling approach by varying parameters such as the level of the maximum price to be expected within the planning horizon or by modifying the approach to estimate the price effect from market coupling (cf. Appendix A). These different observations strengthen, amongst others, the case for a regulatory framework which is as stable and transparent as possible in order not to hamper the prediction of fundamental market factors. This becomes all the more relevant in coupled electricity markets where the degree of interrelation is particularly strong.

5.2. Impact of a new interconnector

In addition to the base case, we perform an extension of the analysis by altering the underlying interconnection network. Given the currently on-going project ALEGrO, we include in the base case a new interconnector between the German and Belgian market area, which is starting operation in 2019 and is the first direct interconnector between the two zones.[18] We assume the interconnection capacity to be 1,200 MW and the total project budget to amount to EUR 430 million (Elia, 2013).

Over the complete simulation period, we see that the new interconnector has a welfare-enhancing effect on the total system (adding EUR 2.9 billion)[19] as well as a positive impact on generation adequacy; for instance, the number of loss-of-load events in the system is reduced by nearly half. Furthermore, the electricity from RES being curtailed because of oversupply declines by 38%. From the fictitious perspective of a private investor, the project offers an internal rate of return of 13.2% and, thus, is likely to be value-creating. However, while sufficient congestion rents accrue on the ALEGrO interconnector, the total of congestion rents in the system is declining because of a higher price convergence implying a lower rate of return for the owners of the other interconnectors. The results are summarized in Table 3.

5.3. Introducing a strategic reserve

For the third case study, we consider a complementary strategic reserve in Germany.[20] As we leave all other market areas unchanged, this leads to an asymmetric market design constellation in the system. In a first step, we analyze the effects of the strategic reserve in the implementing market area. As expected, the strategic reserve, which has a maximum volume of 5.3 GW in the years 2024-206, provides additional generation capacities in scarcity situations and thus raises generation adequacy in the modeled German market area. Over the whole simulation period, 35 loss-of-load events (85%) can be avoided

[17] 95% confidence interval: [6.2;10.3].

[18] In order to evaluate the effects of this new interconnector in isolation, we rerun the simulation without the new interconnection while all other assumptions are held constant (simulation run 2) and compare the outcome with the previous results (simulation run 1b; cf. Table 1).

[19] By running additional simulations with incremented interconnection capacities, we can show that net social welfare further increases. Eventually, a theoretical social optimum exists in terms of welfare when marginal welfare is zero but marginal generation adequacy is still positive, i.e., the two energy policy targets are conflicting on the system level for an additional unit of interconnection capacity.

[20] The results in this section are based on a comparison between simulation run 3 including the strategic reserve and the previously performed simulation run 1b (cf. Table 1).

Table 3
Impact of a new interconnector between Germany and Belgium.

Evaluation criteria	Unit	Effect
Total welfare	million EUR	+2,909.3
Congestion rent (DE-BE)	million EUR	+712.1
Congestion rent	–	−12.8%
LOLE	–	−48.9%
ENS	–	−53.9%
RES curtailed	–	−38.0%

All values cumulated over the full simulation period and given for the total system (if not stated otherwise)

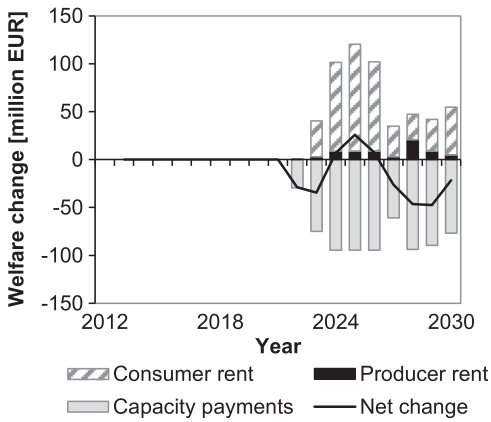

Fig. 9. Yearly welfare effects of the strategic reserve in the implementing market area (Germany).

by those power plants which are contracted as reserve and which, otherwise, would have been closed early for economic reasons. Nevertheless, the total cumulated net welfare effect is negative under the chosen parameterization, i.e., the additional capacity payments necessary to keep the reserve plants from being decommissioned exceed the higher rents from an increased generation adequacy. This relation is dependent on the quality of the operator's forecast concerning the required size of the strategic reserve. Fig. 9 illustrates the yearly welfare effects in the implementing market area.

Additionally, we study the impact of a potential cross-border activation of the reserve, which requires a minimum degree of coordination between the affected market areas and which is only possible under certain constellations (cf. Section 3.3.4). For the simulation period, the cross-border activation yields a reduction of 10.3% of the energy-not-served and of 7 loss-of-load-events in interconnected market areas. While these effects are small in absolute terms when compared to the national activation, which is still prioritized, they are always welfare enhancing since the reserve is already contracted and no additional payments are required.

5.4. Critical appraisal

With regard to the model concept, several spot market participants are represented by a reduced agent model. This applies in particular to demand traders which aggregate total demand in each market area in a single agent and do not feature price elasticity given a lack of detailed data. As a consequence, we cannot assume the consumers' "true" willingness to pay, which distorts numerical values of the presented welfare effects but not the underlying general trends. Although the simulation model has already a high level of detail regarding the techno-economic parameters of conventional power plants, there is still room for improvements (e.g., consideration of part-load efficiencies, integration of combined heat and power restrictions). The same reasoning applies to the representation of investment decisions which could be further enhanced, for instance, by incorporating additional sources of revenues from balancing markets.

Our case studies have a limited geographic scope and cover only a part of the current coupling solution in Europe.[21] The case study featuring a strategic reserve is stylized with simple implementation rules and limited to only one capacity mechanism while by now there exist several other instruments in Europe. As such, we cannot provide specific results beyond the CWE region.

The data required for the simulation runs is inevitably subject to uncertainty. We use public sources for historical data to our best knowledge. For the simulation of future periods we rely on existing studies, i.e., the results can only be considered within the implicitly assumed energy scenario and are not to be mistaken for a deterministic forecast. Within the sensitivity analysis we apply, amongst others, a stochastic simulation which accounts for selected input data types but is itself again subject to limitations.

6. Conclusions and policy implications

In this paper, we have analyzed the potential development of the CWE Market Coupling until 2030 under different scenarios to gain a better understanding of the integrated impact on welfare and generation adequacy in interrelated electricity markets. Based on the analyses, we identify three fields of action for regulatory bodies in Europe in order to support the European Commission's long-term goal of an IEM.

First, European energy policy should provide a stable, transparent regulatory framework with cross-border congestion management in the form of implicit auctions as a key component. Our results indicate that market coupling in Europe increases welfare and generation adequacy and, thus, should from an overall perspective be continued and strengthened. There are different options for market operators, grid operators, regulators and investors to extend market coupling, each requiring a comprehensive comparison of benefits and costs. In the European context, we see, for instance, a wide-spread introduction of a flow-based market coupling, a continuation of the current processes to unite the different Regional Initiatives and the physical extension of the interconnection network (cf. ENTSO-E's Ten-Year Network Development Plan). However, widening market coupling can entail different distributional effects. Overall welfare gains are distributed asymmetrically among market areas and market participants which could cause resistance (Ochoa and van Ackere, 2015). As shown for the German-Belgian interconnector, new interconnection investments also affect congestion rents in the system. Such cannibalization effects could become critical in the case of private investments which might result in a divergence between the social and private optimum of interconnection investments (Hauteclocque and Rious, 2011). Our results further indicate that generation adequacy in the CWE region is declining from 2022 on and that current LOLE targets would be breached in Belgium and the Netherlands. Countermeasures could, for instance, be provided through new interconnectors (e.g., Nooij, 2011) and capacity mechanisms (e.g., Hary et al., 2016). As expected, simulation results are sensitive with respect to the development of underlying fundamental factors (e.g., electricity demand) and decision parameters of agents (e.g., price expectations). All these findings gained from various sensitivity analyses underpin that altering the electricity market design needs to be cautious and coherent. Market participants need to rely on the regulatory framework in order to behave in the intended way, which is particularly relevant in interconnected electricity markets given the different levels of interaction. In the future, other markets (e.g., intraday, balancing energy) are also expected to be coupled tighter, which will further increase the integrative demand on elec-

[21] In 2014, the region covered by the case studies in this paper represented 40% of the total electricity consumption in the area of the current Multi-Regional Coupling (ENTSO-E, 2015).

tricity market design.

Second, the targets of energy policy need to be clearly defined and operationalized. This process must consider potential interactions and conflicts between the targets. With the help of our analyses, we can identify several constellations where welfare and generation adequacy are conflicting. We can show that increasing interconnection capacities in a market coupling raises generation adequacy, although consumers might not always benefit from a welfare perspective. Similarly, capacity mechanisms, in the paper illustrated by a strategic reserve, can lead to higher generation adequacy levels while the overall welfare effect can be negative. When it comes to network investments, there is also a trade-off between adequacy and a market-wide welfare optimum. Consequently, regulators are faced with a complex task to find a balance between the different energy policy targets which is typically subject to different and changing socio-political paradigms. The definition of concrete, numerical target values is further challenged due to uncertainty in general. Therefore, policymakers are encouraged to integrate risk attitudes or to follow a probabilistic approach and determination of targets. Introducing a generation adequacy concept on a European scale is an essential prerequisite to strengthen the IEM. In the future, the list of criteria could also be complemented by a dimension concerning social acceptability in order to attach greater significance to the social repercussions of some energy policy measures (e.g., Stram, 2016).

Third, electricity market designs need to be coordinated among member states. The prime example is market coupling itself which can deliver undeniable benefits in terms of welfare and generation adequacy but requires the participation and collaboration of various stakeholders across borders. Additionally, our simulation results illustrate that coordination is also desirable in the context of capacity mechanisms. In a stylized constellation, the cross-border activation of a previously national strategic reserve supports the considered policy targets.[22] Consequently, national and European regulators need to contain the divergence of national electricity market designs. However, energy policy is currently mainly a national competence of the EU member states and the EU itself lacks direct legislative powers in this regard. Establishing one “true” European market design in the future is an intricate political challenge which cannot proceed without a genuine discussion of the principles of subsidiarity and sovereignty, respectively, in the context of energy policy.

Paying attention as well as acting on these three fields should foster the realization of the IEM. In the future, we see, amongst others, need for additional research with regard to how different price zone configurations, the flow-based market coupling and other capacity mechanisms will affect market results and energy policy targets.

Appendix A. Short-term bidding of electricity trading agents

In the spot market of the developed agent-based simulation model, respective electricity trading agents submit bids, which consider various techno-economic parameters to reflect marginal costs or marginal utility. In particular, power generators calculate bid prices for hour h' of day d and power plant j by summing up variable generation costs $c_{d,j}^{var}$, possible start-up costs $c_{h',d,j}^{start}$ and a potential scarcity mark-up $c_{h',d,j}^{markup}$:

$$P_{h',d,j}^{bid}=c_{d,j}^{var}+c_{h',d,j}^{start}+c_{h',d,j}^{markup} \tag{A.1}$$

Variable generation costs include the costs for fuel and carbon emission certificates as well as other variable operation and maintenance costs:

$$c_{d,j}^{var}=\frac{p_{d,j}^{fuel}}{\eta_j}+\frac{p_d^{carbon}\bullet\varepsilon_j}{\eta_j}+c_j^{O\&M} \tag{A.2}$$

where

c^{var}	variable generation costs $[EUR/MWh_{el}]$
p^{fuel}	fuel price $[EUR/MWh_{th}]$
η	electric efficiency $[-]$
p^{carbon}	carbon price $[EUR/t_{CO_2}]$
ε	carbon emission factor $[t_{CO_2}/MWh_{th}]$
$c^{O\&M}$	operation and maintenance costs $[EUR/MWh_{el}]$

Start-up costs consider opportunity costs from potentially ramping power plants which typically causes additional costs due to higher fuel consumption as well as wear and tear. The power generators' basic strategy for the spot market is to determine when the respective power plants are expected to be operating or idle within the bidding period. If a start-up or shut-down event is expected to occur, the corresponding costs are distributed appropriately across the hourly bids. In the model, the necessary price forecast is generally based on the agents' expectations of the national merit order and residual demand. If the market area is part of a market coupling, market prices are assumed to be influenced by the developments in interconnected markets (cf. Section 2.2.2). Therefore, the price forecast approach is extended by an estimation of the market coupling's price effect based on fundamental factors in interconnected markets (e.g., availability of generation and interconnection capacities, demand, feed-in from RES). Methodologically, a multiple linear regression is used to estimate the additive hourly price effect, which is implemented using the *Recursive Least Squares* algorithm (Zaknich et al., 2005). The approach allows agents to learn the strength and changes of the price effect over time. The scarcity mark-up is an additional factor to reflect that in times when supply is scarce power generators might be able to charge a share of their fixed operational costs and capital costs, i.e., cost components which are variable only in the long term. A formalization of start-up costs and of the mark-up factor in the baseline model is included in Bublitz et al.(2015). The bid volume of the power plant in the respective time step is determined by an exogenously given availability factor and a potential obligation to provide balancing power.

[22] While not accounted for in our model, the asymmetric introduction of a strategic reserve in a coupled system could also lead to market distortions when trigger rules are price-based which in consequence can entail negative welfare effects (Meyer and Gore, 2015). Furthermore, the size of a strategic reserve depends on how interconnectors are considered in the dimensioning process.

Market participants other than power generators generally follow the same bidding process, however, the determination of bid price and volume is simplified. For each of the following items, generation from RES, demand, exchange with market areas not covered by the simulation and pumped storage units, there is a single trader per market area submitting price-inelastic bids.

Appendix B. Model validation results (2014)

See Table B1 and Fig. B1.

Table B.1
Statistical comparison between the results from the simulated spot market and corresponding empirical data.

	Germany		France		Belgium		Netherlands	
	empirical	**simulated**	**empirical**	**simulated**	**empirical**	**simulated**	**empirical**	**simulated**
Mean	32.76	33.04	34.63	33.71	40.79	38.32	41.18	40.25
Standard deviation	12.77	9.49	13.91	10.22	12.68	10.77	10.69	11.77
Minimum	−65.03	13.51	−2.12	−8.46	−0.01	20.07	0.12	24.43
Maximum	87.97	88.27	96.69	84.07	200.00	77.23	96.69	70.68
Correlation	0.78		0.67		0.72		0.77	
MAE[a,b]	2.99 (9.1%)		5.06 (14.6%)		3.93 (9.6%)		2.86 (6.9%)	
RMSE[a,b]	5.10 (15.6%)		5.92 (17.1%)		5.06 (12.4%)		3.38 (8.2%)	

Indicators in EUR/MWh (except coefficient of correlation);[a] Mean absolute error (MAE) and Root Mean SquareError (RMSE) calculated for the sorted price duration curves; [b] Values normalized to respective empirical mean inparentheses.

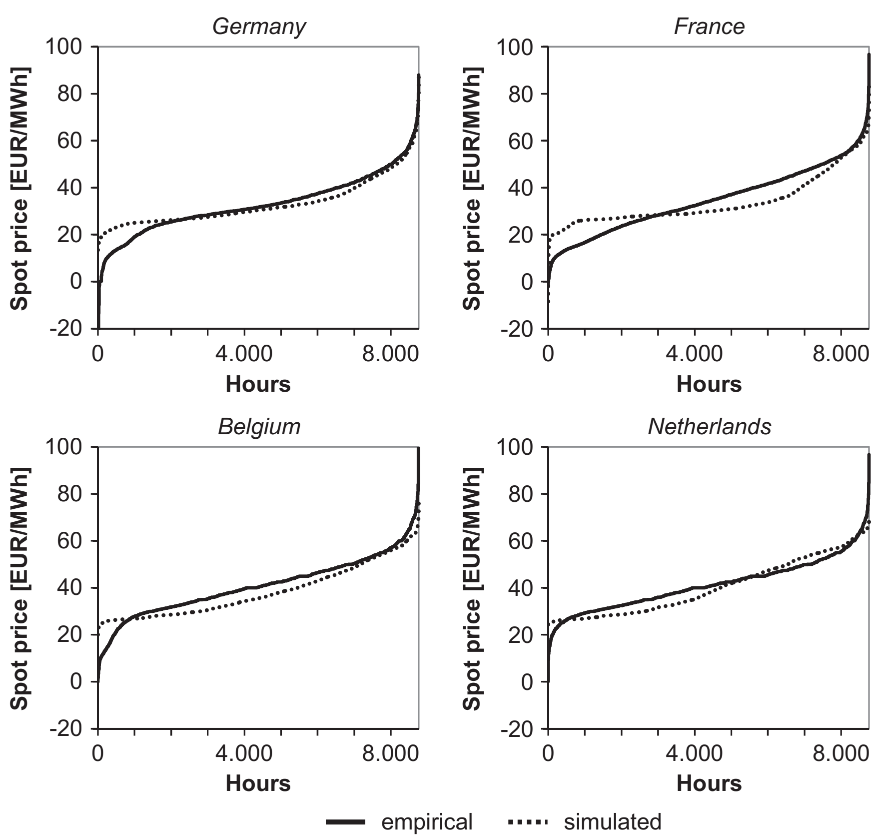

Fig. B.1. Price duration curves of simulated and empirical spot market prices.

Appendix C. Model input data

See Table C1.

Table C.1
Overview of sources for key model input data.

Input type	Entity resolution	Temporal resolution	Data source			
			DE	FR	BE	NL
Fuel prices (gas, hard coal, oil)	system	daily / yearly	(i)			
Fuel prices (uranium)	system	yearly	(ii)			
Fuel prices (lignite)	system	yearly	(iii)			
Carbon prices	system	daily / yearly	(iv)			
Electricity prices (Day-Ahead)	market area	hourly	(v)		(vi)	
Electricity demand (yearly sum)	market area	yearly	(vii)	(viii)	(ix)	
Electricity demand (load profile)	market area	hourly	(x)			
Electricity exchange (exogenous)	system / market area	hourly	(xi)			
Interconnection capacity (NTC)	system / market area	yearly	(xii)			
RES (installed capacity)	market area	yearly	(xiii)	(xiv)	(xv)	
RES (generation profile)	market area	hourly	(xvi)			
Conventional power plants (stock)	agent	–	(xvii)			

(i) historic - EEX market data
scenario: IEA (2012): World Energy Outlook
(ii) historic - Cour des Comptes (2012): Les coûts de la filière électronucléaire
scenario - increase by 1% p.a.
(iii) historic - Schröder, A.; Kunz, F.; Meiss, J.; Mendelevitch, R.; von Hirschhausen, C. (2013): Current and Prospective Costs of Electricity Generation until 2050
scenario - increase by 1% p.a.
(iv) historic - EEX market data
scenario - EEX market data (EUA futures), 50Hertz Transmission; Amprion; TenneT TSO; TransnetBW (2014): Szenariorahmen für die Netzentwicklungspläne Strom 2015 – Entwurf der Übertragungsnetzbetreiber
(v) historic - EPEX SPOT market data
scenario - endogenous
(vi) historic - APX/Belpex market data
scenario - endogenous
(vii) historic - ENTSO-E monthly consumption
scenario - DLR; FhG-IWES; IFNE (2012): Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global (adjusted for recent historic development)
(viii) historic - RTE Consommation intéreure
scenario - RTE (2014): Generation adequacy report on the electricity supply-demand balance in France (2014 Edition) (adjusted for recent historic development)
(ix) historic - ENTSO-E monthly consumption
scenario - Pentalateral Energy Forum (2015): Generation Adequacy Assessment
(x) historic/scenario - ENTSO-E hourly load (normalized)
(xi) historic/scenario - ENTSO-E Cross-Border Commercial Schedules
(xii) historic - ENTSO-E Cross-Border Commercial Schedules (annual maximum)
scenario - historic values held constant, commissioning of new interconnector between Germany and Belgium in 2019 (cf. Section 4 and Section 5.3)
(xiii) historic - BMWi (2015): Zeitreihen zur Entwicklung der erneuerbaren Energien in Deutschland
scenario - DLR et al. (2012) (adjusted for recent historic development)
(xiv) historic - RTE (2014): Statistiques Production Consommation Echanges 2013, ECN (2011): Data on renewable energy in the European Union Member States
scenario - ECN (2011) (adjusted for recent historic development)
(xv) historic - EurObserv'ER (2015): Database Renewable Energy Sources; ECN (2011)
scenario - ECN (2011) (adjusted for recent historic development)
(xvi) historic / scenario - i.a. EEX (2015): Transparency platform, RTE (2015): Portail Clients, Elia (2015): Grid data
(xvii) historic - Platts (2009): World Electric Power Plants (WEPP) Database, Bundesnetzagentur (2015): Power plant list, RTE (2015); additional web research
scenario - endogenous, adjustments to operating lifetime due to Industrial Emissions Directive (IED) and SER Energieakkoord

Appendix D. Stochastic time series simulation

The general approach for the stochastic simulation of time series for electricity demand and for the fluctuating feed-in from wind and photovoltaic plants is based in each hour of the simulation period on an additive combination of a deterministic, seasonal component and a stochastic term. First, historical hourly time series are appropriately preprocessed. For instance, the demand model uses a single representative hour of each day while the other information is stored in normalized day profiles. Second, we estimate a deterministic model considering different types of seasonality (diurnal, weekly, yearly) using a *discrete Fourier transform* to identify the major spectral components. Third, the residuals between the historical time series and the seasonal model are used to calibrate an *Ornstein-Uhlenbeck process* (Iacus, 2008). Eventually, for each time series to be generated a new stochastic path is simulated and the final time series is constructed by adding the seasonal model as well as by integrating the remaining parameters.

For estimating the availability of conventional power plants, we use a *two-stage Markov model* with the two states “available” and “not available” and the failure rate and the repair rate as the transition probabilities. The probabilities follow an exponential distribution and are calibrated using values from literature and empirical data, respectively.

The stochastically simulated time series together with the other exogenous model assumptions form the input dataset for each new spot market simulation within the stochastic simulation, which is repeatedly carried out for one selected year of the simulation.

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