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EWI Working Paper, No 15/07

December 2015

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ISSN: 1862-3808

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Abstract

The European electricity market design is based on zonal markets with uniform prices. Hence, no differentiated locational price signals are provided within these zones. If intra-zonal congestion occurs due to missing grid expansion, this market design reveals its inherent incompleteness, and might lead to severe short and long-term distortions. In this paper, we study these distortions with a focus on the impact of restricted grid expansion under zonal markets. Therefore, we use a long-term model of the European electricity system and gradually restrict the allowed expansion of the transmission grid per decade. We find that the combination of an incomplete market design and restricted grid expansion leads to a misallocation of generation capacities and the inability to transport electricity to where it is needed. This results in an energy imbalance in some regions of up to 2-3 % and the difficulty to reach envisaged political targets in the power sector.

JEL classification: D47, C61, C63, Q40
Keywords: Electricity Market, Grid Expansion, Incomplete Market Design, Misallocation, Energy Imbalance

1. Introduction

The market design of the European single market for electricity consists of regional bidding zones, usually aligned to national borders. There is one uniform price per zone, while implicitly neglecting scarce transmission capacities within these zones. In reality, however, this simplification is often inconsistent with physical realities and hence, represents and inherent market incompleteness. In fact, aggregated zonal prices conceal important information regarding scarcities in the transmission grid that would be important to coordinate market participants in an efficient way.

Funded by the German Federal Ministry for Economic Affairs and Energy based on ruling of the Deutsche Bundestag. The financial support through grant 03ESP239 is gratefully acknowledged. The responsibility for the content of this publication lies solely with the authors.

Joachim Bertsch and Simeon Hagspiel gratefully acknowledge funding of the German research society DFG through research grant HO 5108/2-1.

In the short term, this incompleteness is addressed by the redispatch of generation facilities: after the market clearing, generation units are requested to modify their scheduled dispatch by increasing or decreasing their production level in order to relieve congestion in the grid. An increase in generation is remunerated with the estimated variable costs, partly covered by the saved variable costs of the decreased generation. If the cost estimations were correct and the redispatch measure succeeded in finding the least cost alternative, the short-term market outcome would be optimal, i.e., statically efficient, in the case of inelastic demand.[1]

In the long term, functionality of zonal markets shall be ensured by sufficient expansion of the grid infrastructure. In practice, however, grid expansion is often *insufficient* or at least delayed. For Europe, 30 % of the projects listed in the Ten Year Network Development Plan (TYNDP) are reported as delayed or rescheduled (ENTSO-E (2015)). For Germany the situation is even worse: 50 % of the projects are reported as delayed (Bundesnetzagentur (2013c)). There may be various obstacles causing delays of planned grid expansion. One of the main reasons are long and inefficient approval procedures (Schneider and Battaglini (2013), Steinbach (2013)). But even if approval procedures are successfully completed, the lack of public acceptance because of the landscape impacts may further delay the realization of infrastructure projects (ENTSO-E (2010), Schneider and Battaglini (2013)). According to ENTSO-E (2015), these obstacles account for one third of investment delays.

At the same time, due to the uniform price for all market participants, the resulting intrazonal scarcity in transmission capacities is not taken into account in the investment decisions of generation. In fact, (zonal) markets should ensure that sufficient capacity is installed to meet demand on a zonal level. However, there might be a misallocation of generation capacities within the zones due to missing locational price signals. These misallocations are exacerbated by missing grid capacities that might not allow to transport electricity to the customers. Thus, missing grid expansion might severly jeopardize the long-term functionality of zonal markets. Especially, although redispatch might induce efficient market outcomes in the short term, it does not suffice to heal the incompleteness of the market design to achieve long-term, i.e., dynamic, efficiency as locational price signals are not considered.[2] As we will show, this might induce severe inefficiencies in the market outcome, which are increasing with the level of grid restriction.

In Europe, the effect of misallocation of generators and missing transmission capacity is particularly relevant due to fundamental changes in the supply and demand structure caused by strong climate protection efforts.[3] A substantial shift from conventional to renewable generation, which

[1] In practice, this result will probably not be entirely realized due to ramping constraints of redispatched power plants. Furthermore, the system operator may have restricted information and restricted access to cross-border capacities, which impedes optimality of the redispatch.

[2] See (Burstedde, 2012) for a detailed discussion of the (in-)efficiencies of several redispatch designs.

[3] The European Union (EU) formulated an ambitious 2030 energy strategy, including a EU domestic reduction of greenhouse gases (GHG) by 40 % compared to 1990, a share of 27 % renewable energy, and a 27 % reduction in energy consumption compared to 2005 (European Commission, 2014).

is usually far away from current generation and load centers, increases the importance of sufficient grid infrastructure. A blueprint for the described dynamics in a zonal market design with an increasing share of renewables is the case of Germany, where short-term intra-zonal congestion is removed using redispatch measures. In order to avoid situations where redispatch would be necessary but no generation capacities are available at the right location, the German Transmission System Operators (TSO) contract generation capacity in advance at locations which are expected to be relevant for future congestion relieve. This so-called grid reserve ensures locally sufficient generation capacity. Table 1 illustrates the development of the renewables share, redispatch measures as well as the grid reserve quantity. As can be seen, redispatch measures broadly increased with an increasing share of renewables, caused by missing transmission grid capacities. Meanwhile, also the grid reserve quantities increase. This development clearly shows the effect and the deficits of the zonal market design.

Year	2010	2011	2012	2013	2014	2015 (Q1/2)
Renewable share of gross electricity demand [%]	16.6	20.2	22.8	23.9	25.8	-
Redispatch volume [GWh]	-	-	4956	4604	5197	5253
Redispatch costs [Mio. €]	48	129	165	115	139	252.5
Grid reserve [GW]	-	1.6	2.5	2.5	3.1	6.7-7.8

Table 1: Development of renewable share, redispatch measures and grid reserve in Germany[4]

In the literature, several papers investigate grid expansions in the short as well as in the long term. Schaber et al. (2011) analyze the importance of transmission grid expansion for the integration of renewables in Europe with a linear dispatch and investment model. They find that grid integration costs amount to 25 % of renewables investment costs. Schaber et al. (2012) analyze grid expansions for the European system in 2020 given an increasing share of wind and solar power. A cost-minimization model of the European power system is applied under the assumption of a nodal pricing regime. Results indicate lower electricity prices in proximity of renewables and benefits for conventional plants in case of grid expansion. Optimal grid expansion amounts to 20 % respectively 60 % of today's capacity, depending on whether underground cable or overhead lines are used. Fürsch et al. (2013) quantify the benefits of optimal grid expansion up to 2050 by applying a dispatch and investment model coupled with a load flow grid model that determines NTC values for the market coupling. They compare optimal grid expansion with moderate expansion of interconnector capacities, and find that with a large share of renewables, high grid expansion (an additional 76 % capacity compared to today) proves to be optimal to exploit good renewable sites. The linkage between renewables, grid expansion, and generation backup capacities was investigated

[4]Sources: Bundesnetzagentur (2012), Bundesnetzagentur (2013a), Bundesnetzagentur (2013b), Bundesnetzagentur (2013c), Bundesnetzagentur (2014), Baake (2014), Bundesnetzagentur (2015a), Bundesnetzagentur (2015b), AGEB (2015)

by Steinke et al. (2013). They use a stylized model to analyze the effects of grid expansion on the necessity of backup capacities and storage. They find that an ideal grid reduces the need of backup capacities from 40 % to 20 % with a share of 100 % renewables. Hagspiel et al. (2014) analyze the optimal grid expansion until 2050 using a linear dispatch and investment model coupled with an AC grid model via Power Transfer Distribution Factors (PTDF). They find that minimal grid expansion for achieving an ambitious CO_2 reduction target of 90 % leads to an increase of 21 % of total system costs. Oggioni and Smeers (2012) as well as Kunz (2013) deal with the impact of zonal markets and redispatch for Germany and Europe in the short run. In doing so, Oggioni and Smeers (2012) use a six node model and Kunz (2013) a European short-term electricity market model. Grimm et al. (2016) build on a trilevel modelling approach investigating the long run impact of different market designs. They apply their theoretical model to a three and six node case study and find that investment decisions of firms and TSOs do not have to lead to the social optimum in a market environment. Bertsch et al. (2015) develop a theoretical framework to analyse and compare different market designs. In a large-scale application it is shown that zonal markets with redispatch lead to inefficiencies compared to nodal pricing, representing the first best.

We contribute to the existing literature by investigating the particular relevance of grid expansion under zonal markets. We show that the market design is inherently incomplete due to missing price signals, and that important scarcities in the grid are not properly considered for investment decisions. For this, we build on a long-term fundamental model of the European electricity market developed in Bertsch et al. (2015), allowing the representation of the European zonal markets with redispatch. The model includes generation dispatch, power flows, as well as generation and grid investments. In contrast to Bertsch et al. (2015), we implement the EU 2030 energy strategy to ensure the results are in line with current European policies. Furthermore, we extend the analysis by designing six scenarios that differ with respect to their level of allowed grid expansion. We are hence able to investigate in great detail the relevance of grid expansion for the market outcome.

Our results show that restricted grid expansion together with the inherent incompleteness of the market design has significant effects. We restrict grid expansion per decade from zero, i.e., no grid expansion at all, to 30 TWkm throughout six different scenarios. In case of restrictions ranging from 0-15 TWkm of grid expansion per decade, there are energy imbalances of up to 2 % (3 %) for 2020 (2030). Also with less restricted grid expansion, these energy imbalances still amount to more than 0.2 % for scenarios 15 TWkm in 2020. In 2030, however, significant energy imbalances only occur for the scenarios of restrictions of up to 5 TWkm. The highest energy imbalances are found to be in Southern Germany. Thereby, energy imbalances indicate that generation is missing at some locations, entailing the need to either provide additional generation capacity outside of the market (e.g., by means of a grid reserve as in Germany), or to curtail load. Furthermore, no grid expansion jeopardizes the achievement of the EU 2030 climate targets: the share of renewables is 1.5 percentage points lower than in any other scenario, resulting from a curtailment of up to 7.7 % of photovoltaic (PV) generation and over 3 % of wind generation. Missing grid expansion hence results in higher CO_2 emissions in the power sector and implies the need to shift CO_2 emissions from the power sector to other, probably more expensive sectors. DC lines are found to be of particular value for the integration of renewables as they allow point-to-point transfers from renewables generation to load sites.

Overall, the results demonstrate the shortfalls of the zonal market design in the light of restricted grid expansion which is a scenario that appears to be very likely. The more restricted grid expansion is, the more administrative intervention will be needed to avoid energy imbalances possibly causing expensive and politically unwanted load curtailment. One alternative might be to administratively contract generation capacity outside the market. To overcome this problem, a redefinition of zones or introduction of locational price elements may be a suitable way to effectively reduce the amount of administrative intervention. Furthermore, obstacles for grid expansion should be removed in order to ensure sufficient levels of grid to connect generation and load.

The paper is structured as follows: Section 2 introduces the model and numerical assumptions. Results are presented in section 3. Section 4 concludes.

2. Methodology

2.1. Model

To simulate the development of the electricity system with zonal markets and redispatch, we follow the approach described in Bertsch et al. (2015) and combine a cost-minimizing dynamic linear investment and dispatch market model with a model of the AC grid using a linear Power Transfer Distribution Factor (PTDF) representation of the load-flow. To deal with the non-linear dependence of the PTDFs on the grid impedances, the models are solved iteratively by updating PTDF matrices until convergence is achieved as proposed in Hagspiel et al. (2014).

The model represents an intertemporal equilibrium model that simultaneously solves the operation and investment of generation and the transmission infrastructure. The model relies on a set of simplifying assumptions: we assume perfect competition among generators, perfect regulation of TSOs, the absence of transaction costs and uncertainty, inelastic demand, continuous expansion of generation and transmission capacities and continuous adjustment of the corresponding transmission impedances. For a thorough discussion of the model development and characteristics, the reader is referred to Bertsch et al. (2015).

We make use of a separated representation of generation and transmission in order to represent the status quo of European electricity markets with unbundled generation and transmission firms. The separation of the problem helps us to implement the market incompleteness induced by the zonal market design and the related information deficit. Our iterative solution algorithm is based on two stages that are solved sequentially. First, the generation market equilibrium is determined by minimizing generation and investment costs while meeting an (inelastic) demand and considering inter-zonal transmission capacities. This implies that the zonal market for electricity supply and demand (including both, operation and investment) only considers interconnectors (and no intra-zonal grid congestion). The solution represents the result of perfect competition in the electricity market. Technologies for balancing supply and demand in each zone are conventional and renewable generation technologies as well as storage. We consider pumped hydro storage, hydro storage dams and the possibility to build new Compressed Air Energy Storage (CAES) from 2020 onwards. In the second stage, the TSO is in charge of investments in transmission capacities as well es the operation of redispatch measures across borders given the market results of the first stage. This represents one perfectly incentivized Transmission System Operators (TSO) (or several perfectly coordinated and incentivized TSOs) for all considered markets with the objective of minimizing its (their) costs while keeping the system stable, i.e., matching zonal demand and supply while ensuring that no line is overloaded. At the transmission level, either AC or DC interconnections are available. While the DC interconnections allow direct transfers of electricity between neighboring regions, the utilization of the AC grid is subject to loop flows represented by the PTDF.

Equations (1a)-(1l) state a simplified yet representative formulation of the problem: At the generation stage, total costs X are minimized such that an exogenously defined demand d per zone $m, n \in M$ is met at all points in time t.[5,6] Zonal demand is determined by aggregating nodal demand levels $d_{i,t}$ for all nodes within a zone $i \in I_m$.[7] Costs for generation technologies consist of the variable costs $\gamma_{i,t}$ for generation $G_{i,t}$ and the yearly fixed and (annualized) investment costs $\delta_{i,y}$ for the generation capacity $\overline{G}_{i,y}$. Both types of costs may change over time (note that y represents instances of investment, e.g., years, while t are dispatch situations, e.g., hours). Generation at a node is restricted by the installed capacity (Equation 1c). To balance supply and demand in zone m, generation in that zone may be complemented by trades $T_{m,n,t}$ from other zones n. Thereby, each trade from zone m to zone n equals the negative trade from zone n to zone m and is in turn restricted by inter-zonal transmission capacities $\overline{P}_{m,n,t}$ (Equation 1d).

The second stage consists of minimizing costs Y occurring at the transmission level due to grid expansion and redispatch. The grid can be expanded by adding line capacity between two nodes at costs $\mu_{i,j,y}$, while redispatch quantities $R_{i,t}$ have the same variable costs $\gamma_{i,t}$ as in the generation stage. Negative redispatch quantities can be only as high as generation levels obtained at the first stage, while positive redispatch quantities are restricted by generation capacities (Equation

[5]The depicted model is a simplified version of the model used for the large-scale application. The large-scale model includes amongst others technical (e.g., minimal load, maximum load, ramping, etc.), political (e.g., nuclear phase-out), as well as environmental (European CO_2 quota) constraints that are for reasons of clarity neglected in the theoretical framework. A more detailed representation of the market model (generation stage) may be found in Richter (2011) or Jägemann et al. (2013), while the AC grid model (transmission stage) is described in Hagspiel et al. (2014).

[6]A detailed overview containing all parameters, variables and sets is depicted in Table 5 in the Appendix.

[7]In the numerical simulation, we use interdependent hours and type days and scale the volumes to yearly quantities. Furthermore, costs are discounted to the starting year. Several generation technologies with different characteristics such as peak or base load exist at each node. However, for the sake of simplification we omit these model properties in this formulation.

1g). The sum of all (positive and negative) redispatch measures has to amount to zero (Equation 1h) to keep the system balanced. Generation (including generation and redispatch), demand as well as the existing infrastructure induce power flows on transmission lines that are restricted by transmission capacities $\overline{P}_{m,n,y}$ (Equation 1i).[8] The exchange between the generation and the transmission stage takes place via the inter-zonal transmission capacities $\overline{P}_{m,n,t}$.[9] Thereby, function g determines those inter-zonal transmission capacities for each dispatch time t (that are provided to the generation market, i.e., the first stage of the model) based on grid capacities $\overline{P}_{i,j,y}$, generation $G_{i,t}$, demand $d_{i,t}$ and redispatch $R_{i,t}$. The expansion of transmission capacities $\overline{P}_{i,j,y}$ times line length $l_{i,j}$ per decade b is restricted by some value z. The model is re-run with stepwise changes of capacity restriction levels z, thus allowing a fine-grained identification of the effects of limited grid expansion.[10] Due to the functional relationship of trades and transmission capacities, the market clearing condition has to reoccur on the transmission stage (Equation 1f). Trades from zone m to n are again equal to the negative trade from zone n to m (Equation 1l).

To demonstrate the deficiencies of the zonal market with redispatch, we can compare problem (1a)-(1l) with a two-stage nodal pricing regime representing the first-best benchmark. The corresponding model can be found in the Appendix. The main difference stems from zonal markets m, n being replaced by nodes i, j. As a consequence, TSOs need no redispatch $R_{i,t}$ as locational price signals are directly incorporated in the dispatch. All relevant information is available to all market participants at all times, making nodal pricing the first-best efficient benchmark. For a thorough comparison of different market designs and their performance including zonal as well as nodal pricing regimes, the reader is referred to Bertsch et al. (2015).

Generation

$$\min_{\overline{G}_{i,y}, G_{i,t}, T_{m,n,t}} \quad X = \sum_{i,y} \delta_{i,y} \overline{G}_{i,y} + \sum_{i,t} \gamma_{i,t} G_{i,t} \tag{1a}$$

$$\text{s.t.} \quad \sum_{i \in \mathbf{I_m}} G_{i,t} - \sum_{n} T_{m,n,t} = \sum_{i \in \mathbf{I_m}} d_{i,t} \qquad \forall m, t \tag{1b}$$

$$G_{i,t} \leq \overline{G}_{i,y} \qquad \forall i, t \tag{1c}$$

$$T_{m,n,t} = -T_{n,m,t} \leq \overline{P}_{m,n,t} \qquad \forall m, n, t \tag{1d}$$

[8] In our case power flows are represented by PTDFs that are treated as a parameter while solving the transmission stage, such that Equation (1i) becomes a linear constraint. However, we account for non-linearities in the load flow equations by updating PTDFs based on the new transmission capacities when iterating with the AC grid model.

[9] Note that this approach differs from Bertsch et al. (2015), where the exchange worked via transmission capacity marginals.

[10] Note that we use j, k and q as alias for i in order to represent different nodes in the formulation.

Transmission

$$\min_{\overline{P}_{i,j,y},R_{i,t}} \quad Y = \sum_{i,j,y} \mu_{i,j,y}\overline{P}_{i,j,y} + \sum_{i,t} \gamma_{i,t} R_{i,t} \tag{1e}$$

$$\text{s.t.} \quad \sum_{i \in \mathbf{I_m}} G_{i,t} - \sum_{n} T_{m,n,t} = \sum_{i \in \mathbf{I_m}} d_{i,t} \qquad \forall m, t \tag{1f}$$

$$0 \leq G_{i,t} + R_{i,t} \leq \overline{G}_{i,y} \qquad \forall i, t \tag{1g}$$

$$\sum_{i} R_{i,t} = 0 \qquad \forall t \tag{1h}$$

$$|P_{i,j,t}(\overline{P}_{k,q,y}, G_{k,t}, d_{k,t}, R_{k,t})| \leq \overline{P}_{i,j,y} \qquad \forall i, j, t \tag{1i}$$

$$\overline{P}_{m,n,t} = g(\overline{P}_{i,j,y}, G_{i,t}, d_{i,t}, R_{i,t}) \tag{1j}$$

$$\sum_{y \in b} \overline{P}_{i,j,y} l_{i,j} \leq \sum_{y \in b-1} \overline{P}_{i,j,y} l_{i,j} + z \qquad \forall b \tag{1k}$$

$$T_{m,n,t} = -T_{n,m,t} \quad \forall m, n, t \tag{1l}$$

2.2. Numerical assumptions

The geographical scope of the simulation, as shown in Figure 1, contains a high-resolution nodal representation of the Central Western European (CWE) region, and an aggregated representation of the neighboring countries.[11] The CWE region consists of 5 zonal markets where nodes within the zones are aggregated and zones correspond to national borders (Belgium, Netherlands, Luxembourg, Germany and France) that are coupled via inter-zonal transmission capacities offered to the market. Due to limitations in publicly available data and models, our approach to the zonal coupling only considers cross-border line capacities. Note that in practice, the mechanism applied in the CWE region may in addition include some intra-zonal congestion in the capacity allocation.[12] Physical feasibility of the dispatch on the grid level is ensured by a cross-border redispatch. To account for trades with neighboring countries, 5 satellite regions are included: Southern Europe (Italy, Austria[13] and Switzerland), Eastern Europe (Czech Republic, Poland, Hungary, Slovakia and Slovenia), Northern Europe (Sweden, Norway, Finland and Denmark), South West Europe (Spain and Portugal) and North West Europe (UK and Ireland). The transmission grid of the CWE region is represented by 65 nodes, while the transmission grids of the satellite regions are represented via one node per region. In total, 174 grid connections and 70 nodes are represented in the model.

[11] With this simplification we neglect that a detailed representation of all countries would probably impact congestion in the CWE region.

[12] For further technical details, see CWE FBMC (2014).

[13] Although Austria is currently in the same bidding zone as Germany, we treat it as part of the Southern Europe. This has two main reasons: First, numerical complexity is reduced and second, the effect on the results in case Austria is included with higher granularity is expected to be limited.

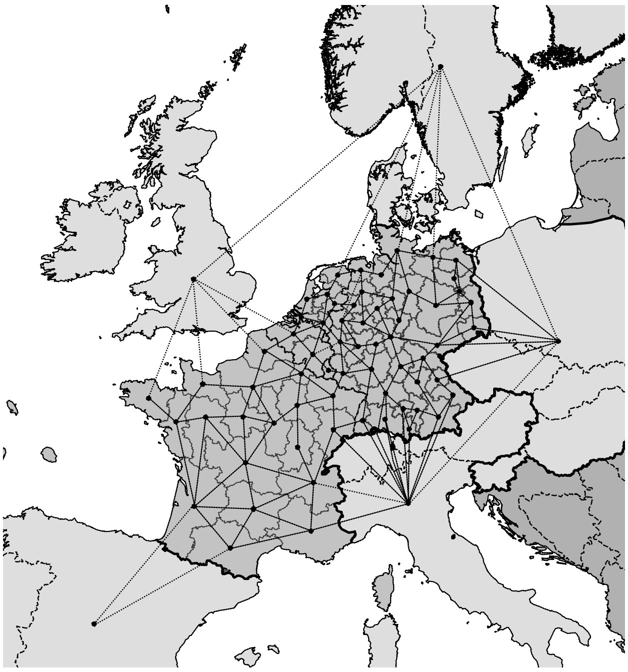

Figure 1: Representation of the CWE and neighboring regions in the model

The existing electricity system including power plants[14] and transmission grids[15] as of 2011 was used as the basis for the simulations of the years 2020 and 2030.[16] Existing generation capacities are shut down after reaching the end of their technical lifetime (the model is also allowed to shut down plants earlier if economically beneficial). Investments into new generation capacities (conventional as well as renewables) are subject to political constraints (e.g., no nuclear investments in Germany) or technical restrictions (e.g., areas for renewable sites). The transmission grid topology mainly consists of AC lines, but also includes some DC lines (existing ones plus the projects planned in the 2012 version of the Ten Year Network Development Plan of the European Network of Transmission System Operators for Electricity (ENTSO-E, 2012)). Costs of future years are discounted to 2011-values with a discount rate of 10 %.[17] Years are represented by nine typical days including different demand levels, wind and solar infeed, distinguished by weekday and weekend.[18] The typical days

[14] The data for the power plants stems from the power plant database developed at the Institute of Energy Economics at the University of Cologne. This database comprises nearly all European power plants greater than 10 MW and is constantly updated by publicly available sources (e.g., the power plant list of the German regulator) and the Platts WEPP database (Platts, 2009).

[15] The grid model was developed based on the publicly available map and data on the European transmission grid infrastructures from ENTSO-E.

[16] 2040 and 2050 are also included in the simulation to control for end time effects. Years in between are accounted for via scaling of the simulated years. Thus, investments into generators as well as the grid infrastructure are possible in 2020, 2030, 2040 and 2050, whereby only 2020 and 2030 are shown in the paper.

[17] This value was chosen to represent typical returns on investment. Note that the costs of capital for investments in the electricity sector are hard to estimate, but considering the rate of return for regulated investments (e.g., around 9 % for grid expansion projects in Germany) this seems to be a fair assumption.

[18] Typical days are constructed such that they represent statistical features of electricity demand as well as of

are coupled to account for seasonal storage, and include one day to cover extreme weather events.

CO_2 emissions are constrained according to the European targets shown in Table 2 representing a yearly reduction of 2.2 % (compared to 2005) up to 2050 (European Commission (2014)). The maximum amount of CO_2 emissions that can be emitted per year is implemented as a constraint restricting the generation of (conventional) power plants. Thus, a CO_2 quota (in contrast to a CO_2 price) is included in the model. If – due to the restricted grid expansion – the restrictions on CO_2 emissions cannot be met, the model allows for additional CO_2 emissions. However, generators pay a penalty of 100/t CO_2 for each unit exceeding the admitted quota.[19] These additional emissions can be interpreted as shifting CO_2 abatement from the power sector to other sectors of the EU Emissions Trading System (ETS). Although this shifting of CO_2 is not explicitly modeled, this might imply an increase in CO_2 emission costs if more expensive abatement technologies have to be developed.

Year	**2020**	**2030**	**2040**	**2050**
compared to 2005	-21 %	-43 %	-65 %	-87 %

Table 2: Assumptions for CO_2 reductions [%]

We assume there is no explicit target for either the share or capacity of renewables in addition to the CO_2 mechanism, meaning that renewables are deployed endogenously due to CO_2 restrictions. However, we will report the deployment of renewables and discuss the implications for the European 27 % renewables goal in total energy consumption in Section 3. In addition, we assume that the production of PV and wind (onshore and offshore) can be curtailed. This might be necessary if the production of PV and wind capacities exceed the demand in this region and transmission capacities are insufficient to transport the production to other regions. Despite the goals on energy efficiency, the electricity consumption is projected to increase, e.g., due to electrification of heating processes and transportation. Electricity demand is taken from the EU energy road map (European Commission (2013)).

As the most important trigger in our analysis, we model different scenarios varying the restriction levels for grid expansion, as indicated in Table 3. Numbers correspond to the allowed grid expansion z in $TWkm$ per decade. While grid expansion is entirely forbidden in *Scenario 0*, the amount of allowed grid expansion increases throughout the different scenarios. Within *Scenario 30*, where grid expansion is restricted to 30 TWkm per decade, the restriction is not binding any more, hence *Scenario 30* represents an unrestricted scenario. To understand the orders of magnitude, a restriction of 5 TWkm would mean that, e.g., 2 lines, each with 5 GW and 500 km length can be

solar and wind resources along with their multivariate interdependencies found in the original data. Local weather conditions are included through the use of detailed wind speed and solar radiation data (EuroWind, 2011)

[19]We consider energy efficiency measures as an alternative CO_2 abatement option (see e.g. McKinsey&Company (2009)).

built in a decade. Note that the restriction is imposed as a constraint on the sum of AC and DC lines.

Max. grid expansion	0	5	10	15	20	30

Table 3: Scenarios of allowed grid expansion per decade [TWkm/10a]

Due to the imposed constraint on grid expansion, the model may become unable to fully serve demand (except for *Scenario 30* where grid restrictions are not binding). Due to missing local price signals, the market equilibrium might lead to an allocation of generators far away from load centers. Specifically, if transmission capacities are limited, and the congestion in the grid cannot be fully resolved by redispatching generation, energy imbalances occur. Those imbalances can be solved in various ways to ensure technical feasibility. On the demand side, one possibility to overcome an imbalance is load curtailment which is, however, usually avoided as much as possible due to the high value of lost load. In our model, we allow to curtail load with a value of lost load (VOLL) of 7.41 € per kWh (Growitsch et al., 2015). This rather high value forces the model to curtail load as a last resort to ensure feasibility. However, one may also think of other measures to relieve imbalances. In fact, measures on the supply side are much more prominent. Additional generation capacities could be contracted in an administrative procurement (i.e., outside the market) to ensure security of supply even in critical situations. This procedure is applied in Germany, for instance.

3. Results

3.1. Impacts of missing grid expansion

3.1.1. Redispatch and energy imbalances

Figure 2 shows the yearly energy imbalances in all scenarios, i.e., the mismatch between supply and demand after adjusting the dispatch with a physically feasible redispatch and grid expansion. Energy imbalances might occur due to missing grid infrastructure (if grid expansion is restricted) together with a misallocation of generation capacities. These factors may lead to the fact that not all load in all regions can be served given the installed grid and generation infrastructure. *Scenario 0* shows the highest level of energy imbalances as no grid expansion is allowed and redispatch measures are insufficient. In the CWE region, energy imbalances of around 2 % of total load in 2020 and nearly 3 % in 2030 if no grid expansion are observed. All other scenarios result in energy imbalances of below 0.5 % in all years. With an increase of the allowed grid expansion, energy imbalances are reduced.

Due to increasing wind capacities built up in the North of Germany without taking into account the ability to transport this generation to load centers in the South, the most severe energy imbalances are in Southern Germany. However, due to the meshed grid energy imbalances also

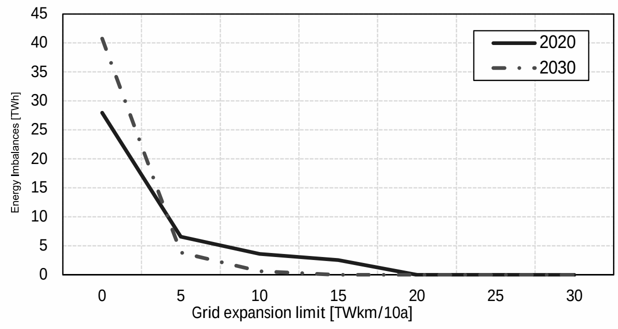

Figure 2: Energy imbalances in different scenarios

occur in the BeNeLux-countries and the neighboring regions. Figure 3 shows the regional distribution and severity of energy imbalances in *Scenario 0* for 2030.[20] The distribution in the other scenarios is similar, but lower. Noticeably, energy imbalances increase over time in *Scenario 0*, while they decrease in all other scenarios. This is due to the inter-temporal effect of grid expansion (cf. Section 3.2.2).

The overall quantity of redispatch measures shows a similar behavior over the scenarios as the energy imbalances, and are highest for the most restricted case (Figure 4). However, the decline in redispatch with a less restricted grid expansion is not as steep as for energy imbalances. This can mainly be explained by the significantly lower overall costs of redispatch, which are only the difference of the variable costs of the redispatched power plants. Even without any restriction posed on grid expansion, a relatively small amount of redispatch measures is still part of the optimal solution when weighed against grid extension costs. The distribution of redispatch, however, shows no distinct pattern.

Figures 5 and 6 show the number of hours, in which transmission lines are at 100 % utilization after redispatch indicating the importance of specific transmission lines. As can be seen, the line load decreases with increasing grid expansion. However, in 2030 the pattern for this decrease differs over the scenarios. Different lines are expanded throughout the scenarios and hence, lead to different utilization rates induced by the meshed grid and corresponding loop flows. The line load at the borders of the CWE region shows the importance of the Scandinavian and Iberian countries for the electricity flows in Europe.

3.1.2. Total system costs

Total system costs are a measure for the overall efficiency of the system. Intuitively, a system with more constrained grid expansion induces higher system costs. For the different scenarios, we find that no grid expansion at all increases total system costs by 138 % compared to the unrestricted

[20]Note that the map only includes energy imbalances in the CWE region even though there are also imbalances in the satellite regions.

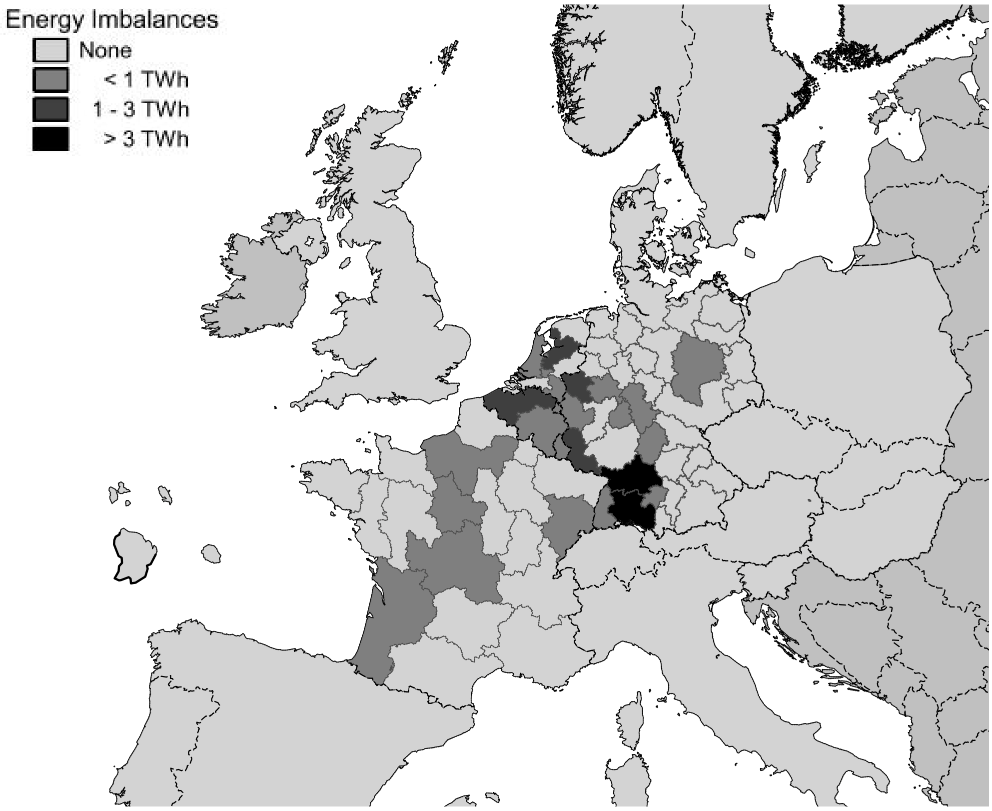

Figure 3: Geographical distribution of energy imbalances in Scenario 0 for 2030

case. Figure 7 shows the dependence of total system costs on grid expansion. It can be seen that even a small amount of grid expansion decreases total system costs drastically.

To further analyze this result, Table 4 shows the composition of total systems costs (discounted to €$_{2011}$). The main variation between the scenarios results from differences in the costs to relieve energy imbalances between the scenarios where grid expansion is restricted. The increase of costs aligned to the removal of energy imbalances arises from sub-optimal siting of generators. Due to the market design which is unable to uncover scarcities in the grid within a bidding zone by means of appropriate price signals, investments are made based on supply site characteristics only. As a result, there is not enough generation capacity available at every node and it is furthermore not possible to import sufficient capacity without grid expansion. This in turn leads to situations where redispatch measures trying to overcome internal grid restrictions in each bidding zone are not sufficient any more. Hence, energy imbalances have to be relieved at high costs. In the most extreme scenario with no grid expansion at all, this leads to the additional effect that the implemented CO_2 quota cannot be fulfilled anymore by the electricity sector, meaning that some other sectors have to increase their CO_2 reduction efforts.[21]

[21]The shifting of CO_2 emissions is not explicitly included in the applied modelling framework.

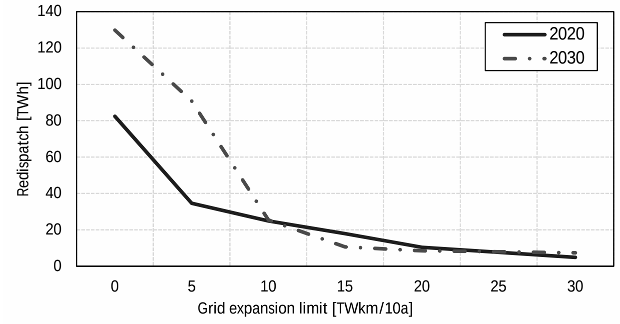

Figure 4: Redispatch measures in different scenarios

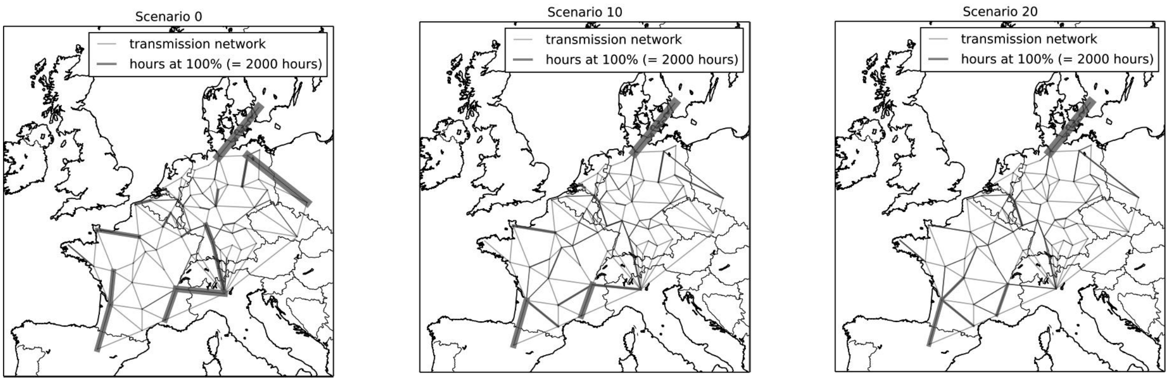

Figure 5: Line load after redispatch measures in different scenarios 2020

Max. grid expansion [TWkm/10a]	0	5	10	15	20	30
Generation [Bn. €]	940.7	938.1	932.5	930.6	930.2	929.5
Grid (including redispatch) [Bn. €]	8.2	8.1	7.9	9.7	10.2	10.7
Clearance of energy imbalances [Bn. €]	1.169.9	211.5	93.5	65.7	0	0
Shifting of CO_2 to other sectors [Bn. €]	120	0.6	0	0	0	0
Total [Bn. €]	2238.3	1158.2	1033.9	1006.1	940.9	940.2

Table 4: Total system costs of scenarios (in $€_{2011}$ up to 2030)

Remarkable – while looking at the results on total system costs – is the fact that grid expansion costs are rather low compared to any other cost factor and almost negligible if generation and grid costs are compared. The non-monotonous trend of the grid costs over the scenarios can be explained by the included redispatch costs, which depend on the optimization of the generation and not the transmission level.

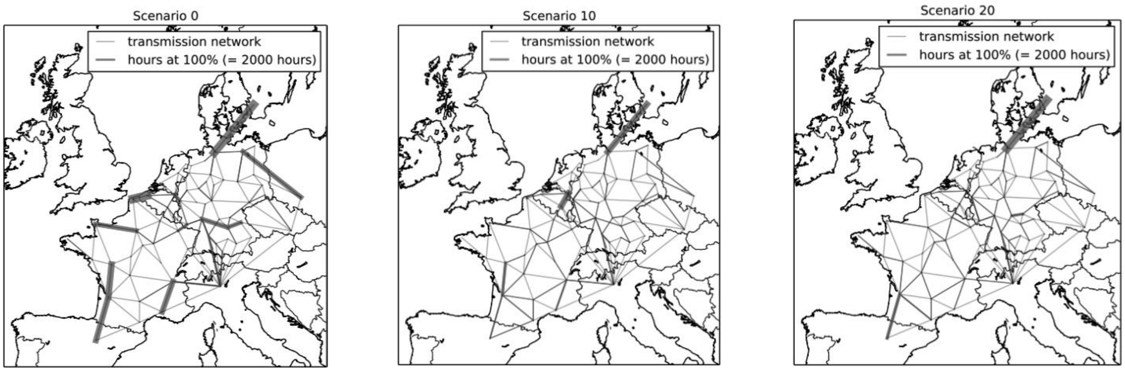

Figure 6: Line load after redispatch measures in different scenarios 2030

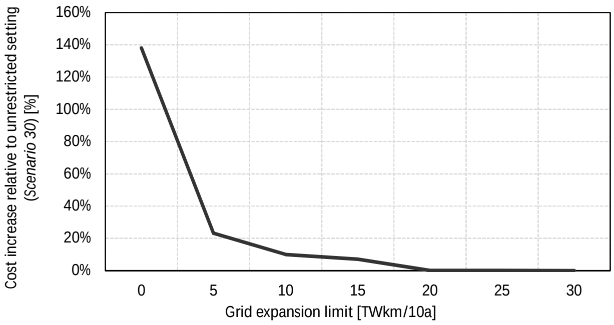

Figure 7: Total system cost decrease with grid expansion

3.1.3. Fulfillment of the EU 2030 targets

In case of no grid expansion (*Scenario 0*), the amount of CO_2 emissions that have to be reduced by other sectors (than the power sector) within the EU-ETS amounts to 176 mt CO_2 in 2020 and 391 mt CO_2 per year in 2030. These numbers should be interpreted with care, as feedback loops with other sectors covered by the EU ETS that are induced by an increasing CO_2-price are not considered here. However, the general result that CO_2 emissions are shifted to other sectors should probably hold.

To deal with restricted grid expansion, generation from renewable resources may be curtailed.[22] As can be seen in Figure 8, the need to curtail the production of renewables decreases dramatically as the restriction of grid expansion is relaxed. In 2030, 7.7 % of available PV generation is curtailed in the case of no grid expansion, which drops to just 0.4 % if 5 TWkm/10a are allowed. The drop for onshore wind from 3.3 % to 1.4 % is less dramatic. Furthermore, the regional distribution of curtailment differs. With no grid expansion, curtailment of offshore wind only occurs

[22]We here focus on weather-driven renewable energy sources which are especially relevant in the context of curtailment due to the fact that they cannot be dispatched freely.

on the North Coast of France in 2030. For PV and onshore wind, curtailment is concentrated in Southern Germany, and along the North and West Coasts of France, where there are significant grid bottlenecks.

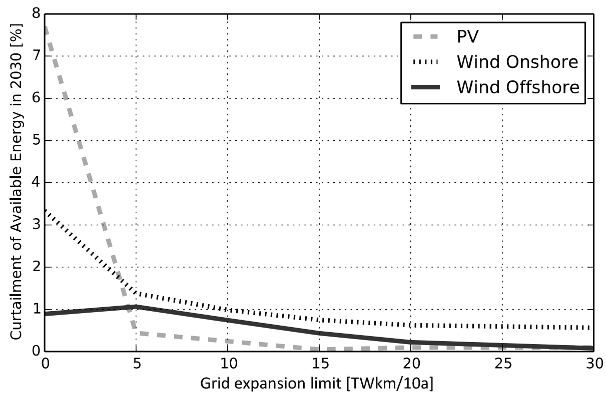

Figure 8: Curtailment of renewables for the different scenarios

The curtailment of renewables impacts the overall renewables quota only in the most restricted scenario and only in 2030. While the renewables quota for all other scenarios is around 44 % in 2030, for *Scenario 0* the quota is about 1.5 % percentage points lower due to the curtailment. Considering the three main targets of European energy policy consisting of a secure, affordable and climate-friendly energy, our results show that missing grid expansion might degrade these targets. Especially with no or only minimal grid expansion, energy imbalances, the fulfillment of the implemented CO_2 quota as well as total system costs increase substantially compared to scenarios with less extreme grid restrictions. Thus, it can be concluded that grid expansions are of high importance in order to meet the European energy targets.

3.2. Development of grid capacities

3.2.1. DC and AC capacities

Figure 9 shows the grid expansion in the different scenarios for the period from 2011 to 2020 as well as between 2020 and 2030 for AC, DC, as well as the aggregated grid expansion, measured in TWkm.[23] Between 2011 and 2020, the total grid expansion restrictions are binding for the system in *Scenario 0* through *20*, whereas between 2020 and 2030 grid restrictions are binding only for the *Scenarios 0* through *15*. Thus, for *Scenario 30*, grid expansion is not restricted in any decade,

[23]Note that care should be used when interpreting these results because it has been assumed that the transmission expansion is continuous. In reality transmission investment is lumpy because of investment in rights-of-way, transmission towers and conductors of standard capacities. However, since for the AC network we consider only the upgrade of existing transmission corridors, the lumpiness can be smoothed by other measures such as re-conductoring or upgrading the voltage level of the lines. Investigations of the lumpiness of transmission investment have typically shown that lumpiness leads to under-investment Joskow and Tirole (2005), so our continuous stylized approach errs on the conservative side of over-estimating new capacity.

which means that the investments made in this scenario are system optimal, such that *Scenario 30* can serve as a benchmark with respect to cost efficiency (see above).

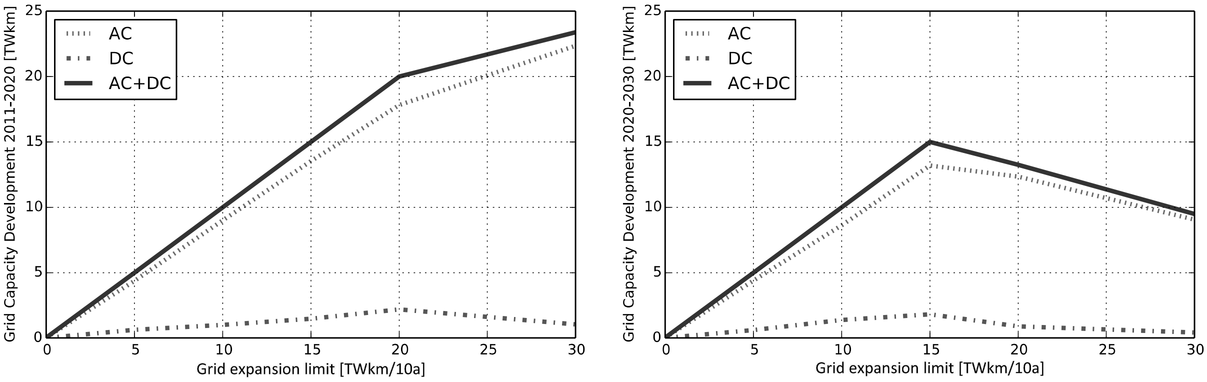

Figure 9: Capacity development in TWkm for the period 2011-2020 (left) and 2020-2030 (right)

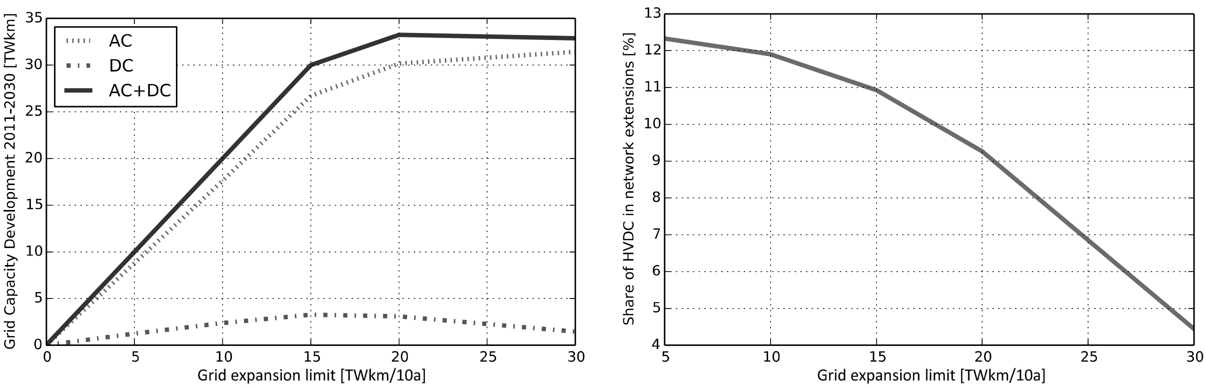

Figure 10: Total capacity development for 2011-2030 (left) and the share of DC in the total network expansion (right)

To put the total grid expansion into context, the starting grid from 2011 for the CWE region has a capacity of 70.8 TWkm, split between 68.0 TWkm for AC and 2.8 TWkm for DC. In *Scenario 30*, which has a total of 32.9 TWkm of grid expansion between 2011 and 2030, this represents a grid capacity expansion of 46.4 %.[24]

In Figure 9 and 10, it can be seen that the AC network is extended significantly more than the DC network. One reason is that there are simply more AC connections available to the optimizer to extend; only DC connections that already exist and those planned in the TYNDP 2012 are fed into the initial network topology for optimization. Another reason is that DC lines are more expensive because of the costs of the AC-DC converter stations at each end of the line.[25] However,

[24]In the optimal grid scenario considered by Hagspiel et al. (2014), the grid for the entire ENTSO-E area was extended by 48 % between 2011 and 2030.

[25]See Table 9 in the Appendix for the transmission cost assumptions

the decrease in DC capacities with a restriction of more than 20 TWkm per decade indicates that DC lines are prioritized when the grid restrictions are enforced. The share of DC in the total network expansion decreases monotonically as the grid restrictions are relaxed (see Figure 10). In absolute terms, for the total period 2011-2030, the DC expansion increases, peaks at just over double the existing DC capacity, and then decrease as the grid restrictions disappear. In Figure 9 it can be seen that DC capacity increases as the overall capacity limit increases in each decade, but only as long as the overall grid restriction for AC and DC is binding. When grid restrictions are no longer binding for a decade (*Scenario 30* for 2011-2020 and *Scenario 20* for 2020-2030), the DC capacity drops as cheaper AC lines are prioritized over extending DC lines. This shows that DC lines help the system to deal with the grid expansion restrictions and to compensate missing AC lines. A reason for preferring DC to AC is that the power flow is more controllable, so that power transfers can be directed over long distances, rather than spreading out in the AC network in "loop flows", which overload wide areas of the AC network. This underlines the importance of DC lines for example to integrate renewable energies into the system. As a result, whenever grid restrictions are in place, DC lines allow a better system optimum.

3.2.2. Inter-temporal effects

In Figure 9, an interesting interplay between grid expansion during the two decades 2011-2020 and 2020-2030 can be seen.[26] The less restricted grid expansion are, the more transmission lines are built in the first decade between 2011 and 2020. Grid expansion in the second decade increases first and then decreases, which shows that it is more valuable for the system to have lines installed early, i.e., by 2020. This higher value may be due to the fact that the lines built in the first decade are used for a longer time. The effects also become visible when looking at the imposed grid expansion restrictions: The 2011-2020 restriction is binding longer (up to and including *Scenario 20*) than the 2020-2030 restriction (up to and including *Scenario 15*), which shows the inter-temporal effect of grid expansion and thus, the optimality of building the grid earlier. The inter-temporal effect is strong enough that the total grid expansion from 2011 to 2030 is lower in *Scenario 30* than *Scenario 20* (see Figure 10), because of the suboptimal binding grid restriction in *Scenario 20* for the decade 2011-2020.

3.2.3. Geographical distribution

Figure 11 shows the geographical distribution of the grid expansion for three scenarios including the optimal grid from *Scenario 30.* Noticeably, many of the grid expansion are concentrated in France and its borders with other countries. This results from the good wind resources in France, that are located particularly along its coastline. The electrical load along the coast is weak, so network extensions are needed to transport the wind power to load centers elsewhere in Europe.

[26] Recall that 2040 and 2050 are also included in the optimization in order to avoid end-time effects.

These good wind resources are currently under-exploited, but represent the cheapest option to decrease CO_2 emissions in the CWE region.

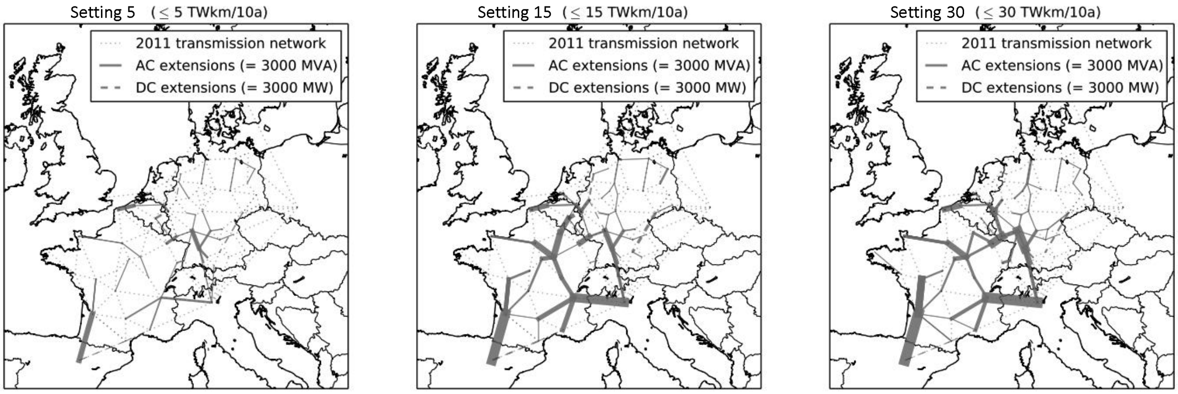

Figure 11: Maps of grid expansion for *Scenarios* 5*,* 10 *and* 30

There are also grid bottlenecks within Germany, which are overcome with both new AC lines and DC lines along the planned corridors from North to South Germany. The controversial DC line within corridor D, planned by the German TSOs to carry wind and solar power from East to South Germany (Bavaria), is extended in each scenario where grid expansion is allowed; Corridor A ranging from the North Sea to Southern Germany is also expanded in *Scenario 15*.

3.2.4. Inter- vs. intra-zonal grid expansion

In the grid model for the CWE region in 2011, 30 % of the grid capacity measured in TWkm is made up of cross-border lines (this is higher than the actual grid, because of the way countries at the boundary of the CWE region have been aggregated to single nodes, lengthening cross-border lines). However, interconnectors make up 42 % of all grid expansion in *Scenario 30*, meaning that interconnector capacity is more valuable on average than internal, national grid connections. This is particularly due to the possibility to exploit cheaper generation sites and being then able to transport it to load centers within Europe using interconnector capacities. Between 2011 and 2030, interconnector capacity rises by 65 %. There is some overlap between the distribution of grid expansion calculated here and the European Commission's Projects of Common Interest[27], particularly for the internal DC lines in Germany and the strengthening of interconnectors between Spain and France and between Germany and Switzerland. However, grid expansions in Figure 11 are much more heavily concentrated in France and its interconnectors, due to the significant expansion of wind power in France in the scenarios presented here. Similarly, the dominance of grid expansion in France is not reflected in the 2012 or 2014 TYNDP.

[27] `https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest`

3.3. Generation and generation capacities

The total generation capacities and total dispatch in the CWE region in 2030 are shown in Figure 12 for each scenario. Overall, there is very little change in installed capacities as grid restrictions are lifted. Comparing *Scenario 0* to *Scenario 30*, there is an increase of wind capacity of 17 GW, which takes place exclusively in France as inland sites with lower capacity factors than the coast are exploited. This raises the wind capacity in France from 55 GW to 72 GW in 2030. This better use of cheap wind resources in France is also reflected in the grid expansion (see Figure 11). There is a small drop in solar capacity of 3.8 GW in the British Isles, as grid expansion allow PV to be replaced by cheaper wind generation. In each scenario the offshore wind capacities are identical, amounting to 42.6 GW in 2020 and 42.0 GW in 2030.

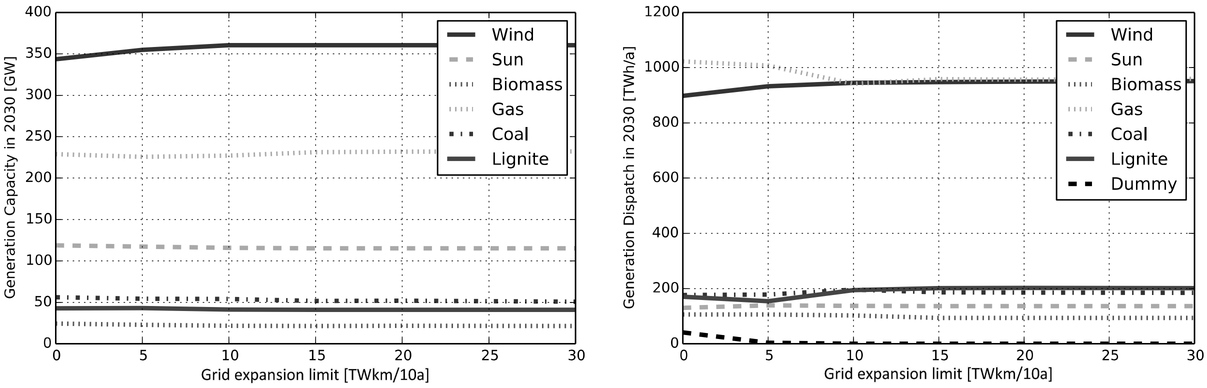

Figure 12: Total generation capacity (left) and yearly dispatch (right) in 2030 for the different grid restriction scenarios

More change is visible in the yearly dispatch of each technology. Between *Scenario 0* and *Scenario 30* there is a 53 TWh/a increase in wind generation, almost exclusively due to the extra wind capacity in France but also due to reduced curtailment of renewables in France, the Netherlands and Germany, as grid bottlenecks ease. Solar generation increases by 6 TWh/a despite the lower capacity, due to lower renewable curtailment in France and particularly in Germany. Gas generation is reduced by 63 TWh/a and replaced by CO_2-free renewable generation as well as lignite generation, primarily from Central Eastern European countries (increasing by 31 TWh/a). This substitution of gas with lignite as grid capacity increases is induced by lower fuel costs of lignite than gas, which outweigh its higher CO_2 emissions per kWh. There is also 8 GWh/a more coal generation in the Iberian peninsular, enabled by the grid expansion between Spain and France.

The distribution of generation capacity is in general very insensitive to grid expansion because of the way the grid and market are coupled. In the initial dispatch and generation capacity optimization the internal grid constraints of each country are not visible; the internal bottlenecks only become apparent in the next step, as redispatch is performed in each bidding zone. However, the redispatch does not directly affect the optimality of the investment and dispatch decisions in the market. The only impact stems from the indirect effect of altered interconnection capacities, which become visible in the scenarios with little grid expansion.

The capacity and generation of pumped hydro storage and hydro storage dams remains nearly constant throughout all scenarios, which shows that the role of these types of storage in the system is not influenced by restrictions on grid expansion. Thus, storage is no substitute for grid expansion. Pump storage capacity is highest in the Southern region (Switzerland, Austria and Italy) whereas hydro storage capacity is highest in Northern Europe (mainly Norway) followed by the southern region (22 and 14 GW). However, as the potential in these countries is already mostly exhausted, there are no capacity expansion in these regions. Nevertheless, the value of storage is demonstrated when looking at the United Kingdom (UK) where pump storage capacity increases from 3 to 6 GW when grid expansion are highly restricted and to only 5 GW in the less restricted scenarios. At the same time the good and until now not exhausted wind resources in the UK are explored and thus wind capacities increase from 10 GW in 2011 to roughly 72 GW in 2030 throughout all scenarios. As exports to other countries are limited, other sources of demand to absorb this wind generation are needed. Therefore, storage is built. Thus, for the very special case of the UK, storage is a substitute to extending the DC connections (which are limited) to the rest of the CWE region. In addition, grid bottlenecks in France prevent imports of wind power from the UK, which may also drive the expansion of storage capacity in the UK when grid expansions are restricted.

4. Conclusion

We investigated the effect of restricted grid expansion for the EU's 2030 energy strategy under the current market design. Specifically, we contributed to the existing literature an in-depth analysis of the long-term effect of grid expansion restrictions in zonal markets with redispatch after market clearing. If grid expansions are restricted, this market design reveals its inherent incompleteness, because zonal markets fail to provide efficient locational price signals. Our analysis was based on a large-scale model of the European electricity market with a focus on the Central Western European region. We used a linear model covering the generation and transmission level with endogenous investment and dispatch decisions for both levels. Restrictions for grid expansion were implemented and gradually tightened, reaching from optimal expansion to no expansion.

We found that the incompleteness of the market design leads to a misallocation of generation capacities and the inability of the system to transport electricity to where it is needed. Thus, energy imbalances occur. Although they decrease sharply if some grid expansion is allowed, we still see energy imbalances even for an allowed grid expansion of 15 TWkm per decade. Affected regions are mainly those that are characterized by poor conditions for renewables, i.e., comparably low wind speeds and low solar radiation, and far away from (new) generation sites. Most severe energy imbalances appear in Southern Germany. These imbalances indicate the need for additional measures that have to be undertaken in order to ensure system stability, either affecting the demand or the supply side. On the supply side, imbalances can be solved by procuring additional capacity, while on the demand side load curtailment would be necessary. In practice, however, the latter is observed very rarely and usually avoided as much as possible. Therefore, supply side measures are more frequently used, e.g., by contracting additional generation capacity outside the market to ensure security of supply. For example, Germany administratively procures additional generation capacity, especially in Southern Germany where significant imbalances occur.

The restriction on grid expansion has a visible effect on European climate targets only if no or very little grid expansion is allowed. With no grid expansion, the renewables share is 1.5 percentage points lower compared to the other scenarios. As a consequence, conventional generation with higher CO_2 emissions has to jump in, such that the indirect effect of rising CO_2 abatement costs appears. One approach to deal with restricted grid expansion is the utilization of DC instead of AC lines. When overall grid expansion is restricted, DC can bring advantages by directing long-distance power flows, which would otherwise cause loop-flows in the AC network causing wide-spread overloading.

In order to overcome the depicted shortcomings of the zonal market design, several options are available. First, the obstacles of grid expansion could be removed to avoid intra-zonal congestion. As pointed out earlier, the main obstacles are approval procedures as well as social opposition which would need to be addressed by all involved parties. However, from past experience, it seems unlikely that grid expansion could be completely avoided in the future. Thus, an adaptation of the current market design should be considered as a second option. As has been shown, the prevailing market design is inherently incomplete, which may have severe consequences, especially when facing substantial changes in the supply structure. Hence, additional measures are needed, such as administrative intervention to ensure sufficient levels of generation capacity outside the market (as it is currently handled in Germany by contracting existing and procuring newly built capacity as a grid reserve for redispatch), different shapes of price zones, or via an implementation of locational price elements into the market. Moreover, the issue of the right location should also play a role when designing renewable support schemes, since they are the main driver of the changing infrastructure.

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Appendix

Abbreviation	Dimension	Description
Model sets		
$i, j, k, q \in \mathbf{I}$		Nodes, $\mathbf{I} = [1, 2, ...]$
$m, n \in \mathbf{M}$		Zonal markets, $\mathbf{M} = [1, 2, ...]$
$i \in \mathbf{I_m}$		Nodes that belong to zonal market m, $\mathbf{I_m} \subset \mathbf{I}$
$t \in \mathbf{T}$		Points in time where dispatch decisions are made, e.g. hours , $\mathbf{T} = [1, 2, ...]$
$y \in \mathbf{Y}$		Points in time where investment decisions are made, e.g. years, $\mathbf{Y} = [1, 2, ...]$
$b \in \mathbf{B}$		Decades of grid expansion restriction, $\mathbf{B} = [1, 2, ...]$
Model parameters		
$\delta_{i,y}$	EUR/kW	Investment and FOM costs of generation capacity in node i at time y
$\gamma_{i,t}$	EUR/kWh	Variable costs of generation capacity in node i at time t
$\mu_{i,j,y}$	EUR/kW	Investment costs of line between node i and node j at time y
$d_{i,t}$	kW	Electricity demand in node i at time t
$l_{i,j}$	km	Length of line between node i and node j
z	$TWkm$	Grid Expansion Limit per decade
Model primal variables		
$\overline{G}_{i,y}$	kW	Generation capacity in node i at time y, $\overline{G}_{i,y} \geq 0$
$G_{i,t}$	kW	Generation dispatch in node i at time t, $G_{i,t} \geq 0$
$T_{m,n,t}$	kW	Electricity trade from market m to market n at time t
X	EUR	Costs of generation
Y	EUR	Costs of TSO
$\overline{P}_{i,j,y}$	kW	Line capacity between node i and node j at time y, $\overline{P}_{i,j.y} \geq 0$
$\overline{P}_{m,n,t}$	kW	Capacity between market m and node n at time t determined by function g, $\overline{P}_{m,n,t} \geq 0$
$P_{i,j,t}$	kW	Electricity flow on line between node i and node j at time t
$R_{i,t}$	kW	Redispatch in node i at time t

Table 5: Model sets, parameters and variables

4.1. Representation of a nodal system

Generation

$$\min_{\overline{G}_{i,y},G_{i,t},T_{i,j,t}} \quad X = \sum_{i,y} \delta_{i,y}\overline{G}_{i,y} + \sum_{i,t} \gamma_{i,t} G_{i,t} \tag{2a}$$

$$\text{s.t.} \qquad G_{i,t} - \sum_{j} T_{i,j,t} = d_{i,t} \qquad \forall i,t \tag{2b}$$

$$G_{i,t} \leq \overline{G}_{i,y} \qquad \forall i,t \tag{2c}$$

$$T_{i,j,t} = -T_{j,i,t} \leq \overline{P}_{i,j,t} \qquad \forall i,j,t \tag{2d}$$

Transmission

$$\min_{\overline{P}_{i,j,y}} \quad Y = \sum_{i,j,y} \mu_{i,j,y}\overline{P}_{i,j,y} \tag{2e}$$

$$\text{s.t.} \qquad |P_{i,j,t}(\overline{P}_{k,q,y}, G_{k,t}, d_{k,t}, R_{k,t})| \leq \overline{P}_{i,j,y} \qquad \forall i,j,t \tag{2f}$$

$$\sum_{y \in b} \overline{P}_{i,j,y} l_{i,j} \leq \sum_{y \in b-1} \overline{P}_{i,j,y} l_{i,j} + z \qquad \forall b \tag{2g}$$

$$T_{i,j,t} = -T_{j,i,t} \qquad \forall i,j,t \tag{2h}$$

4.2. Model assumptions

Country	**2011**	**2020**	**2030**
Belgium	87	98	105
Germany	573	612	629
France	466	524	559
Luxembourg	7	8	8
Netherlands	113	128	137
Eastern	276	328	366
Northern	387	436	465
Southern	450	528	594
Southwest	317	378	433
United Kingdom	400	450	481

Table 6: Gross electricity demand (without own consumption and pump storage) [TWh]

To depict the CWE region in a high spatial resolution, we split the gross electricity demand per country among the nodes belonging to this country according to the percentage of population living in that region.

Technology	2020	2030
Wind Onshore	1253	1188
Wind Offshore (<20m depth)	2800	2350
Wind Offshore (>20m depth)	3080	2585
Photovoltaics (roof)	1260	935
Photovoltaics (ground)	1110	785
Biomass gas	2398	2395
Biomass solid	3297	3295
Biomass gas, CHP	2597	2595
Biomass solid, CHP	3497	3493
Geothermal	10504	9500
Compressed Air Storage	1100	1100
Pump Storage	1200	1200
Lignite	1500	1500
Lignite Innovative	1600	1600
Coal	1200	1200
Coal Innovative	2025	1800
CCGT	711	711
OCGT	400	400
Nuclear	3157	3157

Table 7: Generation technology investment costs [€/kW]

Fuel type	2011	2020	2030
Nuclear	3.6	3.3	3.3
Lignite	1.4	1.4	2.7
Oil	39.0	47.6	58.0
Coal	9.6	10.1	10.9
Gas	14.0	23.1	25.9

Table 8: Assumptions for the gross fuel prices [€/MWh$_{th}$]

Grid Technology	Extension costs	FOM costs
AC overhead line incl. compensation	445 €/(MVA*km)	2.2 €/(MVA*km)
DC overhead line	400 €/(MW*km)	2.0 €/(MW*km)
DC underground	1250 €/(MW*km)	6.3 €/(MW*km)
DC submarine	1100 €/(MW*km)	5.5 €/(MW*km)
DC converter pair	150000 €/MW	750.0 €/MW

Table 9: Assumptions for the grid extension and FOM costs