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Abstract: *Using hourly data, we show that the convergence of German and French electricity spot prices depends on the employed generation mix structure, on the trade (export/import) capacity between the two countries, and on characteristics of neighbouring markets. Only when German and French electricity markets employ "similar" generation mixes price spreads vanish, and the likelihood for congestion of electricity flows is significantly reduced. This implies that, at least, a part of the convergence that was documented in recent literature is spurious, because it is not (only) driven by the forces of arbitrage, but by the similarity of the generation structures. The direction of congestion matters in this regard. Furthermore, we document consistent evidence for the most important predictions of trade theory if markets are characterized by increasing marginal cost (i.e. supply) curves and limited cross-border capacities.*

Keywords: Market Integration, Electricity, Renewables, Technology Differences, Jaffe Index.

JEL codes: D47, F15, L81, L98, Q42, Q48

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1. Introduction

Ever since the Treaty of Rome in 1957, the free movement of persons, capital, services and goods have been strongly emphasized as fundamental components of economic and social integration in Europe. Like other industries, however, electricity markets in Europe have historically developed based on independent national systems. The three Energy Packages (1996, 2003 and 2009) show the permanent effort of the European Commission (EC) to change national electricity markets toward a competitive European internal electricity market. Depending on the respective country, independent regulatory authorities and independent transmission system operators have been established, privatization and liberalization has taken place, existing vertically integrated companies have been (legally or fully ownership) unbundled, incentive regulation schemes have been introduced, renewables got integrated in national markets, national/regional power exchange markets have been established, market coupling[1] has been regionally introduced, and transmission capacities as well as interconnection capacities have been increasing. Thus, a lot of effort has been put into establishing integrated markets, and this paper asks what the status of integration in electricity markets is by testing the main predictions of trade theory.

Although there is no lack of empirical evidence on integration and price convergence (see Zachman, 2008; Böckers et al., 2013; Gugler et al., 2016), fairly little is known about the drivers of integration and price convergence between two adjacent electricity markets in Europe. In contrast to other commodities, electricity moves freely between two adjacent markets in a certain hour, while in the next hour it may face trade barriers that hinder full price convergence and market integration (see Gugler et al., 2016). This paper attempts to explicitly address this issue by examining the impacts of generation mixes, trade with third countries and interconnection[2] capacity between Germany[3] and France on spot price spreads as well as congestion[4] probabilities between Germany and France. Like Keppler et al. (2016), we consider our dependent variables price spread and interconnection capacity congestion to be good indicators of integration of two adjacent electricity markets. Our rich dataset uses hourly data from 01.04.2011 to 31.12.2014 for generation mixes, electricity spot prices, load,

[1] Market coupling entails simultaneous auctioning of available transfer capacity and electricity. Hence, it promotes efficient allocation of interconnector capacity.

[2] Interconnections are electric power transmission (transportation) lines that enable movement of electricity from country A to country B.

[3] Since Germany and Austria constitute one spot market-pricing zone, we refer to this pricing zone as Germany.

[4] Congestion of interconnection capacities takes place when demand for electricity trade exceeds interconnection capacity. As a result, prices diverge (price spreads increase) and thus full price convergence cannot be achieved.

interconnection capacity, wind, solar and nuclear electricity. We look at German and French electricity markets because they together account for nearly 40% of the EU-28 total electricity generation in 2014 (Eurostat, 2014) and they also play a central role in the process of European electricity market integration regarding the fact that they are interconnected with 13 other European electricity market areas[5]. This paper employs a very rich dataset to empirically show that convergence of German and French electricity spot market prices depends not only on the trade (export/import) capacity between the two countries, and on the characteristics of neighbouring markets (like Italy and Denmark), but also on the employed generation mix structures. A feature of electricity markets is that in certain hours two neighbouring electricity markets may employ either different or similar generation technologies to meet their domestic demands and export needs. Moreover, the similarity/dissimilarity may change from hour to hour. The novelty of this paper is the construction of a generation mix similarity index (GMSI) for German and French electricity markets following Jaffe (1986). The GMSI between the German and French merit orders (i.e. supply curves) up to their intersection with their demand curves is a measure of how similar their generation mixes are in a certain hour.

Our first main result is that the law of one-price (i.e. no cross-border congestion) between Germany and France occurs <u>only</u> in those hours where generation mixes are fairly similar. In contrast, there is excess demand for interconnection capacities and price divergence in those hours where generation structures are dissimilar. Regarding convergence of European electricity markets, this implies that at least part of the convergence that is documented in the literature[6] is spurious, because it is not (only) driven by the forces of arbitrage, but by the similarity of the generation structures. In this regard, integration of two adjacent electricity markets that employ different generation technologies provide greater security of electricity supply in the event that one kind of generation technology becomes limited. In addition, market integration ensures access to a more diversified power plants' portfolio, which in turn helps to improve the reliability of the electricity system through reducing the cost of maintaining capacity adequacy.

As a result, we have identified two problems. First, according to standard trade theory (see e.g. Grossman & Helpman, 1994; Matsuyama, 2000), the benefits of cross-border trade and diversification of the electricity generation portfolio (like less need of a large reserve

[5] Spain, Switzerland, Italy, Slovenia, Hungary, Czech Republic, Poland, Sweden, Denmark (East and West), United Kingdom, Netherlands and Belgium.

[6] See e.g. Gugler et al. (2016); Keppler et al. (2016); Pellini (2012); Nepal & Jamasb (2012); Nitsche et al. (2010); Zachmann (2008); De Vany & Walls (1999).

margin[7] or outright capacity markets[8] (UN, 2006; OECD/IEA, 2014)) are largest exactly when Germany and France employ *dissimilar* generation mixes. However, exactly in those hours congestion of interconnection capacities mostly occurs, and the gains from trade cannot be obtained. Second, as documented by our index measuring similarity of generation structures (GMSI), generation structures in Germany and France have become more *dissimilar* in recent years. Enormous investment in renewables generation capacities (wind and solar) paralleled by the nuclear phase-out (only) in Germany have made generation mixes less similar compared to its neighbour France. Thus, full price convergence and the benefits of diversification can only be achieved by additional investment in cross-border capacity.

Moreover, we are able to empirically distinguish different impacts of nuclear, wind and solar generation, load and trade with third countries on market integration depending on the direction of interconnection capacity congestion[9]. The argument that wind and solar electricity generation in Germany is making the two largest electricity markets in Europe, German and French electricity spot markets, less integrated (e.g. Keppler et al., 2016) does not necessarily hold, since their effect on integration depends primarily on the direction of interconnection capacity congestion. E.g., when France exports to Germany, additional wind and solar generation in Germany would decrease the likelihood of interconnection capacity congestion.

We also show that price spreads and the likelihood of congestion between adjacent market pairs heavily depend on the influences coming from neighbouring markets. Regarding the fact that Germany mostly exports to France[10] and France mostly exports to Italy[11], increasing interconnection capacity between France and Italy <u>increases</u> price spreads between Germany and France and congestion probabilities from Germany to France. This occurs because additional exports to Italy increase prices in France and thus increase price spreads to Germany further leading to higher imports from Germany to achieve price equality, which in turn may exceed interconnection capacities. Likewise, wind electricity in Denmark strongly affects the probabilities of interconnection congestion between Germany and France in the same

[7] A country's reserve margin measures the difference between the peak electricity generating capacity and the peak demand (Joskow, 2007). Countries mostly hold reserve electricity generation capacities to respond to short- and long-run outages (e.g. overnight solar electricity, hydroelectricity in a year with little rainfall, etc.) and thus ensure security of electricity supply.

[8] Capacity markets remunerate electricity firms for holding available generation capacity and not only for actually producing and delivering electricity.

[9] Electricity flows either from Germany to France or from France to Germany. As a result, interconnection capacities can be congested only in one direction (this holds only for electricity markets that have implemented market coupling (see Gugler et al., 2016)).

[10] So that most of the time the price in Germany is lower than the price in France ($P_{DE} < P_{FR}$).

[11] So that most of the time the price in Italy is higher than the price in France ($P_{IT} > P_{FR}$).

way as own (i.e. German) wind electricity does. Therefore, our second main result is that externalities from cross-border trade matter for European electricity markets and, as such, deciding for pure national energy policies to solve main problems such as integration of renewables and security of supply may not work.

The paper is organized as follows. In section 2, we review the literature to date and the actual developments in European electricity markets. In section 3, we discuss generation mix similarities and integration of adjacent electricity markets and describe the construction of the generation mix similarity index ($GMSI$). Data and variables are described in section 4. Our empirical strategy is described in section 5. The main empirical findings are presented in section 6. Finally, conclusions are in section 7. In the Appendix we show how we have developed a state-of-the-art (standard) fundamental market model of electricity supply, which we use in building the generation mix similarity index ($GMSI$).

2. Literature review on internal European electricity markets

This section discusses the relevant empirical literature on the integration of electricity markets and the factors that interfere with it. The literature is mainly concentrated on assessing the degree of integration of European electricity markets (e.g. Da Silva & Soares, 2008; Zachmann, 2008; Böckers et al., 2013). Besides, some studies assess the impacts of certain national energy policies on the integration of European electricity markets. Eventually, we shortly discuss the difficulties in establishing internal European electricity markets coming from different national energy policies regarding the actual developments in promoting renewable technologies and implementation of capacity remuneration mechanisms.

Gugler et al. (2016) point out that market integration increased from 2010 to 2012, however partly due to increased feed-in from intermittent renewables then decreased until 2015. In addition, they find that the efficiency of integration (measured by speeds of price adjustment) is quite modest. Additional investment in interconnection capacities and further promotion of market coupling would have a positive and significant impact on the integration of European electricity markets.

Keppler et al. (2016) use hourly data for German wind and solar electricity and French nuclear generation from November 2009 until June 2013, and assess their impact on the convergence of German and French spot prices and on the congestion of interconnection capacities. Additional wind and solar electricity in Germany increases the likelihood of interconnection congestion and thus leads to more price divergence, while nuclear generation in France has the opposite effect. However, the study does not consider the direction of congestion – which is an asset of our paper.

Regarding national unilateral policies from EU member states, Grossi et al. (2015) have investigated the impacts of the German nuclear phase out and expansion of renewables due to fixed feed-in tariffs on neighbouring countries' energy markets. They found that nuclear phase out caused a price increase in neighbouring spot prices of up to 19% while renewable energy generation caused a price decrease of up to 0.17% for each percent of additional generation from German renewables. This underlines the importance of a coordinated approach of European energy policy in an increasingly integrated European electricity market (Phan & Roques, 2015).

Gianfreda et al. (2016) show that a high share of renewable energy generation has decreased the long-run dependence of electricity from gas and coal prices. In addition, they show that EU member states are becoming less integrated as the share of renewable energy generation increases. This in turn would call for a more coordinated policy at the EU level in promoting renewable energy sources, which also should be in accordance with the process of establishing internal energy markets.

European Energy Packages (Directive 96/92/EC, Directive 2003/54/EC, Directive 2009/72/EC) adopted over the last two decades show the constant efforts and ambitions of the EU to establish one single European electricity market and a decarbonized European electricity supply. Therefore, investments took place in reducing interconnection capacity limitations in order to support market integration. In this context, the EC has identified energy infrastructure priorities for 2020 and beyond and has suggested guidelines for the development of a European energy infrastructure (EC, 2011).

Generally, EU member states employ quite different structures regarding their electricity generation mix. Following the aim of decarbonising electricity supply (Directive 2009/28/EC) many countries have introduced diverse support schemes to promote renewable technologies. Wind and solar generation capacity deployments are highly concentrated in some EU member states, such as Germany, Spain and Great Britain. These countries account for 56% of the total wind generation in the year 2014, while Germany, Italy and Spain account for 78% of the total solar generation (ENTSO-E, 2015). Contrary to the German nuclear phase-out in 2011 after Fukushima, some EU member states like France, Finland, Poland, Slovakia, Bulgaria and Romania still have nuclear power plants under construction (EC, 2015). This shows the divergences driven by different national energy policies across EU member states.

Although an integrated European electricity market would ensure better security of electricity supply, governments still drive national energy policies relating to security of electricity supply (Grigorjeva, 2015). Since energy-only markets provide inefficient price signals for long-term investments if heavily distorted by national low-carbon policies, many EU member states have implemented different capacity remuneration mechanisms[12] (Ellenbeck et al., 2015). The introduction of these mechanisms in several EU member states obviously shows that some countries have selected an isolated approach in addressing concerns relating to security of electricity supply, even though security of electricity supply has become at least a regional issue (Eurelectric, 2016). In this respect, Booz & Co (2013) have pointed out that national-based approaches to ensure security of supply will cost EU member states between €3-7 Billion per year. Moreover, these may (1) impact changes in the composition of generation mixes across EU member states, (2) create institutional barriers for market integration and, thus, represent a considerable risk in achieving European integrated electricity markets and (3) cause different market distortions, such as hampering competition (Zgajewski, 2015; Mastropietro et al., 2015). In the next section, we assess the main determinants of electricity market integration in Europe.

3. Generation mix similarities and market integration between neighbouring markets

In this section, we graphically illustrate the intuition behind the impact of the structure of generation mixes of two adjacent markets on spot price spreads. Note that electricity is a homogenous good in terms of its physical properties. Besides, we assume that electricity spot markets operate under conditions of perfect information and thus work efficiently (Graf & Wozabal, 2013). Graph 1 illustrates actual generation capacities data ordered according to the marginal costs of production by generation technology[13] in market A (let us call it France) and neighbouring market B (Germany). At first sight, both markets appear to have relatively different generation mixes, since nuclear and water power plants make up almost 70% and 20% of total generation capacities of market A, respectively, while in market B over 40% and 50%

[12] Belgium, Finland, Great Britain, Ireland, Italy, Lithuania, Poland, Portugal, Spain and Sweden.
[13] All types of renewables (wind, solar, geothermal, pellets, etc.), hydro, nuclear, coal, gas and oil power plants.

of total generation capacities are renewables (wind and solar) and coal, respectively.[14] That is, market A has quite a flat merit order curve based on the high share of water and nuclear capacities, which becomes very steep at the end due to a low share of peak-load technologies with high marginal costs. On the other hand, the flat section of the merit order curve in market B strongly depends on the level of intermittent renewable generation, while the second part is relatively steep because of the high share of coal and then gas power plants.

[Graph 1]

In Graph 1, we depict markets A and B with equal national demand schedules ($D_A^{off-peak} = D_B^{off-peak}$ and $D_A^{peak} = D_B^{peak}$). In both periods, peak and off-peak, and under autarky the price in market A is lower than in market B ($P_A^{off-peak} < P_B^{off-peak}$ and $P_A^{peak} < P_B^{peak}$). Note that when demand peaks price spreads between markets A and B become smaller ($\Delta P^{peak} < \Delta P^{off-peak}$)[15], if generation technologies become more similar. If trade between markets A and B is supported only with limited interconnection capacity, interconnection capacity congestions (and price spreads) are less likely to occur when demand peaks, since generation mixes turn out to be more similar, than in off-peak periods, where generation mixes are less similar (see also Mutreja et al., 2014). Accordingly, besides demand levels, generation mix similarities and interconnection capacities determine the likelihood of interconnection capacity congestion and the level of price spreads in the presence of increasing marginal cost (=supply) schedules and limited interconnection capacities. Note that this kind of "convergence" is not (only) driven by the forces of arbitrage, but by the increased similarity of the generation mix which happens to occur in peak periods. Therefore, we view this kind of convergence at least in part as spurious.

GMSI

In order to measure the similarity of generation structures between German and French electricity markets we follow Jaffe (1986)[16] and construct the generation mix similarity index

[14] Renewables and hydro power plants with essentially zero marginal costs and nuclear power plants with relatively low marginal costs are located in the flat section of the merit order curve. Note that wind and solar electricity generation is quite volatile by the hour, while hydro generation is characterized only by seasonal fluctuations. Like nuclear power plants, various types of coal power plants have a low level of generation flexibility. Usually, renewables, hydro, nuclear and coal power plants are known as base-load technologies. Various type of gas and oil power plants have both high level of generation flexibility and marginal costs and, as such, are known as peak-load technologies.

[15] $\Delta P^{off-peak} = P_B^{off-peak} - P_A^{off-peak}$; $\Delta P^{peak} = P_B^{peak} - P_A^{peak}$

[16] Bloom et al. (2013) also employ the same approach like Jaffe (1986) and construct firms' technological proximity and firms' product market proximity measures to estimate R&D spillovers.

($GMSI$) for each hour using specific information from the German and French merit-order curves[17]. Different generation technology classes $\tau \in (1, Y)$[18] in Germany and France meet the corresponding demand curves in any given hour. We identify 70 different generation technology classes in Germany and France, and denote electricity generated by generation technology class τ for hour h in Germany and France, respectively, by $g_{DE,\tau,h}$ and $g_{FR,\tau,h}$. $g_{DE,h} = \sum_{\tau=1}^{70} g_{DE,\tau,h} = d_{DE,h}$ is total electricity generation e.g. in Germany that meets demand $d_{DE,h}$ at a certain hour, h. The vector $T_{DE,\tau,h} = \frac{g_{DE,\tau,h}}{g_{DE,h}}$ is the share of electricity generated by the generation technology class τ over total electricity generation for a specific hour, h, e.g. in Germany. The Jaffe index

$$GMSI_{DE,FR,h} = \frac{T_{DE,\tau,h}T'_{FR,\tau,h}}{\left(T_{DE,\tau,h}T'_{DE,\tau,h}\right)^{1/2}\left(T_{FR,\tau,h}T'_{FR,\tau,h}\right)^{1/2}}$$

between German and French merit orders (i.e. supply curves) up to their intersection with their demand curves is our measure of generation mix similarity between Germany and France. $T_{DE,\tau,h}T'_{FR,\tau,h}$ is the uncentered covariance between the shares of electricity generated by generation technology class (τ) at a specific hour (h). The advantage of $GMSI_{DE,FR,h}$ is that it normalizes the uncentered covariance on the standard deviations of the share vectors. As a result, $GMSI_{DE,FR,h}$ will not automatically rise when generation technology classes are aggregated. $GMSI_{DE,FR,h}$ takes values between zero and one, with a value of zero indicating completely different generation mixes in Germany and France in a given hour, and a value of one indicating essentially the same employed technologies in that hour. From Graph 1, we expect that when $GMSI_{DE,FR,h}$ gets higher spot price spreads and the likelihood of congestion get lower.

Trade with other neighbouring countries

Standard literature on integration of electricity markets does not consider trade with third countries. Graph 2 exemplarily makes visible the impact of electricity trade between Germany and Denmark and between France and Italy on the integration of German and French electricity spot markets.

[Graph 2]

[17] See the Appendix for information relating to the construction of both German and French merit-orders.

[18] E.g. hard coal, gas, oil, etc.

A particular high share of renewables and other technologies with low marginal costs distinguishes the structure of the merit-order of the Danish (DK) and German (DE) electricity markets from the French (FR) and Italian (IT) markets. Therefore, in an assumed autarky scenario, Danish and German markets obviously meet their national demands at the lowest price followed by France and Italy ($P_{DK} < P_{DE} < P_{FR} < P_{IT}$). According to trade theory, electricity flows from the low to the high price market area[19]. Hence, Germany exports electricity to France shifting both the German demand curve D_{DE} ($EXP_{DE\rightarrow FR}$) (dashed line) and the French supply curve S_{FR} to the right ($IMP_{DE\rightarrow FR}$) (dashed line). Accordingly, the equilibrium price in the French market decreases ($P_{FR} > P'_{FR}$) and in the German market it increases ($P_{DE} < P'_{DE}$). The two markets have one uniform electricity spot price ($P'_{FR} = P'_{DE}$) in those hours with abundant interconnection capacities.

If France exports electricity to Italy shifting both the French demand curve D_{FR} ($EXP_{FR\rightarrow IT}$) (dashed line) and the Italian supply curve S_{IT} to the right ($IMP_{FR\rightarrow IT}$) (dashed line), the equilibrium price in Italy decreases ($P_{IT} > P'_{IT}$) and in France it increases ($P'_{FR} < P''_{FR}$)[20]. Note that these standard trade theory results imply that electricity exports from France to Italy have increased price spreads ($P'_{DE} < P''_{FR}$) and the likelihood of congestion between Germany and France. Moreover, the likelihood of congestion is increased in the direction from Germany to France, but decreased from France to Germany[21].

Another illustration is Denmark. Denmark exports its abundant wind electricity to Germany shifting both the demand curve D_{DK} ($EXP_{DK\rightarrow DE}$) (dashed line) and the supply curve S_{DE} ($IMP_{DK\rightarrow DE}$) (dashed line). This leads to a price decrease in Germany ($P'_{DE} > P''_{DE}$) and a price increase in Denmark ($P_{DK} < P'_{DK}$). The price decrease in Germany further increases price spreads to France[22] and the likelihood of congestion. Moreover, the likelihood of congestion is increased in the direction from Germany to France, but decreased from France to Germany.

Summarizing, in markets with increasing marginal cost (=supply) schedules and limited cross-border capacities (e.g. in electricity markets) cross-border externalities abound. For example, exporting from France to Italy and importing from Denmark to Germany increase

[19] See Baldwin & Wyplosz (2015) for a thorough discussion on open-economy supply and demand curves.

[20] Due to congested interconnection capacities, uniform prices between France and Italy are rarely observed.

[21] France exports to Germany in 38% of the hours. Yet, French exports to Italy increase French spot prices and hence spot price spreads between Germany and France and the likelihood of interconnection capacity congestion from France to Germany decrease.

[22] $(P''_{FR} - P''_{DE}) > (P''_{FR} - P'_{DE})$.

spot price spreads and the likelihood of congestion between Germany and France. We also derive results on the direction of congestion.

4. Data and variables

The empirical analysis employs a very rich data set for the period from 01.04.2011 to 31.12.2014. Hourly electricity spot prices are derived from the respective power exchanges: EPEX Spot for Germany and France and GME for Italy. We obtained very rich data relating to generation capacities by plant type and construction year for Germany and France from Platts Power Vision. The Energy Economics Group from TU Vienna and Austrian Power Grid (APG) have provided us with data relating to the availability of power plants and efficiency factors by plant type, turbine type and construction year. Among other sources, we combined these data sets to construct the merit orders for each hour in both German and French electricity markets. In the Appendix, we describe in detail the construction of the merit orders and the source of the employed data.

Hourly load data for Germany and France are obtained from ENTSO-E. Hourly day-ahead forecasts for intermittent renewables (wind and solar) electricity generation in Germany for the period from 01.04.2011 to 31.12.2014 are obtained from the German TSO-s (TransnetBW, Tennet, 50hertz and Amprion) and the Austrian TSO, APG. French hourly day-ahead wind forecasts for the period from 01.04.2011 to 31.12.2014 are obtained from the French TSO, RTE. RTE also provided us with hourly nuclear generation data from 01.04.2011 to 31.12.2014. Hourly day-ahead forecasts for wind electricity in Denmark East and West are obtained from Energienet. Hourly data on available transfer capacities (ATC) and allocated capacities (AC) between Germany and France and between France and Italy are obtained from the central office for cross-border transmission capacity for central Europe (CASC).

Dependent variables. This study employs four different dependent variables and accordingly four regression equations. *Absolute value of spot price spreads* are defined as $Spread_{DE,FR,h} = |P_{DE,h} - P_{FR,h}|$. In order to obtain *interconnection capacity congestion between Germany and France*, $ICC_{DE,FR,h}$, we first compute the difference between available transfer capacities, $ATC_{DE,FR,h}$, and allocated capacities, $AC_{DE,FR,h}$, and generate the variable available interconnection capacity, $AIC_{DE,FR,h} = ATC_{DE,FR,h} - AC_{DE,FR,h}$. If $AIC_{DE,FR,h} = 0$, interconnection capacities are congested, while $AIC_{DE,FR,h} > 0$ indicates free interconnection capacities. The dummy variable $ICC_{DE,FR,h}$ equals one if $AIC_{DE,FR,h} = 0$ indicating congestion (and zero else).

Since the data for $ATC_{DE,FR,h}$ and $AC_{DE,FR,h}$ are available for both directions ($ATC_{DE\rightarrow FR,h}$, $ATC_{FR\rightarrow DE,h}$ and $AC_{DE\rightarrow FR,h}$, $AC_{FR\rightarrow DE,h}$), we construct two variables to distinguish interconnection capacity congestion[23] when electricity flows from Germany to France ($ICC_{DE\rightarrow FR,h}$) and from France to Germany ($ICC_{FR\rightarrow DE,h}$) are congested, respectively.

Explanatory variables. This study employs the following explanatory variables: (1) generation mix similarity index of German and French electricity markets; (2) load in Germany and France; (3) nuclear generation in France; (3) wind and solar forecasts in Germany; (4) wind forecasts in France and Denmark; (5) interconnection capacity between Germany and France and between France and Italy[24] and (7) day of the week, yearly and holiday dummies. Next, we make a detailed description of our explanatory variables and their expected effect on our dependent variables, $Spread_{DE,FR,h}$, $ICC_{DE,FR,h}$, $ICC_{DE\rightarrow FR,h}$ and $ICC_{FR\rightarrow DE,h}$.

Generation mix similarity index of German and French electricity markets, $GMSI_{DE,FR,h}$. Ceteris paribus, we expect a low (high) $GMSI_{DE,FR,h}$ (relatively dissimilar (similar) generation mix) to increase (decrease) interconnection congestion and spot price spreads.

Loads in Germany and France, $L_{DE,h}$ and $L_{FR,h}$, are introduced to control for electricity demand on both sides of the border. Since France imports from Germany in the majority of hours between 2011 and 2014 (meaning $P_{DE} < P_{FR}$), we expect that an increase in demand for electricity in Germany increases the spot price in Germany and leads to lower spot price spreads to France. On the other hand, an increase in demand for electricity in France would further increase the spot price in France leading to higher spot price spreads. The same logic applies to interconnection capacity congestion: more load in Germany decreases congestion, more load in France increases congestion.

[23] The introduction of market coupling has enabled efficient allocation of interconnection capacities, and as a result, high demand for interconnection capacity may lead to congestion of interconnection capacity, but congestion can occur only in one direction if market coupling is in place (Gugler et al., 2016).

[24] We introduced Denmark due to (1) a high share of capacities of wind electricity generation, (2) a constantly decreasing number of congested hours with Germany and (3) availability of the data for a longer period. We introduced Italy, since France has the highest interconnection capacities with Italy and it mostly exports to Italy. We also have checked for interconnection capacities with Spain, Sweden, Czech Republic, Hungary and Slovenia. The data for these countries are available for a shorter period and therefore we do not report the results. The results are available upon request.

Yet, the analysis of the impact of a demand increase in Germany and France with respect to the direction of interconnection capacity congestion is more subtle. When electricity flows from Germany to France, an increase in demand for electricity in Germany leads to higher German electricity spot prices and lower spot price spreads, $Spread_{DE,FR,h}$, which in turn decreases the likelihood that interconnection capacities from Germany to France are congested. This is because less electricity export is necessary to achieve price equality. Thus, more load in Germany is expected to decrease the likelihood of interconnection capacity congestion from Germany to France. On the other hand, an increase in demand for electricity in France increases spot prices in France and spot price spreads, and thus increases the likelihood of congestion of electricity flows from Germany to France, since more electricity export is necessary to complete price equality. Analogously, the respective opposite effects of an increase in demand for electricity in Germany and France are expected for congestion in the direction from France to Germany.

Nuclear generation in France, $N_{FR,h}$, is introduced to control for the high amounts of nuclear generation in France. Since nuclear carries very low marginal costs, we expect that nuclear generation in France puts downward pressure on the spot price level in France and since France mostly imports from Germany also on spot price spreads, and on the likelihood of interconnection capacity congestion. Moreover, we expect that the likelihood of congested exports from Germany to France decreases. On the contrary, in the other direction from France to Germany, the likelihood of congestion increases.

Wind and solar forecasts in Germany, and wind forecast in France and Denmark, $W_{DE,h}$, $S_{DE,h}$, $W_{FR,h}$ and $W_{DK,h}$, are introduced to control for huge amounts of wind and solar electricity generation in Germany and wind electricity in France and Denmark. Every additional MW of low cost electricity generation from renewables in Germany decreases the spot price in Germany further and thus increases spot price spreads to France and the likelihood of congestion of electricity flows from Germany to France. Hence, like Keppler et al. (2016), we expect that additional $W_{DE,h}$ and $S_{DE,h}$ increases price spreads between Germany and France (by decreasing German spot prices), since Germany is the net exporting market area. On the other hand, we expect that additional wind and solar electricity in Germany decreases the likelihood that electricity flows from France to Germany are congested, since less electricity exports are necessary to achieve price equality. Wind electricity in France, $W_{FR,h}$, is expected to have the opposite effect of wind electricity in Germany on price spreads and congestion. Wind electricity in Denmark, $W_{DK,h}$, is introduced in order to control for the impacts of renewable policies in third countries and it is expected to have the same impact as wind electricity in Germany, since the number of hours with similar prices between Germany and Denmark (East and West) is very high and increasing over time[25].

Interconnection capacity between Germany and France, $IC_{DE,FR,h}$, takes the values of $ATC_{DE\rightarrow FR,h}$ when $P_{DE,h} < P_{FR,h}$ and of $ATC_{FR\rightarrow DE,h}$ when $P_{DE,h} > P_{FR,h}$. Thus, $IC_{DE,FR,h}$ measures interconnection capacity in MW between Germany and France. It is intuitive to expect that an increase in interconnection capacity between Germany and France has a negative impact on spot price spreads and congestion. Note, that we do not include this variable in the direction of congestion equation, since interconnection capacity per se should not be a predictor in which direction congestion is likely to occur.

Interconnection capacity between France and Italy, $IC_{FR,IT,h}$, is constructed like interconnection capacity between Germany and France. As such, it measures interconnection capacity in MW between France and Italy. In section 4, we presented the impacts of trade with third countries on market integration between two adjacent markets. Ceteris paribus, we expect that increasing interconnection capacity between France and Italy leads to an increase in spot price spreads, $Spread_{DE,FR,h}$, and in the likelihood of congestion of the interconnection capacities, $ICC_{DE,FR,h}$. This is likely to occur because France exports in about 90% of the hours to Italy, since electricity prices are higher in Italy. Thus, when more exports become possible, France exports more to Italy and French spot prices increase. This increases the price spread between France and Germany on average, since electricity prices are already higher in France. This logic also leads us to expect that larger interconnection capacities between France and Italy lead to a higher (lower) congestion likelihood of the Germany (France) to France (Germany) direction. Finally, we additionally employ seasonal fixed effects (day of week, yearly and holiday dummies) to capture seasonal demand variations.

Table 1 and Table 2 show variable definitions, expected signs and the source of the data as well as all descriptive statistics, respectively. Wholesale spot prices are lower in Germany on average than in France (40.5 €/MWh versus 42.6 €/MWh). The average absolute spread is 5.3 €/MWh. In 45% of hours interconnection capacities between Germany and France are congested. In 29% of hours congestion occurs in the Germany to France direction, in 16% in

[25] Graph 2 illustrates the impacts of exporting (low marginal cost) wind electricity from Denmark to Germany on German and French price spreads.

the other direction[26]. The average GMSI is 64.3%. Note, however, that GMSI nearly takes on values in the whole range between zero and one. Thus, there is huge variation in the similarity of generation mixes in Germany and France across hours.

[Table 1]

[Table 2]

Table 3 shows the developments of our dependent variables and $GMSI_{DE,FR,h}$ between 2011 to 2014. It can be seen that in the year 2011 interconnection capacities were congested in 38% of hours, 11% from Germany to France and 27% from France to Germany. The number hours with interconnection capacity congestion *increased* in the more recent years to around 50%. Congestion probabilities particularly increased in the Germany to France direction (from 11% in 2011 to 32% in 2014), reverting the pattern from 2011. Note that $GMSI_{DE,FR,h}$ has constantly decreased from 0.78 in 2011 to 0.59 in 2014, which means that generation technologies have become *less* similar in recent years. In the next section, we estimate the impacts of our variables on price spreads and on the likelihood of interconnection capacity congestion between Germany and France.

[Table 3]

5. Empirical model

First, we estimate the impacts of $GMSI_{DE,FR,h}$ and other control variables on the magnitude of spot price spreads between German and French electricity spot markets,

$$\begin{aligned} Spread_{DE,FR,h} = {} & \alpha_1 + \varphi_1 Spread_{DE,FR,h-1} + \beta_1 GMSI_{DE,FR,h} + \gamma_1 L_{DE,h} + \delta_1 L_{FR,h} \\ & + \epsilon_1 N_{FR,h} + \pi_1 W_{DE,h} + \rho_1 S_{DE,h} + \tau_1 W_{FR,h} + \omega_1 W_{DK,h} + \theta_1 IC_{DE,FR,h} \\ & + \mu_1 IC_{FR,IT,h} + D_h' \partial_1 + \varepsilon_{1,h} \end{aligned} \quad (1)$$

The subscript h indicates the frequency of observations (hour). Our dependent variable is $Spread_{DE,FR,h}$, which we define as the absolute value of the difference between the German

[26] Since the two markets are subject to market coupling (see also Gugler et al., 2016, Keppler et al., 2016), this implies that the German price is lower than the French price in 29% of hours, the French price is lower than the German price in 16% of hours and there is price equality in 55% of hours.

and French spot electricity prices. The one hour lagged dependent variable is included to control for intraday demand and supply rigidities[27]. We employ a simple OLS estimator to estimate equation (1). β_1 measures the impact of $GMSI_{DE,FR,h}$ on the price spread. γ_1 and δ_1 are load coefficients in Germany and France, respectively. ϵ_1 shows the impacts of nuclear generation in France on the price spread. π_1 and ρ_1 measure the impact of day-ahead forecasts of wind and solar electricity in Germany on the price spread, respectively. τ_1 is the coefficient for day-ahead forecasts for wind electricity in France. ω_1 shows the coefficient for day-ahead forecasts for wind electricity in Denmark. θ_1 measures the impact of interconnection capacity between Germany and France on the price spread. μ_1 is the coefficient for interconnection capacity between France and Italy. The vector D includes dummies for the day-of-week, year and holidays.

Second, we estimate the determinants of interconnection capacity congestion. We employ a logit model to estimate the impacts of our explanatory variables on the likelihood of interconnection capacity congestion between Germany and France.

$$\begin{aligned} P\big(ICC_{DE,FR,h} = 1\big) &\\ &= \alpha_2 + \beta_2 GMSI_{DE,FR,h} + \gamma_2 L_{DE,h} + \delta_2 L_{FR,h} + \epsilon_2 N_{FR,h} + \pi_2 W_{DE,h} \\ &+ \rho_2 S_{DE,h} + \tau_2 W_{FR,h} + \omega_2 W_{DK,h} + \theta_2 IC_{DE,FR,h} + \mu_2 IC_{FR,IT,h} + \partial_2 D \\ &+ \varepsilon_{2,h} \end{aligned} \tag{2}$$

In contrast to other empirical studies, in this study we distinguish between the directions of interconnection congestion. This is a very important issue, since not only the sizes of the coefficients but also their signs are expected to differ depending on the direction of interconnection congestion (see above). Therefore, we separate $ICC_{DE,FR,h}$ into congested hours from Germany to France, $ICC_{DE\rightarrow FR,h}$ (Equation (3)), and from France to Germany, $ICC_{FR\rightarrow DE,h}$ (Equation (4)):

$$\begin{aligned} P(ICC_{DE\rightarrow FR,h} = 1) &\\ &= \alpha_3 + \beta_3 GMSI_{DE,FR,h} + \gamma_3 L_{DE,h} + \delta_3 L_{FR,h} + \epsilon_3 N_{FR,h} + \pi_3 W_{DE,h} \\ &+ \rho_3 S_{DE,h} + \tau_3 W_{FR,h} + \omega_3 W_{DK,h} + \mu_3 IC_{FR,IT,h} + \partial_3 D + \varepsilon_{3,h} \end{aligned} \tag{3}$$

[27] For example, most of the conventional power plants (nuclear and coal) cannot adjust their generation from hour to hour over the day, e.g. due to fixed start-up and ramping costs. When we exclude this variable, results remain unchanged.

$$P(ICC_{FR\to DE,h}=1)$$
$$= \alpha_4 + \beta_4 GMSI_{DE,FR,h} + \gamma_4 L_{DE,h} + \delta_4 L_{FR,h} + \epsilon_4 N_{FR,h} + \pi_4 W_{DE,h} + \rho_4 S_{DE,h} + \tau_4 W_{FR,h} + \omega_4 W_{DK,h} + \mu_4 IC_{FR,IT,h} + \partial_4 D + \varepsilon_{4,h} \quad (4)$$

We expect opposite signs for the estimated parameters in Equation (3), $\gamma_3, \delta_3, \epsilon_3, \pi_3, \rho_3, \tau_3, \omega_3$ and μ_3 and Equation (4), $\gamma_4, \delta_4, \epsilon_4, \pi_4, \rho_4, \tau_4, \omega_4$ and μ_4.

6. Discussion of the main results

Table 4 shows the estimation results based on Equations (1)-(4). Equation (1) is estimated by OLS, whereas we estimate Equations (2)-(4) by logistic regression for which we report odds ratios.[28] Like other studies, we assume that demand for electricity is exogenous, because of negligible short-term elasticity (for more information, see Borenstein (2009); Green & Newbery (1992)). Note that the lagged dependent variable introduced in Equation (1) does not imply inconsistency for very large time series data sets as we employ (see Keele & Kelly, 2006). In any case, when we exclude it, all results hold up. All reported standard errors are robust to any form of heteroscedasticity and autocorrelation for all specifications. Most estimated coefficients and odds ratios are statistically significant and *all* have the expected sign.

Regarding Eq. (1) the coefficient of the lagged dependent variable, $Spread_{DE,FR,h-1}$, is positive and highly significant meaning that there exist some persistent spreads stemming from intraday supply and demand rigidities. For example, nuclear and most of the conventional power plants might not be able or willing to adjust their supply according to demand from hour to hour over the day, e.g. due to fixed start-up and ramping costs. In addition, demand is mostly rigid over several hours over the day.

[Table 4]

The negative and statistically significant coefficient of $GMSI_{DE,FR,h}$ (Eq. (1)) indicates that more similar generation technologies in Germany and France decrease price spreads.[29]

[28] Odds ratios give the probability of congestion of interconnection capacities compared to the probability of no congestion. An odds ratio greater (smaller) than one implies a positive (negative) coefficient, since the coefficient is the natural logarithm of the odds ratio.
[29] We also have constructed a dummy variable that controls for marginal generation technologies in Germany and France. It takes values of one in case of similar marginal generation technologies and zero otherwise. The results are very similar to GMSI and are available upon request.

Thus, a $GMSI_{DE,FR,h}$ of one implies that price spreads between Germany and France are almost eliminated[30]. In addition, from Eq. (2) we see that $GMSI_{DE,FR,h}$ has a negative and statistically significant impact on the likelihood of interconnection capacity congestion ($ICC_{DE,FR,h}$). The odds ratio of 0.218 implies that if $GMSI_{DE,FR,h}$ increases by 0.1, the odds of interconnection capacity congestion are 78.2% lower (=$(1-0.218)*100$). Ceteris paribus when $GMSI_{DE,FR,h}$ approaches zero (completely dissimilar generation mixes) and one, respectively (completely similar generation mixes)[31], the estimated predicted probabilities for congested interconnection capacities are around 69% and 32%, respectively. In line with our expectations, we see that convergence and integration of European electricity markets heavily depend on generation mixes of European electricity markets.

Consistently, more similar applied technologies in Germany and France lead to much lower congestion probabilities in the direction of Germany to France than from France to Germany. Both countries have similar supply structures mostly during peak times when both employ predominantly gas as the marginal technology. In these hours price spreads are mostly eliminated and lower exports from Germany to France imply that interconnection capacities are abundant.

Comparing estimated coefficients of Eq. (1) and odds ratios of Eq. (2), the expectation of negative and positive impacts of $Load_{DE,h}$ and $Load_{FR,h}$ is confirmed for both equations, respectively. On average German spot prices are lower than French spot prices (see Table 2), and as a result, when demand for electricity in Germany (France) increases electricity spot prices increase (decreases) as well and, thus, $Spread_{DE,FR,h}$ becomes smaller (larger). This in turn means that high electricity demand in Germany (France) has a negative (positive) impact on the odds of interconnection capacity congestion on average. In terms of odds ratios, if $Load_{DE,h}$ and $Load_{FR,h}$ increase by $1GWh$, the odds that interconnection capacities become congested are 7.2% lower and 8.4% higher, respectively. This effect can be disentangled in larger odds of congestion in the Germany to France direction, and smaller odds of congestion in the France to Germany direction. Load in France has the exact opposite effects (see Eq. (3) and (4)).

As expected, electricity generation by wind in Germany increase price spreads and congestion, with the (expected) exception of equation (4). The same signs are obtained using

[30] The average price spread is 5.31 $€/MWh$ (see Table 2). A move of $GMSI_{DE,FR,h}=0$ to $GMSI_{DE,FR,h}=1$ reduces price spreads by around 3.5 $€/MWh$.

[31] We estimate the predicted probabilities of interconnection capacity congestion for $GMSI_{DE,FR,h}=0$ and $GMSI_{DE,FR,h}=1$, by fixing other control variables at their means, using the Stata command $margins, at(GMSI_{DE,FR,h}=(0\ 1))\ atmeans\ post$ (see Torres-Reyna, 2014).

solar generation in Germany, however, this variable is insignificant for price spreads. As expected, wind electricity in France has the exact opposite effects, while the magnitude of the coefficient and odds ratios is higher. Additional wind electricity may have such a large negative impact on both price spreads and congestion due to a high share of nuclear (low-cost) electricity generation in France. Wind electricity in Denmark also displays the same signs as wind and solar electricity in Germany, however, it is only significant for the congestion equations. The impact of nuclear generation in France on price spreads is as expected negative and significant.

Not surprisingly, an increase in own, i.e. German-French interconnection capacity $IC_{DE,FR,h}$, is associated with significantly lower price spreads as well as with lower odds of congestion. E.g., ceteris paribus, the predicted probabilities of congestion between Germany and France for the minimum and maximum interconnection capacity ($IC_{DE,FR,h}$) of $0\ GW$ and $3.665\ GW$ (see Table 1) are around 89% and 17%, respectively. On the other hand, increasing interconnection capacity between France and Italy, $IC_{FR,IT,h}$, increases both price spreads and the odds for interconnection capacity congestion between Germany and France. Since France mostly imports from Germany, exporting more electricity from France to Italy further increases the spot price level in France relative to the German spot price level and as more trade sets in capacity becomes more likely to be congested. Consistently, capacities become more congested in the direction from Germany to France and less in the direction from France to Germany. Hence, it seems that increasing interconnection capacities and, thus trade flows, between France and Italy play an important role for the degree of electricity market integration between Germany and France. Moreover, the direction of congestion is important. As mentioned above, this occurs because France mostly exports to Italy. When electricity flows from France to Germany and at the same time interconnection capacities between France and Italy together with trade increases, interconnection capacity congestion between Germany and France, $ICC_{FR\rightarrow DE,h}$, occurs less often. Thus, one can conjecture that ceteris paribus once French and Italian electricity spot markets become better integrated, integration of German and French electricity spot markets might suffer. E.g., ceteris paribus, the predicted probabilities of congestion between Germany and France ($ICC_{DE,FR,h}$) for the minimum and maximum interconnection capacity between France and Italy of $0\ GW$ and $3.579\ GW$ (see Table 1), are around 40% and 66%, respectively. Thus, externalities matter a lot in electricity markets.

In sum, the main result of this study is that electricity spot price spreads are almost eliminated and the likelihood of interconnection capacity congestion is significantly reduced once both German and French electricity markets employ very similar generation mixes. Put differently, if German and French electricity generation mixes are very dissimilar, the likelihood of congestion is largest. We further show that more interconnection capacity between France and Italy and more wind generation in Denmark positively affects both price spreads and the likelihood for interconnection capacity congestion between Germany and France. Moreover, *all* standard predictions of trade theory in markets characterized by increasing marginal cost (=supply) and limited cross-border trade capacity are borne out by the data. Interdependencies and externalities clearly are main features of European electricity markets.

7. Conclusion

The European Commission has been constantly attempting to harmonise and integrate the historically independent national electricity systems in order to achieve an internal European electricity market. However, the absence of well-coordinated national energy policies across EU member states may distort developments toward an internal European electricity market. Integration of European national electricity markets necessitates interconnection capacity to make possible electricity flows from one market to another market.

This study investigates the impacts of similarities/differences in generation structures between German and French electricity markets on the electricity spot price spreads and on the likelihood of interconnection capacity congestion. We find that when German and French electricity markets employ similar generation technologies, electricity spot price spreads are almost eliminated, while the likelihood for interconnection capacity congestion significantly decreases.

What do these results imply in terms of convergence of European electricity markets? Our first main result is that at least part of the "convergence" that we witnessed in recent years, and which was documented in recent literature, is spurious. In other words, it is not (purely) driven by the forces of arbitrage but (also) by coincident similarities in the generation structures. We see zero price spreads only in those hours where it happened that generation mixes are fairly similar, e.g. because the marginal technologies were the same (e.g. gas or coal). In those hours prices converged and cross-border capacities were not exhausted between Germany and France. In those hours, however, where generation mixes are dissimilar, prices (still) diverge and cross-border capacities are (still) exhausted between Germany and France. Two facts aggravate the problem. First, the benefits of cross-border trade and diversification of power generation (like less need for a capacity market) are largest exactly when the generation mixes are *dissimilar*, but in those hours congestion probabilities are largest. For example, Germany would profit most from an integrated market with France when the wind is strong in Northern Germany and much excess electricity could be exported to France, as is the case when there is very little wind in Germany and France could export a lot of its nuclear electricity. However, in exactly those hours cross-border capacities are congested. Second, the average GMSI between Germany and France decreased in recent years from 0.78 in 2011 to 0.59 in 2014. Clearly, the large relative increase of renewables (wind and solar) and the unilateral phase out of nuclear energy in Germany in recent years made generation mixes more *dissimilar* compared to its neighbour France adding to the problem. Hence, the aim of integrating European electricity markets is to ensure access to a more diversified power plants' portfolio, which in turn is expected to increase security of electricity supply and improve the reliability of the electricity system through reducing the cost of maintaining capacity adequacy. This study, however, shows that the more dissimilar generation mixes are the higher the likelihood that interconnection capacities become congested and, as a result, diversification effects cannot be obtained. Therefore, full price convergence and the benefits of diversification can only be achieved by additional investment in cross-border capacity.

In addition, we provide several other interesting and consistent results, all derived and embedded in standard trade theory. For example, not surprisingly, more interconnection capacity implies more integration (lower price spreads and lower likelihood of congestion). Put differently, integrating two diverse markets and realising the benefits of integration requires sufficient interconnection capacity investment, while integration of two relatively similar markets does not require high interconnection capacity investment (but of course, diversification effects are also lower).

Furthermore, price spreads and the likelihood of congestion between a pair of countries heavily depend on the influences of neighbouring countries in electricity. Wind electricity in Denmark affects the likelihood of congestion between Germany and France in the same way as own (i.e. German) wind electricity does. More interconnection capacity between France and Italy increases price spreads, increases congestion probabilities from Germany to France and reduces them from France to Germany, since France mostly imports from Germany but mostly exports to Italy. Our second main result therefore is that interdependencies and cross-border externalities abound in European electricity markets, and any sensible solutions to the main problems such as integration of renewables and security of supply cannot be achieved by purely national energy policies.

8. References

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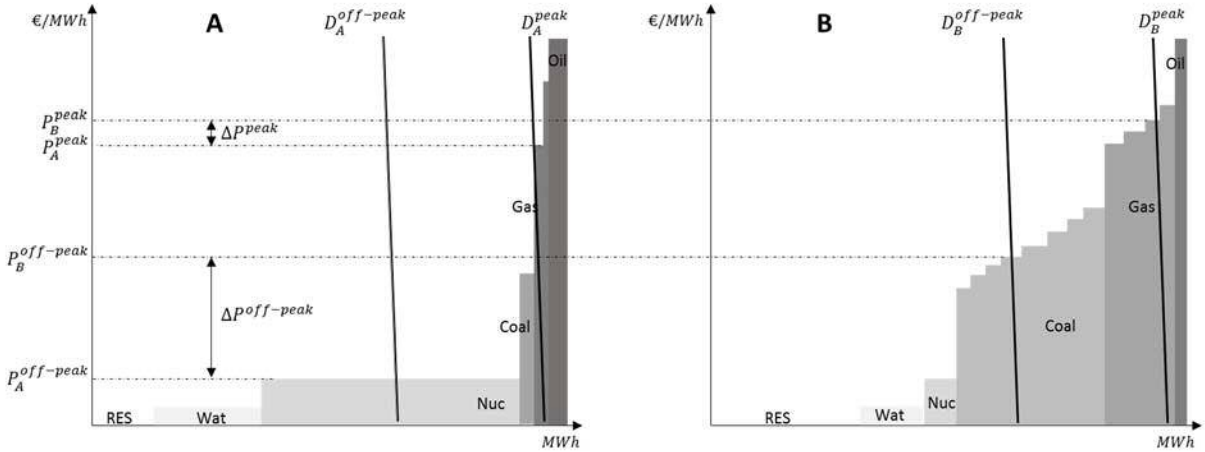
Tables and Figures

Graph 1. Generation mixes and price convergence



Graph 2. Electricity trade and market integration

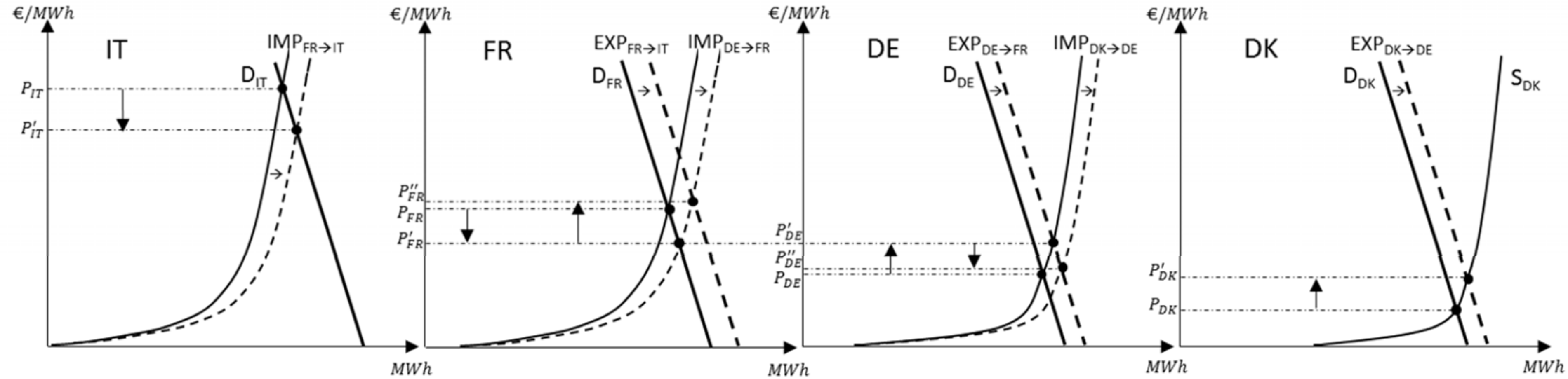


Table 1. Variables description, sources and expected signs

Variable	*Description*	*Source*	*Expected sign* $Spread_{DE,FR,h}$	$ICC_{DE,FR,h}$	$ICC_{DE\to FR,h}$	$ICC_{FR\to DE,h}$
Dependent						
$Spread_{DE,FR,h}$	Absolute value of spot price spreads between Germany and France, in €/MWh	EPEX				
$ICC_{DE,FR,h}$	Derived from available transfer capacities and already allocated capacities between Germany and France. It equals 1 for congestion of interconnection capacities and zero otherwise	CASC				
$ICC_{DE\to FR,h}$	It equals one for congestion of interconnection capacities from Germany to France and zero otherwise	CASC				
$ICC_{FR\to DE,h}$	It equals one for congestion of interconnection capacities from France to Germany and zero otherwise	CASC				
Explanatory						
$GMSI_{DE,FR,h}$	Measures the similarity of generation mix structures between Germany/Austria and France. It lies between zero and one.	*Several*[a)]	(-)	(-)	(-)	(-)
$L_{DE,h}$	Aggregate consumption in Germany, in MWh	*ENTSO-E*	(-)	(-)	(-)	(+)
$L_{FR,h}$	Aggregate consumption in France, in MWh	*ENTSO-E*	(+)	(+)	(+)	(-)
$N_{FR,h}$	Nuclear generation in France, in MWh	*RTE*	(-)	(-)	(-)	(+)
$W_{DE,h}$	Forecasts for wind electricity generation in Germany, in GWh	*German TSOs*[b)]	(+)	(+)	(+)	(-)
$S_{DE,h}$	Forecasts for solar electricity generation in Germany, in GWh	*German TSOs*	(+)	(+)	(+)	(-)
$W_{FR,h}$	Forecasts for wind electricity generation in France, in GWh	*RTE*	(-)	(-)	(-)	(+)
$W_{DK,h}$	Forecasts for wind electricity generation in Denmark (sum of wind generation in both East and West Denmark), in GWh	*Energienet*	(+)	(+)	(+)	(-)
$IC_{DE,FR,h}$	Interconnection capacity between Germany and France, in GWh	*CASC, EPEX*	(-)	(-)		
$IC_{FR,IT,h}$	Interconnection capacity between France and Italy, in GWh	*CASC, EPEX, GME*	(+)	(+)	(+)	(-)

[a)] Platts Power Vision, APG, RTE, TransnetBW, Tennet, 50hertz and Amprion, E-Control, EEG – TU Vienna, Energy Agency, EEX, BAFA (the German Federal Office of Economics and Export Control), U.S. Energy Information Administration
[b)] APG, TransnetBW, Tennet, 50hertz and Amprion.

Table 2: Descriptive statistics

Variable	Observations	Mean	Std. Deviation	Min	Max
$P_{DE,h}$	32888	40.46	16.22	-100.00	210.00
$P_{FR,h}$	32894	42.65	18.57	-100.00	500.00
Dependent					
$Spread_{DE,FR,h}$	32879	5.31	9.90	0.00	380.00
$ICC_{DE,FR,h}$	32904	0.45	0.50	0.00	1.00
$ICC_{DE\rightarrow FR,h}$	32904	0.29	0.46	0.00	1.00
$ICC_{FR\rightarrow DE,h}$	32904	0.16	0.37	0.00	1.00
Explanatory					
$GMSI_{DE,FR,h}$	32904	0.64	0.15	0.01	0.99
$L_{DE,h}$	32904	62.38	11.79	34.48	89.94
$L_{FR,h}$	32904	54.10	12.02	29.70	102.10
$N_{FR,h}$	32904	46.21	6.33	14.25	61.04
$W_{DE,h}$	32904	5.88	4.82	0.32	29.30
$S_{DE,h}$	32904	3.23	5.00	0.00	24.50
$W_{FR,h}$	32904	1.64	1.12	0.10	7.37
$W_{DK,h}$	32904	1.26	1.00	0.00	4.89
$IC_{DE,FR,h}$	32904	2.21	0.58	0.00	3.67
$IC_{FR,IT,h}$	32904	0.74	0.72	0.00	3.58

Note: The data relating to load, nuclear, wind and solar forecast and interconnection capacities are in GWh. $GMSI_{DE,FR,h}$ is an index which by construction can take values between zero and one. $P_{DE,h}$, $P_{FR,h}$ and $Spread_{DE,FR,h}$ are in $€/MWh$. The rest of variables are dummies.

Table 3. Dependent variables and $GMSI_{DE,FR,h}$, 2011-2014

Direction	2011	2012	2013	2014
$ICC_{DE\rightarrow FR,h}$	11%	30%	42%	32%
$ICC_{FR\rightarrow DE,h}$	27%	7%	12%	17%
$ICC_{DE,FR,h}$	38%	37%	53%	49%
$Spread_{DE,FR,h}$	3.96	4.16	7.68	4.75
$GMSI_{DE,FR,h}$	0.78	0.63	0.60	0.59

Table 4. Regression Coefficients (Eq. (1)) and Odds Ratios (Eq. (2), (3) and (4))

$Equation$	Eq.(1) $Spread_{DE,FR,h}$		Eq.(2) $ICC_{DE,FR,h}$		Eq.(3) $ICC_{DE \to FR,h}$		Eq.(4) $ICC_{FR \to DE,h}$	
$Spread_{DE,FR,h-1}$	0.683	***						
	(0.038)							
$GMSI_{DE,FR,h}$	-3.478	***	0.218	***	0.112	***	0.365	***
	(0.735)		(0.035)		(0.023)		(0.090)	
$Load_{DE,h}$	-0.121	***	0.928	***	0.873	***	1.135	***
	(0.013)		(0.002)		(0.003)		(0.005)	
$Load_{FR,h}$	0.201	***	1.084	***	1.275	***	0.676	***
	(0.020)		(0.003)		(0.006)		(0.005)	
$Nuc_{FR,h}$	-0.175	***	0.986	***	0.847	***	1.396	***
	(0.020)		(0.004)		(0.005)		(0.013)	
$Wind_{DE,h}$	0.073	***	1.037	***	1.218	***	0.857	***
	(0.017)		(0.005)		(0.007)		(0.007)	
$Solar_{DE,h}$	0.015		1.039	***	1.105	***	0.892	***
	(0.010)		(0.004)		(0.005)		(0.006)	
$Wind_{FR,h}$	-0.306	***	0.858	***	0.671	***	1.923	***
	(0.047)		(0.012)		(0.012)		(0.047)	
$Wind_{DK,h}$	0.024		1.067	***	1.245	***	0.915	***
	(0.044)		(0.018)		(0.025)		(0.027)	
$IC_{DE,FR,h}$	-1.307	***	0.375	***				
	(0.129)		(0.010)					
$IC_{FR,IT,h}$	0.784	***	1.338	***	1.635	***	0.587	***
	(0.087)		(0.025)		(0.039)		(0.023)	
$Constant$	10.998	***	35.928	***	6.100	***	0.017	***
	(1.149)		(8.000)		(1.681)		(0.006)	
$Day\_of\_week\_FE$	Yes		Yes		Yes		Yes	
$Yearly\_FE$	Yes		Yes		Yes		Yes	
$Holiday\_FE$	Yes		Yes		Yes		Yes	
$Observations$	32,872		32,904		32,904		32,904	
$R-squared$	0.624							

Note: Coefficients (for Eq. (2), (3) and (4)) can be obtained using the following formula: Coefficient = ln($odds\ ratio$), e.g. the coefficient for $GMSI_{DE,FR}$ in Eq.(2) is $coefficient = \ln(0.218) = -1.523$. We get negative (positive) coefficients for odds ratios lower (greater) than one. Robust standard errors in parentheses. *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.

Appendix

A fundamental model for calculating marginal costs

We develop a state-of-the-art (standard) fundamental market model of electricity supply and demand in electricity generation, as applied in other studies (e.g. Borenstein and Bushnell,1999; Schröter, 2004; Sensfuß, 2007; Sensfuß et al., 2008; Burger et al., 2007, Chapter 4; Graf and Wozabal, 2013; Hirth, 2013) to identify generation technology classes that are in the merit order. Hence, we construct hourly supply curves (i.e. the merit order curve) by applying data on installed capacities and combine these with technical information on plant characteristics and other relevant data (e.g. plant availability scores and efficiency factors; see below). Hourly demand, on the other hand, is simply determined by hourly load in the market (net of cross-border trade). The Austrian transmission system operator, Austrian Power Grid (APG), and the Energy Economics Group (EEG) of the Technical University of Vienna, both having developed their own fundamental models, provided us with background knowledge, modelling support, and information.

Trading in wholesale electricity in Europe happens to a large extend at day-ahead spot markets, which are organized at power exchanges. In a power exchange, suppliers and consumers place bids (e.g. EPEX at 12 a.m.) for any hour of the following day. Such power exchanges are generally characterized by many suppliers and consumers and have high liquidity (Gugler et al., 2016). According to Graf and Wozabal (2013), firms bid their capacities at marginal costs at the EPEX day-ahead market and thus the market worked efficiently. In our case, this is necessary to determine which generation technology classes are in the merit order. That is, firms will only generate electricity from their owned technology capacity if its marginal costs of producing are below the spot price. Therefore, we calculate hourly marginal costs of each generation technology class in order to construct *hourly merit orders*.

Data

We obtain detailed information on *installed capacity* (Cap) at the generation unit level for the period 2011–2014 from Platts PowerVision. The following information is obtained on generation unit level: plant name, construction and retire date, turbine type, fuel type, plant type, operational status, and installed capacity (in MW). In contrast to other sources like Bundesnetzagentur (2011) that publishes a list of German power plants with installed capacities larger than 20 MW, Platts PowerVision provides data for all European countries irrespective of the size.

APG provided us with information on *availability factors (AF)* of power plants turbine and fuel type. The availability of a power plant is an operational limitation determined, for example, by planned revisions (e.g. maintenances) and seasonal demand fluctuations. In accordance with Schröter (2004), we consider three periods: winter season, summer season and transition phase, in order to adjust our availability measure to seasonal demand fluctuations. Low electricity demand during summertime allows for higher operational flexibility. Thus, most of the planned revisions take place during summer, so that our availability measure is significantly lower during this period. Our availability measure represents a percentage number (i.e. values between zero and one). With respect to renewables, we utilize hourly data on wind and solar forecasts (provided by the respective transmission system operators) to assess their availabilities. Bids at day-ahead markets generally follow wind and solar generation forecasts based on wind and sunshine forecasts. Biogas power plants are considered a renewable source of electricity and receive fixed rates for their generation, and thus generate a constant power output (Graf and Wozabal, 2013). Eventually, we multiply the respective installed capacity with the availability score of each plant type to create a measure of *available capacity*.

APG and Energy Economics Group of TU Vienna (internal power plant database) provided us with information on the *efficiency factors* (EF) of power plants by fuel and turbine type. The efficiency factor shows the relationship between energy input in terms of primary energy and energy output in terms of electricity. In our model, the efficiency factor of each generation unit is a function of turbine type, fuel type, and construction year (see Graf and Wozabal, 2013; Schröter, 2004; Sensfuß et al., 2008). The variable takes up values between zero and one.

Construction of marginal costs, and electricity generated by generation technology classes

Next, we calculate *marginal costs* for each hour (h) and by 70 generation technology classes (which are a combination of turbine type, fuel type, and construction year). For this purpose, we take fuel prices, the carbon dioxide (CO_2) price, emission factors, and efficiency factors into consideration. Even though data on various measures do not vary by hour (e.g. daily), we impute these values for each hour (h).

$$mc_{\tau,h} = mc_{tt,ft,cy,h} = \frac{FP_{ft,h} + (CO2P_{ft,h} \times CO2E_{ft})}{EF_{tt,ft,cy}}$$

where:

mc = Marginal cost (€/MWh)
τ = Generation technology class
FP = Fuel price (€/MWh)
EF = Efficiency factor (%)

$CO2E$ = CO_2 emission factor (tCO_2/MWh)
$CO2P$ = CO_2 spot price (€/MWh)
tt = Turbine type (steam turbine, combined cycle, etc.)
ft = Fuel type (hard coal, gas, oil, etc.)
cy = Construction year
h = Hour

We distinguish between 22 plant types, which are combinations of 12 turbine types and 12 fuel types. For these plant types, we collected data on their *efficiency factors (EF)* depending on their respective *construction years*, which gives us 70 different combinations. The idea is that older plants are less efficient and, thus, have higher marginal costs. Moreover, we collected data on *fuel prices (FP)* depending on the 12 fuel types over time. As the daily price of coal, we use ARA month future data provided by EEX. For gas, we use the daily price data provided by BAFA (the German Federal Office of Economics and Export Control). As there is no spot market for lignite and consequently no price information available, in accordance with Graf and Wozabal (2013) we assume the lignite price to be 80% of the coal price. As the daily price of oil we utilize Europe Brent Spot FOB provided by U.S. Energy Information Administration. Given missing uranium prices for nuclear power, like Graf and Wozabal (2013) we assume a constant (and negligible) input price of USD 9.33 per MWh (see OECD/IEA, 2010). Furthermore, we collected data on the degrees of CO_2 emissions by fuel type, which gives us the *CO_2 emission factors* (CO2E). The respective information was provided by APG. We utilize data on daily *CO_2 spot prices* from the European Energy Exchange (EEX).

Next, we obtain electricity generation for each generation technology class τ that are in the German and French merit orders for hour h (up to their intersection with their demand curves). Our *availability factors* (AF) (i.e. a percentage score of total installed capacity) vary across 22 plant types and across three seasons of the year (i.e. summer, winter, and transition period). To obtain electricity generated by generation technology class in Germany and France ($g_{DE,\tau,h}$ and $g_{FR,\tau,h}$), we multiply generation technology classes' installed capacities (Cap) with their respective availability factors (AF).

$$g_{DE,\tau,h} = Cap_{DE,\tau,h} \times AF_{\tau,h} \text{ and } g_{FR,\tau,h} = Cap_{FR,\tau,h} \times AF_{\tau,h}$$

where:

g = Electricity generated (MWh)
Cap = Installed capacity (MW)
AF = Availability factor (%)