The Impacts of Variable Renewable Production and Market Coupling on the Convergence of French and German Electricity Prices

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ABSTRACT

This paper estimates the impact of two separate factors on the spread between French and German electricity prices, the amount of production by variable renewables and "market coupling". As renewable electricity production is concentrated during a limited number of hours with favourable meteorological conditions and interconnection capacity between France and Germany is limited, increases in production of wind and solar PV in Germany lead to increasing price spreads between the two countries. Our estimates based on a sample of 24 hourly French and German day-ahead prices from November 2009 to June 2013 confirm that renewable electricity production in Germany has a strongly positive impact on price divergence. On the other hand, market coupling, the establishment of a combined order book on the basis of information of both markets, which was introduced in November 2010, can be shown to have mitigated the observed price divergence. Both results have policy relevant implications for welfare and the optimal provision of interconnection capacity.

Keywords: Electricity price convergence, Renewable energies, Intermittency, Market coupling, France, Germany

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1. INTRODUCTION

This paper estimates the impact of the amount of production by variable renewables in Germany and market coupling on the spread between French and German electricity prices. This is the first time that these two factors with their opposing impacts on price spreads and welfare have been assessed jointly. Both, production from variable renewables (wind and solar PV) and market coupling, have become decisive determinants of price spreads and efficiency in European electricity markets in recent years and foreshadow the issues confronting electricity markets elsewhere in the years to come. Their welfare effects also pose the question of what should be the appropriate level of interconnection capacity in markets with large amounts of variable renewable production and to which extent market coupling can substitute for such added interconnection capacity.

France and Germany are the two most important electricity markets in continental Europe, disposing of the two largest European generation systems as well as the highest consumption. Their interaction has a decisive influence on electricity prices all over Europe. While French gains 75%

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of its electricity from nuclear power, Germany has in recent years invested heavily in wind and solar PV. Their respective capacity today exceeds 36 GW (wind) and 38 GW (solar PV). While in 2014 their share was only 9.9% (wind) and 6.3% (solar PV) of total German production, their impact on electricity prices is far more significant due to their low variable cost and, in particular, their time structure of production, which is clustered around high output hours when it strongly impacts interconnection flows.

Interconnecting two adjacent areas of electricity production through market coupling absorbs some of those impacts and improves combined welfare by allowing electricity to flow from the low cost area to the high cost area. This lowers prices in the high cost area, raises them in the low cost area and thus has prices in both areas converge. With unconstrained interconnection capacity, price convergence is, of course, complete and the two areas are merged into a single area. With constrained interconnection capacity, the challenge for transport system operators (TSOs) and market operators is using the available capacity in an optimal manner. This is the logic behind the "market coupling" mechanism installed by European power market operators in November 2010 in the Central Western Europe (CWE) electricity market, of which France and Germany are the two largest members. Market coupling aims at optimising welfare by ensuring that buyers and sellers exchange electricity at the best possible price taking into account the combined order books of all power exchanges involved as well as the available transfer capacities between different bidding zones. By doing so, interconnection capacity is allocated to those who value it most.[1]

Market coupling arose as part of the integration process of European electricity markets on the basis of the collaboration of network operators and market operators and has become a general template for market integration between adjacent countries.

As predicted by theory, electricity prices in France and Germany converged substantially in 2010 and 2011 in the wake of market coupling (see below for more detailed descriptive statistics) with concomitant welfare benefits. These benefits were shared between both countries. In first approximation, France exports base-load power, while Germany exports peak-load power, thus exporting and importing at different times of the day. However since 2012, electricity prices between France and Germany *diverged*, a process that accelerated during 2013. The hypothesis this paper is exploring is that this divergence is due to the significant production of variable renewables (wind and solar PV) in Germany, which tends to cluster during certain hours. Typically, solar production around noontime constitutes such an event. However, wind production is also highly auto-correlated and tends to have a significant impact during a limited number of hours of the year. When the production of variable renewables with low variable costs is high, German exports tend to saturate interconnections thus causing price convergence to cease and French-German electricity prices to diverge.

This article assesses the combined impact of market coupling and production from variable renewables on the spread between French and German day-ahead electricity prices on the basis of three and a half years of hourly data for electricity prices on the EPEX Spot day-ahead market as

1. At the writing of this article, markets were coupled on the basis of available transfer capacity (ATC), i.e. the bilateral transmission capacity available for commercial transactions once otherwise reserved capacities such as network safety margins or capacities already reserved through long-term contracts have been deducted from physically available total transfer capacity (TTC). Since 20 May 2015, European electricity markets operated by EPEX Spot are coupled through so-called flow-based market coupling. The latter goes beyond the simple optimisation of available interconnection capacities but integrates and optimises "loop flows", the passage of bilateral electricity flows through third countries, independent of the latter's own prices. This will allow for even finer optimisation of overall available interconnection capacity. If anything, this will strengthen the results from this paper as far as market coupling is concerned.

well on nuclear, wind and solar PV production. This is the first time the effect of solar PV and wind generation as well as market coupling on price convergence is assessed empirically. Previous works on these issues, such as the articles by Pellini (2012) for Italy and by Denny et al. (2010) for Ireland-Great Britain, were based on simulations.

The structure of the article is as follows. Section 2 provides a brief review of the relevant literature and sets out the contribution of this paper. Section 3 gives some descriptive statistics on price spread and details the mechanism of the French and German power exchanges. Section 4 describes data and the econometric framework. Section 5 presents our main results on the impact of renewable on price spread. Section 6 provides additional results on the congestion of interconnection capacity. Section 7 discusses welfare impacts and Section 8 concludes.

2. LITERATURE REVIEW AND CONTRIBUTION OF THIS ARTICLE

In December 2008, the European Commission in its 2nd Climate and Energy package decided to promote renewable production in the European energy mix. The target was to reach 20% of renewable energy in the total energy consumption in the EU by 2020. This led to large investments in wind and solar PV, which are characterized by both variable production and low marginal costs. This results in lower average prices, increased volatility and reduced load factors for existing producers of dispatchable thermal power. See, for instance, Woo et al. (2011) in their empirical study of the Texas ERCOT electricity market. In their scenario analysis, MacCormack et al. (2010) also found that wind integration tends to increase average costs of production as the generator capacity factor was declining.

Due to the low average load factors of solar PV and wind, large amounts of capacity are required to arrive at meaningful contributions to electricity supply. This means that when the climatic conditions are favourable, very sizeable amounts of electricity are produced. Germany's more than 70 GW of combined solar PV and wind capacity corresponds to roughly two thirds of peak demand and is far larger than demand at certain low demand hours (e.g., week-ends), while producing less than 15% of annual demand. This means that at certain hours renewable production is larger than the German electricity system is able to absorb either due to limited demand or due to limited internal interconnections. This indicates a general policy conclusion, namely that higher shares of renewable energy require strengthening internal networks and external interconnections.

Schaber et al. (2012) computed a model based on historical data in order to assess the effect of grid extensions for the market, with an increasing share of wind capacities until 2020. They found that grid extension helped to reduce the externalities of wind integration. In a similar spirit, Spiecker et al. (2013) developed a model covering 30 European countries which simultaneously optimized generation investments as well as the utilization of transmission lines. Their model confirms that wind integration requires the development of additional interconnection capacities (see also Lynch, Tol and O'Malley (2012)). To our knowledge no econometric studies on the impact of variable renewables in European studies exist for the time being.

Interconnection congestion remains a frequent by-product of wind and solar generation. The consequence is, of course, price divergence between the two sides of the border. From a social welfare point of view, this price divergence is detrimental to the combined welfare of both countries. With unconstrained interconnections, consumers in the higher price zone would gain more in terms of consumer surplus than what consumers in the lower price zone would lose. Based on a simulation model, Doorman and Frøystad (2013) for instance found that developing an HVDC interconnection between Norway and Great Britain would strictly generate an increase in welfare. Physical interconnection extension is also part of the solution proposed by Creti et al. (2010) for the Italian market.

According to the current trend of European network investments, one should not expect a substantial increase in interconnection capacity anytime soon. In a study of European electricity prices from 2002 to 2006, Zachmann (2008) found that market integration failure was only partially due to the lack of physical interconnection capacities. At the time, the lack of cross-border congestion management was also an important factor in holding back market integration. It is here that market coupling plays its role as an intermediate solution towards market convergence and the efficient integration of variable renewable energy in the European electricity system.

By aggregating all offers and requests, market coupling optimizes the allocation process of cross-border capacities. In an early study Hobbs et al. (2005) estimated that the welfare impact of market coupling between Belgium and the Netherlands delivered an increase in social surplus only under certain conditions concerning the pricing behaviour of producers. In a more recent study, Ehrenmann and Neuhoff (2009) found through a numerical simulation for the North-Western European network that implicit auction (market coupling) performs better than explicit auction when generators act strategically. Market coupling is therefore a simple and effective way to integrate markets and lower the negative effects of variable wind and solar generation. The present study validates the findings of such simulation exercises by way of an empirical analysis benefitting from a very complete data set.

This paper is an extension of the existing literature on the impacts of variable renewables and market integration. It presents however a number of novel features that go beyond empirically confirming results already known from modelling for a particular set of countries. The use of ex post econometric testing rather than scenario building is necessary in order to capture the impact of the introduction of market coupling, a key feature in the management of European interconnections. The introduction of market coupling implies a switch from explicit auctioning of interconnection capacity with decentralised decision-making to implicit auctioning with centralised decision-making. Prior to market coupling interconnection were allocated through explicit auction by decentralised decision-makers without full knowledge of the supply and demand situation. This led occasionally to a suboptimal allocation of interconnection capacity (e.g. imports from the higher cost country). With market coupling, interconnection capacity is managed directly by the market operator after aggregating all the supply and demand offers. This means that market coupling eliminates "transaction costs", which are impossible to simulate. With explicit auctions, for instance, traders may take suboptimal decisions due to a lack of information (relative to the uncertainty of the weather for instance) by booking interconnection capacity for export that is ultimately not needed. With market coupling such inefficiencies would be immediately reallocated. Simulation cannot render such changes and an empirical approach is thus the only way to analyse the impacts of the change from explicit to implicit auctions.

Second, contrary to the articles mentioned above, this paper is concerned with price spreads rather than with price levels. Price spreads between adjacent markets are a sign of economic inefficiency. In European electricity markets, today price spreads are *increasing* despite the mitigating impact of market coupling. This is a highly policy-relevant result. It begs questions about the appropriate manner to support variable renewables as well as the provision of optimal levels of interconnection capacity to complement their deployment.

Finally, the results below show the great importance of a key feature of variable renewables, the fact that their production is auto-correlated and clusters around hours with favourable meteorological conditions. This clustering is responsible for discontinuous trade flows, interconnection saturation and price divergence. For variable renewables such as solar PV and wind average production figures, whether averaged over the day, the week, the season or the year, do not provide meaningful measures of their impacts. This is why working with hourly datasets is indispensable. Since specific hours have repeated characteristics (solar PV production is always highest at noon), a panel regression with 24 distinct hourly specific effects was chosen. The highly significant results allow confident statements on the impacts of market coupling and variable renewable production on price spreads and efficiency.

For reasons mainly related to data availability, the results of this paper also have a number of limitations. The most obvious is that France and Germany not only trade with each other but also with a number of other countries. France is also connected to Belgium, Switzerland, Italy and the United Kingdom, while Germany is also connected to the Netherlands, Switzerland, Austria, the Czech Republic, Poland, Denmark and Sweden. However, three and a half years of hourly price data were available only for France and Germany. In addition, the French-German border is a neuralgic point for European electricity trade and the determination of electricity prices all over continental Europe. France's maximum import capacity from Germany stands at 4.4 GW (out of a total of 10 GW for French imports and of 9 GW for German exports), and its maximum export capacity at 2.4 GW (out of a total of 14 GW for French exports and of 12 GW for German imports). The French-German supply situation is particular not only with respect to the quantities traded but also with respect to the fact that the region of Central Western Europe (CWE) that includes France, Germany, Belgium, the Netherlands and Luxemburg was the first region where market coupling was introduced. Ideally we would have liked to include Benelux data, but this was unfortunately not possible due to data constraints.

Adding third countries would undoubtedly have increased the explanatory power of the estimations reported below, however on the basis of all available evidence this would have only strengthened the observed effects. During periods of high variable renewable production Germany not only exports to France but also to Poland and, more relevant to our analysis, to Belgium and the Netherlands from whence comes a secondary effect on French electricity prices that goes in precisely the same direction as the primary impact of direct exports from Germany to France.

The decisive nature of the impact of German solar PV and wind production on French-German trade flows is revealed by a simple fact. Due to its large nuclear baseload capacity with low variable costs, France has positive net exports, frequently based on long-term contracts, with all of its trading partners except Germany. In 2013, France exported 5.3 TWh to Germany and imported 15.3 TWh from Germany. Variable renewables and the extremely low prices that come in their wake thus even supersede the French structural surplus of production over consumption.

Two further limitations of this paper are more virtual than real. For one, the model does not include any production from coal, gas or nuclear in Germany, which still provide the bulk of electricity. Even if data had been available, it is not at all clear that this would have affected the estimations in a significant manner. The German electricity system today is driven by renewable wind and solar production. Supply from dispatchable sources such as coal, gas and nuclear is a *residual quantity* that results passively from the interaction of demand and renewable production. The situation is analogue in France where the small amount of fossil production is a residual of the interaction between exogenously scheduled nuclear production and electricity demand. The reason in both cases is that variable renewables and nuclear are the technologies with the lowest marginal costs in Germany and France respectively and thus have priority dispatch. Adding fossil production in either country (or German nuclear production) would have provided no new information and just created collinearity issues in the regressions.

Second, the model does not include prices for coal, gas or CO_2. The latter certainly have an impact on the level of electricity prices even if the underlying production is a residual phenomenon. During the three and a half years covered by this analysis, European carbon prices declined to exceptionally low levels. In addition, coal prices declined for independent reasons. The two factors taken together meant that coal-fired power generation substituted for gas-fired power generation in both France and Germany, as in the rest of Europe, lowering prices in both countries in the process. In some small measure this might have increased German exports, especially based on coal, to France beyond the impact of the production from the variable renewables, wind and solar, for which this analysis is testing. However, this is not a foregone conclusion as French gas production receded also for domestic reasons and French nuclear remain of course more competitive that coal at any carbon price. Future research may confirm whether the European merit order switch had significant any impact on French-German electricity trade flows.

The present paper also focuses not on price levels but on spreads and market efficiency. In particular, it analyses spreads as the result of the physical phenomenon of congestion. This is possible since German production by variable renewables is driven by meteorology (as well as installed capacity, of course) and thus independent of market prices. While the underlying trade flows in both directions are driven by relative prices, the paper shows precisely that when renewable production kicks in, trade flows become unidirectional, congestion sets in and prices diverge, *independently* of the fact whether coal or gas is the marginal fuel and independently of the price of the marginal fuel.

3. FRENCH-GERMAN PRICE SPREADS: STYLISED FACTS AND ANALYSIS

An intuition for the impacts of both market coupling and variable renewable production is provided already by looking at a number of descriptive statistics. The data show a significant improvement in price convergence after the market coupling of the 10th of November 2010. Convergence is defined by convention as the percentage of hours during which absolute price differences are below 0.1 €/MWh. In 2009 and before market coupling, German and French prices converged only 1% of the time. After the introduction of market coupling, prices converged 67% of the time in 2011. However, the trend has been downward in recent years. While in 2012 the convergence rate was still 64%, it was only 41% for the first semester of 2013.

Table 1 shows in detail the percentage of convergence for each month since 2011. We see that winter and summer months, sometimes for different reasons, suffer particularly from congestions. During winter, events are driven by the high thermo-sensibility in France, when peak consumption for electric heating rises by up to 2.3 GW for every 1°C drop of temperature. In response French imports increase strongly as electricity from Germany, of which a substantial but variable part is produced by wind and solar PV, is the most cost-effective option. This means that interconnections are saturated more frequently than during other times of the year and prices diverge.

The effect is noticeable, for instance, during the extremely cold month of February 2012 when prices converged only 20% of the time (see column 2 in Table 1). Demand was so high that on the 9th of February 2012 at 10 am due to congestion French prices reached 1938 €/MWh, whereas in Germany prices were around only 100 €/MWh. In summer, air conditioning consumes one third of peak electricity production, which also induces added exchanges between France and Germany, increases congestion and price spreads.

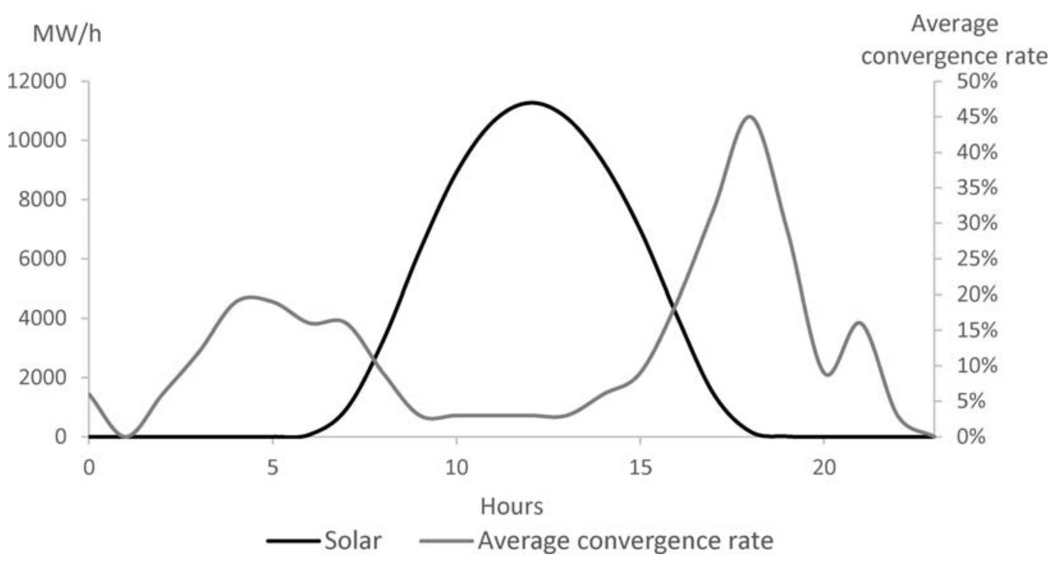
Figure 1 shows results on German solar PV production and price convergence in March 2013, when the overall convergence rate was 12% as reported in Table 1. As can be seen in Figure 1, price convergence is poor during the night and at noon. For instance, during the whole month

Table 1: Price Convergence between France and Germany

Month	2011	2012	2013
Jan	77%	63%	38%
Feb	76%	20%	26%
Mar	72%	52%	12%
Apr	73%	73%	48%
May	64%	72%	66%
Jun	44%	74%	57%
Jul	48%	85%	N.A
Aug	53%	82%	N.A
Sep	72%	75%	N.A
Oct	82%	51%	N.A
Nov	82%	69%	N.A
Dec	63%	50%	N.A
Average	67%	64%	41%

Note: convergence is defined as the percentage rate of hourly price spreads below €0.1 per MWh.

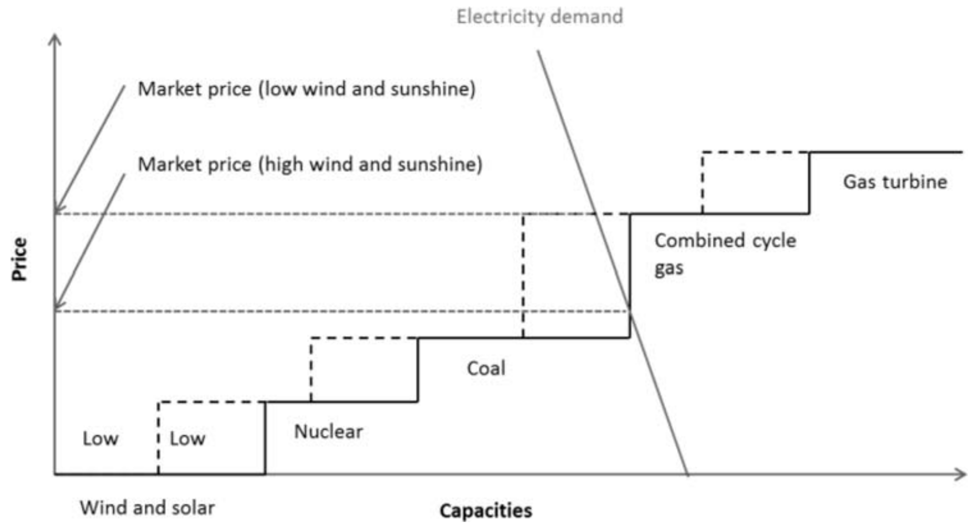
Figure 1: Solar PV Production in Germany and Price Convergence in March 2013 (Average hourly production and average convergence rate of French and German electricity prices)



prices at 2 am and 12 pm never converged. Similarly, from 8 am to 3 pm, the convergence rate has not exceeded 10%. It was above 40%, however, at 6 pm.

This is the result of two effects. First, Figure 1 shows how convergence decreases when solar PV production increases and *vice versa*. In terms of their average production at certain hours from the day during March 2013, solar PV production varies from 0 GWh at night to more than 11 GWh at noon time. Wind production is equally variable but, in Germany at least, its production cannot be associated with individual hours of the day and its average hourly production associated

Figure 2: Shifting of the merit order curve to the right due to low variable cost renewables



with a particular hour of the day varies only between 5.7 GWh and 6.9 GWh. The congestion effect is thus most easily illustrated with the help of solar production data. The reason for this is straightforward. When solar PV production is high, prices in Germany are low and France massively imports this cheap electricity until interconnections are saturated and prices start to diverge.

The second effect is demand. When German demand is high during early evening hours, wind production and rapidly declining solar PV production are more easily absorbed, interconnections are decongested and prices converge.

This does not mean that France directly imports electricity from wind and solar producers. Once uploaded, one electron is indistinguishable from another. What happens is that the influx of variable renewables with zero short-run marginal cost pushes the merit order curve to the right (see Figure 2). This means that variable costs and prices will fall in the country concerned. The high variability of solar PV and wind generation as well as the existence of ramp costs (which impede dispatchable plants from exiting the market for short periods of time) can lead to very low or even negative prices. Consequently, traders in neighbouring countries will begin to import, arbitraging between domestic production costs and prices and now less expensive imports.

We investigate the extent to which French and German prices diverge due to the congestion of interconnections in function of increases of solar and wind generation as well as market coupling. Table 2 shows absolute price spread at hourly levels from 2009 to 2013.

Two phases can be distinguished in this table. First, the absolute average spread between German and French electricity prices decreased between 2009 and 2011 due to market coupling introduced in late 2010 (see results below). Second, the absolute average spread doubled during 2012 and 2013 reaching the same level as in 2009.

Table 2 also reports intraday changes: contrary to the first period, in 2012 and 2013 there were high spreads during the night and between 10 am and 2 pm due to wind and solar respectively.

As will be shown in the econometric analysis below, this is heavily influenced by the massive build-up of new solar PV and wind capacity in Germany and increased power production from these sources. Since 2010, average daily solar and wind production in fact increased by 380 and 25 per cent respectively (Table 3).

Table 2: Hourly Averages of the Spread between French and German Electricity Prices

Hours	2009	2010	2011	2012	2013
0	8.38	5.32	4.24	6.06	11.37
1	10.24	6.43	4.79	5.62	10.82
2	11.2	6.36	5.59	4.58	9.41
3	11.01	5.16	8.04	3.73	6.96
4	7.73	4.96	9.08	3.37	6.21
5	6.86	5.47	7.29	3.14	7.47
6	10.72	7.47	6.26	4.16	8.6
7	12.29	7.17	5.6	3.35	7.15
8	10.55	6.27	3.87	4.96	7.31
9	11.1	7.23	2.44	9.92	9.72
10	9	6.09	2.1	10.97	10.26
11	8.12	5.54	2.05	7.67	10.38
12	8.03	5.57	1.93	7.97	10.56
13	6.86	5.17	1.92	6.11	9.69
14	7.35	5.17	1.8	5.64	9.71
15	4.92	4.11	1.6	3.58	6.81
16	4.59	3.6	2.72	2.63	5.26
17	5.9	3.24	3.84	1.59	4.51
18	11.11	6.72	3.15	4.19	7.03
19	12.91	6.19	3.48	3.84	10.38
20	10.78	5.66	4.95	3.83	9.54
21	7.02	4.81	3.98	3.07	8.38
22	7.17	4.95	1.76	4.9	10.26
23	8.94	5.9	2.47	8.08	12.84
Average	8.87	5.61	3.96	5.12	8.78

Note: Price spreads are expressed in €/MWh.

Table 3: Average Daily Production of German Solar and Wind (GWh)

Technology	2010	2011	2012	2013
Wind	99.3	125.0	125.3	124.3
Solar	20.8	50.9	76.3	79.0

Electricity consumption in France and Germany as well as French nuclear generation are also important explanatory variables. In particular, the difference between French and German consumption is positively related to the price spread: the higher French demand, the greater the likelihood of finding interconnections congested due to increased imports; the lower German demand, the greater the surplus of German production that is available for exports. It is important to recall that neither French nor German consumption is correlated with renewable production. Conversely, nuclear generation as the base of the French load curve is negatively linked to the price spread. Even if nuclear generation is quite stable during the day, its variations throughout the year are significant. For instance, when several nuclear plants are in maintenance, the French market is more dependent on German production.

4. DATA AND EMPIRICAL FRAMEWORK

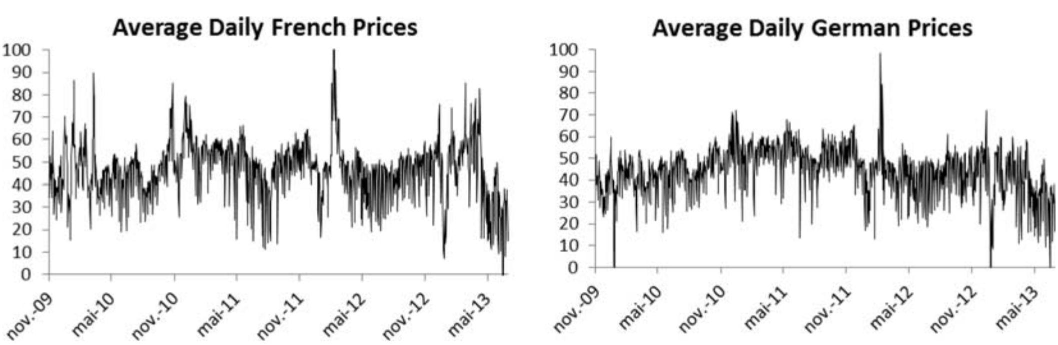
We resort to an econometric approach to analyse the determinants of the spread between French and German electricity prices. As explained in section 2, the impact of market coupling, which is akin to a reduction in informational transaction costs, forbids its explicit representation in a market simulation model and imposes an econometric approach.

In formulating the econometric model, it was necessary to choose between a standard time series model and a panel data model. Two reasons made a panel data regression model with 24 individual hourly specific effects more suited to our purpose. First, individual hours have specific characteristics (e.g., hours with sunshine) that need to be taken into account. Second, the process of price formation on the EPEX Spot day-ahead market does not generate a single time series with continuously updated information. In fact, the 24 hourly prices of a specific day are provided *at the same time* at 12h30 the day that precedes production and delivery. These 24 prices are therefore generated by the market according to the same information set. The price at hour *h* am (day t) does not integrate any additional information compared to the price at hour *h-1* am (day t). There is an enlargement of the information set when we consider day-ahead prices of day *t* compared to day-ahead prices of day *t-1*. Such panel data formulation in the analysis of day-ahead electricity markets is thus well established; see, for instance, Huisman, Huurman and Mahieu (2007) or Karakatsani and Bunn (2008).

Our panel is thus composed of 24 distinct time series for all variables over 1,344 days from 1 November 2009 to 30 June 2013. The total data set includes 32,210 hours. All data is hourly data, which allows accounting for intraday variation in the production of variable wind and solar PV.

Hourly day-ahead prices for the French and German electricity markets were provided by EPEX Spot, the market operator for day-ahead and intraday markets in Germany, France, Austria and Switzerland since 2008. Prices are expressed in Euros per MWh. The dependent variable is the difference between French and German hourly day-ahead prices. To check the stationarity of price spreads, we apply several standard panel data unit root tests and conclude that hourly price spreads are stationary.

Figure 3: Average daily prices in France and Germany



Data Source: EPEX Spot

As explained in the sections 2 and 3, we make the assumption wind and PV productions are positively correlated with price spreads. Data on hourly German solar PV and wind production are provided by the European Energy Exchange (EEX) in GW. Wind production can vary from 0.1 to 24 GW, whereas solar generation can vary from 0 to 23 GW. It is this volatility of renewable production rather than their average contribution that generates issues for cross-border transport. The use of hourly data is therefore essential to evaluate their respective impact on price spread.

Data on hourly consumption in France and Germany is available from the European Network of Transmission System Operators for Electricity (ENTSO-E) and indicated in GW. As mentioned, we use here the difference between French and German consumption as an explanatory variable. This consumption spread measures the strength of the tendency for France to import German electricity. Interconnections tend to congest and prices to diverge when French demand for imports is high due to strong consumption and Germany has low prices due to weak consumption. Together with the relevant elements of the supply system, this consumption differential is thus a convenient synthetic variable that summarises the internal supply and demand situations.

Data on hourly nuclear generation in France, also in GW, is provided by RTE, the French transmissions system operator. From the preceding, it also follows that nuclear production is expected to be negatively correlated with the French-German price spread as it limits the need for imports.

Subsequently, we use a panel data linear regression to estimate the impact of the aforementioned determinants of price spreads. We chose to add individual hourly fixed effects rather than random effects to model individual hour specific characteristics. As the number of daily observations is very large, there is no significant difference between both estimators. In addition, the result of the Hausman test confirms that random effects might not be appropriate. The model is thus:

$$Spread_{h,t} = \beta_0 + \beta_1 ConsDiff_{h,t} + \beta_2 Nuclear_{h,t} + \beta_3 Solar_{h,t} + \beta_4 Wind_{h,t} + \beta_5 Spread_{h,t-1} + u_h + \varepsilon_{h,t},\ for\ h = 0, \ldots, 23\ and\ t = 1, \ldots, T \quad (1)$$

Where: $Spread_{h,t} = p_{h,t}^{Fra} - p_{h,t}^{Ger}$ is the day-ahead prices spread at hour h and day t.
$ConsDiff_{h,t}$ *is* the difference between French and German consumptions at hour h and day t,
$Nuclear_{h,t}$ is the production from nuclear plants in France at hour h and day t,
$Solar_{h,t}$ is the electricity generation from solar PV in Germany at hour h and day t,
$Wind_{h,t}$ is the electricity generation from wind in Germany at hour h and day t,
u_h is the individual fixed effects for hour h, with $\sum_{h=0}^{23} u_h = 0$,
$\varepsilon_{h,t}$ is the error term.

In order to assess the market coupling effect in November 2010, we added in a second equation the dummy variable MC_t (for market coupling) to equation (1), which is equal to one after 10 November 2010 and zero before that date, as well as interaction terms between this dummy and generation from solar PV and wind. This allows us to formulate equation (2):

$$\begin{aligned} Spread_{h,t} = {} & \beta_0 + \beta_1 ConsDiff_{h,t} + \beta_2 Nuclear_{h,t} + \beta_3 Solar_{h,t} + \beta_4 Wind_{h,t} \\ & + \beta_5 Spread_{h,t-1} + \beta_6 MC_t + \beta_7 MC_t \times Solar_{h,t} + \beta_8 MC_t \times Wind_{h,t} \\ & + u_h + \varepsilon_{h,t}\ for\ h = 0, \ldots, 23\ and\ t = 1, \ldots T. \end{aligned} \quad (2)$$

5. RESULTS: IDENTIFYING THE DRIVERS OF THE FRENCH-GERMAN PRICE SPREAD

Estimates of equation (1) are reported in Table 4. The R^2 between is equal to 76% which means our model explains around 3/4 of the variance of average hourly price spreads. In our view, the change in production of renewables during the day, especially solar PV, explains a good deal of the variation of hourly average price spread. As the overall R^2 is equal to 30%, we conclude that our set of regressors is less able to explain variations of the price spread within each hour.

All coefficients are significant and have the expected sign. This confirms the key hypothesis of this article, namely that German wind and solar renewable production have a positive effect on

Table 4: Estimating the Determinants of the Franco-German Electricity Price Spread

VARIABLES	(1) $Spread_{h,t}$	(2) $Spread_{h,t}$
$Spread_{h,t-1}$	0.340***	0.331***
	(0.00508)	(0.00508)
$Nuclear_{h,t}$	−0.181***	−0.127***
	(0.013)	(0.0133)
$Solar_{h,t}$	0.392***	0.795***
	(0.0211)	(0.0781)
$Wind_{h,t}$	0.475***	0.570***
	(0.0130)	(0.0276)
$Cons\_diff_{h,t}$	0.426***	0.424***
	(0.00928)	(0.00926)
MC_t		−1.689***
		(0.205)
$MC_t \times Solar_{h,t}$		−0.253***
		(0.0729)
$MC_t \times Wind_{h,t}$		−0.0878***
		(0.0311)
Constant	5.847***	4.060***
	(0.608)	(0.627)
Number of observations	32,210	32,210
R^2 overall	0.306	0.313
R^2 between	0.760	0.782

Notes: (i) Standard errors in parentheses. Standard errors are computed with the Huber-White robust variance estimators. (ii) ***, **,* respectively denotes rejection of the null hypothesis of insignificant coefficient at 1%, 5% and 10% significance levels.

the French and German electricity price spread. The fact that the spread at hour *h,* day *t* is correlated to its lagged value at day *t-1* reflects the inertia due to the structure of the production and consumption system and the persistence of weather patterns.

The impact of French nuclear power generation on the French-German price spread has the expected negative sign and, even if not very large, is highly significant. The higher the electricity output from nuclear plants, the less German and French prices diverge. Nuclear production can here be taken as a proxy for French production in general, of which it constitutes 75%. Other things being equal, the more electricity is being produced by French nuclear plants, the less France needs to rely on imports, which tend to lead to congestion and price divergence. Thus with high nuclear output, interconnections remain available and prices converge.

Finally, the coefficient of the difference between French and German consumption is significant and positive. This means that the price spread increases either when French consumption is high or German consumption is low. In both cases, French imports from Germany are increasing, which leads to more frequent interconnection congestion and, consequently, to price divergence.

The second column reports the coefficients associated with the estimation of equation (2). The coefficient associated with the market coupling dummy MC_t is negative and significant. Once market coupling had been introduced, price differences were structurally reduced regardless of the hour of the day.

More importantly, the results show that market coupling considerably reduced the impact of variable renewables on the price spread. Interaction terms between the MC_t dummy and both solar and wind generations have significant negative coefficients. An increase in hourly wind production of 1 GW in Germany thus causes on average a divergence of French and German electricity prices of 0.48 €/MWh with market coupling and would cause a divergence of 0.57 €/MWh without market coupling. The effect is even more important for an increase of 1 GW in hourly solar PV production, where the effect with market coupling is 0.542 €/MWh and 0.795 €/MWh without. The mitigating impact of market coupling is considerably stronger for the influence of solar PV on the price spread. This is due to the fact that solar PV production exhibits an even stronger auto-correlation than wind production and is concentrated during an even smaller number of hours. The vast majority of solar PV power is also produced by a large number of decentralised producers unable to arbitrage between the French and the German electricity markets on their own. For these two reasons, the efficiency increasing impact of market coupling is thus particularly strong.

This means that market coupling helped to absorb the variability of German electricity and improved the management of the available interconnection capacity. It thus increased the amount of cross-border exchanges that could be realised at critical times and mitigated the distortive effect of variable renewable generation on price convergence between 2010 and 2013.

As in any econometric study, we assume that variables other than the dependent variable (the spread of French-German electricity prices) and the explanatory variables (German wind and solar PV production, the French-German consumption differential and French nuclear production) either have no significant impact on the dependent variable or remain stable. This is a strong assumption for the period under consideration. We already spelled out in section 2 why the impact of coal, gas and CO_2 prices on spreads, as opposed to absolute levels, can be expected to be limited at best.

Electricity produced by variable renewables is not the only, but according to these estimations the decisive factor in explaining the recent increase in the differential between French and German electricity prices, an increase that was only temporarily delayed by market coupling. Their auto-correlation, i.e. the concentration of their output during a subset of hours, leads to very high trade flows, congestion and price divergence during those hours. On the other hand, the relative absence of renewable production during the rest of the time does nothing to further price convergence. An uncongested interconnection will have prices converge whether its capacity is used at 80% or at 20%. What is decisive in terms of price divergence is the marginal contribution of variable renewables at certain hours, not their average contribution. This makes them such a fascinating subject of study.

This does not mean that German solar PV and wind production alone can explain everything about the Franco-German price spread. The fact that France and Germany also trade with other countries has already been mentioned. There exists also a more technical variable that intrigues experts, namely the variations on the available transfer capacity (ATC) on the French-German interconnection that is at least partly correlated with variable renewable production, cross-border flows and hence price spreads. In principle, one would assume that ATC does not display much short-term volatility, is unaffected by renewable production and is thus of little explanatory power to explain either congestion or the differential between French and German electricity prices. A recent paper by Salah Abou El-Enien (2014, unpublished), however suggests that ATC may well be negatively correlated with variable renewable production. There is anecdotal as well as statistical evidence that transport system operators (TSOs) *increase* the safety margin of the total transfer capacity in the face of increased forecasts of wind and solar production in order to be able to respond flexibly to the inherent unpredictability of renewable production. This, of course, decreases ATC and further increases the impact of renewable production on spreads. However, due to the

Table 5: Testing for Marginal Effects on Congestion

VARIABLES	Logit *Congestion*$_{h,t}$	Ratio of hours with congestion after marginal increase in variable
Congestion$_{h,t-1}$	0.223***	5.693***
	(0.00601)	(0.240)
Solar$_{h,t}$	0.0277***	1.241***
	(0.000691)	(0.00693)
Wind$_{h,t}$	0.0223***	1.189***
	(0.000595)	(0.00536)
Nuclear$_{h,t}$	−5.19e-06***	0.999***
	(5.29e-07)	(4.10e-06)
Constant	−0.277***	0.115***
	(0.0243)	(0.02217)
Observations	23,120	23,120

Notes: (i) Standard errors in parentheses, (ii) ***, **,* respectively denotes rejection of the null hypothesis of insignificant coefficient at 1%, 5% and 10% significance levels.

independent and to some extent arbitrary action of TSO's, this effect might not be entirely captured by renewable production alone and ATC figures might thus contain added information about the Franco-German price spread. However, including ATC in our regressions did not enhance their explanatory power. Future research may want to probe this issue further.

6. A ROBUSTNESS CHECK: MODELLING THE PROBABILITY OF CONGESTION

The previous results on the impact of renewable production on price spreads are corroborated by testing for marginal effects of wind and PV production on the probability of interconnection congestion. Interconnection congestion is defined as a dummy variable equal to one when the German-French price spread is larger than 0.1 €/MWh and zero otherwise. We resort to a logit regression to model this probability of congestion.

Results reported in Table 5 confirm the assumption that variable renewable generation tends to increase cross-border congestion. Column (1) shows the positive effect of solar PV and wind generation on the likelihood of interconnection congestion, while column (2) reports the odds ratios. The latter implies that increasing the German solar generation by only 1 GWh would increase the odds of observing congestion (versus no congestion) on French-German interconnections by 24% (average daily peakload of German solar PV at noontime is 5.8 GWh). An increase of 1 GWh of wind power would increase the likelihood of additional congestion by 19% (average daily peakload of German wind is 5 GWh). An increase in the production of French nuclear power would instead slightly *decrease* the ratio of hours with congestion vs. hours without congestion. In order to put these marginal changes into perspective, it is recalled that over the period observed the French-German interconnection was saturated 43% of the time. The results confirm again that it is indispensable to take renewable power generation as well as the broader supply and demand balance into account in assessing infrastructure needs and operations of the European electricity systems.

7. WELFARE IMPACTS AND OPTIMAL INFRASTRUCTURE PROVISION

Price convergence is also a function of available interconnection capacity. The theoretical common price in the absence of network constraints (unlimited interconnection capacity) thus provides an important normative benchmark for assessing losses of consumer surplus and welfare. EPEX Spot and EEX provide this benchmark by publishing since October 2010 the European Electricity Index (ELIX). The ELIX is calculated on the basis of the actual aggregated bid and offer curves of France, Germany and Switzerland assuming unlimited interconnection capacity. In other words, the ELIX approximates for each hour the price that *would occur* if unlimited interconnection capacities between the three countries existed. This is, of course, a hypothetical case. Attaining the ELIX price would require significant investment in interconnection capacities and thus increase the price paid by consumers through higher transportation tariffs and limit their welfare gains.

Congestion and increasing price spreads imply welfare losses as profitable trades between two countries are not made due to physical constraints. Of course, alleviating such physical constraints does not come costless. Building interconnections implies costs. However one can assess at least the order of magnitude of the annual economic welfare loss by working with the ELIX reference price, which is the theoretical price that would prevail in the absence of transmission constraints.[2] These welfare costs would then need to be put in relation with the costs of adding interconnection capacity up to the point where its marginal costs equals the marginal benefit of additional electricity trades.

This estimation was performed for the year 2012. With unlimited interconnection capacity between Germany and France, the price would by definition always correspond to the ELIX reference price. In this case, daily average prices during 2012 would have been on average 4.15 €/MWh lower to reach the average level of the ELIX price of 42.78 €/MWh. Assuming a locally linear long-term elasticity of French electricity demand of -1 (see Bourbonnais and Keppler, 2013), such a 9.1% decrease in prices would have implied an increase in annual demand to 533 TWh and an increase in consumer surplus of € 2.29 billion. It would have led to a decrease in consumer surplus for German consumers of € 265 million. Even given the unavoidable approximations of such an exercise, the results allow two important conclusions. First, improving interconnections could lead to significant further increase in welfare even after market coupling. Second, while German consumers would experience higher prices than they otherwise would, their losses are considerably smaller than the gains of their neighbours.

This analysis was undertaken to show the orders of magnitude at stake. Several *caveats* apply. First, increases even in the combined surplus of French and German consumers are not equivalent to increases in total net welfare. German and French producers also respectively received higher and lower infra-marginal rents and profits. A more complete analysis would have to take into account all four effects, net them out and relate them in the context of a marginal analysis to the costs of infrastructure provision. Only detailed cost-benefit analysis on the basis of daily supply and demand curves and benefitting from detailed data on grid investment costs could establish precisely the optimal trade-off between infrastructure investment and trading gains.[3] The order of magnitude of the estimates above nevertheless provide a good indication of the benefits of electricity trading and, subject to construction costs, further increasing in electric interconnection capacity between the two countries. With the annualised costs of an additional GW of interconnection

2. This approach follows that of Creti et al. (2010) for the Italian Power Exchange (GME), where losses due to interconnection constraints at the French-Italian border were estimated to be at € 160 million in 2007.

3. See Janssen (2014). This recent doctoral thesis provides elements for a conceptual framework for assessing investment in transport infrastructure. While stopping short of developing an easily implementable model, it discusses the principal considerations that would need to go into the development of such a model and offers a number of leads for the interested reader.

capacity measured in the lower hundreds of millions, there clearly is still room for capacity expansion. Work on the optimal level of infrastructure provision in this perspective is currently on-going.

Of course, the optimal level of physical interconnection capacity is not a fixed datum. It depends precisely on issues such as market coupling and variable renewable production. If market coupling has been able to improve the utilisation of existing infrastructure, increased production from variable renewables in Germany has by now more than compensated this effect and has driven the system to its limit. Research currently under way, is precisely concentrating on the calculation of the optimal level of interconnection capacity under different assumptions about the structure and the variability of production.

8. CONCLUSIONS

On the basis of hourly EPEX Spot price data for 2009 to 2013, this article provides evidence that the variable production from solar PV and wind electricity in Germany has considerably increased spreads between French and German electricity prices. Large quantities of this solar PV and wind electricity that cannot be absorbed by domestic demand in Germany, are exported to neighbouring countries (particularly France) thus congesting interconnections and reversing price convergence. Market coupling significantly mitigated and for a while delayed the full impact of the growth of wind and solar PV production. However its benefits have now been superseded by even greater production by variable renewables posing the question of the adequacy of current interconnection infrastructures.

Price convergence between markets is desirable since it maximises consumer surplus. As illustrated above, in the case of French consumers for 2012 the increase in consumer surplus could have been as high as € 2.29 billion, with a concomitant welfare loss of German consumers of € 265 million, had unlimited interconnection capacity been available at all times. The combined consumer surplus effect for the two countries, taking into account the loss in consumer surplus by German producers as well as other gains and losses on both sides of the border will be assessed in future work.

This article demonstrates that the significant increase in the production of variable renewables that Europe has witnessed in recent years has modified the fundamentals of electricity trade and requires a new look at European power market integration. At the policy level, this poses the questions of what constitutes success in terms of market harmonization and what level of physical infrastructure provision is socially optimal at both the national and the European level.

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