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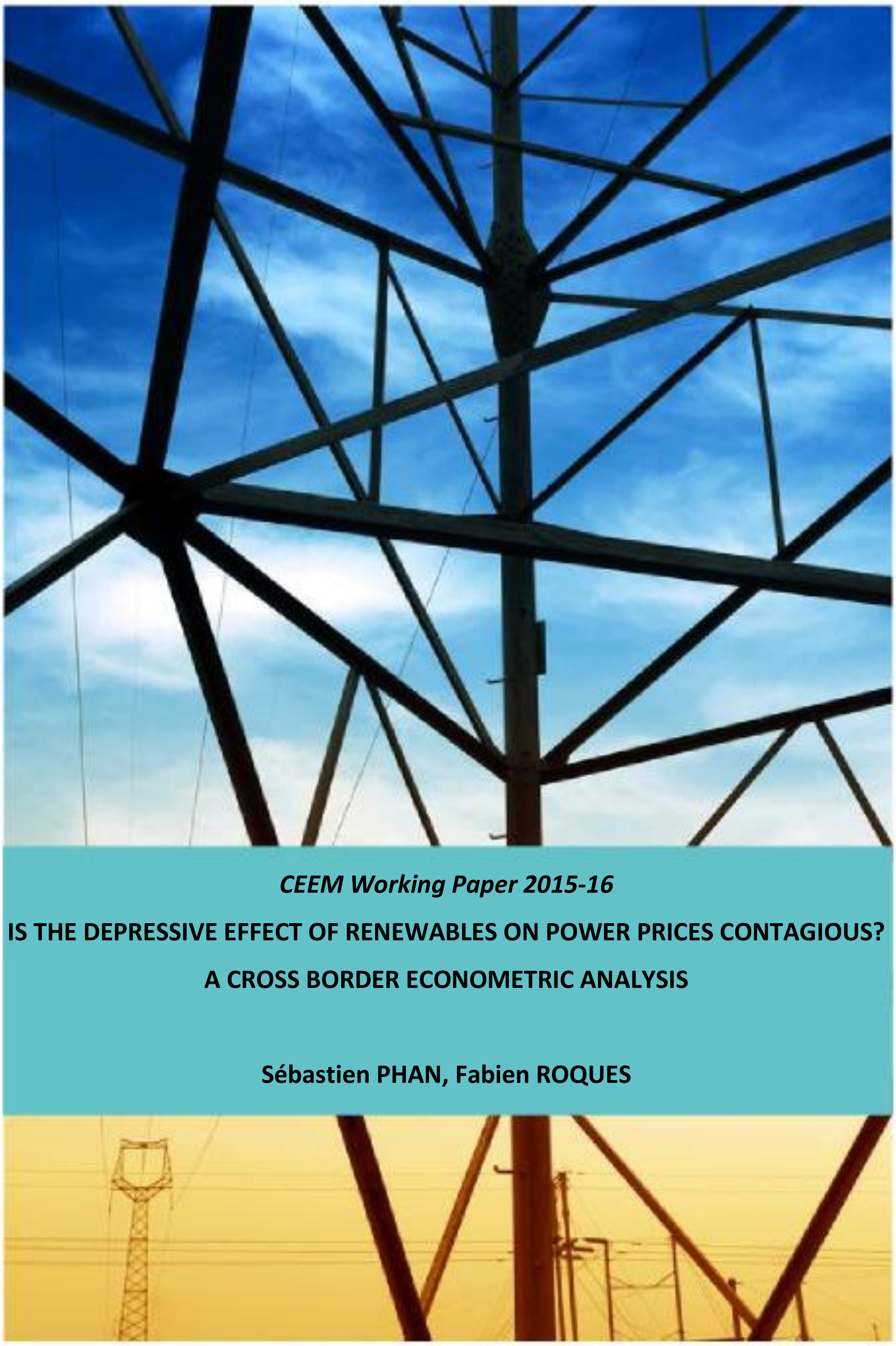

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IS THE DEPRESSIVE EFFECT OF RENEWABLES ON POWER PRICES CONTAGIOUS? A CROSS BORDER ECONOMETRIC ANALYSIS

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IS THE DEPRESSIVE EFFECT OF RENEWABLES ON POWER PRICES CONTAGIOUS? A CROSS BORDER ECONOMETRIC ANALYSIS[1,2]

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ABSTRACT

European power markets have become more integrated and the implementation of market coupling has reinforced the efficiency of cross-border trading. This paper investigates empirically the impact of renewables growth in Germany on German and French power price volatility. We find that renewables depress power prices on average and increase volatility not only domestically but also across borders. We also leverage market resiliency data to investigate the impact of increases in interconnection capacity. We find that power price volatility would decrease in France despite some contagion effects of volatility from German renewables production. Our findings have important policy implications as they demonstrate the need to coordinate cross-border support policies for renewables in order to mitigate the impact of volatility on power prices in coupled power markets.

Key words: electricity market, renewables, market coupling, GARCH

1. INTRODUCTION

European electricity markets have become increasingly integrated in the past decade.[5] The European Commission continues to push for further integration, through building up cross border lines, and the removing barriers to cross border trade. The flagship project of coupling day ahead markets through implicit auctioning of transmission rights started with 3 countries in 2009 (France, Belgium and the Netherlands), and was extended to Germany in 2011. By the end of 2015 about 85% of the power consumption in the EU will be coupled in a single market. By implicitly allocating interconnection capacity, market coupling ensures an efficient use of cross border interconnection capacity. This has dramatically increased price convergence across European countries.

[1] We are grateful to EPEXSPOT for providing the data on power prices and market resilience that were used in this paper.

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[5] Cross border trade of electricity has grown to represent about 232 TWh/year, or about 7% of total electricity produced.

In parallel, European countries have set ambitious deployment targets of renewables for 2020 and 2030 (20% and 27% of final energy consumption, respectively). Renewable energy generation has grown from 20% in 2000 to 31% in 2015 in Europe, with countries such as Germany leading the charge. The rapid growth of renewable energy generation has had significant effects on power prices in a number of European countries. As a result, electricity prices have become more and more correlated with wind and solar intermittent production.

The joint process of deploying renewables and integrating power markets raises a number of questions. Renewables are known to affect power price dynamic within a country. However, in the case of neighbouring markets with market coupling, to what extend do policies to support renewables on one side of the border affect power price dynamic on the other side? Moreover, the effect of renewables does depend on the amount of physical cross-border capacity available. To what extent does an increase in interconnection capacity influence the effect of renewables on cross border prices, and what are the implications for the value of new interconnections?

This paper investigates both issues by considering the case of France and Germany. Renewables have grown dramatically in Germany over the past few years, from 17GW of solar PV and 27GW of wind turbines in 2010 to more than 70 GW altogether in mid-2014. Moreover, France and Germany were among the 5 pioneering countries where market coupling was launched in 2011. With more than 3 years of empirical data, we investigate the effect of renewables' growth in Germany on French power prices. Using resilience data from the spot market operator, we also simulate the effect of intermittent generation on cross border power prices for different levels of additional interconnection capacity between France and Germany.

We find that intermittent generation of renewables have a significant impact on electricity prices in both the domestic (German) and the neighbouring market (France). In addition, we find that increasing the interconnection capacity between France and Germany would generate a transfer of the volatility generated by the German wind production to French power prices. However, the analysis of the overall effect of an interconnection expansion shows that the transfer of wind – related price volatility is mitigated and even offset by the dampening effect of integrating the French and power markets (resulting from larger demand and supply).

The remainder of this paper is structured as follows. Section 2 presents the literature review, section 3 describes the data and introduces the research questions. Section 4 discusses the specifications of the econometrics analysis. Finally the results are presented and analysed in section 5 and section 6 concludes by discussing the policy implications from our results.

2. LITERATURE REVIEW

There is well established evidence that renewables have a depressive effect on average power prices, and that they increase the volatility of power prices in the short term. This is often referred to as the 'merit order' effect of renewables such as wind and solar. They are low variable cost technologies and displace more expensive technologies in the merit order, leading to a reduction in average prices. Based on theoretical works, several authors have characterized the depressing effect of intermittent renewable generation on electricity prices (see for instance Jensen and Skytte, 2002; Sensfuss et al., 2008; and Nicolosi and Fürsh, 2009). Würzburg, Labandeira, and Linares (2013) provide a survey of current simulated and empirical studies which assess the relationship between renewable generation and electricity prices. Concerning the German market, Bode and Groscurth (2006), and Traber and Kemfert (2009 and 2011) found that renewable generation lowered the average electricity price based on simulations. This effect has also been confirmed in Denmark

(Holttinen et al., 2001; Munksgaard and Morthorst, 2008) and in Spain (Saenz de Miera et al., 2008; Linares, Santos, and Ventosa, 2008). Our paper contributes to this literature in several ways.

First, whilst most studies rely on simulated power prices or empirical data with limited granularity, we leverage empirical data with hourly granularity for power prices and both solar and wind production. To the best of our knowledge we are the first paper to simultaneously investigate in France and Germany the joint effect of solar PV and wind production on power price levels and variability. Neubarth et al. (2006) used a simple regression (OLS) to find the effect of wind generation on German prices. Woo et al. (2011) applied an autoregressive model on the intra-day Texan market (based on data of 15 minutes intervals on wind production and power prices). Similar studies have been conducted with Spanish, Irish and Dutch hourly data (Gil, Gomez-Quiles, and Riquelme, 2012; O'Mahoney and Denny, 2011; Nieuwenhout and Brand, 2011). Jonsson et al. (2010) analysed hourly Danish data of wind and prices, using a non-parametric regression model. More recently, Benhmad and Percebois (2013) conducted an econometric study on the effect of wind generation on German prices over the 2009-2012 period using GARCH and TGARCH models.

Second, there are to our knowledge no papers investigating the impact of renewables on cross border power prices in the case of coupled markets with *implicit allocation* of transmission capacity. Keppler et al. (2014) investigated the effect of market coupling on spot prices in Germany and France. They found that allocating interconnection capacities through implicit auction (market coupling) had improved the electricity price convergence between the two areas (concerning the inefficiency of explicit auction see Creti et al., 2010; or Bunn and McInerney, 2013). However, they also found that wind and solar generation tend to increase the French-German price spread. Our paper takes the analysis one step further by considering explicitly the relationship between wind and solar generation in Germany and power prices in France and Germany.

Third, based on empirical resilience data (overall supply and demand orders) we simulate the impact of increasing the physical interconnection capacity between France and Germany on power price dynamics in both countries – and more specifically on the volatility of power prices. This complements the existing literature which employs simulation models to study the impact of grid expansion on power price dynamics and volatility. For instance, Schaber et al. (2012) model the effect of grid extensions for European power markets, with an increasing share of wind capacity until 2020; Denny, Tuohy, and Meilbom (2010) focus on Ireland and Great-Britain. They both found that grid extension would lead to more homogeneous and stable electricity prices. In a similar spirit, Spiecker et al. (2013) developed a model covering 30 European countries which simultaneously optimized generation investments and the transmission line utilization. Their model indicates that wind integration requires the development of additional interconnection capacities (see also Lynch, Tol, and O'Malley 2012). The intuition behind these results is that interconnections increase the geographical spread of wind generation, and because windstreams are less correlated over large distances this tends to smooth out the variability of wind production over the full portfolio (see Roques et al. (2010) for a discussion on optimal geographic diversification of wind sites). This in turn lowers the variability of power prices in the aggregated area, and this effect can be particularly important for isolated area (see Söder et al., 2007). Note that although the power price variability may decrease at a local level, one can still expect shock transmission and volatility transfer between areas (see Worthington, Kay-Spartley, and Higgs, 2005; Bunn and Gianfreda, 2010).

3. RESEARCH QUESTIONS AND DATA DESCRIPTION

3.1. Impact of renewables on cross-border power price dynamics

As a first step, we want to confirm the results of previous studies - namely that wind generation has a negative impact on the average spot prices and a positive effect on price variance - with a more recent dataset and by taking both wind and solar generation into account (all studies surveyed focus exclusively on wind). Knowing that Germany has continued to increase its intermittent renewable capacity since the previous studies and that interconnection has not been increased, we could legitimately expect the results to be convergent. Our first research hypothesis can therefore be formulated as follows:

Hypothesis 1: Renewables' intermittent generation has a positive impact on electricity price volatility domestically.

The purpose of this research is also to confirm the intuition that German wind generation also has an impact on French prices. Our assumption is that interconnection between France and Germany is large enough to spread the wind volatility to French prices, especially since our study covers a period where French and German day-ahead markets are coupled. Our second research hypothesis is therefore as follows:

Hypothesis 2: Intermittent generation of renewables in one country impacts power price volatility in neighbouring countries.

Based on a previous study (Benhmad and Percebois, 2013; Ketterer, 2014; Clò, Cataldi, and Zoppoli, 2015) the econometric analysis is conducted with a GARCH model, which is particularly relevant for this study because it estimates both the mean and the variance of the dependent variable (please see the next session for a detailed justification of the model specification and relevant literature).

Our database covers the period between January 1st, 2012 and June 30th, 2014. Contrary to previous studies, our data contains solar PV generation and hourly prices. This point is critical because it is possible to exploit the intraday variability of solar and wind generation but also the effect of the time shift between French and German peak demand occurrence. Figure 1 shows the average electricity prices over the period for each hour of the day, with significant variability both between and within the days. German renewable generation and day-ahead prices for France and Germany come from the EPEX SPOT and EEX databases.[6] Due to limits in data availability, we did not use French solar and wind generation. This seemed a reasonable assumption to make given that French solar and wind generation in France represent a much lower share of the electricity mix than in Germany. In April 2013, France only had 7.6GW of wind capacity and 4.1GW of solar capacity compared to the nearly 70GW of variable renewable capacity in Germany.[7]

Since electricity consumption is one of the most important components of electricity prices, we used French and German hourly demand in our model. Consumption data is taken from the ENTSO-E publically available database.[8] We included French and German demand in both equations because foreign consumption is expected to impact domestic prices through interconnections.

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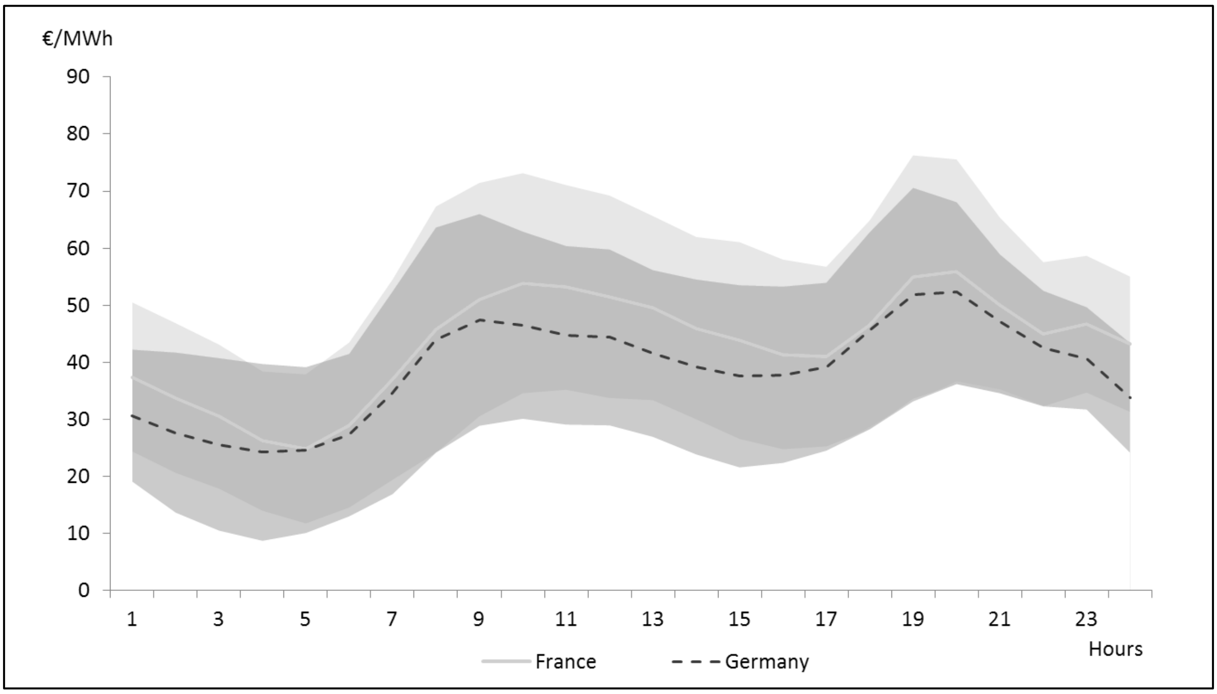
[6] EPEXSPOT is a large continental power exchange.

[7] Using French wind and solar capacity data would be an interesting extension of this research which could confirm if there is a symmetric impact of French renewables production on German power prices. But omitting this variable does neither question the relevance of our GARCH model nor the effect of German wind on prices.

[8] ENTSO-E is the association representing the 41 European electricity Transmission System Operators.

Figure 1: Average hourly prices in France and Germany between 2012 and 2014.



3.2. Potential effect of increased interconnection capacity on cross-border power price dynamics

In a second phase, we assessed the effect of increasing interconnection capacity on French and German prices. Our research assumption is as follows:

Hypothesis 3: Increasing interconnection capacity modifies the impact of intermittent renewable generation on power price volatility in both domestic and neighbouring markets.

Our intuition is that by enlarging interconnection capacity, the German market would "transfer" part of the volatility generated by wind generation to the French market. When we increase interconnection capacity, we expect German prices to be less affected by wind volatility and French prices to be more sensitive to wind production.

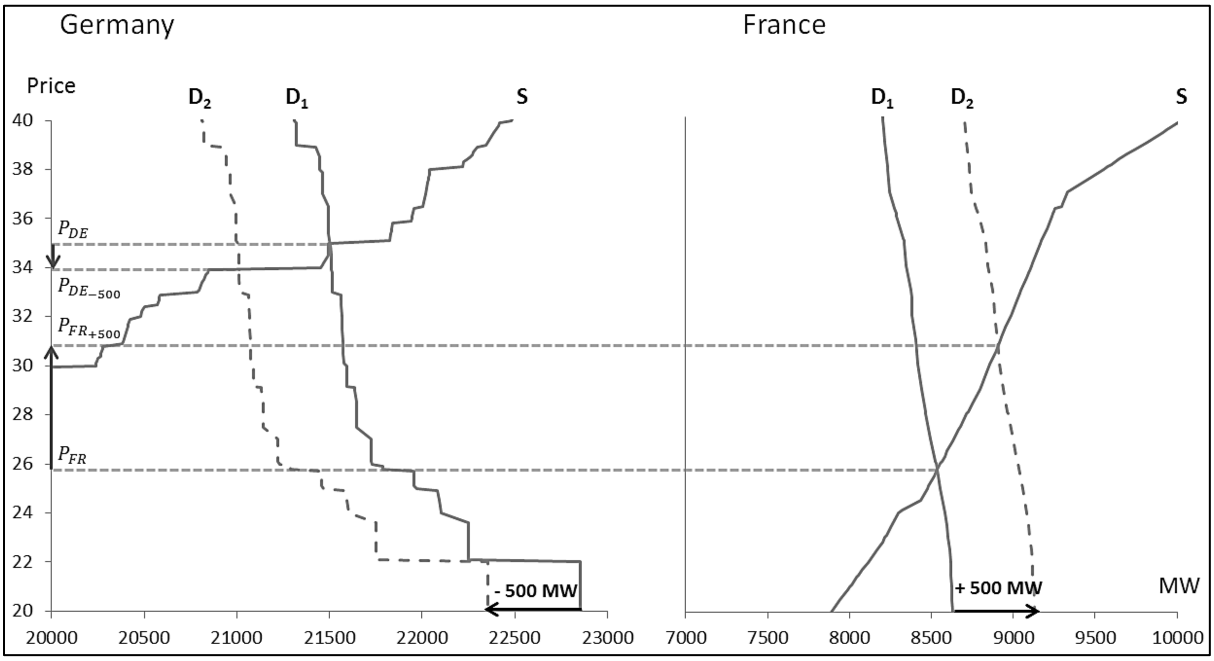
In order to evaluate the impact of increasing interconnection capacity, we use resilience data from EPEXSPOT. Market resilience data can be seen as the opposite of the elasticity, because they provide information on the price variation resulting from variation in demand. The effect of an interconnection expansion on electricity prices can then be modelled by simultaneously looking at the effects of a positive variation of the demand in the exporting country (the country with the lowest price) and a negative variation of the demand in the importing country.

For instance, it is possible to know what would have been the price in both Germany and France if the interconnection was expanded by *x* MW. Resilience data is calculated by EPEXSPOT by aggregating the overall demand and supply orders each hour for a demand variation of 500MW and 1000MW.[9] With this database we simulated French and German prices that would have happened if the interconnection would have been larger by 500MW and 1000MW between January 2012 and June 2014.

[9] This means that sometimes we had to use linear interpolation to found the equilibrium price and quantity.

For example, Figure 2 illustrates the market equilibrium for May 5th, 2013 at 10pm. At this specific hour the German price was higher than the French price (which means that interconnection was congested). We can simulate prices for an interconnection expansion of 500MW if we simultaneously compare the French theoretical price if the demand was 500MW higher with the German price if the demand was 500MW lower. Similarly, when the French price is higher than the German price, the increase of the interconnection is simulated by looking at the French price that would have resulted if the French demand was lower (and the German price for a 500MW higher demand). Note that in this example, increasing the interconnection capacity by 500MW would have not been enough to reach a full price convergence but a 1000MW expansion would have been sufficient (and possibly oversized). The impact on power prices in Germany and France is different, with a small change in prices in Germany and a more significant change in France (>4 euros). This would have generated a surplus gain both for German consumers and French producers, and would have lowered the TSOs congestion rent.[10]

Figure 2: Market resilience for a 500MW demand variation in France and Germany on the 05/05/2013 at 10pm.



Data: EPEX spot

Resilience data is particularly useful to assess the effect of a higher interconnection capacity on the mean and the variance of electricity prices, but also the effect on the relationship between intermittent generation and electricity prices in France and Germany. Indeed, we use our GARCH model on the two simulated prices series (accounting for a 500MW and 1000MW interconnection expansion, respectively) for both France and Germany. Although this is ex post modelling, we can assess what would have been the effect of a larger interconnection between the two countries over the 2012-2014 period.

[10] Congestion rent is collected equally by the two TSOs and is equal to the price difference time the interconnection capacity. Therefore, reducing the price spread by increasing the interconnection capacity would lower the TSOs rent but not necessarily their utility since their main objective is to maximize the global welfare.

4. ECONOMETRIC MODEL

Modelling electricity price involves several econometric issues. The non-storable nature of electricity leads to relatively high price volatility. Since demand varies during the day, supply has to adjust in real time to balance the electricity system. Therefore, power prices are higher during peak consumption periods. The demand variability across the day has been taken into account in our model with the addition of a dummy variable equal to 1 if we are in a peak period.

Similarly, the seasonality of electricity prices has to be corrected. During the winter demand and power prices are particularly high (especially in France due to the high thermo-sensitivity of French consumers. Huisman (2008)' demonstrates the impact of the weather on price variation and shows that the marginal effect of temperature variations on power prices changes across seasons. We use dummy variables to take into account power price seasonality.

Consumption is used as an explanatory variable. Even if part of the supply is more and more uncorrelated with the consumption, demand remains one of the main drivers of electricity prices. Since market coupling ensures an efficient utilisation of interconnection capacity (see for instance Newbery and McDaniel (2002), Creti et al. (2010) and Keppler et al. (2014)) it seems reasonable to add neighbour consumption in the estimation of each market. We expect French prices to be lower when the German consumption is decreasing and vice versa. One could argue that French and German demands are highly correlated meaning that it would not be necessary to include both. It would be wrong to make such an assumption because French and German consumers have different consumption profile. For instance, French peak consumption is one hour after the German peak (6 pm and 7 pm, respectively). Consumption data have been taken from ENTSO-E database and does not account for the auto consumption.

Considering the volatility of electricity price, conditional heteroscedasticity models appeared to be the most appropriate solution. GARCH models are commonly used to analyse variation of commodity markets because they are fitted to capture the fluctuation and clustering of volatility. Knittel and Roberts (2005) were among the first to use GARCH model on electricity prices. Several other authors have also used the GARCH model to analyse electricity prices, especially for price volatility. For instance Petrella and Sapio (2009) used GARCH model to assess the impact of market design on price volatility (introduction of contracts for differences, white certificates and market liberalization). Following the previous studies, we use an AR-GARCH model:

$$y_t = \mu + \sum_{i=1}^{l} \phi_i y_{t-i} + \epsilon_t$$

$$h_t = \omega + \sum_{i=1}^{p} \alpha_i \epsilon_{t-i}^2 + \sum_{j=1}^{q} \beta_j h_{t-j}$$

Where y_t is electricity price[11] at time t and h_t is its conditional variance. μ is the constant term, ϵ_t is the error term and ω is the long-run variance. If we want our model to be stationary we have to respect the following two conditions:

$$\alpha_i + \beta_j < 1$$

$$\alpha_i, \beta_i > 0$$

<u>Hypothesis 1: Renewables' intermittent generation has a positive impact on electricity price volatility domestically.</u>

[11] Electricity prices are stationary both in France and Germany, the Dickey Fuller statistics are -38.34 and -30.08, respectively (the 1% critical value is -3.43).

In order to test our first hypothesis, we need to slightly modify our model. We adjusted the mean equation (y_t) and the variance equation (h_t) with explanatory variables. We used consumption and renewable generation to improve our estimation of both the mean and the variance. With these modifications the specification for the ARX-GARCHX model becomes:

$$y_t = \mu + \sum_{i=1}^{l} \phi_i y_{t-i} + \sum_{j=1}^{m} \theta_j X_j + \epsilon_t$$

$$h_t = \omega + \sum_{i=1}^{p} \alpha_i \epsilon_{t-i}^2 + \sum_{j=1}^{q} \beta_j h_{t-j} + \sum_{k=1}^{s} \theta_k X_k$$

Where X_j represents the vector of the explanatory variable including consumption, renewable generation and dummy variables.

Hypothesis 2: Intermittent generation of renewables in one country impacts power price volatility in neighbouring countries.

The model introduced previously is applied to both French and German prices. It is then possible to assess the impact of German renewables generation on the French prices. We expect the impact to be the same as the one in Germany but slightly lower because interconnection capacity and management are not optimal. The explanatory variable vector (X_k) still includes German generation of renewables and both French and German consumption.

Hypothesis 3: Increasing interconnection capacity modifies the impact of intermittent renewable generation on power price volatility in both domestic and neighbouring markets.

One of the main concerns of this study is to analyse the relationship between intermittent renewables generation and price volatility under changes of interconnection capacity. We then apply the same model to the simulated prices accounting for interconnection capacity modifications. Since we want to use the same equation specification for the six different series of prices[12] it is necessary to keep a simple equation for the conditional variance. Therefore, for each regression the conditional variance is only composed of the ARCH term (α), the GARCH term (β), the wind generation and the consumption in the concerned country.

Using autoregressive models implies finding the optimal number of lags for the dependent variable. Previous studies used daily data and based their estimation on the AR(7) model to consider the week cycle. Knowing that our study relies on hourly data we decided to conduct both an AR(1) model and an AR(24) model based on the Akaike information criterion (AIC) to test both the hour-1 and the day-1 specification. The selected period is from January 1st, 2012 to June 30th, 2014.

[12] For both France and Germany: base line prices, prices with an interconnection expansion of 500 MW and prices for an expansion of 1000MW.

5. RESULTS

5.1. Impact of renewables on power price dynamic cross border

5.1.1 Results for Germany

Table 1 reports the results of the regression on German prices. Our results seem to be in line with previous studies (Jonsson et al.(2010), Woo et al.(2011) Benhmad et al.(2013) and Ketterer (2014)), wind generation has a negative impact on electricity prices. Increasing wind generation by 1 GW would decrease on average the German price by €0.63/MWh. As we expected, the German demand has a positive effect on prices. The higher the demand is, the higher the prices are.

Moreover, interconnections and market coupling seem to be effective; the French demand has a significant and positive effect on German prices. Our intuition is confirmed, interconnection capacity is well used and cross-border exchanges are going in the right direction. Note that results presented in table 1 are taking into account dummy variables that control for seasonality and intraday variation.

Previous studies focused only on the impact of wind generation. We added to our mean equation the solar PV production and found that it has a significant and negative impact on German prices, as increasing solar generation by 1GW would decrease on average the German price by €1.12.

Table 1 reports the AR(1) and AR(24) regressions in columns (A) and (B), respectively. Results seem to be robust to the lag specification and wind effect is highly significant in both models. The effect of wind is slightly higher in the model (B) but the sign and the magnitude of the other coefficients are globally the same. Note that α and β are positive and their sum is smaller than 1 in both case.

Table 1 also reports the conditional variance estimation. The coefficients are significant (p-value < 0.01), positive and their sum is smaller than one. Our results confirm the first hypothesis as well as findings from previous studies: over the selected period wind generation tends to increase price volatility in Germany.

Table 1: GARCH model of German electricity prices (2012-2014)

	(A)	(B)
VARIABLES	German price	German price
	Mean equation	
Solar	-1.12***	-1.02***
	(1.73e-02)	(1.62e-02)
Wind	-0.634***	-1.22***
	(3.17e-02)	(8.57e-03)
Φ1	0.9068***	
	(9.78e-04)	
Φ24		0.6281***
		(2.26e-03)
French consumption	0.474***	0.458***
	(9.51e-03)	(7.61e-03)
German consumption	1.080***	0.915***

	(1.03e-02)	(6.22e-02)
μ	-31.51***	-20.46***
	(0.606)	(0.304)
	Variance equation	
α	0.4906***	0.7069***
	(7.51e-03)	(0.0112)
β	0.1424***	0.0398***
	(4.49e-03)	(4.80e-03)
Wind	0.0682***	0.1035***
	(1.11e-03)	(1.65e-03)
German consumption	0.0325***	0.022***
	(5.68e-04)	(7.56e-04)
ω	0.426	0.845***
	(0.0415)	(0.0564)
Observations	21,500	21,500

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

5.1.2 Results for France

To our knowledge, there are no previous studies that assess the impact of intermittent renewables on French prices. Results of French price estimations are reported in table 2. Hypothesis 2 is confirmed: both wind and solar generation in Germany have a negative effect on French prices. German solar and wind generation decreases prices in Germany and interconnections contribute to the convergence of French and German prices.

Increasing both solar and wind generation by 1 GW would decrease the average French price by €0.67 and €0.45, respectively. As we might expect, coefficients of both French and German consumption are significant and positive. Internal demand is directly correlated to prices as we saw previously and German demand is also linked to prices through exports and imports. For instance, increasing French consumption by 1 GW would increase on average, the French price by €1.12. As regressions (A) and (B) show, French results are robust to the lag specification. The sign of each coefficient does not change according to the regression (C or D), α and β are positive and their sum is smaller than 1.

Our results are slightly lower than those of Clò et al. (2015), who based on Italian data between 2005 and 2012, found that an increase of 1GWh in the hourly average of daily production from solar and wind sources reduced on average electricity prices by 2.3 €/MWh and 4.2 €/MWh, respectively. This difference can be explained by a difference in methodology (average daily price against hourly price) and also the period studied. In addition, Italy is less interconnected with neighbouring markets than Germany and France, thus our assumption is that the well managed French-German interconnection mitigates the effect of renewables production (see section 5.2 for a more in depth discussion of this point).

Table 2: GARCH model of French electricity prices (2012-2014)

	(C)	(D)
VARIABLES	French price	French price
Mean equation		
Solar	-0.674***	-0.583***
	(1.65e-02)	(1.61e-02)
Wind	-0.459***	-0.521***
	(3.49e-02)	(3.49e-02)
Φ1	0.9274***	
	(1.67e-03)	
Φ24		0.5842***
		(1.14e-03)
French consumption	1.23***	1.06***
	(1.18e-02)	(8.29e-03)
German consumption	0.584***	0.605***
	(1.14e-02)	(7.35e-03)
μ	-42.80***	-34.85***
	(0.433)	(0.243)
Variance equation		
α	0.3383***	0.6274***
	(3.93e-03)	(9.31e-03)
β	0.4722***	0.3228***
	(3.50e-03)	(2.09e-03)
Wind	0.00756***	0.00855***
	(1.29e-03)	(2.56e-03)
French consumption	0.0478***	0.0529***
	(3.96e-04)	(6.67e-04)
ω	-1.072***	-1.037***
	(0.0296)	(0.0546)
Observations	21,500	21,500

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Concerning the conditional variance of French prices, our results confirm the second hypothesis, namely that wind generation in Germany has a positive impact on prices variance in France. From a public policy point of view this is an interesting result. The massive development of intermittent renewables in Germany has a significant impact on power prices in France, as it decreases the average electricity price but it also increases the volatility. One potential solution could be to increase interconnection capacity; the intuition is that by enlarging the market the volatility generated by intermittent renewable energy would be scattered. Our next section investigates this issue.

5.2 The potential effect of increased interconnection capacity on power prices dynamic cross border

5.2.1 Impact on power price variability

By enlarging the size of the market, the intuition is that increasing cross border interconnection capacity would decrease the price volatility in both French and German markets. However as we saw in *section 5.1.2* German wind generation has a positive effect on the price variance in France, therefore increasing the interconnection capacity could potentially reinforce the impact of wind-induced volatility and thereby increase volatility in France. These two forces act in opposition and the overall net effect is not easily predictable.

In order to identify which effect dominates, we use the amount of available transfer capacity (ATC) as an explanatory variable in the conditional variance equation. The ATC is determined by TSOs in order to keep some safety margin on the interconnection. This provides information about the relationship between the amount of cross-border exchanges and price volatility[13]. Table 3 presents the results of the AR(1)-GARCH model, with only the coefficients of the conditional variance equations reported. Our third hypothesis is validated since the ATC coefficient is significant and positive. This means that increasing the exchange capacity between France and Germany would reduce the price volatility, the "wind effect" is offset by the positive effects of integrating markets (larger demand and supply).

Table 3: Effect of ATC on the variance of electricity prices

	AR(1)-GARCH	AR(1)-GARCH
VARIABLES	French price	German price
Variance equation		
α	0.107***	0.542***
	(1.01e-03)	(7.66e-03)
β	0.885***	0.180***
	(1.19e-03)	(5.47e-03)
ATC	-0.000258***	-0.000374***
	(2.53e-05)	(6.74e-06)
Constant	-0.112479*	3.05***

[13] ATC is not exactly the amount of cross border exchanges, it accounts for the available capacity that are allocated through implicit auctions.

	(0.0593)	(0.0168)
Observations	21,140	21.140

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Now that we have confirmed that cross-border exchanges decrease the price volatility in the two countries, we would like to test further the third hypothesis by analysing what would be the impact of a larger interconnection on the relationship between renewables generation and price volatility.

Based on resilience data we computed two alternative time series accounting for an expansion of the interconnection capacity of 500 MW and 1000MW, respectively. By simply comparing the standard deviation of prices in each scenario we found that increasing interconnection capacity would have lowered the price variation in both countries. Table 4 reports these statistics, the reduction of the volatility is more pronounced in France than in Germany. This result is very relevant to policy debates because it shows that even if Germany is “exporting” to France the volatility generated by wind production, the overall effect of coupling the two markets the reduction of French power price volatility (namely that price volatility is decreasing).

Table 4: Standard deviation of French and German prices by scenario

Scenario	Base case	+500 MW	+1000 MW
France	28.08	22.06	20.07
Germany	17.25	17.07	17.00

5.2.2 Transfer of the wind volatility

By increasing the cross-border capacity we should expect a higher impact of wind and solar on the volatility of French electricity price. To estimate what would be the effect of an interconnection expansion we applied our GARCH model to the alternative price time series. Table 5 reports the results of the 500MW and 1000MW alternatives for French and German price. For each regression the GARCH model is well specified ($\alpha, \beta > 0$ and $\alpha + \beta < 1$) and most of the coefficients are highly significant (p-value < 0.01).

Looking at the variance equation of German prices in the 500MW scenario (E) shows a smaller coefficient associated to wind generation compared to the base case (A). With larger interconnection German wind production is exported and then its effect on price variation is reduced in Germany. French prices seem to react in a different way. The bigger the interconnection expansion is, the larger the impact of wind generation. Increasing wind generation by 1GW would increase French price variance by 0.007, 0.05 and 0.07 in the base case, the 500MW and the 1000MW alternatives, respectively.

Table 5: Impact of an interconnection expansion on price volatility (2012-2014)

	(E)	(E*)	(F)	(F*)
Scenario	500MW	1000MW	500MW	1000MW
VARIABLES	P_{GER}	P_{GER}	P_{FR}	P_{FR}
		Mean equation		
Solar	-1.081***	-1.055***	-0.758***	-0.801***
	(1.58e-02)	(1.58e-02)	(1.53e-02)	(1.54e-02)
Wind	-0.769***	-0.778***	-0.586***	-0.585***
	(2.94e-02)	(3.26e-02)	(3.52e-02)	(4.24e-02)
Φ1	0.906***	0.910***	0.925***	0.929***
	(8.98e-04)	(1.16e-03)	(2.04e-03)	(2.33e-03)
Cons_fr	0.504***	0.574***	1.147***	1.044***
	(8.64e-03)	(9.51e-03)	(1.11e-02)	(1.21e-02)
Cons_ger	1.052***	1.026***	0.717***	0.769***
	(1.06e-02)	(1.10e-02)	(1.15e-02)	(1.25e-02)
μ	-31.27***	-33.33***	-45.33***	-42.92***
	(0.534)	(0.563)	(0.563)	(0.618)
		Variance equation		
α	0.487***	0.428***	0.355***	0.283***
	(7.09e-03)	(5.92e-03)	(3.78e-03)	(3.68e-03)
β	0.166***	0.170***	0.425***	0.402***
	(5.13e-03)	(7.38e-03)	(2.70e-03)	(5.14e-03)
Wind	0.0511***	0.0434***	0.0524***	0.0787***
	(9.34e-04)	(1.04e03)	(1.11e-03)	(8.60e-04)
Cons_ger	0.0321e***	0.0317***		
	(4.88e-04)	(5.30e-04)		
Cons_fr			0.0449***	0.0440***
			(3.92e-04)	(3.61e-04)
ω	-0.011	0.063	-1.069***	-0.851***
	(0.035)	(0.040)	(0.030)	(0.031)
Observations	21,500	21,500	21,500	21,500

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

This result is also reflected in the mean equation estimation. The magnitude of solar and wind coefficient in the mean equation of model (E), and *a fortiori* in (E*), is smaller than in model (A). The downward pressure put by solar and wind generation on German prices is less important when interconnections are larger. In contrast, the average electricity price in France is all the more decreased when interconnections are larger.[14]

6. POLICY DISCUSSION

Our empirical findings in this paper raise a number of policy relevant questions.

First, our empirical results confirm findings from previous studies about the depressive effect of renewables on average power prices in the short term. Investment in clean technologies driven by support schemes displace thermal plants in the merit order, leading to lower power prices and revenues for thermal pants. By reducing power prices, policies supporting renewables undermine power prices and thereby prevent renewables from becoming competitive based on wholesale market revenues. This "cannibalization effect" implies that there may be a structural and permanent need for subsidies for renewables if their cost reduction does not outweigh their depressive effect on power prices. Moreover, the depressive effect on wholesale prices can undermine fixed cost recovery for other technologies and create the need for complementary mechanisms such as capacity remuneration mechanisms, ultimately increasing cost for consumers. Managing the pace of deployment of subsidized technologies is therefore key both to control the total system costs, and to provide investors with a long term perspective on the value of existing assets and potential new thermal plants.

Second, our empirical findings demonstrate that in an integrated power market, national policies to support renewables have a significant impact on cross-border power prices. This in turn affects prices for consumers on the other side of the border and the profitability of other types of generation. Our findings raise questions regarding the subsidiarity approach chosen for renewables support, at the same time as power markets have become more integrated: if European countries are free to choose their own generation mix in keeping with Article 194 of the Lisbon treaty, shouldn't there be a mechanism to ensure that the national RES objectives do not distort power prices and impose costs to other stakeholders across the border? We therefore recommend that member states should improve the coordination of renewables support schemes on a regional basis to manage their impact on power markets, for instance by agreeing on common technology deployment roadmaps on a regional basis and redesigning the existing cooperation mechanisms to remove the perceived barriers to their implementation.

Finally, our empirical findings raise questions as to how to evaluate the costs and benefits of additional interconnection capacity. Progress on building interconnections that support electricity integration of electricity markets has been slow over the past decade. However, there is a widespread belief that there would be significant benefits in having more interconnected electricity markets, estimated to range between €12.5 to €40bn/year in 2030 in a recent European Commission study. However, this does not mean that all interconnection projects would be socially beneficial and the selection of projects receiving public support needs to be based on a robust cost benefit analysis. Whilst typical impact assessments investigate the consumer welfare impact of further price convergence, they often do not take into account the national targets for RES deployment in a

[14] Note that the limits of these results remain on the data. Even if they represent a small share of the energy mix, we do not assess the effect of French renewables capacity on price volatility. It is possible that the volatility of wind generation in France compensates the volatility of German wind production. Moreover, France and Germany are connected (both or individually) by eleven other countries that we did not took into account in the simulation of the interconnection expansion.

dynamic way. As our research demonstrates, these can significantly affect power price dynamics on both sides of the border and affect the welfare impact of new interconnections.

7. CONCLUSION

European twin objectives of deploying large amounts of renewables and integrating power markets raises a number of questions about the consistency of these two objectives, and in particular the impact of renewables on power market dynamic. In recent years the implementation of market coupling has driven some more convergence of power prices across European countries. France and Germany were part of the 5 pioneering countries in which market coupling was launched in 2011. At the same time, European countries such as Germany have seen very significant increases in the generation from wind and solar generation support with out-of-market subsidies. Renewables have grown dramatically in Germany over the past few years, from 17 GW of solar PV and 27GW of wind turbines in 2010 to more than 70 GW altogether in mid-2014.

Our paper extends the existing literature and demonstrates based on empirical data that on average, renewables depress power prices and increased volatility. Moreover, our paper is the first to our knowledge to assess the impact of RES deployment in Germany on a neighbouring country – France. With more than 3 years of empirical data, we investigate the effect of renewables' growth in Germany on French power prices. Using resilience data from the spot market operator, we also simulate the effect of intermittent generation on cross border power prices for different levels of additional interconnection capacity between France and Germany.

The results show that between 2012 and 2014, an interconnection expansion would have decreased the average price difference between French and German markets. Moreover, even if this expansion would have led to a slight increase in German prices (and a decrease in French prices), the overall effect is a reduction of price variance in both France and Germany. Looking only at the descriptive results encourages us to promote more market integration. However, based on the econometric results, we also found that increasing interconnection capacity would have transferred the volatility generated by the wind production from Germany to France. Even if the price variance is decreasing when interconnections are larger, the price variance is also more sensitive to the wind generation. This means that if Germany continues to massively develop intermittent renewables, the overall effect of an interconnection expansion could potentially overrun the positive effect of interconnecting markets. Our findings therefore have important policy implications as they demonstrate the need to coordinate cross-border support policies of renewables in order to mitigate the impact on power prices.

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