The impact of the European Union Emission Trading Scheme on electricity generation sectors

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Abstract

In order to comply with their commitments under the Kyoto Protocol, France and Germany participate in the European Union Emission Trading Scheme (EU ETS) which predominantly concerns the electricity generation sector. In this paper we seek to know if the EU ETS gives appropriate economic incentives for an efficient system in line with the Kyoto commitments. If so, electricity producers in these countries would include the price of carbon in their cost functions. After identifying the different sub periods of the EU ETS during its pilot phase (2005-2007), we model the prices of various electricity contracts and look at the volatilities around their fundamentals while evaluating the correlation between electricity prices in the two countries. We find that electricity producers in both countries were constrained to include the carbon price in their cost functions during the first two years of the operation of the EU ETS. During that period, German electricity producers were more constrained than their French counterparts and the inclusion of the carbon price in the cost function of electricity generation was much more stable in Germany than in France. Furthermore, the European market for emission allowances has increased the market power of the former public French electricity producer and has greatly contributed to the partial alignment of the wholesale price of electricity in France with that in Germany.

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Keywords: Carbon Emission Trading, Multivariate GARCH models, Structural break, Non Parametric Approach, Energy prices.

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1 Introduction

For the implementation of the Kyoto Protocol, whose objectives have been in force since January 2008, the European authorities organized a European market for CO2 permits in January, 2005. This is the European Union Emissions Trading Scheme (EU ETS). It is concerned mainly with energy[1] and the major emitters of the industrial sector. The market is based on a mechanism of "*cap and trade*" where the actors are receivers of free annual carbon emission permits at the beginning of the year. They have to achieve their commitment by providing permits corresponding to tons of emitted CO2 at the end of the year. Those that have emitted more CO2 than their allocation have to comply by buying more permits on the market. The energy sector and mainly the sector of electricity generation is by far the biggest CO2 emitter. Hence it received the largest share of the Community allocation for the period 2005-2007. This allows us to glimpse the close relationship between the electricity market, the market for fossil fuels used in electricity generation and the European market for CO2 permits.

The main objective of the EU ETS is to encourage the industry's biggest emitters to reduce their carbon emissions and invest in clean technologies. So, achieving this objective is dependent on the emergence of a real carbon price signal. The latter would require electricity producers to make long-term choices to produce electricity with fewer emissions. In this context, the ex-post empirical analysis of the impact of the introduction of the European market for CO2 permits on energy markets and particularly on that of electricity, is essential to assessing the efficiency and the consequences of the introduction of the EU ETS.

The price of electricity is determined by the cost of fossil fuels, the impact of environmental policies and measures and climatic factors such as temperature and rainfall. In Europe, it is widely agreed that gas and coal prices account for the variations in the electricity price. Economic theory teaches us that carbon price is a marginal cost and that the carbon permit has an opportunity cost equal to its market price. It suggests that the carbon price should be included in the price of electricity. Empirically, the sharp fall in the price of CO2 of about 10 € / ton in April, 2006 which was followed at once by a fall of 5 to 10 € / MWh on the electricity market (Reinaud, 2007) and the English company British Energy which lost 5 % of its market capitalization in three days during the same period (Bunn and Fezzi, 2007) are all evidence of the influence of the carbon market on the electricity market. Many studies have dealt with the impact of carbon prices on electricity prices in various European markets for the last three years. Sijm et al. (2005, 2006) studied the Dutch and German electricity markets to determine the fraction of the carbon price which is reflected in the price of electricity. Their study was based on an Ordinary Least Squares (OLS) estimate of a basic linear model. Honkatukia et al. (2006) studied the long-run and short-run dynamics of electricity, gas and coal prices and the price of carbon permits in the Finnish market, based on a VAR analysis. Bunn and Fezzi (2007) adopted a similar approach to analyze the English electricity market excluding the price of coal and including the temperature and dummies as exogenous variables. They carried out a structural analysis of the relationship between energy prices and carbon prices through short-run restrictions. The varying results

[1] Oil refining, electricity production, heating and gas transportation.

of these studies reflect the fact that approaches are different and the countries surveyed are of great diversity in their energy mixes. So, the absence of a unanimous response to the problem of the effect of the EU ETS on the price of electricity (Reinaud, 2007) is mainly due to the coexistence of various electricity markets in Europe and the heterogeneity of energy mixes in the European Union countries. Furthermore, these studies only covered, at most, the period from January 2005 to May 2006.

This article aims to provide a clear answer about the impact of the introduction of the EU ETS on the electricity generation sector by taking into account this heterogeneity. It deals with the volatility of the electricity price around its fundamentals and compares two European countries with very different energy mixes, France and Germany. We estimate a model based on the cost function of electricity generation, which includes the cost of carbon and measures the instantaneous correlation between the wholesale electricity prices in both countries. This paper covers all the pilot phase of the EU ETS (2005-2007) and takes into account its different sub periods. It is organized as follows: Section 2 presents the functioning of the electricity sector and the EU ETS, and the mechanism of the price formation for emission permits and its impact on the electricity sector ; Section 3 presents a descriptive analysis of the relationship between electricity markets on the one hand and primary energy and carbon markets on the other hand, and the steps of the econometric modelling ; Section 4 presents the results and their interpretation ; Section 5 concludes.

2 The electricity generation sector and the EU ETS

The electricity sector received nearly 55 % of the Community allocation for the pilot phase of the European market for CO2 permits. Before analyzing the impact of the introduction of carbon constrains on this sector, it is advisable to present its organization and functioning. This sector is organized around four main areas : production, transportation, distribution and marketing. Purely financial activities such as brokerage and trading over the counter or on power exchanges are added to these four market segments. Electricity generation is the main polluting activity in this sector and has been opened up to competition in the process of liberalizing the electricity market in Europe from 1998. Electricity is produced from various primary energy sources such as nuclear, coal, oil, gas, hydropower, biomass, wind, solar and geothermal power. The proportions of the use of these different primary energy sources in electricity generation in a country determine its energy mix. The latter is very different from one European country to another because of differences in energy policies and specific geographical and geological features of each country. Additionally, electricity is not a good like another because it is not storable, which confers on its generation sector particular characteristics which we detail in the following.

2.1 The profitability of power plants and the *merit order* between power generation technologies

Electricity demand is characterized by important fluctuations. It shows variations from one hour to another, one day to the next and one season to another during the year. These changes require the need for an instantaneous equilibrium between supply and demand, resulting in a continuous adaptation of electricity supply to changes in demand. As electricity production presents very different costs according to the technology used, profitability is different, depending on the choice of the primary energy used in electricity generation. Therefore, electricity production is subject to a sequential use of production technologies which depends on the production costs. The producers start up power plants to meet the demand, in increasing order of variable marginal costs of production. That is the concept of "*merit order*" between the various technologies which use different sources of primary energy in electricity generation. The *merit order* is determined by the variable marginal cost of production which takes into account only the variable costs (the costs of fuels and operational costs). It reflects an order of profitability so that production plants with the lowest variable marginal costs come first in plans for electricity generation. Nonetheless, the *merit order* between technologies is not fixed. The inclusion of the price of carbon allowances in the cost functions of the most polluting technologies can have an impact on the *merit order* between primary energy sources used to produce electricity and thus reverse the order of profitability. So, we determine the Switching price (Sijm et al., 2005) which is the price of carbon at the point when it becomes more profitable for a producer to use a gas power plant rather than a coal plant.

The choice of power production plans does not depend only on the *merit order* between power generation technologies. Power producers take into account some technical parameters such as the number of functioning hours necessary for the profitability of a given type of power plant, the depreciation of fixed capital invested in various power plants, and the availability of Kwh produced. So, electricity producers make delicate calculations and very sensitive assessments of the production costs of different technologies while ensuring production follows the demand curve in real time. In peak periods, a number of production units are used. As demand decreases, the number of production units decreases. This means stop and restart units depending on the level of demand. The operational features of the production units (including start-up time, the levels of maximum and minimum production, energy efficiency) predestine power plants to a mode of continuous or discontinuous production.

2.2 The Emissions Trading Scheme and its impact on electricity producers

The CO2 emission permit is a free traded good. Its price is determined by the meeting of supply and demand on the market. But in the case of emission permits, it is necessary to make the distinction between the short-term daily market and the long-term annual compliance to which market participants have committed themselves. Thus, the differences in horizon between the daily market for emissions and the annual commitment suggest phenomena of persistent shocks. Indeed, while agents instantly record shocks on a daily basis, they can also react to information collected over time by incorporating carbon into their long term strategies. This can cause the phenomenon of persistent shocks.

Initially, the allowance market was scheduled to run in two phases (Phase 1: 2005-2007; Phase 2: 2008-2012). During each of these two phases, each member of the European Union must accept a national allocation plan for an annual reduction of CO2 emissions while retaining the prerogatives relating to the definition of major variables, such as the ceiling of the emissions attributed to the device, the list of plants that will be concerned and the rules for allocating quotas to existing and new facilities. The plan is based on a percentage of emission reductions for each installation in a country from the principle of "*grandfathering*". Therefore, there is an obligation to reduce annual CO2 emissions, which is uncertain because of this very principle. Then, throughout the European Union, there is a supply function of reduction of CO2 emissions (Bunn and Fezzi, 2007) reflecting increasing marginal costs of reducing emissions over a year. In the sector of electricity generation, this supply function reflects the changes that occur in the *merit order* curve between the primary energies used in electricity generation. As these changes depend on the energy mixes and installed productive parks in each country, the supply function of reducing CO2 emissions includes the low costs of reducing CO2 emissions by the substitution of lignite for coal in electricity production in Germany, and the higher abatement costs of the more expensive alternative of substituting gas for coal in electricity generation. The response of the electricity sector to the obligation to reduce annual emissions of CO2 is different from one EU country to another. It depends on the country's energy mix and therefore the prices of primary energies and the price reached by the carbon quota.

Agents are involved in the daily market for allowances by buying and selling permits for CO2 emissions. They make their decisions based on their forecasts $E_t\left[f\left(D_j\right)\right]$, where f is the function of emission reduction supply and D_j the required emission reduction during phase j. These forecasts, which focus on the annual equilibrium price of CO2, evolve continually during the year (Bunn and Fezzi, 2007). Therefore, the fact that electricity producers that emit more CO2 than their allowances are starting to buy allowances on the market to be in compliance, makes it reasonable to predict that the carbon price is added to the fuel and operational costs of electricity generation. On the other hand, due to the free allocation of CO2 emission allowances to participants at the beginning of the period and the emergence of a carbon price from the daily market, these permits are a new liquid asset available to participants, creating an opportunity cost for emission permits equal to their market price (Sijm et al., 2006).

3 Electricity price formation, database and econometric modelling

3.1 From stylized facts to the econometric model

Electricity wholesale markets in France and Germany are of oligopolistic market design. The price of electricity results from the market clearing of supply and demand on power exchanges and is equal to the marginal cost of electricity generation plus a mark-up. Due to the fact that electricity demand is inelastic, the relative difference between the price of electricity and its marginal cost of production remains constant. Thus, with a constant mark-up rate, changes in electricity prices will reflect the changes in the cost of electricity generation and the prices of electricity will depend directly on the marginal cost of producing electricity. Electricity demand fluctuates continuously within a certain interval. Its curve meets the supply curve of electricity at one point of this interval and achieves the electricity market equilibrium, thus determining the wholesale price of electricity. The range within the demand fluctuation corresponds to minimum and maximum quantities of electricity consumed at any time during the year. This interval coincides with the quantity of electricity produced to meet demand from primary energy sources that may differ between countries with regard to their diverse energy mixes and their levels of electricity demand. The marginal cost of electricity is equal to the cost of primary energy used to produce the latest unit of electricity, operating costs, plus any inclusion of carbon costs in the production of that unit. The price of the primary energy used to produce the latest unit of electricity is a major determinant of electricity prices. For these two countries, the primary energy can be either gas or coal. Moreover, depending on whether the cost of carbon is included in the electricity generation cost function, the price of carbon dioxide emissions will either be a determinant of electricity price or will have no influence on it.

Climatic variables such as temperature, rainfall or brightness may also be important determinants of the price of electricity in a country. Indeed, the temperature and lighting can influence the demand for electricity while rainfall may have an impact on the supply of electricity in a country for which the proportion of hydropower in the energy mix is high. The importance of any of these variables is then dependent on the location and composition of the country's energy mix. In the two countries covered by our study, temperature is crucial in electricity prices. It exerts a dual effect on energy demand in general and particularly on that of electricity. The relationship between electricity demand and the temperature is a non-linear « V » shaped function, as electricity demand increases for both low and high temperatures (Engle et al., 1986). To take into account the nonlinearity of the relationship between electricity price and temperature, we estimate this function, in the cases of both countries, by the second order local polynomials method, in order to determine the threshold for which the electricity price-temperature gradient is reversed. Hence, we define two variables of temperature for each country: the change in temperature above the threshold (T^{hot}) and temperature variation below the threshold (T^{cold})[2].

Starting from these stylized facts concerning the electricity price formation process, we estimate an empirical time series model. The econometric specification of the relationship between the price of electricity and its determinants expressed above will be shown using a dynamic modelling because price variables in

[2] To linearise the "V" shaped function, one has to consider that if during the intra-period variation the temperature crosses the threshold the relationship is reversed. To overcome this problem T_t^{hot} is defined as all the variation in the temperature that occurs above the threshold and T_t^{cold} as all the variation that occurs below. In fact, if temperatures in t and $t+1$ are such that one is above the threshold for which the relationship between the price of electricity and the temperature is reversed and the other below, then $T_t^{hot} = Threshold - temperature(t)$ and $T_t^{cold} = température(t+1) - Threshold$. See the Appendices for more detail about determining the threshold.

general are functions of expectations formed by agents from their past experience and new information they have, in other words, past and contemporary prices. So one can write expectations of the value of future electricity prices expressed in the current period as follows:

$$P_t^{elect} = E_t\left[P_t^{elec*}|Z_t, P_{t-1}^{elec}, P_{t-2}^{elec}, ...\right] = g\left(Z_t, P_{t-1}^{elec}, P_{t-2}^{elec}, ...\right) \tag{1}$$

Z_t represents the new information available to agents in the current period, such energy prices entering the electricity generation process, and P_{t-i}^{elec} the past values of the electricity price. We opt for an econometric model where the price of electricity is based on its past values, on the current prices of gas, coal and carbon dioxide emissions and on the temperature variables T^{hot} and T^{cold}. This gives the following equation (2):

$$\begin{aligned} P_t^{elec} \quad &= \quad \alpha_0 + \sum_{i=1}^{p} \alpha_i P_{t-i}^{elec} + \beta P_t^{gas} + \delta P_t^{coal} + \gamma P_t^{carbon} \\ &\quad +\lambda_1 T_t^{cold} + \lambda_2 T_t^{hot} + \varepsilon_t \end{aligned} \tag{2}$$

Where P_t^y the logarithm of the price of the commodity y at the period t. The number of lags p of the dependent variable to take as a regressor will be determined for each country, minimizing the Akaike (AIC) or the Bayesian (BIC) information criterion.

3.2 Data and descriptive analysis

As our study aims at identifying the responses of the electricity sector to the introduction of the EU ETS, we will use electricity prices in € / MWh from different contracts on the electricity stock exchanges[3] of both countries. As the market segment of intra-day contracts lacks liquidity and is only intended to respond to unpredictable temporary physical needs during the day, we will use the day-ahead and the month-ahead base load[4] electricity prices of the French and German electricity stock exchanges. These data sets and all those used in this study are weekday frequencies and run from July 4th, 2005 to June 29th, 2007. Due to its liquidity, the carbon spot price of the Powernext stock exchange expressed in € per ton will be used. On the primary energy markets the following price series expressed in € per MWh will be used. It is the gas price of the month-ahead future contract traded on the Zeebrugge hub and the coal price of the month-ahead future contract Coal CIF ARA. The variables of temperature T^{hot} and T^{cold} were taken from the Powernext daily index of temperature (expressed in degrees Celsius) for both countries. These indexes are calculated from a weighted average, by regional population, of temperatures recorded at representative regional weather stations in each country. Finally, we have all of a sample of 520 observations for each series of data and we will now present their main characteristics.

[3] It is Powernext in France and EEX in Germany.

[4] The base load price of electricity is the price on the block for 24 hours. It is an arithmetic average price of 24 hours of the day (from 0h to 23h).

Figures 1 to 3 present the variations of price of various electricity contracts on the French and German electricity stock exchanges, as well as the changes in the prices of gas, coal and carbon.

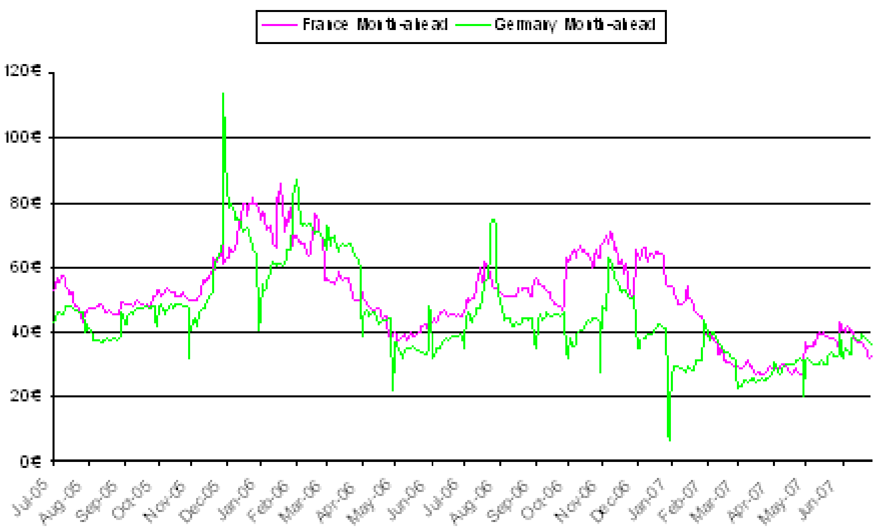


Figure 1: Month-ahead contract electricity price in France and Germany

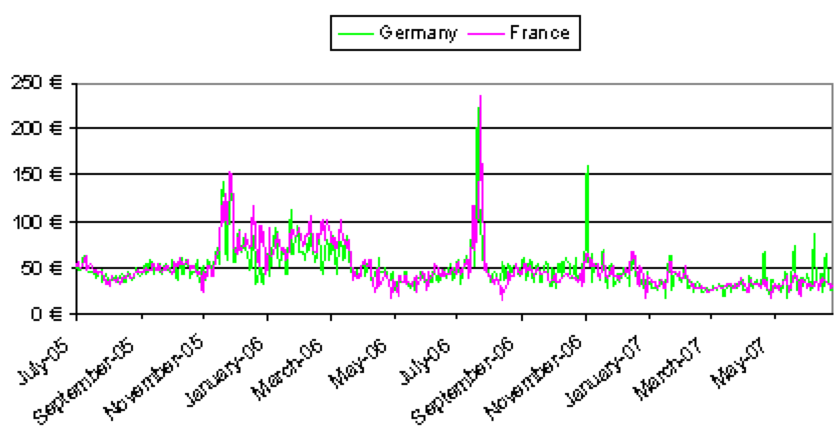


Figure 2: Day-ahead contract electricity prices in France and Germany

These figures show that the prices of various electricity contracts have varying volatilities. Prices of day-ahead contracts are of an extreme volatility compared to those of month-ahead contracts. The price of coal shows no major changes and remained relatively stable within a range of 6 to 8 € / ton during the period from July, 2005 till June, 2007 with a trend towards the upper bound of the range at the end of the period. During the same period the price of gas shows a decreasing general trend marred by large

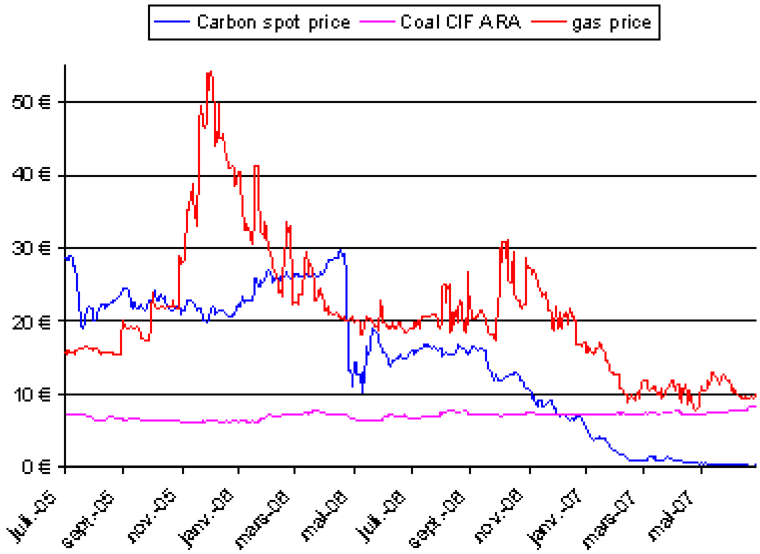


Figure 3: Carbon, gaz and coal prices

fluctuations, including a significant increase during the winter of 2005 when gas prices rose from just under 20 € / MWh in October to over 50 € / MWh in December. The spot price of carbon fluctuated in a range of 20 to 30 € per ton from the launch of Powernext[5] until April, 2006 when the price of CO2 emissions fell to nearly 15 € in only three days. This sudden collapse of the carbon price followed the disclosure of the 2005 verified emissions by the European authorities. The results revealed a net long position of the carbon market with more allowances than actual emissions.

It was a carbon market correction which induced a significant break in the series of carbon spot prices. It was likened to a structural break (Alberola et al., 2008) in the sense that the progression of the series of carbon spot prices completely changed after the shock. Then, with the approach of the end of the pilot phase of the EU ETS, the carbon spot price continued to decline and converge towards zero, confirming the long position of the carbon market not only for the first two years of its operation but over the whole pilot phase. In addition, the youth of the market for emission permits, and its instability because players are in learning period, suggests the presence of other structural breaks in the series of carbon spot prices. Moreover, Alberola et al. (2008) have identified two structural breaks in this series. The first was in April 2006, mentioned above, and the other occurred on October 26, 2006 following the announcement of a reduction in allowances of nearly 15% for the second phase of the EU ETS (2008-2012). Hence, as done by Alberola et al. (2008), we apply a unit root test with two structural breaks to detect the dates of breaks which occurred in the series of carbon spot prices. We chose the unit root test with double change in the mean pioneered by Clemente Montanès and Reyes[6] (1998). This test makes the dates of breaks endogenous.

[5] The French carbon stock exchange was launched on 1 July 2005.

[6] See the Appendices for more detail about this test.

It includes two test procedures, each depending on detrending or not the series before performing the unit root test. Thus, the procedure applying a filter before the test is called *AO* (Additive Outlier) and serves to capture sudden changes in the series. The one which detrends and performs the test at the same time is called *IO* (Innovational Outlier) and serves to capture incremental changes in the mean of the series. The test findings concerning dates of breaks are summarized in Figure 4.

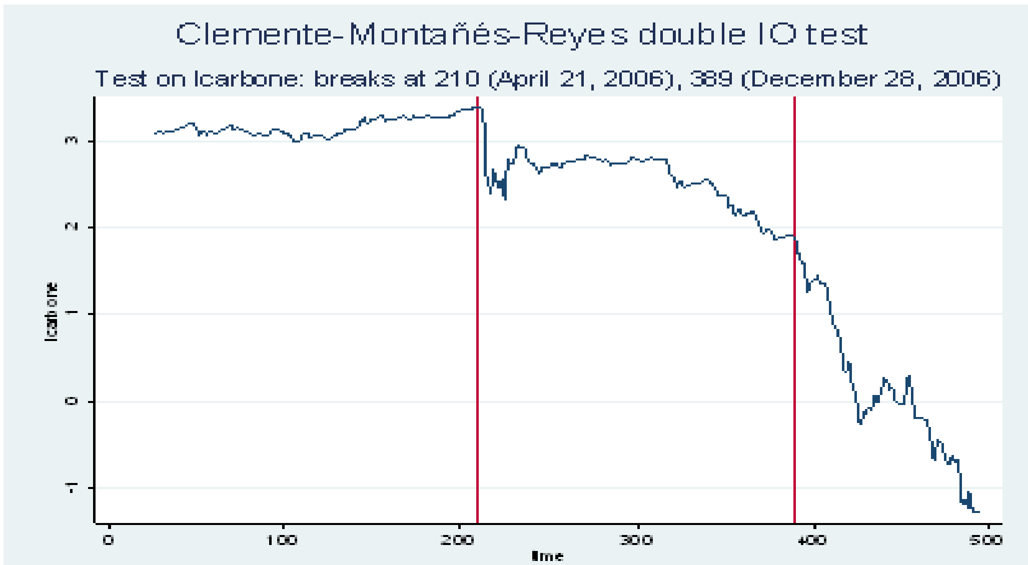


Figure 4: Detection of dates of structural breaks occurring on log carbon spot price series

The results of the test run on the logarithm spot price series of emission allowances suggest two structural breaks. Indeed, if we retain the results of the test by Clemente Montanès and Reyes based on the *IO* procedure, we note that it detects two structural breaks that occurred on April 21, 2006 and December 28, 2006. The first date corresponds to a sharp drop in the price of carbon due to a market correction following the publication by the European authorities of verified emissions for 2005. The second date corresponds to the beginning of the convergence towards zero of the carbon spot price following a change in agents' decisions on the carbon market. Indeed, due to the mild winter in 2006 which ensured a weaker electricity demand than in the winter of 2005, agents revised their forecasts for the equilibrium price of carbon downward. The long position of the carbon market in 2005, despite a cold winter, prompted agents to anticipate a long position in the market in 2006 due to new information which they had concerning the mild winter of 2006. Thus, from December 2006, the participants in the carbon market anticipated an exceeding of the allowances for 2006 and for the whole pilot phase of the EU ETS, including therefore the year 2007. This induced an excess of allowance supply on the market which led to a fall in the carbon price initiating a convergence towards zero in January 2007. These changes in agents' expectations were largely influenced by the Stern[7]

[7] The Stern Review on the Economics of Climate Change is a report released on October 30, 2006 by economist Lord Stern for the British government, which discusses the effect of climate change on the world economy. It was widely discussed and

review on the economics of climate change and the United Nations conference on climate change in Nairobi, which began recalling the excess supply of allowances on the European carbon market during its first period of operation. Then the carbon spot price was lower than 1€ per ton in February 2007. The two structural breaks which occurred in the carbon spot price series and its convergence towards zero in the first period of the EU ETS were the consequences of an excess of allowances at the beginning of the period compared to actual emissions and of the lack of allowance banking from one year to another and especially from the first period of the EU ETS to the second.

3.3 Estimation of the models

In order to select the most appropriate representation of the modelling of each electricity price series, we estimate model (2) by Feasible least squares ($FGLS$) for each of them. We shall retain the most relevant models according to the Akaike (AIC) and the Schwarz (BIC) information criterion, criteria MSE and R^2 which are indicators of the explanatory power of a model. However, despite having used a robust estimation method for Heteroskedasticity, we focus special attention on the structure of regression residuals to ensure their good statistical properties, all the more so as the price series we have are of high frequency. Concerning this last point, since Engle (1982) we know that in the context of time series models for macroeconomic and financial data, variances of the disturbances were less stable than is generally assumed and they often varied over time. We will then test the presence of $ARCH$ effects, a very common form of Heteroskedasticity in the time series of high frequency. We call models (a), (b), (c) and (d) models from the equation (2) where the series of electricity prices taken into account are respectively those of the French month-ahead contract, the French day-ahead contract, the German month-ahead contract and the German day-ahead contract. $ARCH$ tests applied to the residuals of models (a) and (c) concerning the month-ahead electricity contracts do not reject the null hypothesis of no $ARCH$ effects, while the residuals of models (b) and (d) concerning day-ahead electricity contracts reject the null hypothesis of no $ARCH$ effects. These last two models present an $ARCH$ heteroskedasticity in the residuals. This presence of $ARCH$ effects requires their modelling alongside the mean equations. In addition, studying the stability of residuals is supplemented by the analysis of correlograms and partial correlograms of the disturbances. This analysis confirms the stability of residuals of the model (a) while correlograms of the residuals of models (c) and (d) show the presence of a seasonality of order 5 in the prices of German electricity contracts. This seasonality is daily during the week, because the data are often weekday frequencies. To capture the seasonality we build five dummies $season_i$, $i = 1, 2, 3, 4, 5$, each corresponding to one business day of the week j, j = Monday, ... Friday. This gives the variable $season_1$:

$$season_1 = \begin{cases} 1 \; if & j = monday \\ 0 & otherwise \end{cases} \quad \text{and so on for every business day}$$

it predicts that the total allowances in the first period of the EU ETS will be only 1% below projected "business as usual" emissions.

Once the remaining seasonal variables are built, we re-estimate models (c) and (d) including variables $season_i$ for $i = 1, 2, .., 5$, then we check the stability of new estimated residuals. We call these two new models respectively models (c') and (d'). The results show that the explanatory powers of both models and all the selection criteria of models were significantly improved. In addition, $ARCH$ tests conclude on the presence of $ARCH$ effects in the residuals of model (d') but not in those of model (c').

The presence of $ARCH$ effects in the models (b) and (d') requires their inclusion in modelling. Thus, models of different series of electricity prices may vary depending on whether we model $ARCH$ or $GARCH$ effects detected in the disturbances of preliminary regressions or take into account the existence of seasonality as in the case of models (c) and (d). These many considerations justify the selection of the following models for modelling each electricity price series. In the case of month-ahead contracts, the prior model (a) will be used for the final modelling of the French electricity price with its high explanatory power, led by both an R^2 of 97% and root mean squared error ($RMSE$) of only 4%, and the stability of its residuals. Due to its good statistical properties, we retain the model (c') for the final modelling of the price of German month-ahead electricity contract. Indeed, the analysis of correlogram and partial correlogram of the residuals of this model suggests that the disturbances have a white noise structure. In addition, this model presents an R^2 of $85,7\%$ and a root mean squared error of only 11%. Concerning the price series of day-ahead contracts, the concern to take into account any interdependence[8] of the French and German electricity markets leads us to retain the following model with Dynamic Conditional Correlation (Engle, 2002; Engle and Sheppard, 2001) DCC$_E$(1,1) errors:

$$
\begin{cases}
P_t^{elec/fra} = \alpha_0 + \sum_{i=1}^{2} \alpha_i P_{t-i}^{elec/fra} + \beta P_t^{gas} + \delta P_t^{coal} + \gamma P_t^{carbon} \\
\quad + \lambda_1 T_t^{cod/fra} + \lambda_2 T_t^{hot/fra} + \varepsilon_t^{fra} \\
\\
P_t^{elec/ger} = \alpha_0 + \sum_{i=1}^{2} \alpha_i P_{t-i}^{elec/ger} + \beta P_t^{gas} + \delta P_t^{coal} + \gamma P_t^{carbon} \\
\quad + \lambda_1 T_t^{cod/ger} + \lambda_2 T_t^{hot/ger} + \sum_{j=2}^{5} \psi_j season_j + \varepsilon_t^{ger} \\
\\
(\varepsilon_t^{fra}, \varepsilon_t^{ger}) \rightsquigarrow N(0, H_t)
\end{cases}
$$

The model $DCC_E(1,1)$ is defined as:

$$
\begin{cases}
H_t = D_t R_t D_t \\
D_t = diag(\sqrt{h_{11t}}, \sqrt{h_{22t}}) \\
R_t = (diag\ Q_t)^{1/2}\ Q_t\ (diag\ Q_t)^{-1/2}
\end{cases}
$$

Where the 2×2 symmetric positive definite matrix Q_t is given by:

$$
Q_t = (1 - \theta_1 - \theta_2)\overline{Q} + \theta_1 u_{t-1} u_{t-1}^T + \theta_2 Q_{t-1}
$$

[8] The estimate results of models of the prices of month-ahead electricity contracts in both countries using the SUR method are not conclusive.

With u the matrix of standardized residuals. $\overline{Q}$ is the 2×2 unconditional variance matrix of u_t, and θ_1 and θ_2 are non-negative parameters satisfying $\theta_1 + \theta_2 < 1$. The approach to estimating the $DCC(1,1)$ model includes two steps[9]. First, the conditional variance of the price of day-ahead electricity contracts in each country is estimated from a $GARCH(1,1)$ specification at the same time as the conditional mean equation. Thereafter, the standardized residuals of regressions performed in the first step are used to model the correlation in an autoregressive way to obtain the conditional correlation matrix varying over time. The conditional variance-covariance matrix H_t is the product of the diagonal matrix of conditional standard deviation D_t with the conditional correlation matrix R_t and the diagonal matrix of conditional standard deviation D_t. The $R_t = \begin{pmatrix} 1 & \rho_{12t} \\ \rho_{21t} & 1 \end{pmatrix}$ matrix measures the instantaneous conditional correlation between electricity prices of day-ahead contracts on German and French power exchanges. The results of estimates of these models are presented in Table 1 and Figure 5.

However, structural breaks in the carbon spot price series, which occurred on April 21, 2006 and December 28, 2006, detected with the Clemente Montanès Reyes test using the IO[10] procedure, seemed likely to have an impact on the long-run relationship between the price of carbon and that of electricity and its fundamentals. Indeed, we have identified a long-run relationship between the price of electricity and its fundamentals based on the average correlations between these variables over the whole period from July 4, 2005 to June 29, 2007. However, the correction which occurred on the carbon market after the announcement of the 2005 compliance results and especially the convergence towards zero of the spot carbon price which began on December 28, 2006, could alter this relationship by drastically reducing the weight of the carbon cost in the cost functions of electricity generation. This fall in the cost of carbon, which could bring about changes in the *merit order* between technologies of electricity generation, is likely to alter the long run relationship between the price of electricity, the price of fossil fuels and the price of carbon. To evaluate the potential impact of the structural breaks in the carbon spot price on the long-run equilibrium relationship between the prices of different electricity contracts and their fundamentals, we proceed to test the stability of estimated coefficients of carbon, gas and coal price variables. We assume that all the other estimated coefficients are stable. So we test the equality of these coefficients for the periods before and after the carbon spot price structural breaks. In practice, we test first the equality of these coefficients for the periods before and after December 28, 2006. Then we test the equality of coefficients for the periods before and after April 21, 2006, restricting the total sample to the period from July 4, 2005 to December 27, 2006 in order to purge our estimates of the weight of any changes occurring after December 28, 2006. The results of these stability tests suggest that the long-run relationship between the price of electricity, the fossil fuel price and the carbon spot price is unstable over the whole period and that it changed from December 28, 2006 in the cases of the German electricity contracts and the French day-ahead contracts. Furthermore, these results support the

[9] See the Appendices for more detail about estimating this model.

[10] The dates of the structural breaks in the carbon spot price series detected with the AO procedure are close to the dates detected with the IO procedure. However, the results concerning the impact of structural breaks detected with the AO procedure on the long-run relationship between electricity prices and their determinants are less conclusive.

conclusion that, for all electricity contracts, the correction which occurred on the carbon market in April 2006 did not affect the long-term relationships.

The carbon spot price structural break which occurred on December 28, 2006 affected the long-run equilibrium relationship between the price of electricity and its fundamentals in the cases of German electricity contracts and French day-ahead ones. This justifies the estimation of models of these electricity contracts over two sub-periods: the period from July 04, 2005 to December 27, 2006 and the period from December 28, 2006 to June 29, 2007 for comparison purposes. The next section is devoted to interpreting the estimation results.

4 Results and interpretation

Table 1 presents the estimation results of the models used for modelling the prices of various French and German electricity contracts over the whole period from July 4, 2005 to June 29, 2007 and by sub-periods. We focus first on the full period results and then comment the results by sub periods.

Over the whole period, all the estimated coefficients at 5% level of significance have the expected signs. The estimated parameters of the logarithmic price variables in the mean equations are interpreted as long-run elasticities because the models reflect the long-run relationships. Higher values of estimated coefficients of lagged electricity price variables and their degrees of significance reflect the high dependence of contemporary electricity prices on those of the previous periods. This dependence is due to the expectations of contemporary electricity prices held by agents in previous periods. These results suggest that temperatures do not affect the prices of month-ahead electricity contracts while the estimated coefficients of temperature variables T^{hot} and T^{cold} reflect the fact that overall, milder temperatures push the price of day-ahead electricity contracts downwards, and that variations in temperatures towards extreme values lead to a rise in these prices. In particular, a positive variation of temperatures above the threshold, all other things being equal, leads to higher prices for French and German day-ahead electricity contracts, in the same proportions, while a positive change in temperatures below the threshold leads to a decrease in prices in different proportions. In the latter case, higher temperatures below the threshold in France and Germany, in the same proportions, will cause a decline in the price of the French electricity contract twice as steep as the German one. As the temperature affects the price of electricity only through electricity demand, we can easily conclude that temperature influences only the prices of day-ahead electricity contracts. Indeed, the short term of day-ahead contracts and the difficulty of predicting with accuracy the levels of temperature beyond a few days, explains why the electricity supply intended to meet the changes in electricity demand due to temperature variations is provided through day-ahead contracts. We note, however, that electricity prices in Germany introduce a daily seasonality during the week. For the day-ahead contract, this seasonality is manifested by a decrease in electricity prices during the week. So, the day being Tuesday, Wednesday, Thursday or Friday results, all other things being equal, respectively, in a reduction of the logarithm of the day-ahead contract

Table 1. Estimation results of the selected models

Country Contract	France Month ahead	France Day Ahead			Germany Day Ahead			Germany Month Ahead		
Period	full period	full period	before break	after break	full period	before break	after break	full period	before break	after break
Mean equation										
P_{t-1}^{elec}	0.937***	0.610***	0.589***	0.565***	0.471***	0.443***	0.357***	0.656***	0.773***	0.428***
	(0.015)	(0.052)	(0.064)	(0.090)	(0.058)	(0.058)	(0.129)	(0.13)	0.086	(0.121)
P_{t-2}^{elec}		0.214***	0.215***	0.159	0.251***	0.246***	0.212**	0.202	0.122	0.078
		(0.051)	(0.065)	(0.097)	(0.056)	(0.071)	(0.106)	(0.129)	0.080	(0.152)
P_{t}^{gas}	0.043***	0.094***	0.125***	0.040	0.128***	0.170***	0.070	0.080***	0.062***	-0.030
	(0.010)	(0.030)	(0.036)	(0.097)	(0.042)	(0.043)	(0.115)	(0.026)	0.023	(0.132)
P_{t}^{coal}	0.007	-0.181*	-0.017	0.638	0.057	0.140	1.49*	0.068	0.056	0.541
	(0.026)	(0.104)	(0.145)	(0.613)	(0.145)	(0.146)	(0.904)	(0.076)	0.073	(0.367)
P_{t}^{carbon}	-0.001	0.004	0.067***	0.019	0.019**	0.093***	0.016	0.002	0.022**	-0.019
	(0.002)	(0.007)	(0.023)	(0.022)	(0.009)	(0.021)	(0.027)	(0.004)	0.011	(0.019)
T^{hot}	-0.000	0.012***	0.006	0.028***	0.011***	0.007	0.031***	0.004*	0.005*	0.001
	(0.001)	(0.004)	(0.005)	(0.008)	(0.004)	(0.005)	(0.008)	(0.002)	0.003	(0.004)
T^{cold}	0.001	-0.031***	-0.030***	-0.037***	-0.014***	-0.012**	-0.028**	-0.013	-0.009**	0.086
	(0.001)	(0.004)	(0.006)	(0.007)	(0.004)	(0.005)	(0.013)	(0.008)	0.004	(0.055)
$cons$	0.103*	0.732***	0.181	-0.431	0.695**	0.313	-1.52	0.084	-0.027	0.582
	(0.057)	(0.222)	(0.344)	(1.230)	(0.329)	(0.350)	(1.83)	(0.151)	0.164	(0.883)
$season_2$					-0.076**	-0.070*	-0.067	0.083***	0.076***	0.086
$season_3$					-0.193***	-0.176***	-0.174**	0.105***	0.084***	0.126**
$season_4$					-0.240***	-0.217***	-0.251***	0.106***	0.097***	0.116*
$season_5$					-0.406***	-0.397***	-0.332***	0.089***	0.073***	0.117*
Conditional variance equation										
$cons$		0.001***	0.002***	0.01	0.005***	0.04***	0.011*			
$ARCH$		0.173***	0.159***	0.155**	0.251***	0.244***	0.584**			
$GARCH$		0.813***	0.809***	0.804***	0.665***	0.675***	0.352*			
$likeliho$	954.13	164.69	111.28	59.83	135.19	139.33	14.68	376.73	431.06	45.58
AIC	-1894.26	-307.39	-200.56	-97.66	-240.39	-248.67	0.633	-729.46	-838.12	-67.17
BIC	-1864.50	-260.64	-156.99	-65.95	-176.64	-189.25	43.87	-678.46	-790.65	-32.58

*Standard errors are in () ; * ** and *** refer respectively to the 10%, 5% and 1% significance levels of estimated coefficients.*

price of 7%, 19%, 24% and 40% compared to the first day of the week. The fall in the price of electricity of 40% on Friday compared to Monday is due to reduced demand for electricity over the weekend, as the day-ahead contracts are traded on Friday to match the electricity demand of Saturday.

The estimation results of mean equations argue that there are important differences between countries and electricity contracts in the way that the costs of primary energies and carbon are included in the cost functions of electricity generation. In France, only the price of gas has an impact on the price of electricity at the long-run equilibrium. However, this impact is twice as high on the day-ahead contract compared to the month-ahead electricity contract. Indeed, all other things being equal, higher gas prices of 1% lead to an increase of 0.04% in the month-ahead contract price and 0.09% in the day-ahead one. The price of carbon, on average over the whole period, was not a determinant of the prices of French electricity contracts. In Germany, the price of gas, unlike that of coal, has been a determinant of the price of both contracts of electricity. Thus, all things being equal, higher gas prices of 1% result in an increase of 0.08% in the month-ahead contract price and 0.13% in the day-ahead one. The price of carbon had an impact only on the price of the day-ahead contract. A rise of 1% in the price of emission permits results, all other things being equal, in an increase of 0.02% in the price of the German day-ahead electricity contract. The elasticity of the electricity price relative to the gas price is higher for day-ahead electricity contracts than for month-ahead contracts. This reflects a smaller weight of the gas price in the cost function of electricity traded through month-ahead contracts compared with day-ahead ones. This result reinforces the idea that electricity generation is subject to a *merit order* between technologies, based on variable marginal costs. The gas price has a greater impact on electricity prices in Germany, compared to France. This difference in the weight of gas prices in the cost of electricity generation is due to the heterogeneity of the French and German energy mixes, the proportions for gas being respectively 3% and 10%.

The estimates of the conditional variance equations over the whole period suggest that the electricity price variations of German and French day-ahead contracts are volatile, the French contract being more volatile than the German. Indeed, the sum of $ARCH$ and $GARCH$ coefficients is higher in France than in Germany. So is the variance of the electricity price around its fundamentals, mainly the price of carbon dioxide, hence a greater stability of the price of the German day-ahead electricity contract around its long run equilibrium path compared to the price of French equivalent.

The impact of carbon prices on electricity prices mentioned above represents an average impact over the whole period from July 4, 2005 to June 29, 2007, whereas the stability test results suggest that the structural break in the carbon spot price which occurred on December 28, 2006 has affected the long-run equilibrium relationship between the prices of German day-ahead and month-ahead electricity contracts and the French day-ahead contract on the one hand, and the prices of gas, coal and emission permits on the other. However, this structural break has not affected the stability of the estimated coefficients of model (a). We can deduce that the carbon spot price was not a determinant of the electricity price in the French month-ahead contract. Indeed, these two series of prices are completely disconnected, as the estimated coefficient of the carbon price in model (a) is not significant and the structural breaks which occurred in the carbon spot price series did not affect the estimated coefficients of this model. Moreover, the instability of estimated coefficients of the other models, induced by the structural break which occurred on December 28th, 2006 in the series of carbon spot prices, is evidence of the close link between the prices of electricity contracts in these models and the price of emission permits, despite the non significance in some models of the estimated coefficient of carbon prices on average over the whole period.

Table 1 also contains the estimation results of models over the periods before and after the structural break of December 28, 2006 in the carbon spot price series. These results suggest that the carbon spot price has been a determinant of the price of electricity throughout the period before the convergence towards zero of the carbon spot price and therefore during the first two years of the EU ETS operation. The price of electricity was completely disconnected from the carbon spot price in the last year of the pilot phase of the EU ETS. During the period from July 4, 2005 to December 27, 2006, an increase of 1% in the carbon price resulted respectively, all other things being equal, in an increase of 0,093%, 0,067% and 0,022% in the prices of German and French day-ahead electricity contracts and in the German month-ahead contract. The elasticities of the prices of day-ahead electricity contracts relative to gas prices were higher during this period compared with the whole period. However, the coal price has not been a determinant of the price of any electricity contract. During the period from December 28, 2006 to June 29, 2007, electricity prices of the various contracts were completely disconnected from the spot price of carbon. During this period the price of gas was not a determinant of electricity prices of the various contracts and the price of coal was without effect on them. This reflects distortion in the long-run equilibrium relationships between the prices of electricity in the three contracts and their determinants. The analysis of selected models' criteria confirms this result. The structural break in the carbon spot price on December 28, 2006 distorted the entire relationship between the price of electricity and the prices of gas, coal and carbon permits. This may be evidence of a change in the *merit order* between technologies of electricity generation, caused by the structural break in the carbon spot price series. This also proves that the European market for emission allowances had an impact on the power generation sector in both countries, even if it was not of the same magnitude.

Figure 5 presents the dynamic of the conditional correlation between the prices of day-ahead electricity contracts in France and Germany. This correlation was positive and highly significant. It was stable at around 0,3 during the period before the structural break in the carbon spot price series in December 2006. Then it dropped significantly by almost 30%, following the convergence towards zero of the carbon spot price (Figure 6), reaching a stable value of about 0,2. The stability of the conditional correlation over each sub period is due to the extreme values of estimated coefficients of the model $\mathrm{DCC}_E(1,1)$. In fact, over each sub period, $\widehat{\theta}_1 \simeq 0$ and $\widehat{\theta}_2 \simeq 1$ with $\widehat{\theta}_1 + \widehat{\theta}_2 < 1$, which implies $Q_t \simeq Q_{t-1}$ and therefore: $\begin{pmatrix} 1 & \rho_{12t} \\ \rho_{21t} & 1 \end{pmatrix} \simeq \begin{pmatrix} 1 & \rho_{12t-1} \\ \rho_{21t-1} & 1 \end{pmatrix}$. This result is confirmed by a comparison test between a DCC model and a Constant Conditional Correlation (Nakatani and Teräsvirta, 2009; Bauwens et al., 2006) CCC model.

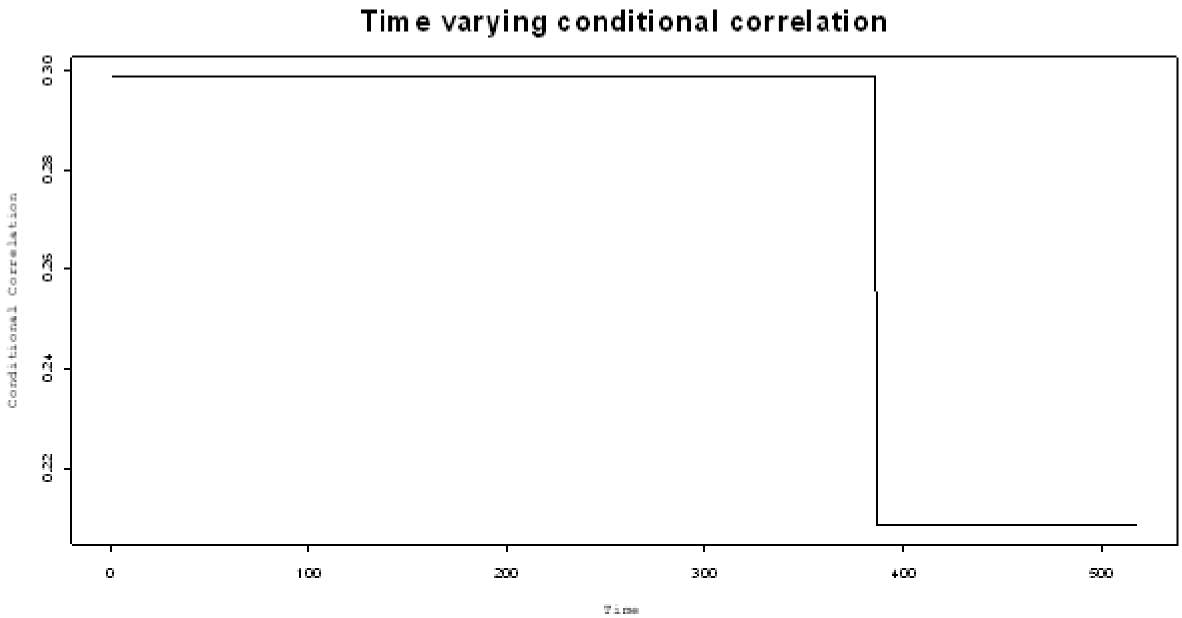


Figure 5: Conditional correlation of French and German electricity prices of day-ahead contracts

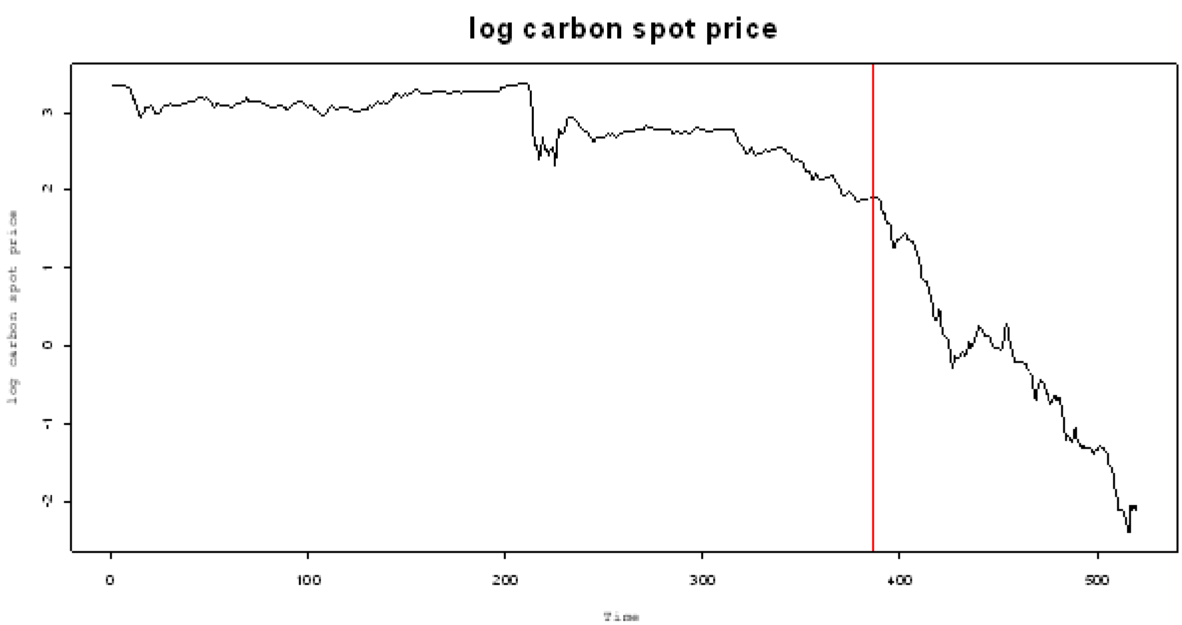


Figure 6: Log carbon spot price series

Electricity prices in Germany and France were much more correlated during the first two years of operation of the EU ETS than over the period that followed. The highest correlation coincided with the period during which the electricity producers were most constrained by the EU ETS. So, in a context where the debate on the possible manipulation of the electricity wholesale prices in France by the former public producer is still relevant today[11], it seems reasonable to expect that the wholesale prices of electricity in France are partially aligned with those of Germany[12]. Indeed, a positive and significant correlation between German and French electricity prices, even though the price of carbon was not significant, corroborates the idea that the French electricity producers take advantage of the French energy mix in terms of production costs. During the first two years of the EU ETS operation, the carbon market allowed French electricity producers to make more profits from the composition of their productive parks. This can be explained by the stronger correlation between French and German electricity prices during the same period.

Finally, the study of the impact of the introduction of the EU ETS on the electricity generation sectors in both countries compares the elasticity of the electricity price relative to the carbon price for each type of electricity contract. Regarding day-ahead electricity contracts, we note that during the first sub-period, the elasticity of the electricity price compared to the price of carbon is higher in Germany than in France. For the month-ahead electricity contracts, we find that the price of carbon is not a determinant of the price of electricity in France while the price of carbon was a determinant of the electricity price in Germany during the first two years of the EU ETS. We conclude that German electricity producers have respected the carbon constraint more than their French counterparts. This is largely explained by the differences in composition of the energy mixes of both countries. This finding is supported by the greatest stability of the price of the German day-ahead electricity contract around its path of long-run equilibrium during the first two years of the EU ETS operation, compared to the price of the French day-ahead electricity contract. Indeed, during this period, comparing the sum of the coefficients of $ARCH$ and $GARCH$ effects of each model representing these prices shows that a deviation of the price of the day-ahead electricity contract from its equilibrium path, following an over or underestimation of the price of carbon by the electricity producers, the return to equilibrium is faster in Germany than in France.

5 Conclusion

We modelled and estimated the relationship between electricity prices, the prices of primary energies used in electricity generation and the price of carbon dioxide emission permits, for France and Germany. This enabled us to reflect the heterogeneity of responses to carbon constraints in the electricity generation sectors and to evaluate the efficiency of the EU ETS, taking into account this heterogeneity. We have shown that

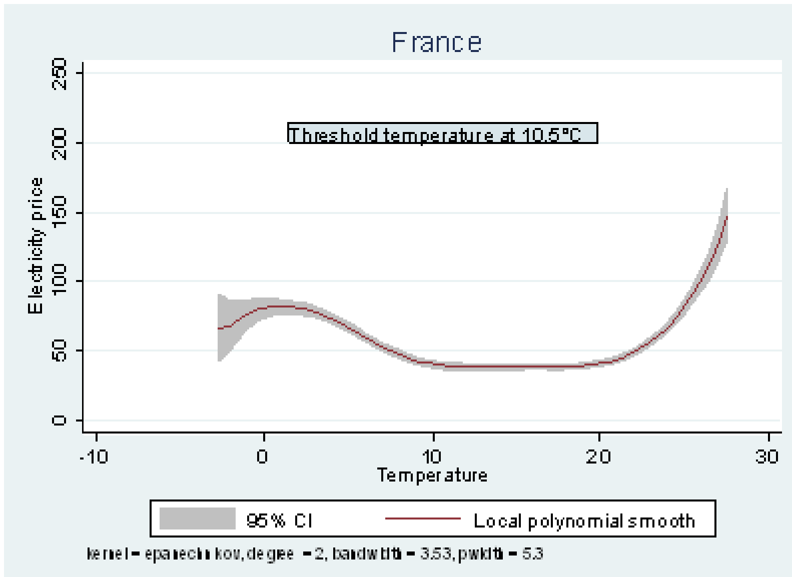
[11] This debate has been re-opened by recent suspicions about electricity producers in France. Indeed, in a recent press release dated March 11th, 2009, the European Commission suspects the French former public producer of electricity of illegal conduct. The suspected illegal conduct may include actions to raise prices on the French wholesale electricity market.

[12] As highlighted by Glachant (2007), if one cannot find obvious sources of price manipulation in France, one can assume that the French former public and dominant electricity producer leaves the setting of wholesale prices in France to the competitive fringe. These competitors are building gas power plants, which means that opening up the market will eliminate the economic effects of the French energy mix.

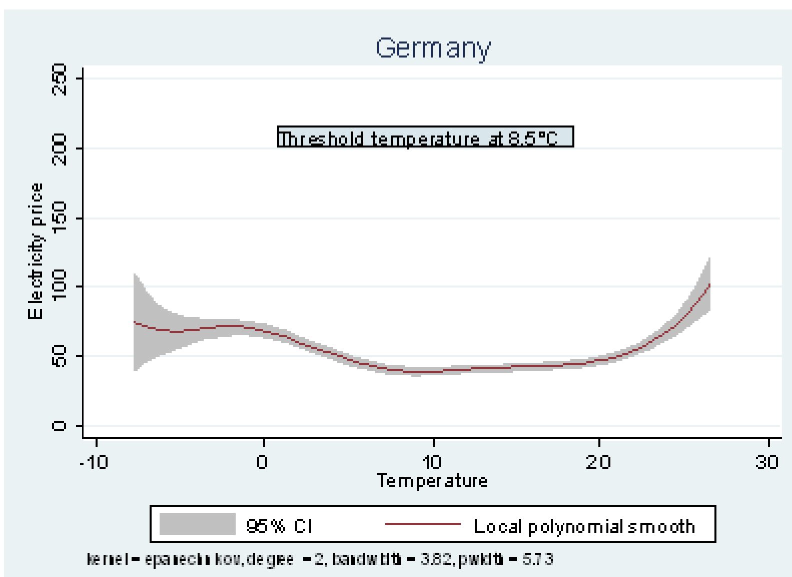
the impact of carbon constraints on the electricity generation sectors, during the pilot phase of the EU ETS, depended on the energy mix of the country. During that period, the impact was felt in two phases. The first concerns the first two years of the EU ETS, during which electricity producers included the cost of carbon in their production cost function; the second was the phase during which the carbon constraint no longer weighed on the decisions of electricity producers. However, producers in countries using predominantly fossil fuels, big carbon emitters, had undergone more carbon coercion and thus were more likely to include the price of emission permits in their electricity generation cost functions. The conditional correlation between the prices of day-ahead electricity contracts in France and Germany had dropped by 30% between the two phases. This drop was due to the collapse of the carbon price and its convergence towards zero. Hence, the EU ETS increased the market power of the former public French electricity producer and greatly contributed to the partial alignment of the wholesale price of electricity in France with at in Germany. Throughout the whole pilot phase (2005-2007), the efficiency of the European market for emission allowances had not been able to compel electricity producers to reduce their emissions and invest in cleaner technologies. However, it was a good step towards achieving the objectives of the Kyoto Protocol. The inefficiency of the EU ETS was mainly due to the largesse granted by the national authorities of European countries for their power generation sectors which were considered to be strategic, and to certain defining mechanisms set up by the EU ETS. Thus, excess allocations and the impossibility of "*banking*" on the following periods have bounded the horizon of the carbon market and eventually prevented the creation of a scarcity which is the essence of carbon coercion. This greatly contributed to the convergence towards zero of the carbon spot price at the end of the pilot phase of the EU ETS, relaxing the carbon coercion to which producers of electricity were subjected during the first two years of the operation of the carbon market.

A APPENDICES

A.1 Non parametric estimates of electricity price and temperature relationships



Non parametric regression of French electricity price on temperature



Non parametric regression of German electricity price on temperature

A.2 The test by Clemente Montanès and Reyes

The Clemente Montanès and Reyes (1998) test with double change in the mean (1998) using the AO procedure and implemented to a series y is based on the estimation of the following equation:

$$y_t = \mu + \delta_1 DU_{1t} + \delta_2 DU_{2t} + \widetilde{y_t}$$

Where $DU_{mt} = 1$ for $t \succ T_{bm}$ and 0 otherwise, for $m = 1, 2$. T_{b1} et T_{b2} are the dates of structural breaks and will be searched by the scan method. The noise of this equation becomes the dependent variable on the equation to estimate follows:

$$\widetilde{y_t} = \sum_{i=1}^{k} \omega_{1i} DT_{b1,t-i} + \sum_{i=1}^{k} \omega_{2i} DT_{b2,t-i} + \rho\widetilde{y_{t-1}} + \sum_{i=1}^{k} \theta_i \Delta\widetilde{y_{t-i}} + e_t$$

Where $DT_{bm,t} = 1$ for $t = T_{bm} + 1$ and 0 otherwise for $m = 1, 2$. This equation is estimated for each pair (T_{b1}, T_{b2}) in search of the least t-statistic of the unit root hypothesis that is then compared with values tabulated by the authors. In addition, the same test applied to the series y_t using the IO procedure is based on the estimation of the following equation:

$$y_t = \mu + \delta_1 DU_{1t} + \delta_2 DU_{2t} + \varphi_1 DT_{b1,t} + \varphi_2 DT_{b2,t} + \rho y_{t-1} + \sum_{i=1}^{k} \theta_i \Delta y_{t-i} + e_t$$

Testing the unit root hypothesis is equivalent of testing whether the coefficient ρ is not significantly less than 1.

A.3 Two-step estimation of DCC$_E$ models

The estimation of parameters of multivariate models is based on the method of maximum likelihood. So with Gaussian residuals, the likelihood function is:

$$L_T = \sum_{t=1}^{T} \log f(y_t \mid \theta, \eta, I_{t-1})$$

Where $f(y_t \mid \theta, \eta, I_{t-1}) = |H_t|^{-\frac{1}{2}} g(H_t^{-\frac{1}{2}}(y_t - \mu_t))$ the density function of y_t given the vector of parameters θ and η. We assume that $(y_t - \mu_t) \rightsquigarrow N(0, I_N)$. Thus, the loglikelihood function is:

$$L_T(\theta) = -\frac{1}{2} \sum_{t=1}^{T} \left[\log |H_t| + (y_t - \mu_t)' H_t^{-1} (y_t - \mu_t)\right]$$

The Gaussian likelihood provides a consistent quasi-likelihood estimator even if the true density is not Gaussian. In the case of a DCC model the loglikelihood is composed of two parts. The first part depends on the parameters of volatility and the second part depends on the parameters of the conditional correlations knowing the volatility parameters. So, with $H_t = D_t R_t D_t$ we obtain:

$$L_T(\theta) = -\frac{1}{2} \sum_{t=1}^{T} \left[\log |D_t R_t D_t| + u_t' R_t^{-1} u_t\right]$$

where $u_t = D_t^{-1}(y_t - \mu_t)$ and $u_t' R_t^{-1} u_t = (y_t - \mu_t)' D_t^{-1} R_t^{-1} D_t^{-1}(y_t - \mu_t)$. With these notations, the loglikelihood is:

$$L_T(\theta) = -\frac{1}{2}\sum_{t=1}^{T}\left[\log|D_t R_t D_t| + u_t' R_t^{-1} u_t\right]$$

$$L_T(\theta) \quad = \quad \underbrace{-\frac{1}{2}\sum_{t=1}^{T}\left[2\log|D_t| + u_t' u_t\right]}_{Q1L_T(\theta_1^*)} \underbrace{-\frac{1}{2}\sum_{t=1}^{T}\left[\log|R_t| + u_t' R_t^{-1} u_t - u_t' u_t\right]}_{Q2L_T(\theta_1^*, \theta_2^*)}$$

with θ_1^* the parameters of the conditional variance D_t and θ_2^* those of the conditional correlation R_t. Then the loglikelihood function can be written as follows:

$$L_T(\theta) = Q1L_T(\theta_1^*) + Q2L_T(\theta_1^*, \theta_2^*)$$

(θ_1^*, θ_2^*) are found in two stages. At the first stage we estimate $\theta_1^* = \arg\max Q1L_T(\theta_1^*)$ and at the second stage we estimate $\theta_2^* = \arg\max Q2L_T(\theta_1^*, \theta_2^*)$.

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