Convergence Across European Electricity Wholesale Spot Markets: Still a Way To Go.

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The creation of a genuine pan-European electricity market has been a priority for policy makers since the middle of the 1980's. To this end, Member States of European Union have dismantled the vertically integrated electricity supply industries and have removed barriers to cross-border trade. This paper evaluates the effectiveness of two decades of reforms, analysing convergence between wholesale spot prices of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK to January 2012. The general framework of fractional cointegration is used to check the progress towards market integration. Time-varying pairwise relations are estimated to evaluate whether convergence is instead an ongoing process. In addition, estimations of multivariate GARCH models allow an assessment of returns volatility transmission between markets. This paper shows that the European policy measures of the past two decades have not yet fully delivered on their promises.

Keywords: *market integration, price convergence, wholesale electricity markets, European Union.*
JEL Classification: *C22, L94, Q4.*

1 Introduction

The Internal Electricity Market (IEM) has been one of the core objectives of the European Union since the middle of 1980's, as the national markets integration is expected to provide European consumers with a cheaper, more sustainable and secure electricity supply. However, common rules for achieving the IEM were taken only with Directive 96/92/EC, which established the dismantling of the vertically integrated electricity supply industries, the introduction of competition to both generation and retail activities, and the non-discriminatory third-party access to transmission and distribution networks. Though of key importance for achieving a truly competitive and integrated market, the first electricity directive was criticized for having granted to much freedom to Member States about the transposition of its principles into national legislation and for having left unaddressed important points such as the type of wholesale market organization to set up, the problem of consumers' rights to choose the energy suppliers, and the lack of cross-border trade

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(Vasconcelos, 2009). Subsequent legislation, namely the second and the third energy market package, filled the gaps of the first electricity directive and accelerated the completion of the IEM. In particular, Regulation 1228/2003/EC and the following Regulation 714/2009/EC established important rules to promote cross-border exchanges of electricity, which had resulted to be underdeveloped compared to other sectors of the economy due to scarce interconnection capacity between countries and to inefficient usage of the interconnectors (EC, 2007 pp.171-187) [1].

A further stimulus to cross-border trade was given by the European Regulators' Group for Electricity and Gas (ERGEG) with the launch, in 2006, of the Electricity Regional Initiatives (ERI) project. This project, which was conceived as an interim stage towards complete market integration, consisted in creating seven electricity regions in Europe, each of which was tasked with identifying practical solutions to implement the provisions included in the cross-border trade regulations (ERGEG, 2010). The seven regions, listed in Table 1, were created with some countries included in more than one regional grouping to ensure convergence to full market integration. A lead National Regulatory Authority (NRA) was appointed for each region to coordinate the work of the stakeholders involved[2]. Thanks to the regional approach of ERI, in recent years, market operators of Central West Europe, Northern Europe and of South West Europe have started using a new and efficient method to manage the respective interconnection capacities. This mechanism, called market coupling, allows power exchanges to match bids and offers of electricity from different markets with the objective of maximizing the usage of the daily available cross-border interconnection capacity and thus of reducing price differentials (EuroPEX, 2003).

[1] This is because historically electricity industries and infrastructures were developed by governments to guarantee self-sufficiency rather than to facilitate trade across borders.
[2] Stakeholders include regulators, transmission system operators, power exchanges, generation companies, consumers, Members States and the European Commission (ERGEG, 2010).

	Baltic States (BS)	Central East Europe(CEE)	Central South Europe (CSE)	Central West Europe (CWE)	Northern (NE)	South-West Europe (SWE)	France, UK, Ireland (FUI)
NRA	***Latvia***	***Austria***	***Italy***	***Belgium***	***Denmark***	***Spain***	***UK***
Austria		X	X				
Belgium				X			
Czech Republic		X					
Denmark					X		
Estonia	X						
Finland					X		
France			X	X		X	X
Germany		X	X	X	X		
Greece			X				
Hungary		X					
Ireland							X
Italy			X				
Latvia	X						
Lithuania	X						
Luxembourg				X			
Netherlands				X			
Norway					X		
Poland		X			X		
Portugal						X	
Slovakia		X					
Slovenia		X	X				
Spain						X	
Sweden					X		
United Kingdom							X

Table 1: Electricity Regional Initiatives in Europe. Source: ERGEG.

Given that market coupling has proved to lead to substantial price convergence where it has been implemented, the Agency for the Cooperation of Energy Regulators (ACER) has selected it as target model to be implemented EU-wide by 2014 (ACER, 2011 a, b). Market coupling projects in operation in 2012 and future developments are summarized in Table 2.

It is important to assess empirically the level of integration of European electricity markets, given the efforts of the European Union to restructure the electricity industry and to implement ad-hoc projects to remove barriers to cross-border trade. This paper contributes to the literature on electricity market integration analysing the behaviour of electricity prices of the broadest set of European countries and over the longest available sample period. Wholesale electricity spot prices to the end of January 2012 are used for each of the national electricity markets of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK.

Market Coupling Projects in operations in 2012		***Market Coupling Projects to be implemented between 2012 and 2014***	
ERI		***ERI***	
NE	Market splitting among Norway, Finland, Sweden and Denmark since 1999, extended to Estonia since April 2010		
CWE	Price coupling among Belgium, France and the Netherlands between November 2006 and November 2010.Price coupling among Belgium, France, Germany (including Austrian area) and the Netherlands since November 2010.		
CWE and NE	Tight volume coupling between CWE and Nordic market via: DK West cable between Germany and West Denmark since 2010, Kontek cable between Germany and East Denmark since 2010, Baltic cable between Germany and Sweden since 2010 and NordNed cable between the Netherlands and Germany the since November 2011.	CWE, NE (including Sweden-Poland interconnector and Estonia interconnector), and FUI (including the BritNed - Britain Netherlands interconnector- and the IFA-Interconnexion France Angleterre-).	European Price Coupling (EPC) to be implemented by Q4 2012. Integration of SEM (Irish single market) is expected by Q4 2014.
CWE and FUI	Price coupling between CWE and Great Britain via the BritNed cable between the Netherlands and Great Britain since April 2011.		
NE and CEE	Price coupling between Northern region and Poland via the SWE-POL cable between Sweden and Poland since December 2010.		
CEE	Price coupling between Czech Republic and Slovakia since September 2009.	Integration of CEE	Hungary plans to couple with Czech Republic and Slovakia in the first half of 2012. These projects will join EPC by the end of 2012. Price coupling covering the whole region is planned by Q4 2013.
SWE	Market splitting between Spain and Portugal since 2007.	Integration of SWE	Spain and Portugal should start the testing phase for joining EPC by Q1 2012. Final deadline is Q2 2013.
CSE	Price coupling between Italy and Slovenia since January 2011.	Integration of CSE	Discussion on the implementation of price coupling started in Q4 2011. Final deadline is Q1 2014.
		Integration of BS	A common electricity market, based on Nord Pool Spot will be introduced in the Baltic countries and price coupling will be implented in the region by Q4 2013.
		Integration of South East Europe	Romania and Bulgaria need to implement price coupling by the end of 2014 and then they will join the Czech Republic, Slovakia and Hungary project.

Table 2: Market coupling projects in operation in 2012 and cross-regional roadmap for implementing single European Price Coupling. Source: ACER, 2011b.

Moreover, in this paper market integration is assessed in a more comprehensive way than previously undertaken. The general framework of fractional integration and cointegration is used to test achieved convergence, while time-varying pairwise relations are estimated to evaluate whether market integration is an ongoing process. Multivariate GARCH (MGARCH) estimates provide an indication of returns volatility transmission between markets belonging to each electricity region.

The remainder of this paper is organized as follows. Section 2 reviews the economic literature on electricity market integration and convergence. Section 3 presents the dataset employed in the analysis. Section 4 describes the empirical analysis performed to measure market integration. Section 5 concludes and provides a brief description of questions for further work.

2 Literature

Over the past two decades, the opening of competitive electricity markets in Europe, Australia and the United States has generated a growing literature on the empirical evaluation of regional and national electricity markets integration. The methods to assess market integration have ranged from simple data exploratory approach to cointegration analysis to MGARCH models.

Among the first studies, De Vany and Walls (1999) employ cointegration analysis to find evidence of market integration between 11 regional markets in the western United States over the period 1994-1996. The analysis of both peak and off-peak prices reveals that strong integration and perfect integration are mainly an off-peak phenomenon[3]. Park et al. (2006) estimate contemporaneous and short-term price interdependencies between 11 US electricity markets located in the Western Interconnected System, in the Eastern Interconnected System and in the Texas Interconnected system, between 1998-2002, using vector autoregression model, causal flows based on directed acyclic graph and innovation accounting analysis. The results show that price interdependencies vary by time frame. In contemporaneous time, prices transmissions between western, eastern and Texas

[3] Strong market integration implies testing for the null hypothesis of β=1 in the cointegration relation $p_{it} = \alpha + \beta p_{jt} + \varepsilon_{it}$, and perfect integration, i.e. achieved convergence, requires both α=0 and β=1.

markets are found to be weak, while for longer time frames, a stronger interrelation between western and non-western markets emerges.

In Europe, Bower (2002) employs cointegration analysis to test for market integration between Scandinavia, England & Wales, Germany, Spain and the Netherlands using hourly prices for 2001. He finds that all markets but Spain are integrated. Using a data exploratory approach, Armstrong and Galli (2005) find convergence in hourly spot prices for France, Germany, Spain and the Netherlands over the period 2002-2004. In the Nord Pool area, between 2000 and 2003, Haldrup and Nielsen (2006) show that market integration depends on whether the transmission grid is congested or not, since they find evidence of fractional cointegration between electricity prices only when there is no congestion. Zachmann (2008) evaluates both achieved and ongoing convergence between Austria, Czech Republic, France, Germany, East Denmark, West Denmark, Poland, Spain, Sweden, the Netherlands and the United Kingdom over the period 2002-2006. The results highlight that a single European electricity market had not been achieved by mid-2006, but also show evidence of ongoing convergence (mostly during off-peak hours) between the markets of bordering countries. Bunn and Gianfreda (2010) demonstrate that integration is not due only to the geographical proximity of two markets, as they find it between Germany and the UK as well as between Germany and Spain. Germany is found to be strongly integrated with neighbouring markets also by Nitsche et al. (2010). Bosco et al. (2010) find cointegration between the German, French, Austrian and Dutch markets up to 2007, but show that only the German and French markets are strongly integrated. Moreover, they highlight that peripheral zones, including the Spanish and Nordic markets, do not share a common trend with the other countries. Nepal and Jamasb (2011) evaluate the degree of convergence between the Irish Single Electricity Market (SEM) and major continental markets of Germany, Netherlands, Belgium, Austria and Scandinavia, over the period 2008-2011. Using the same time-varying approach as in Zachmann (2008), they find that convergence between SEM and other European markets is low, due the poor level of interconnection capacity between Ireland and Great Britain.

Balaguer (2011) assesses the level of market integration between Denmark and Sweden and between France, Germany and Italy looking at Norwegian and Swiss exporters' behaviour over the period 2003-2009. He finds a high degree of market integration between Denmark and Sweden, but a poor level of integration between France, Germany and Italy.

In contrast to the methodologies employed by much of the literature, in this paper, fractional integration and cointegration analysis is used to test for European electricity market integration. Moreover, as in Zachmann (2008) and in Nepal and Jamasb (2011), ongoing convergence is tested using a time-varying approach.

An issue not previously tested in the literature on EU electricity market integration is that of volatility transmission between markets. Transmission of volatility has however been investigated in Australia. Worthington et al. (2005) finds that both own and cross-volatility spillovers are statistically significant across the five markets of the Australian National Electricity Market (NEM). Higgs (2009) extends the work of Worthington et al. (2005) employing three alternative MGARCH models, namely the constant conditional correlation (CCC) model of Bollerslev (1990), the dynamic conditional correlation model of Tse and Tsui (2002) (TTDCC) and the dynamic conditional correlation model of Engle (2002) (EDCC). The author finds that the relationship between volatilities of the states of the NEM are best characterised by the TTDCC model and that the closer and the better interconnected the markets, the stronger the volatility spillovers between them. In this paper market integration is measured with MGARCH models akin to the work carried out by Higgs (2009).

3 Data

The dataset consists of wholesale spot electricity prices as quoted by the following power exchanges: APX Power NL (Netherlands), APX Power UK (Great Britain), BELPEX (Belgium), EPEX SPOT (clearing the French, German and Swiss markets), EXAA (Austria), HTSO (Greece), IPEX (Italy), Nord Pool Spot (system price for Scandinavia), OMIE (Spain and Portugal), OTE (Czech Republic), POLPX (Poland), SEM (Ireland). Table 3 reports summary information about each of the markets.

Power Exchange	*Price Name*	*Country*	*Currency*	*Participation*	*Year of establishment*	*Available Sample*	*Average day-ahead price in 2011 (€/MWh)*	*Minimum day-ahead price in 2011 (€/MWh)*	*Maximum day-ahead price in 2011 (€/MWh)*	*Total consumption 2011 (TWh)*	*Day-ahead market volume 2011 (TWh)*	*Share of power traded in day-ahead market %*
APX Power NL (Amsterdam Power Exchange)	*APXNL*	Netherlands	€	Voluntary	1999	03/01/2000-31/01/2012	51.91	23.13	73.04	117.84	40.4	34%
APX Power UK (Amsterdam Power Exchange)*	*APXUK*	Great Britain	£	Voluntary	2001	27/03/2001-31/01/2012	55.12	44.20	66.77	320.08	10.4	3%
BELPEX (Belgian Power Exchange)	*BELPEX*	Belgium	€	Voluntary	2006	22/11/2006-31/01/2012	49.37	11.26	206.10	86.49	12.4	14%
EPEXSpot (European Power Exchange)	*EPEXDE*	Germany	€	Voluntary	2005	08/02/2005-31/12/2012	51.12	13.63	68.30	544.27	224.6	41%
EPEXSpot (European Power Exchange)	*EPEXFR*	France	€	Voluntary	2005	22/04/2005-31/01/2012	48.89	11.26	66.30	478.22	59.7	12%
EPEXSpot (European Power Exchange)	*SWISSIX*	Switzerland	€	Voluntary	2006	12/12/2006-31/01/2012	56.18	12.75	75.95	64.41	12.1	19%
EXAA (Energy Exchange Austria)	*EXAA*	Austria	€	Voluntary	2002	22/03/2002-31/01/2012	51.80	25.30	66.35	68.57	7.6	11%
HTSO (Hellenic Transmission System Operator)	*HTSO*	Greece	€	Mandatory	2005	01/10/2005-31/01/2012	59.36	29.24	117.91	52.92	Not Available	
Ipex (Italian Power Exchange)	*IPEX*	Italy	€	Voluntary	2004	01/04/2004-31/01/2012	72.23	53.80	98.07	328.09	180.4	55%
Nord Pool Spot	*NORDPOOL*	Scandinavia+Estonia	€	Voluntary	1999	01/07/1999-31/01/2012	47.05	5.79	87.43	387.78	288.1	74%
OMIE (Operador del Mercado Ibérico de Energía)	*OMIEES*	Spain	€	Voluntary	1998	02/01/1998-31/01/2012	49.92	15.52	65.31	261.66	185.1	71%
OMIE (Operador del Mercado Ibérico de Energía)	*OMIEPT*	Portugal	€	Voluntary	2007	01/07/2007-31/01/2012	50.45	16.16	67.93	50.51	31.0	61%
OTE (Czech Electricity and Gas Market Operator)	*OTE*	Czech Republic	CZK	Voluntary	2002	01/01/2002-31/01/2012	50.56	17.42	71.69	62.98	10.0	16%
POLPX (Polish Power Exchange)	*POLPX*	Poland	Zt	Voluntary	2000	01/07/2000-31/01/2012	49.61	27.57	71.91	145.70	19.7	14%
SEM-O (Single Electricity Market Operator)	*SEM*	Republic of Ireland and Northern Ireland	€	Mandatory	2007	01/11/2007-31/01/2012	61.75	48.35	102.19	35.10	33.57	96%

**Data refer to APX Power UK Spot.*

Day-ahead price of 2011 are comparable with those of the pre-crisis 2006.

Table 3: Power Exchanges in Europe. Source: Consumption data from ENTSO-E, with the exception of SEM-O data which was provided by EirGrid. All day-ahead volumes and prices are from each respective power exchanges' website, except APXNL price data which was supplied by Bloomberg.

The wholesale spot electricity markets considered in this analysis operate as day-ahead auction markets[4], conducting double-sided multi-unit uniform price sealed bid auctions. In this type of auction, which is held the day-ahead the physical exchange of electricity, buyers and sellers submit to the market operator sealed bids and offers specifying how many units of electricity they are willing to buy/sell at every price, for each of the 24 hours of the following day[5]. The market operator aggregates bids and offers so as to construct 24 demand and supply curves, and determines hourly equilibrium prices and quantities. Since electricity can be generated with a variety of technologies, the equilibrium price, known as system marginal price (SMP), is the price offered by the marginal generation unit required to satisfy demand and it is the uniform price received by all the units called into operation. If, at each location, spot prices were equal to the variable cost of production of the marginal generation unit, electricity prices would differ only by the price of transmission capacity between the locations. Moreover, if an efficient amount of interconnection capacity could be built resulting in no congestion, then transmission prices would tend to zero.

The APX Power UK spot market is the only one in this study that does not operate as a day-ahead auction market, but as a continuous trading market where participants trade both half-hourly and blocks of hours products (in lots of 1 MW of constant flow of electricity) posting their orders on an electronic platform [6]. Trades are cleared continuously and participants get the price they have bid.

Day-ahead markets have opened gradually across Europe since the end of 1990's and are present not only in the countries listed in Table 3, but also in Hungary, Romania, Serbia, Slovakia and Slovenia[7]. Since participation in the day-ahead markets is not compulsory in most countries, the level of liquidity of the different exchanges, as measured by the ratio between volumes traded on the spot market and total consumption, varies considerably. As reported in Table 3, in 2011, the

[4] The term spot market is used to define both the day-ahead market and the real-time market. In Europe, the term spot electricity market is used as a synonym for the day-ahead market (see Weron, 2006, pp.7-8).
[5] For the SEM market only, the market operator holds 48 auctions for each of the 48 half-hours of the following day.
[6] Though APX launched a UK day-ahead market in late 2008, the spot market price represents the reference wholesale price.
[7] Romanian data was not available in a suitable format, while Hungary, Serbia, Slovakia and Slovenia have been excluded from this analysis because their respective markets opened between 2009 and 2010.

most liquid day-ahead markets were Nord Pool Spot (74%), OMIE Spain (71%) and OMIE Portugal (61%) and IPEX (55%), while the least liquid markets included the APX Power UK (3%), EXAA (11%) and EPEXSpot France (12%). There is large variations of wholesale electricity price between countries, with the IPEX market was the most expensive power exchange in 2011 (72.23 €/MWh) and Nord Pool Spot the cheapest (47.05 €/MWh).These differences in spot prices reflect the characteristics of the production mix of the several countries but also the degree of internal competition.

The data used in the study has been constructed using the original hourly and half hourly prices, as quoted by each respective power exchange. The reported market prices have been aggregated to obtain daily arithmetic averages and then transformed into natural logarithms. This is necessary as hourly electricity prices cannot be regarded as a pure time series process, since in day-ahead markets hourly prices are set in 24 different auctions that take place at the same time. This means that the information set used to determine prices is the same for all the auctions, while it differs over days. Therefore in order to perform a time series analysis, the raw data must be aggregated in daily averages (Huisman et al., 2007). The electricity prices that are not quoted in euros (APXUK, OTE, POLPX) have been converted in euro using the daily official exchange rates of European Central Bank as reported at: http://www.ecb.eu/stats/exchange/eurofxref/html/index.en.html.

Descriptive statistics of log daily prices are reported in Table 4. Every price series is analysed using the whole sample available, reported in column 7 of Table 3, with the exception of the POLPX series, for which the observations from 01/07/2000 to 15/10/2002 were eliminated, since the market failed to determine prices for several days of the first two years of operation. The descriptive statistics highlight that log daily electricity prices feature high volatility and non-normality. In particular, it emerges that all series but APXUK, HTSO, POLPX and SEM are leptokurtic; while all series but APXUK, EPEXFR, POLPX and SEM are left-skewed (i.e. low extreme values are more likely to occur than high extreme ones).

4 Empirical Analysis

The empirical evaluation of EU electricity markets integration is carried out using a multi-step analysis. Section 4.1 reports the fractional cointegration analysis that aims at finding evidence of achieved convergence or perfect market integration between the European markets. Section 4.2 provides estimates of time-varying relations for all market pairs to explore ongoing convergence. Section 4.3 employs MGARCH models to measure returns volatility spillovers between national markets.

4.1 Testing for market integration

Cointegration analysis has been used often to assess market integration among electricity markets. The first step in this analysis is therefore to establish whether the price series are individually integrated and if so, of what degree. Table 5 reports the Phillips and Perron (1988) unit root test (PP), the KPSS test of Kwiatkowski et al. (1992), and the Gaussian semi-parametric (GSP) test (Robinson and Henry, 1998) for long memory. The PP tests the null hypothesis H_0: $y_t \sim I(1)$, while the KPSS tests the null of H_0: $y_t \sim I(0)$. Both the tests are carried out using the Barlett kernel and the Newey-West automatic bandwidth selection method. The results of the PP test show that the null hypothesis of unit root can be rejected for all series, while the KPSS test results show that all series except for BELPEX, EPEXDE, EPEXFR and SWISSIX are *I(1).* Contradictory evidence about the order of integration of electricity prices is well documented in the literature. Escribano et al. (2002), Lucia and Schwartz (2002), Knittel and Roberts (2005), Worthington et al. (2005), Higgs (2009) and Bunn and Gianfreda (2010) all find electricity prices to be *I(0)*, while others including De Vany and Walls (1999), Bosco et al. (2010) find electricity prices to be *I(1)*. Long memory and mean reversion are observed by Haldrup and Nielsen (2006), Koopman et al. (2007) and Haldrup et al. (2010). The results of the GSP test in last row of Table 5 clearly indicate that all series display long memory and non-stationarity, since the memory parameters *d* are estimated to lie in the interval [0.5, 1). Given that daily electricity prices feature outlying observations and within-week seasonality, to confirm the robustness of the results, the same unit root and long memory tests were performed also for logarithms of weekly medians[8].

The non-stationarity of price series allows to check whether market integration of the European markets had been achieved. Two markets are said to be perfectly integrated if their price series are cointegrated together with that their difference is statistically equal to zero (De Vany and Walls, 1999). Therefore, for each of the N(N-1)/2 (i.e. 105) pairs of prices the following OLS regression is estimated, using the longest common sample.

$$\ln p_t^i - \ln p_t^j = \alpha + \varepsilon_t \tag{1}$$

Two fractionally integrated series are said to be fractionally cointegrated if the memory parameter of the cointegrating error (d_ε) is estimated to be smaller than those of the parent series (d_i and d_j with $i \neq j$). Perfect integration is achieved if the constant α is not statistically different from zero.

Table 6 reports the results of GSP estimates of the d_ε for all the fractional cointegration relationships estimated, while Table 7 shows the estimates of the α, which represent the log differences between electricity prices. The results in Table 6 highlight that all the 105 pairs of prices are fractionally cointegrated, however from Table 7 it emerges that the null hypothesis of α=0, i.e. perfect integration, is rejected for all market pairs but the pairs APXNL-APXUK, EPEXFR-OMIEES, EPEXDE-OMIEPT, EPEXFR-EXAA, EXAA-OMIEES and EXAA-OMIEPT. Perfect integration can be attributed to cross-border trade only for EPEXFR-OMIEES, since these are the only two countries that directly border. By contrast, for the remaining five cases (APXNL-APXUK, EPEXDE-OMIEPT, EPEXFR-EXAA, EXAA-OMIEES and EXAA-OMIEPT), achieved convergence can be interpreted as the result of the use of the same marginal generation technology combined with a similar degree of competition and common institutional arrangements. Therefore, the majority of European electricity markets are far from being perfectly integrated.

[8] The results are reported in supplementary material.

	APXNL	APXUK	BELPEX	EPEXDE	EPEXFR	EXAA	HTSO	IPEX	NORDPOOL	OMIEES	OMIEPT	OTE	POLPX	SEM	SWISSIX
Mean	3.704	3.713	3.820	3.801	3.825	3.655	4.033	4.198	3.404	3.577	3.843	3.453	3.562	4.052	3.946
Median	3.692	3.712	3.844	3.823	3.831	3.672	4.051	4.214	3.437	3.602	3.850	3.547	3.449	4.068	3.999
Maximum	6.493	5.582	5.750	5.709	6.418	5.181	4.770	4.960	4.904	4.642	4.536	5.004	4.787	4.994	5.192
Minimum	-2.303	2.602	1.818	-2.303	2.253	1.815	3.024	0.191	1.358	0.904	0.904	-3.488	2.799	3.254	2.546
Std. Dev.	0.478	0.437	0.394	0.403	0.393	0.438	0.301	0.260	0.498	0.392	0.357	0.717	0.308	0.285	0.364
Skewness	-0.183	0.392	-0.098	-2.829	0.028	-0.327	-0.263	-2.466	-0.527	-0.398	-1.791	-3.981	0.482	0.002	-0.421
Kurtosis	9.962	2.997	4.143	44.285	4.444	3.651	2.597	30.934	3.455	4.103	12.251	34.145	2.227	2.684	3.172
Jarque-Bera	8934.91	101.61	106.30	184422.40	215.52	127.91	42.29	95952.00	252.79	396.28	6872.57	158586.60	215.75	6.20	57.77
Probability	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.045	0.000
Observations	4412	3963	1897	2549	2476	3603	2314	2862	4598	5143	1676	3683	3395	1492	1877

Table 4: Descriptive statistics of log daily electricity prices computed with Eviews 7.

	APXNL	APXUK	BELPEX	EPEXDE	EPEXFR	EXAA	HTSO	IPEX	NORDPOOL	OMIEES	OMIEPT	OTE	POLPX	SEM	SWISSIX
PP test	-46.335**	-12.539**	-25.535**	-41.085**	-28.649**	-33.181**	-20.15**	-43.378**	-5.306**	-21.673**	-8.277**	-37.704**	-9.252**	-15.044**	-18.414**
Bandwith	44	32	36	39	40	48	33	43	17	40	21	37	40	28	38
KPSS test	2.589**	3.871**	0.362	0.213	0.225	3.494**	0.941**	1.479**	4.392**	3.713**	1.141**	5.554**	5.901**	0.992**	0.305
Bandwith	50	50	33	39	39	45	38	42	53	54	32	42	44	31	33
GSP estimate of d	0.629**	0.696**	0.649**	0.612**	0.653**	0.605**	0.84**	0.696**	0.837**	0.678**	0.832**	0.518*	0.82**	0.84**	0.73**

**, ** denote 5% and 1% level of significance respectively.*
For PP, null hypothesis H_0: series=non stationary. Critical values -3.43 for 1% level of significance and -2.86 for 5% level of significance.
For KPSS, null hypothesis H_0: series= stationary. Critical values 0.739 for 1% level of significance and 0.463 for 5% level of significance.
For GSP, Wald test is performed to test the null hypothesis H_0: d=0.49. X^2 critical value 3.84 for 5% level of significance and 6.64 for 1% level of significance.

Table 5: Unit root and long memory tests on log daily electricity prices. Unit root tests are performed with Eviews 7, GSP test with G@rch 6.

To evaluate whether the process of convergence towards the single market is ongoing, the α parameters are further investigated to check for potential instability over the respective sample periods. For all the fractional cointegration relationships, CUSUM tests suggest that all the α except that of EPEXDE-EXAA are unstable over the respective sample period[9].

4.2 Testing for ongoing convergence

To explore the time-varying behaviour of the several α, state space models are set up for the relationships specified above.

$$\ln p_t^i - \ln p_t^j = \alpha_t + \varepsilon_t \qquad \varepsilon_t \sim N(0, \sigma^2_{\varepsilon}) \tag{2}$$

$$\alpha_t = \alpha_{t-1} + \upsilon_t \qquad \upsilon_t \sim N(0, \sigma^2_{\upsilon}) \tag{3}$$

Where the first equation is known as the signal or measurement equation and the second equation is known as the state or transfer equation. The state equation captures the impact of the unobservable variable α_t, which represents the time-varying factors that determine market integration, i.e. presence of cross-border trade, use of the same marginal generation technology and of a common regulatory framework. In this set up, α_t is assumed to follow a random walk process. The time-varying relationships are estimated via the Kalman filter and smoother algorithm (Kalman, 1960), which is a recursive procedure for calculating the optimal estimator of the state vector α_t using all the information available up to time t. The Kalman filter is made up by the prediction equations, which allows the one-step ahead estimate of the state mean and variance given their initial values, and by the updating equation, which allows for the incorporation of the new information available at time *t* in the estimate of the state vector $\hat{\alpha}_t$ .The smoothing algorithm is a backward recursion that computes optimal estimates of the state vector using the information available after time *t*.

[9] The results are reported in supplementary material.

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORDPOOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
APXNL		0.367 (0.011)	0.294 (0.016)	0.166 (0.014)	0.373 (0.014)	0.341 (0.012)	0.489 (0.015)	0.385 (0.013)	0.395 (0.011)	0.418 (0.011)	0.470 (0.017)	0.372 (0.012)	0.420 (0.012)	0.261 (0.018)	0.404 (0.016)
APXUK			0.326 (0.016)	0.198 (0.014)	0.310 (0.014)	0.332 (0.012)	0.521 (0.015)	0.386 (0.013)	0.557 (0.011)	0.501 (0.011)	0.501 (0.017)	0.396 (0.012)	0.486 (0.012)	0.279 (0.018)	0.433 (0.016)
BELPEX				0.194 (0.016)	0.261 (0.016)	0.309 (0.016)	0.461 (0.016)	0.404 (0.016)	0.477 (0.016)	0.436 (0.016)	0.443 (0.017)	0.300 (0.016)	0.393 (0.016)	0.294 (0.018)	0.344 (0.016)
EPEXDE					0.251 (0.014)	0.016 (0.014)	0.380 (0.015)	0.314 (0.014)	0.380 (0.014)	0.305 (0.014)	0.346 (0.017)	0.271 (0.014)	0.300 (0.014)	0.172 (0.018)	0.274 (0.016)
EPEXFR						0.382 (0.014)	0.514 (0.015)	0.423 (0.014)	0.467 (0.014)	0.398 (0.014)	0.463 (0.017)	0.390 (0.014)	0.388 (0.014)	0.341 (0.018)	0.354 (0.016)
EXAA							0.488 (0.015)	0.398 (0.013)	0.490 (0.012)	0.456 (0.012)	0.482 (0.017)	0.359 (0.012)	0.440 (0.012)	0.299 (0.018)	0.497 (0.016)
HTSO								0.447 (0.015)	0.673 (0.015)	0.505 (0.015)	0.488 (0.017)	0.425 (0.015)	0.536 (0.015)	0.446 (0.018)	0.514 (0.016)
IPEX									0.474 (0.013)	0.412 (0.013)	0.495 (0.017)	0.351 (0.013)	0.347 (0.013)	0.382 (0.018)	0.479 (0.016)
NORDPOOL										0.631 (0.010)	0.651 (0.017)	0.436 (0.012)	0.660 (0.012)	0.542 (0.018)	0.550 (0.016)
OMIEES											0.370 (0.017)	0.403 (0.012)	0.512 (0.012)	0.449 (0.018)	0.510 (0.016)
OMIEPT												0.442 (0.017)	0.544 (0.017)	0.455 (0.018)	0.527 (0.017)
OTE													0.406 (0.012)	0.285 (0.018)	0.427 (0.016)
POLPX														0.364 (0.018)	0.486 (0.016)
SEM															0.408 (0.018)

Table 6: Estimates of the memory parameter d for the residuals of the fractional cointegration relationships. Estimates are carried out with G@rch 6.

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORDPOOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
APXNL		-0.002	0.022	0.074	0.053	0.094	-0.150	-0.372	0.268	0.068	0.038	0.283	0.218	-0.159	-0.104
		(0.005)	(0.003)	(0.005)	(0.004)	(0.004)	(0.008)	(0.006)	(0.008)	(0.006)	(0.007)	(0.01)	(0.007)	(0.005)	(0.004)
APXUK			0.109	0.142	0.121	0.102	-0.081	-0.307	0.183	0.102	0.138	0.308	0.232	-0.053	-0.016
			(0.006)	(0.006)	(0.006)	(0.005)	(0.007)	(0.006)	(0.007)	(0.005)	(0.007)	(0.01)	(0.005)	(0.005)	(0.007)
BELPEX				0.031	-0.007	0.012	-0.213	-0.435	0.164	0.052	0.025	0.054	0.052	-0.174	-0.126
				(0.006)	(0.003)	(0.004)	(0.009)	(0.007)	(0.009)	(0.008)	(0.009)	(0.005)	(0.007)	(0.007)	(0.005)
EPEXDE					-0.021	-0.018	-0.224	-0.432	0.148	-0.014	-0.009	0.109	0.131	-0.198	-0.156
					(0.005)	(0.004)	(0.009)	(0.007)	(0.008)	(0.007)	(0.01)	(0.006)	(0.007)	(0.008)	(0.007)
EPEXFR						0.003	-0.199	-0.414	0.163	0.011	0.036	0.120	0.145	-0.161	-0.117
						(0.004)	(0.009)	(0.006)	(0.008)	(0.007)	(0.009)	(0.006)	(0.007)	(0.007)	(0.004)
EXAA							-0.205	-0.431	0.081	0.000	0.010	0.205	0.130	-0.181	0.137
							(0.008)	(0.005)	(0.007)	(0.005)	(0.008)	(0.009)	(0.006)	(0.006)	(0.005)
HTSO								-0.222	0.351	0.231	0.178	0.300	0.330	-0.047	-0.084
								(0.005)	(0.01)	(0.007)	(0.007)	(0.008)	(0.008)	(0.007)	(0.008)
IPEX									0.579	0.430	0.420	0.583	0.576	0.205	-0.308
									(0.007)	(0.006)	(0.007)	(0.008)	(0.005)	(0.006)	(0.007)
NORDPOOL										-0.081	-0.135	0.125	0.049	-0.298	0.290
										(0.008)	(0.013)	(0.012)	(0.006)	(0.01)	(0.008)
OMIEES											-0.050	0.206	0.130	-0.250	0.175
											(0.002)	(0.011)	(0.006)	(0.007)	(0.008)
OMIEPT												0.026	0.026	-0.219	0.142
												(0.008)	(0.009)	(0.007)	(0.009)
OTE													-0.076	-0.213	0.179
													(0.01)	(0.007)	(0.006)
POLPX														-0.192	0.174
														(0.006)	(0.007)
SEM															-0.051
															(0.007)

Table 7: Estimates of the log differences between electricity prices (α) with standard errors in parenthesis. Estimates are carried out with Eviews 7.

From the visual inspection of the smoothed estimates of the state vectors ($\hat{\alpha}_t$), it is possible to classify the pairwise time-varying relations into four groups according to the degree of convergence displayed. These groups include markets that display: (1) clear evidence of ongoing convergence, i.e. convergence is more frequent than divergence and it becomes quite stable and clear from a given date onwards; (2) mixed evidence of convergence, i.e. convergence periods alternate with divergence periods without a regularity; (3) seasonal convergence, i.e. convergence periods alternate with divergence periods according to a regular pattern; and (4) no convergence. Table 8 reports the classification of market pairs, while Figures 1-4 show some illustrative examples of the behaviour of the smoothed convergence indicators[10].

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORD POOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
APXNL		on-going	mixed	on-going	on-going	on-going	no	no	no	mixed	mixed	on-going	on-going	no	seasonal
APXUK			no	no	no	no	no	no	no	mixed	mixed	on-going	no	no	no
BELPEX				mixed	on-going	mixed	no	no	no	no	no	mixed	mixed	no	no
EPEXDE					mixed	on-going	no	no	no	mixed	mixed	on-going	on-going	no	seasonal
EPEXFR						on-going	no	no	no	mixed	mixed	on-going	on-going	no	mixed
EXAA							no	no	no	mixed	mixed	on-going	on-going	no	seasonal
HTSO								no	no	no	no	no	no	no	no
IPEX									no	no	no	no	no	no	no
NORDPOOL										no	no	on-going	no	no	no
OMIEES											on-going	on-going	no	no	no
OMIEPT												no	no	no	no
OTE													on-going	no	seasonal
POLPX														no	no
SEM															no

Table 8: Summary of results for the convergence analysis.

Market pairs displaying clear evidence of ongoing convergence all belong to the areas of Central-Western and Central-Eastern Europe; 20 pairs (or approximately 19% of pairs) are included in this group. Among them are the market pairs of BELPEX-EPXFR and OMIES-OMIEPT (see Figure 1), for which convergence can be attributed to the introduction of market coupling/splitting projects in 2006 and in 2007 respectively. Cross-border trade and use of same marginal generation technology is the driver of convergence for APXNL-EPEXDE and for EPEXDE-OTE. Ongoing convergence is present

[10] The full set of figures is reported in supplementary material.

also between markets that do not share a common geographical border, such as APXNL-EXXA and APXUK-OTE, but that, in the largest majority of cases, share at least one border with Germany.

Market pairs that show mixed evidence of convergence are 17 (approximately 16%) and include both markets that are directly interconnected, e.g. EPEXFR-SWISSIX, EPEXDE-EPEXFR and markets that are geographically distant, e.g. BELPEX-EXAA and BELPEX-POLPX (see Figure 2). For these latter market pairs, convergence is driven by similarity in the production structure.

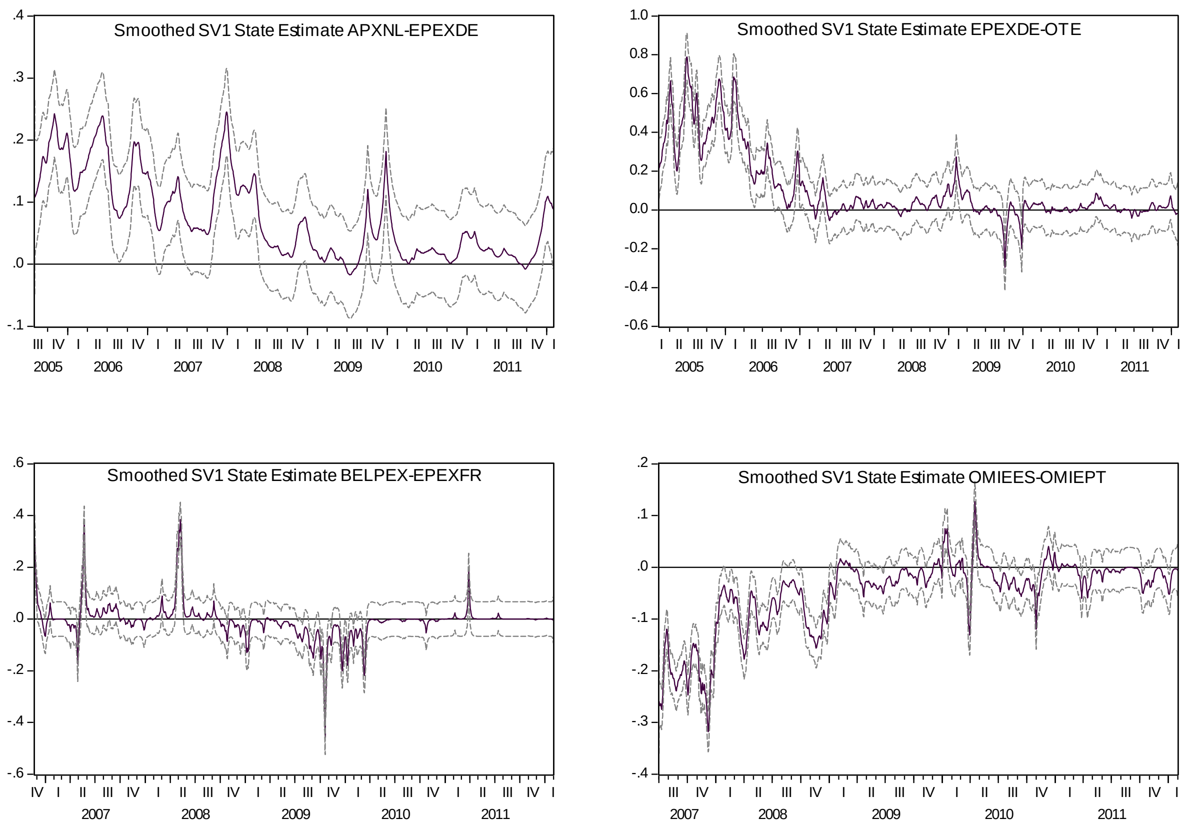

Figure 1: Smoothed integration indicators for European electricity markets pairs displaying evidence of ongoing convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

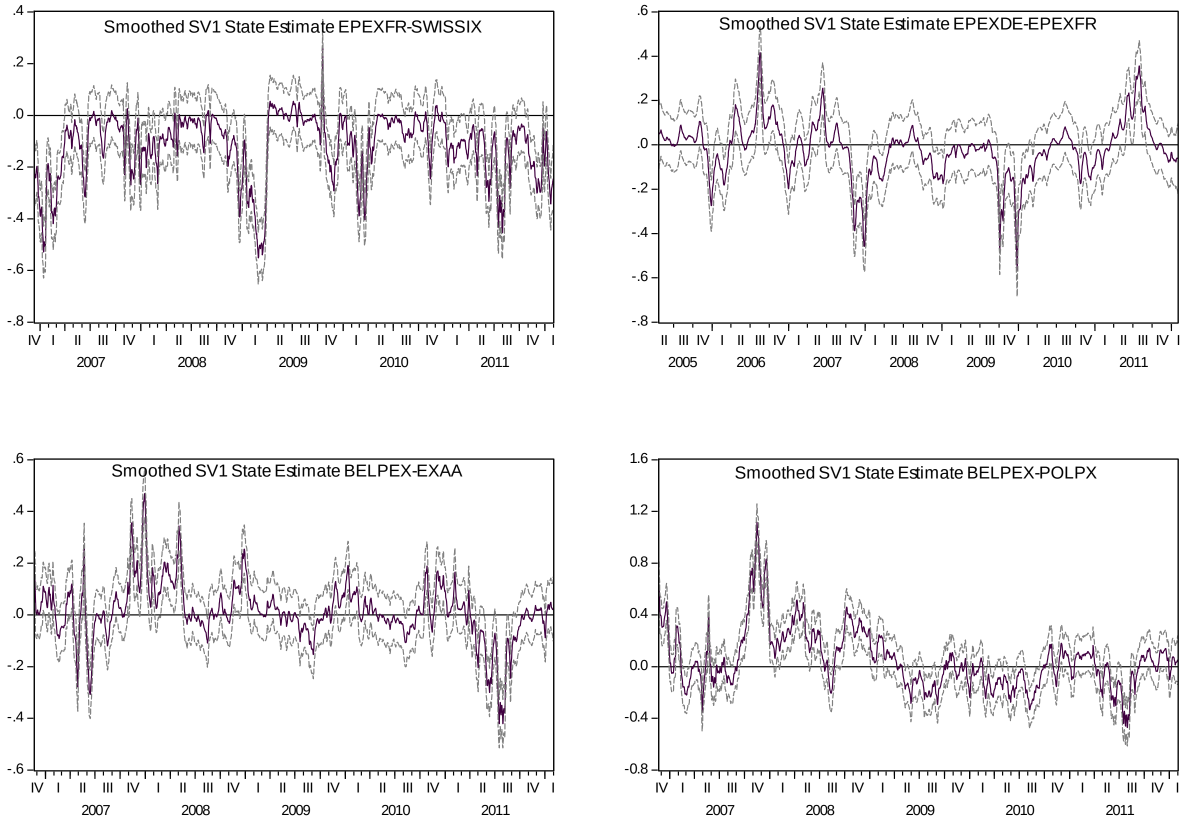

Figure 2: Smoothed integration indicators European electricity market pairs displaying mixed evidence of convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

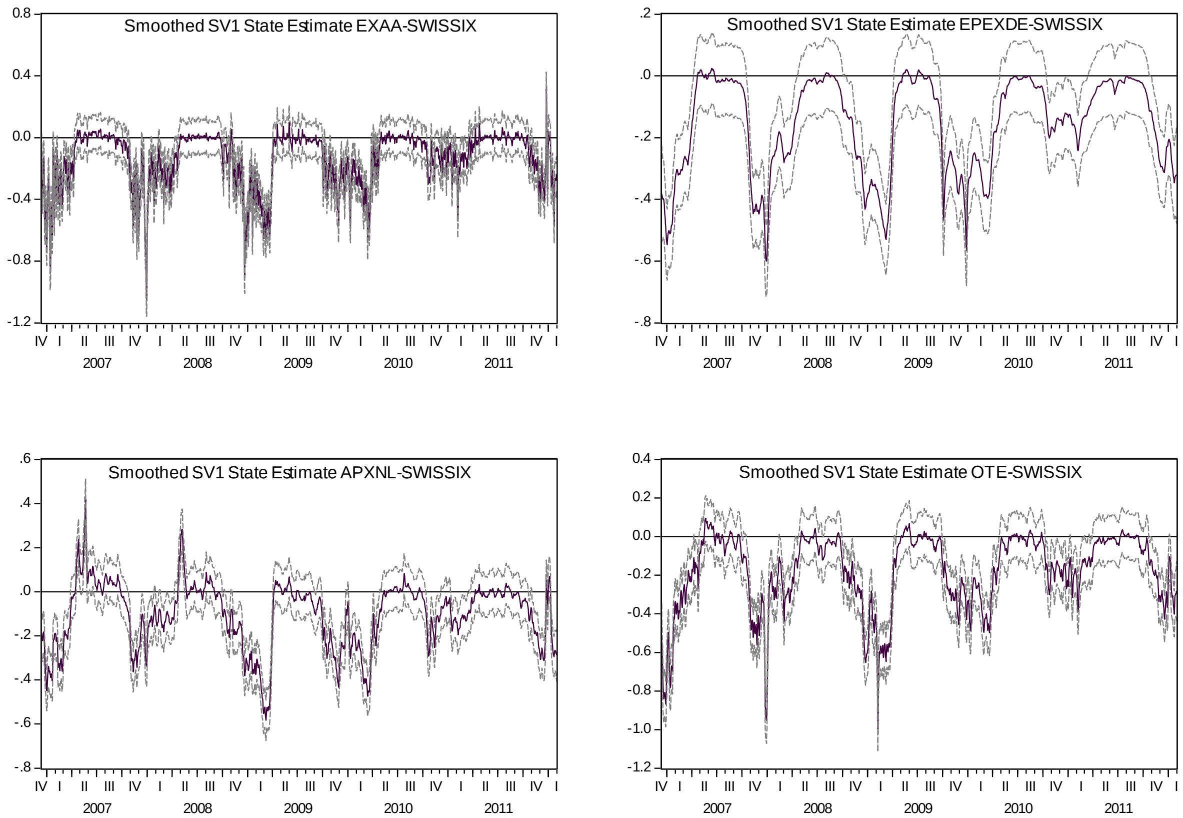

Figure 3: Smoothed integration indicators for European electricity market pairs displaying evidence of seasonal convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

The third group of market pairs, reported in Figure 3, displays a mixed evidence of convergence featuring a seasonal pattern. This is a Swiss phenomenon, since it involves the pairs EXAA-SWISSIX, EPEXDE-SWISSIX, APXNL-SWISSIX and OTE-SWISSIX. During the winter months in Switzerland, electricity demand is the highest, the level of hydro reservoirs is at its lowest and the average price is higher than those of many EU markets (around 63 €/MWh); by contrast in spring and summer the country enjoys an oversupply of cheap hydroelectricity, which pushing the price down (average price is around 47 €/MWh), leads the Swiss price converging to those of other European markets.

Figure 4 includes four representative pairs (of the 64 market pairs) that do not show any evidence of convergence. From the analysis of these pairs, it emerges that the Greek market (HTSO), the Italian market (IPEX) and the Irish one (SEM) never converge to any other market; while NORDPOOL converges only to Czech market OTE. This result is not surprising given that SEM and HTSO are isolated from major markets of continental Europe, and given that the Nordic market, though well interconnected with Germany, features a peculiar production mix with a large predominance of hydropower plants that makes it the least expensive power exchange in Europe. The Italian market, though geographically near to the central Europe markets of France, Switzerland and Austria, does not exhibit evidence of convergence to other markets because its production mix is biased towards fossil fuel plants and natural gas plants turn out to be marginal much more frequently than in other countries[11].

[11] In 2011 combined cycle gas turbine (CCGT) technology was the marginal plant for about 65% of the time.

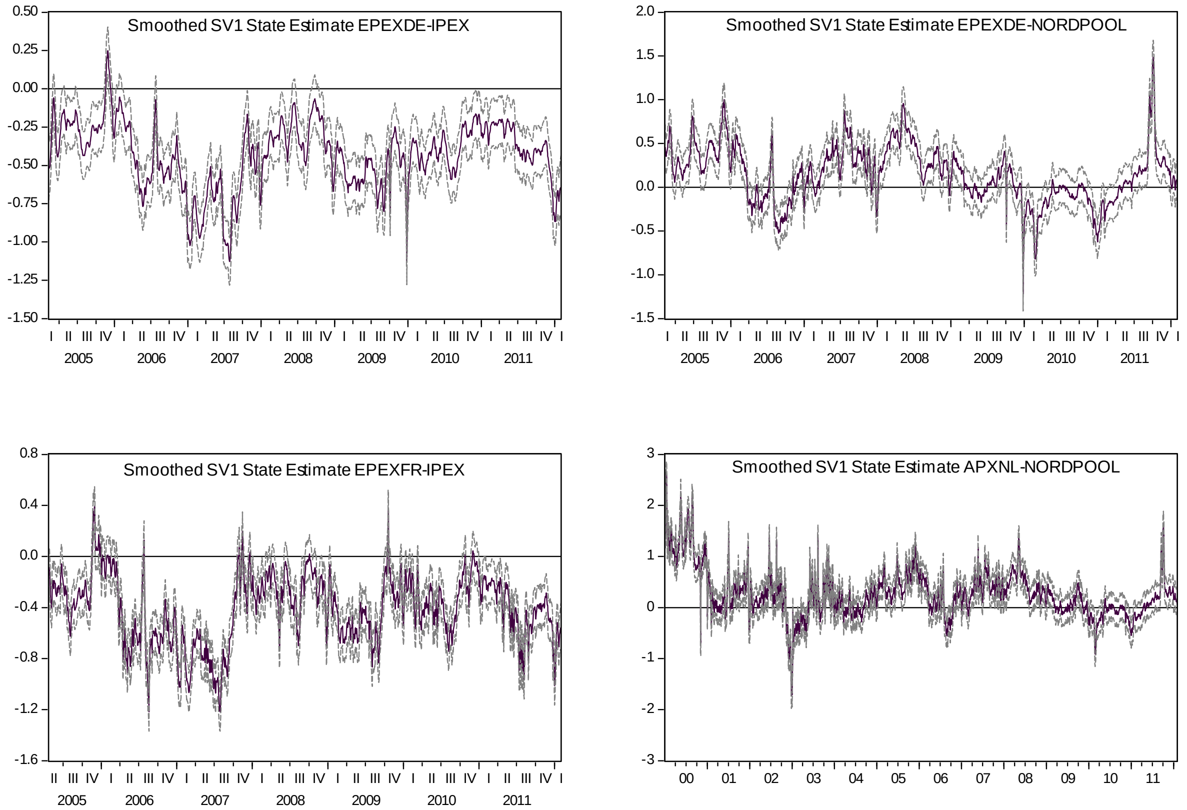

Figure 4: Smoothed integration indicators for European electricity market pairs displaying no evidence of convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

4.3 Returns volatility transmission between European electricity markets

Another method to assess market integration consists of analysing the returns volatility transmission across markets. This can be done by estimating MGARCH models. The decision to model returns volatility rather than price volatility is based on the non-stationarity feature of the price series. As convergence has been shown to be a regional phenomenon, the estimate of MGARCH models for volatility transmission is carried out on markets in the same geographical area. Therefore, the 15 markets are grouped into three areas: North-Western Europe, including Ireland, the UK, the Netherlands, Belgium, France, Germany and Scandinavia; Central-Southern Europe, including Germany, France, Spain, Portugal, Italy, Switzerland, Austria and Greece; Central-Eastern Europe, including Austria, Czech Republic, Germany and Poland.

As a first step, univariate GARCH (1,1) and EGARCH(1,1)[12] are estimated for each electricity market[13]. The GARCH (1,1), introduced by Bollerslev (1986), specifies the conditional variance of ε_t as an ARMA(1,1) process:

$$h_t = \alpha_0 + \alpha_1 \varepsilon_{t-1}^2 + \beta_1 h_{t-1} \tag{4}$$

where h_t is the conditional variance of the error term ε_t , α_1 measures the impact on current volatility of shocks occurring in the previous period and β_1 measures previous period's volatility impact on current volatility.

An EGARCH (1,1) model, originally proposed by Nelson (1991), allows shocks to the price series to have an asymmetric impact on volatility, as defined by the following specification:

$$\ln(h_t) = \alpha_0 + \alpha_1 (\varepsilon_{t-1} / h_{t-1}^{0.5}) + \lambda_1 \left| \varepsilon_{t-1} / h_{t-1}^{0.5} \right| + \beta_1 \ln(h_{t-1}) \tag{5}$$

If the standardised shock in previous period $\varepsilon_{t-1}/h_{t-1}^{0.5}$ is positive, the impact of the shock on the log of conditional variance is given by $\alpha_1 + \lambda_1$. If it $\varepsilon_{t-1}/h_{t-1}^{0.5}$ is negative the impact of a shock on conditional variance is $-\alpha_1 + \lambda_1$.

A comparison of the Akaike Information Criterion (AIC) and the Schwartz Bayesian Criterion (SBC), statistics of each estimation reveals that the EGARCH (1,1) models fit the data best. Therefore, the conditional variances from the univariate EGARCH (1,1) are used to calculate the conditional correlation matrices for constant conditional correlations (CCC) and dynamic conditional correlations (DCC) models. The CCC model of Bollerslev (1990) is defined as:

$$H_t = D_t R D_t = \left(\rho_{ij} \sqrt{h_{iit} h_{jjt}} \right) \tag{6}$$

where

$$D_t = diag(h_{11t}^{1/2} \ldots h_{NNt}^{1/2}) \tag{7}$$

[12] Among the several GARCH models these two have been selected because are the most used in the literature to describe the conditional variance of electricity prices, see among others Escribano et al. (2002), Knittel and Roberts (2005) and Higgs (2009).

[13] The results are reported in supplementary material.

and h_{iit} is, in this case, a univariate EGARCH (1,1) model while $R = (\rho_{ij})$ is a symmetric positive definite matrix, containing the constant conditional correlations ρ_{ij}.

The assumption of constant conditional correlations is then checked via the tests proposed by Tse (2000) and by Engle and Sheppard (2001). Table 9 reports the results of these tests. The null hypothesis of constant correlations is rejected for all the correlations considered.

	North-Western Europe	*Central-South Europe*	*Central-Eastern Europe*
LMC Tse (2000)	262.073 (0.000)	357.171 (0.000)	170.557 (0.000)
Engle and Sheppard (2001) test (5)	498.567 (0.000)	161.184 (0.000)	40.5650 (0.000)
Engle and Sheppard (2001) test (10)	883.196 (0.000)	240.079 (0.000)	136.914 (0.000)

P-value in parenthesis. LMC~X²(N(N-1)/2)) under H_0: CCC model, with N= number of series*
P-values in parenthesis. E-S Test(j)~X²(j+1) under H_0: CCC model

Table 9: Constant conditional correlations tests. Estimations are carried out with G@RCH 6.

The DCC model of Engle (2002) is specified as follows:

$$H_t = D_t R_t D_t \tag{8}$$

where D_t is the same as in Equation 7, while R_t

$$R_t = diag(q_{11t}^{-1/2} \dots q_{NNt}^{-1/2}) Q_t \, diag(q_{11t}^{-1/2} \dots q_{NNt}^{-1/2}) \tag{9}$$

where Q_t is a *NxN* symmetric positive definite matrix $Q_t = (q_{ijt})$ given by:

$$Q_t = (1-\alpha-\beta)\overline{Q} + \alpha u_{t-1} u'_{t-1} + \beta Q_{t-1} \tag{10}$$

where $u_t = (u_{1t}\, u_{2t} \dots u_{Nt})'$ and the elements $u_{it} = \varepsilon_{it} / \sqrt{h_{iit}}$. $\overline{Q}$ is the NxN unconditional variance matrix of standardised residuals u_t and α and β are non-negative scalar parameters satisfying α+β<1.

Given that electricity prices were found to be leptokurtic, returns are assumed to be distributed according to the Student *t* distribution.

The estimations of the DCC models indicate the presence of significant and positive volatility spillovers across Europe, since the estimated correlations are all positive and significant at 1% level.

Table 10 reports some descriptive statistics of the estimated DCC, while Figures 5-7 show the respective plots.

North-Western Europe	***Mean***	***Median***	***Maximum***	***Minimum***	***Std. Dev.***	***Observations***
DCC APXNL-BELPEX	0.917	0.933	0.992	0.530	0.047	1491
DCC APXNL-EPEXDE	0.807	0.827	0.913	0.285	0.067	1491
DCC APXNL-EPEXFR	0.893	0.916	0.954	0.415	0.063	1491
DCC APXNL-NORDPOOL	0.665	0.676	0.845	-0.003	0.064	1491
DCC APXNL-SEM	0.230	0.227	0.616	-0.134	0.081	1491
DCC APXUK-APXNL	0.375	0.379	0.674	-0.098	0.080	1491
DCC APXUK-BELPEX	0.380	0.385	0.686	-0.206	0.081	1491
DCC APXUK-EPEXDE	0.335	0.338	0.595	-0.086	0.073	1491
DCC APXUK-EPEXFR	0.360	0.366	0.717	-0.383	0.083	1491
DCC APXUK-NORDPOOL	0.340	0.340	0.684	-0.138	0.075	1491
DCC APXUK-SEM	0.211	0.211	0.695	-0.148	0.087	1491
DCC BELPEX-SEM	0.221	0.220	0.601	-0.158	0.082	1491
DCC EPEXDE-BELPEX	0.795	0.811	0.901	0.258	0.063	1491
DCC EPEXDE-NORDPOOL	0.659	0.669	0.860	-0.264	0.071	1491
DCC EPEXDE-SEM	0.191	0.190	0.554	-0.289	0.082	1491
DCC EPEXFR-BELPEX	0.971	0.984	0.994	0.496	0.048	1491
DCC EPEXFR-EPEXDE	0.788	0.805	0.888	0.272	0.062	1491
DCC EPEXFR-NORDPOOL	0.631	0.641	0.820	0.143	0.066	1491
DCC EPEXFR-SEM	0.200	0.198	0.552	-0.189	0.079	1491
DCC NORDPOOL-BELPEX	0.655	0.666	0.832	0.027	0.068	1491
DCC NORDPOOL-SEM	0.234	0.231	0.638	-0.041	0.078	1491
Central-Southern Europe	***Mean***	***Median***	***Maximum***	***Minimum***	***Std. Dev.***	***Observations***
DCC EPEXDE-HTSO	0.309	0.313	0.534	0.018	0.083	1675
DCC EPEXDE-IPEX	0.397	0.402	0.727	-0.057	0.130	1675
DCC EPEXDE-OMIEES	0.291	0.298	0.499	-0.025	0.088	1675
DCC EPEXDE-OMIEPT	0.320	0.329	0.539	0.005	0.093	1675
DCC EPEXDE-SWISSIX	0.701	0.734	0.873	0.349	0.111	1675
DCC EPEXFR-EPEXDE	0.742	0.754	0.884	0.392	0.085	1675
DCC EPEXFR-HTSO	0.348	0.350	0.588	0.032	0.094	1675
DCC EPEXFR-IPEX	0.421	0.423	0.758	-0.051	0.128	1675
DCC EPEXFR-OMIEES	0.360	0.359	0.719	0.052	0.105	1675
DCC EPEXFR-OMIEPT	0.384	0.389	0.591	-0.044	0.102	1675
DCC EPEXFR-SWISSIX	0.771	0.788	0.927	0.444	0.109	1675
DCC EXAA-EPEXDE	0.775	0.791	0.885	0.405	0.070	1675
DCC EXAA-EPEXFR	0.800	0.823	0.918	0.473	0.088	1675
DCC EXAA-HTSO	0.372	0.380	0.623	0.014	0.090	1675
DCC EXAA-IPEX	0.465	0.465	0.759	0.082	0.119	1675
DCC EXAA-OMIEES	0.366	0.380	0.638	0.090	0.095	1675
DCC EXAA-OMIEPT	0.398	0.410	0.583	0.046	0.095	1675
DCC EXAA-SWISSIX	0.854	0.897	0.986	0.448	0.131	1675
DCC HTSO-OMIEPT	0.248	0.245	0.521	-0.118	0.095	1675
DCC HTSO-SWISSIX	0.364	0.367	0.613	-0.044	0.096	1675
DCC IPEX-HTSO	0.328	0.332	0.565	-0.004	0.101	1675
DCC IPEX-OMIEPT	0.275	0.279	0.629	-0.127	0.116	1675
DCC IPEX-SWISSIX	0.439	0.436	0.758	-0.081	0.135	1675
DCC OMIEES-HTSO	0.244	0.246	0.502	-0.200	0.105	1675
DCC OMIEES-IPEX	0.276	0.280	0.536	-0.029	0.104	1675
DCC OMIEES-OMIEPT	0.809	0.835	0.963	0.439	0.113	1675
DCC OMIEES-SWISSIX	0.374	0.387	0.579	-0.050	0.094	1675
DCC SWISSIX-OMIEPT	0.401	0.413	0.602	-0.083	0.099	1675
Central-Eastern Europe	***Mean***	***Median***	***Maximum***	***Minimum***	***Std. Dev.***	***Observations***
DCC EPEXDE-OTE	0.633	0.667	0.846	0.209	0.143	2548
DCC EPEXDE-POLPX	0.469	0.472	0.711	0.141	0.097	2548
DCC EXAA-EPEXDE	0.769	0.788	0.885	0.405	0.074	2548
DCC EXAA-OTE	0.737	0.798	0.907	0.289	0.146	2548
DCC EXAA-POLPX	0.537	0.534	0.797	0.138	0.126	2548
DCC POLPX-OTE	0.491	0.498	0.764	0.136	0.142	2548

Table 10: Descriptive statistics of DCC between returns of electricity prices of North-Western Europe, Central-Southern Europe and Central-Eastern Europe. Estimates of DCC are performed with G@RCH 6.

In the North-Western area, APEXNL-BELPEX, APEXNL-EPEXDE, APEXNL-EPEXFR, EPEXDE-BELPEX, EPEXFR-BELPEX, EPEXFR-EPEXDE exhibit strong returns volatility spillovers (with correlations equal or larger than 0.8). The correlations between SEM and all the other markets are the weakest, being always smaller than 0.3. Volatility spillovers between APXUK and the continental markets are rather modest, since correlations average around 0.35. NORPOOL displays an intermediate level of correlation with other European continental markets (around 0.65). These results suggest that within the markets of the North-Western region the best interconnected markets (i.e. those of continental Europe) are also the most integrated, while peripheral markets show weaker interdependencies with the core of Europe.

In Central-Southern Europe, the pairs EPEXDE-SWISSIX, EPEXFR-EPEXDE, EPEXFR-SWISSIX, EXAA-EPEXDE, EXAA-EPEXFR, EXAA-SWISSIX AND OMIEES-OMIEPT feature the strongest level of correlation (on average above 0.7). Moreover, there is a clear seasonal pattern, consisting of high correlation in spring, summer and in the first part of autumn, and of low correlation in winter, between EPEXFR and SWISSIX and between EXAA and SWISSIX, as depicted in Figure 6. Volatility spillovers between the Greek market HTSO, the Spanish OMIEES, the Portuguese OMIEPT and the rest of Central-Southern Europe, are rather weak, since correlations are always below 0.4. IPEX shows slightly stronger correlation with those countries to which it is directly interconnected (around 0.4), namely France, Austria, Switzerland and Greece, than with Spain and Portugal that are geographically distant. These results confirm that even for Central-Southern Europe the best interconnected markets are the most integrated.

In Central-Eastern Europe, EXAA-EPEXDE and EXAA-OTE feature strong volatility spillovers (correlations are above 0.70), while EPEXDE-OTE, EPEXDE-POLPX and POLPX-OTE show an intermediate level of correlation (between 0.5 and 0.63). Moreover, the correlations between EPEXDE-OTE and EXAA-OTE show an upward trend in their behaviour (see Figure 7). As for Central-Western and Central-Southern Europe, here again the level of interconnectivity and geographical proximity play the most important role in explaining volatility transmissions across markets.

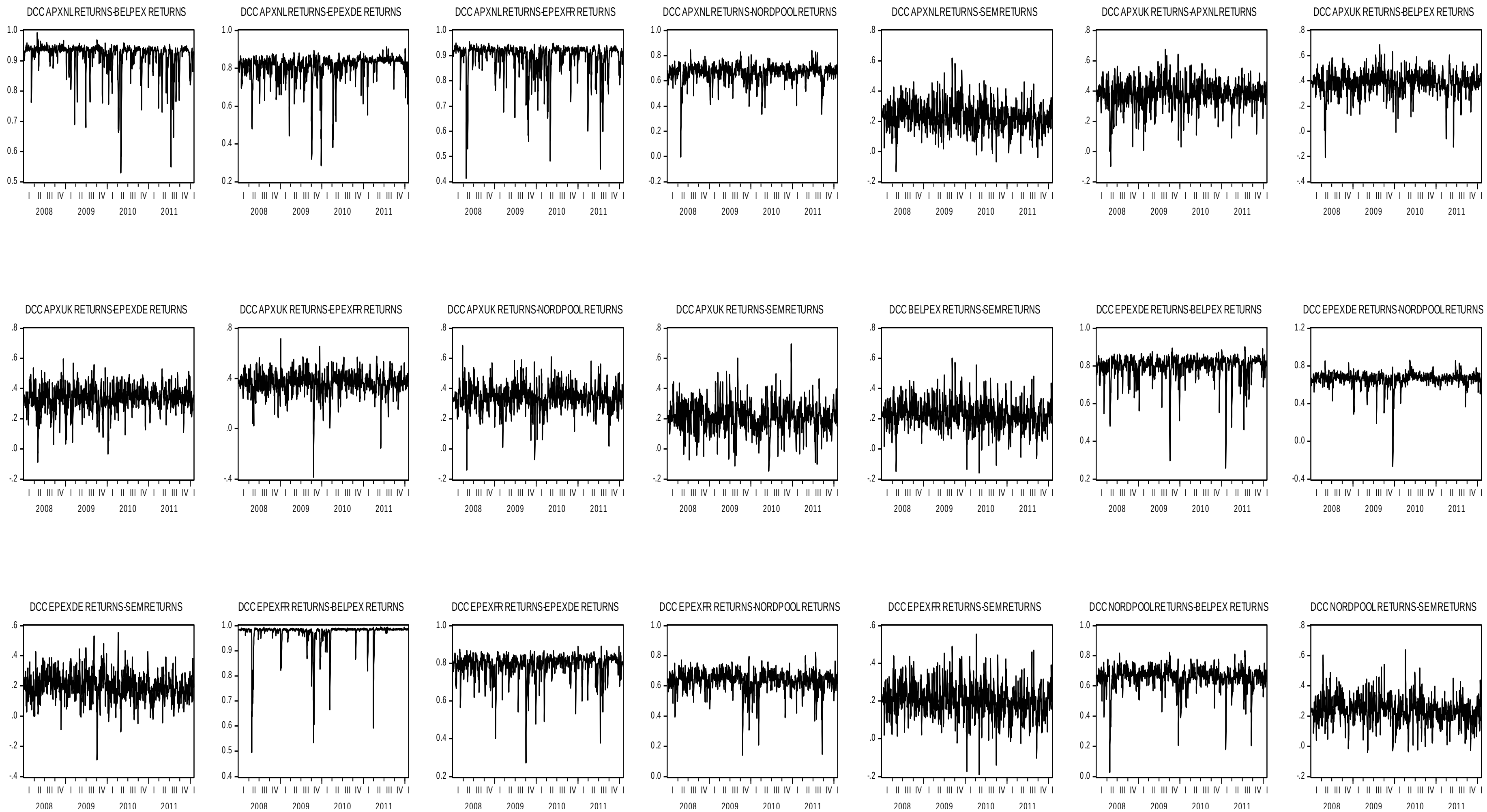

Figure 5: Dynamic conditional correlations between returns of electricity prices of North-Western Europe 2008-2011. Estimates of DCC are performed with G@RCH 6.

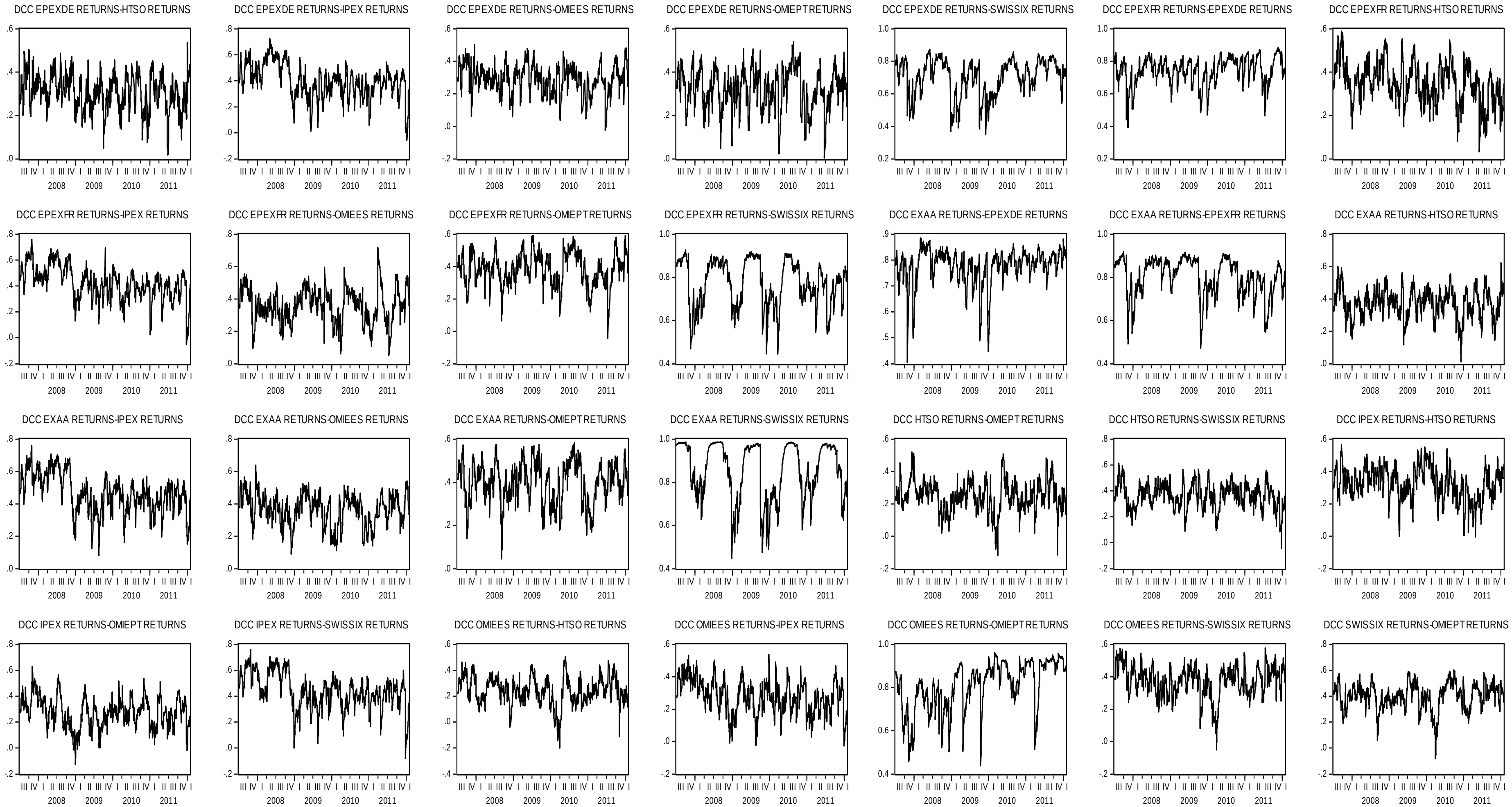

Figure 6: Dynamic conditional correlations between returns of electricity prices of Central-Southern Europe 2007-2011. Estimates of DCC are performed with G@RCH 6

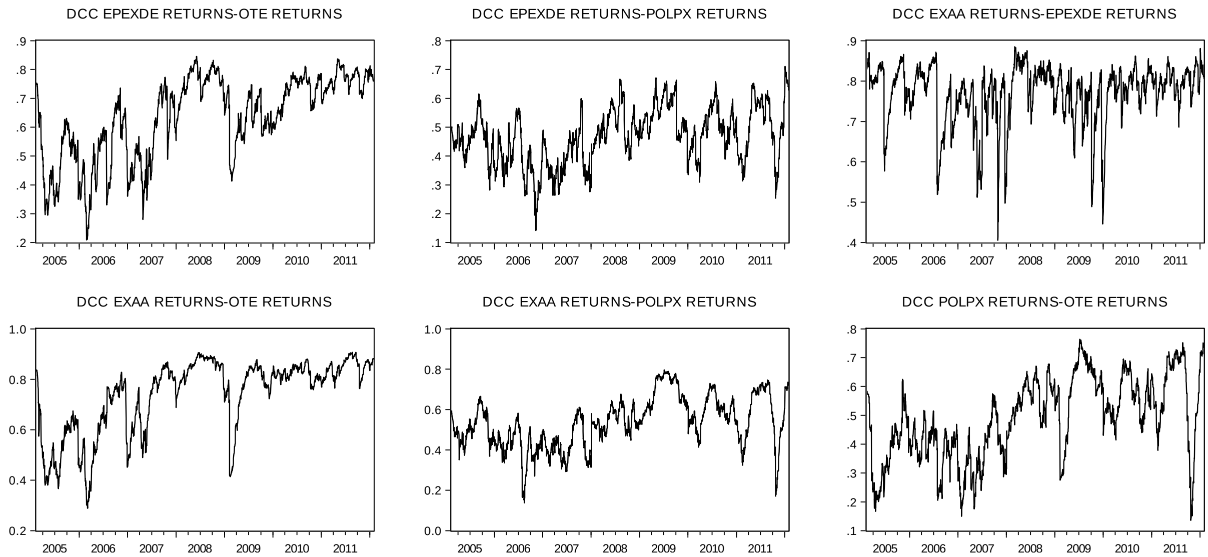

Figure 7: Dynamic conditional correlations between returns of electricity prices of Central-Eastern Europe 2005 - 2011. Estimates of DCC are performed with G@RCH 6.

5 Conclusions

This paper provides a comprehensive investigation of market integration between European electricity markets. The spot market prices generated by the power exchanges of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK are used to test for market integration. Fractional cointegration analysis reveals that only a limited number of markets have reached perfect integration and consequently that full market integration Europe wide is still far away. This finding is consistent with those of Zachmann (2008) and Bosco et al (2010). However, evidence of convergence was found in 41 of the 105 market pairs (39% of market pairs tested), almost all belonging to countries at the core of continental Europe. The remaining 64 market pairs (about 61%) showed no sign of market convergence. In particular, the peripheral electricity markets of Greece, Ireland, Italy and Scandinavia showed little evidence of convergence to other markets. The major determinants of absence of convergence seem to be both the geographical distance from continental Europe markets, as for Greece and Ireland, and marked specificity in the composition of the national electricity plants portfolios, as in case of Italy and Scandinavia.

Positive and significant DCC estimates suggest presence of volatility spillovers across regional markets, namely North-Western Europe, Central-Southern Europe and Central-Eastern Europe. Analysis of returns volatility spillovers confirmed that the level of interconnectivity and geographical proximity play the most important roles in explaining volatility transmissions across regional markets and hence market integration.

Overall, the findings highlight that the policy measures undertaken by the European Commission have been only partially successful in delivering the internal electricity market. The most important challenges ahead are the complete diffusion of market coupling to manage cross-border congestions efficiently, and a more effective oversight activity by energy regulators to increase competition, especially for markets poorly interconnected with their neighbours. Moreover, over a longer time horizon, the European Commission must ensure the development of new interconnection capacity, since this is crucial not only to eliminate bottlenecks that prevent price convergence, but also, and more importantly, to guarantee a secure and sustainable electricity supply to all European consumers.

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