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Reassessing the integration of European electricity markets: A fractional cointegration analysis☆

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ABSTRACT

This study extends existing literature on the assessment of electricity market integration in Europe, by developing and testing hypotheses on the convergence of electricity wholesale prices, and adopting a time-varying fractional cointegration analysis. In addition, the potential impacts of some special events that may affect system capacity (new interconnection, market coupling, increase in share of intermittent generation) on spot and forward markets are considered and evaluated. Daily spot prices from February 2000 to March 2013 of nine European electricity spot markets (APX-UK, APX-NL, Belpex, EPEX-FR, EPEX-DE, IPEX, Nordpool, Omel and OTE) and month-ahead prices in four markets (French, British, German and Dutch) from November 2007 to December 2012 are investigated. Results show that unit root tests, which are generally used in the literature to test market integration, are inadequate for assessing electricity spot market convergence, because spot prices are found to be fractionally integrated and mean-reverting time series. Furthermore, spot price behaviour and their association with different markets change over time, reflecting changes in the EU electrical system. One-month-ahead prices, by contrast, were found to have become more resilient to shocks and to follow more stable trends.

1. Introduction

The present study aims to assess whether liberalised European electricity wholesale markets are increasingly associated and converging to a single price. Empirical evidence is important since the integration of European electricity markets has been in process for many years and was planned to be completed by 2014 (European Commission, 2012a). The first step towards a pan-European liberalised wholesale market was taken in 1996 with *EU Directive 96/92/EC*, which defined common rules for the generation, transmission and distribution of electricity and aimed at creating an efficient supranational European market (Gebhardt and Höffler, 2007). Subsequent electricity market directives (e.g. *2003/54/EC* and *2009/72/EC*) have also addressed emission targets for the electricity sector and specified paths to integrate renewable energy. In the last decade, cross-border transmission has been fostered through energy transactions at power exchanges and electricity markets have been joined via interconnectors, such as the NorNed linking Norway and The Netherlands. Market coupling initiatives attempt to optimise the usage of interconnector capacity and to ensure that electricity flows from low to high price areas. Yet, in the last quarter of 2012, the European Commission claimed that a pan-European market for electricity had been delayed, because member states had been slow in adjusting their legislation and most energy policies remained centred on national interests (European Commission, 2012a). Since decisions on electricity mixes and system capacity are made by individual states, they may conflict with the aims of competitive prices and security of supply in connected markets. In this context, an assessment of the speed of mean reversion of wholesale prices towards a common price is informative for regulators and policy-makers, both locally and regionally, because it indicates how quickly and flexibly the supply side reacts to unexpected events (Bosco et al., 2006). This study investigates the speed of mean reversion and convergence of electricity prices in nine European spot markets and four one-month-ahead markets. In contrast to previous literature, it allows for associations between markets to be time-varying, in the sense that the model specification can vary over time. It also analyses how specific events that may have an impact on electricity generation and cross-border transmission capacity in one market may intervene in the process of electricity market integration.

This article is divided into six parts. In the next section, the literature on electricity market integration is reviewed. Section 3 sets the hypotheses to be tested and identifies special events that are likely to affect European electricity wholesale prices and, consequently, may have an impact on their co-movement. The fourth section describes the method that is adopted to model the long run dynamics of electricity prices in the study, which is reported in Section 5. Finally, Section 6 summarises the findings and concludes the paper.

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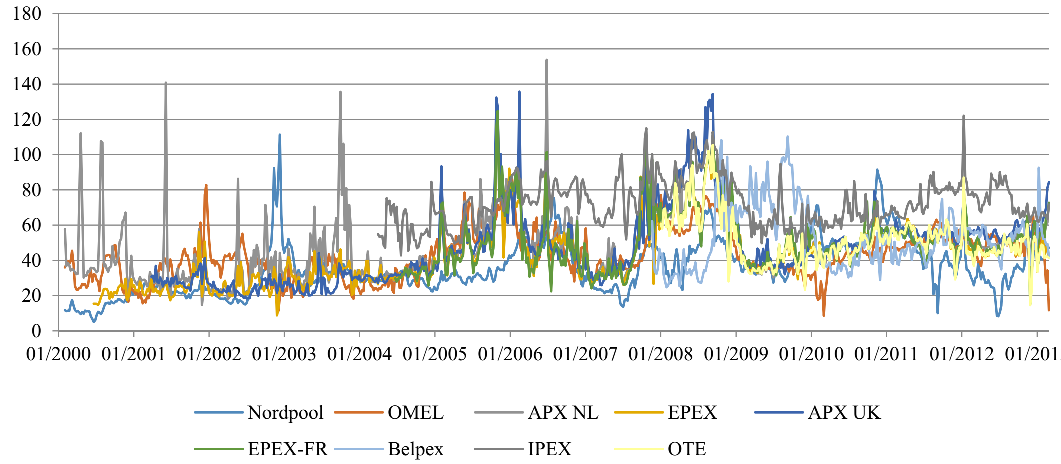

Fig. 1. Week-daily electricity spot price series in €/MWh from 28.02.2000 to 29.03.2013.

2. Assessments of electricity market integration

Most literature on electricity market integration used the Law of One Price (Fetter, 1924) as the theoretical foundation for determining whether two geographic regions, in which a well-defined product is traded, comprise a single market. Accordingly, cointegration analysis (Johansen, 1988, 1991) became the most used econometric method for assessing market integration (used for example by: Böckers and Heimeshoff, 2012; Bosco et al., 2010; Bunn and Gianfreda, 2010; Balaguer, 2011; Kalantzis and Milonas, 2010; Nitsch et al., 2010). Among cointegration studies of electricity prices, Robinson (2007, 2008) focused on retail data from 1978 to 2003 for ten European countries (Denmark, Finland, France, Germany, Greece, Ireland, Italy, Portugal, Spain and the UK), and concluded that electricity prices in these countries had converged. However, this method requires the time series to follow a trend, and as such, may be too restrictive when investigating the time series behaviour of electricity spot prices which have often been described as stationary or mean-reverting processes (Karakatsani and Bunn, 2008). In fact, the suitability of this method for the analysis of electricity prices was already questioned in one of the early studies of market integration, when Boissellau (2004) analysed six European spot electricity markets in 2002, and observed that most price series were stationary, thus concluding that the nature of the data did not allow for testing long run integration. Subsequently, Armstrong and Galli (2005) examined the four main electricity day-ahead wholesale markets in the Eurozone with common borders and similar price-setting processes (France, Germany, The Netherlands and Spain), and found that the average price difference decreased between January 2002 and December 2004 in almost all pairs of markets, but more so during peak periods of demand. Consequently, they inferred that prices in the main continental European markets were converging. Nevertheless, Zachmann (2008) showed that by mid-2006, market integration of eleven European markets (Austria, the Czech Republic, East Denmark West Denmark, France, Germany, Netherlands, Poland, Spain, Sweden and the UK) had not been attained.

Overall, there are indications of price convergence in subsets of markets. For example, the studies of De Jonghe et al. (2008) and Nitsch et al. (2010) concerning the effect of market coupling on day-ahead prices in Belgium, France and The Netherlands, found a sharp decrease in price differences after the event, which took place in November 2006. Bosco et al. (2010) also concluded that week-daily average prices in the German and French markets were integrated. Moreover, Bunn and Gianfreda (2010), who analysed price levels and volatilities via cointegration analysis, causality tests and impulse-response models, found evidence of increasing market integration between Germany, France, Spain, The Netherlands and the UK. Yet, they rejected their hypothesis of higher integration in the forward market than in the spot market. In addition, Huisman and Kilic (2013), when using regime switching models to capture changes between 2003 and 2010, observed a decrease in the impact of price spikes and volatility, and also noted the similarity in the parameter estimates of the Belgian, Dutch, French, German and Nordic models of day-ahead prices. Yet, a study of six

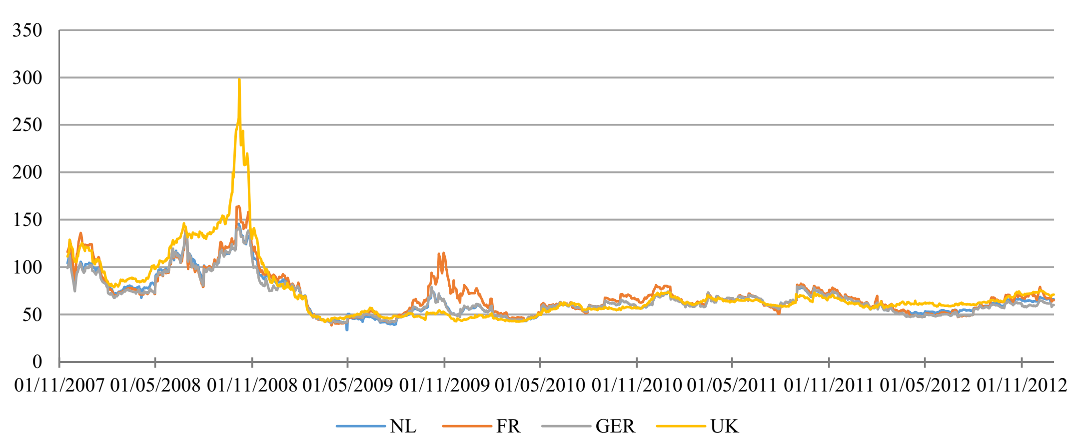

Fig. 2. Week-daily electricity forward prices in €/MWh from November 2007 to December 2012.

Table 1
Electricity spot prices from February 2006 to December 2012.

	Mean	Median	Max.	Min.	Std. dev.	Skew.	Kurt.	PP	KPSS	ELW	FELW	Obs.
APX_NL	48.16	45.56	191.81	2.05	20.027	1.593	7.886	−21.099**	1.515**	.547 [.546; .549]	.550 [.548; .551]	3415
APX_UK	47.28	44.27	184.74	16.27	21.633	1.573	6.881	−9.822**	2.458**	.639 [.637; .640]	.627 [.625; .629]	3113
BELPEX	52.92	49.81	128.68	15. 11	18.419	1.009	3.996	−6.521**	0.324	.662 [.659; .665]	.650 [.647; .653]	1376
EPEX-DE	42.91	40.95	145.97	3.47	17.606	1.094	5.256	−11.060**	3.295**	.600 [.598; .602]	.586 [.585; .588]	3315
EPEX-FR	51.57	48.69	154.76	7.11	18.025	1.258	5.410	−11.144**	0.246	.659 [.657; .661]	.672 [.670; .674]	2267
IPEX	72.62	71.06	136.67	27.51	13.879	0.480	3.605	−12.795**	0.456	.648 [.646; .650]	.663 [.661; .665]	2326
Nordpool	35.44	32.82	114.81	4.76	15.140	0.964	4.772	−4.658**	2.360**	.857 [.855; .858]	.853 [.851; .854]	3415
OMEL	42.95	41.58	103.76	0.79	14.315	0.435	3.218	−8.016**	1.507**	.717 [.715; .719]	.726 [.724; .728]	3415
OTE	51.33	49.12	120.07	−13.39	14.906	1.098	5.547	−8.581**	0.877**	.705 [.702; .708]	.656 [.653; .660]	1349

*, ** denote a 5% and 1% levels of significance, respectively. For the PP test, the null hypothesis is H_0: y_t has a trend. Critical values are −3.43 for a 1% significance level and −2.86 for a 5% significance level. For KPSS, the null hypothesis is H_0: y_t is stationary. Critical values are 0.739 for a 1% significance level and 0.463 for a 5% significance level.

European spot and forward markets in the period between 2005 and 2010 (Lindström and Regland, 2012) concluded that integration was only partial, therefore supporting the findings of Balaguer (2011), who examined the period between 2003 and 2009, and showed that, while wholesale electricity markets in Denmark and Sweden were highly integrated, prices in France, Germany and Italy diverged.

In this context, three recent studies explicitly question integration in European wholesale electricity markets. Pellini (2012) used fractional cointegration to assess the convergence of 15 European spot markets, and determined that the integration of European markets still has a long way to go. In a similar vein, Autran (2012) concluded that, despite signs of regional convergence, market integration of the Belgian, Dutch, French and German spot and future markets had not been achieved in the period between 2006 and 2011. In contrast to previous studies, the latter conclusion is based on a jump diffusion model with time varying estimates, and the author observed a "*stepwise*" convergence, which might be explained by market coupling. More recently, Castagneto-Gissey et al. (2014) explored time-varying interactions among 13 European electricity markets between 2007 and 2012 using Granger-causal networks, and found that a peak in connectivity concurred with the implementation of the Third Energy Package. Furthermore, they observed that market coupling and interconnector commissioning increased the association between markets, however they agreed with Pellini's (2012) conclusion that electricity market integration remains to be achieved.

All in all, the literature suggests that there are variations in how electricity markets might be associated within the EU, and reinforces the need for further examining integration within a time-varying framework that explores the potential impact of special events. It is striking that most studies have used models with fixed parameters, which cannot capture contextual changes. Some authors (Bunn and Gianfreda, 2010; Huisman and Kilic, 2013) allowed for changes in a yearly basis, but may have been unable to identify special events within the whole period studied since they assessed convergence for each year in their study. The present study attempts to overcome some of the limitations in the literature by allowing the time series to vary between mean reversion and non-stationarity. Furthermore, the time-varying framework, which is adopted, enables the assessment of the possible effects of special events on electricity price convergence.

3. Hypotheses

Central to the present study are the long run price dynamics of evolving EU electricity markets, which can be screened for changes. Following the objectives of the directives on liberalisation and integration, resilience and flexibility should have increased, therefore:

H1. As liberalisation evolves, the ability of EU electricity markets to overcome supply and demand shocks more quickly increases.

Whenever demand surpasses the available transmission capacity, price convergence is inhibited, and two separate pricing areas are likely to prevail (Belpex, 2013). Given the increasing interconnectivity and the gradual implementation of EU directives, which ultimately prescribe a pan-European market, electricity prices in markets subject to these policies should converge:

H2a. EU electricity markets are increasingly integrated.

In comparison with spot and intra-day markets, forward and future contracts are subject to less uncertainty. They are less exposed to the impact of extreme weather conditions or unplanned power plant failures. Moreover, they trade base-load capacity, which is more stable and therefore predictable. Consequently, European electricity forward markets are likely to display stronger (more persistent) cointegrating relationships than their respective spot markets. Following Bunn and Gianfreda (2010), we also test:

H2b. Greater cointegration is observed in electricity forward prices when compared to prices in the respective spot markets.

Recent market coupling initiatives aim to maximise the total economic surplus of all participants: cheaper electricity generation in one electricity market can meet demand and reduce prices in a connected market, therefore supply fluctuations can be balanced (Belpex, 2012). Increased price resilience is expected after market coupling and greater interconnector capacity, at least in those markets which are directly coupled or interconnected. Consequently:

H3a. The speed of mean reversion after a market connecting event is faster than the mean reverting speed of the price series before the event.

Table 2
One-month forward electricity prices from November 2007 to December 2012.

	Mean	Median	Max.	Min.	Std. dev.	Skew.	Kurt.	PP	KPSS	ELW	FELW	Obs.
FR	70.54	66.25	164.25	38.50	22.16	1.43	5.21	−3.093*	1.3024**	0.886 [.792;.970]	0.925 [.831;1.019]	1337
GB	72.22	61.92	298.20	42.07	32.73	2.69	12.45	−2.528	1.248**	1.085 [.991;1.179]	1.152 [1.058;1.246]	1337
GER	66.15	60.95	141.50	40.90	19.34	1.50	5.20	−2.661	1.333**	0.888 [.794;.972]	0.922 [.828; 1.016]	1337
NL	67.24	61.80	145.60	33.60	19.95	1.36	4.66	−2.492	1.332**	0.932 [.838;1.026]	0.986 [.892;1.080]	1337

*, ** denote a 5% and 1% level of significance, respectively. For the PP test, the null hypothesis is H_0: y_t has a trend. Critical values are −3.43 for a 1% significance level and −2.86 for a 5% significance level. For KPSS, the null hypothesis is H_0: y_t is stationary. Critical values are 0.739 for a 1% significance level and 0.463 for a 5% significance leve.

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Table 3
Order of integration d for electricity spot price series.

	Mean	Median	Max.	Min.	Std. dev.	Skew.	Kurt.	Obs.
APX-NL	0.658 [.525; .791]	0.662	1.032	0.384	0.094	0.268	4.071	3215
APX-UK	0.583 [.450; .716]	0.611	1.085	0.243	0.130	−0.378	3.100	2913
BELPEX	0.715 [.582; .848]	0.702	1.124	0.382	0.084	0.466	4.070	1176
EPEX-DE	0.643 [.510; .776]	0.659	0.922	0.292	0.101	−0.831	3.423	3115
EPEX-FR	0.736 [.602; .869]	0.733	1.044	0.498	0.084	−0.139	2.997	2067
IPEX	0.677 [.543; .810]	0.651	1.026	0.426	0.111	0.735	3.228	2126
Nordpool	0.913 [.779;1.046]	0.868	1.735	0.591	0.186	1.459	5.450	3215
OMEL	0.724 [.590; .857]	0.733	1.114	0.370	0.124	−0.367	3.522	3215
OTE	0.658 [.524; .791]	0.636	0.966	0.391	0.125	0.846	3.098	1149

Summary statistics for the order of integration d of electricity spot prices, estimated with FELW, window size $w = 200$ and bandwidth $m = 54$.

In contrast, when neighbouring markets are not directly joined, i.e. when they are neither a part of a market coupling initiative nor linked by an interconnector:

H3b. There is no change in the speed of mean reversion of spot prices in markets which are not directly affected by the new connection.

National policies that impact a market's generation capacity may also affect electricity price dynamics in neighbouring markets. In the particular case of Germany's nuclear phase-out act of 2011, base load capacity was reduced after the closure of eight plants between March and August 2011, thus changing the German market's supply stack (increase in the share of intermittent renewables in the electricity mix). Given Germany's geographically central position as well as the size of its market, we hypothesise:

H3c. Germany's decrease in secure capacity has lowered the ability of electricity spot prices to revert to the mean in the German and neighbouring markets.

4. Methods

4.1. Assessing mean reversion: integration and fractional integration

The Phillips and Perron test (PP) and KPSS test (KPSS), which have been proposed by Phillips and Perron (1988) and Kwiatkowski et al. (1992) respectively, can be used to test for a trend or unit root in a time series. While in the former test, the alternative hypothesis of a mean reverting stationary series is tested against the null hypothesis of a trendy time series, in the KPSS test the opposite is assessed. Since electricity spot prices are commonly found to be mean reverting (e.g., Escribano et al., 2002; Knittel and Roberts, 2005; Lucia and Schwartz, 2002; Worthington et al., 2005) and their time series show periods of high and low volatilities with spikes that take some time to dilute (Bunn and Gianfreda, 2010), they are unlikely to have a unit root (be an integrated process of order 1, $I(1)$). Consequently, a less restrictive framework is needed when modelling electricity spot prices.

In this context, fractionally integrated processes are more suitable to model the characteristics of electricity spot price time series, because they are likely to have a temporal dependence that is intermediate between an $I(1)$ (unit root or non-stationary) and an $I(0)$ (stationary) process. By definition, a process X_t is said to be $I(d)$ if its fractional difference, $(1 - L)^d X_t$, is an $I(0)$ process. The fractional difference operator $(1 - L)^d$ is defined as follows:

$$(1-L)^d = \sum_{k=0}^{\infty} \frac{\Gamma(k-d)L^k}{\Gamma(-d)\Gamma(k+1)}, \qquad (1)$$

where d, which is the parameter describing the speed of mean reversion, can take any real value and governs the long run dynamics of an $I(d)$ process. For $-\frac{1}{2}<d<\frac{1}{2}$ the process is stationary and invertible, for $d>\frac{1}{2}$ the process is non-stationary but mean-reverting when $\frac{1}{2}\leq d<1$ (Robinson, 1994).

In testing H1 and assessing the speed of mean reversion, we use the Exact Local Whittle (ELW) estimator by Shimotsu and Phillips (2005) and the semi-parametric two-step Feasible Exact Local Whittle (FELW) estimator by Shimotsu (2006) to estimate the order of integration d of electricity price time series (see Appendix A). The semi-parametric ELW and FELW estimators have been described as robust against misspecification of the short run dynamics of a process (Okimoto and Shimotsu, 2010) and are therefore reliable when

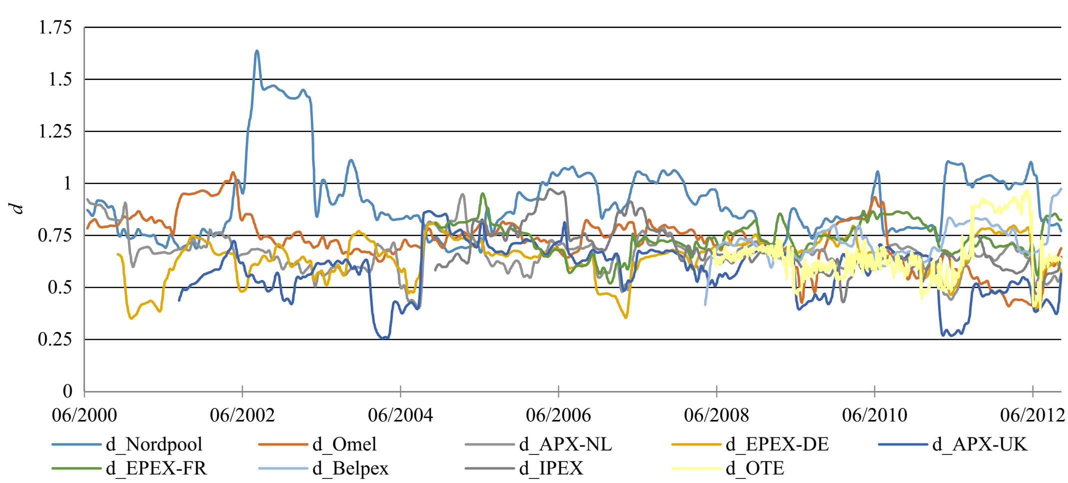

Fig. 3. Order of integration d of week-daily electricity spot prices.

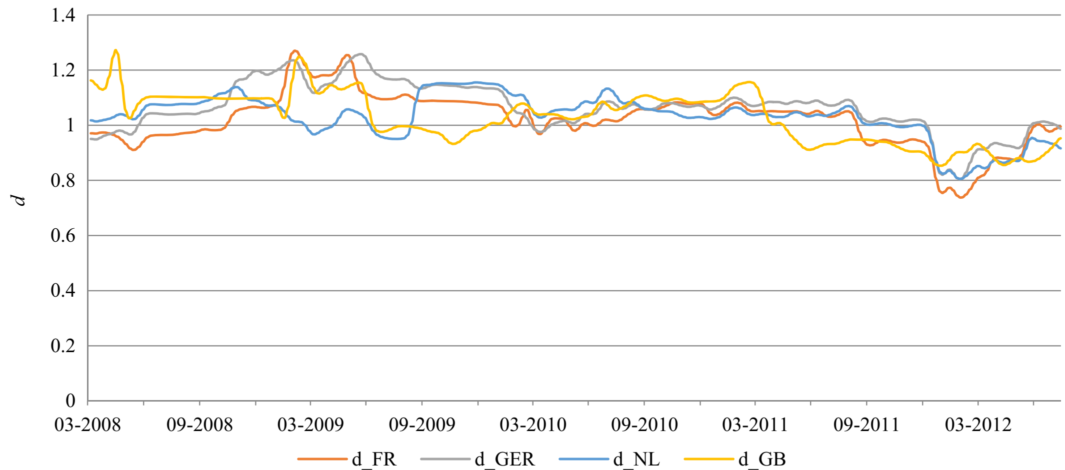

Fig. 4. Order of integration *d* of electricity week-daily month-ahead prices.

assessing whether a time series is fractionally integrated. The FELW is applicable to both stationary ($d < 1/2$) and non-stationary ($d \geq 1/2$) processes, so that there is no need to restrict the interval for d when analysing a time series.

4.2. Assessing price convergence: fractional cointegration

Fractional cointegration (Granger, 1986; Engle and Granger, 1986; Johansen, 1988) is the co-movement of fractionally integrated time series, i.e.: *Two time series x_t and y_t, integrated of order d, are said to be fractionally cointegrated of order (d, b) if the error correction term given by*

$$z_t = y_t - \beta * x_t \tag{2}$$

is fractionally integrated of order b, where $0 < b \leq d$ (Banerjee and Urga, 2005).

Hansen and Johansen's (1999) or Rangvid and Sørensen's (2000) proposals of rolling cointegration procedures for unit root time series have been generalised to test fractionally integrated time series. In rolling tests for cointegration, the sample size is kept the same, but the sample period (window) is allowed to vary (Rangvid and Sørensen, 2000). These tests have been previously employed in different contexts and data, e.g. international inflation rates (Kumar and Okimoto, 2007), spot and forward exchange rates (McMillan, 2005) and commodity futures prices (Fernandez, 2010). It is noteworthy that Pellini (2012) also used fractional cointegration to assess price convergence in EU electricity markets, but relied on a less robust estimator (Geweke and Porter-Hudak, 1983; Robinson and Henry, 1999) rather than the FEWL estimator and did not use a rolling cointegration test. Her analysis focused on the whole time series, thus she did not assess changes over time, which are expected due to special events that might have affected the electricity markets during the period examined.

Table 4
Order of integration *d* for one-month ahead electricity price.

	Mean	Median	Max.	Min.	Std. dev.	Skew.	Kurt.
FR	1.020 [.887; 1.153]	1.040	1.463	0.718	0.099	−0.349	4.397
GB	1.027 [.894; 1.160]	1.036	1.472	0.828	0.096	0.174	2.993
GER	1.064 [.930; 1.197]	1.068	1.275	0.782	0.091	−0.397	3.504
NL	1.032 [.8986; 1.165]	1.040	1.168	0.779	0.081	−0.897	3.734

Summary statistics for the order of integration d of one-month ahead electricity prices, estimated with FELW, window size $w = 200$ and bandwidth $m = 54$.

5. The empirical study

5.1. Data

We analyse week-daily electricity spot and month-ahead price series. Hourly or half-hourly electricity spot prices from APX-NL (The Netherlands), APX-UK (Great Britain, GB), EPEX-DE (Germany), EPEX-FR (France), IPEX (Italy), Nordpool (Denmark, Finland and Sweden; plus Estonia (from 2010), Lithuania (from 2012) and Latvia (from 2013)) OMEL (Spain and Portugal) and OTE (Czech Republic) power exchanges in €/MWh, £/MWh or NOK/MWh have been transformed to mean-average week-daily prices and converted to €/MWh using the daily exchange rate from Datastream (Reuters, 2013). The data sources are either the respective spot markets (the Amsterdam Power Exchange, the European Energy Exchange, Gestore Mercati Energetici, Nordpool, Operador del Mercado Ibérico de Energía or Operator trhu s elektrinou) or Datastream (Reuters, 2013). Different starting dates are considered in order to allow for an investigation of the longest publicly available samples at the time of the data collection. As illustrated Fig. 1, the spot series for APX-NL, Nordpool and OMEL began on 28 February 2000; EEX-DE on 17 July 2000; APX-UK on 25 April 2001; IPEX on 30 April 2004; EPEX-FR on 23 July 2004; and Belpex on 21 December 2006. OTE is the shortest sample, beginning on 29 January 2008. All electricity spot price series end on 29 March 2013. It is noticeable that the time series are volatile with upwards and downwards spikes that often take some time to revert to their previous level. IPEX tends to show higher prices and a larger frequency of periods with similar behaviour. Generally the figure suggests some co-movement, but there are also large spikes or outliers that appear to be unique to a particular market that may affect the assessment of correlation.

The month-ahead price time series, which were obtained from Platts, cover a subset of four interconnected markets in the following countries: France, GB, Germany and The Netherlands. Observations are of weekdays (Mondays to Fridays) in the period between November 2007 and December 2012, thus comprising 1337 data points per forward market. The time series are plotted in Fig. 2, which shows that month-ahead prices are less volatile and move more closely than it can be observed in Fig. 1. The strong bull run of electricity prices in the second quarter of 2008 might be traced back to a price hike of Brent crude oil (European Commission, 2008a). In the third quarter of

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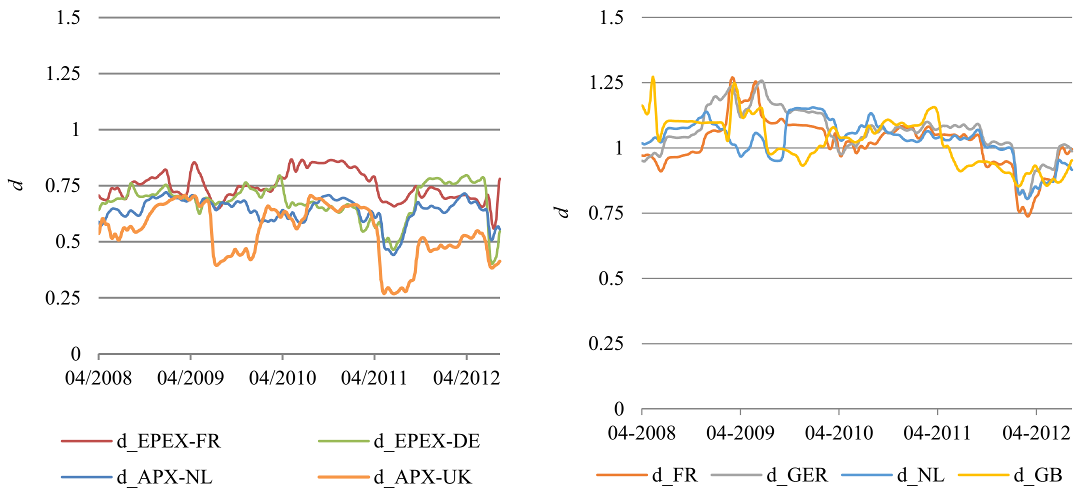


Fig. 5. Comparison of orders of integration d between electricity spot and forward markets between April 2008 and August 2012.

2008 electricity forward prices started to deflate as the economic crisis became more concrete (European Commission, 2008b).

5.2. Analysis procedure

Prior to the analysis of the spot price data, an outlier treatment inspired by Trück et al. (2007) was conducted. Accordingly, outliers were defined as observations which exceeded the rolling window mean average by three standard deviations over a one-month period and were replaced by the mean average. After five iterations, convergence was achieved, so that no other data treatment was required. The forward price time series are well-behaved and therefore the raw data are analysed.

An assessment of the order of integration d is carried out by comparing unit root tests with estimates of the order of fractional integration over the entire sample period. To test H1 and assess mean reversion, we examine the summary statistics and plots of estimated values for d and 95% confidence intervals over the sample period by means of a rolling window estimation using FELW and a window size of 200. Following Lopes and Mendes (2006), the bandwidth m for estimating the FELW is equal to 54.

As a faster speed of mean reversion would imply having a downward trend in estimates of the order of integration d. Ordinary least square regressions (OLS) are estimated for each time series of estimated ds:

$$\hat{d}_t = c + \alpha \hat{d}_{t-1} + \varepsilon_t \tag{3}$$

where: $\hat{d}_t$ is the estimated order of integration, c is the constant or average d, ε_t is the error term and α the slope coefficient. The slope coefficient α should be negative (5% significance level) for H1 to be supported by the data.

A fractional cointegration analysis is conducted to test H2a, whether markets are becoming more integrated, and H2b that integration is greater in the forward markets than in spot markets. The necessary conditions for a time series to be fractionally cointegrated are as follows: (1) having a common order of integration ($0 < d < 1$); and (2) an error correction term, which is obtained by rolling window ordinary least square regressions (OLS), of lower order of integration. In case of H2a, the percentage of days on which the time series was fractionally cointegrated before 21 November 2006, which is when the TLC (Trilateral Market Coupling) and the Belgian power exchange (Belpex) were launched, are compared with the percentage of days on which they were fractionally cointegrated after the date. The forward price data

Table 5
Percentage of time of fractional cointegration and average price dispersion before and after TLC spot markets.

Market pair	Fractional cointegration			Average price dispersion		
	Before TLC	After TLC	p-Value	Before TLC	After TLC	p-Value
APX-UK APX NL	82%	83%	0.334	11.013	7.834	0.00001
Nordpool APX-NL	37.5%	23.2%	–	17.216	15.142	0.0002
Nordpool EPEX-DE	28%	32.6%	0.000	10.528	13.543	–
APX-NL EPEX-DE	78.9%	89.9%	0.000	10.180	3.786	0.00001
EPEX-FR EPEX-DE	85.7%	70%	–	5.779	4.829	0.0041
EPEX-FR OMEL	92.4%	64.8%	–	11.056	10.666	0.2277
EPEX-FR IPEX	43.5%	47.9%	0.042	23.831	22.133	0.0033
EPEX-FR APX-UK	90%	40%	–	8.466	8.985	–

Percentage of time of fractional cointegration between neighbouring or directly interconnected market pairs before and after 21 November 2006. P-value based on a one-sided test for proportions. Average price dispersion before and after 21 November 2006. P-value based on from a one-sided test for proportions.

Table 6
Percentage of time of fractional cointegration and average price dispersion before and after 20 January 2010 forward prices.

	Fractional cointegration			Average price dispersion		
	Before	After	p-Value	Before	After	p-Value
FR_GER	97%	100%	0.000	6.825	2.964	.0001
GER-NL	67%	100%	0.000	2.365	1.384	.0001
NL-GB	65.5%	96.6%	0.000	13.038	3.996	.0001
FR-GB	74.2%	98.7%	0.000	15.325	5.151	.0001

Percentage of time of fractional cointegration between neighbouring or directly interconnected market pairs before and after 20 January 2010. P-value based on a one-sided test for proportions. Average price dispersion before and after 20 January 2010. P-value based on a one-sided test for proportions.

are divided into two series of equal length, the split date is 09.06.2010. One-tailed tests for differences in proportion are used to assess whether or not there is support for increasing integration (i.e. proportion after the special event date greater than the proportion before). Thereafter, another one sided t-test assesses changes in price dispersion. Price dispersion should decrease as convergence increases, i.e. less price dispersion is expected after the event. Convergence for of all markets that are directly interconnected is then graphically analysed: the order of integration d, which is estimated using a rolling window of 200 observations, is plotted for each pair of price series as well as the error correction term for the longest possible common period determined by the shorter series. The plots are smoothed using a HP filter (Hodrick and Prescott, 1980) and a smoothing parameter $\lambda = 250$. When testing H2b, we compare four pairs of spot and forward markets to assess significant differences in the degree of convergence over a common time span, and test if convergence in forward markets is larger than convergence in spot markets.

Variants of H3a–H3c are tested via the Chow (1960) breakpoint test, which is the most commonly used test to assess the presence of a structural break with a known date. One hundred perturbed series, in which a $N(0,1)$ distributed noise is added to the original price series, are generated and their order of integration is estimated using the FEWL based on 260 consecutive observations, corresponding to a period of one year, both before and after the special events. For H3a, a one-tailed t-test of means before and after the event is conducted when the markets were to have been affected by the special event, and tests:

$$H_0: \ d_{after} = d_{before},$$
$$H_1: \ d_{after} < d_{before}.$$

A two tailed t-test is then used for markets that could have been indirectly affected by the special events. That is for H3b, it is tested:

$$H_0: \ d_{after} = d_{before},$$
$$H_1: \ d_{after} \neq d_{before}.$$

In order to test H3c, whether or not Germany's energy transition has lowered the ability of electricity prices to revert to the mean in Germany and in neighbouring markets, we test:

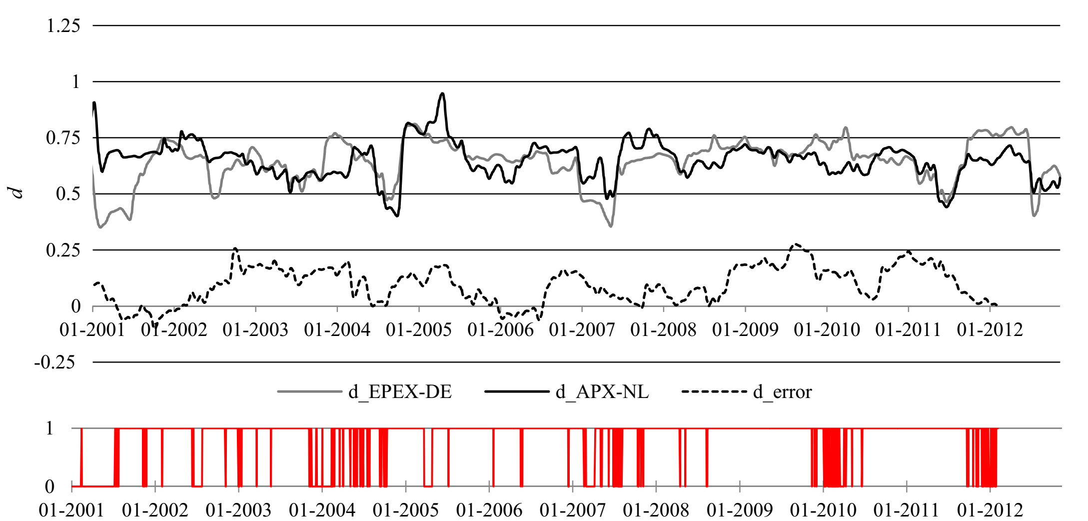
$$H_0: \ d_{after} = d_{before},$$
$$H_1: \ d_{after} > d_{before}.$$

5.3. Empirical results

5.3.1. Electricity spot prices

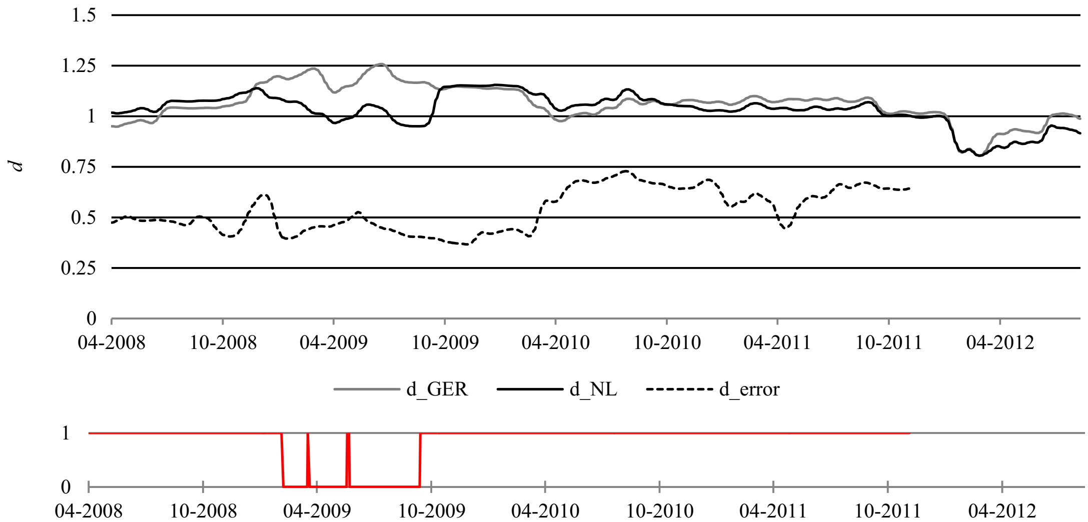
Table 1 summarises the data distribution and electricity price behaviour after the outlier treatment. The second column shows that mean prices range between 35.44€/MWh (Nordpool) and 72.62€/MWh (IPEX); the lowest daily mean average is observed in OTE (−13.39€/MWh) and the highest daily mean average in APX-NL (191.81€/MWh). Standard deviations, as shown in column 6 of Table 1, vary between 13.88€/MWh and 20.02€/MWh with IPEX having the least and APX-NL the most amount of variation. Positive skewed distributions and excess kurtosis are observed in all markets.

5.3.1.1. Integration and fractional integration of electricity spot prices. The Phillips and Perron (1988) unit root test (PP) and the KPSS test of Kwiatkowski et al. (1992) are reported in column nine and ten respectively. According to the former, a unit root is rejected for all price series, thus implying that factional cointegration suits the data and standard cointegration analysis (Johansen, 1988, 1991) is not reliable. The KPSS is less conclusive, as it rejects the hypothesis of stationarity for electricity prices in most spot markets with the exception of Belpex, IPEX and EPEX-FR. Rejections of the opposite null hypotheses by the tests suggest that APX-NL, APX-UK, Nordpool, OMEL and OTE electricity spot prices are neither mean-reverting nor trendy. In fact, similar conflicting evidence has been documented in the literature: Escribano et al. (2002), Lucia and Schwartz (2002), Knittel and Roberts (2005), Worthington et al. (2005) and Bunn and Gianfreda (2010) found electricity prices to be $I(0)$; by contrast, De Vany and Walls (1999) and Bosco et al. (2010) concluded that electricity prices were $I(1)$. A possible



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 6. EPEX-DE & APX-NL — assessment of cointegration.



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 7. German & Dutch one-month-ahead prices — assessment of cointegration.

explanation for this contradiction has been offered by Diebold and Rudebusch (1991) and Sowell (1990), who have shown that the power of standard unit root tests is low when the true time series process is fractionally integrated. Indeed, this explanation tallies with the estimates of the order of integration that are shown in Table 1, where we observe that both the ELW and FELW estimators, (columns 11 and 12) are in the interval (.5; 1), thus supporting the adoption of the fractional cointegration framework in this study.

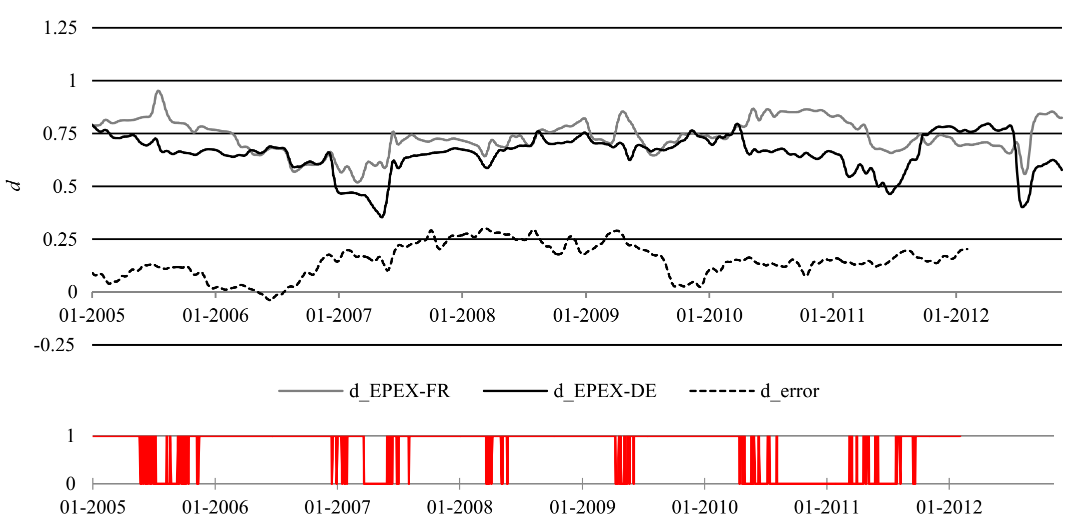
5.3.2. Month-ahead electricity prices

The month-ahead prices are summarised in Table 2, and are reasonably well-behaved. Their mean average are found to be higher than average spot prices, as shown in the second column; they range from 66.15€/MWh in Germany to 72.22€/MWh in GB, and reflect the added risk premium and expectations of generation costs.

5.3.2.1. Integration and fractional integration of electricity forward prices. Estimates of the order of integration range from 0.886 (France) and 1.085 (GB), in the case of the ELW, and between 0.922 (Germany) and 1.152 (GB) when based on the FELW, thus suggesting that month-ahead prices are non-stationary. Columns nine and ten of Table 2 report the statistics of the KPSS and PP unit root tests. They confirm a trend in all electricity forward price series, apart from France, for which there is an apparent contradiction: according to the KPSS test statistics the series is stationary ($I(0)$), while according to the PP test the series has a unit root ($I(1)$). Furthermore, the order of integration d for all price series, based on the ELW and FELW estimators, have overlapping 95% confidence intervals, as shown in columns 11 and 12.

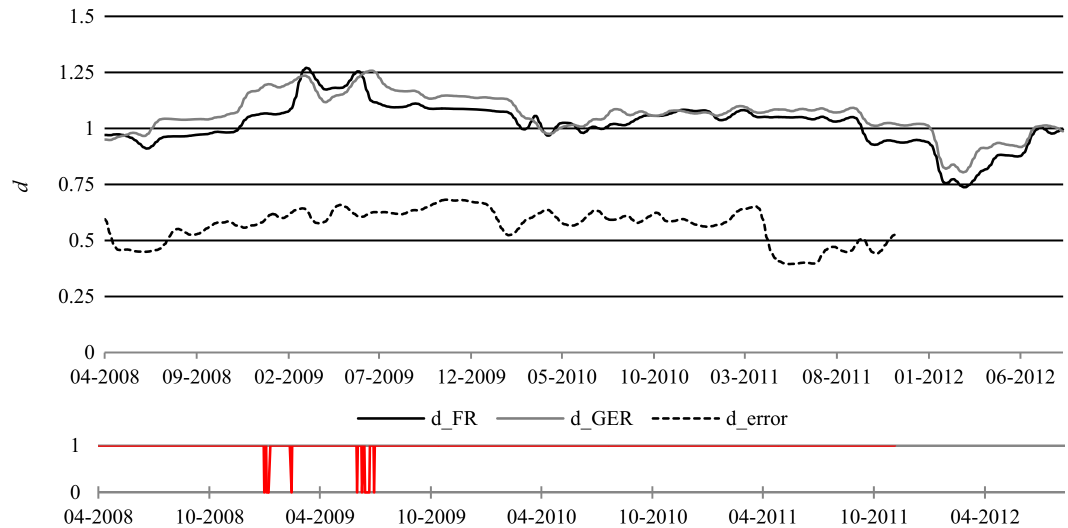
5.3.3. Time varying fractional integration: assessing H1

Table 3 summarises the distributions of the estimated parameter d for each spot price time series, which are plotted in Fig. 3 from the earliest available starting date. The mean of the estimated *ds* is consistent with the reported estimates based on ELW and FELW over the entire sample. For instance in Table 3, the mean of the estimated *ds*, reported in the first column, is equal to 0.715 for Belpex. This is of a similar magnitude as the estimated order of integration obtained over the whole sample (Table 1), which was equal to 0.662 (ELW) or 0.650 (FELW). Furthermore, whole sample estimates are included in the 95% confidence intervals for the mean order of integration d, which are reported



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 8. EPEX-FR and EPEX-DE — assessment of cointegration.

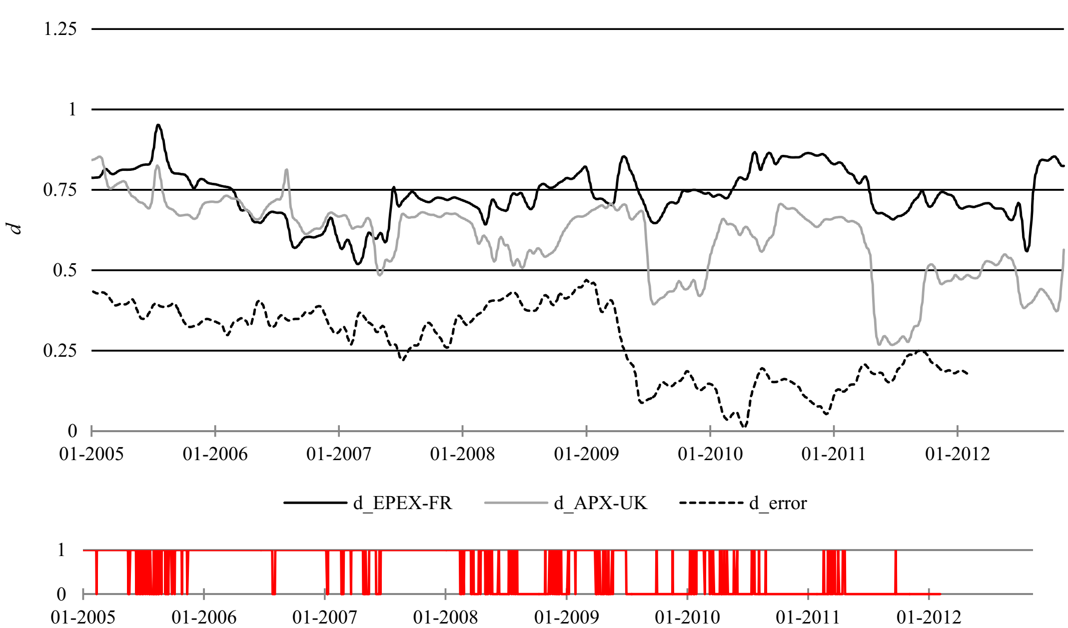


Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 9. German and French one-month ahead prices — assessment of cointegration.

in parentheses in Table 3. Values between 0.5 and 1 mean that spot price series are fractionally integrated but mean-reverting. APX-UK prices have with the lowest mean average estimate for d (0.583), thus showing the fastest speed of reversion to the mean. Such a low value of d could reflect a large share of flexible gas-based generation (46.2% in 2010) in its electricity mix (Eurostat, 2013a), which has shorter ramping times, or, in comparison to other spot markets in the period studied, its shorter settlement periods and gate closure nearer to delivery. Other markets have order of integration varying between 0.643 (EPEX-DE) and 0.913 (Nordpool). The highest value suggests a trend in the time series, which may be explained by the large share of hydro-based capacity, which makes electricity prices in the Nordpool dependent on hydrological conditions (Botterund et al., 2010). For example, the maximum observed value, reported in column 4, is 1.735, which occurred during a 'power drought' in 2002, when Norway witnessed its driest summer in 70 years and available reserve capacity was below critical levels (Dooley, 2002). The minimum order of integration, d, in the fifth column, corresponds to APX-UK (0.243). All markets, except Nordpool, exhibit periods during which the order of integration, d, is below the critical value of 0.5, which are periods when the time series are invertible. But spot markets also show periods during which the estimated order of integration is greater than one, which is indicative of non-stationary behaviour. The exceptions are OTE and EPEX-DE, which have consistently stationary prices. As a whole, estimates of d are similar to those reported by Pellini (2012). Still, there are differences, e.g. for the d estimates in APX-UK and Belpex prices, which could be due to sampling variations since Pellini's (2012) data does not cover the last 10 months in this study.

These findings together with Table 3 and Fig. 3 highlight the time-varying nature of the spot price series. This study's approach to examining electricity market integration in the EU through rolling windows is therefore justified and contributes to the literature.



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 10. EPEX-FR and APX-UK — assessment of cointegration.

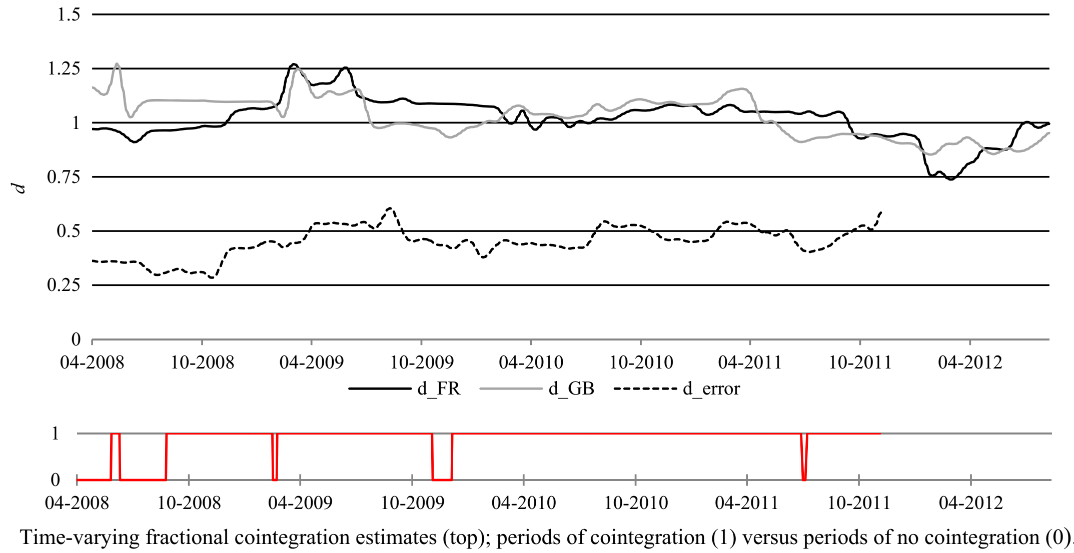


Fig. 11. French and British one-month ahead prices — assessment of cointegration.

Concerning month-ahead prices, the estimates of the order of integration are plotted in Fig. 4 and their distribution is summarised in Table 4. Mean average values (from 1.02 to 1.06) confirm our previous observations based on the whole sample: forward prices in the period studied are non-stationary. It is noteworthy that this finding could be linked to price expectations, which rely on the cost of generation and correlate forward prices with energy commodity prices (coal and gas), as discussed in the literature (e.g. Bloys van Treslong and Huismann, 2010; Douglas and Popova, 2008).

5.3.4. Speed of mean reversion: assessing H1

Fig. 5 shows forward and spot prices during the period from April 2008 to August 2012, when the time series overlap. It indicates that the ability of the electricity spot markets to overcome supply and demand shocks quickly did not increase, because there is no significant negative downward trend in the estimates of the order of integration (Eq. (3)). Hence, there is no support for H1. For forward markets, however, a statistically significant (1% level) downward slope may be seen in Fig. 5, whose estimates range from −0.00012 (France) to −0.0002 (GB). In summary, electricity one-month-ahead markets have become more resilient to shocks, whereas spot day-ahead markets have not.

5.3.5. Time varying fractional cointegration: assessing H2a

Prices in liberalised electricity markets are expected to converge as markets integrate. However, in the spot markets, the cointegrating relationships vary, as summarised in Table 5, in which the percentage of days of fractional cointegration with directly connected market pairs are reported. P-values obtained from tests of differences in proportion are shown in the last column. The periods before and after the trilateral market coupling, which occurred on 21 November 2006, are compared. For four spot markets (Nordpool and APX-NL, EPEX-FR and EPEX-DE, EPEX-FR and OMEL, as well as EPEX-FR and APX-UK), the observed change is not as hypothesised: there was less or no change in convergence. However, for three market pairs (Nordpool and EPEX-DE, APX-NL and EPEX-DE, EPEX-FR and IPEX), we find an increase in convergence at 5% significance level. This result differs from Pellini's (2012) which only supported price convergence in two pairs of markets, (APX-NL and EPEX-DE).

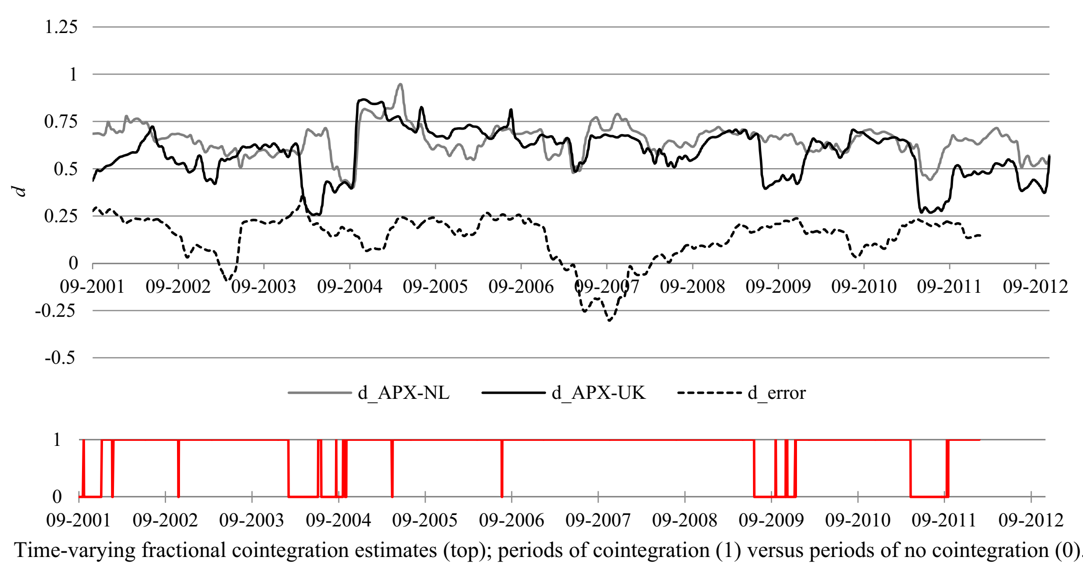


Fig. 12. APX-NL and APX-UK — assessment of cointegration.

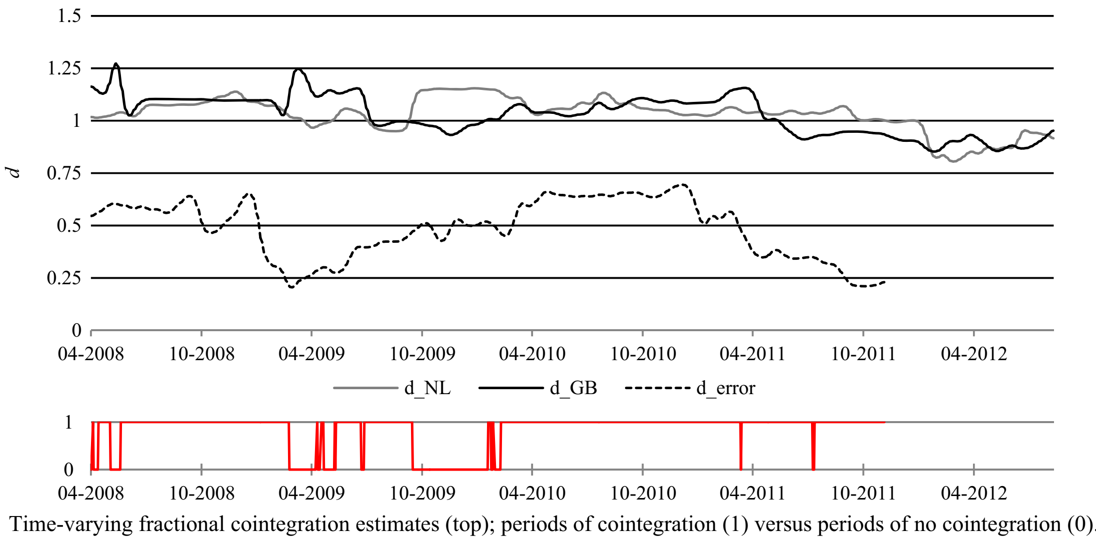


Fig. 13. Dutch and British one-month ahead prices — assessment of cointegration.

Considering average spot price dispersion before and after the TLC, as shown in columns five to seven of Table 5, one would expect price dispersion to decrease with increasing market integration. The p-values, in column seven, confirm lower price dispersions after the TLC for five market pairs (APX-UK and APX-NL, Nordpool and APX-NL, APX-NL and EPEX-DE, EPEX-FR and EPEX-DE as well as EPEX-FR and IPEX). The expectations of cointegrated prices and decreasing price dispersion were supported by (APX-UK, APX-NL), (APX-NL, EPEX-DE) and (EPEX-FR, IPEX). However, for one market pair (EPEX-FR and OMEL) there was no decrease in price dispersion and for two pairs (Nordpool and EPEX-DE; EPEX-FR and APX-UK) an increase was observed. Overall, results are mixed and we lack full support for H2a–H2b, therefore: EU electricity spot markets are not becoming increasingly integrated.

By contrast, when we consider one-month-ahead prices, we find significant increases in convergence, as reported in Table 6. For example, periods of fractional cointegration between the German and Dutch markets increased by 30%. For all market pairs, we find significant decreases in price dispersion, as reported in columns five to seven of Table 6. Hence, price convergence is supported, and H2a is not rejected in the case of forward markets. This may tally with the view that long term capacity auctions enable optimal coupling in forward electricity markets.

The rejection of H2a by some spot markets indicates that there are other factors that influence price convergence and divergence. Figs. 6 to 21 illustrate the time-dependence of the order of integration d for neighbouring electricity spot and forward price series in more detail. The grey and black lines show the smoothed rolling window estimates of the order of integration of the two respective price series, which should not be significantly different. In addition, the dotted line shows the order of integration of the error correction term (z_t of Eq. (2)), which should be lower than those of the original price series for the two markets to be integrated. In the lower part of Figs. 6 to 21, it is indicated when these conditions hold and the two price series are cointegrated, and also when the conditions are violated and cointegration is rejected. We will now consider different pairs of neighbouring countries and assess the impact of specific developments in their electricity markets.

5.3.5.1. Germany and The Netherlands. Fig. 6 shows that, from July 2000 to March 2013, electricity spot prices in EPEX-DE and APX-NL were integrated 84% of the period, and confirms previous observations made by Zachmann (2008) on data from 2002 to 2006. Integration appears to have stabilised over time, except for two periods of accumulated breakdowns during the winter of 2010 and 2012, which were on average colder and characterised by higher residential demand. According to Eurostat (2013b), there were 36 more heating degree days (HDD) in each month of the first quarter of 2010 compared to the same period of 2009.[1] The first two weeks of February 2012 were extremely cold and electricity consumption in the EU-27 grew by 5.1% compared to the same month in the previous year (European Commission, 2010a, 2012b).

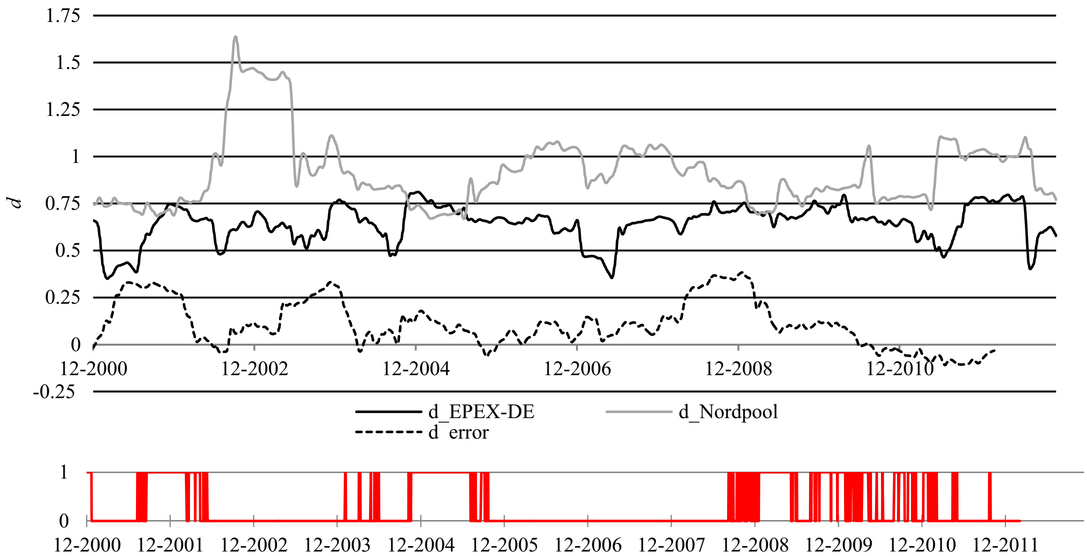
Month-ahead electricity price series were also fractionally cointegrated for 84% of the time between April 2008 and November 2011, although there was a period of divergence in 2009, as shown in Fig. 7. This divergence reflects higher estimates of d for German month-ahead prices, which might have been associated with the introduction of the German EEG law (*Erneuerbare Energien Gesetz*) on 1 January 2009 that prioritises the dispatch of electricity generated by renewables.

5.3.5.2. France and Germany. From January 2005 to January 2012, EPEX-DE and EPEX-FR were integrated for almost 75% of the period, as illustrated in Fig. 8. This finding confirms previous observations in literature (e.g. Bosco et al., 2010; Pellini, 2012; Zachmann, 2008) of a strong association between the two largest European markets. However, periods of divergence are also identified, for which there are several possible explanations. First, in the summer of 2010, exceptionally high temperatures increased the demand for cooling and river temperatures, so that some French nuclear power plants could not rely on these rivers for cooling and became unavailable. Second, in the winter of 2010, the German supply side was affected by unplanned nuclear plant outages (Gundremmingen-B in the first half of November, Biblis-B in December). Moreover, a wave of strikes in France reduced the generation of nuclear plants (European Commission, 2010c).

French and German forward markets were cointegrated 98.5% of the time, as depicted in Fig. 9. There are only a few days in June and July 2009, when the cointegrating relationship broke down, possibly due to concerns of imminent strikes in the French power sector (European Commission, 2009).

5.3.5.3. GB and France. The British and French markets have been interconnected since the 1960s and were cointegrated during half of the period studied (November 2004 to November 2011). Fig. 10 shows a

[1] HDDs are defined relative to the outdoor temperature. On days when the daily average outdoor temperature is below 21 °C, HDD values are in the range of positive numbers; otherwise HDD equals zero (European Commission, 2012b).



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 14. EPEX-DE and Nordpool — assessment of cointegration.

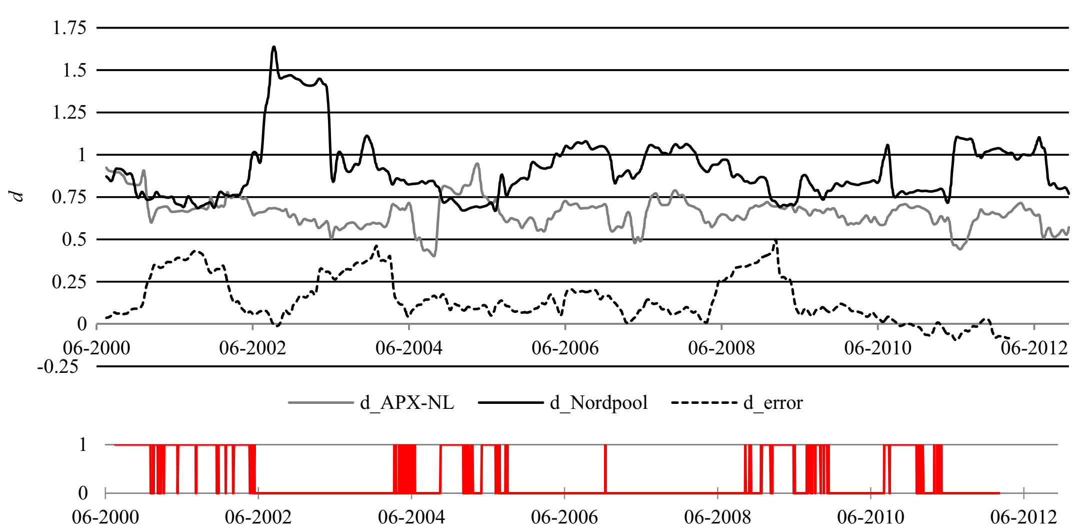
tendency towards less cointegration in the spot markets. Forward markets are cointegrated between April 2008 and November 2011 (85% of the period), as shown in Fig. 11.

5.3.5.4. GB and The Netherlands. Fig. 12 shows that APX-NL and APX-UK, are cointegrated during 83% of the period (January 2005 to January 2012), thus confirming previous findings (e.g. Pellini, 2012). Similarly, Fig. 13 indicates that the Dutch and British one-month-ahead prices converged for 82% of the days between April 2008 and November 2011.

Both figures indicate a period of divergence in 2009. The significantly lower value for *d* in APX-UK, as shown in Fig. 12, may reflect the competitiveness of gas and the clean spark spread in 2009. Divergence between the British and the Dutch markets in 2010 may be due to failures of the NorNed interconnector at the beginning of February (European Commission, 2010a). Another drop in the order of integration *d* of British one-month ahead prices can be observed in the 2nd quarter of 2011, which might have been due to a public holiday (29th of August) and gas prices that increased following maintenance work on gasification facilities in Quartar plus fears of a growing demand from Japan in the aftermath of the events in Fukushima. (European Commission, 2011b). These observations, however, were not reflected in the month-ahead market.

5.3.5.5. Nordpool with Germany and The Netherlands. Cointegration between the Nordpool and adjacent markets was low: only 28% of days with EPEX-DE and 31% with APX-NL, as seen in Figs. 14 and 15, respectively. However, from the second half of 2008, after a long period of divergence, there was an increase in cointegrated days, which might follow the commissioning of NorNed interconnector on 6 May 2008 (Tennet, 2013).

5.3.5.6. Belgium with France, The Netherlands and Germany. The trilateral market coupling between Belgium, France and The Netherlands started in November 2006. Figs. 16 and 17 illustrate that, since then, the orders of integration of spot prices are not significantly different in Belpex and EPEX-FR (fractionally cointegrated 90% of the time) as well as Belpex



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 15. APX-NL and Nordpool — assessment of cointegration.

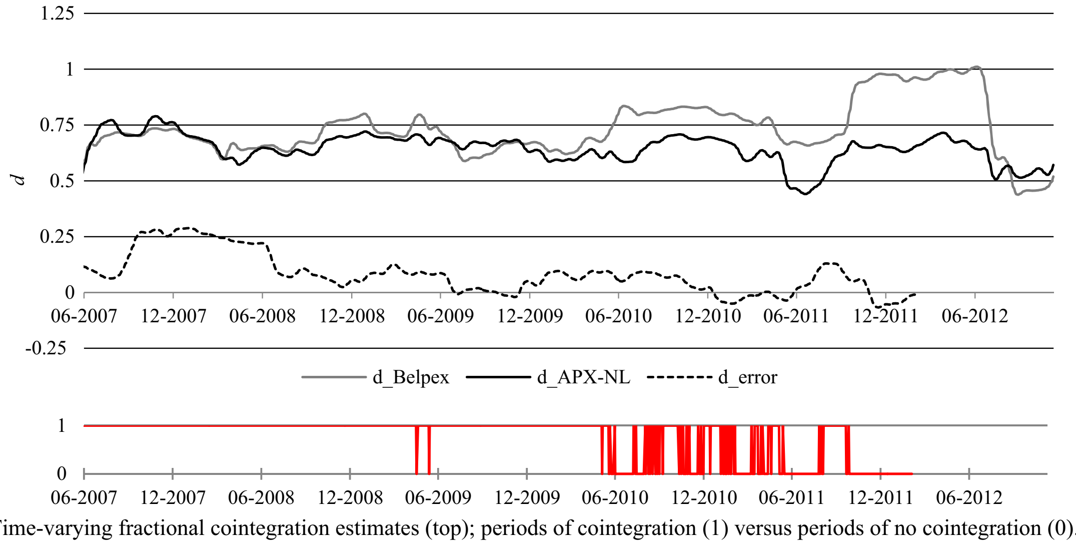


Fig. 16. Belpex and APX-NL — assessment of cointegration.

and APX-NL (fractionally cointegrated 76% of the time). Fig. 17 shows that EPEX-FR and Belpex electricity spot prices share strong common price dynamics, with few exceptions occurring mainly in winter and spring. These results confirm previous findings of strong convergence between Belpex and EPEX-FR (e.g. Autran, 2012; Pellini, 2012). Divergences can be observed in the period from 2010 to 2011 between the Dutch and the Belgian markets, which might reflect imports from the German system, which had a larger production of wind power in the period (Öko Institut, 2013; Weigt et al., 2010). Fig. 18 shows that German and Belgian electricity spot prices were continuously fractionally cointegrated until June 2010.

5.3.5.7. The Czech Republic and Germany. Fig. 19 illustrates that German and Czech electricity spot prices were fractionally cointegrated during 84% of the period between June 2008 and March 2011. From the second half of 2009 until the first quarter of 2010, frequent deviations from common long run dynamics between the Czech and German electricity spot prices can be observed. This development may reflect the new law (*EEG*) leading to negative prices in the German spot market (European Commission, 2010b). Another cluster of brief periods of no fractional cointegration can be found in the third and fourth quarters of 2011. Unusual events such as the cancellation of daily auctions in mid-October, as well as two holidays (Czech Independence Day and All Saints) might have affected Czech prices in the fourth quarter 2011. Furthermore, slightly colder than normal weather conditions led to an increase in the demand for electricity thus creating an upward pressure on spot prices in the region (European Commission, 2011b), which might have also contributed to the observed divergences.

5.3.5.8. France with Italy and Spain. According to Fig. 20, OMEL and French market EPEX-FR were fractionally cointegrated during 72% of the days in the period between December 2004 and February 2012, which is consistent with Zachmann's (2008) and Pellini's (2012) assessments of more frequent convergence than divergence.

Deviations may be due to increasing shares of intermittent wind power and limited net transfer capacity between OMEL and EPEX-FR, which ranged from 500 to 600 MW from 2006 to 2011, which is significantly lower than between Belpex and EPEX-FR (2300 to 3400 MW). French and Spanish electricity spot prices de-coupled in the first quarter of 2011, when fewer nuclear power plants were available because of outages and maintenance (European Commission, 2011a). Fig. 21,

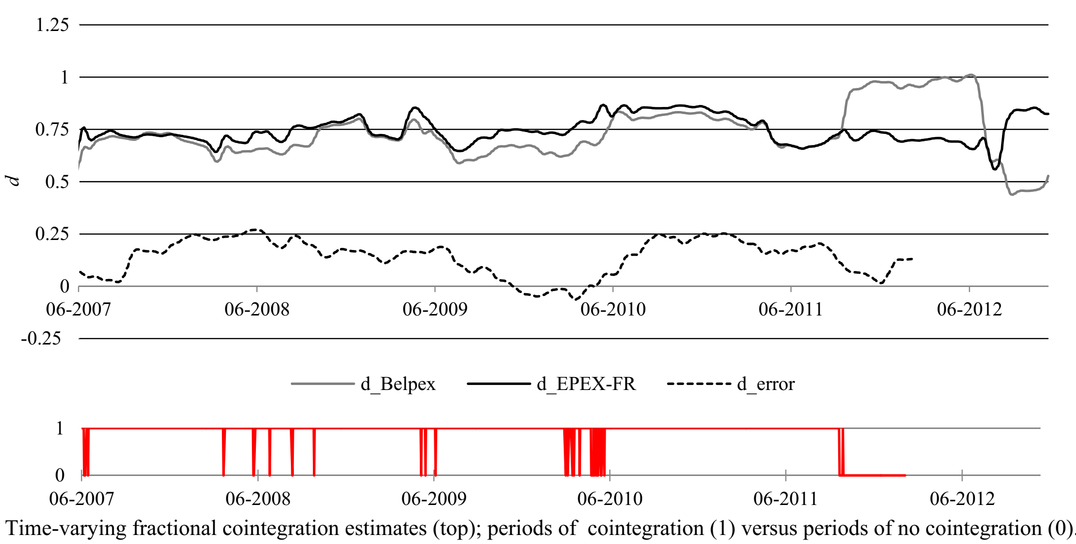


Fig. 17. Belpex and EPEX-FR — assessment of cointegration.

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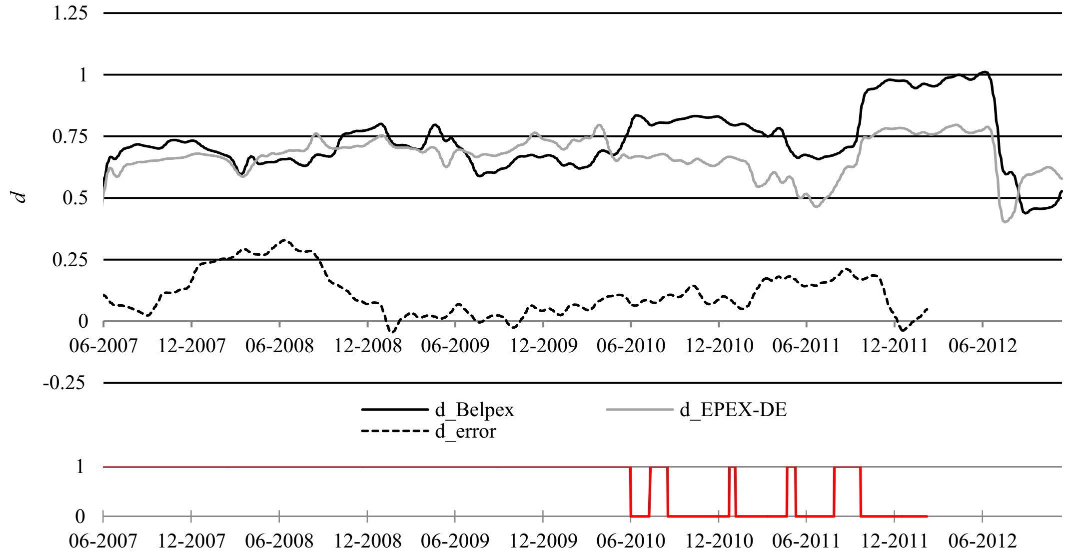

Fig. 18. Belpex and EPEX-DE — assessment of cointegration.

illustrates that IPEX and EPEX-FR share common long run dynamics during only 50% of the period.

5.3.6. Periods of fractional cointegration in spot versus forward markets: assessing H2b

When comparing the proportion of days of fractional cointegration in forward and spot markets, Table 7 shows that for two out of three market pairs, integration was significantly higher in forward markets between November 2007 and November 2011. The cointegration relationship between French and German month-ahead prices was stable (98.5% of fractional cointegration). In contrast, cointegration between their spot markets was the least frequent (67.3%). A similar pattern was observed in other pairs (British & Dutch or French). However, for Germany and The Netherlands convergence was more frequent in the spot market compared to the forward market. We therefore reject H2b, which stated greater convergence in the forward compared to the spot market, and confirm previous findings in the literature (Bunn and Gianfreda, 2010) which were judged to reflect the extent of market maturity and the low liquidity in the forward market.

5.3.7. Special events and mean reversion: assessing H3a–H3c

5.3.7.1. Interconnector: assessing H3a and H3b. As shown in Table 8, one year after the launch of the NorNed interconnector (6/05/2008), the parameter *d* had decreased significantly (5% significance level) for Nordpool from 0.9693 to 0.8421. However, there is no statistically significant change in the order of integration for APX-NL, Belpex or EPEX-DE.

Similarly, Table 9 considers the potential effect of the introduction of the BritNed interconnector, which links GB (Isle of Grain) and The Netherlands (Rotterdam), since 1 April 2011 (BritNed, 2013). The order of integration in the British (APX-UK) spot prices, d_{before} (0.6294) is significantly (1% significance level) larger than after interconnection, d_{after} (0.3316). However, there is no statistically significant change in the order of integration *d* in the Dutch electricity spot market, Belpex, EPEX-FR or EPEX-DE.

Overall, we find mixed evidence for H3a and H3b on the increasing speed of mean reversion after the commissioning of an interconnector for directly affected markets. However, changes in the speed of mean reversion appear to depend on the level of interconnection before the new connection.

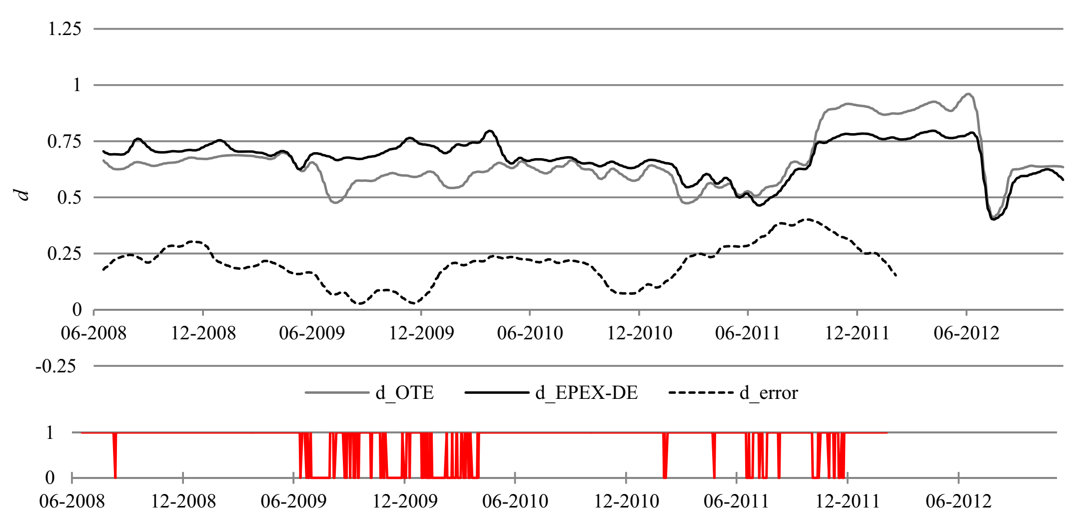

Fig. 19. OTE and EPEX-DE — assessment of cointegration.

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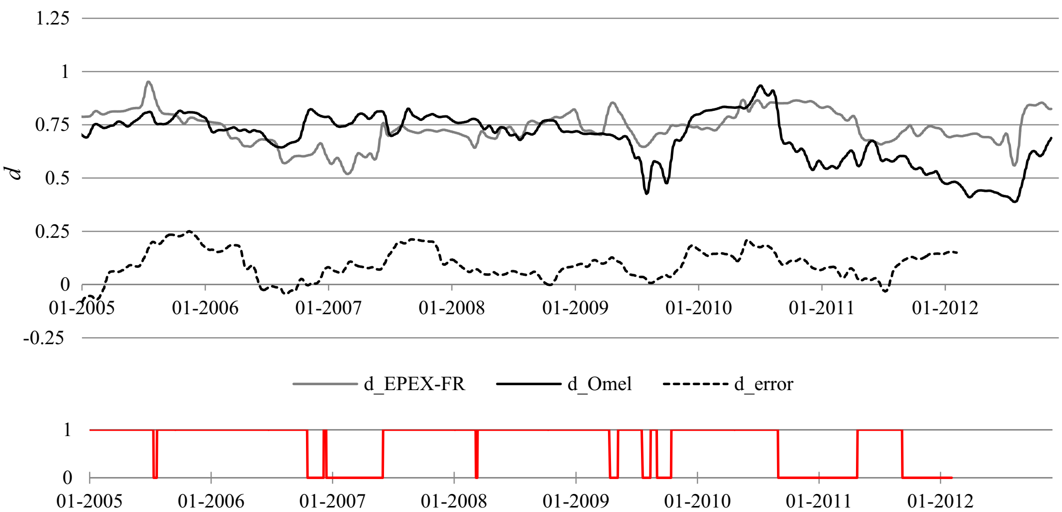


Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 20. EPEX-FR and OMEL — assessment of cointegration.

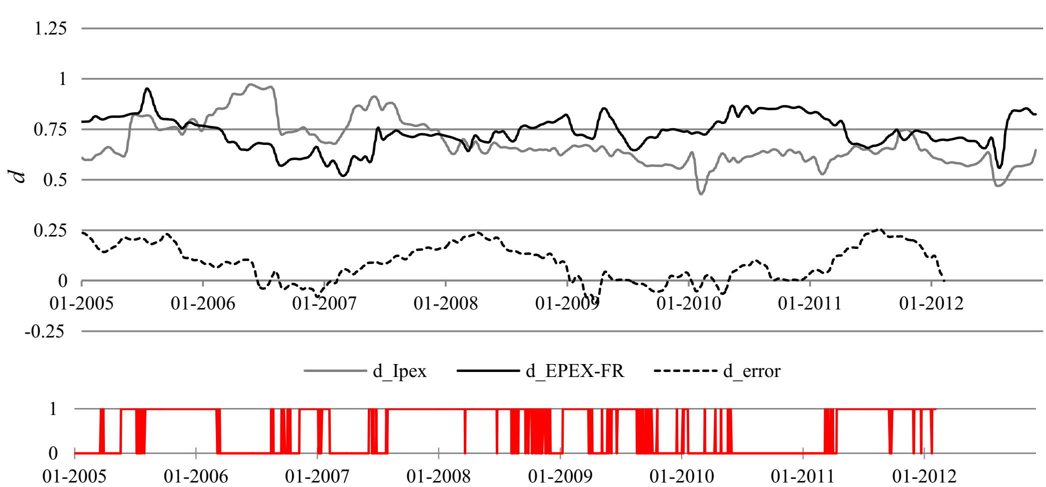
5.3.7.2. Market coupling: assessing H3a and H3b. On 21 November 2006, Belgium, France and The Netherlands coupled their day-ahead (spot) electricity markets through their power exchanges and transmission system operators (TSO) to the TLC (Belpex, 2012). Similar to previous studies (Autran, 2012; De Jonghe et al., 2008; Nitsch et al., 2010), which observed (but not formally tested) changes in the level of mean reversion in spot prices, the results of this study show that since the TLC, the order of integration *d* decreased significantly. Table 10 shows that *d* changed significantly for EPEX-FR and APX-NL, which were part of the initiative, but also for IPEX and EPEX-DE, which were not. In the other neighbouring electricity markets, OMEL and APX-UK, no significant change in the estimates of the parameter *d* was observed. Belpex has been excluded from the analysis because it started with the launch of TLC.

Nordic–German market coupling started on 9 November 2011. As shown in Table 11, in which the average order of integration during one year after and one year before market coupling are compared, a decrease in the order of integration of Nordpool spot prices can be noticed. Concerning the other markets, the long run spot price behaviour only changed in the French spot market, where a significant increase in the order of integration is observed in Table 11.

Table 12 compares the order of integration before and after the Central Western European market coupling (CWE) and shows significant changes in the estimates for *d* in EPEX-FR, APX-NL and EPEX-DE and, most noticeably, for spot prices in the three markets that were not directly addressed by the initiative (APX-UK, OMEL and OTE). For Belpex and IPEX prices, the reduction in the order of integration was insignificant.

The above results are similar to those of reported by Castagneto-Gissey et al. (2014), who found spot price correlation to increase after the CWE market coupling. However, considering all three market coupling events, there is mixed evidence regarding changes in speed of mean reversion after interconnection. Consequently, H3a and H3b are not supported in our study.

5.3.7.3. Germany's energy transition: assessing H3c. By 6 August 2011, eight nuclear power plants totalling 8811 MW or 40% of Germany's nuclear capacity had been removed from the German electricity network within a six-month period (BDEW, 2011). As shown in Table 13, the order of integration of the spot price series – *d* – increased for all markets directly connected to the German electricity market. H3c is



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Fig. 21. IPEX and EPEX-FR — assessment of cointegration.

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Table 7
Comparison of periods of fractional cointegration between spot and forward markets.

Market pair	Integration in spot market	Integration in forward market	p-Value
FR-GER	67.3%	98.5%	0.000
GER-NL	94.2%	83.8%	–
NL-GB	78.1%	82%	0.038
FR-GB	28%	86.5%	0.000

Comparison of periods of fractional cointegration between spot and forward markets between November 2007 and November 2011. P-value based on one-sided t-test.

supported, except for IPEX. It is noteworthy that a comparison of hourly spot prices showed that the number of settlement periods with negative prices increased in Belpex, APX-NL, and EPEX-FR between the year before and the year after the closures. For example, in EPEX-DE this number increased from 8 to 26.

6. Summary and conclusion

Although the European Commission stated that "It is time to complete the internal market for energy" (European Commission, 2012a), we are yet to know whether European electricity wholesale markets are integrated, which is the main question addressed in this study. A review of the literature showed divergent answers and some neglect of well-known characteristics of electricity price processes (mean reversion and spikes). By adopting a time-varying fractional cointegration analysis using both spot and one-month ahead electricity prices, this study investigated not only whether wholesale prices were converging, but also whether the pace of convergence could have been affected by special events on the supply side. The first hypothesis assessed market quality in terms of their reactivity to shocks:

H1. As liberalisation evolves, the ability of EU electricity markets to overcome supply and demand shocks more quickly increases.

The results imply that forward (one-month ahead) markets are likely to have improved their ability to overcome shocks during the period studied. Meanwhile, the behaviour of spot markets, which could be affected by local market trading arrangements and electricity mix, did not change significantly in the periods analysed. Nonetheless, due to more interconnection across markets and the implementation of the EU directives that aim to create a pan-European market, electricity prices are expected to increasingly converge. H2a and H2b focused on convergence, and potential differences between spot and forward markets:

H2a. EU electricity markets are increasingly integrated.

H2b. Greater cointegration is observed in EU electricity forward prices when compared to prices in the respective spot markets.

Increased convergence for all month-ahead markets was observed and price dispersion decreased significantly, thus supporting H2a. Together with greater reactivity to shocks, this support may suggest that market integration is positively associated with resilience, i.e. increased

Table 8
Order of integration d before and after the NorNed interconnector (06.05.2008).

		$\bar{d}$ and *CI*	t-Statistics
APX-NL	d_before	0.6824 [.549; .8158]	0.298
	d_after	0.7027 [.5693; .8361]	
Nordpool	d_before	0.9693 [.8359; 1.1027]	−1.869*
	d_after	0.8421 [.7087; .9754]	
Belpex	d_before	0.7644 [.6310; .8978]	0.000
	d_after	0.7646 [.6312; .8980]	
EPEX-DE	d_before	0.6457 [.5124; .7791]	0.527
	d_after	0.7160 [.5827;.8494]	

The asterisks * and ** denote a 5% and 1% significance levels, respectively. Markets directly affected by the policy (one-tailed test) are printed in bold.

Table 9
Order of integration d before and after the BritNed interconnector (01.04.2011).

		$\bar{d}$ and *CI*	t-Statistic
APX-NL	d_before	0.6859 [.5525; .81926]	1.060
	d_after	0.7580 [.6246; .89136]	
APX-UK	d_before	0.6294 [.496;.76276]	−4.377**
	d_after	0.3316 [.19823;.465]	
Belpex	d_before	0.8255 [.6921; .9589]	1.056
	d_after	0.8974 [.764; 1.031]	
EPEX-FR	d_before	0.8254 [.692; .9587]	1.318
	d_after	0.9151 [.7817; 1.0485]	
EPEX-DE	d_before	0.6404 [.5070; .7738]	1.074
	d_after	0.7135 [.5801; .8469]	

The asterisks * and ** denote a 5% and 1% significance levels, respectively. Markets directly affected by the policy (one-tailed test) are printed in bold.

speeds of mean reversion. Electricity spot markets which are geographically close or well-connected have been found to have longer periods of price convergence. However, overall electricity spot prices were not increasingly converging, and spot price dispersion could not be linked to market integration. Therefore, H2a was rejected for spot markets.

This study also highlighted the relevance of extreme weather conditions, public holidays, reduced plant availability and fuel price developments for changes in the speed of mean reversion and convergence of electricity spot prices. For forward markets, H2b was rejected: from the four market pairs considered, the German and Dutch month-ahead electricity prices rejected the hypothesis.

The potential effects of increases in interconnection capacity were addressed by testing:

H3a. The speed of mean reversion after a market connecting event is faster than the mean reverting speed of the price series before the event.

H3b. There is no change in the speed of mean reversion of spot prices in markets which are not directly affected by the new connection.

In theory, it might be expected that when connecting two markets, price resilience against shocks of the less interconnected market improved. This expectation was supported by our analysis of a year before and a year after operations started in NorNed and BritNed. Moreover, with the exception of the Nordic–German market coupling, spot prices in markets which are directly coupled showed a faster speed of mean reversion after the initiative. Consequently, most market coupling initiatives are fulfilling their objective of delivering a more robust electric system.

Decisions on electricity mix and reserve margin are made at the national level since each EU member state maintains its right to "determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply" (Article 194, Section 2) (European Union, 2007). Yet, in integrated systems and markets, changes in local electricity mixes may

Table 10
Order of integration d before and after Trilateral Market Coupling (TLC) (21.11.2006).

		$\bar{d}$ and *CI*	t-Statistics
EPEX-FR	d_before	0.8036 [.6636;.9436]	−2.453**
	d_after	0.6284 [.4884;.7684]	
APX-NL	d_before	0.7597 [.6197,.8997]	−1.786 *
	d_after	0.6321 [.4921, .7721]	
EPEX-DE	d_before	0.7621 [.6221.;.9021]	−3.557**
	d_after	0.5080 [.368;. 648]	
APX-UK	d_before	0.6863 [.5463; .8263]	1.940
	d_after	0.5477 [.4077; .6877]	
OMEL	d_before	0.8175 [.6775;.9575]	1.468
	d_after	0.9223 [.7823;1.0623]	
IPEX	d_before	0.965 [.825;1.105]	−2.072*
	d_after	0.817 [.677;. .957]	

The asterisks * and ** denote a 5% and 1% significance levels, respectively. Markets directly affected by the policy (one-tailed test) are printed in bold.

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Table 11
Order of integration *d* before and after Nordic–German Market Coupling (09.11.2009).

		$\bar{d}$ and *CI*	t-Statistic
Nordpool	d_before	0.9648 [.8314; 1.098]	−1.900*
	d_after	0.8355 [.7021; .9689]	
EPEX-DE	d_before	0.6441 [.5107;.7776]	1.008
	d_after	0.7127 [.5793; .8460]	
APX-NL	d_before	0.7016 [.5682; .8335]	−0.667
	d_after	0.6562 [.5228; .7896]	
EPEX-FR	d_before	0.7366 [.6032; .8700]	3.208**
	d_after	0.9549 [.8215; 1.0883]	
APX-UK	d_before	0.6566 [.5232; .7900]	0.976
	d_after	0.5902 [.4568; .7236]	
Belpex	d_before	0.7463 [.6129; .8797]	0.003
	d_after	0.7465 [.6131; .8799]	

The asterisks * and ** denote a 5% and 1% significance levels, respectively. Markets directly affected by the policy (one-tailed test) are printed in bold.

affect integration. In the particular case of the German market, which is the largest in the region, secure capacity decreased, therefore we tested:

H3c. Germany's decrease in secure capacity has lowered the ability of electricity spot prices to revert to the mean in the German and neighbouring markets.

This hypothesis was supported. Although nuclear power serves base load and thus may appear to be less related to the speed of mean reversion, the reduction led to a shift in the supply stack, decreasing secure reserve capacity in the German system (BDEW, 2011). A greater share of intermittent renewable sources increased spot price volatility, and the European electricity system may have reacted slowly, as indicated by the increases in the order of integration of the spot price series. Consequently, future research on market integration should consider the electricity mix and other potential price drivers. Moreover, faced with emission targets and demand management, market mechanisms may change and new regulation will follow, which are likely to impact electricity price movements and convergence. Future research should track these developments and implications for the Pan European Electricity market, which is still to become a reality.

Appendix AA.1. *The Exact Local Whittle Estimator (ELW)*

Let us consider the fractionally integrated process X_t

$$\Delta^d X_t = (1-L)^d X_t = u_t 1\{t \geq 1\} \quad t = 0, \pm 1, \ldots$$

Table 12
Order of integration *d* before and after Central West European Market Coupling (CWE) (09.11.10).

		$\bar{d}$ and *CI*	t-Statistic
APX-NL	d_before	0.6570 [.5236; .7904]	−1.783*
	d_after	0.5357 [.4023;.6691]	
EPEX-FR	d_before	0.9559 [.8225; 1.0893]	−3.904**
	d_after	0.6903 [.5569; .8237]	
Belpex	d_before	0.7594 [.626; .8927]	−0.977
	d_after	0.6929 [.5595; .8263]	
EPEX-DE	d_before	0.6723 [.5389;.8957]	−2.514**
	d_after	0.5012 [.3678; .6345]	
OMEL	d_before	0.8007 [.6673;.9341]	2.500*
	d_after	0.6306 [.4972; .764]	
OTE	d_before	0.6570 [.5236; .7904]	2.790*
	d_after	0.4672 [.3338; .6006]	
IPEX	d_before	0.6228 [.4894;.7562]	0.382
	d_after	0.5968 [.4634; .7302]	
APX-UK	d_before	0.5973 [.4639; .7307]	3.201**
	d_after	0.3794 [.246; .5128]	

The asterisks * and ** denote a 5% and 1% significance levels, respectively. Markets directly affected by the policy (one-tailed test) are printed in bold.

Table 13
Order of integration *d* before and after Germany's nuclear power plant closures (06.08.2011).

		$\bar{d}$ and *CI*	t-Statistic
EPEX-DE	d_before	0.5914 [.458; .7281]	2.130*
	d_after	0.7363 [.6029; .8697]	
EPEX-FR	d_before	0.7926 [.6592;.926]	2.994**
	d_after	0.9963 [.8629; 1.130]	
APX-NL	d_before	0.6243 [.4909; .7577]	4.225**
	d_after	0.9118 [.7784; 1.045]	
Belpex	d_before	0.7916 [.6582;.925]	2.847**
	d_after	0.9853 [.8519; 1.119]	
Nordpool	d_before	0.7844 [.65104; .9177]	1.708*
	d_after	1.0122 [.8788; 1.1455]	
OTE	d_before	0.4072 [.2738; .5406]	6.736**
	d_after	0.8655 [.7321; .9989]	

The asterisks * and ** denote a 5% and 1% significance levels, respectively. Markets directly affected by the policy (one-tailed test) are printed in bold.

where $1\{\cdot\}$ is the indicator function. u_t is assumed stationary with zero mean and spectral density $f_u(\lambda) \sim G$ for $\lambda \sim 0$. Inverting and expanding the binominal give the representation of X_t in terms of $u_1, \ldots. u_n$, which is valid for all values of d:

$$X_t = \Delta^{-d} u_t 1\{t \geq 1\} = (1-L)^{-d} u_t 1\{t \geq 1\} = \sum_{k=0}^{t-1} \frac{(d)_k}{k!} u_{t-k}, \quad t = 0, \pm 1, \ldots$$

Shimotsu and Phillips (2005) propose to estimate (d, G) by minimizing the objective function:

$$Q_m(G, d) = \frac{1}{m} \sum_{j=1}^{m} \log\left(G\lambda_j^{-2d}\right) + \frac{1}{G} I_{\Delta d}\left(\lambda_j\right).$$

Concentration $Q_m(G, d)$ with respect to G, Shimotsu and Phillips (2005) define the ELW as

$$\tilde{d} = \underset{d \in [\Delta_1 \Delta_2]}{\arg\min}\, R(d)$$

where Δ_1 and Δ_2 are the lower and upper bounds of the admissible values of d and

$$R(d) = \log\hat{G}(d) - 2d\frac{1}{m}\sum_{j=1}^{m} \log\lambda_j \quad \hat{G}(d) = \frac{1}{m}\sum_{j=1}^{m} I_{\Delta dx}\left(\lambda_j\right).$$

Thereafter the true value of d and G is distinguished by

$$I_a\left(\lambda_j\right) = \left|\omega_a\left(\lambda_j\right)\right|^2$$
$$\omega_a\left(\lambda_j\right) = (2\pi n)^{-1/2} \sum_{t=1}^{n} a_t e^{it\lambda j}$$
$$\lambda_j = \frac{2\pi j}{n} j = 1, \ldots, n.$$

A.2. The Feasible Exact Local Whittle (FELW)

Shimotsu and Phillips (2005) proposes estimating μ_0 by

$$\hat{\mu}(d) = \omega(d)\overline{X} + (1 - \omega(d))X_1$$

where $\omega(d)$ is a twice continuously differentiable weight function such that $\omega(d) = 1$ for $d \leq \frac{1}{2}$nd $\omega(d) = 0$ for $d \geq \frac{3}{4}$. With this estimate of μ_0 we define the FELW estimator as:

$$\widehat{d_F} \min_{d \in \theta} R_F(d)$$

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where θ is the space of the admissible values of d and

$$R_F(d) = \log\hat{G}_F(d) - 2d\frac{1}{m}\sum_{j=1}^{m}\log\lambda_j, \hat{G}_F(d) = \frac{1}{m}\sum_{j=1}^{m} I_{\Delta d(x-\widetilde{\mu}(d))}\left(\lambda_j\right).$$

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