Price convergence in the European electricity market

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1. Introduction

In its decision in 1st instance on the proposed merger of Nuon and Essent, the NMa re-iterated the position on the relevant geographical market for production and wholesale that was earlier taken in its *Visiedocument*.[1] In that document, based to a large extent on the analysis of Brattle (2006)[2], it is argued that for *non-peak hours* there is evidence for the position that the geographical market is certainly larger than the Netherlands, but that instead for *peak hours*, the market is certainly restricted to the Netherlands. Using data of 2005, Bratlle (2006) shows that wholesale electricity prices during peak hours in Germany, Belgium and the Netherlands differed. Moreover, they used a SSNIP test type of analysis to argue that in peak hours the market is indeed confined to the Netherlands.

The analysis of the Brattle group is static in the sense that it does not consider the price path over the years. Thus, it very well may be that wholesale electricity prices during peak hours between different North-West European countries still differed in 2005, but that there is a (strong) tendency over the years for prices to converge. If there is price convergence, then the different markets are moving towards (full) integration. A static analysis does not show this price path over time. Thus, the most important question is whether price convergence can be observed, and if so, if the process of price convergence can be expected to continue in the near future. A dynamic study of price convergence is more relevant for the NMa decision on the proposed merger than a static analysis as the merger will take place in the future and a dynamic study can shed much more light on the issue of geographical market definition at the time the merger will take place than a static study using data on 2005. Furthermore, we have more recent observations at our disposal due to the availability of data over the years 2006 and 2007.

Price convergence is likely to be observed as the last years have shown considerable changes in how different countries are connected with each other. First, national exchanges started trading in the last years in Belgium, France, Germany and the Netherlands. Given the time needed to build up experience and the low volatility of exchanges at their start, it could be expected that this increasingly affects international integration. Second, on 21 November 2006 the power exchanges of the Netherlands, Belgium and France are coupled. This means that no arbitrage between these markets is necessary anymore as the interconnection capacity is optimally used in the bidding process. The exchanges assume that there is a single market which means that only capacity restrictions can result in price divergence. Third, interconnection capacity is increased by investments in new connection capacity and measures (e.g. phase shifters) to use the existing connections more efficiently.

This paper studies price developments over the period January 2002 - July 2007 in the Netherlands, France and Germany to determine whether indeed a process of price convergence exists. To do this, we go back to the original raw data on the per hour

[1] See NMa (2007), 1e fase besluit, numbers 81-93, Nederlandse mededingingsautoriteit, Den Haag and NMa (2006), Visiedocument concentraties energiemarkten, Nederlandse mededingingsautoriteit, Den Haag.
[2] Brattle (2006), Factors affecting geographic market definition and merger control for the Dutch electricity sector, The Brattle Group, London.

one-day-ahead wholesale market prices in the Netherlands, France and Germany.[3] We first fit a flexible trend pattern to these data and investigate the pattern of the difference in these trends. The pictures obtained show a clear tendency for prices to converge between all three countries. We then use more sophisticated tests to argue that indeed the process of market integration is such that it is extremely likely that in 2009 the market for the production and wholesale of electricity is larger than the Netherlands. In such a broader market, the merging firms Nuon and Essent will not have a dominant position.

There exists some older literature suggesting a process of price convergence for electricity prices in North-West Europe. For instance, using data up to 2004, Zachmann (2005) finds clear convergence between Germany and the Netherlands for 12 out of 24 hours.[4] However, there was no full convergence at the end of this period, since significant price differentials for peak hours were still present. Armstrong and Galli (2005) find that also for peak hours the differential decreased between 2002 and 2004.[5] They used data for Germany, France, the Netherlands and Spain. Compared to these papers, we use an up-to-date dataset and a different methodology, but essentially reach the conclusion that the process of price convergence has continued until the present day.

The paper proceeds as follows. Section 2 presents the methodology and data. In section 3 results are presented for non-peak hours and in section 4 for peak hours. Section 5 discusses the relation between the structural changes that one can observe in the market (increases in interconnection capacity and coupling of markets) and the price convergence we find. Section 6 concludes.

2. Methodology and data

If electricity production plants of two countries belong to the same market, wholesale prices should (approximately) be equal between the two countries. If prices are very close to each other, then a SSNIP test analysis is not needed anymore to conclude that the geographical market definition should include at least these two countries. The reverse does not hold true. As explained in the introduction, this paper studies whether there is a process of price convergence between the Netherlands, France and Germany. For the Netherlands, France and Germany we dispose of the per hour wholesale prices for the one-day-ahead market over the period of 1 January 2002 until 11 July 2007. These prices are taken from the electricity exchanges APX, PWXT and EEX.

[3] We study the one-day-ahead market for three reasons. First, if there is price convergence in the day-ahead market and traders know this, they will not accept different prices in the forward markets. Second, forward markets are mu8ch more volatile and therefore difficult to interpret. Third, Nuon and Essent have used forward markets to show price convergence and our study is complementary to what they did.

[4] Zachman, G. (2005), Convergence of electricity wholesale prices in Europe?, Deutsches Institut für Wirtschaftsforschung, Berlin.

[5] Armstrong, M. en A. Galli (2005), Are day-ahead prices for electricity converging in continental Europe? An exploratory data approach. CERNA Working Paper, Ecole Nationale Supérieure des Mines de Paris.

To understand movements in electricity prices, it is important to recall that prices depend on the interaction between demand and supply at any given moment in time as storage of electricity is not possible. This means that prices can fluctuate significantly during one day and the analysis has to be conducted per hour. We have prices for all individual peak (the 9th till the 20th hour for weekdays) and non-peak hours.[6] The NMa and all previously mentioned literature concludes that for non-peak hours the market is broader than the Netherlands. In these hours demand is low resulting in enough interconnection capacity to create an international market. The main discussion is thus about whether an identical conclusion holds for peak hours. This is not obvious as demand is (much) larger and interconnection capacity might be too low. Therefore, we concentrate our attention on the analysis of peak hours, although we show that our approach reproduces the conclusion that there is indeed an international market for non-peak hours.

We start our analysis by estimating a flexible trend equation trough the available price data to get a first impression of how the data of different countries compare with each other. If there is a process towards convergence, we should find that the differences between the trends diminish. If price convergence is reached, the differences should disappear at all. The flexible trend equation we use is the following:

$$P_{i,h,t}^{electricity} = \alpha_1 T + \alpha_2 T^2 + ... + \alpha_9 T^9 + \alpha_{10} + \varepsilon \tag{1}$$

where P is the wholesale price for hour h in country i at day t and is measured in euros per MWh. T is a time trend that increases with 1 for each day of our observations (T=1 for 1 January 2002 and 2018 for 11 July 2007). As we know *a priori* that prices fluctuate considerably over the years, e.g. as a result of changes in demand or supply, we include several trend variables to arrive at the "true" trend pattern that is available in the data. The polynomial equation (of degree 9) we use, allows for a sufficient degree of flexibility (that could not be obtained if a polynomial degree of much lower dimension is used). Moreover, we have checked that higher order polynomials do not create a significantly different picture.

We plot the estimated price trends per country and plot also the differences between the prices in the Netherlands compared to the prices in France and Germany. With perfect price convergence these differences should be zero. Positive values reflect higher prices in the Netherlands compared with Germany or France.

The plots provide a clear first impression of whether a process of price convergence is present. However, only a formal test makes it possible to arrive at a statistically robust conclusion whether price convergence is present. To this end, we use the following approach. We go back to the raw data, take the price ratio between the Netherlands on one hand and Germany and France on the other hand and investigate whether there is a clear and significant (downward) trend available in the time series.[7] We estimate

[6] Our definition of peak hours is based on the observed differences in prices between Germany, France and the Netherlands and not on formal definitions of peak-hours. As we will observe later in more detail, there is a smooth transition from non-peak to peak hours and vice versa, in the sense that the price pattern for hours 8 and 9 as well as the hours 20 and 21 are very close to each other.

[7] A more formal way to test for price convergence is the Kalman filter approach. We applied this approach as a sensitivity analysis and arrived at comparable conclusions as the ones presented in Section 4. The Kalman filter approach is commonly used to study price convergence. See for an overview Grewal, M.S. and P. A. Andrews (1993), Kalman Filtering Theory and Practice, Upper Saddle River, NJ USA, Prentice Hall.

$$\frac{P^{electricity}_{APX,h,t}}{P^{electricity}_{EEX,h,t}} = \alpha_1 T + \alpha_2 + \varepsilon \;\; and \;\; \frac{P^{electricity}_{APX,h,t}}{P^{electricity}_{PWXT,h,t}} = \alpha_3 T + \alpha_4 + \varepsilon. \quad (2)$$

For a given α_2, if $\alpha_1 < 0$ then prices in the Netherlands become smaller relative to Germany over time. For a given α_4, if $\alpha_3 < 0$ then prices in the Netherlands become smaller relative to France over time. If this is the case one can then estimate at which moment T in time the Netherlands and Germany belong to one and the same market, namely when $\alpha_1 T + \alpha_2 = 1$. For the Netherlands and France market integration is reached at the moment T when $\alpha_3 T + \alpha_4 = 1$. As a sensitivity analysis, we test for seasonal effects by estimating a version of (2) including fixed-effects for months and weeks.

Note that each time series is prone to enormous fluctuations. Regularly, one observes high prices when temperatures are extremely low or high. Another reason for high price levels is the occurrence of an unexpected fall-out of an important power station. One such an incident occurred on 22 May 2007, for instance, where a large nuclear power station in Belgium stopped working for several hours. As this incident happened at the end of our data period we have introduced a dummy variable to take account of price differences that day.[8]

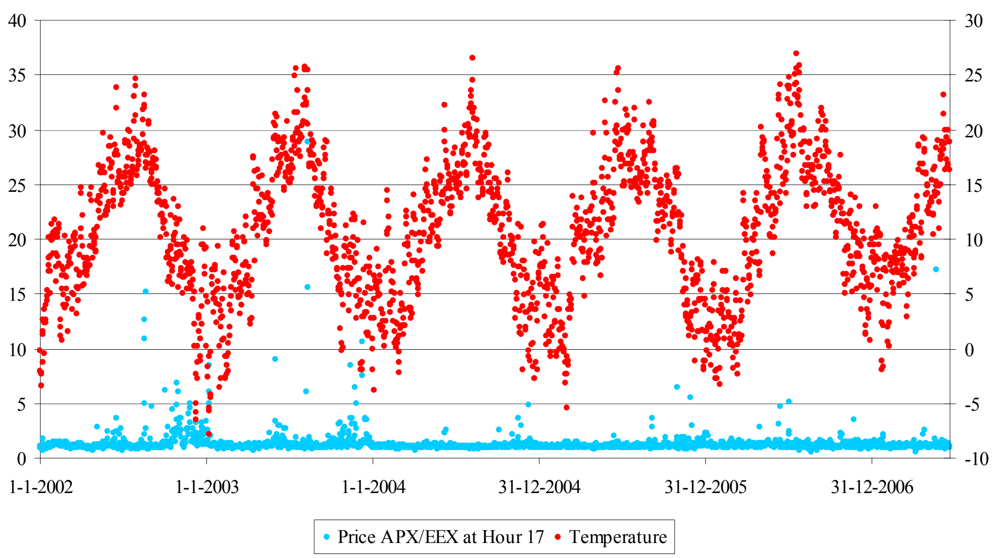


Figure 1. Price APX divided by price EEX (left axis) and temperature (right axis)

3. Results non-peak hours

We first present the results of the estimated time trend for non-peak hours based on the specification described in equation (1). As an example, Figure 2 shows the estimated time trends for hour 2 based on the specification described in equation (1). One can clearly see that the estimated price trends in the Netherlands, France and Germany are almost identical. The same conclusion can be reached for the other non-peak hours (see Appendix A). In the Introduction we have mentioned that other

[8] Without such a dummy variable the general conclusion about the last period would be highly skewed because of this incident.

studies also find that prices for non-peak hours have already converged for some years. Thus, one can conclude that an international electricity wholesale market exists for non-peak hours and that the geographical market definition for non-peak hours should be larger than the Netherlands. As the analysis of non-peak hours does not yield any new results, we do not analyse these hours in more detail.

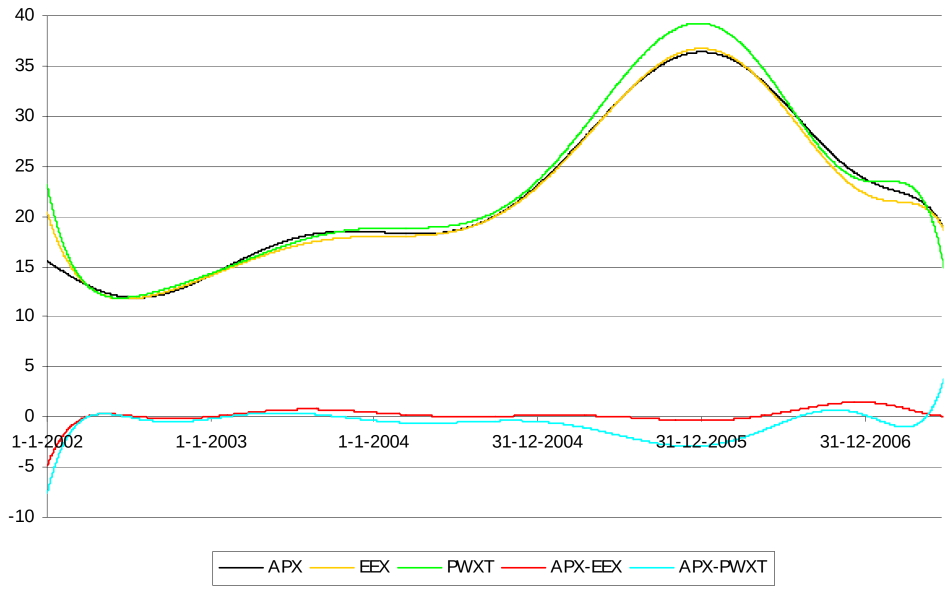


Figure 2 Time trend results non-peak hours for hour 2: prices in euro per MWh

4. The analysis of Peak hours

We now present the analysis for peak hours. First, we analyse figures based on the flexible trend analysis described in equation (1). As an example, Figure 3 presents the estimated time trend for hour 18.[9] There are a few interesting observations to be made on the basis of these pictures:

(i) At nearly all days in the sample period, the time pattern of the series for Germany and France is nearly the same. This implies that as far as wholesale electricity prices are concerned these two countries seem to behave as an integrated market;

(ii) At the beginning of the period we analyse, the Dutch wholesale electricity market is not at all integrated with Germany or France. Prices at the Dutch market are significantly higher and if we would analyse the results for a single year we would find on average significant differences for 2004 and 2005. The results by Zachmann (2005) and Brattle (2006), who found also significant price differences for peak hours in these years, are therefore not surprising. However, the pictures also show that there is a trend towards price convergence as the differences clearly diminish in recent years. This trend is not analysed in Brattle (2006), but is in accordance with Zachmann (2005). The peak of the price difference in 2006 is lower than in 2005 (and that was already lower than the peak in 2004) and also the

[9] As the other hours show a pattern comparable with hour 18 we include the figures for other hours in appendix B.

period for which the estimated price trends differ shortens significantly. In 2006 the peak was very short indeed.

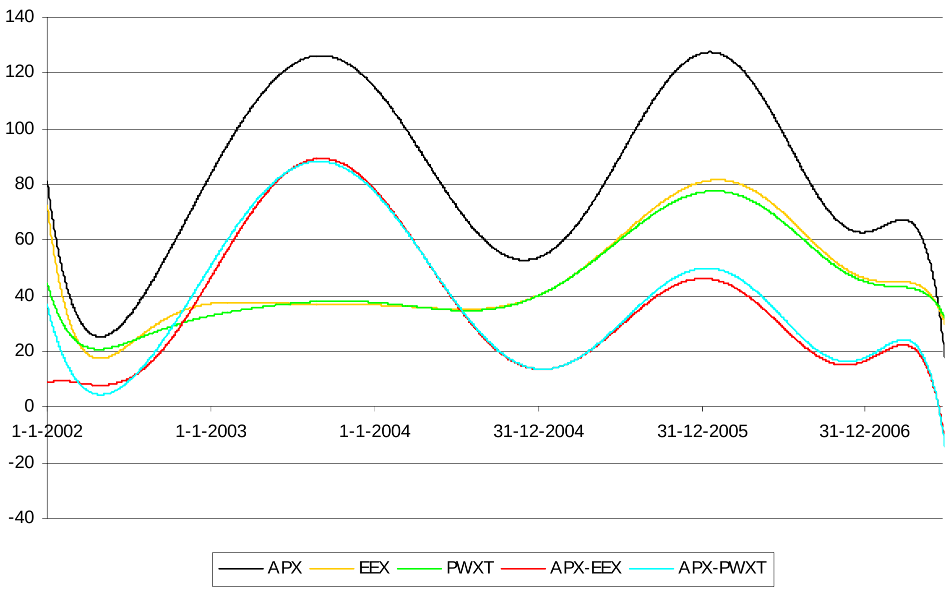


Figure 3 Time trend results peak hours for hour 18: prices in euro per MWh

Figure 3 indicates a process towards market integration as price differences diminish over time and the period of price peaks also shortens. To test this more formally, we use Equation (2) to estimate whether a (negative) trend exists in the price ratio series. Table 1 presents the estimated coefficients for the trends, the estimated price ratio found at 11 July 2007 and also the predicted time period at which market integration will be reached (using statistical extrapolation only).[10]

Table 1 Estimation results trend analysis of price ratios

	Price ratio APX versus EEX			Price ratio APX versus PWXT		
Hour	Coefficient trend[1,2]	Price ratio at 11 July 2007	Price convergence in:	Coefficient trend[1,2]	Price ratio at 11 July 2007	Price convergence in:
9	-0.17***	1.01	Aug 2007	-0.10***	1.14	Mar 2011
10	-0.49***	1.02	Aug 2007	-0.44***	1.10	Feb 2008
11	-0.42***	1.12	May 2008	-0.44***	1.18	Aug 2008
12	-0.39***	1.19	Oct 2008	-0.59***	1.20	Jun 2008
13	-0.34***	1.03	Oct 2007	-0.37***	1.05	Nov 2007
14	-0.55***	1.03	Aug 2007	-0.52***	1.09	Dec 2007
15	-0.40***	1.05	Nov 2007	-0.39***	1.09	Feb 2008
16	-0.42***	0.99	Jun 2007	-0.40***	1.02	Aug 2007
17	-0.31***	1.06	Jan 2008	-0.28***	1.11	Jul 2008
18	-0.42***	1.30	Jun 2009	-0.47***	1.33	Jun 2009
19	-0.10**	1.14	Apr 2011	-0.14***	1.09	Mar 2009
20	-0.05*	1.09	Feb 2012	-0.02	1.08	Aug 2019

Notes: (1) Coefficient multiplied by 1000, (2) ***/**/* means significance at 1/5/10%.

[10] We exclude observations for weekends and observations with price levels lower than 1 euro per MWh (0.3% of total observations) as these observations can result in extreme price ratios.

All trend coefficients are negative indicating that there is indeed a process of price convergence going on. All but one estimated coefficients are significant at the usual confidence levels of 1% or 5%. The only hour where no significant effects are found is in hour 20, which is at the border of the peak/non-peak hour distinction (see below).

On the basis of the estimated trends we can determine the estimated price ratio between the Netherlands and Germany and the Netherlands and France at the last day of our sample, July 11, 2007. This estimated price ratio "cleans" the real price ratio for temporary effects. The ratios range from 0.99 for hour 16 in the comparison between the Netherlands and Germany till 1.33 for hour 18 in the comparison between the Netherlands and France.

When extrapolating the time trends for the Netherlands and Germany we find that market integration will occur before early 2009 for ten out of twelve peak hours. Only for the hours 19 and 20 it takes more time for prices to converge. Comparing the prices for the 19th and especially the 20th hour with other peak-hours shows, however, that for these two hours the price differences are already quite small from the beginning of our sample period onwards. This means that price convergence is not easily found for these hours as trends are rather weak by definition. In fact the analysis shows that the price path in these hours reflects more the price path of non-peak hours and for these hours price had already converged by the beginning of our data period. For the comparison with France rapid price convergence is also found for most hours so that market integration is expected to occur as early as the first months of 2009 for ten out of twelve peak hours.. Again, for hours close to the non-peak hours, in this case hours 9 and 20, prices in the Netherlands and France have been close to each other from the beginning of the sample period onwards so that the time trend is weaker for these hours.

Table 2 Trend coefficients alternative specifications trend analysis price ratios[1,2]

	Price ratio APX versus EEX		Price ratio APX versus PWXT	
	Month fixed effects	Day fixed effects	Month fixed effects	Day fixed effects
9	-0.17^{***}	-0.17^{***}	-0.11^{**}	-0.11^{***}
10	-0.50^{***}	-0.50^{***}	-0.46^{***}	-0.46^{***}
11	-0.43^{***}	-0.43^{***}	-0.46^{***}	-0.46^{***}
12	-0.40^{***}	-0.40^{***}	-0.62^{***}	-0.63^{***}
13	-0.35^{***}	-0.35^{***}	-0.39^{***}	-0.39^{***}
14	-0.57^{***}	-0.56^{***}	-0.54^{***}	-0.54^{***}
15	-0.42^{***}	-0.42^{***}	-0.41^{***}	-0.41^{***}
16	-0.42^{***}	-0.42^{***}	-0.42^{***}	-0.42^{***}
17	-0.33^{***}	-0.43^{***}	-0.30^{***}	-0.30^{***}
18	-0.46^{***}	-0.45^{***}	-0.52^{***}	-0.50^{***}
19	-0.11^{***}	-0.11^{***}	-0.16^{***}	-0.15^{***}
20	-0.06^{**}	-0.06^{**}	-0.02	-0.02

Notes: (1) Coefficient multiplied by 1000, (2) $^{***}/^{**}/^{*}$ means significance at 1/5/10%.

To test for specification errors, we conducted a sensitivity analysis to check for seasonal effects. First, month dummies are included to test for month specific fixed effects. These effects are significant, especially for August, October and November. The general trends remain significant and negative. Their sizes are barely influenced by alternative specifications and are in most cases a little larger (compare Table 1 and 2). This means that Table 1 on average underestimates the speed of convergence compared to estimations where month dummies are included. Second, week dummies are included to test for week specific fixed effects. At two decimals we find nearly no differences with the specification with month dummies.

5. Structural causes

So far, we have only looked at the price data without having any structural view on what may cause price convergence. Such a pure data analysis should ideally be accompanied by a more structural analysis uncovering the causal mechanisms underlying the price convergence results that we found so far. Electricity markets in North-West Europe have undergone several structural changes in the last few years (such as enlarged interconnection capacity and a coupling of the national power exchanges; see also the Introduction). As interconnection capacity will be increased and market coupling of exchanges will occur again in the future, it is worthwhile to analyse the effects of these structural changes. This is what we will do in this section and we mainly focus on the effect of interconnection capacity and market coupling of exchanges.

Over the past years, the interconnection capacity between different countries has been enlarged for the one-day ahead exchange, making capacity restriction a less urgent problem. Moreover, several measures were taken to use the existing interconnection capacity more efficiently. Table 3 gives the available capacity between Germany and the Netherlands for the one-day ahead exchange. The available capacity for the one-day ahead exchange has risen clearly during the years 2002-2006.[11] On average nearly 70% more capacity was available in 2006 compared to 2002 during peak hours. However, in 2007 the capacity decreased again as Tennet allocated more capacity to the month and year auctions at the expense of capacity available for the one-day-ahead market.

Table 3 Capacity interconnection Germany – Netherlands in MW

	Capacity in MW for Eon – Tennet plus RWE – Tennet					
Hour	2002	2003	2004	2005	2006	2007
9	759	792	1001	1116	1207	890
10	726	738	941	1057	1195	870
11	712	720	912	1041	1192	870
12	710	718	905	1038	1191	872
13	710	723	917	1045	1189	868
14	713	728	924	1047	1188	867
15	716	741	941	1062	1189	867
16	720	755	959	1077	1191	884
17	705	758	956	1083	1191	884
18	709	760	943	1058	1192	885
19	717	778	958	1067	1204	889
20	719	797	985	1080	1203	890

[11] This does not necessitate that total interconnection capacity has increased. Even with equal total capacity the capacity for the one-day-ahead exchange can increase if less capacity is used by buyers on the year and month exchange.

To analyse the effect of interconnection capacity on price convergence in a simple way, we estimate the relationships:

$$\frac{P^{electricity}_{APX,h,t}}{P^{electricity}_{EEX,h,t}} = \alpha_1 I_{h,t} + \alpha_2 + \varepsilon \;\; and \;\; \frac{P^{electricity}_{APX,h,t}}{P^{electricity}_{PWXT,h,t}} = \alpha_3 I_{h,t} + \alpha_4 + \varepsilon, \qquad (3)$$

where I represents the interconnection capacity between Germany and the Netherlands at day *t* for hour *h*. This relationship is, of course, too simple to capture all aspects of the complex impact of interconnection capacity on wholesale price differences. In reality, when bidders at the auction for interconnection capacity do not expect that capacity is fully used, an increase in capacity will not have any effect on price differences between countries. When estimating the above relationship using the whole sample, we therefore underestimate the real impact of enlarging the interconnection capacity on peak hours when this capacity is fully used. Therefore, we also estimate the same equation using only data where the interconnection capacity is really binding, which we take to be when the price paid for interconnection is at least equal to 10 € per MW.[12] This is, on average, the case for 20% of our observations for peak hours.

Table 4 presents the estimated marginal effects for an assumed 100 MW increase in interconnection capacity, where the second column for each comparison is based on an analysis where only the data points are used where interconnection capacity is really binding.[13] If $\alpha_1<0$ ($\alpha_3<0$) then an increase in interconnection capacity leads to lower prices for the APX compared to the EEX (PWXT). This is the case for all hours as all coefficients are negative and significant. As may be expected, the coefficients for observations where capacity is binding are higher. This means that increasing capacity has a larger effect on price convergence for hour/day combinations where currently a lack of capacity is present.

Table 4 Effect interconnection capacity Germany – Netherlands on price ratios

	Price APX/EEX		Price APX/PWXT	
Hour	All observations	Price interconnection > 10 euro per MWh	All observations	Price interconnection > 10 euro per MWh
9	-0.04^{***}	-0.09^{***}	-0.04^{***}	-0.09^{**}
10	-0.12^{***}	-0.17^{***}	-0.12^{***}	-0.17^{***}
11	-0.12^{***}	-0.15^{***}	-0.13^{***}	-0.16^{***}
12	-0.10^{***}	-0.11^{***}	-0.15^{***}	-0.16^{***}
13	-0.08^{***}	-0.11^{***}	-0.09^{***}	-0.12^{***}
14	-0.12^{***}	-0.15^{***}	-0.13^{***}	-0.17^{***}
15	-0.10^{***}	-0.12^{***}	-0.10^{***}	-0.14^{***}
16	-0.10^{***}	-0.17^{**}	-0.11^{***}	-0.19^{**}
17	-0.08^{***}	-0.12^{***}	-0.08^{***}	-0.11^{**}
18	-0.15^{***}	-0.23^{***}	-0.16^{***}	-0.23^{***}
19	-0.04^{***}	-0.07^{**}	-0.04^{***}	-0.08^{***}
20	-0.02^{***}	-0.06^{**}	-0.02^{***}	-0.07^{***}
Average	-0.09	-0.13	-0.10	-0.15

Note: $^{***}/^{**}/^{*}$ means significance at 1/5/10%.

[12] We use the price between RWE and Tennet for each hour/day combination.
[13] On average the effects do not change significantly when we include a trend in the estimations.

These figures can best be understood in comparison to the earlier analysis where we estimated the size of the average price ratio in each peak hour between the Netherlands and Germany on one hand and the Netherlands and France on the other hand (Table 1). Comparing these estimates with the estimates presented in Table 4 allows us to calculate how much additional capacity is still needed, on average, before we have full market integration. The results of this calculation are presented in Table 5.

The necessary capacity increase to reach full market integration depends of course on whether coefficients are taken from the full sample or from the sample where capacity is binding. In the first case 420 MW is needed before the Netherlands and Germany are integrated in all hours, while an additional 427 MW of interconnection capacity is needed for market integration of the Netherlands and France. This is, however, probably an overestimation of the increase in interconnection capacity that is really needed for market integration as the effect of an increase in interconnection capacity is larger when we restrict the analysis to observations where capacity is binding. Now, only 211 MW additional interconnection capacity is needed to be able to speak of a fully integrated market between the Netherlands and Germany and only 140 MW to integrate the Netherlands and France. Clearly, relatively little additional interconnection capacity is needed to be able to speak of full market integration.

Table 5 Necessary increase in interconnection capacity Germany – Netherlands in MW

	Capacity needed to integrate APX/EEX		Capacity needed to integrate APX/PWXT	
Hour	All observations	Price interconnection > 10 euro per MWh	All observations	Price interconnection > 10 euro per MWh
9	22	10	315	136
10	14	10	84	60
11	107	86	139	110
12	180	162	135	122
13	43	33	59	44
14	20	17	66	52
15	48	38	86	63
16	0	0	15	8
17	79	55	131	97
18	193	131	202	140
19	382	211	214	116
20	420	153	427	121
Max.	420	211	427	140

The already planned extensions of the import capacity are already larger than the numbers we have estimated to be necessary to be able to speak of market integration.[14] We know, for example, that the planned installation of phase shifters (dwarsregeltrafo's) will increase the interconnection capacity with Germany with about 500 MW in the near future. This increase alone is enough to arrive at a capacity that is necessary for full market integration. Furthermore, the Norned cable with a capacity of 700 MW will be available in 2008 and phase shifters will increase the

[14] Note that we could not analysis the effect of connections with other countries as data were not available for a sufficient long time period (France) or capacity was not increased in the period 2002-2007 (Belgium). This means that it is not sure whether an increase in interconnection capacity with other countries has the same effect as an increase with Germany.

interconnection capacity with Belgium with 300 MW.[15] These increases will stimulate market integration, reducing the chance even further that significant prices differences may exist at any point in time between the Netherlands and other countries. We therefore conclude that in the next two years, even during peak hours, the geographical market will be larger than the Netherlands.

To analyse the effect of market coupling we include in equation (3) a dummy variable for the observations since November 21 2006, the first day the Belpex, PWXT and APX were coupled. We expect the coefficient for this dummy to be significant and negative, suggesting that the price ratios of APX compared to EEX and PWXT are lower. While this is obvious for the price ratio APX/PWXT, an effect for the ratio APX/EEX could also be expected if the electricity markets of the Netherlands and Germany are integrated indeed.

Nearly all coefficients are indeed significant and negative (see Table 6).[16] Only for the APX/EEX ratio for hour 20 and for the APX/PWXT for hour 16 no significant effect is found. Comparing the effects with the effects of increases in interconnection capacity shows that the effects of market coupling are quite substantial. The effect for the APX/EEX ratio is on average equal to an increase in interconnection capacity with 317 MW, while the effect for the APX/PWXT ratio equals 278 MW. For individual hours this figure is even higher with a maximum for hour 19 in both comparisons (469 MW for the APX/EEX and 530 MW for the APX/PWXT). This shows that market coupling is indeed an effective way to integrate markets.

Table 6 Effect market coupling on price ratios

Hour	Price APX/EEX	Price APX/PWXT
9	-0.13*	-0.13*
10	-0.38***	-0.34**
11	-0.36***	-0.30**
12	-0.37**	-0.32**
13	-0.24*	-0.21*
14	-0.37*	-0.33**
15	-0.28**	-0.26**
16	-0.28*	-0.25
17	-0.25*	-0.26**
18	-0.43**	-0.51**
19	-0.17**	-0.22***
20	-0.09	-0.09**
Average	-0.28	-0.27

Note: ***/**/* means significance at 1/5/10%.

Table 3 shows that the available interconnection capacity decreased in 2007 for the one-day-ahead market with on average 316 MW. Our trend analysis makes clear, however, that this did not result in less price convergence in 2007. Apparently the effects of market coupling, started just before less capacity became available, fully compensated for the decrease in interconnection capacity.

[15] See NMa (2006), e.g. article 152, and Allen & Overy (2007), Toelichting aangeboden remedies in kader van beoogde Essent/Nuon fusie, May 15.

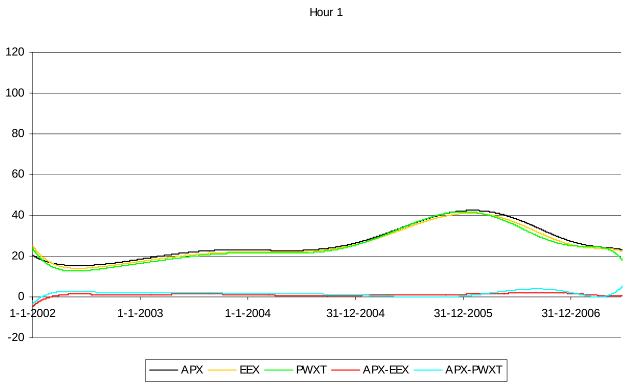
[16] The results for the effects of interconnection capacity on the price ratios are not significantly influenced by including a dummy for market coupling.

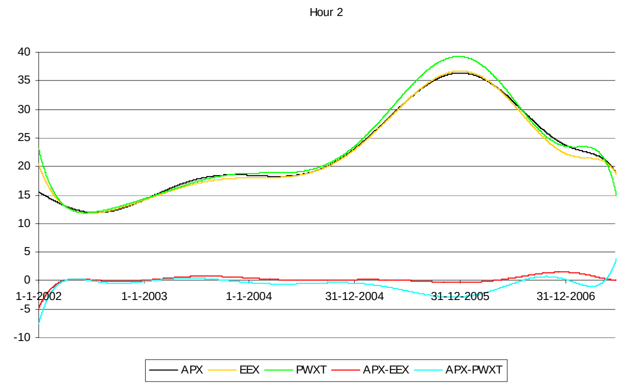
The effects of the market coupling of APX, PWXT and Belpex are interesting as the coming years other markets will be coupled as well. At the end of 2007 a coupling is expected between APX and Nord Pool when The Norned cable is finished. Coupling with the EEX is expected for the near future. Given the results of the coupled APX, PXWT and Belpex, these new initiatives will probably result in a faster process towards market integration.

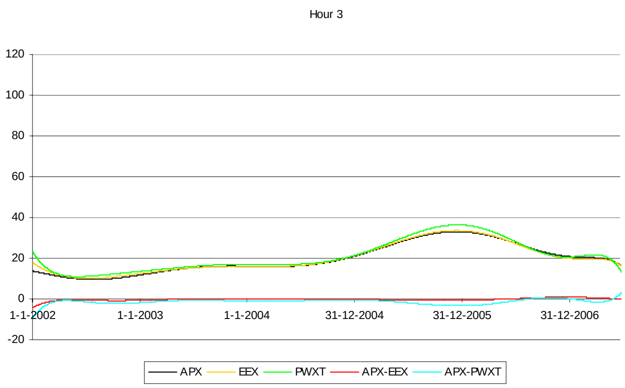
6. Conclusions

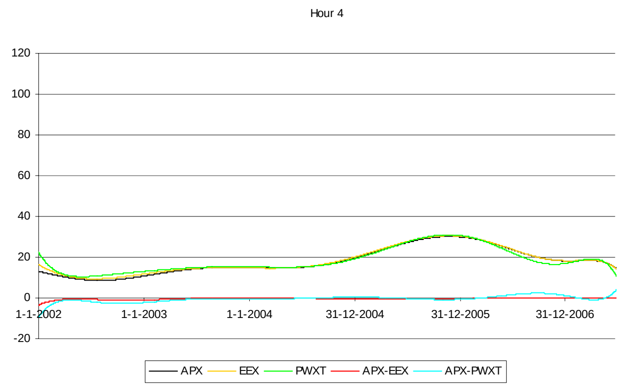
The conclusion of this analysis is crisp and clear. At this very moment a fully integrated wholesale electricity market between the Netherlands and Germany/France does not exist yet. However, the process of price convergence is so strong that market integration can be expected to take place in approximately the next two years. The pure data analysis points in this direction, as well as the analysis relating price difference to available import capacity and to market coupling. Over the last years available capacity has increased considerably and this process of increasing import capacity will continue in the near future when new connection capacity will become available. The same holds true for market coupling as the APX, Belpex and PWXT are expected to couple in the near future with other European exchanges. Therefore, the structural reasons for price convergence in the past, will show up in an even stronger way in the near future. The structural analysis also points at full market integration in the very near future.

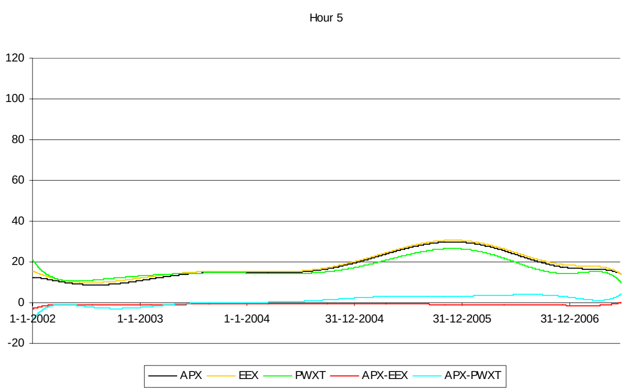
Appendix A. Estimated trends for non-peak hours: prices in euro per MWh

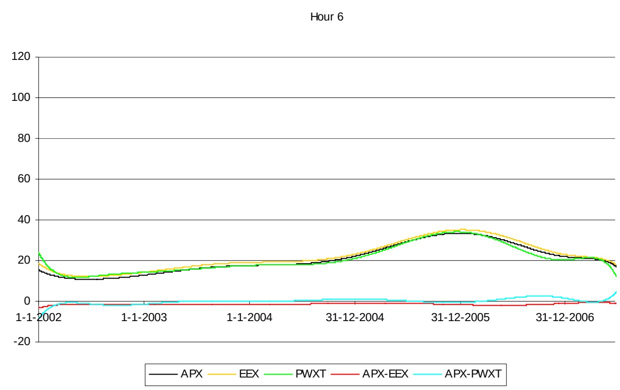


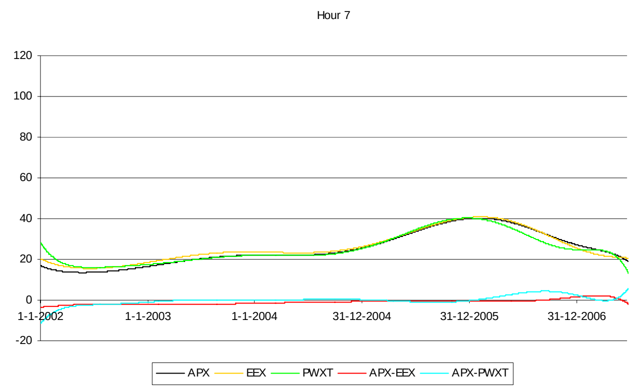








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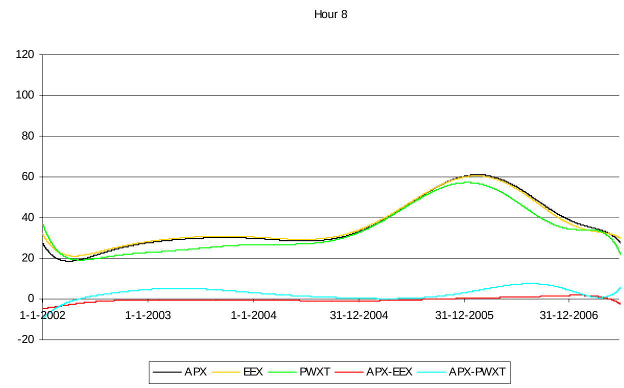
80
60
40
20
0
-20
1-1-2002
1-1-2003
1-1-2004
31-12-2004
31-12-2005
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT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1-1-2002
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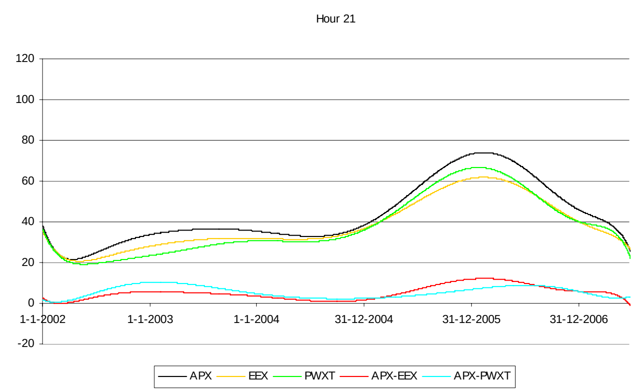
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT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-20
1-1-2002
1-1-2003
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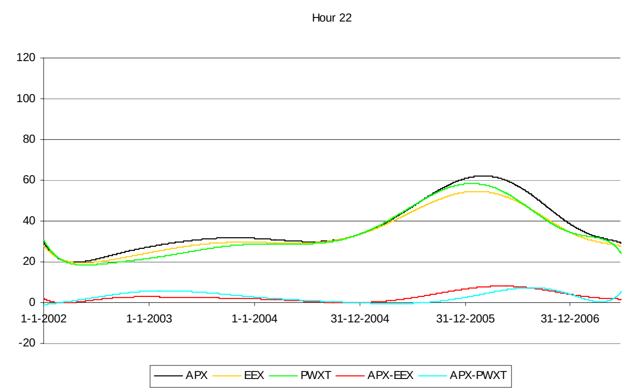
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT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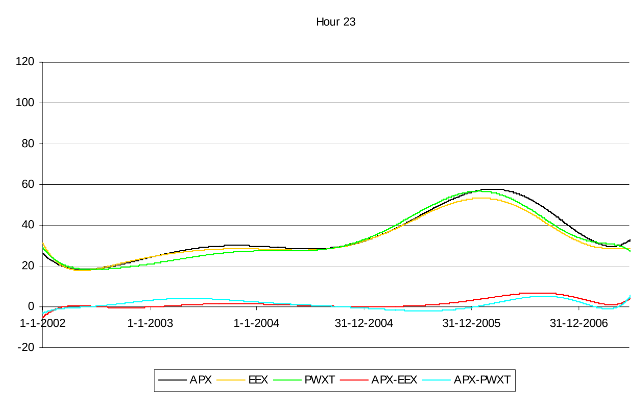
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT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60
40
20
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-20
1-1-2002
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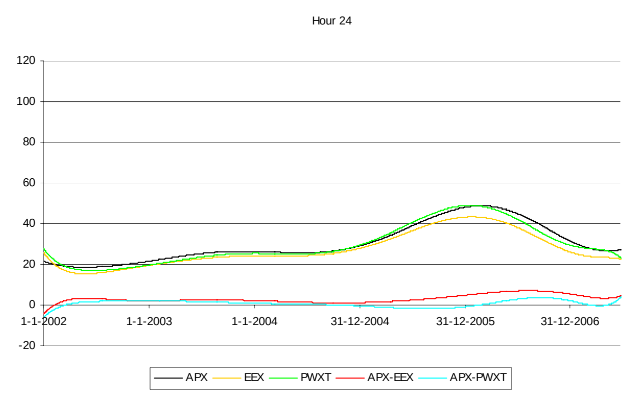
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT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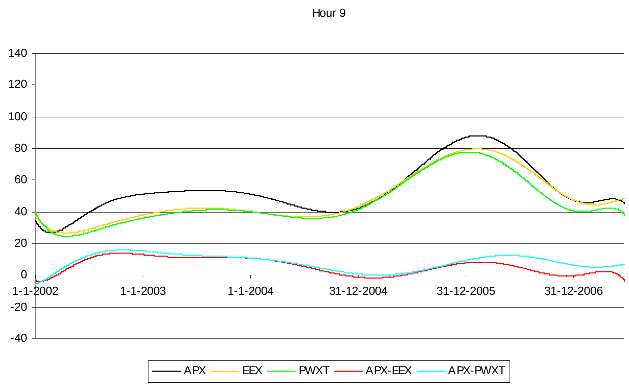
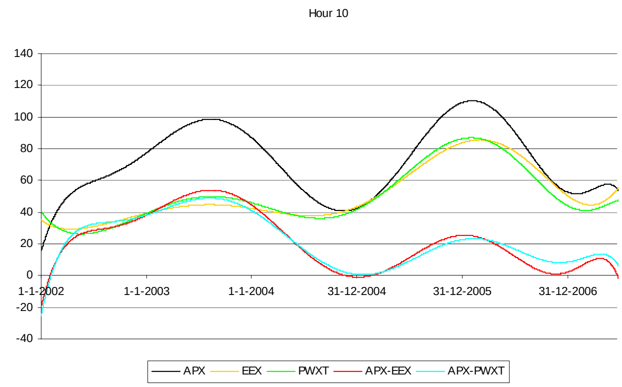
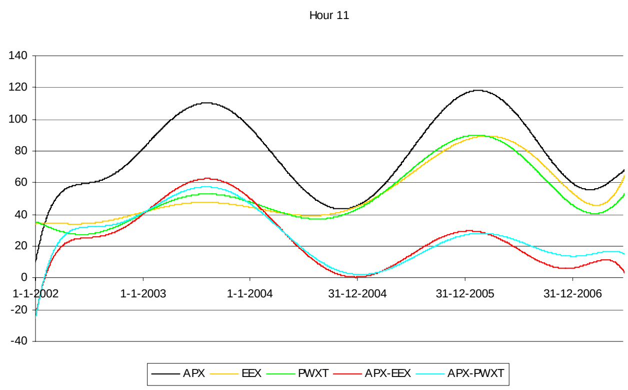
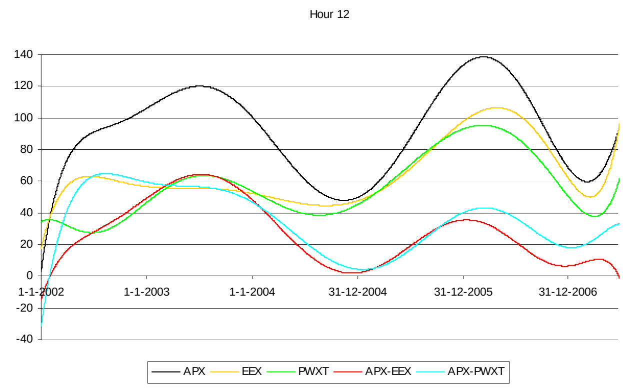
80
60
40
20
0
-20
1-1-2002
1-1-2003
1-1-2004
31-12-2004
31-12-2005
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT

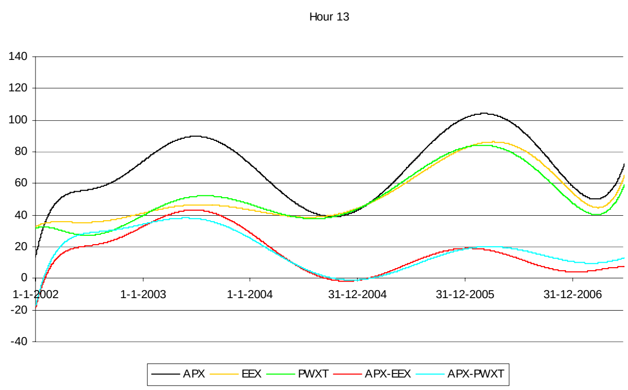
Appendix B. Estimated trends for peak hours: prices in euro per MWh

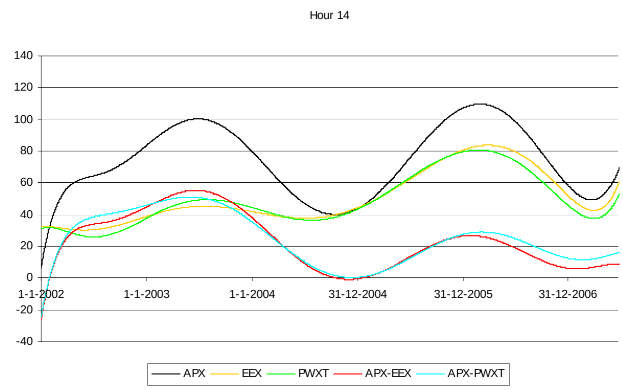


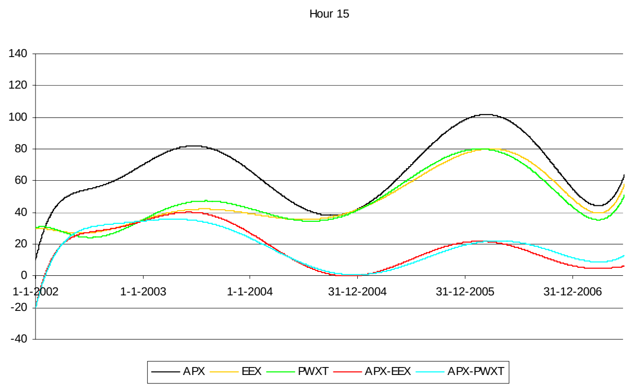








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-40
1-1-2002
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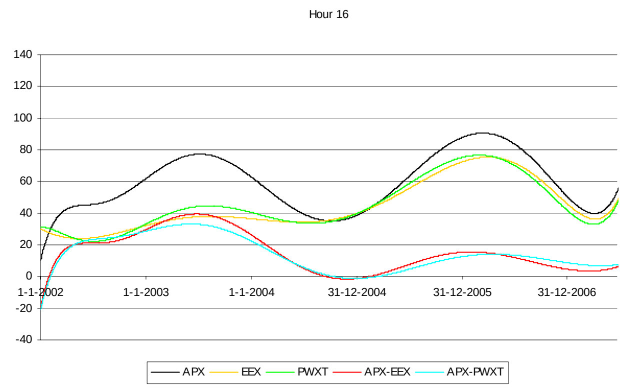
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT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31-12-2006
APX
EEX
PWXT
APX-EEX
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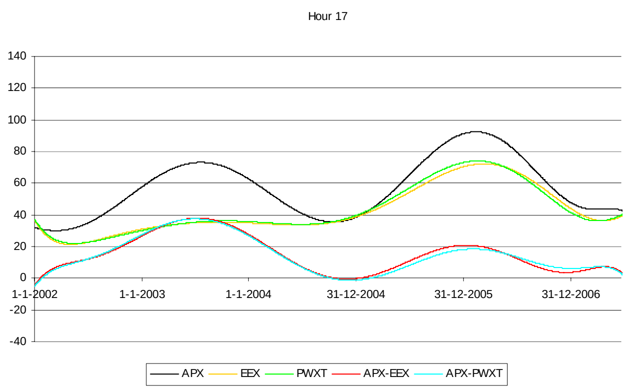
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31-12-2006
APX
EEX
PWXT
APX-EEX
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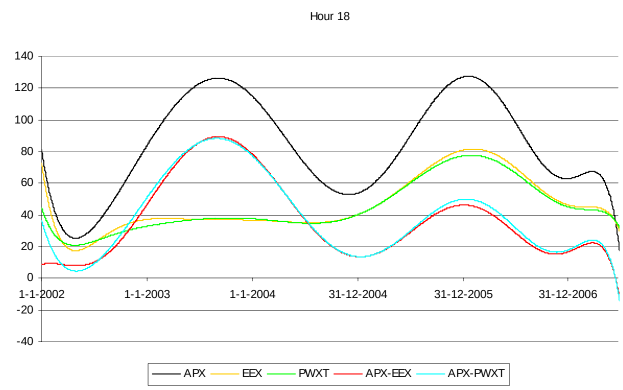
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APX
EEX
PWXT
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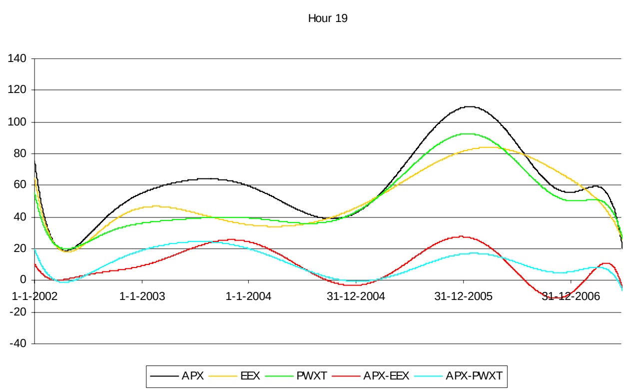
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-40
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31-12-2006
APX
EEX
PWXT
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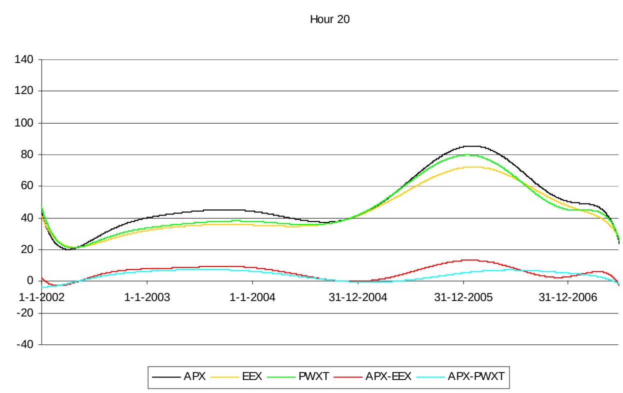
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31-12-2004
31-12-2005
31-12-2006
APX
EEX
PWXT
APX-EEX
APX-PWXT