European Commission

Quarterly Report on European Electricity Markets

MARKET OBSERVATORY FOR ENERGY

VOLUME 4, ISSUE 4: OCTOBER 2011 – DECEMBER 2011

EUROPEAN COMMISSION
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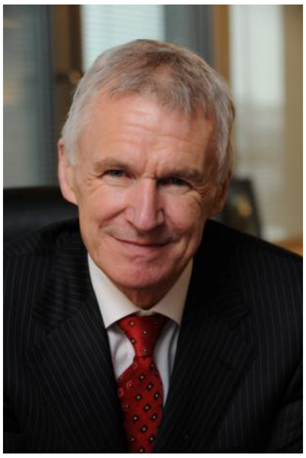
Director-General



Dear readers,

In the fourth quarter of 2011, the eurozone and other European countries experienced deteriorating economic conditions. This was the background for contracting gross value added in major energy intensive sectors such as manufacturing, construction and mining which led to falling EU industrial demand for electricity.

In addition, except for a short-lived cold spell in mid-November, the weather was milder than usual in most parts of Europe throughout the period.

The combination of reduced demand for heating from households and a slowdown in industrial demand for energy resulted in one of the lowest levels of electricity consumption recorded in the EU during the last decade.

These developments impacted wholesale prices for electricity in most of the EU markets throughout the observed period. Alongside spot contracts, forward power prices experienced a continuous downslide in the fourth quarter on projections of weaker future power demand.

There were notable exceptions, however. In Italy, power prices remained high during the whole quarter as a consequence of high oil-indexed prices of gas-powered generation. In Greece, the months of November and December were colder than usual and the substitution of heating oil by electricity in domestic heating resulted in high power prices. In the Balkans, continued high power demand and resulting high prices favoured export arbitrage opportunities from neighbouring countries of Central and Eastern Europe, exerting pressure on domestic power prices in the region.

The negative economic outlook also had an impact on the price of emission allowances, with the consequence that prices fell to levels lower than in the economic recession in 2009.

The topic of focus in the current report is about carbon markets, and more specifically: CO2 factors, which are an important element of the draft Commission guidelines for state aid in the context of the amended EU emission allowance trading scheme post-2012.

Philip Lowe

HIGHLIGHTS

- In the fourth quarter of 2011 milder than usual weather in Europe resulted in a small seasonal increase in heating demand. Above average temperatures in Northern and Western Europe led to reduced demand for power at the end of 2011, which resulted in significantly lower wholesale electricity prices than in December 2010, which was the most recent previous period when Europe experienced a long-lasting cold spell.

- The economic situation in Europe also limited the industrial demand for electricity. In Q4 2011 the economies of the EU-27 registered the lowest year-on-year GDP growth rate since the first quarter of 2010. Concerns about the future of some economies in the eurozone led to falling West European forward power prices during Q4 2011. In mid-December, carbon prices, also fell to levels below that observed even in the most depressed period of the economic crisis in early 2009.

- At the beginning of October 2011 abundant rainfalls contributed to extremely low power prices in some areas of the Nordic power market while in other areas prices remained higher, as a result of bottlenecks in power transportation capacities. Prices in different areas recoupled in the second half of Q4 2011 after the impact of high hydro-power generation disappeared from the Nordic region.

- In the Central Eastern European region, prices in the markets geographically bordering the Balkan countries remained higher than in other markets of the region. This was primarily due to increasing power exports from these countries to the Balkans. One-off events, such as cancellation of daily auctions in mid-October in some countries or restrictions in cross border capacities between the Czech and Slovak market in November 2011 also contributed to higher than usual price volatility in the region.

- Higher interdependence of EU markets could be witnessed in terms of increasing volumes of cross border electricity flows in Q4 2011, which contrasted with decreasing power demand in the EU and declining wholesale traded volumes in European markets.

- In this quarter the 'Focus on' part covers the proposal for the CO_2 factors in the draft new State Aid Guidelines in the context of the Emission Allowance Trading System (ETS) after 2012.

NEW FEATURES IN THIS REPORT

- Market reporting coverage has been extended to the Republic of Ireland and Northern Ireland.

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QUARTERLY REPORT
ON
EUROPEAN ELECTRICITY MARKETS

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A. Recent developments in the electricity markets across Europe

- Electricity supply in the EU-27 was 817.4 TWh in the Q4 2011 (*See Chart 1*), being the second lowest in a decade among the fourth quarters. Compared to Q4 2010 the total EU-27 electricity supply was down by 3.8%.
- The main reason for this low quarterly power supply was the mild weather that lowered power demand especially in November and December 2011.
- The number of heating degree days[1] in these two months were substantially lower compared both to the long term average and to the same period of 2010 (*See Table 1*).
- Compared to the third quarter of 2011 the EU-27 GDP decreased by 0.3% and in comparison to Q4 2010 it only grew by 0.7%, which was the lowest

[1] Heating degree days (HDDs) express the severity of a meteorological condition for a given area and in a specific time period. HDDs are defined relative to the outdoor temperature and to what is considered as comfortable room temperature. The colder is the weather, the higher is the number of HDDs. These quantitative indices are designed to reflect the demand for energy needed to heat a building. Cooling degree days (CDDs) are defined in a similar manner; the higher the outdoor temperature is, the higher is the number of CDDs. On those days, when the daily average outdoor temperature is higher than 21°C, CDD values are in the range of positive numbers, otherwise CDD equals zero.

growth rate since Q1 2010 (*See Chart 2*). In manufacturing industry, which is an energy intensive economic branch the year-on-year gross value added decreased by 1.4% in Q4 2011. Lower economic growth also contributed to lower demand for power in the EU.

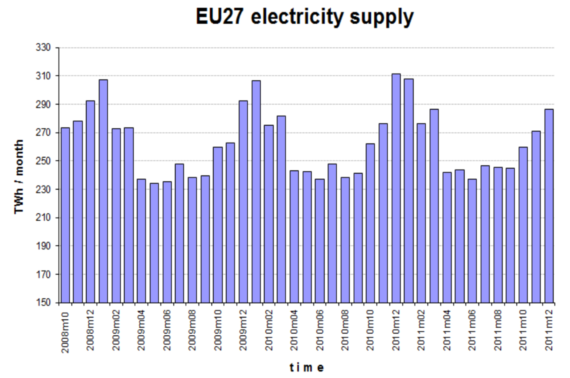


Chart 1 *Source : Eurostat*

Adapting to the changes in Eurostat's database, electricity supply is now presented instead of consumption.

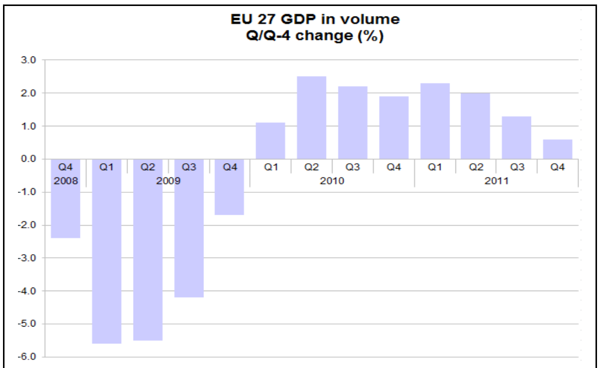


Chart 2 *Source: Eurostat*

Selected Principal European Economic Indicators Gross domestic product (GDP) at market prices is the final result of the production activity of resident producer units. It is defined as the value of all goods and services produced less the value of any goods or services used in their creation. Data are calculated as chain-linked volumes (i.e. data at previous year's prices, linked over the years via appropriate growth rates). Growth rates with respect to the same quarter of the previous year (Q/Q-4) are calculated from raw data.*

EU 27 Heating Degree Days in Q4
Values for 2009, 2010, 2011 and 1980 – 2004 average

	October	November	December
2009	249.62	318.69	520.91
2010	269.28	385.58	609.43
2011	234.30	354.44	450.97
LT avg.	236.95	391.82	512.14

Source : Eurostat /JRC

A.1 Wholesale markets

- In the fourth quarter of 2011 the monthly average crude oil price was moving in a narrow range of 80-82 €/bbl (*See Chart 1*). The daily crude oil price quotations shaped up a slightly increasing trend, mainly due to the increasing seasonal demand, news on potential EU sanctions against Iran and to the depreciation of the euro against the USD in November and December. Meanwhile, the situation of European economy exerted a lowering impact on crude oil demand.
- Natural gas prices showed a strong correction in the first two weeks of October 2011 from their lows at the end of Q3 2011 (*See Chart 2*). Until mid-December gas prices remained stable and during the last two weeks of 2011 they plunged in the consequence of mild winter and heating demand being lower than the seasonal norm.
- In the consequence of increasing coal imports to Europe (especially from the US), the increasing coal supply weighed on prices, which was partially cushioned by depreciating euro (*See Chart 4*). At the beginning of Q4 2011 daily coal import price stood at 88.4 €/Mt and at the end of the quarter it

was 85.9 €/Mt (expressed in USD these values were 117.8 \$/Mt and 111.2 \$/Mt, respectively).

- Prices for European emission allowances prices continued their downward trend which started in June 2011 during the fourth quarter of the year (*See Chart 3*). Emission prices also serve as an indicator of the economic situation in Europe; and economic concerns in the eurozone weighed on carbon prices. European Commission's decision on selling 300 million emission quotas in mid-November also contributed to the decrease in carbon prices which reached their quarterly lows on the 14th of December in a range of 7-8 €/ CO_2 tonnes of equivalent. This price was even lower than in February 2009 during the economic crisis in (9-10 €/CO2 tonnes of equivalent).
- On the 21st of December carbon prices soared following the vote in the European Parliament's committee on withholding a considerable amount of emission allowances from entering into the third phase of the ETS system. However, this price hike proved to be short-lived and at the end of 2011 carbon prices finished the year close to their quarterly lows.

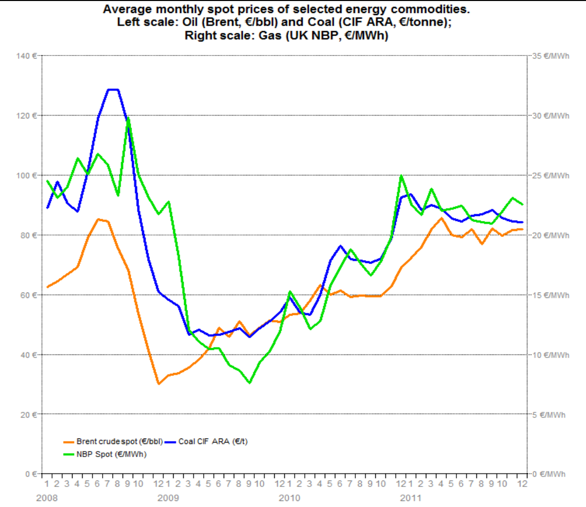


Chart 1 Source: Platts

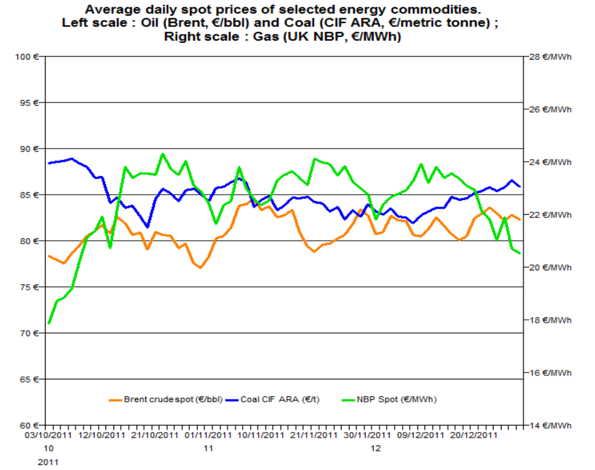


Chart 2 *Source: Platts*

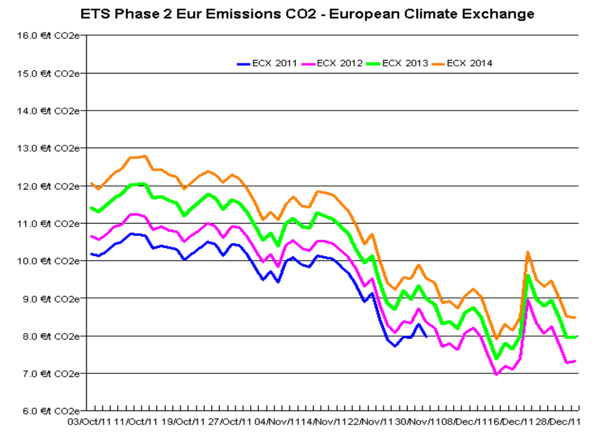


Chart 3 *Source: Platts*

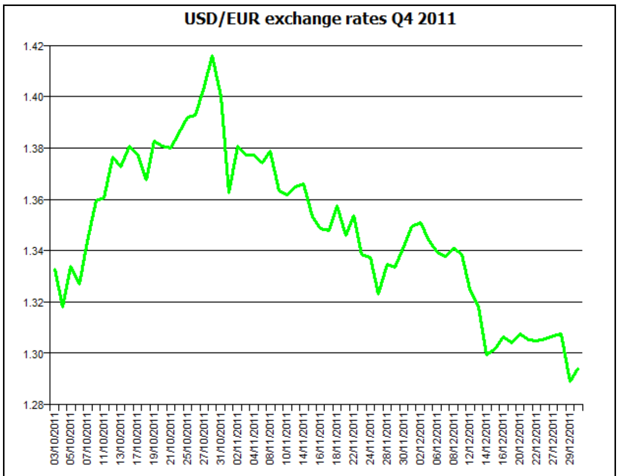
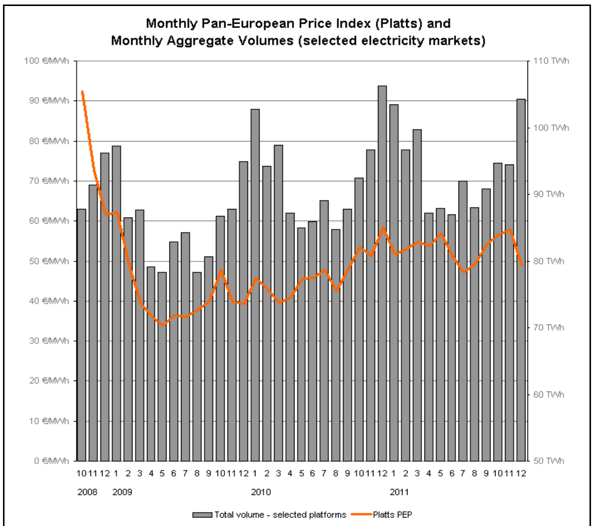


Chart 4 *Source: Platts*

A.1.1 Day-ahead

EU wholesale markets

- Following the seasonal pattern of the last couple of years traded volume of day-ahead electricity rose significantly during Q4 2011 compared to the previous quarter. However, compared to Q4 2010 the overall traded volume decreased by 0.7%.
- In December 2011 the combined monthly traded volume of power on the fifteen observed markets reached 104.2 TWh, which was the second highest monthly volume ever.
- From July to November 2011 Platt's Pan-European Price Index (PEP) rose by 10 €/MWh and in November it reached 58 €/MWh, which was the highest since December 2010. In different power regions different reasons led to the highest (or close to the highest) monthly average prices in November 2011, the analysis can be found in the respective chapters of this quarterly report. PEP index fell back to 48.6 €/MWh in December 2011, the main reason was the lower-than-usual power demand in most of the European countries, mainly affected by mild weather.



Sources: Platts (price index) and selected European electricity wholesale markets (volumes). The selected markets are :
Nordpool Spot A.S;
European Energy Exchange (EEX);
Amsterdam Power Exchange (APX Power NL);
Powernext Day-ahead S. A.;
Belpex Spot;
Energy Exchange Austria (EXAA);
Gestore del Mercato Elettrico (IPEX);
Mercado de Electricidad (OMEL);
Operator trhu s elektrinou (OTE);
Towarowa Gielda Energii S.A. (PolPX);
Hungarian Power Exchange (HUPX);
APX Power UK;
Operatul Pietei de Energie Electrica din Romania (OPCOM);
BSP Southpool;
Διαχειριστης ελληνικου συστηματος μεταφορας ηλεκτρικης ενεργειας (ΔΕΣΜΗΕ), Hellenic Transmission System Operator

Regional markets

Central Western Europe (DE, FR, NL, BE, AT)

- The increase in the traded volume of day-ahead power in the five markets of Central West European power region continued in Q4 2011; in December alone the combined monthly volume exceeded 30 TWh (*See Chart 1*). The quarterly traded volume in the CWE region was 91

TWh, being 9.5% higher than in Q4 2010. This amount of traded volume represented 26.3% of the region's quarterly power supply (345 TWh in Q4 2011).

- Both monthly baseload and peakload prices were stable in October and were the highest in November in Q4 2011. In December 2011 they fell back and were lower than a year before.
- An important factor in the evolution of CWE power prices in Q4 2011 was the mild weather as heating degree day values were lower by more than 10% than the long term average in each month of the quarter.
- Electricity baseload contracts were traded in the in the range of 50-60 €/MWh throughout October. A short-lived cold spell in mid-November assured the highest electricity prices during the whole quarter (*See Chart 2*). This time daily baseload average prices were above 60 €/MWh, and on the 16th of November French peakload prices reached 81 €/MWh following a strike threat in the energy sector. November was a dry month, which resulted in a lower level of hydro-generation, providing a support for electricity prices in that period.
- From the last week of November 2011 day-ahead baseload power prices began to decrease and finished the year around (or even below) 40 €/MWh, down from 60 €/MWh (or above) observed in mid-November. This significant decrease in prices was mainly due to the unusually mild weather, constantly increasing nuclear power availability in France (*See Chart 3*), improving hydro-based power generation (*See Chart 9*) and windy weather, prompting higher renewable energy input into the grid. Net electricity exports of France picked up again in November and December after decreasing between August and October (*See Chart 4*)
- Reduced industrial power demand at the end of December during the holiday season also contributed to low electricity prices at the end of the year.
- Q4 2011 marked the first anniversary of launching the market coupling in the CWE region (9th of November 2010). Chart 5 shows that practically no adverse power flows occurred in this quarter.
- In October 2011 due to the mild weather and the impact of the market coupling that took place in November 2010 in the CWE region (*See Chart 5*) only a narrow French premium could be observed which sometimes turned to a discount. In Q4 2011, 85% of the hourly German and French prices were within the range of 1 €/MWh.
- There were only a couple of adverse flows between Austrian and Italy, though this was due to a usually high price difference between the two markets as no market coupling exists (*See Chart 6*).
- German clean dark spread[2] was steadily decreasing during the whole Q4 2011. While at the beginning of the quarter it was above 16 €/MWh, at

[2] Dark spreads are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 35 % efficiency.
Dark spreads are given for UK and Germany, with the coal and power reference price as reported by *Platts*.
Clean dark spreads are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity.

the end of December it fell below 8 €/MWh. The decrease in clean dark spread gained momentum in the second half of November as German power prices started to decrease and coal prices remained more stable. In the second half of December a temporary increase in carbon prices helped pushing down clean dark spreads (*See Chart 7*).

- Decreasing power prices can also be tracked in the evolution of the **biomass spreads**[3] (*See Chart 8*). Biomass-based power generation not backed by policy support measures appeared uncompetitive by the end of the fourth quarter of 2011. This development was a consequence of low electricity prices in the CWE region, which, in the case of Germany, was further amplified by higher river shipment freight rates that peaked at the end of November, with a value above 27 €/Mt. In the first ten months of 2011 the average freight rate was 9.6 €/Mt.
- In the first half of Q4 2011 short term price volatility compared to the one-year backward looking one decreased in the absence of market-mover events. From mid-November, as the first cold spells arrived, volatility picked up again. At the end of the year higher volatility was also reinforced by windy weather and the holiday season. (*See Chart 10*)

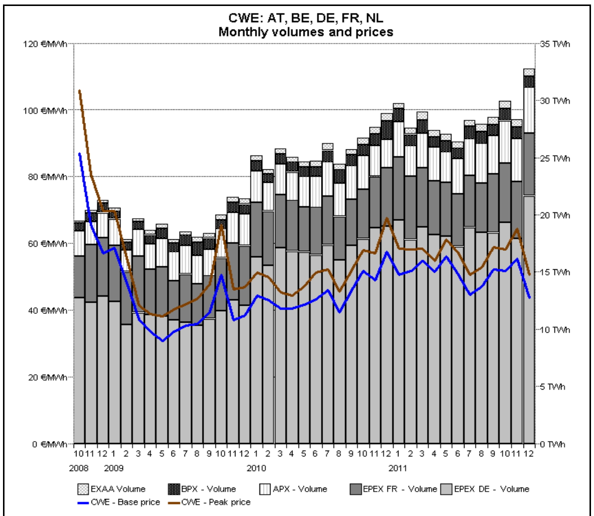


Chart 1 *Source: Platts*

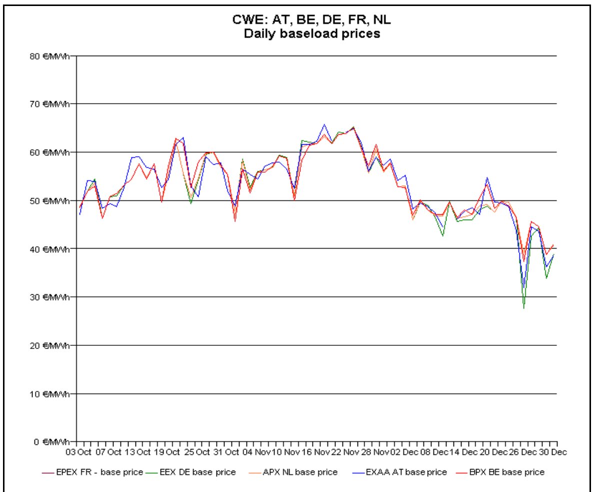


Chart 2 *Source : ENTSO-E Vista*

[3] Biomass spreads are indicative values giving the average difference between (1) the combined price of electricity and carbon emission on the corresponding day-ahead market and (2) the price of industrial wood pellets (delivered month-ahead ex-ship at Rotterdam).
Biomass spreads do not include operation and maintenance costs. However, the German spreads include transport costs of shipping the pellets along the Rhine (Rotterdam – Cologne area).
Specific calculation assumptions: conversion factor of 1 ton of standard wood pellet contains 4.86 MWh of energy; generation efficiency of coal and biomass fired power plants equals 35%; the price of carbon emission is defined as the difference of the German dark and clean dark spreads, calculated according to the methodology of *Platts*.

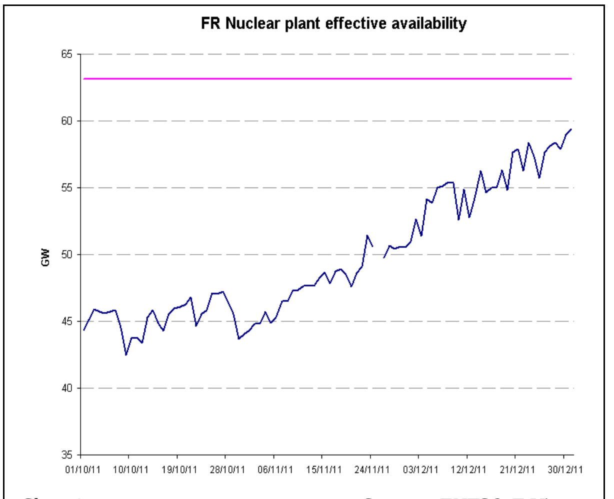


Chart 3 *Source : ENTSO-E Vista*

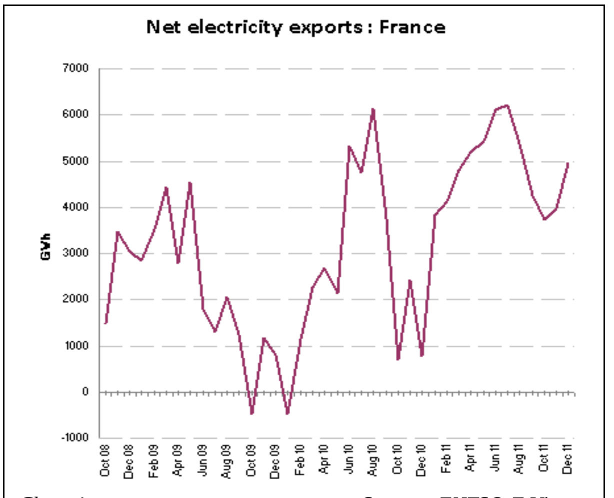


Chart 4 *Source : ENTSO-E Vista*

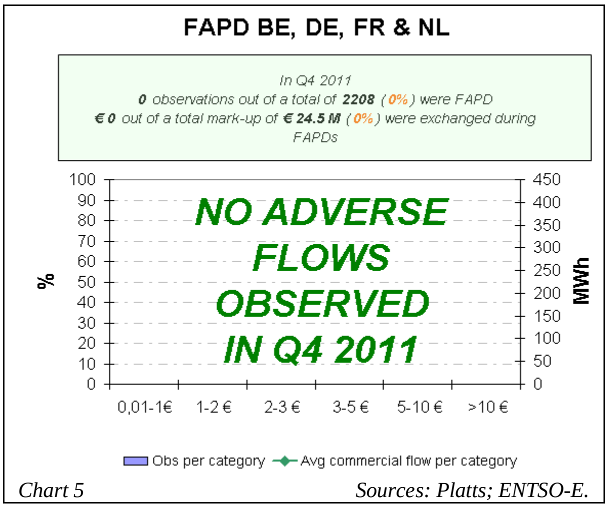


Chart 5 *Sources: Platts; ENTSO-E.*

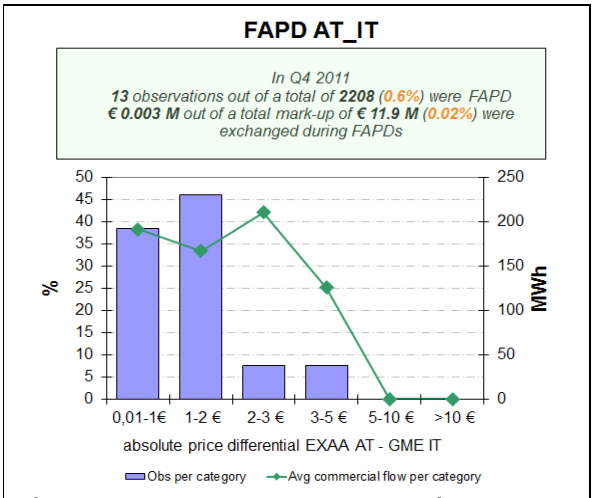


Chart 6 *Source: Platts, ENTSO-E*

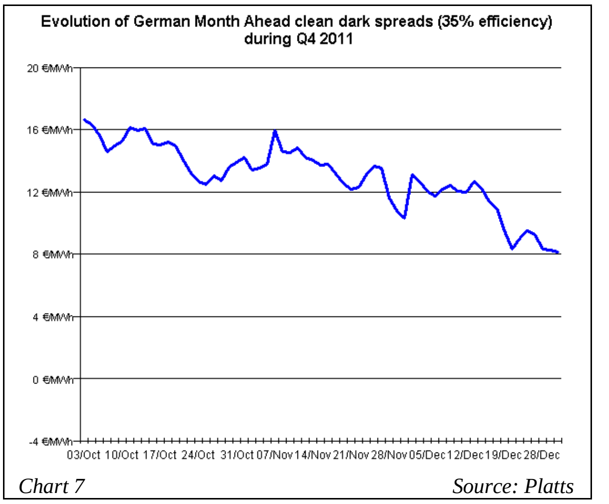
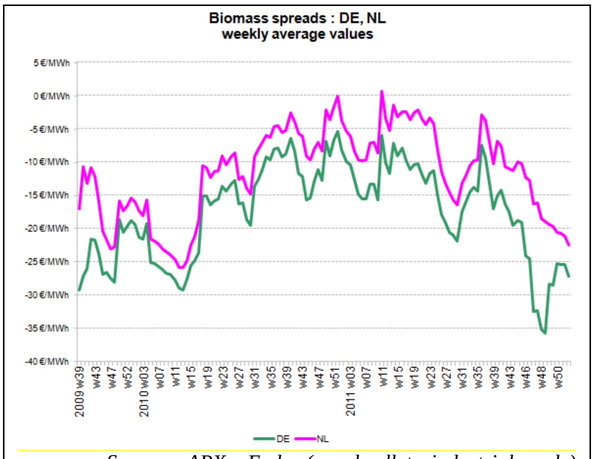


Chart 7 *Source: Platts*



Sources: APX – Endex (wood pellets, industrial grade)

Chart 8 *Platts (electricity and emission prices; freight rates)*

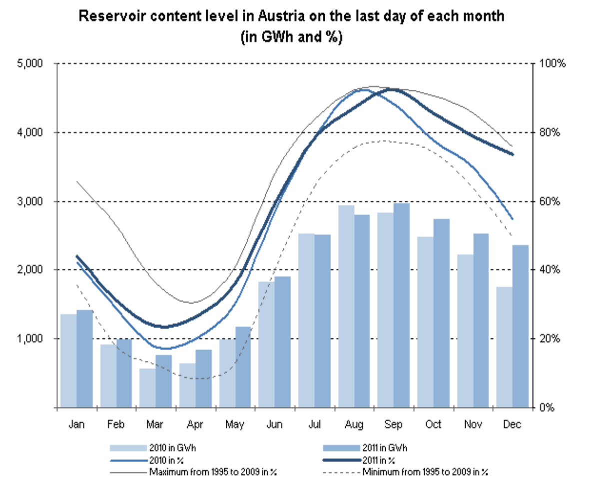
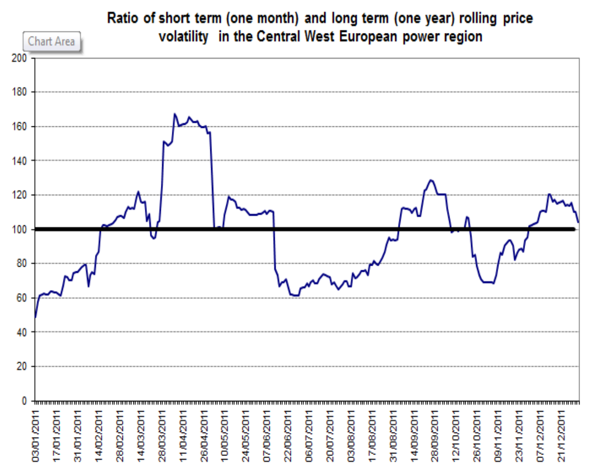


Chart 9 *Source: E-Control*



Source: Power price and volume data, own computations
Chart 10

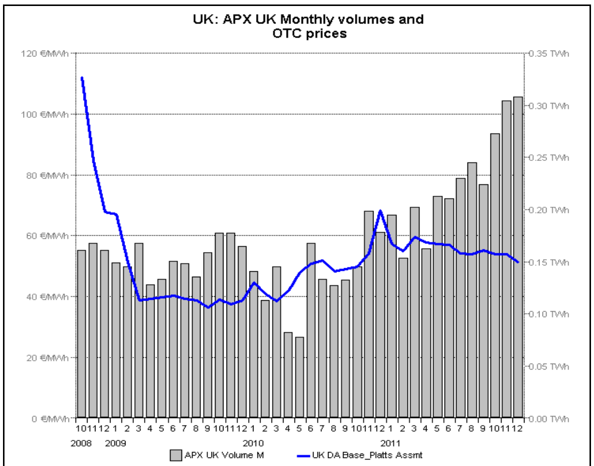
British Isles (UK, IE)

UK

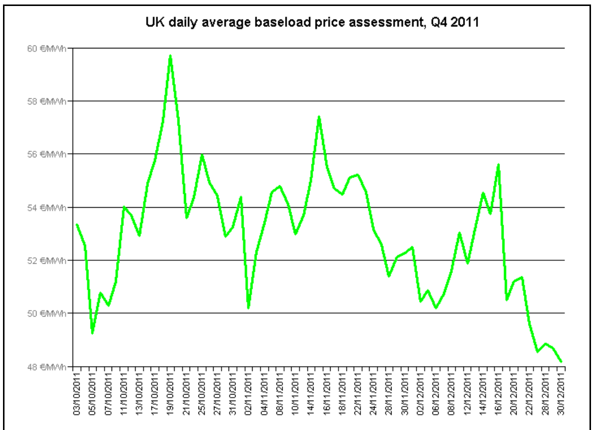
- Monthly average day-ahead baseload power prices in the UK market decreased from 55.3 €/MWh measured in September 2011 to 51.3 €/MWh in December, which latter was the lowest price since June 2010 (*See Chart 1*).
- Weather played an important role in the evolution of power prices in Q4 2011. While at the beginning of October mild temperatures pushed down power prices, from the middle of that month as colder weather forecasts appeared prices began to appreciate which was also reinforced by increasing oil and gas prices. In Q4 2011 electricity wholesale prices peaked on 19th of October (59.2 €/MWh on a daily average). In the following two weeks as temperatures became milder and two nuclear reactors returned to the grid power prices went back to the early October levels. (*See Chart 2*)
- From the beginning of November UK power prices rebounded as equity markets and gas prices started to rise; and by mid-November a cold spell touched much of North and Western Europe. However mid-November UK prices were below their West European peers as higher wind generation helped in keeping prices lower. From the second half of November prices began to fall as weather turned milder and gas prices decreased.
- Until mid-December an upturn in power prices occurred again, primarily due to lower wind generation and an anticipation of colder weather. In the last two weeks of 2011 prices plunged as industrial demand dropped during the holiday season; combined with warmer-than-usual temperatures and a healthy level of wind power generation.
- From the end of October 2011 economic concerns about the future of the eurozone began to weigh on the exchange rate of GBP/EUR, and the euro's depreciation slightly cushioned

the fall in UK power prices in December 2011(*See Chart 3*)

- Frequently alternating weather forecasts and wind generation helped to increase price volatility in the UK power market that rose to its highest level in a year following the slide in prices during the holiday season at the end of 2011.(*See Chart 4*)
- UK daily power price level compared to its French peer fluctuated in a range of +-5 €/MWh during most of Q4 2011 (*See Chart 5*). The biggest discount could be observed on 23rd of November when French prices were high due to cold weather, while a 10 €/MWh UK premium occurred at the end of 2011.
- At the beginning of Q4 2011 clean spark spreads on the UK market stood at higher levels before the recovery of gas prices (*See Chart 6*). During the whole quarter they were on a downward track as decrease in gas prices was not so steep as that in power prices until the end of 2011.



UK values are quoted in € using the €/£ daily exchange rate as reported by Platts.
Chart 1 Source: Platts



UK values are quoted in € using the €/£ daily exchange rate as reported by Platts.
Chart 2 Source: Platts

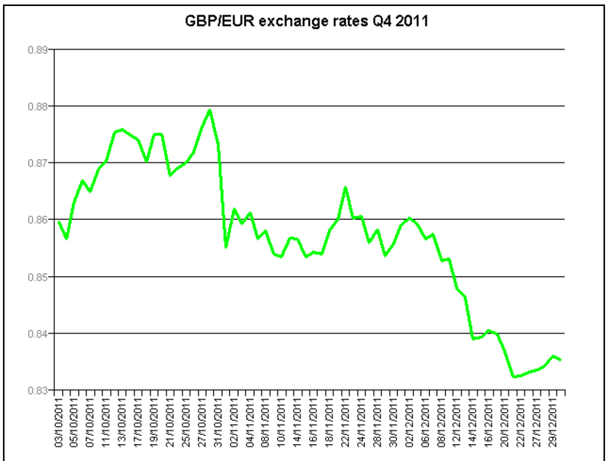


Chart 3 Source: ECB

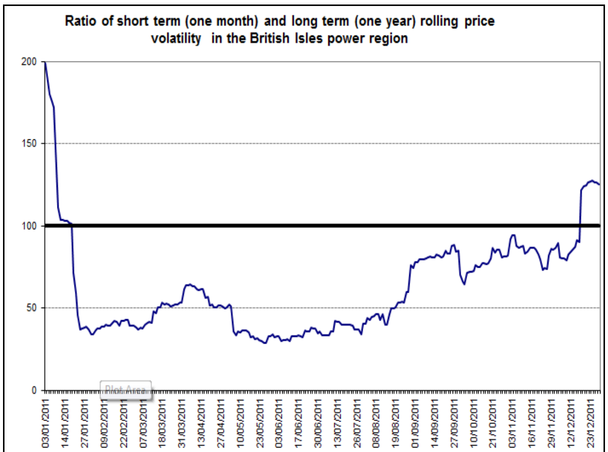


Chart 4
Source: Power price and volume data, own computations.

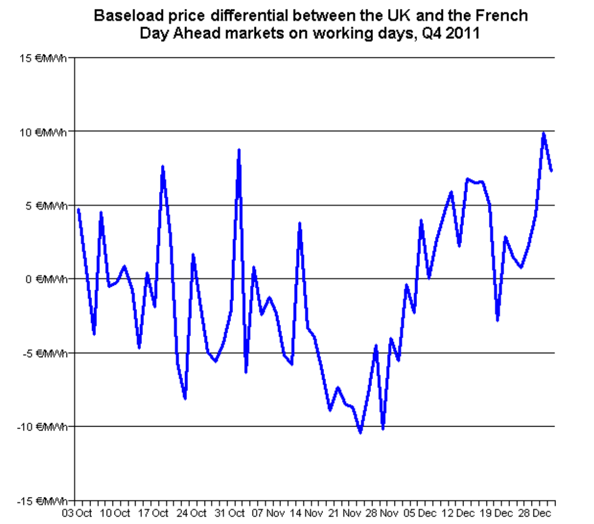
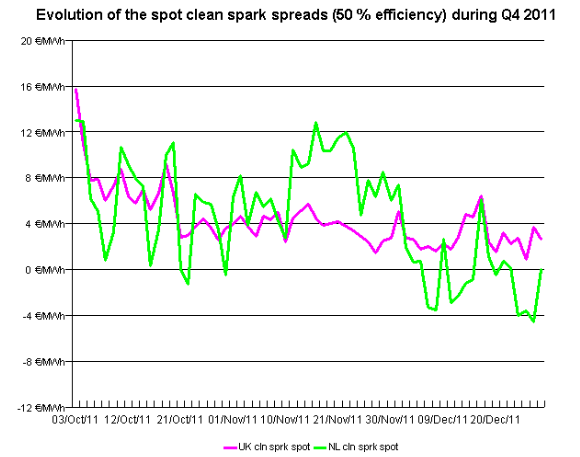


Chart 5 *Source: Platts*



UK values are quoted in € using the €/£ daily exchange rate as reported by Platts.
Chart 6 *Source: Platts*

Ireland

- In the fourth quarter of 2011 monthly traded volume of day-ahead power rose month by month, similarly to last quarter of the previous year, though the quarterly volume decreased by 6.9% compared to Q4 2010 (*See Chart 7*). This decrease might be explained with high heating-related power demand in December 2010 in consequence of the cold weather, which did not occur in Q4 2011.
- The same difference could be observed in the case of monthly average power prices. In Q4 2011 prices remained stable throughout the whole quarter (61-63 €/MWh) and were significantly lower than in December 2010 (69 €/MWh).
- The monthly average traded volume of day-ahead power was around 3 TWh in 2011, which was significantly higher than in many European markets. This can be explained by the fact that the Irish power market functions as a mandatory pool.
- Daily average power prices fluctuated between 55 €/MWh and 70 €/MWh during most of Q4 2011, with a high volatility (*See Chart 8*). With the exception of two trading days in mid-October Irish prices showed a considerable premium to the UK power market (10 €/MWh on a quarterly average - *See Chart 9*).This might be explained by the isolated nature of the Irish wholesale electricity market as the UK is the only country in Europe the island is connected with. The high volatility of the Irish wholesale electricity prices might have been also affected by this geographical isolation of the market.

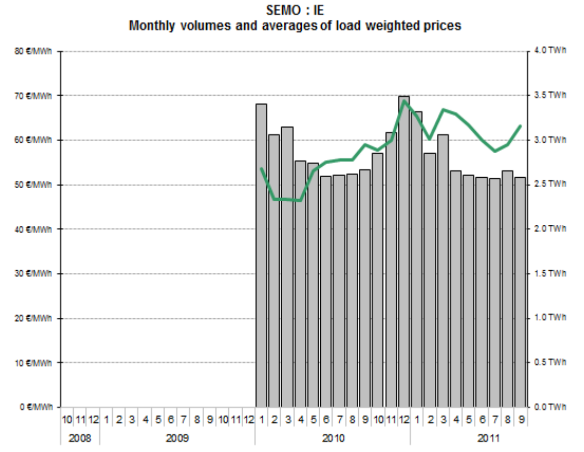


Chart 7 Source: Single Electricity Market Operator (SEMO)

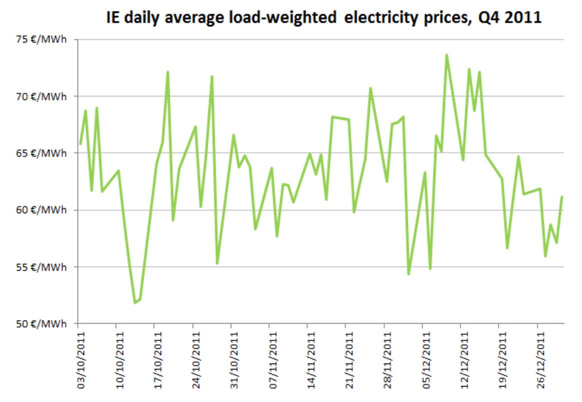


Chart 8 Source: Single Electricity Market Operator (SEMO)

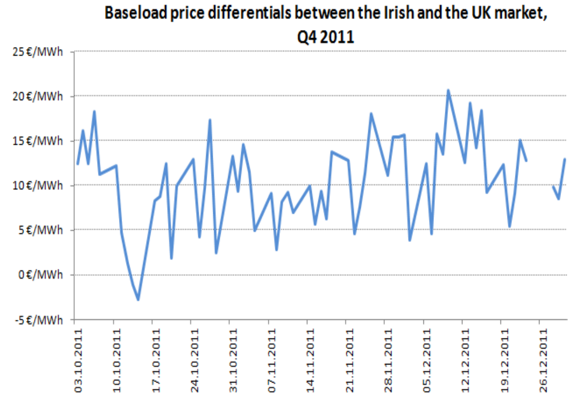


Chart 9 Source: Single Electricity Market Operator (SEMO),Platts

Northern Europe (SE, FI, DK, EE, NO)

- On the 1st of November 2011 Sweden was divided into four bidding power areas. The names of the different areas from north to south are: SE1 (Luleå), SE2 (Sundsvall), SE3 (Stockholm) and SE4 (Malmö).
- Monthly average Nordpoolspot system price reached its intra-annual low in October 2011, the average price of 28 €/MWh was the lowest since May 2008 (*See Chart 1*). This three-year low monthly price was due to very low Norwegian area prices (in the week of October these daily area prices ranged from 4 €/MWh to 12 €/MWh). Similarly to the events of mid-September 2011[4] a sudden increase in hydro-based generation (in the consequence of abundant rainfalls) and bottlenecks in transportation capacities from Norway to other areas led to cheap Norwegian power prices.
- From the second half of October till the end of 2011 the Nordpoolspot system price fluctuated in a range of 35-45 €/MWh, with the exception of the period of Christmas holidays and the end of the year when it fell below 30 €/MWh.
- Interestingly, the rising price trend following the lowest monthly average measured in September-October 2011 broke in December, though according to the strong seasonal nature of the Nordic markets prices normally reach their highest level in January or February. The price decrease in December 2011 can be explained on one hand by the high level of hydro reserves (*See Chart 2*), assuring cheap source of power. On the other hand,

[4] See Quarterly Report on European Electricity Markets, July-September 2011, page 13.

the weather was mild during the whole quarter (and especially in December - HDDs were 20% lower than the long term average) that reduced power demand for heating needs. Furthermore, Nordic economies showed signs of slowdown in Q4 2011 (on quarter-on-quarter basis even contractions occurred in Sweden and Estonia), this achievement also exerted influence on demand for power.

- After the price recovery from the lows in early October Nordic price discount to the German market (*See Chart 3*) began to wane and net power exports of Norway, peaking in October and November, fell back in December 2011 (*See Chart 4*). During the last week of December there were some days when Nordic price discount turned into premium.
- Danish, Estonian and Finnish area prices could not benefit from abundant Norwegian hydro generation in early October (bottlenecks in the power transport to neighbouring areas) and therefore price differential widened between Nordpoolspot system price and these areas during this period. From the second half of October Finnish and Estonian area prices gradually recoupled with the other regions. Danish prices remained closer to their CWE peers, though after mid-November they also recoupled to those of other Nordic markets. By the end of 2011 differentials among area prices became negligible (*See Chart 5*).
- The story of hydro-generation abundance in Norway (and bottlenecks in power transport) also exerted a considerable influence on differentials among Norwegian area prices (*See Chart 6*). In the first two weeks of October 2011 the difference between Norway North and South-western areas became strongly visible. After the end of this event Norwegian area prices were coupled during most of Q4 2011.
- Price volatility on the Nordic market reached its quarterly peak in mid-October 2011 in the consequence of rapidly changing prices linked to hydro-based generation (*See Chart 7*). Later in the quarter the RVI indicator rapidly fell; a slight upturn could be observed only in the last two weeks of 2011 (demand and price fluctuations during the holiday season).

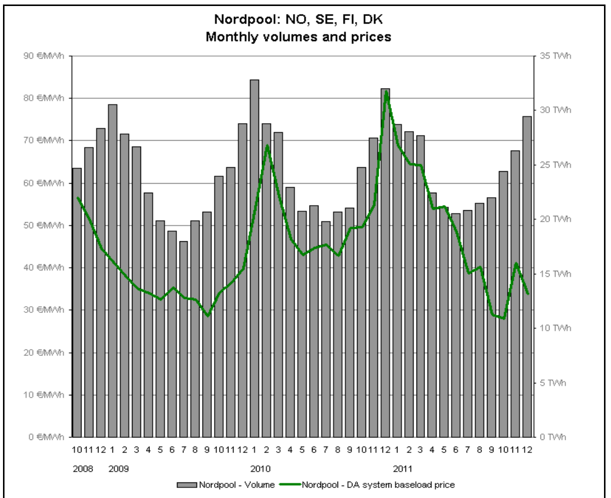


Chart 1 *Source: Platts*

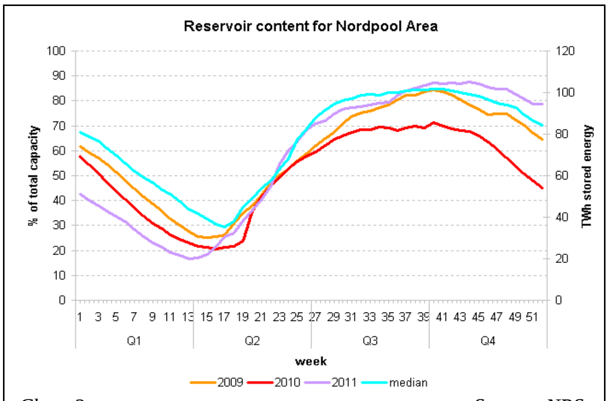


Chart 2 *Source: NPS*

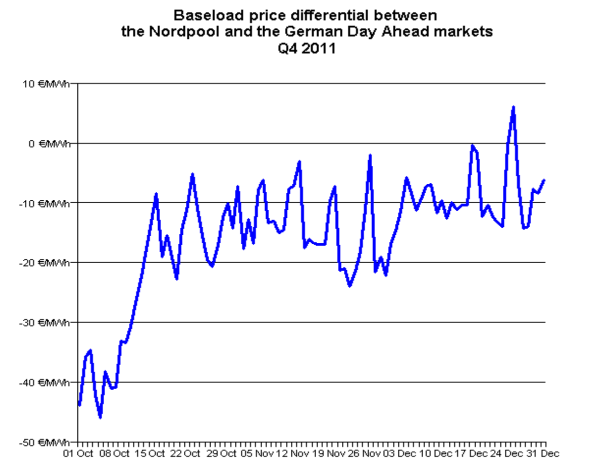


Chart 3 *Source: Platts*

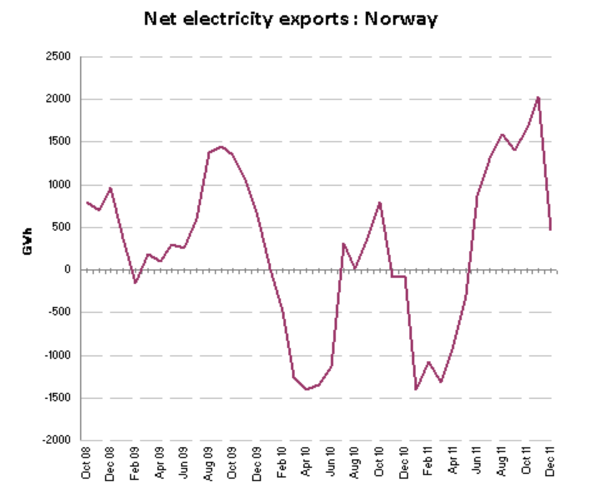


Chart 4 *Source: ENTSO-E Vista*

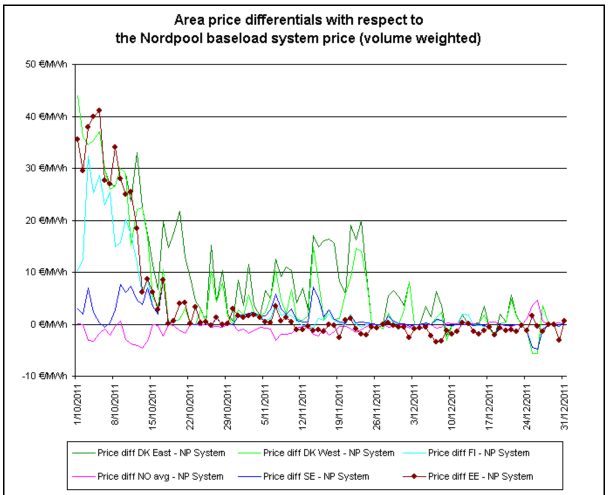


Chart 5 *Sources: Platts, NPS*

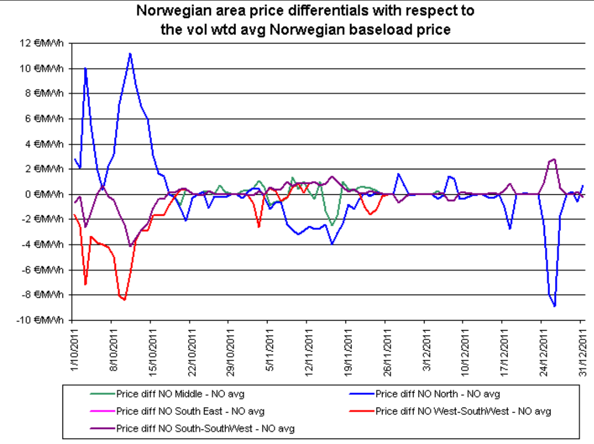


Chart 6 *Source: NPS*

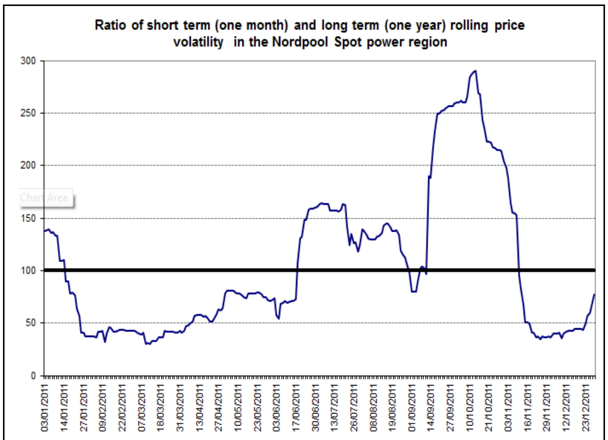


Chart 7
Source: Power price and volume data, own computations.

Apennine Peninsula

Italy

- Italian baseload power prices remained close to their two and a half year high monthly averages set in the preceding quarter and hovered around 78-79 €/MWh in the fourth quarter of 2011 (*See Chart 1*). This achievement bucked the trend of the fourth quarters of the preceding years when prices usually decreased from higher levels measured in the third quarter.

- In October 2011 as the weather turned colder and gas prices on the Italian gas hub began to rise, baseload electricity prices also soared, reaching their highest value in Q4 2011 on the 21st of October (93 €/MWh). Later in that month power prices eased in parallel with decreasing gas and oil prices, combined with milder temperatures (*See Chart 2*).

- At the beginning of November Italian baseload electricity price reached its minimum (64 €/MWh on the 6th of November). Although weather was milder than normal during the last two months of 2011, rising gas and oil prices put a pressure on prices and kept them on higher levels. On some days of December daily average baseload power price rose close to 90 €/MWh and on the 24th during the early hours of Christmas Eve hourly prices rose above135 €/MWh.

- In the fourth quarter of 2011 Sardinian area prices, which decoupled from the national average during Q3 2011 realigned to the system price again, although in mid-November there were two temporary price hikes (*See Chart 3*). By contrast, Sicilian area prices significantly overshot the national average in the first three weeks of October 2011, and then in mid-November they were substantially lower than the system price.

- The fluctuation in the difference between the two island price area and mainland Italy can be explained by reduction of interconnectors or reduction in power generation in the two island areas. Furthermore, photovoltaics-based power generation plays an important role in these areas as opposed to a greater role of conventional generation in mainland Italy, amplifying the volatility of these area prices.

- In the first half of Q4 2011 Italian power prices were more volatile than that the long term (one-year backward looking) volatility would suggest (*See Chart 4*), in the second half of the quarter they were less volatile. Temperatures and price changes of oil and natural gas were less volatile from the second half of November 2011 than in October.

- As the average Italian price premium to the French market was 26 €/MWh in Q4 2011, the negligible ratio of adverse flows (only 1% of the whole time period) between the two markets was not surprising (*See Chart 5*).

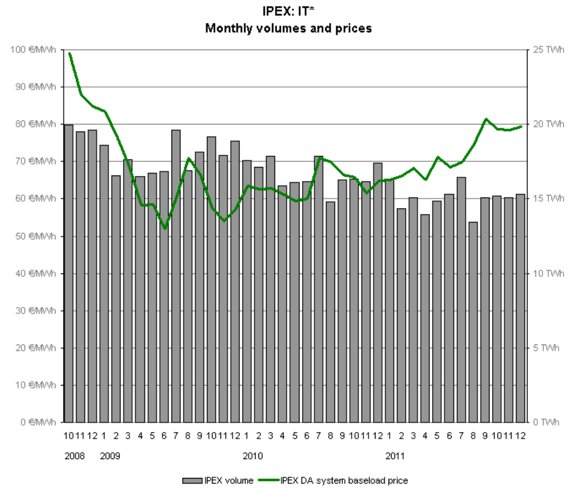


Chart 1 *Source: GME*

** Trade on Italian (IPEX), Greek (DESMIE) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

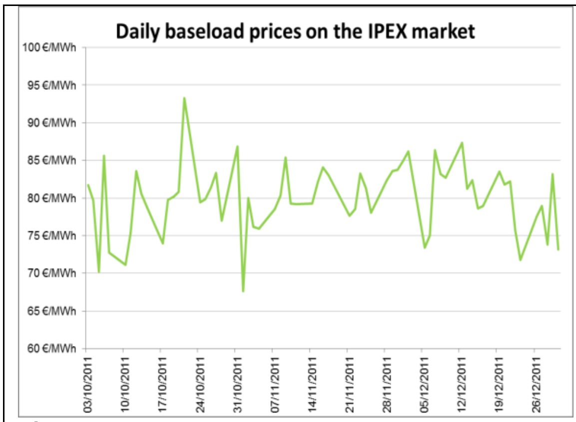


Chart 2 *Source: GME*

* *Trade on Italian (IPEX), Greek (DESMIE) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

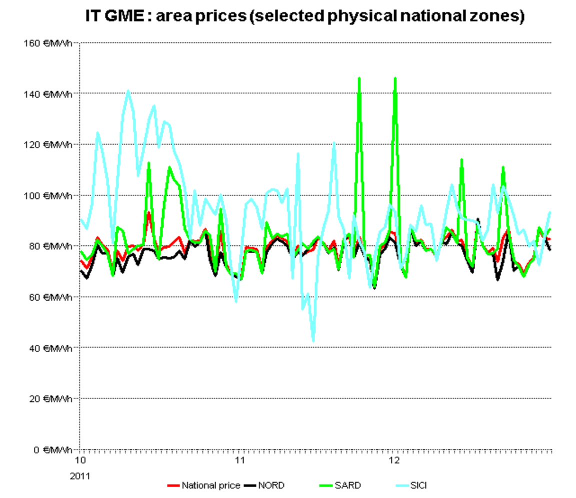


Chart 3 *Source: GME*

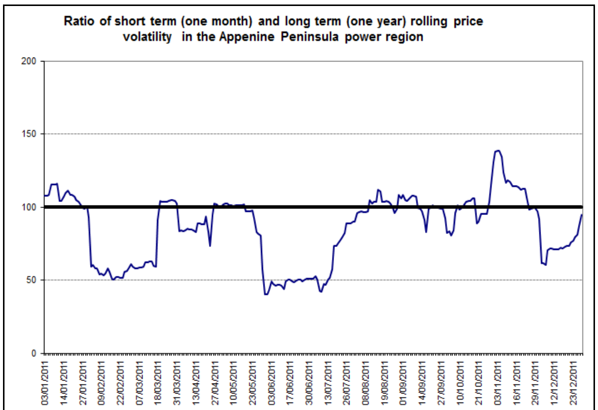


Chart 4
Source: Power price and volume data, own computations.

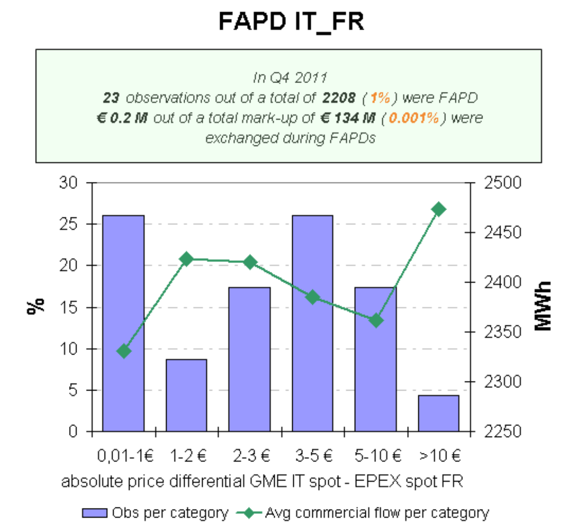


Chart 5 *Sources: Platts; ENTSO-E*

Iberian Peninsula (ES, PT)

Spain and Portugal

- Spanish and Portuguese monthly baseload power prices followed the seasonal pattern in Q4 2011: After the end of the summer period that prompted extra demand of power for cooling needs, prices began to decrease (*See Chart 1*). While in September 2011 the monthly average day-ahead baseload price was 59.7 €/MWh in Spain and 58.6 €/MWh in Portugal; in December the respective values were 51.2 €/MWh and 50.7 €/MWh. Lowest monthly average prices could be observed in November 2011 (49 €/MWh in both countries).

- The new hydro year started on the 1st of October 2011 in Spain, so far in Q4 2011 hydro reserve levels were higher than the ten year median but were lower than in the previous year.(*See Chart 3*) Lower hydro reserves, low wind generation and an unplanned nuclear outage in the middle of October 2011 all contributed to high power prices in the first half of that month (*See Chart 2*).Daily power prices reached their peak in Q4 2011 on the 17th of October (66.4 €/MWh).

- From the second half of October as wind generation picked up and temperatures went down, prices began to decrease. At the beginning of November the daily average electricity price fell to a six month low (41 €/MWh), as a consequence improving hydro and wind based power generation. On the following day prices surged above 60 €/MWh on lower wind forecasts, increasing the volatility of the market.
- During most of November and December 2011 daily baseload electricity prices fluctuated in a range of 50-60 €/MWh, though on some days they broke out from this range. For example, on the 14th of November they fell below 43 €/MWh and on the 16th of December (Friday) they reached their quarterly minimum (39 €/MWh). These plunges in prices were caused by sudden surge in wind power generation, on these two days wind based generation satisfied around 35-40% of Spain's daily power demand. In both cases price plunges were followed by a sharp upturn; on the 19th of December daily power price rose to 63 €/MWh, adding 24 €/MWh to the previous trading day's value.
- The Relative Volatility Indicator (RVI), measuring the relation of short term and one-year backward looking volatility of electricity prices, rose above 100 in early November, which was the highest since January 2011 (*See Chart 4*). Although the OMEL market is not among the most volatile power markets in Europe (mainly due to well-balanced generation sources of different fuels and to the mandatory pool that attracts a high amount of traded volume), it seems that besides fluctuations in temperature and the impact of holiday seasons the amount of wind generation has become a key factor in explaining the short term market volatility on the Iberian market.
- The ratio of adverse flows between the Spanish and French power markets (*See Chart 5*) was 14.4%, slightly higher than in the previous two quarters (around 12%). Price premiums and discounts between Spain and France frequently alternated during Q4 2011 and thus quarterly average price premium to France was low (2.3 €/MWh), promoting opportunities for adverse power flows. Spain's power exports to France (504 GWh) was the highest since Q1 2011.

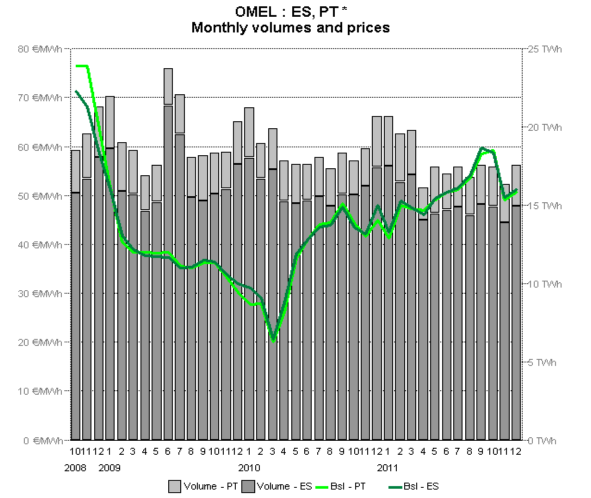


Chart 1 *Source: Platts*
** Trade on Italian (IPEX), Greek (DESMIE) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

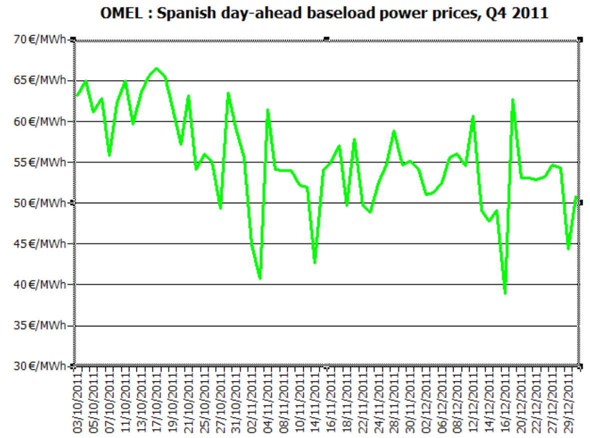


Chart 2 *Source: Platts*

** Trade on Italian (IPEX), Greek (DESMIE) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

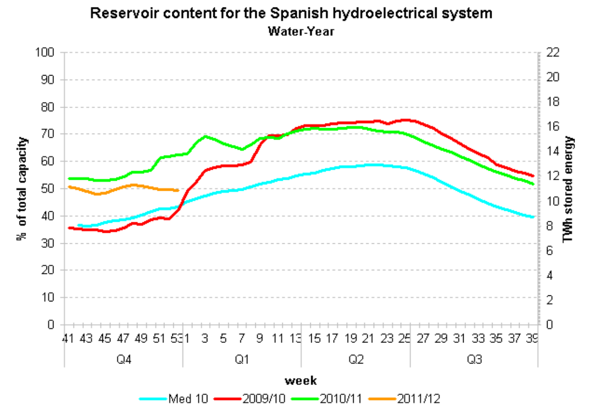


Chart 3 *Source: Ministerio de Medio Ambiente, y Medio Rural y Marino, Gobierno de España*

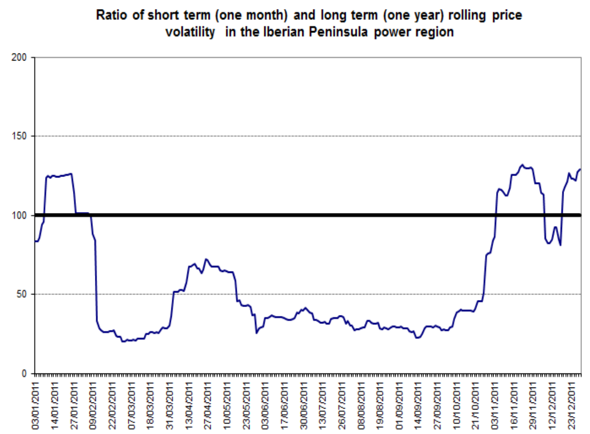


Chart 4

Source: Power price and volume data, own computations.

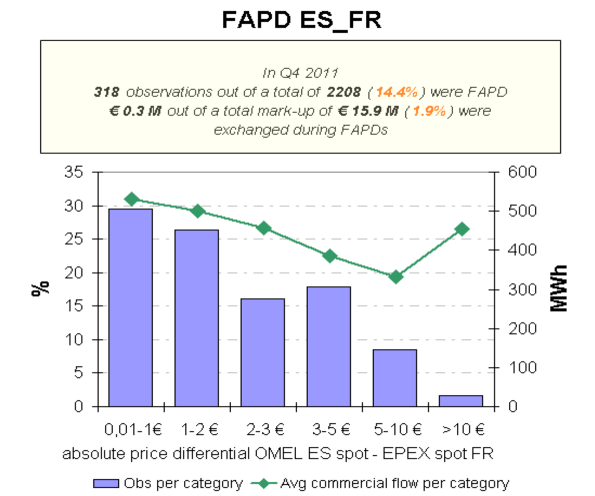


Chart 5 *Source: Platts*

Central Eastern Europe (CZ, HU, PL, RO, SK, SI)

- In Q4 2011 the combined volume of traded day-ahead power in the Central East European region[5] continued to grow and reached 12.1 TWh (*See Chart 1*), which was around one eighth of the electricity supply of the six countries together. Although the dynamics of the evolution of traded volume was impressive in 2011, compared to CWE or Nordpoolspot areas CEE markets have still enough room to grow.
- Both baseload and peakload monthly average power prices reached the highest level since November 2008 on a regional average.
- In October 2011 day-ahead prices in the region were generally moving higher; anticipating colder periods and

[5] In this part of the report Central East European power region comprises Poland, the Czech Republic, Slovakia, Hungary, Romania and Slovenia. Both regional monthly baseload and peakload power prices are computed as of traded-volume-weighted averages of the six countries' prices.

following West European price peers and commodity prices. At the end of the month holidays (Independence Day in the Czech Republic and All Saints Day across the region) pushed down demand and prices.

- On the 13th of October 2011 as the Central Allocation Office cancelled its daily auctions day-ahead prices on the Czech, Slovak and Hungarian markets jumped; inflicting some panic buys. At the same time Polish prices slightly decreased on fears of power being trapped in the domestic market in the consequence of lacking exporting opportunities (*See Chart 2*).

- Contrary to the CWE region, the countries in Central and Eastern Europe faced a slightly colder-than-normal weather in November 2011 that put an upward pressure on prices. Prices in Poland have been driven up by heightened demand and tightened supply margins following the shutdown of the largest block of Belchatow power plant for maintenance. On the 17th of November Polish day-ahead baseload price reached 80.9 €/MWh, the highest level since September 2008.

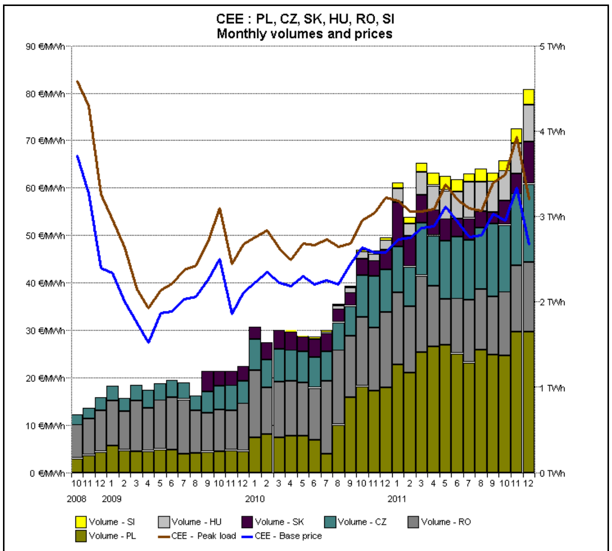
- Prices of the Czech and Slovak market, forming a market coupled area since September 2009, decoupled several times during November 2011. On the 22nd, 28th and 29th of November Slovakian hourly prices in some periods of the day exceeded their Czech counterparts by more than 100 €/MWh, which is not a usual event on a coupled market. Cross border capacity restriction between the CEPS (Czech Transmission System Operator) and SEPS (Slovak Transmission System Operator) hampered power flow from the Czech area to Slovakia, decreasing prices in the former area and increasing them in the latter.

- During the last month of 2011 Hungarian, Slovenian and Romanian prices showed a considerable premium to their Polish, Czech and Slovak counterparts. High power demand from the Balkans, restrictions in the interconnections between Slovakia and Hungary and between Hungary and Romania, and low level hydro reserves following a dry period all contributed to higher prices in these three countries.

- On the other hand, prices in Poland were kept low during December 2011 mainly due to the unusually mild weather and a well-supplied power system assured by abundant power inflow from the Nordic markets (through the SwePol link).

- Daily average prices in the CEE region showed a higher degree of volatility during Q4 2011 than in the preceding two quarters (*See Chart 3*). Extraordinary events, such as cancellation of daily auctions or cross border capacity restrictions contributed to this higher volatility, as well as temporary drops in industrial power demand during the holiday season at the end of the year.

- Adverse power flow ratios showed significant changes only in the case of Slovakia-Hungary (*See Charts 4 and 5*), this might have been related to increasing Hungarian price premium to Slovakia.



Sources:
TGE (PL),OTE (CZ, SK), OPCOM (RO), HUPX (HU), BSP (SI)

Monthly average baseload power prices (€/MWh)			
2011	October	November	December
Hungary	55.4	66.4	57.3
Poland	52.2	59.4	44.2
Czech Republic	51.1	54.8	41.0
Slovakia	51.3	57.5	41.6
Romania	56.0	62.7	59.7
Slovenia	57.1	69.6	63.4

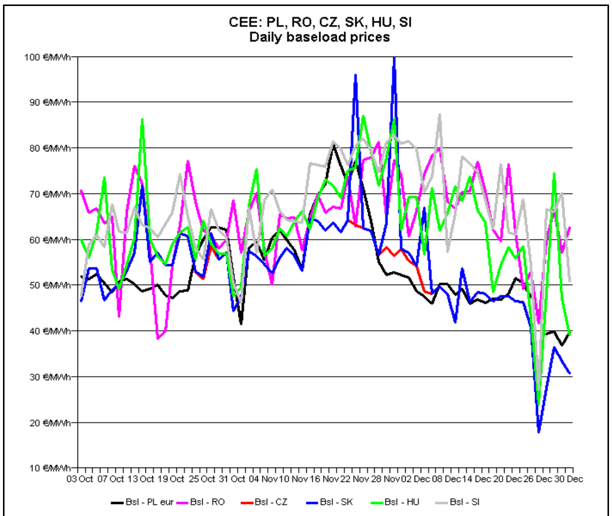


Chart 2 *Sources:*
TGE (PL),OTE (CZ, SK), OPCOM (RO), HUPX (HU), BSP (SI)

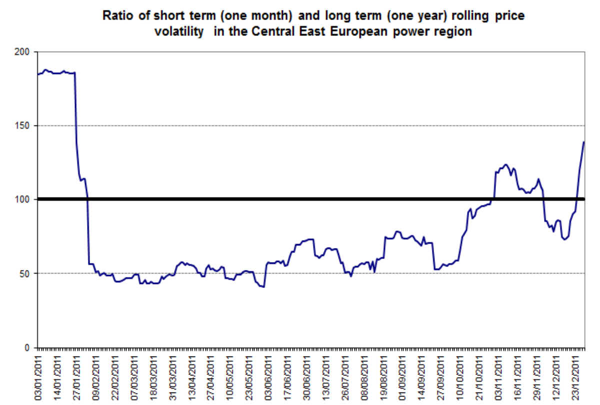


Chart 3
Source: Power price and volume data, own computations.

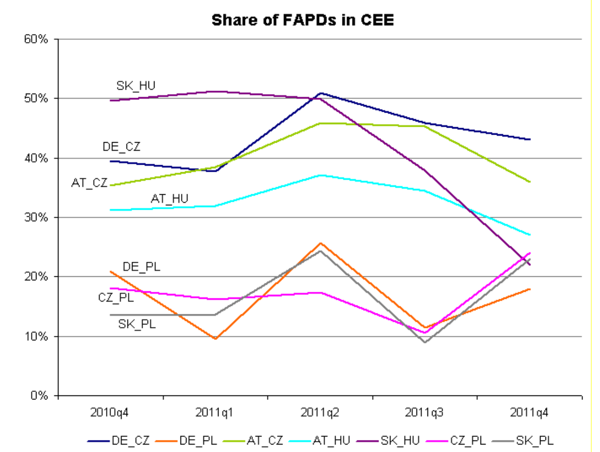


Chart 4 *Sources :*
Platts, ENTSO-e, OTE, HUPX, PolPX

*

Distribution of FAPDs across the price differences

	0.01-1€	1-2€	2-3€	3-5€	5-10€	>10€
DE_CZ	19%	18%	16%	20%	20%	7%
DE_PL	17%	18%	13%	18%	21%	13%
AT_CZ	44%	30%	12%	9%	3%	2%
AT_HU	38%	31%	11%	8%	8%	4%
SK_HU	33%	27%	16%	12%	6%	6%
CZ_PL	28%	18%	12%	19%	14%	9%
SK_PL	26%	18%	12%	18%	15%	11%

Chart 5 *Sources :*
Platts, ENTSO-e, OTE, HUPX, PolPX

South Eastern Europe

Greece

- Both Greek baseload and peakload monthly average power prices showed a considerable increase between September and December 2011 (*See Chart 1*). Baseload power price rose from 61.8 €/MWh to 77.6 €/MWh, while peakload monthly average added 15 €/MWh during the same period and finished the year at 92.8 €/MWh. In December 2011 power prices in Greece were the highest since December 2008.
- During October 2011 daily baseload prices showed a decreasing tendency as the summer hot period was over and cooling demand decreased (*See Chart 2*). On the 28th of October both baseload and peakload daily averages reached their minima in Q4 2011 (slightly above 43 €/MWh).
- Unlike many other European markets, Greece could not experience a mild weather in Q4 2011 as November was significantly colder than usual (HDDs were 38% higher than the long term average). This factor must have contributed to rapid increase of prices. From mid-November to mid-December 2011 daily baseload prices hovered around 80 €/MWh, while their peakload counterparts fluctuated in a range of 90-100 €/MWh during most of this time period. Another important factor was the substitution of oil-based heating with increasing use of air-conditioning appliances as this solution turned out to be cheaper due to high oil prices which also increased the demand for electricity. Several plant outages occurred during November that reduced domestic power supply and increased power prices. The significant peakload premium over baseload prices was also affected by a lower level of hydro generation as substitution of hydro with coal and gas fired generation resulted in higher prices during the peak hours.
- On the 9th of December baseload and peakload daily averages reached their peak in Q4 2011 (99.5 €/MWh and 104.2 €/MWh, respectively). During the last three weeks of 2011 wholesale electricity prices in Greece became cheaper, due to milder temperatures and decreasing industrial demand during the holiday season.
- Price volatility in the Greek market was the highest at the end of October, and afterwards it decreased significantly as the amplitude of daily price fluctuation was lower (*See Chart 3*). During the Christmas period it increased slightly, which was also reinforced by a trial period of a new power plant with fluctuating load to the grid.
- Greek daily baseload power prices showed a significant premium to the Romanian market during most of Q4 2011 (*See Chart 4*), permanent discounts could only be observed at the end of October/beginning of November, when Greek prices were in the trough and their Romanian counterparts were high.
- As Italian prices showed a higher degree of stability than the Greek market, Italian price premium (*See Chart 5*) was high when Greek prices were low (e.g.: end of October 2011) and Italian prices were in discount when Greek prices soared (e.g.: around mid-December 2011).

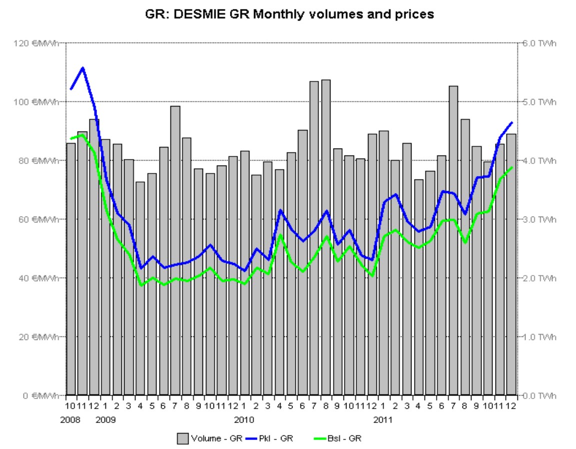


Chart1 *Source: Platts*

* *Trade on Italian (IPEX), Greek (DESMIE) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

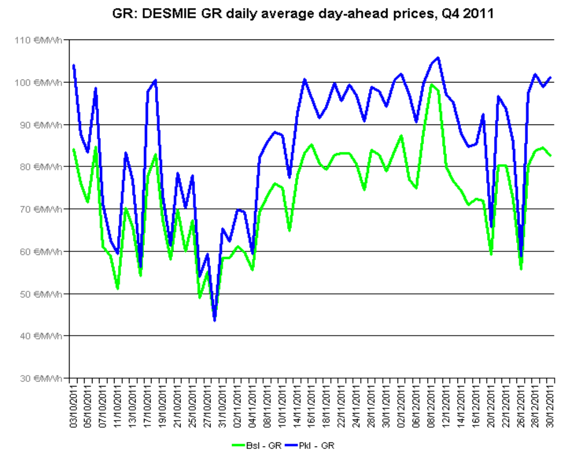


Chart 2 *Source : Platts.*

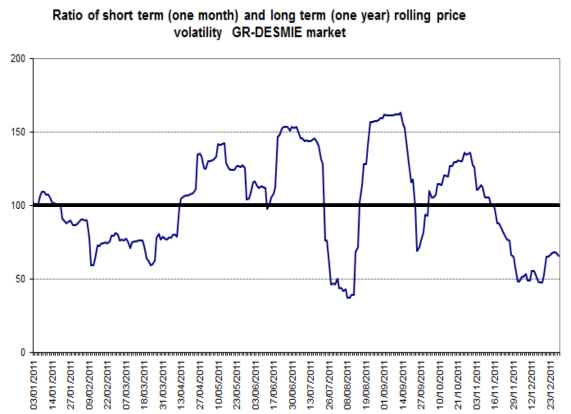


Chart 3

Source: Power price and volume data, own computations.

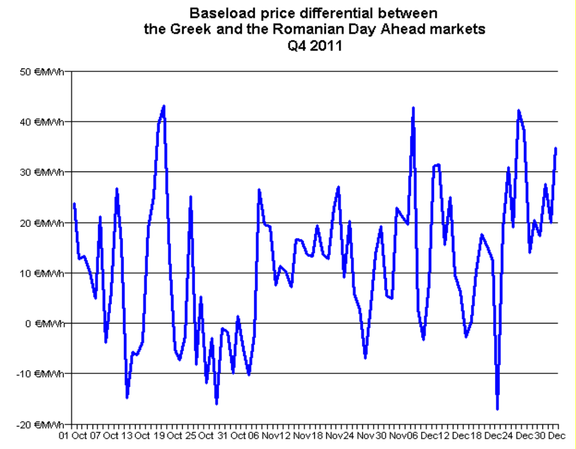


Chart 4 *Sources : DESMIE, OPCOM s.a.*

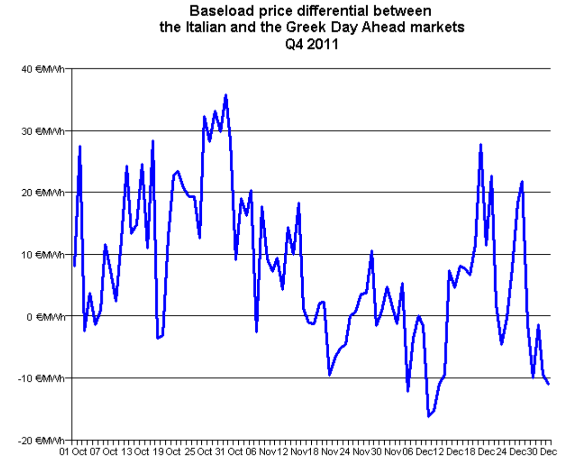


Chart 5 *Sources: IPEX, DESMIE.*

A.1.2 Forward markets

- Year-ahead UK gas prices recoupled with their spot peers in the first half of October 2011 as the UK-Belgian interconnector resumed operation following a temporary disruption in September 2011 which resulted in a significant gas domestic oversupply (*See Chart 1*). From mid-November 2011 both spot and year ahead prices started to decrease, and on monthly average year-ahead contracts finished 2011 at 26 €/MWh, slightly lower than in September (27.3 €/MWh).

- The price evolution of year-ahead coal prices perfectly mirrored that of the spot coal market in Q4 2011. During the whole quarter year-ahead coal prices hovered around 80 €/Mt.
- Both spot and year-ahead daily crude oil prices rose by around 10% between the first and the last trading day of Q4 2011. Year-ahead prices were below the spot quotations during most of the time, the market presumably anticipated a decrease in crude oil prices in the forthcoming twelve months. The discount of year-ahead oil prices might have related to an anticipation of resuming supply from the Middle East and lower demand arising from cooler economic environment.
- Both quarter-ahead and year-ahead power prices (*See Charts 2 and 3*) on the major West European markets showed a steady decrease in Q4 2011, albeit the decrease in quarter-ahead prices was steeper than that of their year-ahead counterparts. A possible explanation for this behaviour of the prices can be a market anticipation of a worsening economic situation in the eurozone and in whole Europe that exerted a downward pressure on future power prices, especially on the short run.
- This can also be seen on the chart showing forward power prices at the beginning of each month of Q4 2011 (*See Chart 5*). In many markets prices were in slight backwardation[6] in October and November 2011 or at least the column in the middle, showing mid-term baseload forward prices was the smallest one. At the beginning of December in some cases (e.g.: Germany, France, Nordpool) slight contangos[7] appeared, showing that market participants might have exaggerated their fears concerning the economic situation in Europe.
- UK spot, month-ahead and year-ahead spark spreads (*See Chart 4*) showed a significant decrease from the beginning of Q4 2011 until mid-December, closely following the decrease in power prices, especially in the case of forward contracts. During the last two weeks of December 2011 spark spreads showed a slight recovery as gas prices started to decrease.

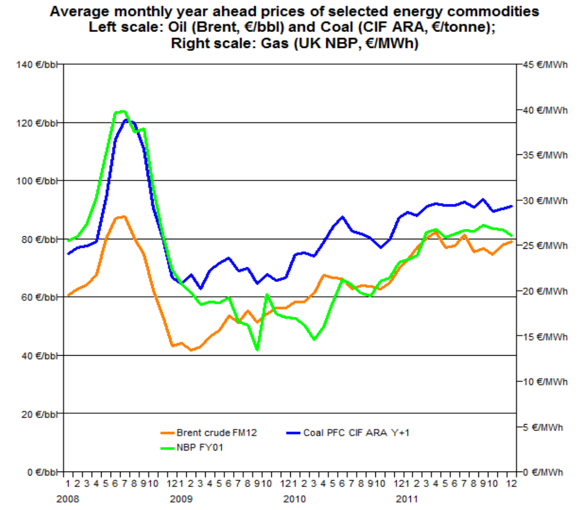
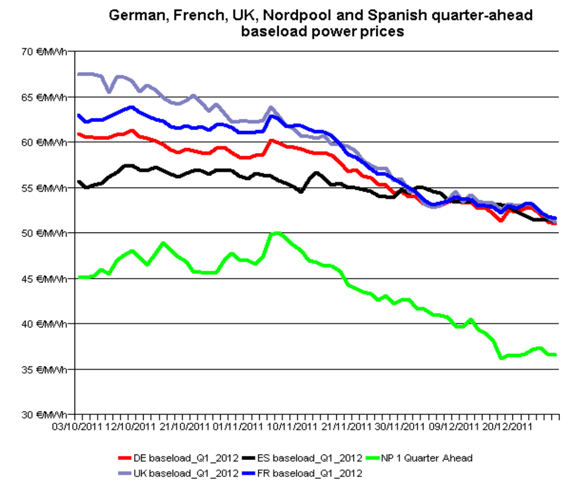


Chart 1 *Source: Platts*

[6] Backwardation occurs when the closer-to-maturity contract is priced higher than the contract which is longer to maturity.

[7] A situation of contango arises in the when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.



Charts 2 *Source: Platts*

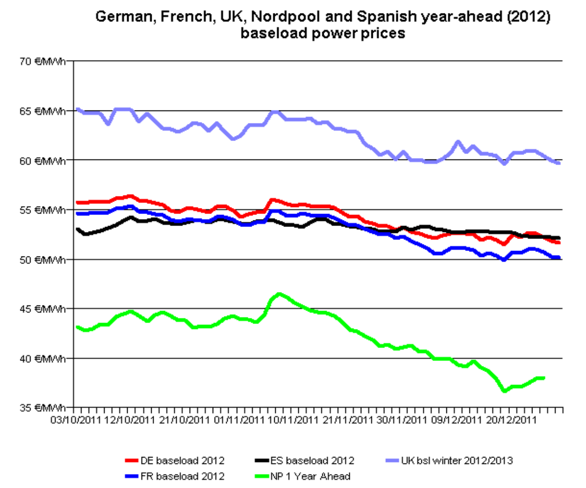


Chart 3 *Source: Platts*

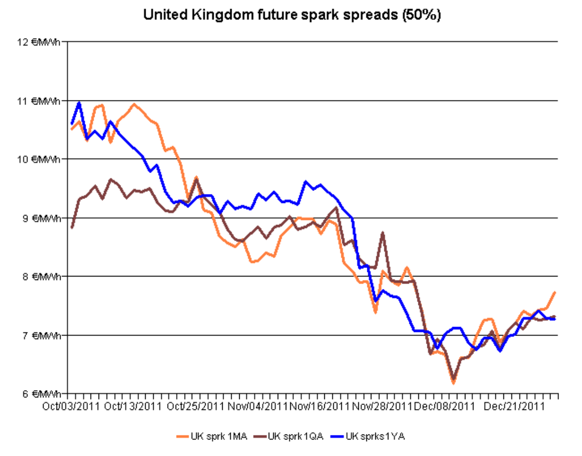


Chart 4 *Source: Platts*

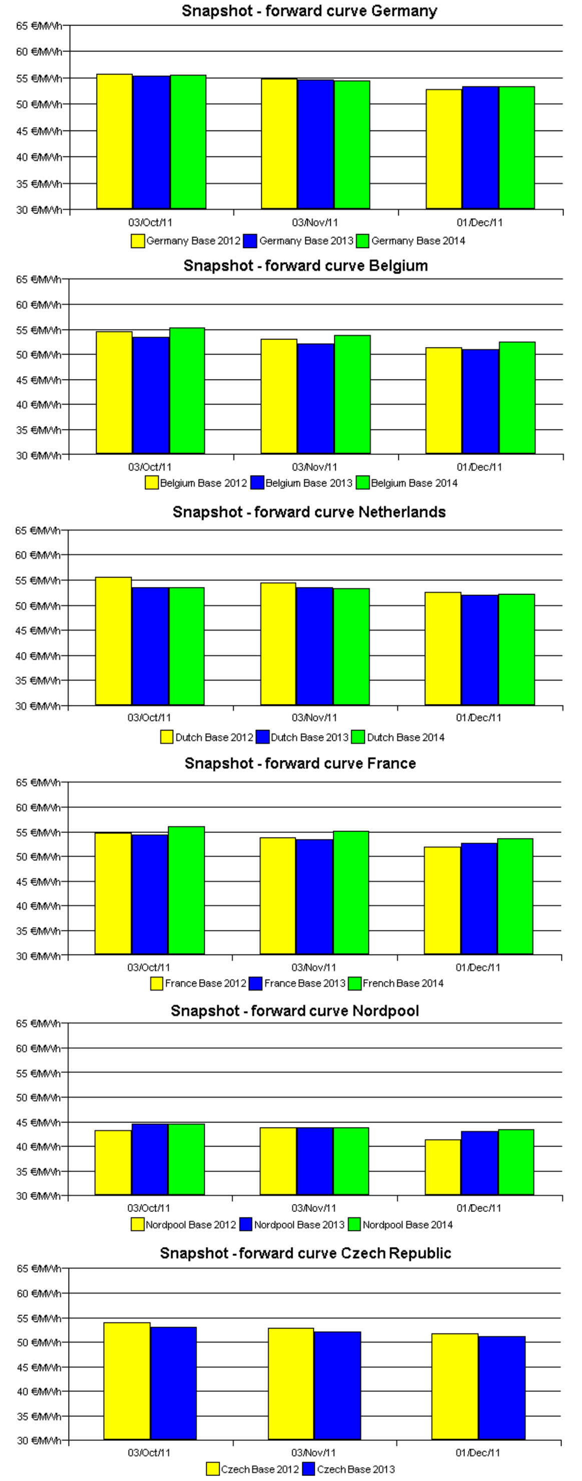
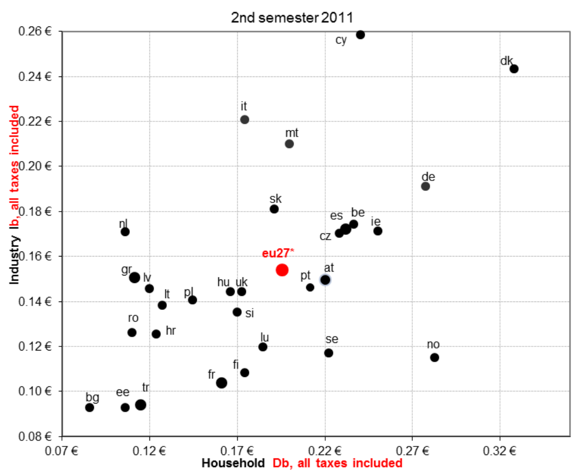


Chart 5 *Source: Platts*

A. 2 Retail markets

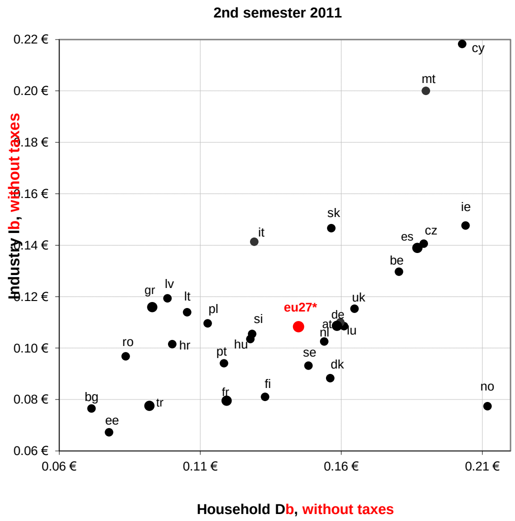
A.2.1 Price level

The next two charts show the electricity prices paid by household consumers in the Member States of the EU as well as in Croatia, Norway and Turkey with annual consumption between 1000 kWh and 2500 kWh, and industrial consumers with annual consumption between 20 MWh and 500 MWh (consumption bands *Db* and *Ib* according to Eurostat's consumption categories). The first chart shows the household and industrial customer prices including all taxes (gross prices), while the second one shows prices without taxes (net prices) in the second half of 2011.



Source: Eurostat
Range for annual consumption:
Household band Db: 1.000kWh<consumption<2.500 kWh

Between the first and the second semester of 2011 the ratio between the lowest and highest gross price increased from 2.5 to 2.8 for industrial consumers and remained relatively stable at 3.8 for household consumers. In absolute terms the range between the lowest and the highest pre-tax prices for households amounted to 14 cents/kWh (down by 2 cents/kWh with respect to the first semester of 2011) and to 15 cents/kWh for industrial consumers (an increase by almost 2 cents/kWh with respect to the first semester of 2011).



Source : Eurostat
Range for annual consumption:
Household band Db: 1.000kWh<cons<2.500 kWh
Industry band Ib:20 MWh<cons<500 MWh

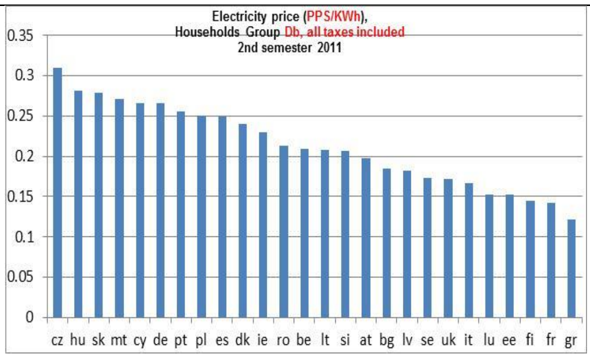
*Notes: Data for Austria as1st semester 2011. EU27*calculations are provisional.*

Denmark and Germany remained the EU Member States where household consumers paid the highest electricity prices, being 32.8 cents/kWh and 27.8 cents/kWh, respectively, in consumption band Db. The lowest price on the other hand was reported in Bulgaria, where households paid 8.6 cents/kWh in the same consumption band.
With the exception of Cyprus (24 cents/kWh), the Czech Republic (23 cents/kWh) and Malta (20 cents/kWh), households in new Member States (NMS)[8] still paid less than the EU average

[8] Member States joined the EU after 2004.

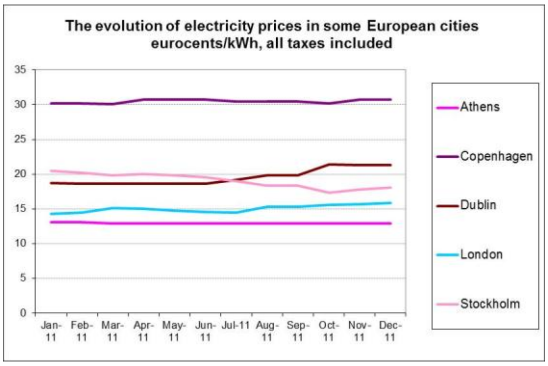
(19.6 cents/MWh[9]) in absolute terms in case their annual consumption was between 1.000 kWh and 2.500 kWh.

When correcting for purchasing power parity (PPS) the picture changes: the five most expensive Member States measured in PPS[10] are all new member states (the Czech Republic, Hungary, Slovakia, Malta and Cyprus). The same observation can be made at the lower end of the graph, with the seven of the eight countries with the lowest prices in PPS all being old member states (Greece, France, Finland, Luxembourg, Italy, the UK and Sweden), and only one new member state (Estonia).



Source : Eurostat
Range for annual consumption:
Household band Db: 1.000kWh<consumption<2.500 kWh
Industry band Ib:20 MWh<consumption<500 MWh

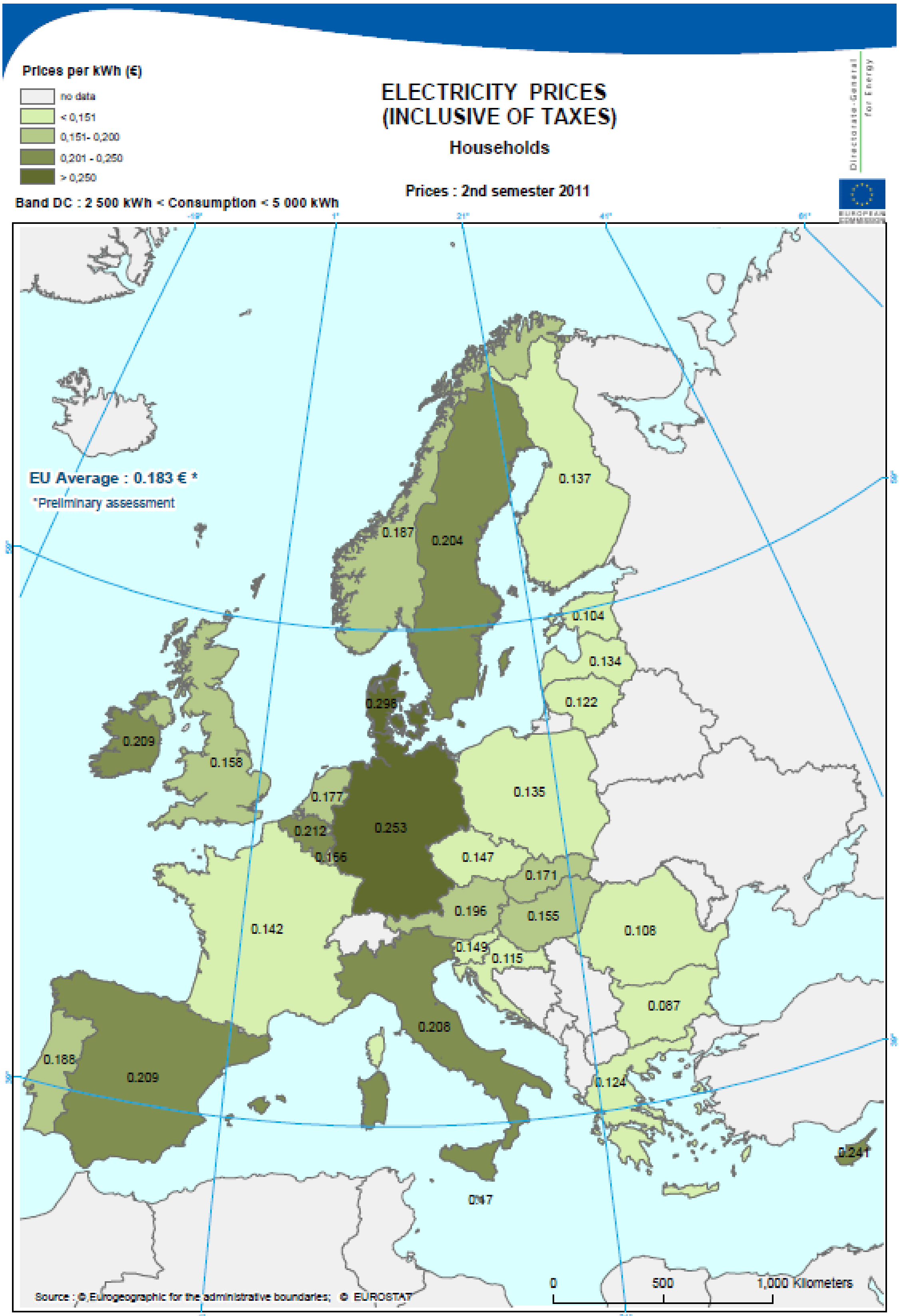
The next chart shows the evolution of all tax inclusive retail electricity prices paid by households in five European capitals between January 2011 and December 2011. During 2011 prices rose the most in Dublin and London. The most significant price fall was observed in Stockholm. Among the 15 capitals monitored in the framework of the HEPI index, Athens saw the lowest and Copenhagen the highest electricity prices.

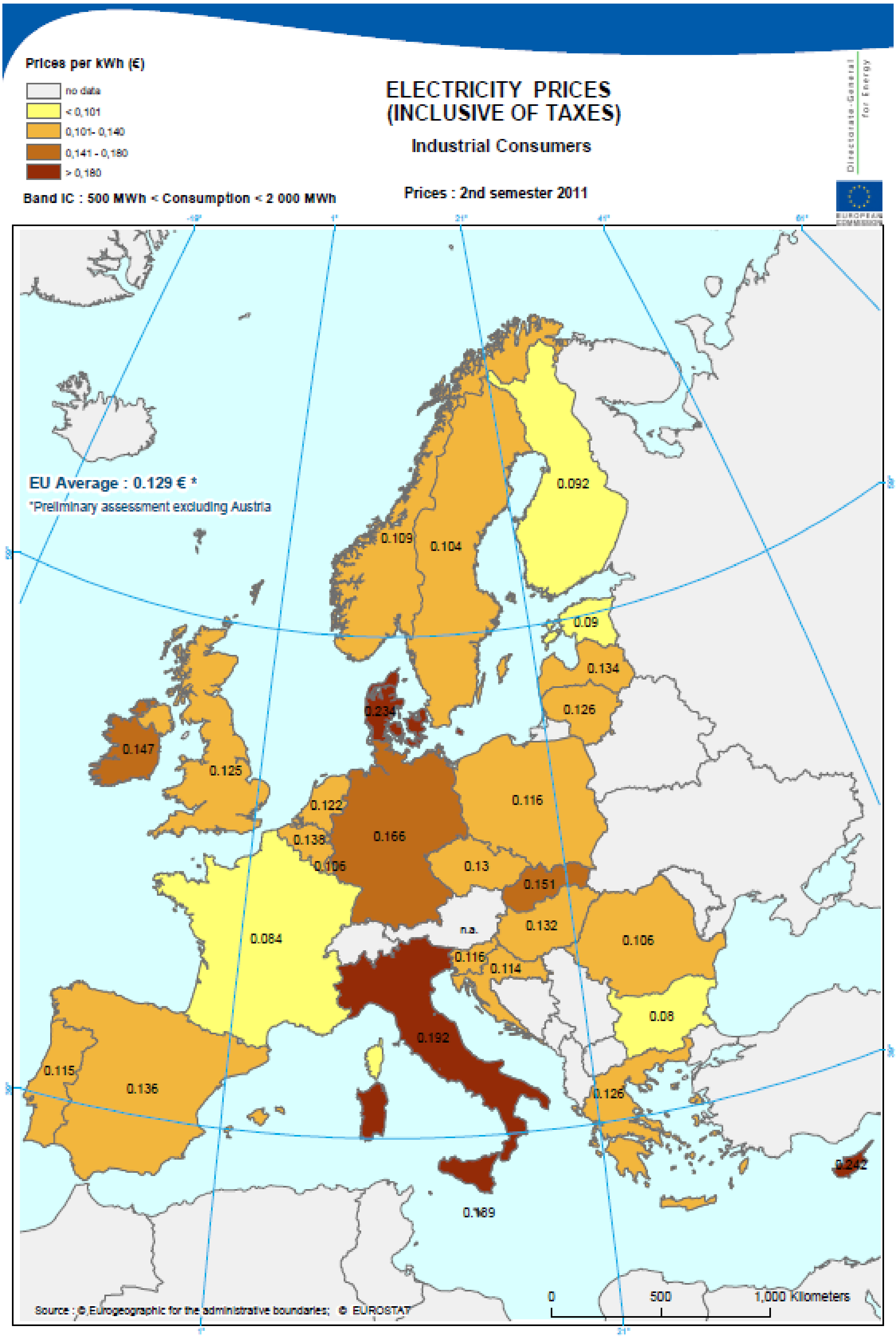


Source: HEPI
The HEPI electricity price index was developed by the Austrian energy market regulator E-control and VaasaEtt Global Energy Think Tank, providing monthly information about the evolution of the final electricity consumer prices in some selected capital cities of EU countries.

The next two maps show the electricity retail prices paid by households and industrial consumers in the second half of 2011. The maps show prices of band Dc in the case of households (meaning households with annual consumption between 2.500 kWh and 5.000 kWh, according to Eurostat's classification) and Band Ic industrial prices for consumers with annual consumption between 500 MWh and 2.000 MWh.

[9] EU27 average is not available for 1st semester of 2011. Throughout the report, the last available average was considered, as of 2010, 2nd semester.
[10] Purchasing power standards

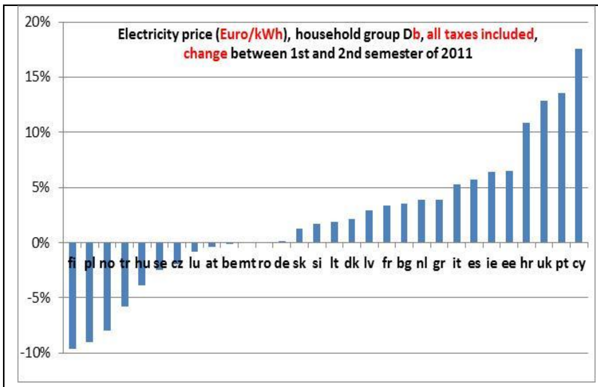

Prices per kWh (€)
no data
< 0,151
0,151- 0,200
0,201 - 0,250
> 0,250
Band DC : 2 500 kWh < Consumption < 5 000 kWh
ELECTRICITY PRICES
(INCLUSIVE OF TAXES)
Households
Prices : 2nd semester 2011
Directorate-General for Energy
EU Average : 0.183 € *
*Preliminary assessment
0.137
0.187
0.204
0.104
0.134
0.122
0.298
0.209
0.158
0.135
0.177
0.212
0.253
0.166
0.147
0.171
0.196
0.155
0.108
0.142
0.149
0.115
0.087
0.208
0.188
0.209
0.124
0.241
0.147
0
500
1,000 Kilometers
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT


Prices per kWh (€)
no data
< 0,101
0,101- 0,140
0,141 - 0,180
> 0,180
Band IC : 500 MWh < Consumption < 2 000 MWh
ELECTRICITY PRICES
(INCLUSIVE OF TAXES)
Industrial Consumers
Prices : 2nd semester 2011
Directorate-General for Energy
EU Average : 0.129 € *
*Preliminary assessment excluding Austria
0.092
0.109
0.104
0.09
0.134
0.126
0.234
0.147
0.125
0.116
0.122
0.166
0.138
0.105
0.13
0.151
0.132
n.a.
0.084
0.115
0.114
0.106
0.08
0.192
0.115
0.136
0.126
0.242
0.189
0
500
1,000 Kilometers
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT

A.2.2 Price dynamics

Electricity prices for household consumers with annual consumption between 1.000 kWh and 2.500 kWh (band Db) rose on average by a modest 2% in the second half of 2011, compared to the previous semester[11]. However, price developments in the individual Member States were quite diverse.

Substantial price increases could be observed in Cyprus (17.5%), Portugal (13.5%), the UK (12.8%) and Croatia (10.8%) In contrast, prices fell in Finland by 9.6%, in Poland by 9% and in Norway by almost 8%. In Hungary, Sweden, the Czech Republic, Luxembourg, Austria and Belgium prices were slightly lower than in the first half of 2011.



Source : Eurostat
Range for annual consumption of :
Household band Db : [1.000 kWh – 2.500 kWh];

The next two maps show the electricity retail prices paid by households and industrial consumers in the second half of 2011. The maps show prices of band Dc in the case of households (meaning households with annual consumption between 2.500 kWh and 5.000 kWh, according to Eurostat's classification) and Band Ic industrial prices for consumers with annual consumption between 500 MWh and 2.000 MWh.

B. Building the internal market for electricity: cross border flows and trade

- Cross border physical flows in Q4 2011 reached 62.7 TWh in the EU-27, which was 10.2% higher than the total volume of cross border flows in the previous quarter. In the fourth quarter of each year cross border flows normally increase in parallel with higher power demand and traded volumes on the wholesale electricity markets. (*See Chart 1*)
- Compared to Q4 2010 cross border physical flows were up by 12.7% in Q4 2011, which was a significant growth taking into account the slight decreases in the evolution of traded power volumes on the European markets (-0.7%), or the reduction in power demand (-3.8%) during the same period. Increasing cross border physical flows in spite of decreasing power demand and traded volumes points to an increasing interdependence among the European power markets.
- Nordic power region was still in a strong net exporter position in the consequence of significant price discounts to other European markets during most of Q4 2011 (*See Chart 2*).
- Central East European power region was in a net power exporter position

[11] In the remaining part of this chapter, unless otherwise stated, price changes are always compared to the previous semester (1st semester of 2011).

again in Q4 2011, as it exported a significant amount of power to the South East European region which was in a stronger net importer position than in the previous quarter.

- Central West European regions acted as a strong net power exporter while the Apennine-peninsula was in a strong net importer position in Q4 2011, showing not too much changes compared to previous periods. As British price premium to France increased at the end of Q4, the UK's net power importer position strengthened.

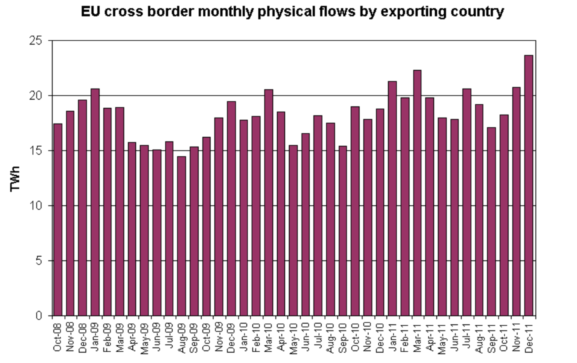


Chart 1 *Source : ETSO*

Note. Data for MT and CY are missing. Data for EE, LT and LV are available since September 2008, and for IE since July 2010. Data on physical flows from and to LU is incorporated in LU's neighbouring countries : DE, BE, FR. Data for a number of Member States is still partial, particularly for Member States in the South East European Region.

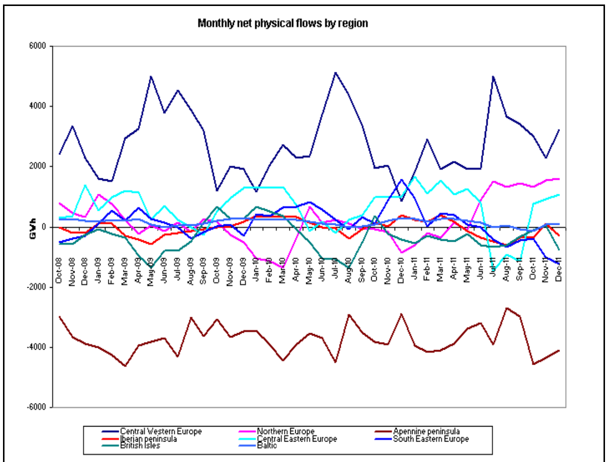
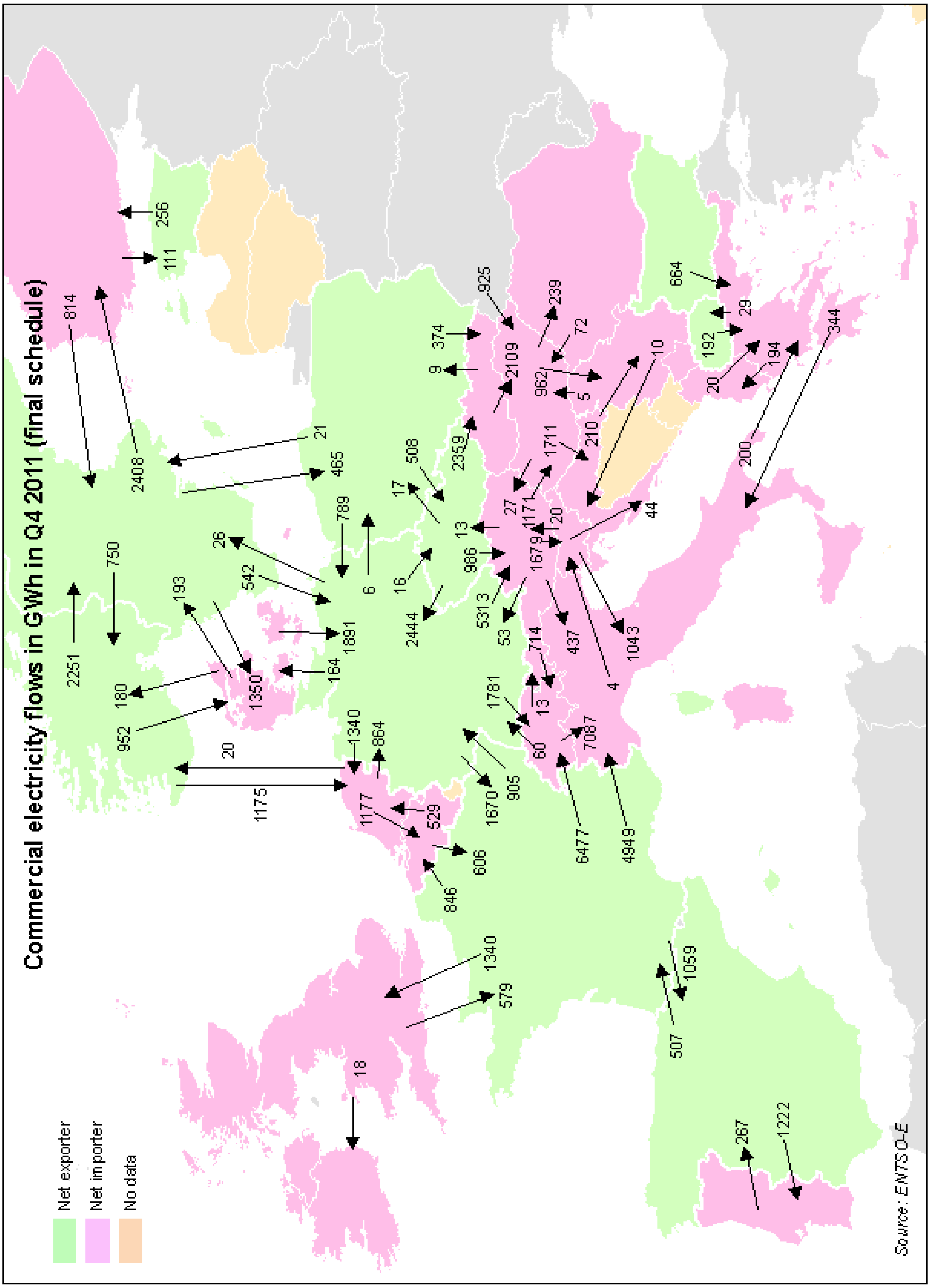


Chart 2 *Source: ETSO.*

European countries are grouped in the following regions :

Central Western Europe	*DE, NL, FR, BE, AT, CH*
Nordic	*SE, FI, DK, NO*
Apennine Peninsula	*IT*
Iberian Peninsula	*ES, PT*
Central Eastern Europe	*PL, CZ, HU, SK*
South Eastern Europe	*SI, GR, BG, RO, HR, AL, FYROM, RS*
British Isles	*UK, IE (from July 2010 on)*
Baltic	*EE, LT, LV*

Note to the map on next page:
Data for some countries are not available (see the legend). Due to presentation constraints the Northern European countries and Cyprus cannot be included on the map completely. Data on the commercial flows concerning Romania, Bulgaria and Serbia are not complete. There is no data available on Kosovo under UNSCR 12/4499. Data on flows between Germany and Austria are estimates. For the majority of the reported borders, commercial flow data is netted on hourly frequency. For the case of the Czech-Slovak border, gross commercial values are given.


Commercial electricity flows in Q4 2011 (final schedule)
Net exporter
Net importer
No data
Source: ENTSO-E

European Commission

C. "Focus on the proposed CO_2 factors in the draft State Aid Guidelines in the context of the Emission Allowance Trading Scheme post-2012"

In 2005 the European Union Greenhouse Gas Emission Trading Scheme (EU ETS) was introduced to reduce CO_2 emissions in a cost-effective way. Directive 2009/29/EC[12] amending Directive 2003/87/EC[13] (ETS Directive) improved and extended the EU ETS in the third trading period 2013-2020 (ETS-3). ETS-3 will be based on a stricter and single EU-wide cap, the allocation of allowances will be made on transitional fully harmonised EU-wide basis and wider auctioning of allowances will be progressively introduced.

The ETS Directive provides for special and temporary measures for certain undertakings, which involve State aid within the meaning of Article 107(1) of the Treaty.

The primary objective of State aid control in this context is to ensure that State aid measures will result in a higher overall level of environmental protection than would occur without the aid. In order to ensure transparency and legal predictability, the Commission is preparing Guidelines that will explain the compatibility criteria which will be applied to these State aid measures.

Aid to undertakings in sectors deemed to be exposed to a significant risk of carbon leakage due to EU ETS allowance costs passed on in electricity prices[14] (a.k.a. aid for indirect emission costs) falls in the scope of the Guidelines.

In the case of aid for indirect emission costs the maximum amount of aid a Member State may grant in favour of installations within an eligible (sub)sector is calculated as the product of a formula with the following variables:

- Aid intensity (expressed as a fraction, e.g. 0.8);
- CO_2 emission factor (tCO_2/MWh, defined in Annex IV of the draft Guidelines),
- Product specific efficiency benchmark (MWh/tonne, defined in Annex III of the draft Guidelines);
- Forward price of EUAs in year t-1 (EUR/tCO_2);

[12] Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community, OJ L 140, 5.6.2009, p.63.

[13] Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, OJ L 275, 25.10.2003, p. 32.

[14] An aid beneficiary is deemed to be exposed to a significant risk of carbon leakage, due to EUA costs passed on in electricity prices, if it is active in one of the sectors specified in a separate Annex of the Guidelines.

- Baseline output.

The CO_2 emission factor denotes the weighted average of the CO_2 intensity of electricity produced from fossil fuels in different geographic areas. It is the result of the division of the CO_2 equivalent emission data of the energy industry by the Gross electricity generation based on fossil fuels in TWh.

The Method for determining the CO_2 factor is based on the following assumptions:

- combustion plants e.g. coal, oil and gas fired power plants are setting the price in each geographical area over entire time in proportion to the final production of energy from these plants.

- geographical areas are defined as zones within which there are no declared congestions (i.e. no capacity allocation takes place) or are coupled through power exchanges with sufficient amount of hours per year showing no price difference between the coupled areas. In both cases, hourly day-ahead power exchange prices within the zone show price divergence of not more than 1% in significant number of all hours in a year. For practical reasons zones would not be smaller than countries.

The Guidelines define the following geographical areas:

- Central-West Europe (Austria, Belgium, France, Germany, Luxembourg, Netherlands),

- Iberia (Portugal, Spain),

- Nordic (Denmark, Sweden, Finland and Norway),

- Czech and Slovakia (Czech Republic and Slovakia), and

- All other Member States separately.

The next table provides details for the level of price convergence taking place in each one of the geographical areas.

To ensure equal treatment of sources of electricity and avoid possible abuses, the same CO_2 emission factor will apply to all sources of electricity supply (auto generation, electricity supply contracts or grid supply) and to all aid beneficiaries in the Member State concerned[15].

[15] Data has been extracted from ESTAT EUROBASE system SIRENE annual series nrg101a - solid fuels, nrg102a - oil products and nrg3a - gas. Indicators (indic_nrf) used "transformation input into main activity producers Electricity plants" (code B_101031). Further the UNFCCC energy to CO2 emissions methodology has been used, in accordance with the IPPC Common Reporting Framework (CRF), also used by ESTAT and EEA for the CO2 emissions calculations. For the 29 products considered by the framework, in terms of fossil solids, liquids and gas, the correspondent IPPC conversion factors "Energy into Carbon" and "Carbon into CO2" have been used.

REGION	DIFFERENCE IN PRICES <1% OVER THE FOLLOWING PERIODS (2011)
Central-West Europe	
FR-BE	99%
NL-DE	90%
FR-BE-NL	68%
BE-NL	68%
FR-NL	68%
FR-DE	66%
DE-BE-FR-NL	64%
IT-continental	79%
Nordics	
SE-FI	77%
FI-EE	44%
NO_sys-DK_1	32%
NO_sys-DK_2	32%
NO_sys-FI	37%
NO_sys-EE	15%
SE-DK_1	48%
SE-DK_2	50%
SE-NO_sys	42%
DK_1-DK_2	89%
DK_2-DE	62%
DK_1-DE	61%

REGION	DIFFERENCE IN PRICES <1% OVER THE FOLLOWING PERIODS (2011)
Iberia	
PT-ES	100%
PT-FR	5%
ES-FR	5%
Center East	
SK-CZ	100%
PL_1-DE	6%
PL_2-DE	6%
PL_3-DE	10%
CZ-DE	12%
HU-DE	10%
PL_1-SE	6%
PL_2-SE	6%
PL_3-SE	25%
PL_1-CZ	6%
PL_1-SK	6%
PL_2-CZ	7%
PL_2-SK	7%
PL_3-CZ	5%
PL_3-SK	5%
HU-SK	15%
HU-RO	3%

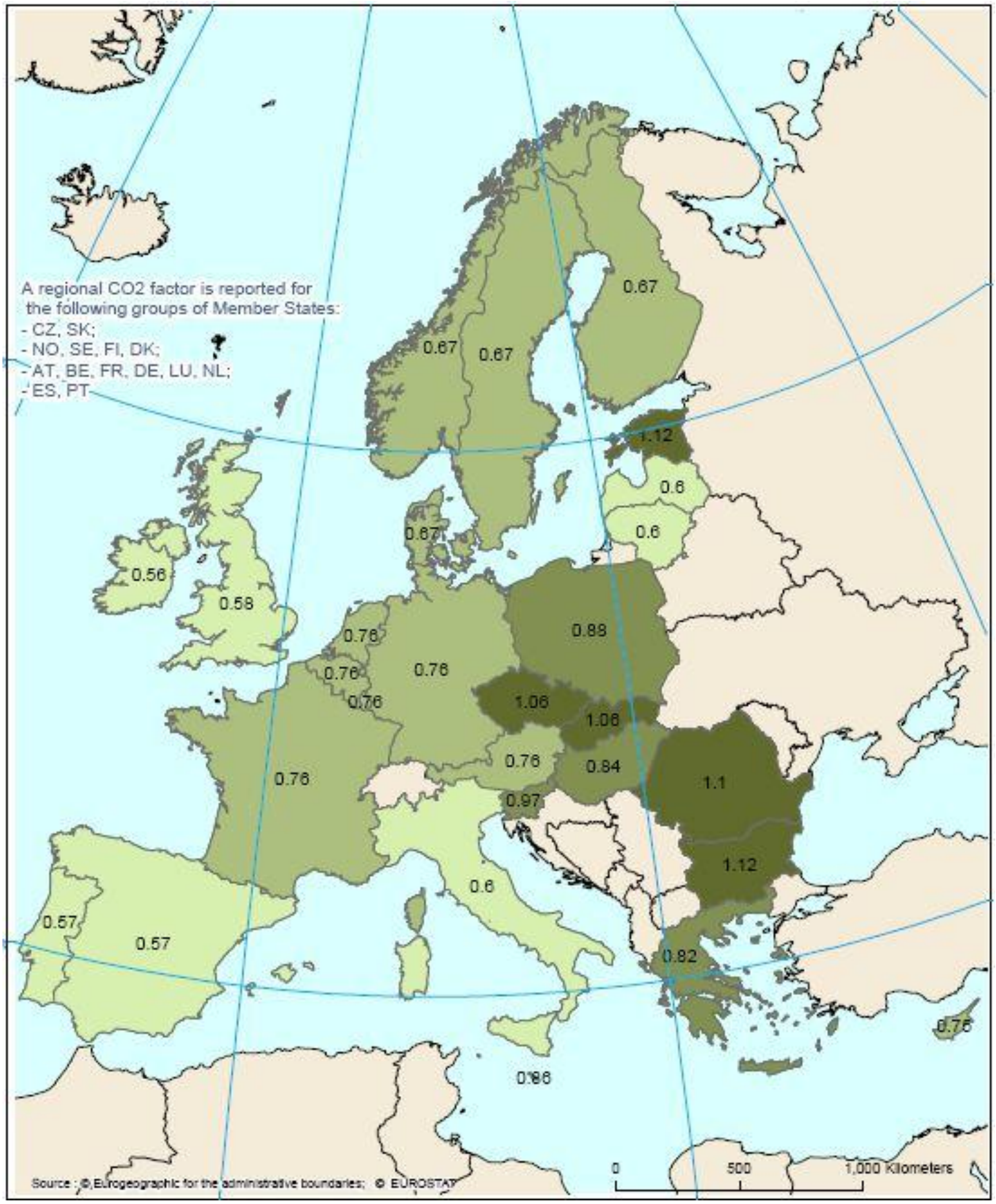
Notes: 1. For the purpose of the calculations on price convergence **DK** is divided in two regions (DK_1 and DK_2), Poland is divided in three regions (PL_1, PL_2 and PL_3) and we use the system price for NO (NO_sys, rather than the five zonal prices).

The map at the end of the section summarises the CO_2 factors by geographical zone. Further information on the public consultation on the draft can be found at:

http://ec.europa.eu/competition/consultations/2012_emissions_trading

/index_en.html

CO2 emission factors by geographical zone



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