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Quarterly Report on European Electricity Markets

Market Observatory for Energy

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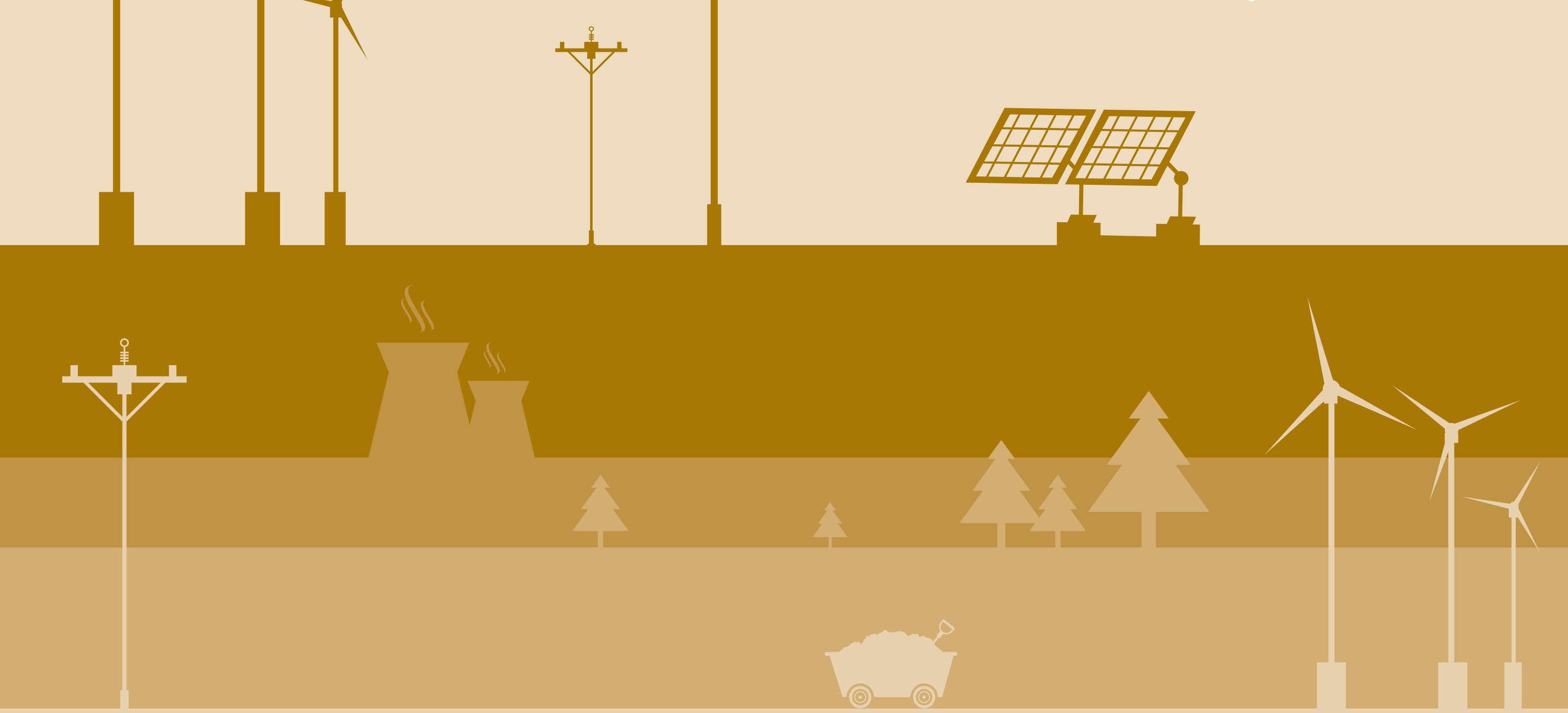

Energy

Our quarterly reports on gas and electricity have gone through some changes in terms of design, structure and contents.

The overall aim was to make our reports more concise and reader friendly, and also more timely.

At the same time, we will endeavour to make any additional analysis on the EU's gas and electricity markets available on the Market Observatory for Energy pages of the DG Energy web site (http://ec.europa.eu/energy/observatory/index_en.htm).

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Highlights

- **Electricity consumption continues to fall slightly in the third quarter of 2012** (by 1.3%) following a smaller fall earlier in the first half of the year (0.5%). Annual electricity consumption in the EU has fallen every year since 2008, by 1.2% on average. The main reason is lower demand from energy-intensive sectors, such as manufacturing and construction.

- **Electricity trade and cross-border flows increased (by 7%) in the second half of 2012**, compared to the same period of last year, in spite of decreasing electricity consumption. This illustrates increasing integration of the European electricity markets.

- **Market coupling in Central and Eastern Europe contributes to converging power prices.** In September 2012 Hungary joined the Czech Republic and Slovakia to form a trilateral market coupling area in the Central and Eastern European region. The result was an immediate decrease in the Hungarian power price premium to Slovakia and more price convergence in the region.

- **Higher than usual divergences observed in the wholesale power prices of Germany, France, Belgium and the Netherlands.** In Germany, wholesale prices fell as higher renewable output and cheaper coal pushed prices down, while lower nuclear output in France and Belgium and more demand for gas-powered generation in the Netherlands drove up power prices in those countries. This provided an illustration of how developments at national level can counter the positive effects of market coupling on prices.

- **Evidence of increasing volatility of prices as more intermittent renewable energy sources are fed into the grid.** A rising share of wind and solar-generated power during the peakload period could be observed in 2012. As a consequence, the peakload power price frequently fell below the baseload price – the opposite of what usually happens. In addition, when wind power generation was particularly high, prices sometimes fell below zero, especially during weekends and nights when demand is usually at its lowest.

- **Coal-fired generation continues to be supported by low carbon prices and falling coal prices on international markets,** in contrast to high and rising natural gas prices in the EU.

- **Significant differences remain in the retail electricity prices paid by household and industrial consumers in different Member States.** Particularly large differences in prices continue to be observed between Member States among low consumption bands, primarily owing to price regulation.

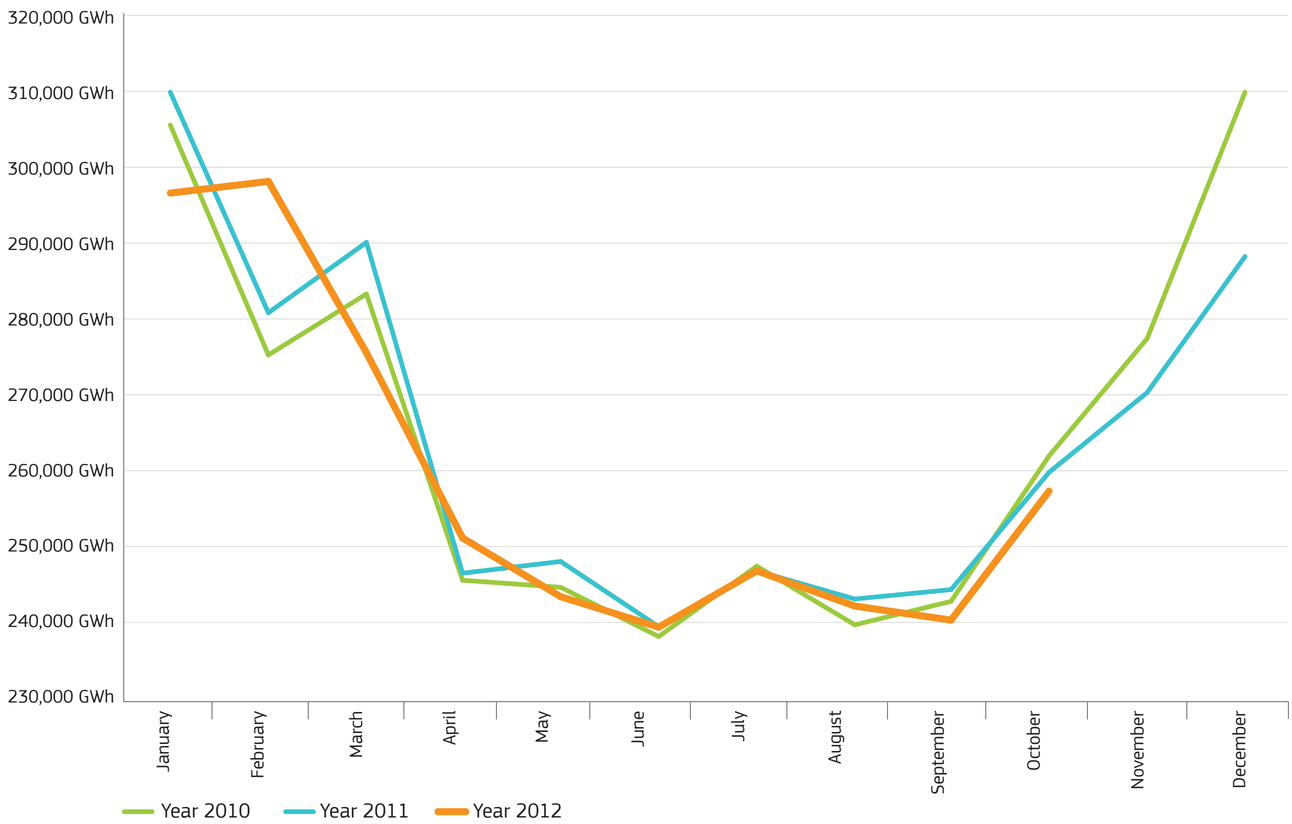
1. Electricity supply, imports and exports

1.1 Evolution of electricity generation

- *Figure 1* presents the electricity generation in the EU-27 presented on a monthly basis. Power generation is normally the highest in the first and the fourth quarter of each year, primarily owing to greater heating and lighting needs during the winter period.

- In February 2012, due to a cold snap experienced across the European continent, power generation in the EU was 6.3% higher than in February 2011 and was also higher than in the same month of 2010. A similar phenomenon could be observed in December 2010 due to a cold period that lasted for several weeks.

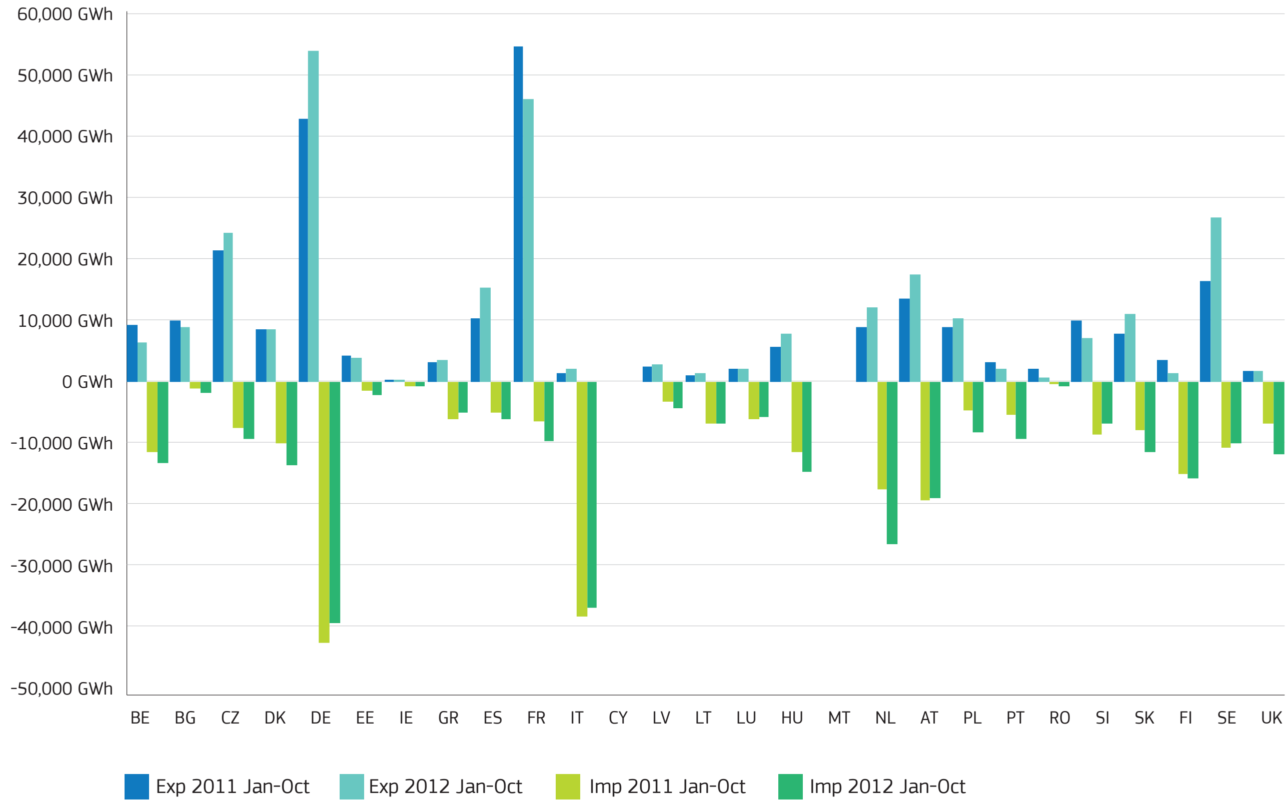
FIGURE 1 - EU-27 ELECTRICITY GENERATION (GWH)



1.2 Electricity imports and exports in EU Member States

- *Figure 2* provides an overview of electricity exports and imports in the EU Member States in the first ten months of 2011 and 2012. Some countries, like France, the Czech Republic or Sweden are net power exporters, whereas other countries, like Italy, the Netherlands, Austria and Finland are net power importers. In 2011, Germany had a balanced electricity import-export position, while in 2012 the country managed to increase its power exports and became a net exporter.

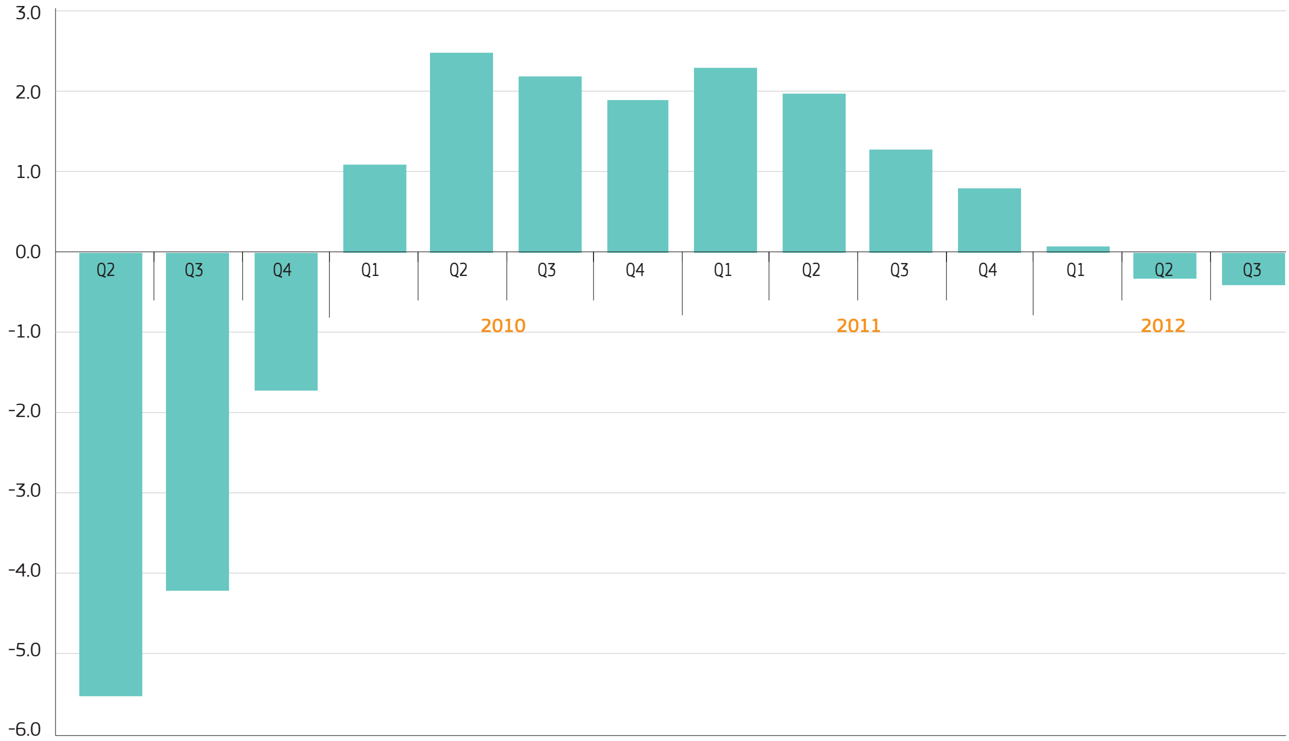
FIGURE 2 – IMPORTS AND EXPORTS OF ELECTRICITY IN EU-27 MEMBER STATES IN THE FIRST TEN MONTHS OF 2012 (GWH)



1.3 Drivers of EU electricity demand

- Gross domestic product (GDP) in the EU-27 shrank by 0.3% in the third quarter of 2012 compared to the same period of 2011. This represented the second successive quarter of negative GDP growth on an annual basis, the first such occurrence since 2009. As decrease in gross value-added in energy intensive sectors, such as manufacturing and construction, was greater than the overall GDP decrease, EU electricity consumption was significantly impacted and went down by 1.3% in Q3 2012,reative to the previous year.

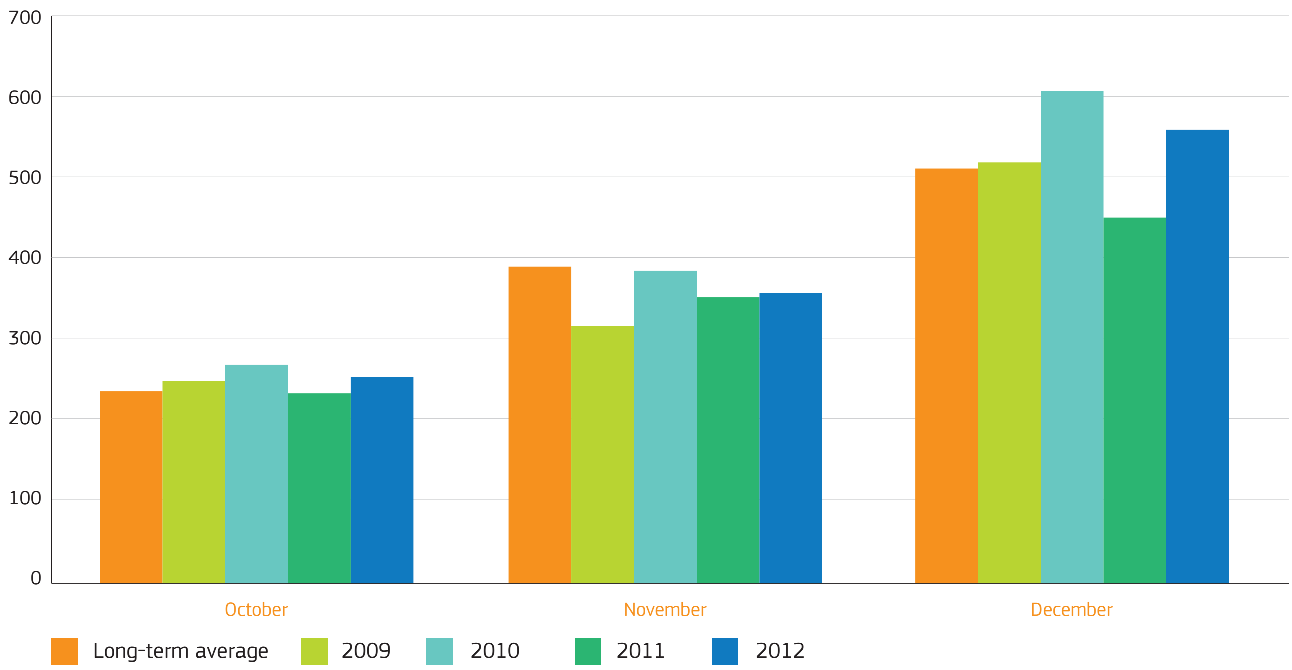
FIGURE 3 – EU 27 GDP Q/Q-4 CHANGE (%)



Source: Eurostat

- No significant differences in temperatures could be observed in October 2012 and November 2012, relative to the same months of recent years or to long term averages for those months of the year. In December 2012 the weather turned cooler than the long term average, as can be seen from the number of heating degree days* shown in the chart below.

FIGURE 4 – EU 27 HEATING DEGREE DAYS (HDDS)



Source: Eurostat/JRC. The colder is the weather, the higher is the number of HDDs.

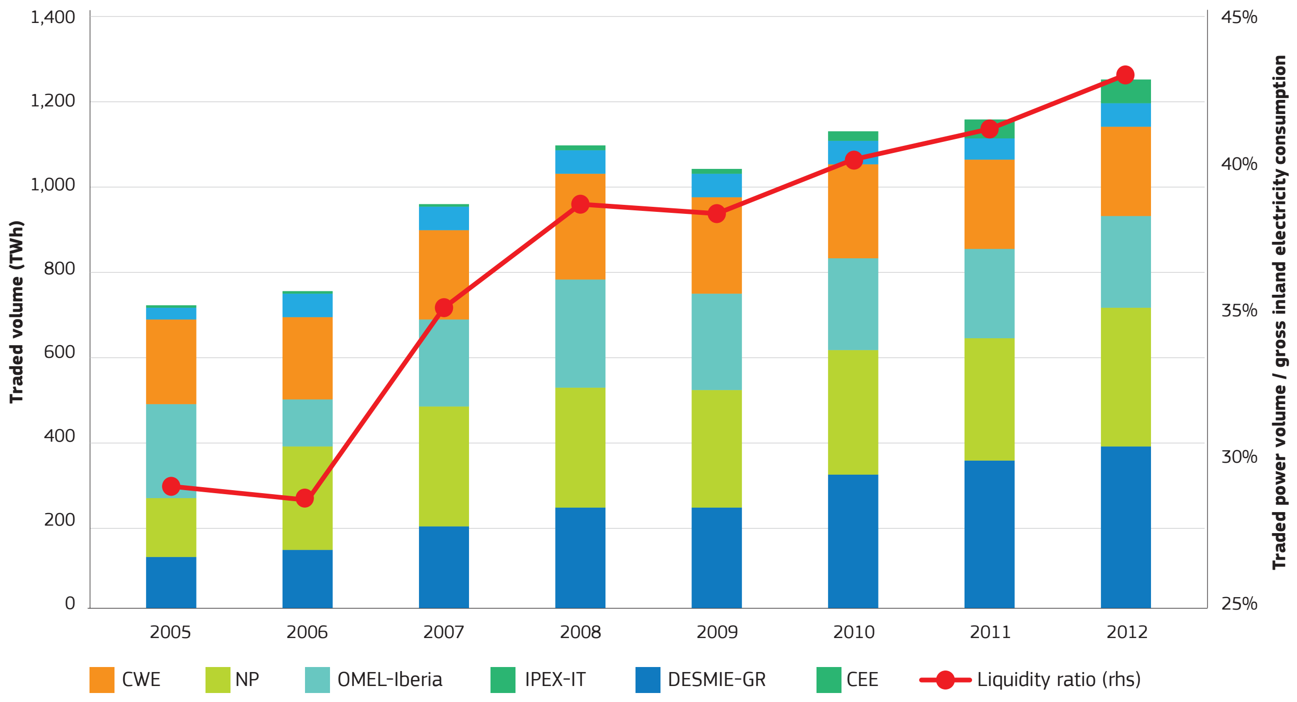
** Please see the Glossary in Chapter 8 for the definitions of professional terms marked by an asterisk (*)*

2. Traded volumes on European wholesale electricity markets

- In the second half of 2012, the combined traded volume of day-ahead power contracts on European wholesale power trading platforms amounted to 624 TWh, an increase of 7.2% compared to the second half of 2011, despite the decrease in gross inland electricity consumption in the EU during that period. These diverging trends contributed to higher market liquidity. By the third quarter of 2012, 44% of the EU's electricity consumption for that quarter was traded in the European day-ahead wholesale power markets.

- As Figure 5 shows, traded volume of power in the European day-ahead markets has been increasing continuously since 2005, with the exception of 2009. The share of the European annual electricity consumption traded in the power markets increased from 29% in 2005 to 43% in 2012.

FIGURE 5 – TRADED VOLUMES ON MAJOR EUROPEAN WHOLESALE ELECTRICITY MARKETS

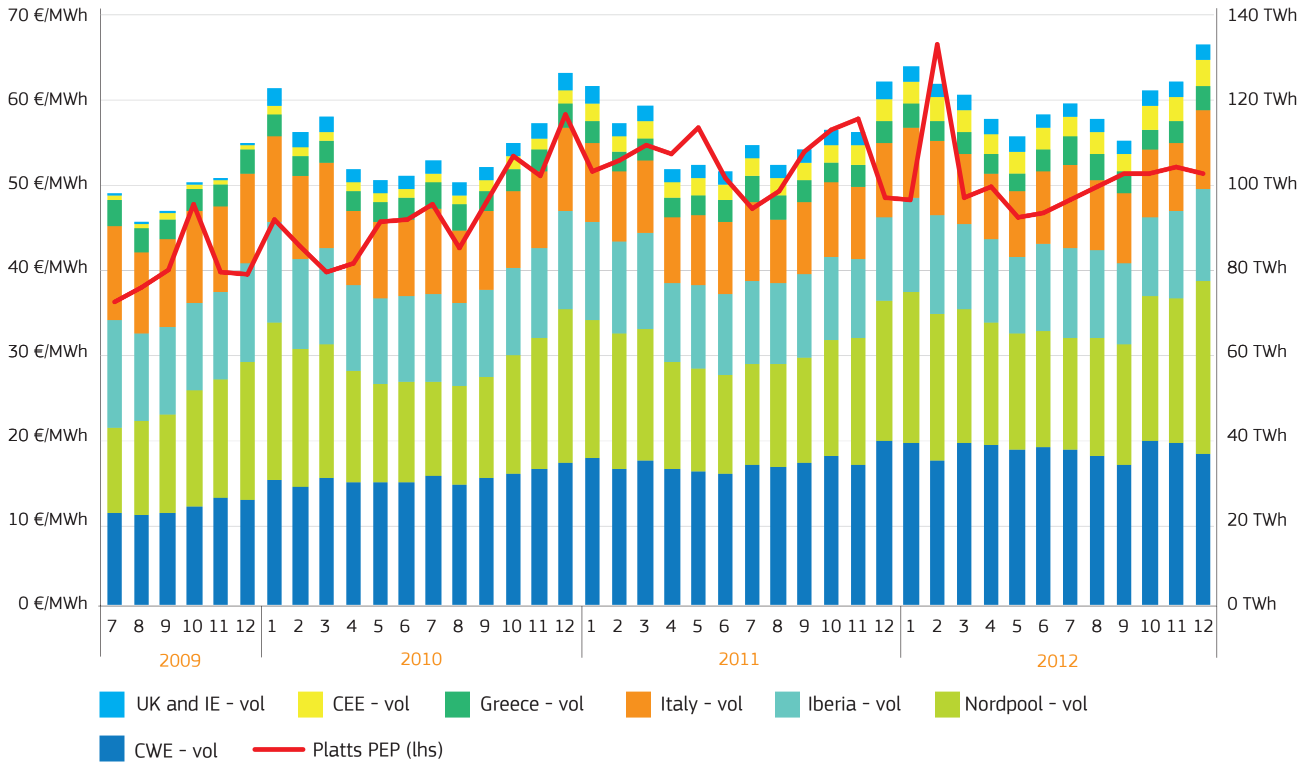


Source: Platts, European power trading platforms, Eurostat

- Monthly traded volume of power was the highest in the Nordpoolspot market and in the CWE region. These two regions are typically considered the most liquid ones in Europe. In the case of Nordpoolspot more than two thirds of the quarterly electricity consumption was traded in the market, while for the CWE region this ratio was around 30% in 2012.

- In the Iberian, Italian and Greek markets, significant volumes of power have been traded, though it is worth noting here that in these countries all power trading contracts are compulsorily carried out in organised markets (mandatory pools, meaning that no bilateral trades exist outside these platforms). The CEE region showed the most dynamic growth in traded volumes during the last three years in the whole of Europe.

FIGURE 6: THE PLATT'S PAN EUROPEAN POWER INDEX AND THE WHOLESALE MONTHLY TRADED VOLUME OF POWER IN DIFFERENT EUROPEAN POWER REGIONS

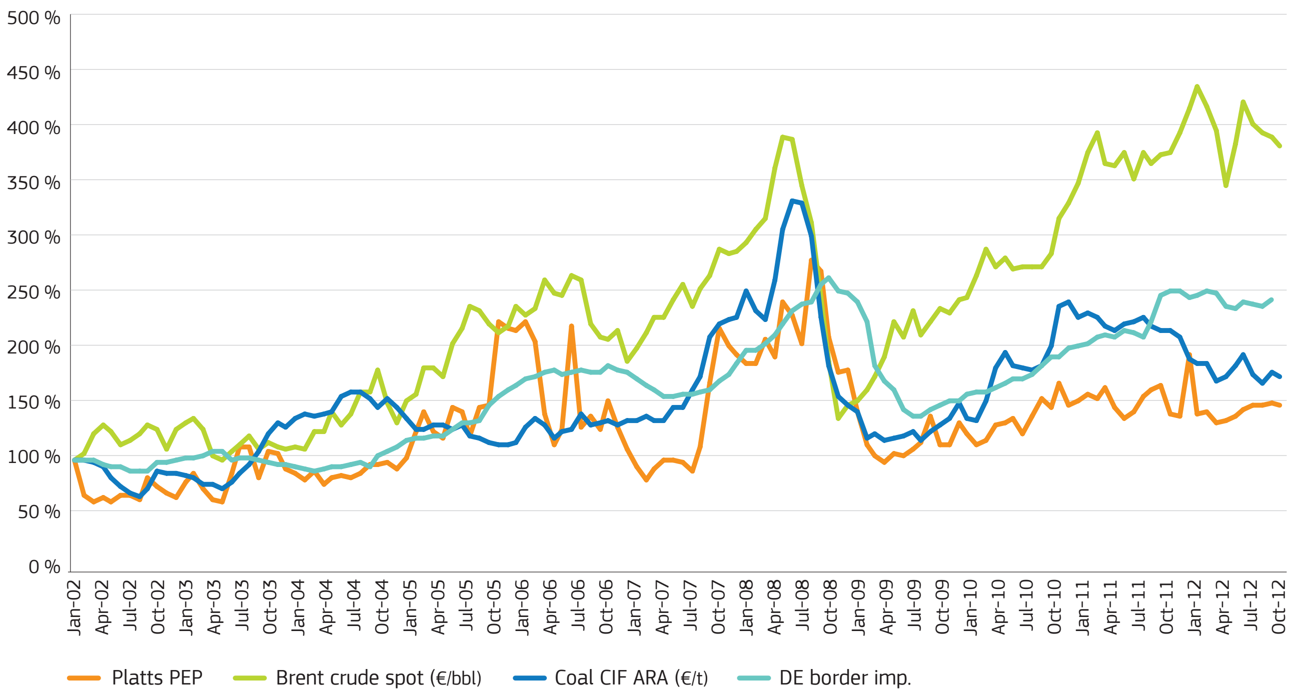


3. Evolution of commodity and power prices

3.1 Evolution of commodity prices, power price and ETS

- *Figure 7* shows the long-term evolution of the Platts European Power Index (PEP), in paralell with the price trends of the Brent crude oil spot, German import gas and North-West European import coal contracts. As can be seen, the increase in power prices in the last eleven years was relatively modest compared to the increase in the prices of coal, gas and oil.
- Since the beginning of 2009, the PEP index (orange curve) remained below the other three curves. Lower increase in wholesale power prices was mainly due to the integration of European wholesale power markets and to the increasing share of renewable energy sources (wind and solar), contributing to lower power generation costs.
- The PEP index was relatively stable in 2012. With the exception of February, when a two-week long cold spell temporarily drove wholesale power prices up across most of Europe, the PEP varied in a narrow range, between 46.1 €/MWh and 52.3 €/MWh. During most of the time in 2012 the PEP index was lower than the previous year, primarily owing to lower generation costs stemming from increasing renewable generation, the rising contribution of cheap coal in continental power mixes and abundant hydro power generatrion in the Nordic markets.

FIGURE 7 – EVOLUTION OF COAL, GAS, OIL AND EUROPEAN AVERAGE WHOLESALE POWER PRICES

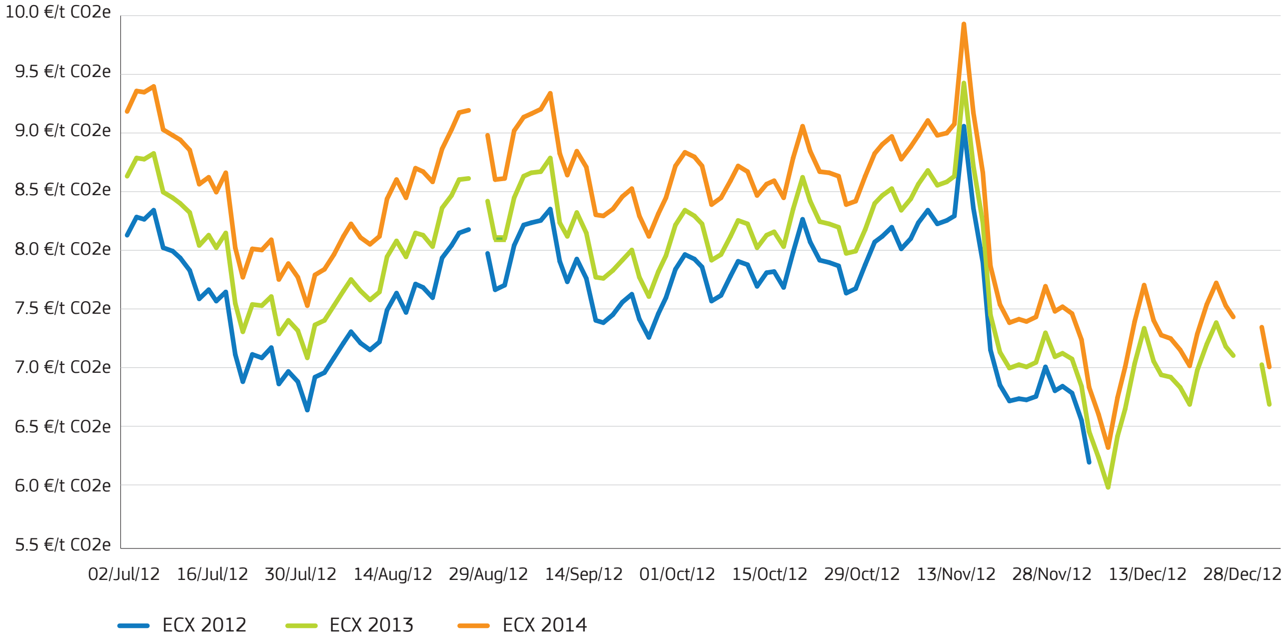


Platts PEP: Pan European Power Index
Brent crude spot: Benchmark price for crude oil in Europe
Coal CIF ARA: Principal coal import price benchmark in North Western Europe
DE border imp. stands for long term contract based import natural gas price on the German border

Source: Platts, BAFA

• Emission allowance prices continued to remain low throughout 2012. Averaging around 8 €/tCO2e for most of the year, they then fell to new lows of around 7 €/tCO2e by the end of the year.

FIGURE 8 – EVOLUTION OF ETS FROM APRIL TO JUNE 2012



3.2 Comparisons of monthly electricity baseload prices on electricity markets

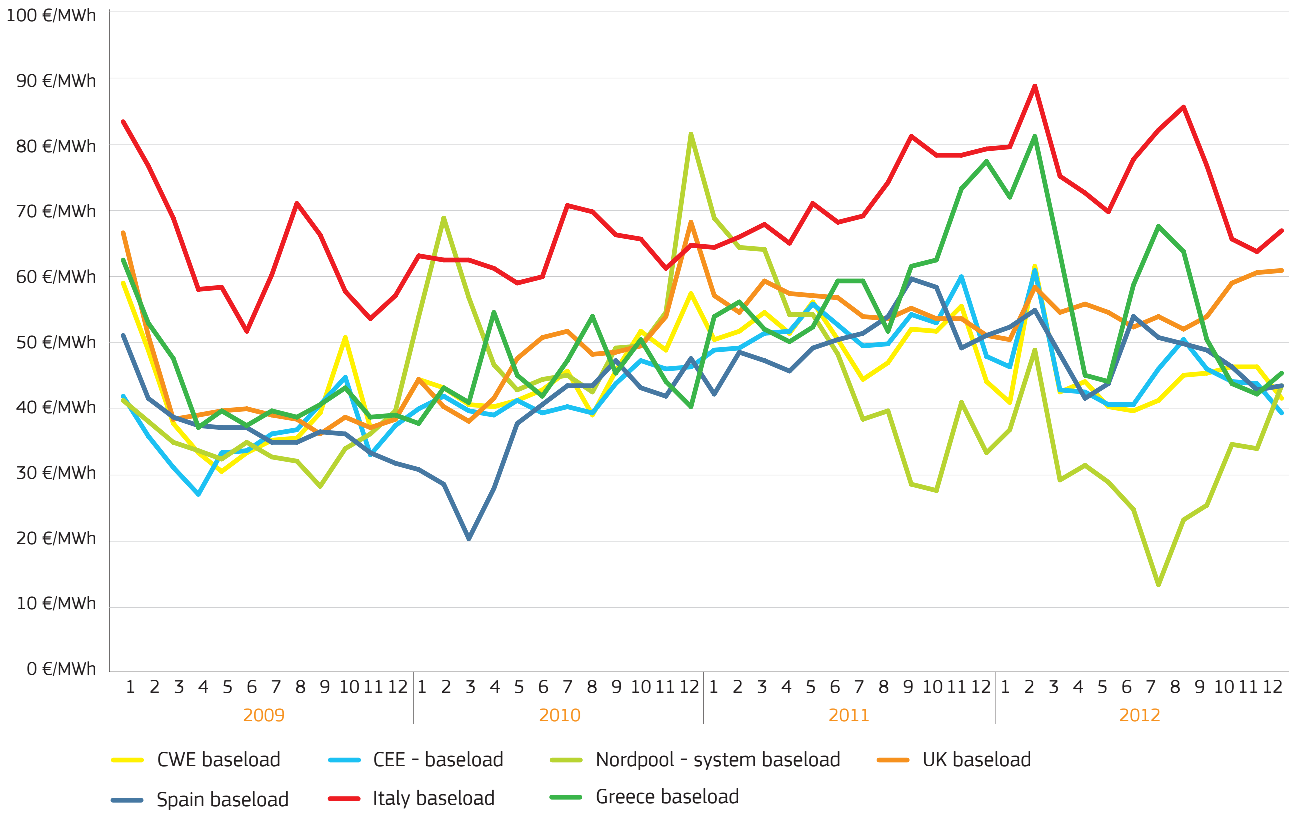
- *Figure 9* shows the evolution of the monthly average regional power prices in seven different regions of Europe between 2009 and 2012. Although there was a perceivable price convergence among different regions, there were some exceptional periods when prices diverged quite significantly.

- Power prices in Italy were higher than in other regions during the observed period, mainly due to a high share of highly priced gas and oil in the country's power generation mix and due to the lack of sufficient electricity interconnections with Italy's neighbours. Prices in the Nordpoolspot market varied in wider ranges during the last four years, primarily owing to the decisive role of hydro-based power generation in this region.

- In the Central Western Europe (CWE) region renewable power generation in Germany and nuclear availability in France are important factors in determining power prices. In the Iberian power mix, hydro availability plays an important role; however, during the last couple of years wind and solar based generation significantly impacted power prices in the region, partly replacing gas-fired generation. Power prices in Central and Eastern Europe are impacted by the CWE market and other factors, such as hydro supply in the Balkans.

- Power prices in the UK are normally higher than their CWE peers, given that the share of both renewable and nuclear generation is lower in the country's power mix than on the continent, while natural gas represents a significant share.

FIGURE 9 – COMPARISONS OF MONTHLY ELECTRICITY BASELOAD PRICES IN REGIONAL ELECTRICITY MARKETS



4. Regional wholesale electricity markets

4.1 Central Western Europe (Austria, Belgium, Germany, France, the Netherlands, Switzerland)

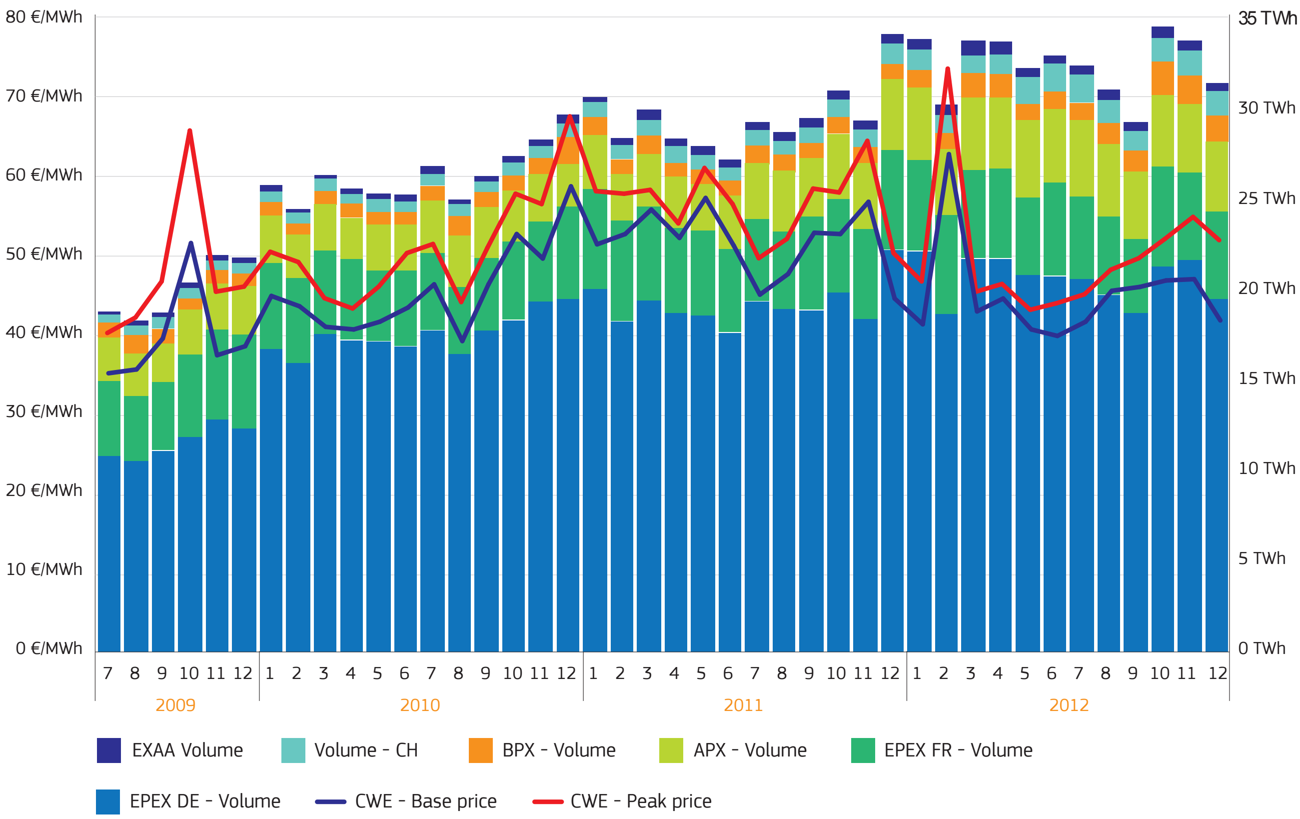
- Due to abundant wind and solar power generation and competitive coal-fired generation, the lowest day-ahead wholesale power prices in the CWE region could be observed in the German market. Permanent French and Belgian prices premiums to Germany were mainly due to the low level of nuclear availability in France and the immediate disconnection of two nuclear plants from the Belgian grid in August, following the discovery of several cracks in their steel structure.

- The existence of French and Belgian price premiums to Germany can be detected in rapidly decreasing weekly price convergence ratios from September 2012 until the end of the year, as Figure 11 shows. Market coupling does not necessarily entail equal prices during all trading hours.

- While a cold spell lifted daily average baseload power prices in the region to above 70 €/MWh in mid-December, by the end of the year power prices fell to 30-40 €/MWh as industrial power demand receded during the holiday season, the weather turned milder and wind generation was running high in Germany.

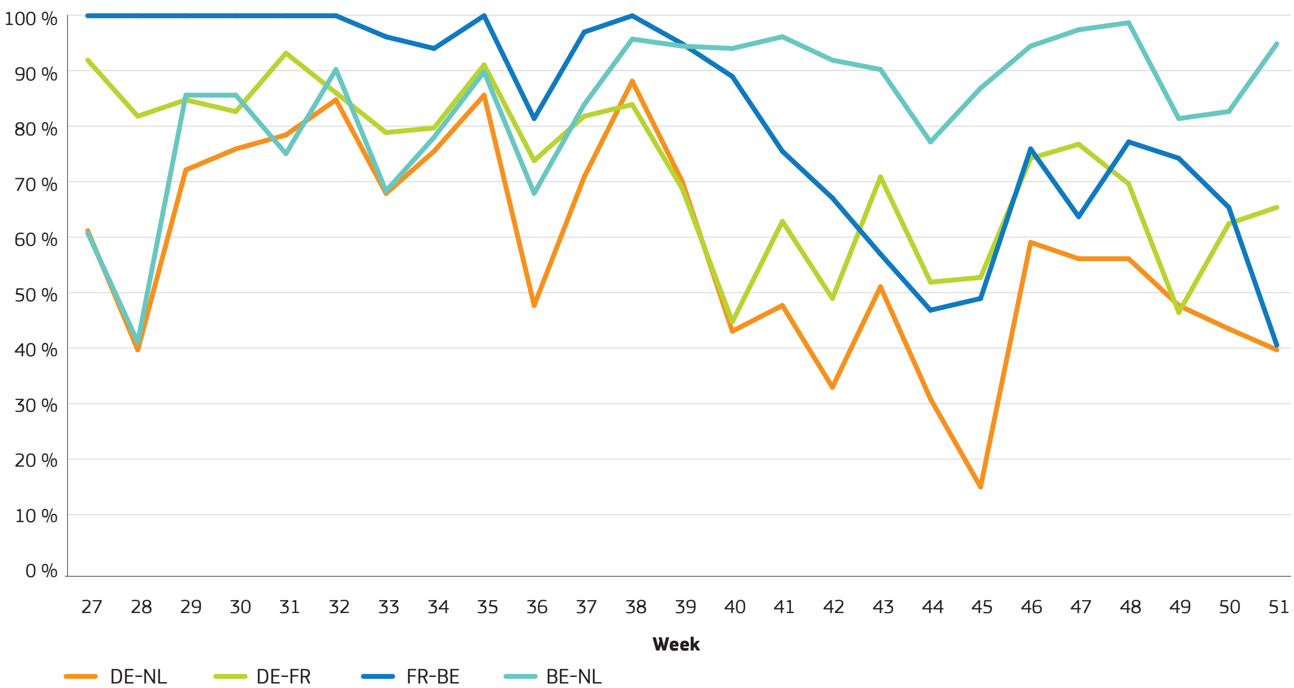
- For the first time in the German power market (EPEX)'s history, daily average power price in Germany turned negative during the Christmas holidays, and on the 25th of December at two o'clock in the morning the hourly price was -222 €/MWh, marking a negative hourly price record.

FIGURE 10 – MONTHLY TRADED VOLUMES AND PRICES IN CENTRAL WESTERN EUROPE



Source: Platts

FIGURE 11 – WEEKLY RATIO OF PRICE CONVERGENCE IN THE CWE REGION



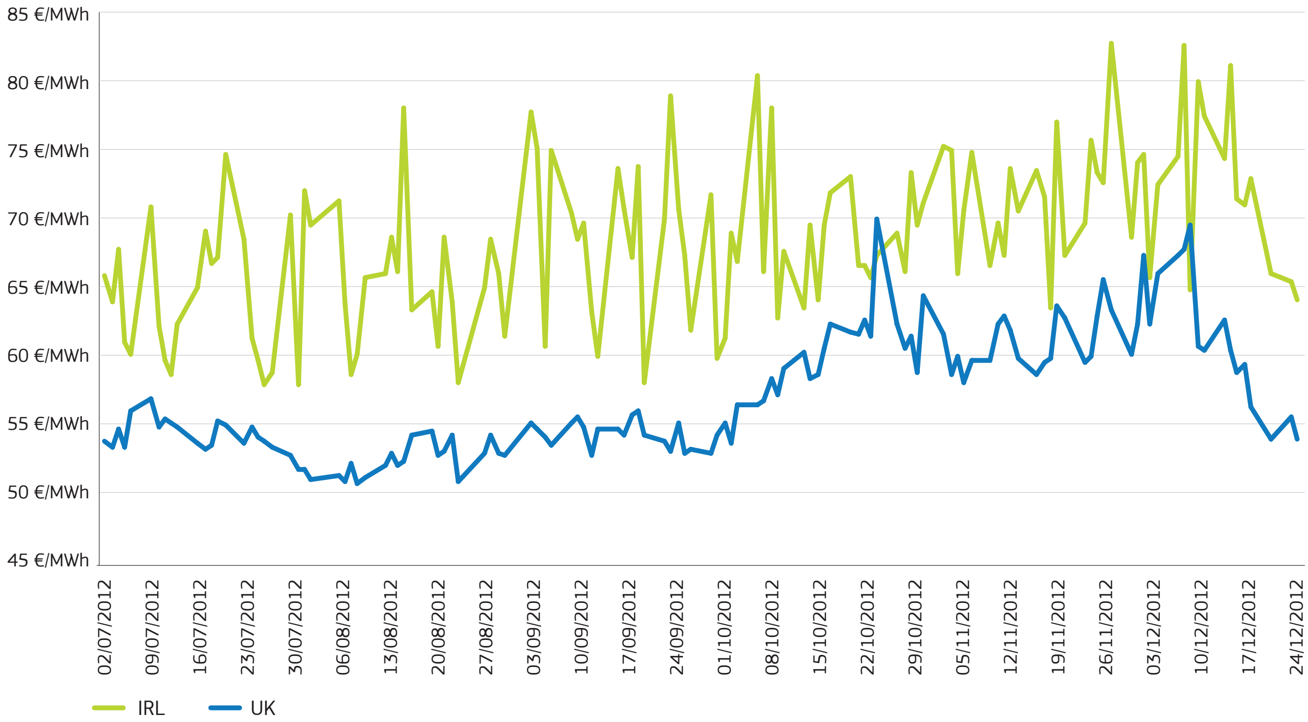
Source: Platts. Prices are considered as convergent if the price difference is less than 1 €/MWh between two neighbouring markets The chart shows the ratio of price-convergent hours in each week.

4.2 British Isles (UK, Ireland)

- The link between natural gas prices and power prices in the UK slightly weakened in 2012, as the amount of power generated from gas decreased by 33% in the first half of the year compared to the same period of 2011, while coal-fired generation was up by 35%. However, in spite of the increasing share of coal and renewables, the role of gas in UK wholesale power price evolution remained decisive.

- The baseload power price in the UK increased in October 2012, primarily owing to rising gas prices, lower nuclear availability and an outage on the France-UK electricity interconnector. By mid-December the daily average price reached its peak in H2 2012 (69 €/MWh), as the December cold spell in North-West Europe increased heating demand. However, increasing nuclear availability, mild weather and subdued industrial demand led to an end-of-year fall in prices.

FIGURE 12 – DAILY AVERAGE POWER PRICES IN THE UK AND IRELAND



- Since the 1st of October 2012, a new 500 MW high voltage direct current subsea power cable has been operational. It has practically doubled the interconnector capacity between the UK and Ireland. The power link gives Ireland the opportunity to export and import power and to increase domestic price competition in the wholesale electricity market. The new interconnector might have played a role in reducing the Irish price premium to the UK, which went down from an average of 12.5 €/MWh in the third quarter to 10.1 €/MWh in the fourth quarter of 2012.

- However, as the share of natural gas is high in the Irish power generation mix (above 60%) and the country imports more than 90% of its gas need from the UK, high gas prices have resulted in increasing power prices. The monthly average baseload power price in Ireland rose to the highest in the last three years between June (57 €/MWh) and November-December 2012 (70 €/MWh). Contrary to the UK, Ireland could not replace gas by coal in its power mix given the limited coal-fired power generation capacities in the country.

4.3 Northern Europe (Denmark, Estonia, Finland, Lithuania, Norway, Sweden)

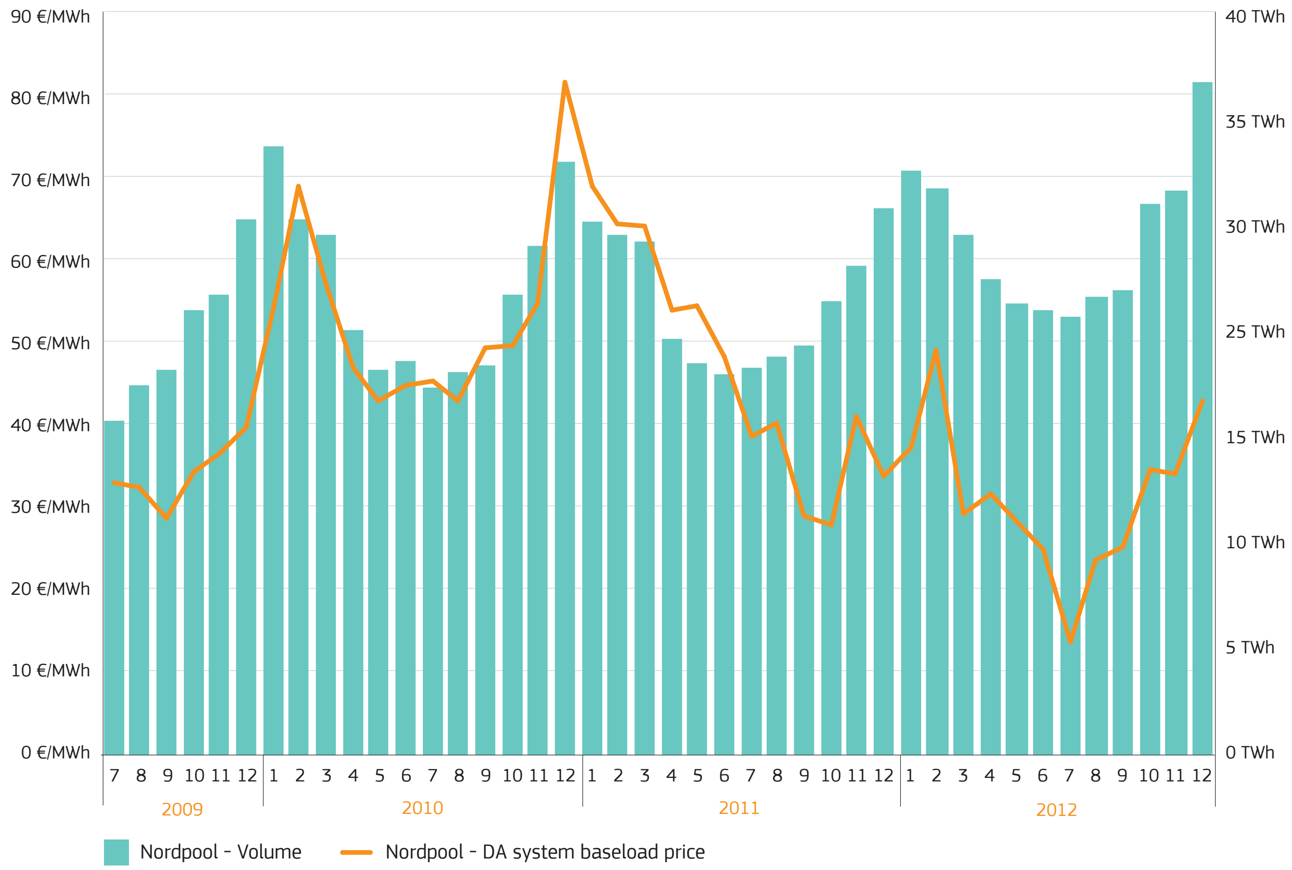
- As Figure 13 shows, the monthly average baseload power price in the Nordpoolspot market shows a strong seasonality. In July 2012 the monthly average Nordpoolspot system price was 13.7 €/MWh, reaching the lowest value since the beginning of 2005. This was mainly due to the abundant hydro-based power generation. The weekly level of hydro reserves was 5-6% higher than the corresponding long-term seasonal weekly value during most of the second half of 2012. Besides hydro generation nuclear power plants, assuring about one fifth of the regional power supply can also impact significantly the Nordpoolspot system price.

- Prices in South Norwegian areas, where hydro-based power generation is concentrated in the region were the lowest in the Nordic region. Finnish and Lithuanian area prices were impacted by Russian electricity imports. Russian authorities imposed a capacity tariff on power exports during peak hours; this made the power import from Russia to Finland uncompetitive.

- In the case of Lithuania a power cable outage in Russia triggered a sudden price spike on the 20th of August (with a daily average price of 123 €/MWh). The lack of interconnections to Sweden and Poland, remaining interconnection bottlenecks with Finland and the lack of sufficient domestic generation capacities explain why Lithuania imports around two thirds of its power needs from Russia.

- Low domestic prices allowed Norway to export its electricity to Sweden, Denmark and to the CWE markets. In August 2012, power exported from Norway amounted to 2.5 TWh, representing the highest monthly exports in the last six years.

FIGURE 13 – MONTHLY TRADED VOLUMES AND PRICES IN NORTHERN EUROPE



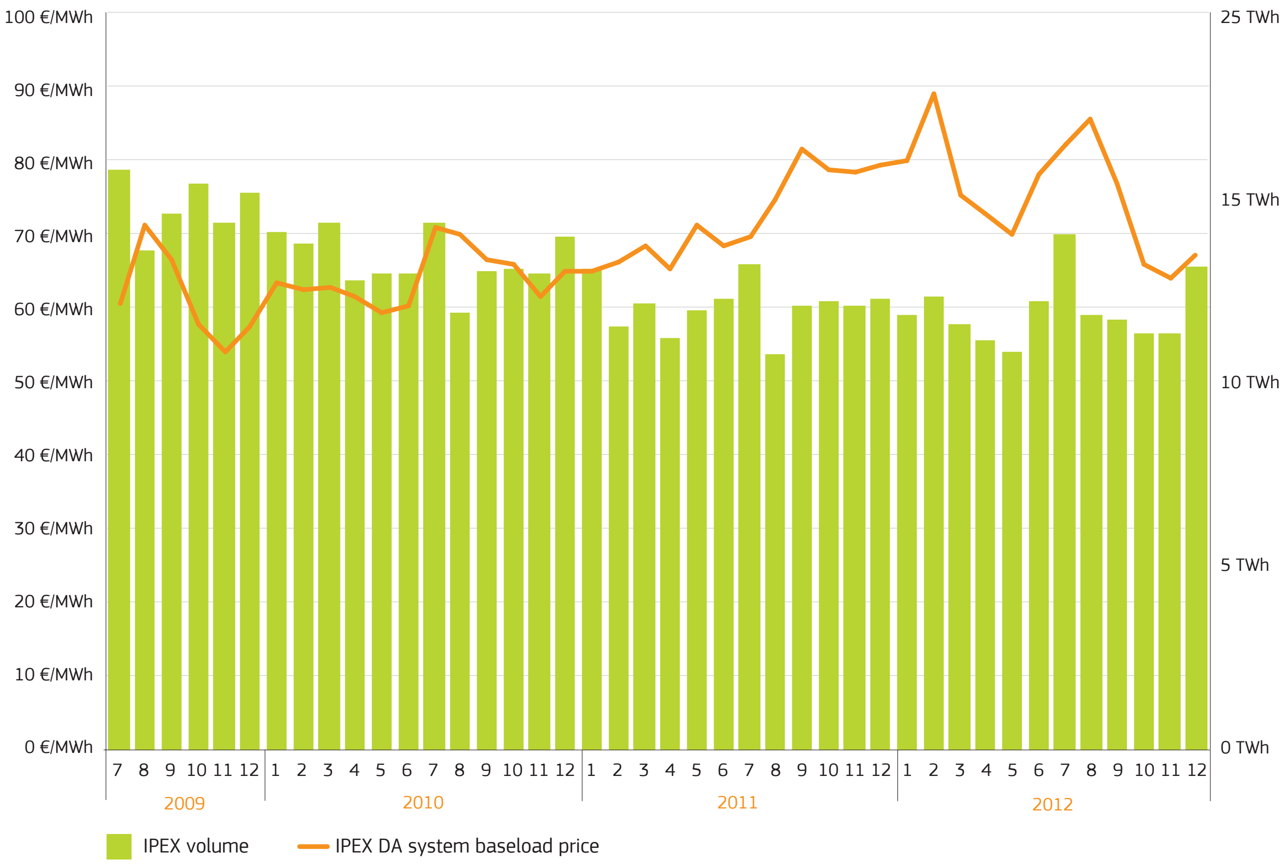
4.4 Apennine Peninsula (Italy)

- During most of July and August 2012 the daily average baseload power price in Italy fluctuated in a narrow range of 80-90 €/MWh, due to the increased cooling-related demand for power, as these two months of 2012 were warmer than the long term average. Power prices began to decrease in September, and by the end of 2012 the monthly baseload average price fell to 67 €/MWh.

- With the share of gas-fired generation decreasing from 53% in 2011 to 45% in 2012, and the share of renewables increasing from 22% to 29% in the same period, power generation costs also decreased. In Q4 2012, the average Italian baseload power price was down by 16% compared to the fourth quarter of 2011.

- In the case of the Sardinian insular power price area a measurable premium (15-20 €/MWh) could be observed to mainland Italy prices before August 2012. In September 2012 this premium disappeared, due to the removal of power flow limitations between the island and mainland Italy. Sardinian area prices remained well-aligned during the last four months of 2012.

FIGURE 14 – MONTHLY TRADED VOLUMES AND PRICES IN ITALY



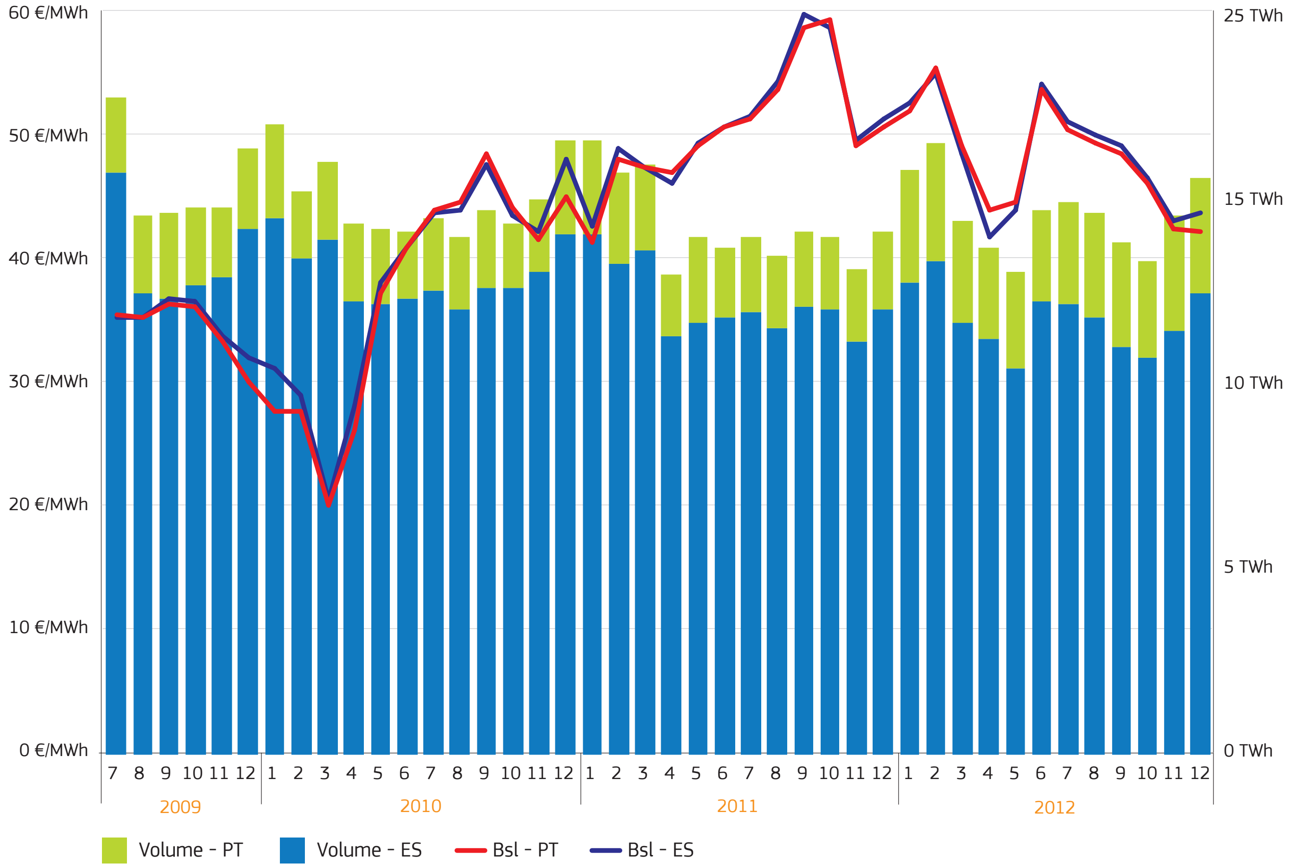
4.5 Iberian Peninsula (Spain and Portugal)

- The monthly average baseload power price in Spain and Portugal decreased gradually in the second half of 2012 to reach 43.7 €/MWh and 42.2 €/MWh, respectively, by December 2012.

- Low industrial demand for power and an increasing share of renewable (wind and solar) generation contributed to the reduction of power generation costs in Spain, enabling the replacement of uncompetitive gas-fired CCGT plants by renewable energy sources. In addition, coal's share in the power mix increased significantly in 2012 (by 65% in the first half of the year compared to the same period in 2011), further contributing to lower generation costs.

• In December 2012, the month-ahead baseload power price went up by 20% compared to the previous month, primarily owing to the anticipation of the impacts of the new 7% tax on power generation, as part of the new Spanish Sustainable Energy Law, which entered into force on the 1st January 2013 and aims at eliminating the country's long standing tariff deficit*.

FIGURE 15 – MONTHLY TRADED VOLUMES AND PRICES IN THE IBERIAN PENINSULA

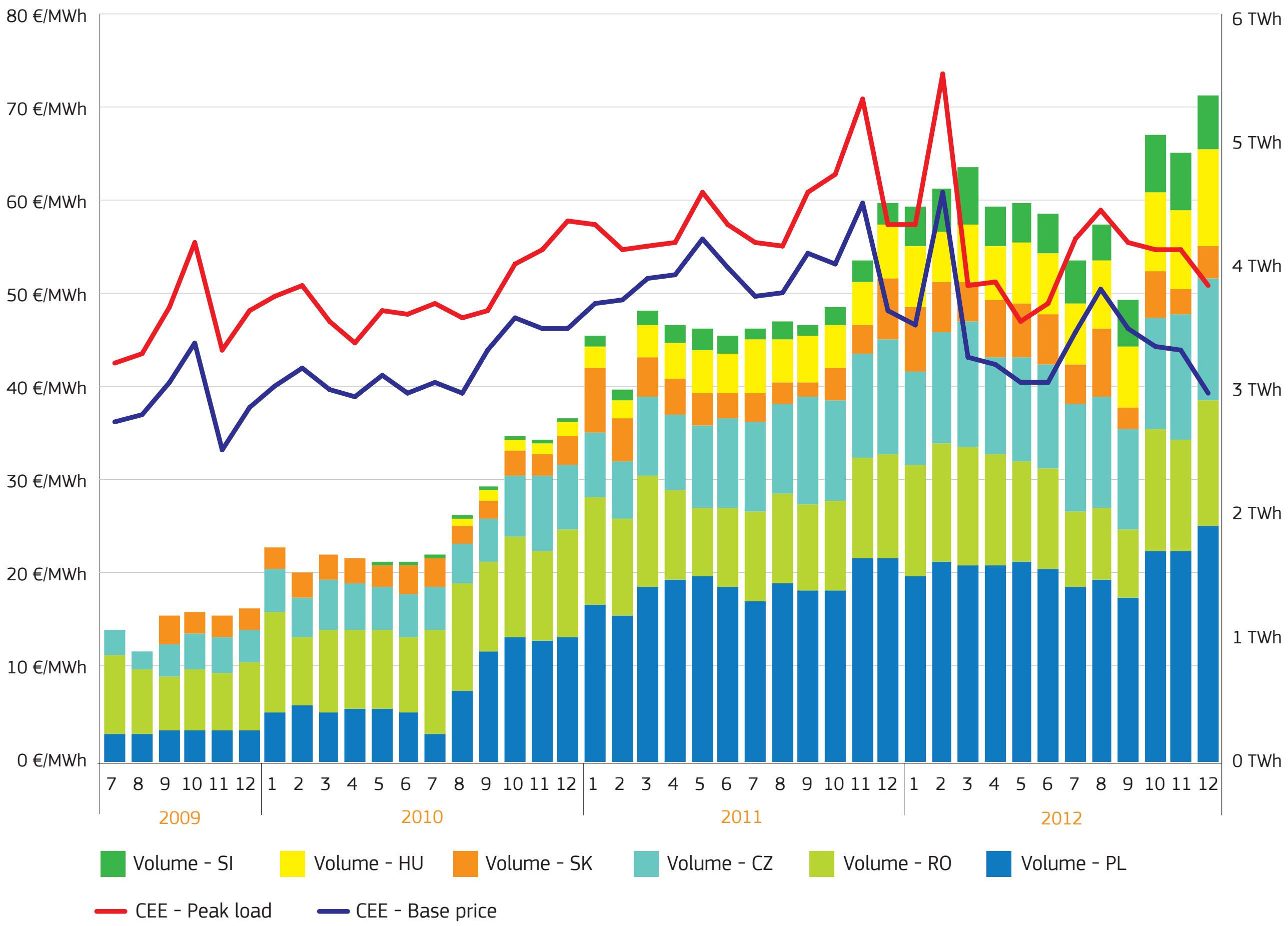


Source: Platts

4.6 Central Eastern Europe (Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia)

- The CEE region showed the most dynamic growth in traded volume of power between July 2009 and December 2012 among the European power regions, increasing from 1 TWh to 5.3 TWh. However, in Q3 2012 only 14% of the quarterly gross electricity consumption of the six countries was traded on CEE platforms, which was significantly lower than the corresponding ratio of 31% in the CWE markets.

FIGURE 16 – MONTHLY TRADED VOLUMES AND PRICES IN CENTRAL EASTERN EUROPE

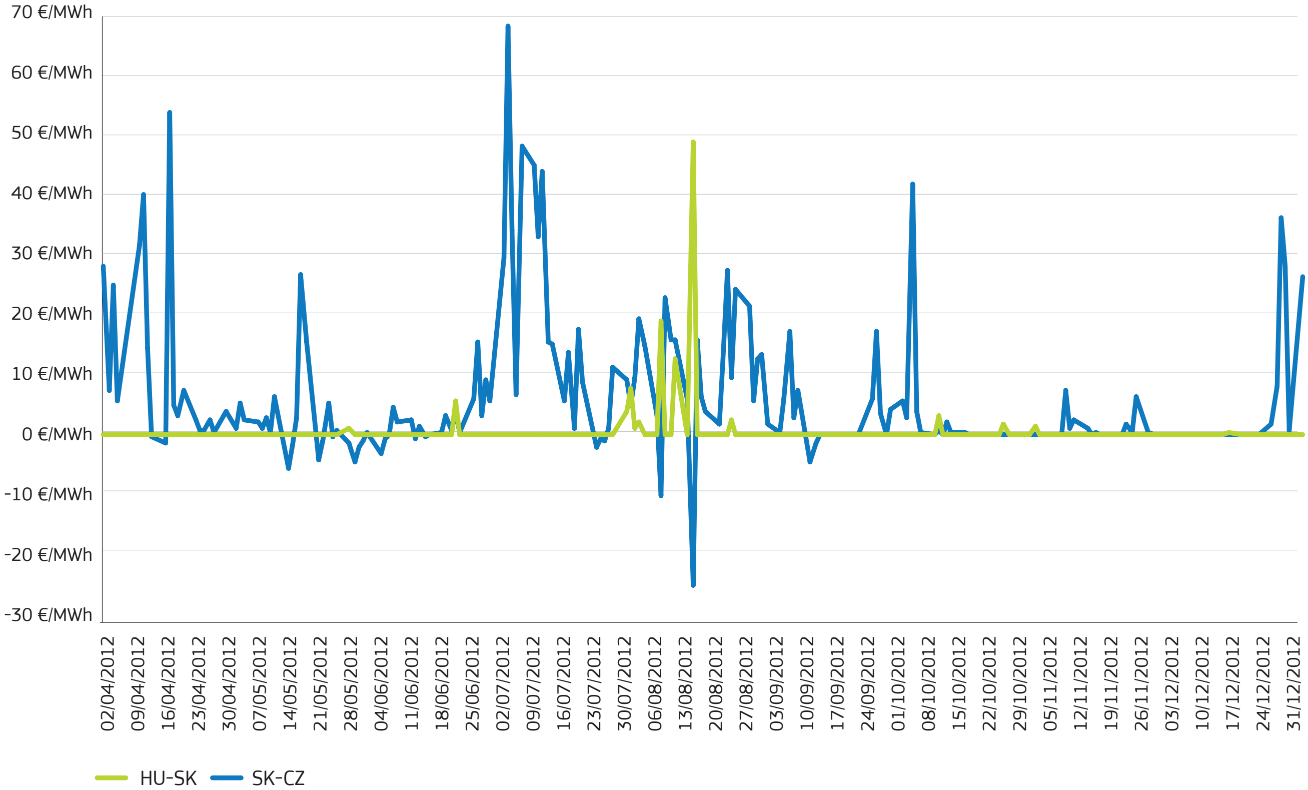


- In July and August 2012 several hot waves across the region, maintenance works on some interconnector capacities and low hydro availability in the Balkans all contributed to high regional power prices, especially in Hungary, Slovenia and Romania.

- On the 12th of September 2012, Hungary joined the Czech-Slovak coupled market, forming a trilateral market coupling in the CEE region. This had an immediate impact on the Hungarian power price level, with a significant fall in the Hungarian premium to the Slovakian price. Nevertheless, physical cross border capacities between Slovakia and Hungary need to be further enhanced, as there were still a high number of hours when price differentials existed.

- The monthly baseload regional average price decreased from 50.7 €/MWh to 39.7 €/MWh, while the peakload average went down from 59.1 €/MWh to 51.1 €/MWh between August and December 2012. This was mainly due to the price-converging impact of the trilateral market coupling, milder-than-usual weather in the last quarter of 2012, and good hydro availability in the Balkans during most of that time.

FIGURE 17 – THE IMPACT OF THE MARKET COUPLING AMONG THE CZECH REPUBLIC, SLOVAKIA AND HUNGARY (PRICE DIFFERENTIAL BETWEEN NEIGHBOURING MARKETS)



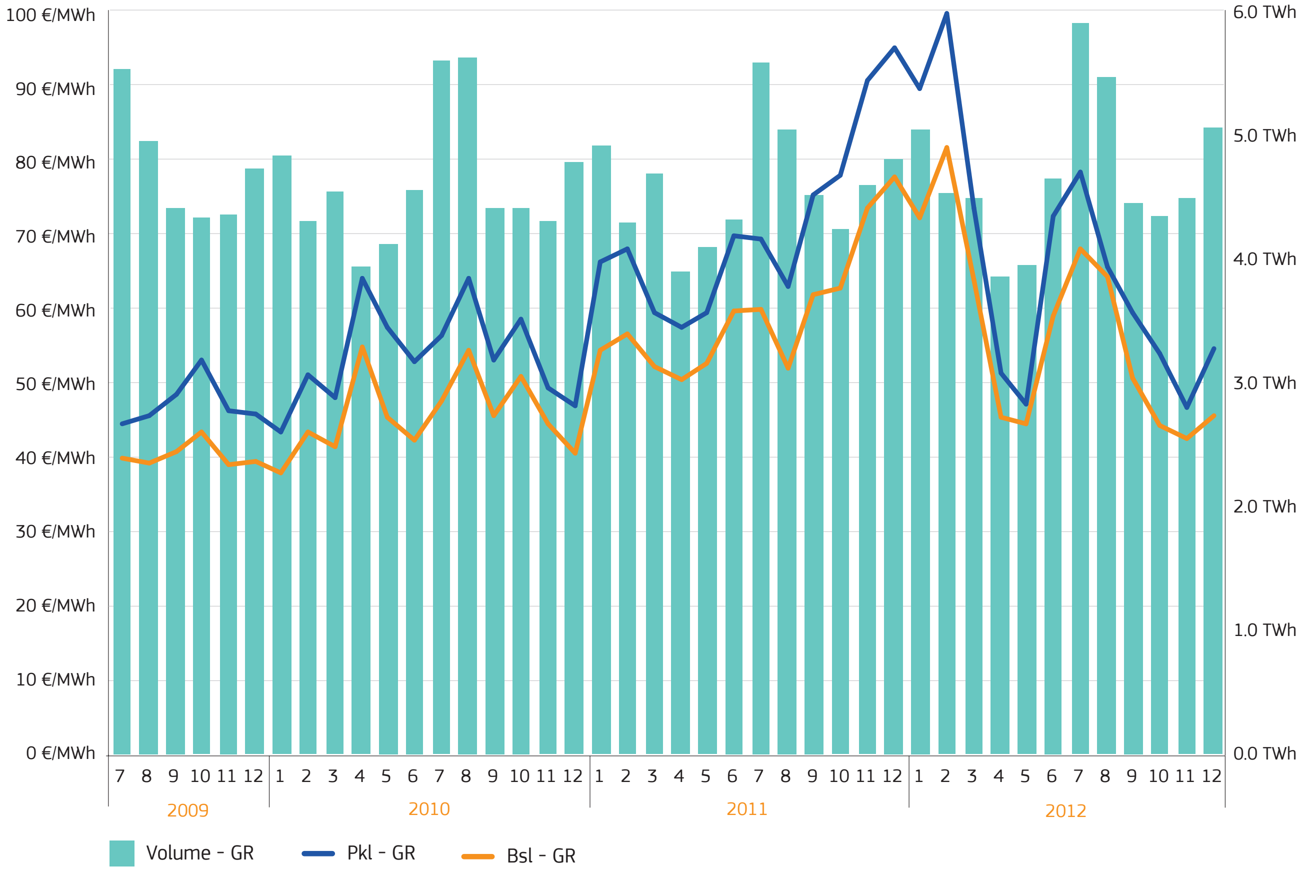
4.7 South Eastern Europe (Greece)

- After hot weather and increasing cooling needs drove the monthly average baseload power price in Greece to reach a 67 €/MWh high in July, it fell progressively to reach a low of 45 €/MWh in December 2012, representing the lowest December price since 2009.

- Falling power consumption and an increasing share of renewables in the power mix increased (from 2.8% to 6.2%) between 2011 and 2012 contributed to falling power generation costs in Greece, especially during peakload periods. In 2012 the average peakload premium to baseload prices was 6.6 €/MWh, being lower than in 2011 (9.5 €/MWh).

- The share of CCGT (gas-fired power generation) increased in Greece in 2012 as a 400 MW new installation was put online in November 2012, contrasting the trend in many European countries.

FIGURE 18 – MONTHLY TRADED VOLUMES AND PRICES IN GREECE



5. Competitiveness of gas and coal-fired power generation

- Coal-fired power generation was profitable in 2012 as *Figures 19* and *20* on the evolution of clean dark spreads* in, respectively, Germany and the UK show.

- In contrast, gas-fired generation suffered from lower power prices compared to the previous year and relatively high (and slightly increasing) gas prices. With the exception of mid-February 2012, when wholesale electricity prices shot up as a consequence of a cold snap, gas fired generation remained unprofitable during most of the year in 2012. In the first half of 2012 the amount of power generated from gas in Germany was down by 15%, while that of coal was up by 8%.

- Clean sparks spreads in the UK fluctuated between zero and 4 €/MWh during the whole year of 2012. As gas prices increased slightly in 2012, higher power prices during the last four months of the year could not assure a better profitability for CCGT generation. Due to a significant spread between profitability of coal-fired and CCGT power generation there was a significant shift from gas to coal in the UK power mix in 2012 (See Chapter 4.2).

FIGURE 19 – EVOLUTION OF THE SPOT CLEAN DARK SPREADS AND SPARK SPREADS IN GERMANY IN 2012

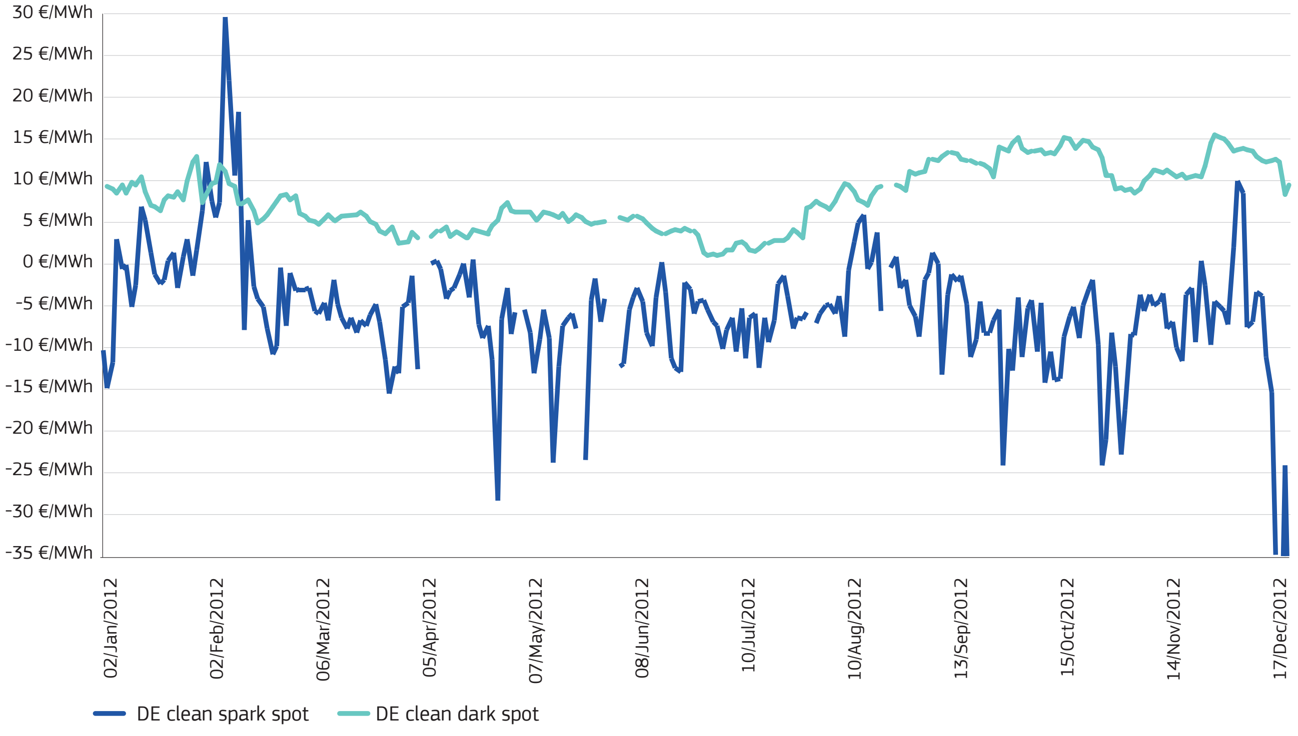
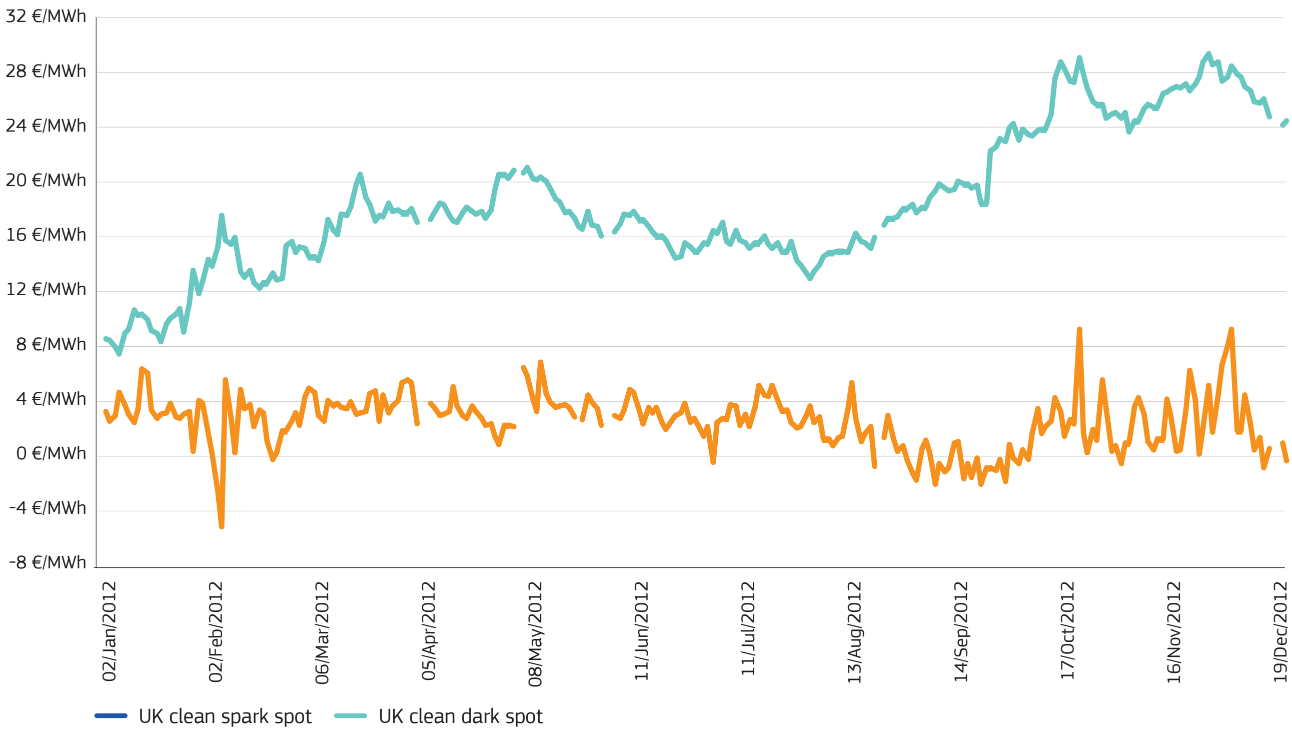


FIGURE 20 – EVOLUTION OF THE SPOT CLEAN DARK SPREADS AND SPARK SPREADS IN THE UK IN 2012



Source: Platts

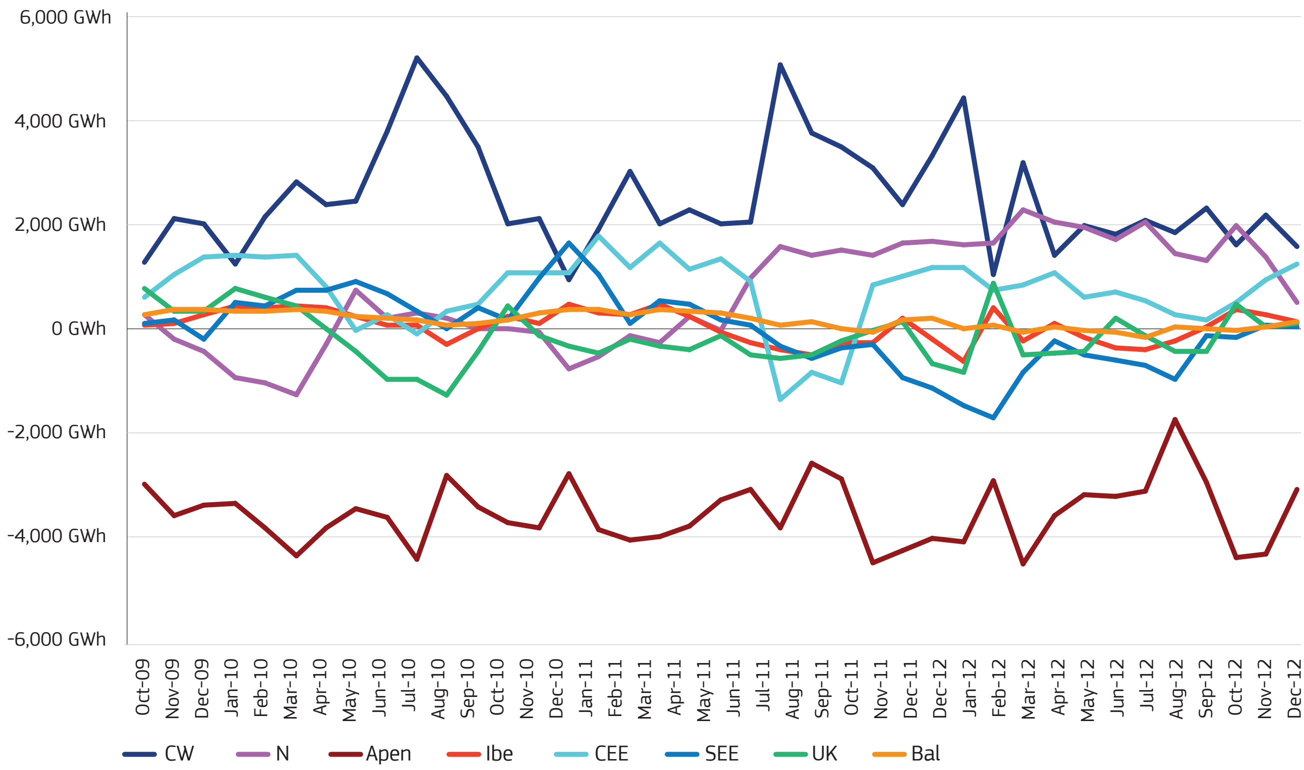
6. Building the internal market for electricity: cross border flows and trade

- In the second half of 2012, monthly cross-border physical power flows in the EU-27 reached 21.4 TWh on average. This was slightly less than in the first half of 2012 (22 TWh) but was 7.2 % more than in the second half of 2011 (19.9 TWh). This was broadly in line with the year-on-year growth in the traded volume of power in selected European markets (7.3%) in the second half of 2012.

- Decreasing electricity consumption coupled with growth in traded volumes and cross border physical flows are signs of increasing market liquidity, growing interdependency and integration of European electricity markets.

- In the second half of 2012, the CWE region continued to be in a strong net power outflow position. The Nordic area's net position also remained strong in Q3 2012, however, as prices started to pick up from the beginning of the autumn the net outflow position began to diminish and in December it reached the lowest level since June 2011. As hydro availability improved in the Balkans during the second half of 2012, South East Europe's position also improved, as there was no need to import power from the CEE region.

FIGURE 21 – EU CROSS BORDER MONTHLY PHYSICAL FLOWS BY REGION



European countries are grouped in the following regions:

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

- The ratio of adverse power flows (or flows against price differentials - FAPDs*) is a useful measure of the effectiveness of existing market couplings or integration of neighbouring power markets. Figure 22 below provides a perfect example of the difference between coupled and non-coupled neighbouring markets.

- In the Central West European region the market coupling took place in November 2010, and since the first quarter of 2011 there have almost been no occurrences of FAPDs. In the second half of 2012, price differences could be observed among participating countries, nevertheless, power did not often flow from the higher to the lower price area and the FAPD ratio remained below 1% during the second half of 2012.

- In contrast, in the Central East European region FAPDs are normally very high. However, as market coupling between the Czech and the Slovak market has existed since 2009, the ratio of FAPDs is practically zero between these two countries. After Hungary joined this coupling area in September 2012, adverse flow ratios between Slovakia and Hungary went down from 40% in Q2 2012 to 12% in Q4 2012, showing the beneficial impacts of market coupling (See Chapter 4.6).

FIGURE 22 – EVOLUTION OF ADVERSE POWER FLOW RATIOS IN THE CENTRAL WESTERN AND CENTRAL EASTERN EUROPEAN REGIONS

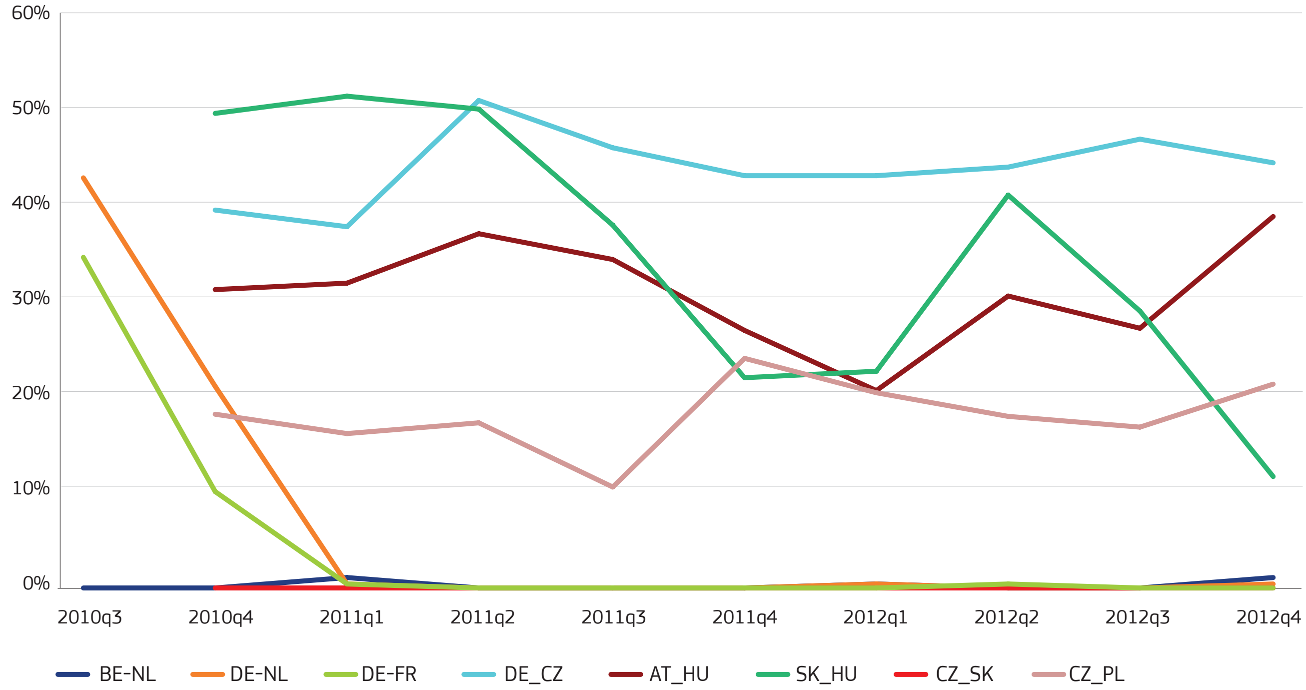
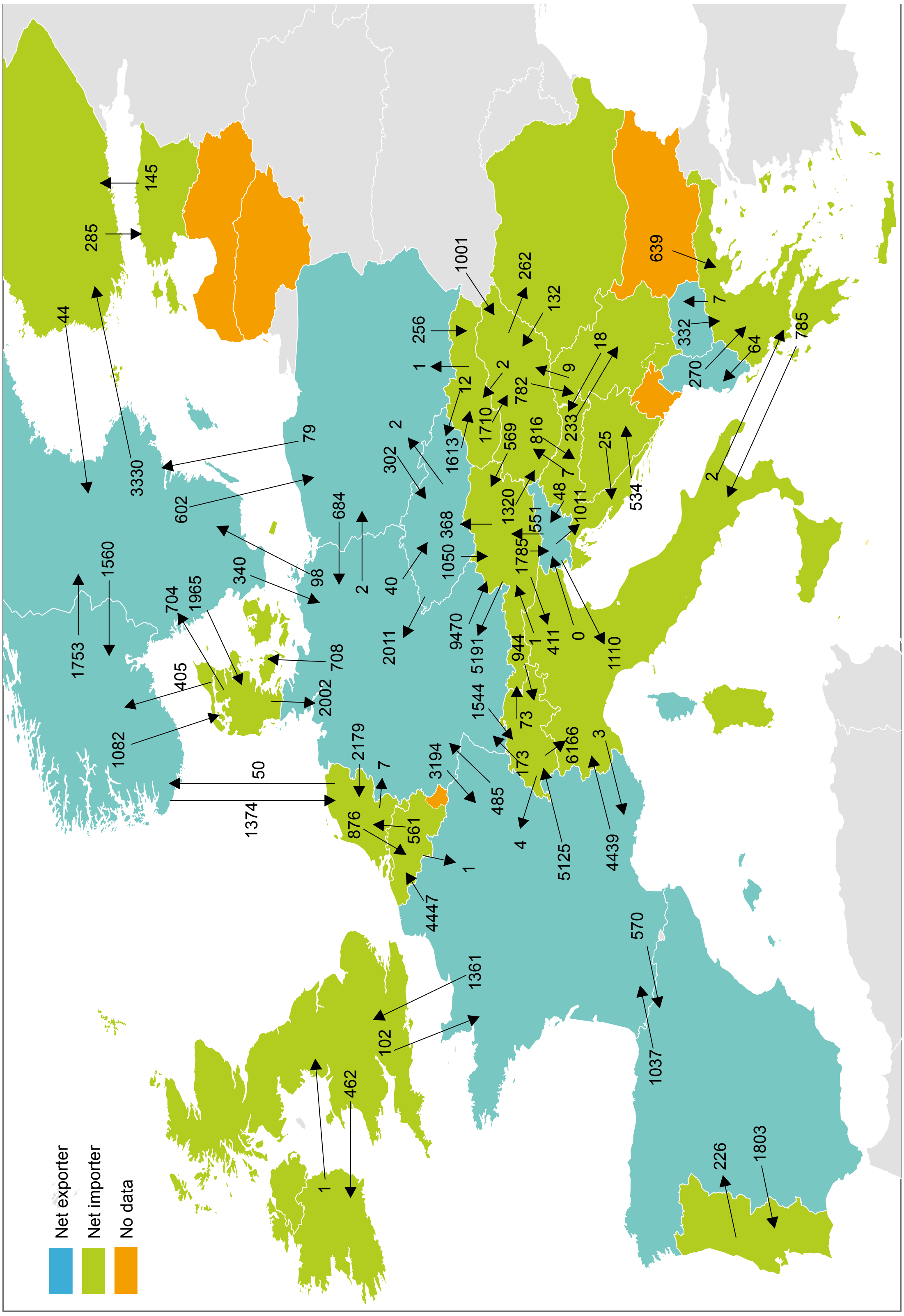


FIGURE 23 – COMMERCIAL ELECTRICITY FLOWS IN GWH IN Q4 2012 (FINAL SCHEDULE)



Source: Platts

Data for some countries are not available (see the legend). Due to presentation constraints Northern European countries 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.

7. Retail electricity prices in the EU

- A comparison of electricity retail prices across the EU reveals significant differences, with prices paid in the most expensive Member States representing several times the price paid in the cheapest (even if taxes and duties are excluded).

- At retail price level the differences are greater for households than for industrial customers in different EU countries.

- In household consumption band Db (annual consumption between 1000 kWh and 2500 kWh) households in Bulgaria paid the lowest price (8.5 €cents/kWh, including taxes), while households in Denmark paid the highest price (33 €cents/kWh, including taxes).

- In industrial consumption band Ib (annual consumption between 20 MWh and 500 MWh) consumers in Estonia paid the lowest price (6.6 €cents/kWh), while consumers in Cyprus paid the highest price (26.1 €cents/kWh).

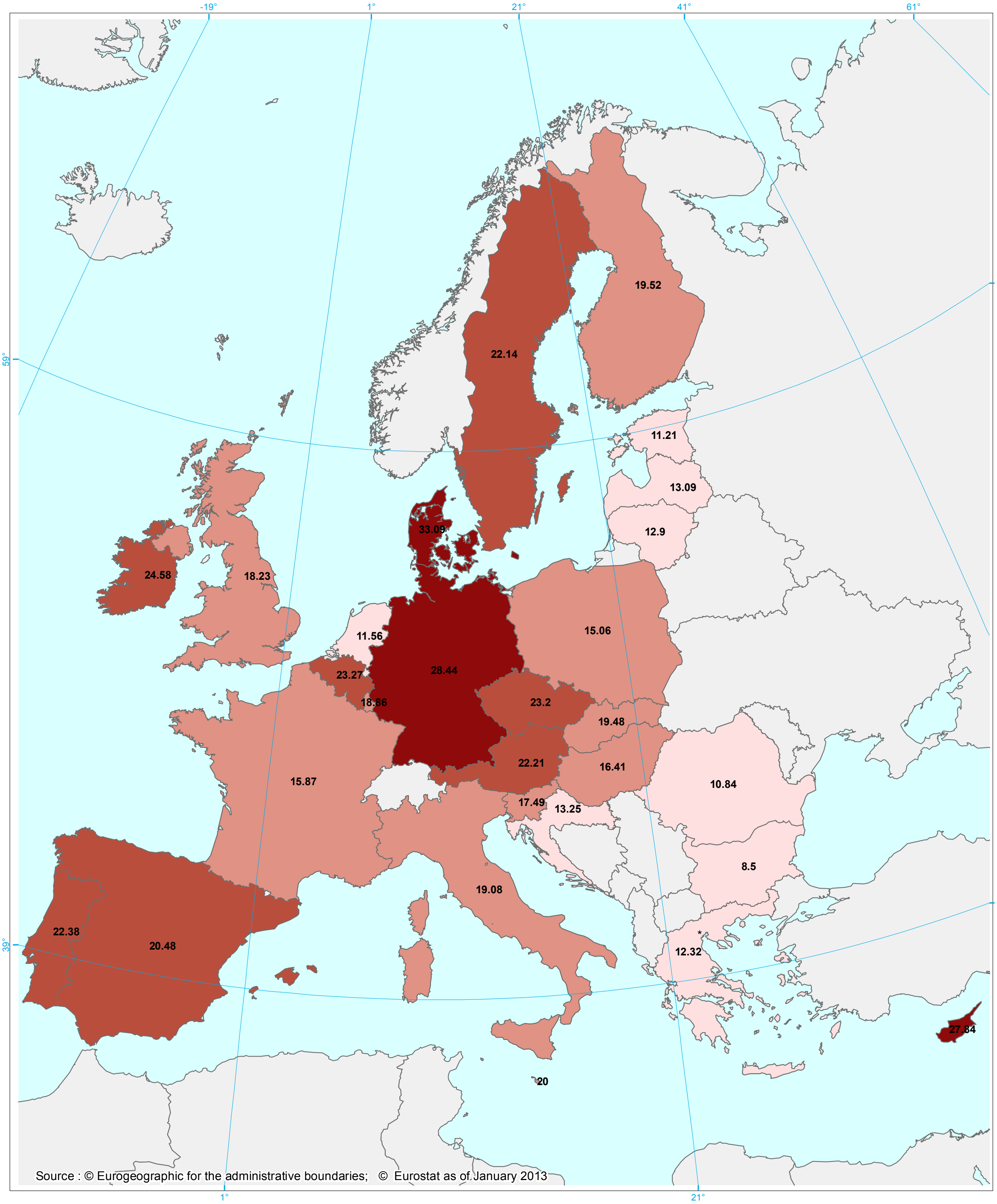
- Retail prices for households and industry were more than three times higher in the most expensive Member State than in the cheapest country on average. This gap is even wider for consumers belonging to the lowest annual consumption band (for household consumers the ratio was 5, while for industrial consumers it was 4). The price gap among the Member States is widening in the case of the lowest annual consumption band for households during the recent years.

- Although the process of the integration of wholesale power markets significantly reduced price differentials among European countries in many cases, large differences among retail electricity prices still existed in 2012.

- However, better price convergence across the EU could be observed for large consumers.

- The two maps on the next two pages show retail electricity prices paid by households (with an annual consumption between 1,000 kWh and 2,500 kWh, including all taxes) and by industrial customers (with an annual consumption between 20 MWh and 500 MWh, excluding all taxes) in the first half of 2012 which are the most recent available Eurostat data.

FIGURE 24 – ELECTRICITY PRICES (INCLUSIVE OF TAXES) - HOUSEHOLDS - PRICES: 1ST SEMESTER 2012

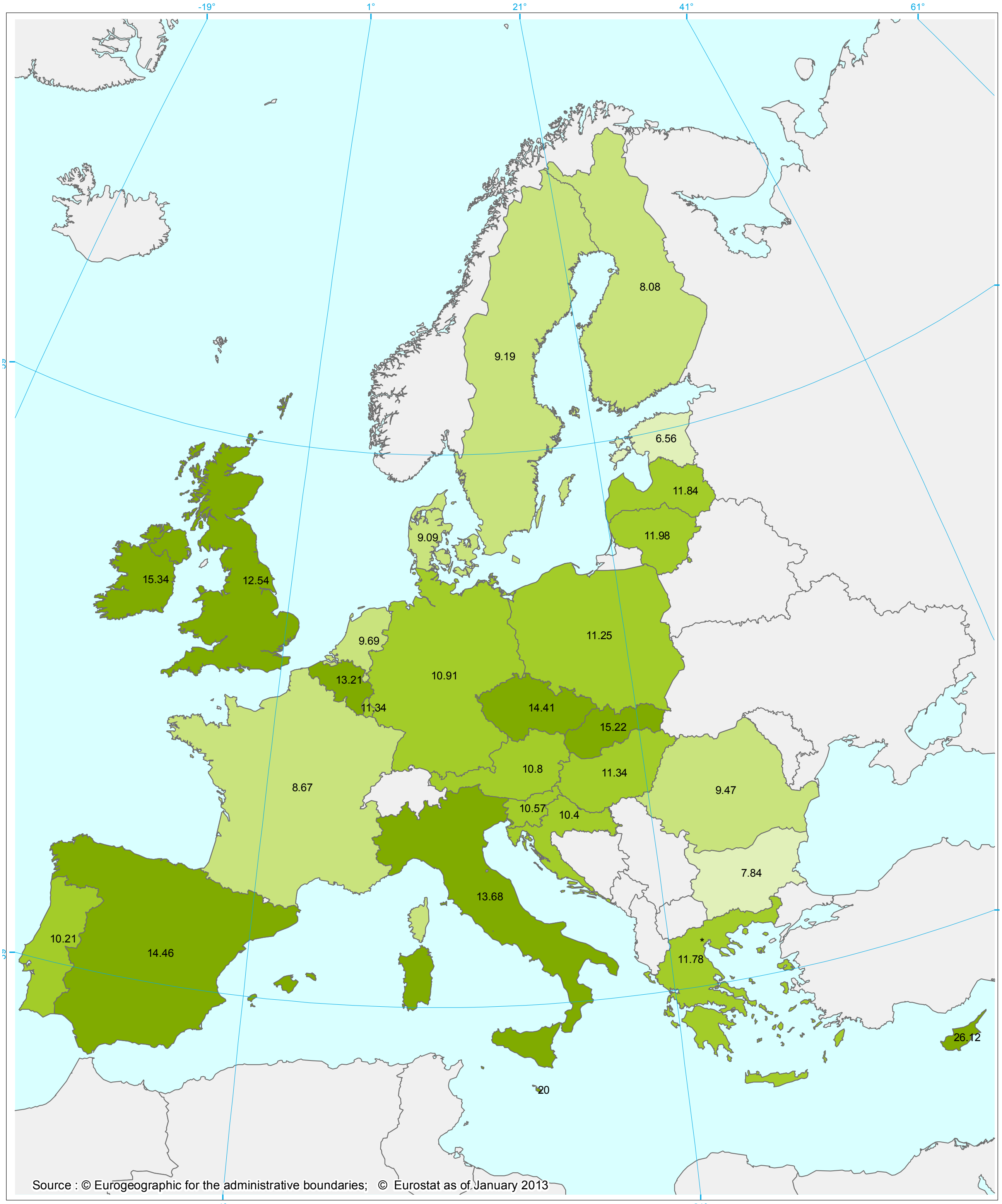


Band Db : 1 000 kWh < Consumption < 2 500 kWh

Prices per kWh (c€)

- no data
- < 15.1
- 15.1- 20.0
- 20.1 - 25.0
- > 25.0

FIGURE 25 – ELECTRICITY PRICES (INCLUSIVE OF TAXES) -INDUSTRIAL CONSUMERS – PRICES: 1ST SEMESTER 2012



Band Ib : 20 MWh < Consumption < 500 MWh

Prices per kWh (c€)

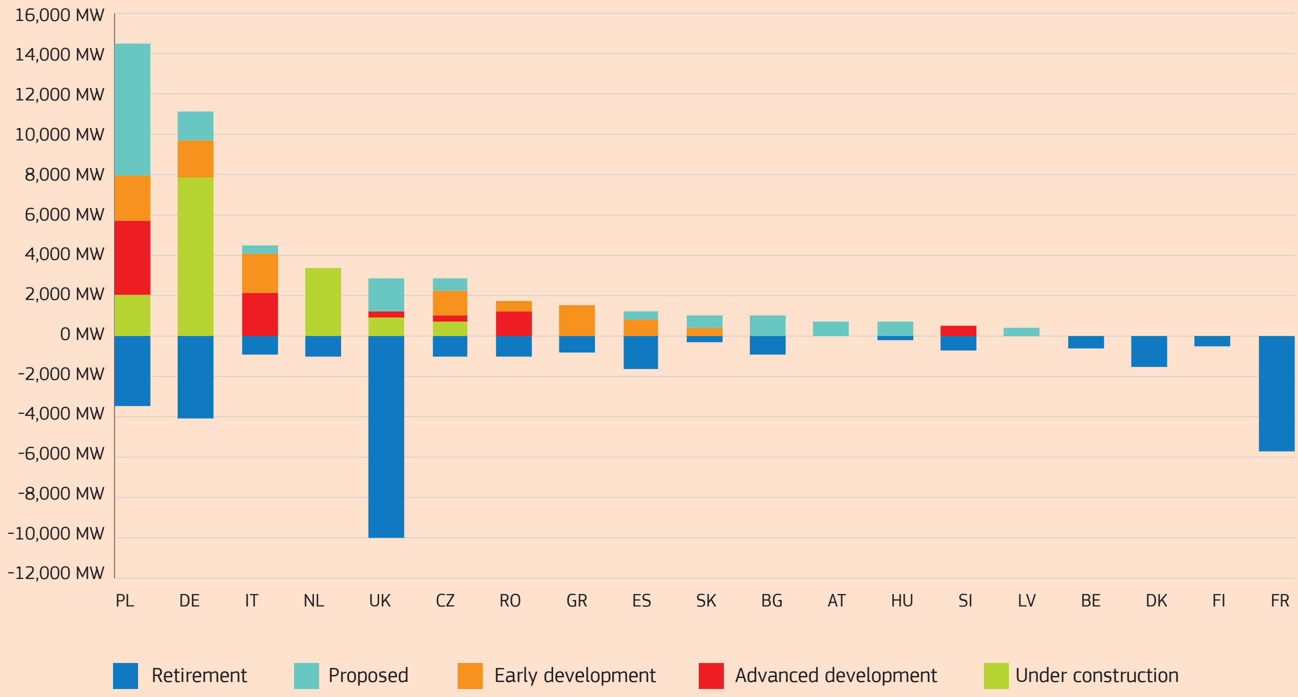
- no data
- < 8.1
- 8.1- 10.0
- 10.1 - 12.0
- > 12.0

Focus on

The impact of the most recent developments of the coal markets and changes in the regulatory environment in Europe on investment decisions in coal-fired power generation

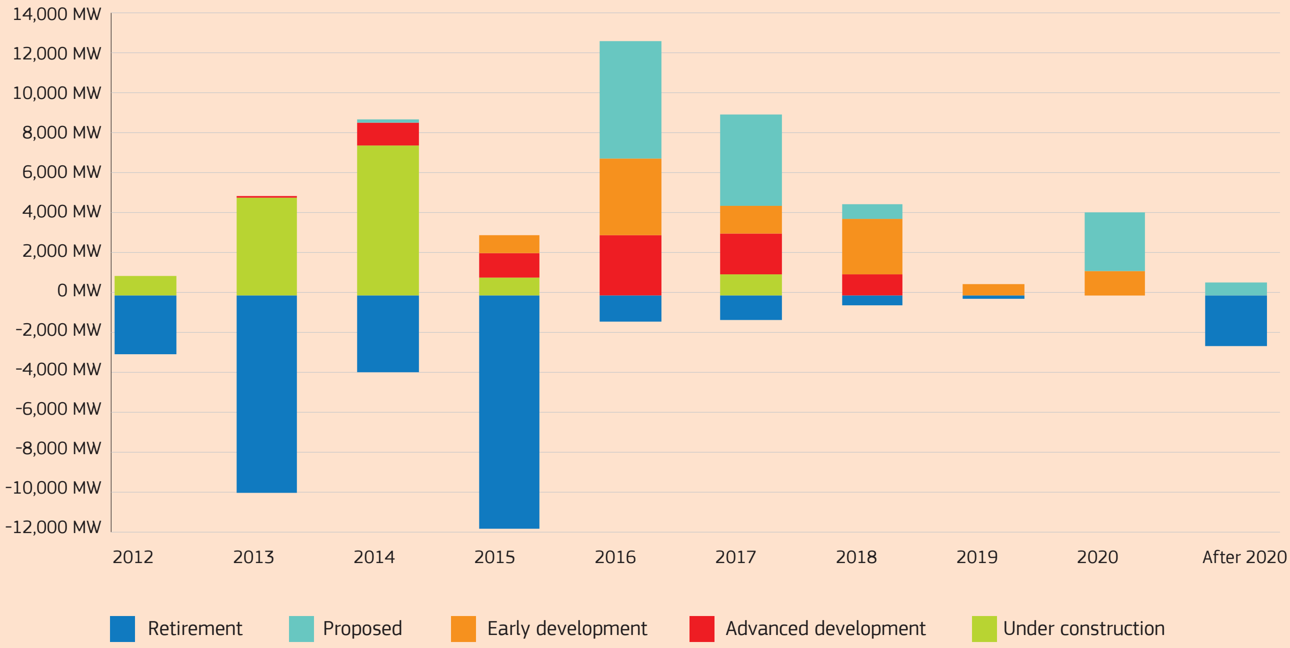
- In the next three years a significant amount of coal-fired generation capacities will be taken offline in the EU. This will be mainly due to non-compliance with the emission requirements of the LCP Directive (Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants), which sets a final deadline (end of 2015) for the exemptions from its own requirements. Other reasons for shut-down will include the age of power plants or economic decisions. In the UK, it is expected that the majority of coal-fired capacities will be impacted, while in Germany only few capacities will be shut down due to the compliance with an earlier environmental legislation. There are a number of projects in different development phases - construction or planning - in Germany and Poland which are LCPD compliant and which are expected to assure the role of coal in these countries' power generation mixes in the foreseeable future.

FIGURE 26 – PLANNED CAPACITY INSTALLATIONS AND RETIREMENTS IN COAL-FIRED POWER GENERATION



Source: Platts

FIGURE 27 – ANNUAL PLANNED DEVELOPMENTS AND RETIREMENT IN COAL-FIRED POWER GENERATION CAPACITIES



Source: Platts

- Current market trends *(See Chapter 5)* and mid-term expectations play a role in future investment decisions in coal-fired power generation, though a straightforward conclusion cannot be made from the current competitiveness of coal compared to gas on the evolution of future investment projects in coal and gas-fired power generation. Current profit margins in coal-fired generation support refurbishment investments, aiming at increasing combustion efficiency and reaching compliance with environmental standards.

- Although a price recovery from the currently low coal price levels is a real option, the IEA's mid-term scenarios show stable coal prices for the next five years. It is expected that abundant coal imports in Europe are going to assure good supply in the market, helping keep prices at relatively low levels. At the same time, gas prices are still at high levels, partly owing to the oil-indexed long term contracts and falling EU imports of LNG. Significant additional domestic production in the EU (e.g.: via shale gas) is not foreseeable in the near future, which could lead to falling natural gas prices in the EU.

- The future of coal-fired generation in the EU will also be influenced by renewable energies as these intermittent sources need backup generation capacities (e.g.: coal or gas). If it becomes technologically feasible to ramp up coal-fired plants as quickly as gas-fired ones in the case of prompt need, this will also strengthen coal's relative position to gas.

- In the case of gas-fired generation, only a small part of the existing capacities is to be decommissioned before 2020 given that the majority of gas power plants will reach the end of their lifetime only after 2020. In the second half of the current decade, larger investment projects currently in early development phase are foreseen. However, if the current unfavourable market conditions remain, many of these projects may be cancelled or postponed for an indefinite period of time.

- Current coal and gas market conditions are not favourable for combined heat and power plants (CHP), given that the majority of the European CHP plants are run by natural gas. On the long run if CHP's contribution to power generation decreases it might have an impact on the attainability of European energy efficiency targets as well, implying that increasing role of coal in the energy mix impacts not only emission reduction targets.

- Although the role of coal will still be significant in the next couple of years, all scenarios of the *Energy Roadmap 2050*[1], adopted by the European Commission, reckon with gradually decreasing coal share in the European power generation mixes in the forthcoming decades. Coal's role will be largely determined by the commercial deployment of carbon capture and storage (CCS) systems in the future.

1. European Commission Communication on Energy Roadmap 2050, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0885:FIN:EN:PDF

8. Glossary

Backwardation occurs when the closer-to-maturity contract is priced higher than the contract which matures at a later stage.

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.

Clean dark spreads are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity. If the level of dark spreads is above 0, coal power plant operators are competitive in the observed period

Clean spark spreads are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity. Spark spreads are indicative prices showing the average difference between the cost of gas delivered on the gas transmission system and the power price. As such, they do not include operation, maintenance or transport costs. The spark spreads are calculated for gas-fired plants with standard efficiencies of 50% and 60%. This report uses the 50% efficiency. Spreads are quoted for the UK, German and Benelux markets.

Contango: 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.

Cooling degree days (CDDs) are defined similarly to the heating degree days (HDDs); 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 21oC, CDD values are in the range of positive numbers, otherwise CDD equals zero.

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.

Flow against price differentials (FAPDs): By combining hourly price and flow data, FAPDs are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of electrical systems.
With the closure of the day-ahead markets (D-1), the prices for each hourly slot of day D are known by market participants. Based on the information from the power exchanges of two neighbouring areas, market participants can establish hourly price differentials. Later in D-1, market participants also nominate commercial schedules for day D. An event named 'flow against price differentials' (FAPD) occurs when commercial nominations for cross border capacities are such that power is set to flow from a higher price area to a lower price area. The FAPD chart provides detailed information on adverse flows. It has two panels.
The first panel estimates the ratio of the number of hours with adverse flows to the number of total trading hours in a quarter. It also estimates the monetary value of energy exchanged in adverse flow regime compared to the total value of energy exchanged across the border. The monetary value of energy exchanged in adverse flow regime is also referred to as «welfare loss». A colour code informs about the relative size of FAPD hours in the observed sample, going from green if less than 10% of traded hours in a given quarter are FAPDs to red if more than 50% of the hours are FAPDs.
The second panel gives the split of FAPDs by subcategory of pre-established intervals of price differentials. It represents the average exchanged energy and relative importance of each subcategory on two vertical axes.

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.

Tariff deficit expresses the difference between the price (called a tariff) that a regulated utility, such as an electricity producer is allowed to charge and its generation cost per unit.