Quarterly Report on European Electricity Markets

Directorate-General for Energy

EUROPEAN COMMISSION

MARKET OBSERVATORY FOR ENERGY

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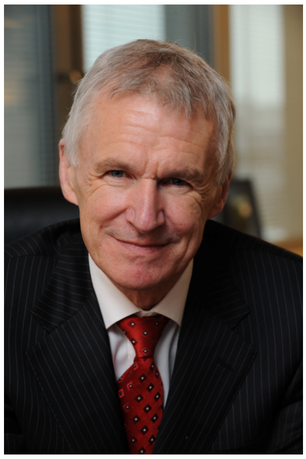
EUROPEAN COMMISSION
DIRECTORATE-GENERAL FOR ENERGY

Director-General



Dear readers,

In the aftermath of the devastating earthquake in Japan, several Member States took important decisions about the future of their nuclear power plants. Electricity wholesale markets across Europe were dealing with specific demand and supply conditions but because market participants used interconnectors to ship power from low to high price areas, regional prices remained within a close range throughout the second quarter of 2011. The Central Western European region provided again a good example of efficient use of cross border capacity. No adverse flows have been recorded since the introduction of a market coupling mechanism.

Investments in infrastructure are an increasingly important aspect of our energy policy. This is evident in the priorities set by Heads of State and Government during the European Council in February 2011. These investments will help to complete the internal market, increase its flexibility and allow better integration of renewables, and increase security of supply. That is why the European Commission proposed a Regulation on "Guidelines for trans-European energy infrastructure", identifying, for the period to 2020 and beyond, a number of trans-European priority corridors and areas for which European Union action is most warranted, and proposing improvements in permit granting procedures, regulatory treatment and if necessary, EU financial support for projects of common interest. Strategic energy networks and storage facilities need to be completed.

Our energy policy has contributed to an impressive growth in wind and solar capacities in the last decade. One of the important instruments of this policy has been the EU framework for support schemes for renewable energy sources, a topic covered in the "*Focus on*" section of this report. As more investment opportunities in renewable energy sources are emerging, functioning power markets are becoming a necessity for their successful integration in the power system.

The building of the internal energy market is advancing well with the new internal energy market institutions now in full operation. Challenges remain, but as shown at the high-level conference on the completion of the EU internal energy market on 29 September, we are committed to tackling all remaining issues.

Philip Lowe

HIGHLIGHTS

- The highest monthly average power price in Central Western Europe level was in May, caused by the low nuclear and wind output in Germany and France.
- Civil war in Libya and unrests in other countries in the Middle East pushed the oil price up.
- No adverse flows were observed in Central Western Europe.
- German and Dutch biomass spread decreased considerably in this quarter after the pellet price rose due to higher demand.
- After several months the premium at which the Nordpool power was traded relative to the German day-ahead market, turned into a discount.
- Following the increase in temperatures, the highest monthly averages on the Iberian Peninsula occurred in June.
- In the second quarter of 2011 quarter-ahead and year-ahead power prices declined on the Central Western and Northern European trading platforms, following the sudden rise in March 2011.
- At the end of June 2011 carbon prices fell to a year low, reflecting renewed fears about the slowdown of the European economy.
- In Greece a strike that concerned the dominant power producing firm resulted in significant rise in power prices at the end of June 2011.
- Following the decision to keep eight nuclear reactors off the grid, Germany remained a net power importer in Q2 2011.

NEW FEATURE IN THIS REPORT

- A map on European retail prices for electricity.

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QUARTERLY REPORT
ON
EUROPEAN ELECTRICITY MARKETS

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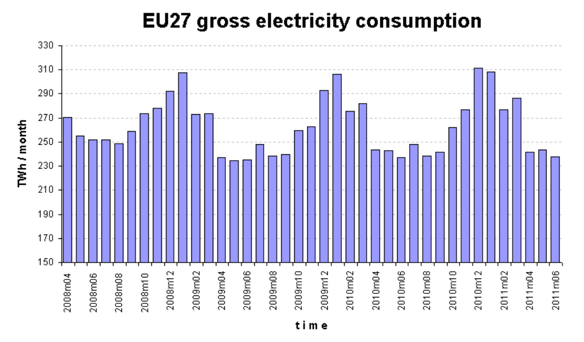
A. Recent developments in the electricity markets across Europe

As it is normally the case in Q2, the EU-wide gross electricity consumption decreased considerably compared to the previous quarter as the weather got milder and heating demand decreased. As shown further in the report, this is also the period when many nuclear power plants undergo maintenance works before the demand in the hot summer months makes the supply increase again.



Source : Eurostat
Adapting to the changes in Eurostat's database, gross electricity consumption now corresponds to electricity supply.

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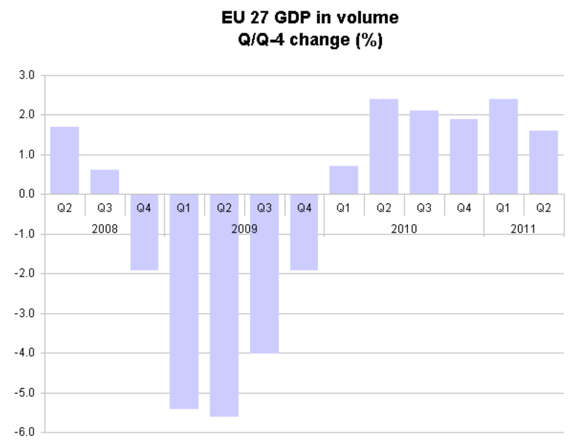
The number of heating degree days[1] confirms that the spring this year was warmer than in the recent years. Especially in April the need for heating was well below the long term average, leading to reduced gross electricity consumption and lower wholesale prices.

EU 27 Heating Degree Days in Q2
Values for 2009, 2010, 2011 and 1980 – 2004 average

	April	May	June
2009	238.64	123.95	67.55
2010	248.26	153.20	58.24
2011	220.34	148.69	60.49
LT avg.	289.25	154.04	66.55

Source : Eurostat /JRC

The change in European quarterly GDP volumes continued to be positive. The year-on-year growth was 1.6% in Q2 2011. The same level of growth was achieved in the Euro area. The seasonally adjusted gross added value of the construction sector, being an energy intensive sector, increased by 0.5% compared to the corresponding period of the previous year (at basic prices). For the industry this rate was 3.9%.



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.*

A.1 Wholesale markets

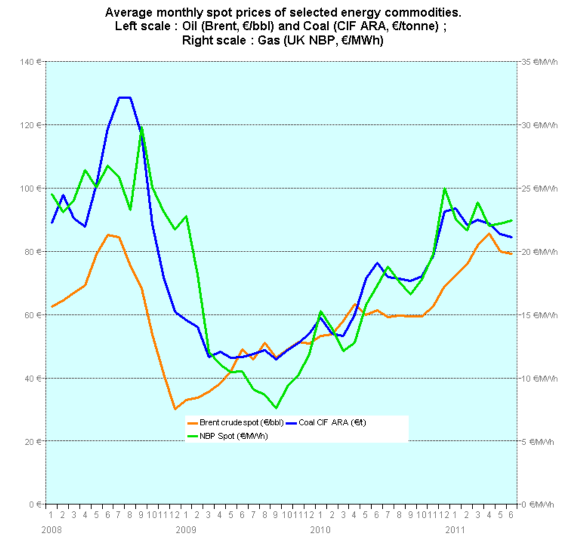
The increase in energy commodity prices in mid-March continued also at the beginning of Q2 2011, although this growth appeared to have gradually eased. The coal and gas prices were in April lower than in March, but the oil prices increased in April even further. The monthly oil average was in March 81.9 €/bbl while in April it grew to 85.7 €/bbl.

The factors that caused the oil price to increase in April were fighting in Libya with the related uncertainty about its oil supplies, spreading unrests throught the Middle East, and the demand for oil in Japan to substitute the decrease in nuclear output.

In Q2 2011 the oil price reached levels which were considered as potentially threatening for the global economic recovery. At the beginning of June the IEA

[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. The 'long term average' is the average HDD value for the years between 1980 and 2004. These quantitative indices are designed to reflect the demand for energy needed to heat a building.

intervened by releasing 60 million barrels of strategic oil stocks, as the OPEC countries could not reach an agreement to increase the output.



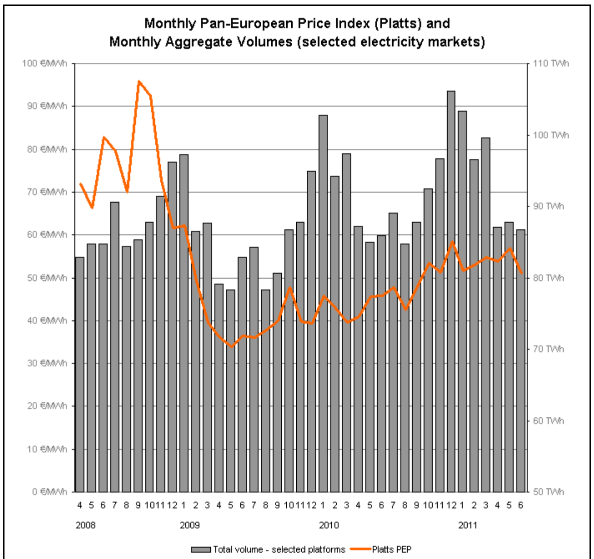
Source : Platts.

Similarly to the oil price, the monthly average gas price at NBP ended the second quarter below levels recorded in the first quarter of 2011. The disrupted supply to the UK from Norwegian and British gas fields was one of the reasons for NBP monthly averages in May and June being above the April average.

A.1.1 Day-ahead

EU wholesale markets

The *Platts Pan European Price Index* reached 53.7 €/MWh in April, 32% higher than in April last year, partly due to more expensive fuels (for example, monthly average price for gas increased on NBP for 72% within the same period). The decreased output form German nuclear power plants also contributed to the higher price level, especially in May when less than 25% of their nuclear capacity was online.



Source: 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) ; Hellenic Transmission System Operator

In June a number of factors contributed to the decrease in the European price index.

Among them were higher hydro levels and nuclear output in France, increased wind output in Germany, combined with lower demand due to mild temperatures and public holidays.

More details on developments on the power markets are presented in the next section.

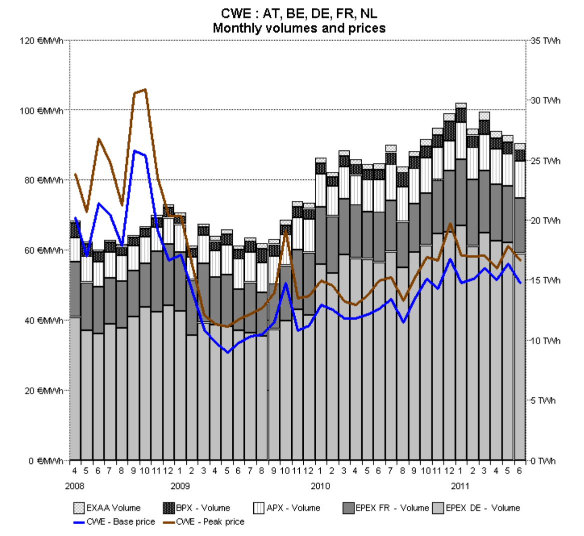
Regional markets

Central Western Europe: AT, BE, DE, FR & NL

After the first quarter the power price in Central Western Europe dropped to the monthly average of 51.5 €/MWh in April. Later in May it reached 56.2 €/MWh, but ended the quarter at 50.6 €/MWh.

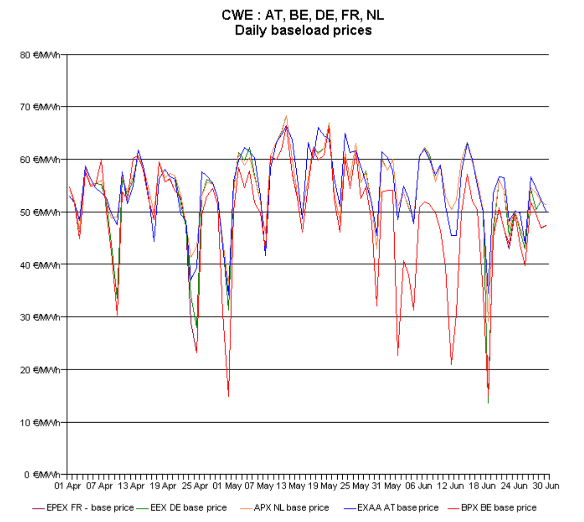
The monthly average in April was strongly affected by the Easter holidays in the second half and the gas price that also decreased during this period. Both power and gas price remained low also at the beginning of May, as new public holidays took place. Furthermore, because weather was warm and gas storage levels high, this contributed additionally to lower gas and consequently power prices.

In the middle of May the price began increasing, leading to the high monthly average. On the daily level it even exceeded 60 €/MWh, the highest baseload price in the quarter. The combination of drivers leading to these spikes was low nuclear availability in France and Germany, along with low wind levels in Germany. Later in June the nuclear availability improved, water levels increased, wind and solar output was high, which made the price fall.



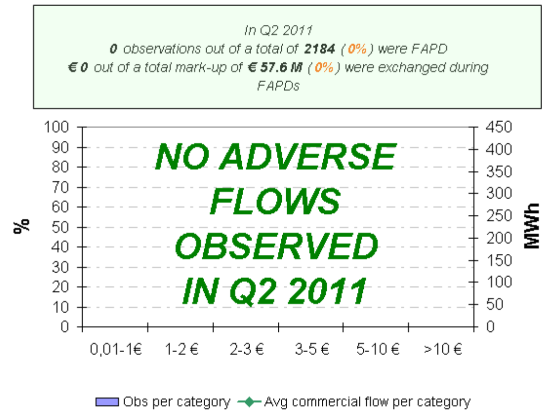
Source : Platts.

The chart on daily prices shows a period at the beginning of June when French (and with them Belgian) prices were several Euros below German and Dutch prices. This happened due to rainfalls in France, some phases of low wind levels in Germany, but also low liquidity due to Ascension and Pentecost holidays.



Source : Platts.

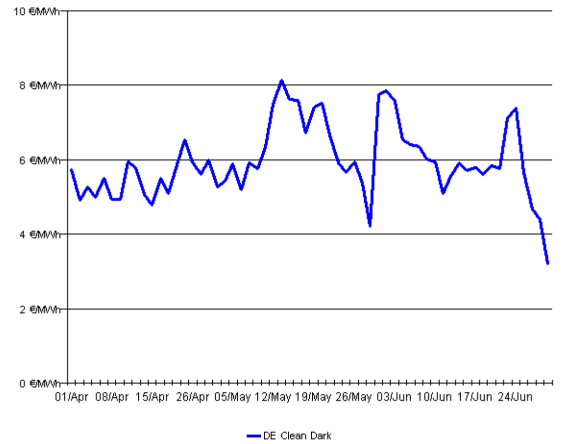
FAPD BE, DE, FR & NL



Source : Platts.[2]

The movement of the German clean dark spread[3] followed closely the evolution of the power price, although it can also be influenced by the coal and the carbon price. The two most obvious peaks in mid-May and at the beginning of June coincide with the price increases. As the German power price decreased by the end of the quarter, the spread decreased as well, with the exception of the spike at the end of June, which appears to be a consequence of short-term low wind output in Germany and lower nuclear availability in France.

Evolution of the Month Ahead clean dark spreads (35% efficiency) during Q2 2011



Source: Platts.

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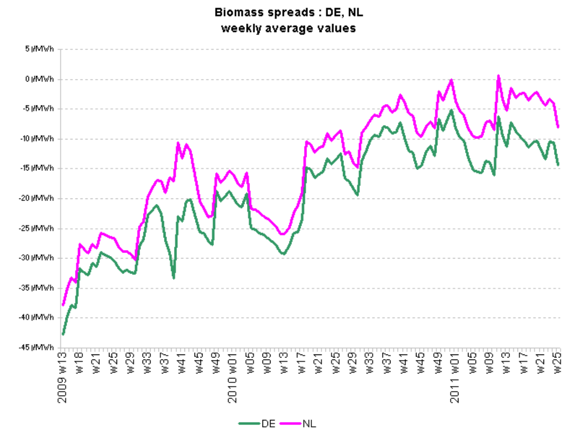
[2] By combining hourly price and flow data, FAPDs are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of electrical systems.
With the closure of the day-ahead markets (D-1), the prices for each hourly slot of day 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.

[3] 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 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.

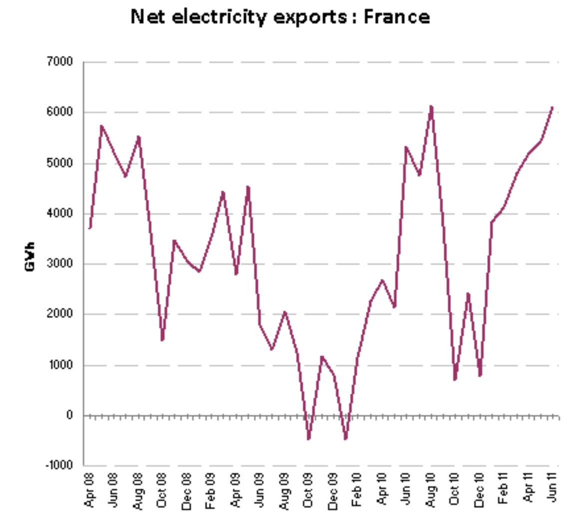
As far as the **biomass spreads**[4] are concerned the negative span widened in Q2 2011, especially by the end of the quarter. This is on one hand a consequence of lower power and carbon prices and on the other hand higher biomass price on APX–Endex. As it appears the higher biomass price is mostly related to higher demand for combustion in power plants (either in power plants that are dedicated to combustion of pellets or in plants that use a mix of coal and pellets). Increased freight rates on the Rhine also contributed to the larger gap between the DE and NL spread.



Source : APX – Endex (wood pellets, industrial grade) ; Platts (electricity and emission prices; freight rates)

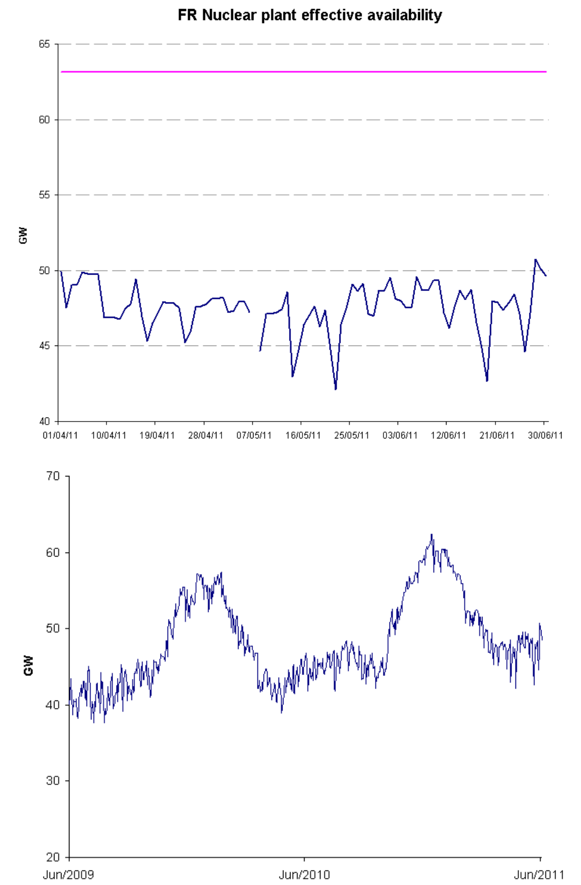
[4] Biomass spreads are indicative values giving the average difference between (1) the combined price of electricity and carbon emission on the corresponding day-ahead market and (2) the price of industrial wood pellets (delivered month-ahead ex-ship at Rotterdam).
Biomass spreads do not include operation 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*.

The French net electricity exports entirely recovered in Q2 2011, summing up to 16.7 GWh (after 12.8 GWh in the previous quarter). Reduced demand for heating meant that more energy was available for export. Furthermore, the French price was often sold at a discount relative to the CWE average which promoted French exports.



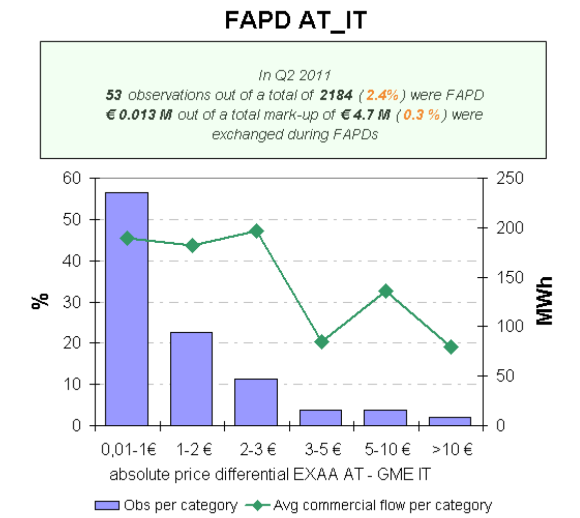
Source : ENTSO-E Vista

The effective availability of the French nuclear fleet decreased in the observed quarter. As the second half of the chart below shows it is a seasonal effect, because after winter domestic demand decreases and planned maintenance of the power plants begins.



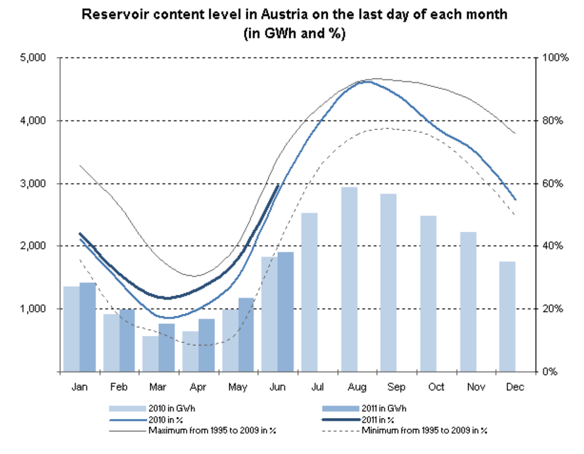
The installed capacity of the reference fleet is 63.13 GW.
Source :RTE France

While there were no adverse flows among the coupled countries in Central Western Europe, some of them were observed on the Austrian-Italian border, albeit less than in the previous quarter. The structure was also different this time, because most of the observations fell into lowest price difference.



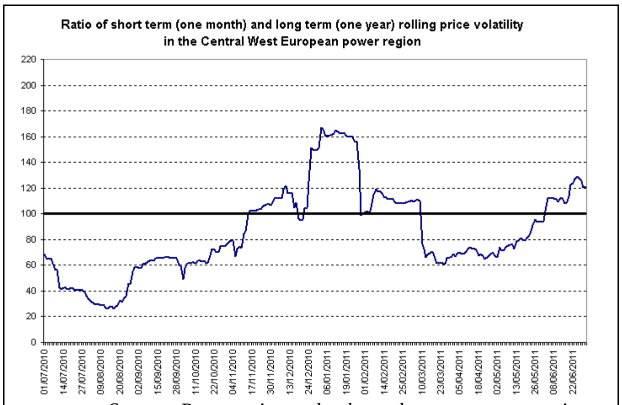
Source : Platts.

On the Austrian side the production was during this period also supported by the increased hydro level, as snow began to melt in the Alps. This quarter the reservoir content level was 13% higher than during the same quarter last year.



Source : E-Control GmbH, Austria

The volatility on the Central West European markets substantially increased in the second quarter of 2011; at the end of June the value of the RVI was above 100; signalling that the short term volatility was higher than the long term trend.



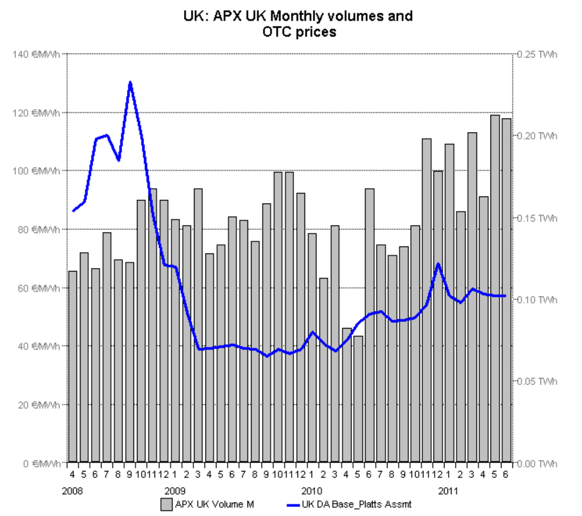
Source: Power price and volume data, own computations.

This was mainly due to the price fluctuation in June, being influenced by public holidays, wind and hydro generation and the fall of emission prices.

British Isles

UK

Monthly average baseload power prices showed a high degree of stability in the second quarter of 2011: while in March the average price reached almost 60 €/MWh, the three months of Q2 2011 could be characterised by a price movement in a narrow range of 57-58 €/MWh. Such a stability could be observed for the last time in the first quarter of 2009.

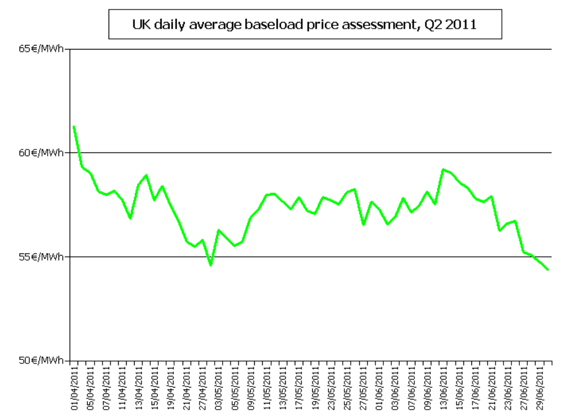


UK values are quoted in € using the €/£ daily exchange rate as reported by Platts.

Source : Platts.

The same refers to the evolution of the daily average power prices. In April 2011 a decreasing price tendency could be observed; starting the quarter with a price above 60 €/MWh and ending the month of April slightly below 55/MWh. In the rest of Q2 2011 prices remained in a range of 55-60 €/MWh, dropping below the lower value at the end of June.

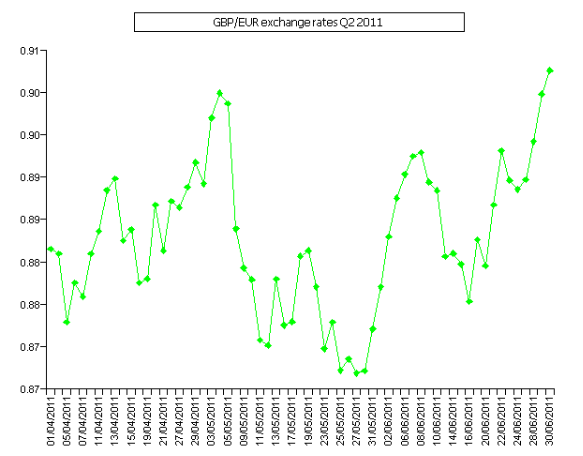
In April the main factors that helped to drive down power prices in the UK were the decreasing fuel prices (after March's spikes) and the public holidays at the end of the month (Easter holidays and the Royal Wedding on the 29th of April). Then in May and in the first half of June gas prices turned up again and the debate in Germany about the future of the nuclear sector also contributed to the rise in UK power prices. In the second half of June 2011 power prices went down in parallel with falling CO_2 emission prices.



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

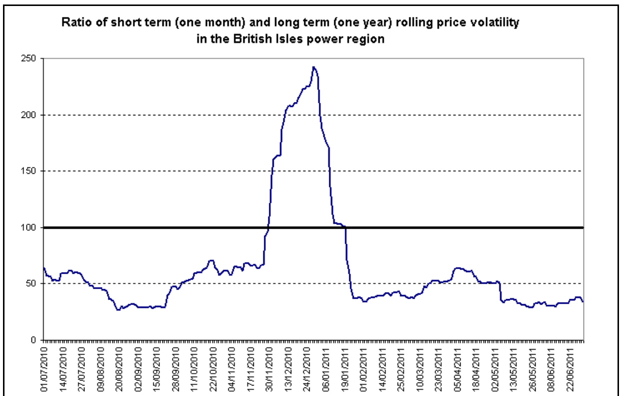
Source : Platts.

The fluctuations in the GBP/EUR exchange rate also influenced the evolution of power prices measured in euros. The strength of the euro at the end of April and June can be detected in lower power prices during these time periods, while its weakness against the British pound appeared in higher power prices at the end of May.



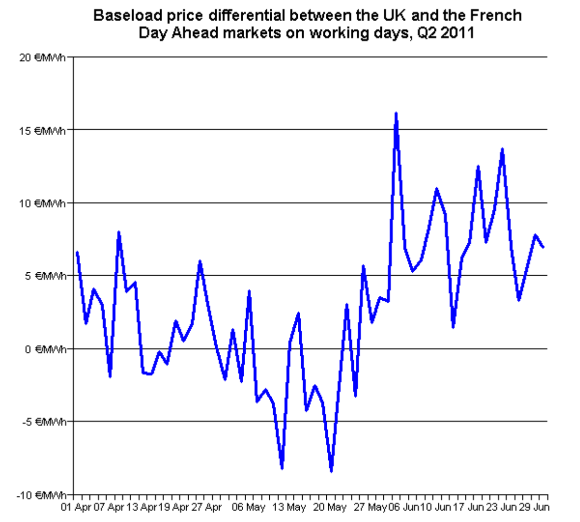
Source: ECB.

The relative volatility indicator confirms the conclusions drawn from the price charts as it shows a minor decline in market volatility during Q2 2011. While the market events in March 2011 contributed to a higher intensity of price fluctuations on the short run, the lack of such important market moving events drove down the RVI indicator on the APX UK market.



Source: Power price and volume data, own computations.

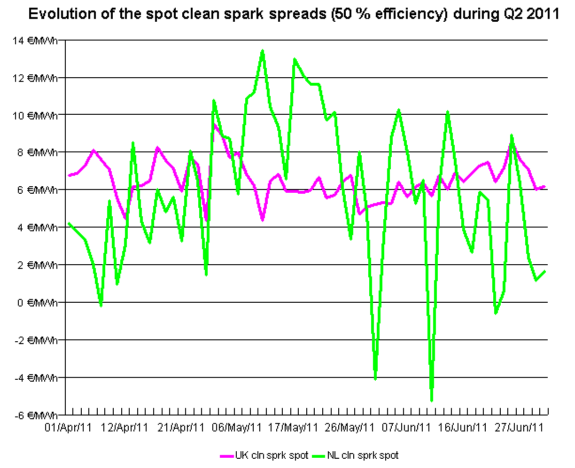
After minor price premiums observed in April the UK power market showed discounts to the French market which reflects the relative expensiveness of the continental power influenced by the market events in Germany. Then in June the UK premium returned as French prices became cheaper.



Source : Platts

The UK clean spark spread[5] was fairly stable during the second quarter of 2011, which was not surprising as both UK power prices and NBP spot gas prices fluctuated only in a narrow range. In contrast, Dutch spark spread proved to be more volatile during Q2 2011, primarily owing the more volatile Dutch power prices.

[5] 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.
Clean spark spreads are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity.



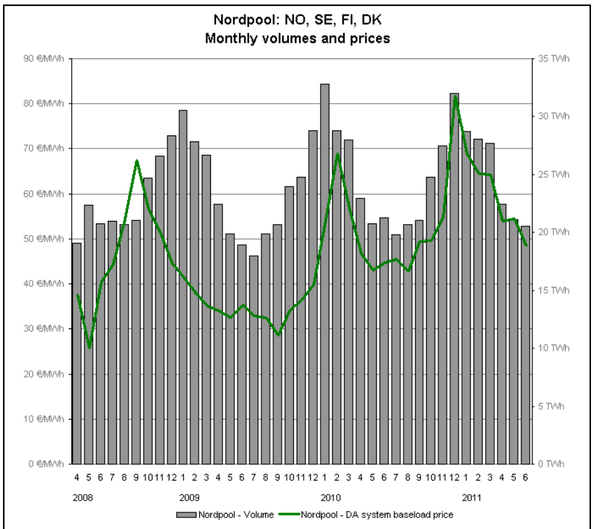
UK values are quoted in € using the €/£ daily exchange rate as reported by Platts

Source : Platts

Northern Europe: DK, EE, FI, NO & SE

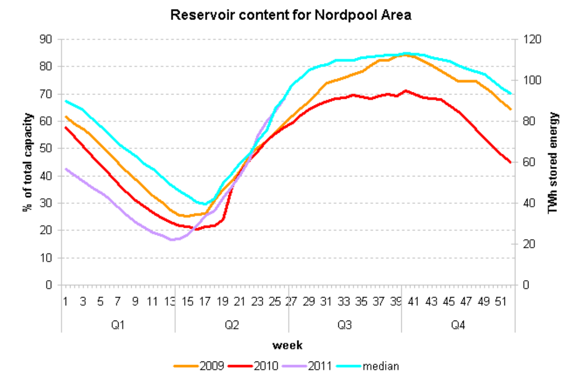
As expected the Nordpool price dropped steeply after the end of another very cold winter. Whereas in March the monthly average was still above 64 €/MWh, it was at 48 €/MWh in June, which represented a drop of more than 25%. Nevertheless, the June average was in 2011 still above the same average in the previous years.

The total quarterly sum of the traded volumes was 64 TWh, i.e. 75% of the gross inland consumption of electricity in the four countries during the same period.

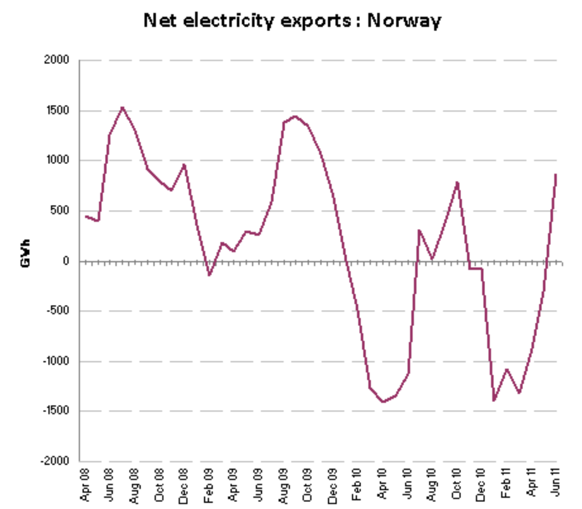


Source : Platts.

Apart from cold winters which pushed up the average price on Nordpool, additional explanation for higher spring prices can be found in the reservoir levels. Because the aforementioned winters were also dry the reservoir content recovered slowly. During the last three years the content was below the median for the second quarter.



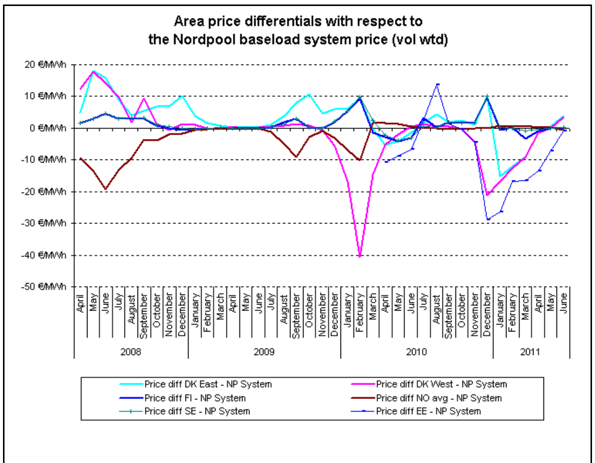
Source : NPS



Source : ENTSO-E Vista

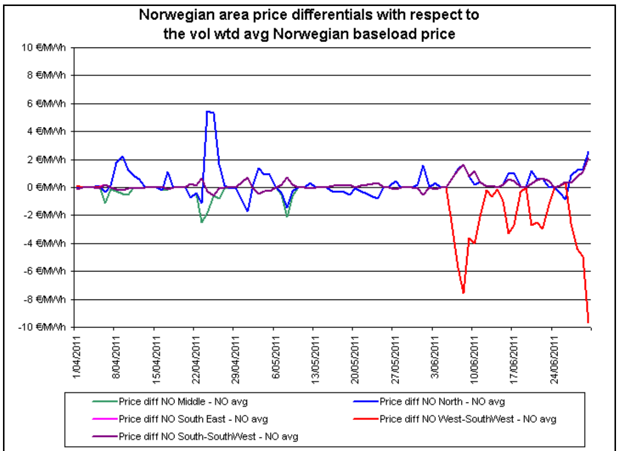
The low reservoir content is also reflected in Norwegian net electricity exports which turned positive only in June, while in March they were still as low as -1300 GWh.

The price differentials show that in Q2 2011 Nordpool areas had prices close to the system average with the exception of Estonia in April and May. When the Nordpool system average price dropped in June to 48 €/MWh, the difference to the Estonian price almost disapeared. Actually, the average quarterly Estonian price was close to 45 €/MWh, whereas the Nordpool system quarterly average was above 52 €/MWh.



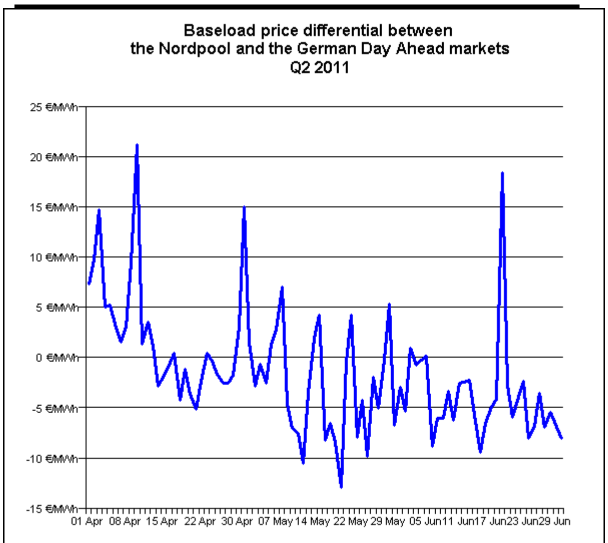
Source : Platts, NPS.

The Norwegian area price differentials were in the observed quarter very close to the Nordpool average. The most obvious event was the large negative differential linked to the NO West-Southwest area in June (i.e. the area NO5 – Bergen). Weather data for Bergen show rainfalls above average in June, influencing the hydropower production. As the additional amounts of hydro generated energy could not be exported elsewhere, the regional prices remained significantly lower than the system price for Norway.



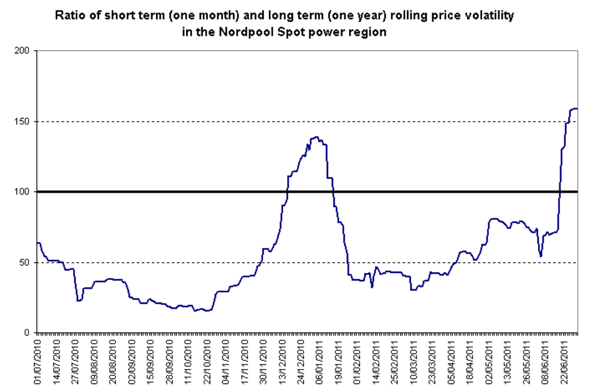
Source : NPS

After a long period of Nordpool premium towards the German market (since November 2010), it turned into a discount in May. This premium had been a consequence of the high Nordpool price during the last winter. When the power production conditions improved in the spring, the Nordpool price dropped below the German one.



Source: Platts.

Volatility on the Nordpool spot market was low at the beginning of Q2 2011. However, in May it began to rise and in the second half of June 2011 it rose significantly; reaching its highest value since March 2010 at the end of the quarter. The higher level of volatility did not confine to one particular price area but it could be observed in the whole Nordpool spot system.

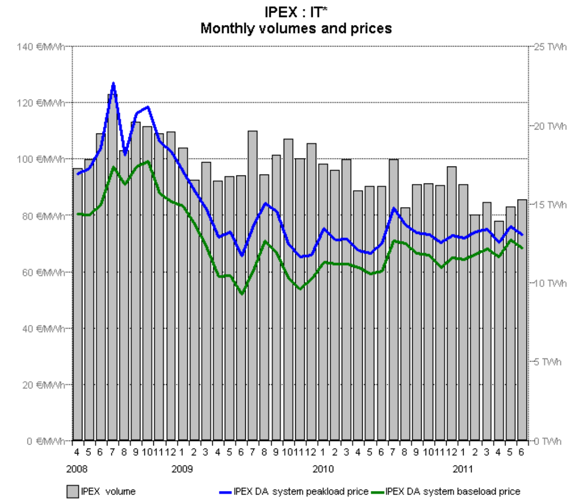


Source: Power price and volume data, own computations.

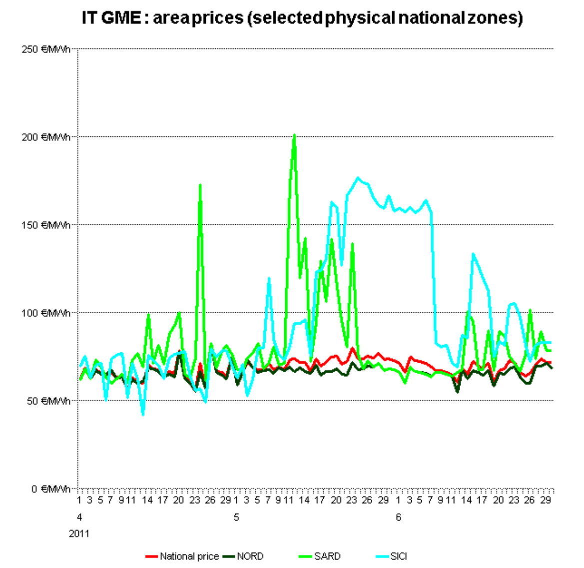
Apennine Peninsula

Italy

The monthly baseload price on IPEX, the Italian wholesale market for electricity, ended the second quarter at 68.4 €/MWh, which was close to the monthly baseload at the end of the first quarter (68.1 €/MWh). Like in the Central Western Europe, the highest monthly average was in May, when the baseload price grew to 71.3 €/MWh and the peakload price to 76.1 €/MWh. As it appears the Italian market was influenced by the increase in the Central Western European market, following the decreased nuclear availability in Germany (see the section on CWE for more details) in the second half of May which on its turn reduced available export amounts for Italy. During this period the daily baseload grew even over 79 €/MWh.



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

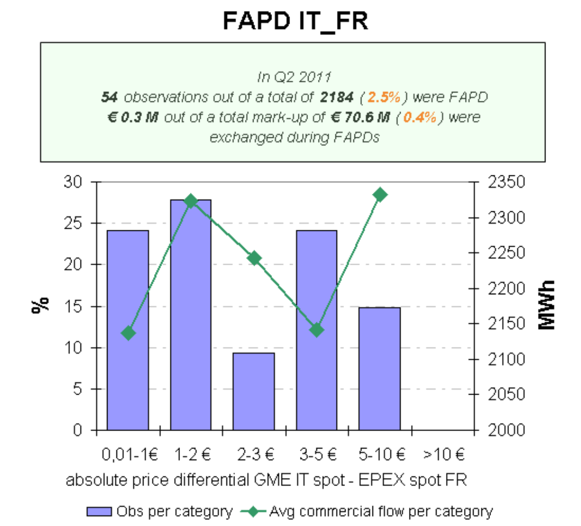


Source : Gestore mercati energitici.

In Sardinia and Sicily there were some periods of large price differences relative to the national average. In Sardinia, although a new interconnector was inaugurated between Sardinia and the mainland with the capacity of 1000 MW, its operation was sometimes limited and the old 300 MW cable was used[6].

[6] The interconnector SAPEI became fully operational in September 2011.

In Sicily, having a limited connection to the mainland (300 MW), there is usually a combination of factors that make the price deviate from the national average: restrictions on the connection to the mainland, lower generation due to technical reasons and changes in supply/demand. As it appears the reduced transit capacity had an effect on the Sicilian price in May.

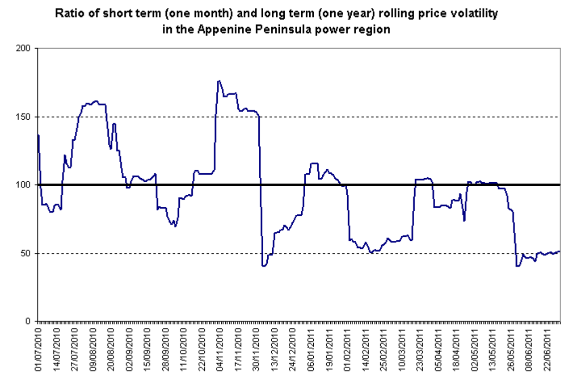


Source : Platts.

The number of adverse flows continued to decrease. In this quarter only 2.5% of observed flows were recorded in periods of adverse price differential, while in 2011 Q1 this share was 9.6% and in 2010 Q4 it was 30% (the number of observations decreased also in absolute terms). This quarter most of the adverse flows occurred in the price differential between 1 € and 2 € and there were no adverse flows above the price differential of 10 €.

At the beginning of Q2 2011 the value of the short term volatility was close to the long term trend, but from the end of May the RVI indicator dropped and remained low during the rest of the quarter.

As the price-increasing impact deriving from the uncertainty concerning the future of the nuclear industry in continental Europe began to disappear, Italian market prices remained stable in the lack of market moving events.



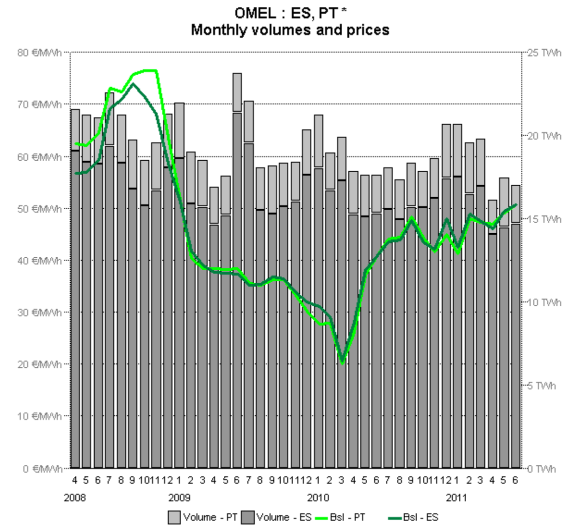
Source: Power price and volume data, own computations.

Iberian Peninsula: ES, PT

After the winter period the Spanish and Portuguese day-ahead prices dropped in April to the average of 46.0 €/MWh and 46.8 €/MWh respectively. The April drop was visible also on many other power exchanges (see the section on CWE for more details). By the end of the quarter the monthly averages grew continously and ended at 50.6 €/MWh on both markets.

In May an important factor contributing to the price growth in Spain was the availability of nuclear rectors, whereas three of them were disconnected from the system. This effect influenced the price also in the beginning of June. However, due to high share of wind generation in Spain lower nuclear availability could partly be offset and the pressure on the prices eased[7].

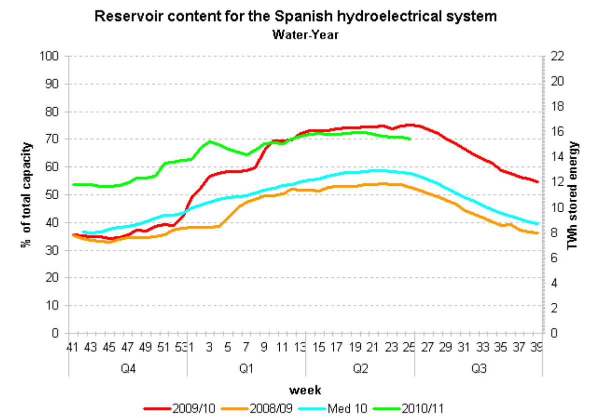
[7] In 2010 Spain was the leading European country in terms of power produced by wind. It produced 43 TWh of wind power and had 20.7 GW of installed



Source : Platts.

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

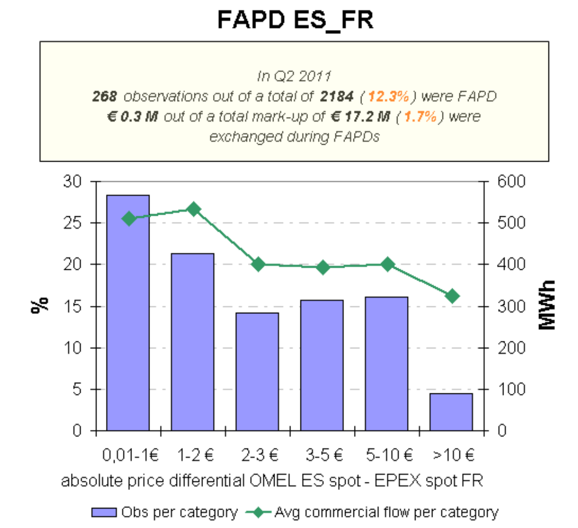
In the second half of June the price was increasing because of high temperatures, leading to higher energy demand for cooling. At the end of the quarter the daily Spanish price grew even over 55 €/MWh, the highest level this year.



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

wind power capacities, covering 16% of the country's annual electricity demand. Germany still had most of the installed capacities (27.2 GW) in Europe, but produced 36.5 TWh, second to Spain. *Source: EurObserv'ER.*

As the chart above shows, hydro levels dropped in the second half of the quarter, giving additional support to the price. Consequently hydropower production decreased. In April 3.7 TWh hours were produced and in June 2.1 TWh (data by ENTSO-E).



Source : Platts.

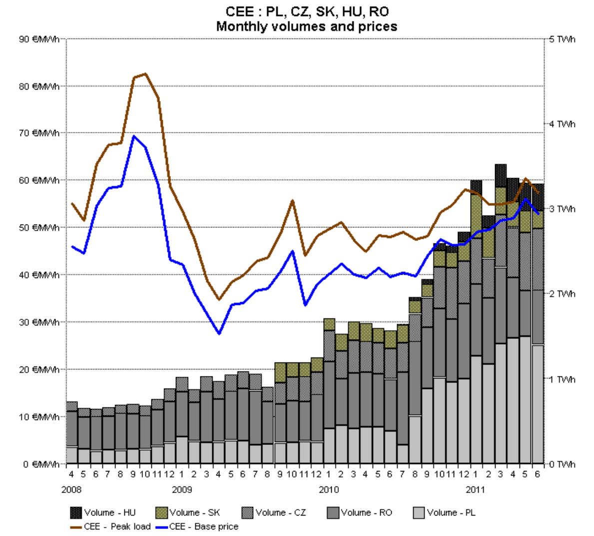
Contrary to the previous two quarters the structure of adverse flows had a "normal" shape in Q2 2011. Most of the observations and highest average commercial flows occurred within the lowest price differentials.

Central Eastern Europe: PL, CZ, SK, HU & RO

Monthly average power prices in the Central East European Region[8] climbed higher during the second quarter of 2011. In May 2011 the monthly average regional baseload price was 56 €/MWh, while the

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

respective peakload prices amounted to 60.4 €/MWh. These prices were the highest since November 2008. In June prices on the regional markets returned to the levels close to those of April 2011. The quarterly traded volume on these five markets amounted to 10 TWh, reaching about 12% of the five participating countries' quarterly gross inland consumption. The quarterly traded volume of power was the highest in the last six years. However, the whole region's volume data were affected as the rapid traded volume growth on the Polish market seemed to come to a halt, nearly a year after the introduction of new trading rules promoting mandatory trade on the power market.



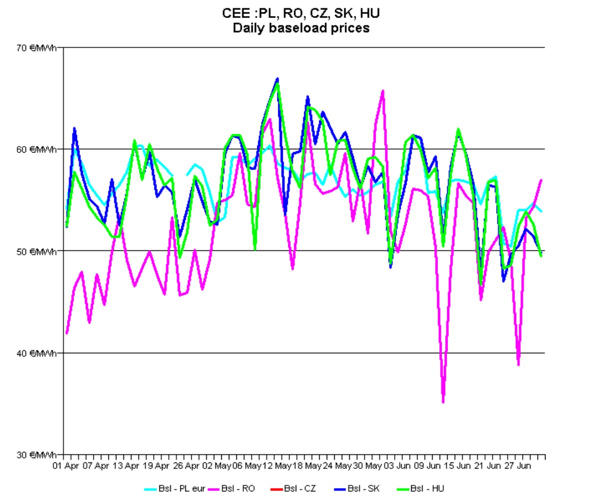
Source: TGE (PL),OTE(CZ, SK), OPCOM(RO), HUPX(HU)

The next table provides an overview about the evolution of the monthly baseload average prices on the five markets of the region. Similarly to the previous quarter Romanian baseload prices were the cheapest in Q2 2011.

Monthly average baseload power prices (€/MWh)			
2011	April	May	June
Hungary	52.0	56.4	52.4
Poland	54.9	55.9	54.5
Czech Republic	52.4	56.7	52.4
Slovakia	52.4	56.7	52.4
Romania	45.5	55.1	49.3

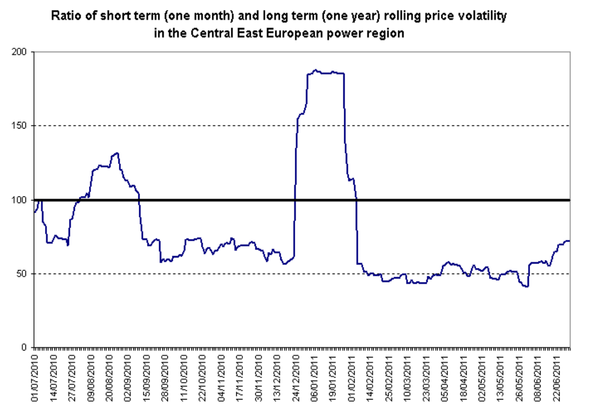
The next chart showing the daily evolution of baseload prices on the region's power markets reaffirms the monthly data in regards to the cheapness of the Romanian prices. However, it should be noted that power prices in Romania proved to be more volatile than those on the other markets in the CEE region. This might be related to the bigger role of hydro generation in Romania and the more-closely-aligned nature of the other four markets to the German power market.

In April 2011 Czech, Slovak, Polish and Hungarian power prices moved in line with each other, influenced by the good wind and solar generation supply from Germany, relatively mild weather and by the Easter holidays. In May however, Polish prices seemed to be less affected by the nuclear industry's developments in Germany. Polish prices remained lower compared to the other three markets. Higher energy commodity prices (oil and gas) seemed to affect Polish prices less than those in the Czech Republic, Slovakia and Hungary.



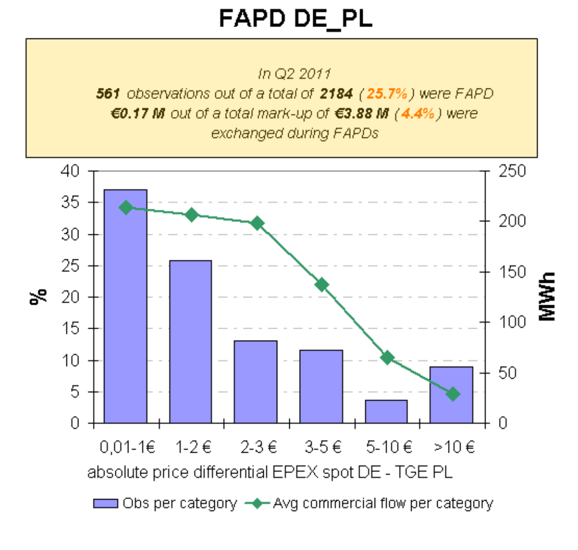
Source : TGE(PL),OTE(CZ, SK), OPCOM(RO), HUPX(HU)

In the last month of Q2 2011 the volatility on the CEE market was picking up again; although the RVI remained well below 100; meaning that the regional markets were less volatile than that the long term trend would imply.



Source: Power price and volume data, own computations.

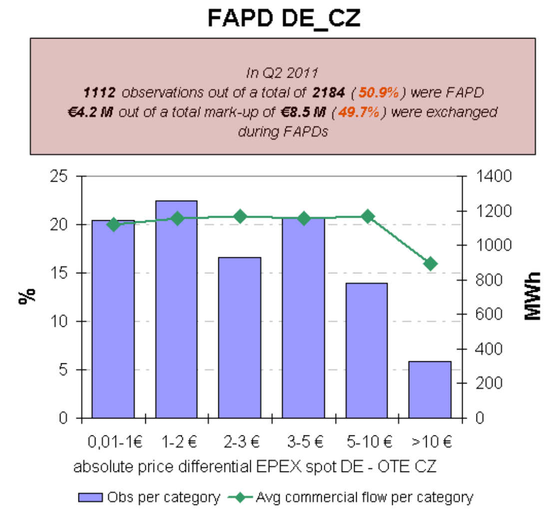
The ratio of adverse power flows (FAPDs) between the German and the Polish power market were low, taking into account of other adverse flow relations in the CEE region. The majority of FAPDs could be found in the price differential range of 0-2 €/MWh in Q2 2011 and the ratio of the power mark-up exchanged in adverse flows was also very low, reflecting a relatively well integrated nature of these two markets. Adverse flows between Poland and Germany were also influenced by frequent loop flows, stemming from abundant wind power generation in the North Seas region.



Source : Platts

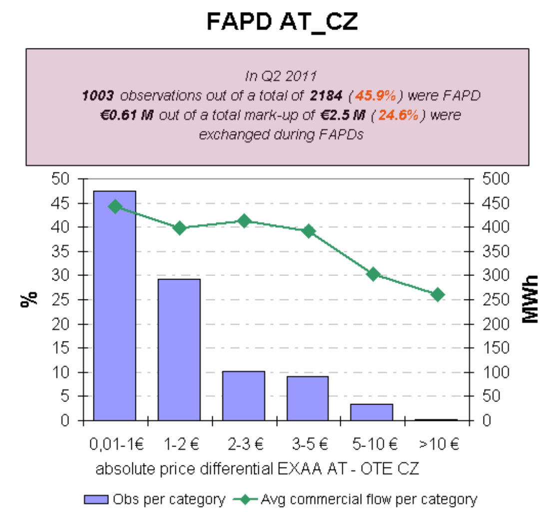
The constantly high ratio of adverse flows between Germany and the Czech Republic, as shown in the next chart, points to a weak integration between these two markets. The frequency of FAPDs was high even in the bigger price differential ranges (almost 10% of adverse flows could be observed with a price differential greater than 10 €/MWh).

The overall majority of the adverse flows (99.5%) between the two countries appeared in the form of Czech power exports to Germany in the second quarter of 2011. It can be assumed that German import power need rose so substantially as the consequence of decreasing domestic generation that it prompted Czech exporters to sell the generated power abroad, even though it could be sold on the Czech market at a higher price. It should also be noted that the Czech domestic market has its demand limitations and the generated power can usually be sold with a profit margin in Germany.



Source : Platts

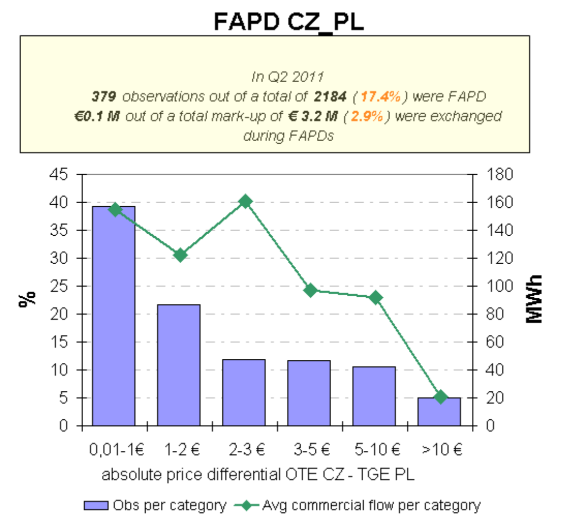
The ratio of the adverse flows was also high between Austria and the Czech Republic. Nevertheless, about three quarters of the FAPDs occurred in a price differential range of 0-2 €/MWh. Czech power exports to Austria amounted to 1 TWh in Q2 2011 which was less than the country's export to Germany in the same quarter (2.5 TWh).



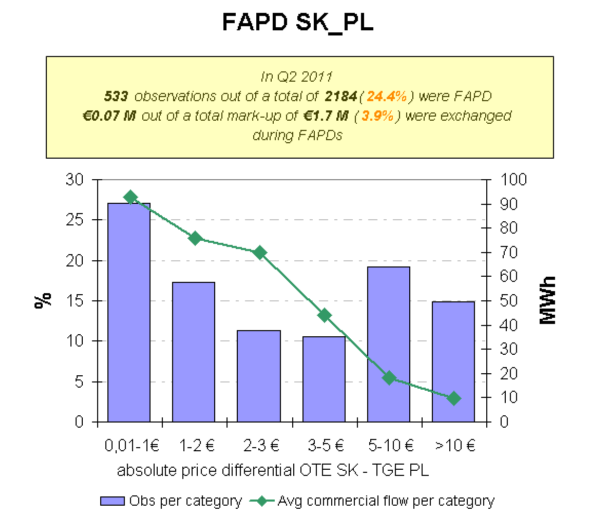
Source : Platts

Both of the Polish-Czech and the Polish Slovak adverse flow occurrence ratios were lower than those in the previous two cases. Both of the two market relations were dominated by Polish power exports (0.55 TWh to the Czech Republic and 0.31 TWh to Slovakia in Q2 2011, with a less important amount of imports from these two countries to Poland).

In the case of the Polish-Slovak market relation the share of adverse flows in higher price differential ranges was higher than in the case of Polish-Czech relation. Given that domestic prices are equal in Slovakia and the Czech Republic (as a consequence of a functioning market coupling), the competitive costs of Polish power generation and the import power demand Slovakia might have played an important role in a more significant ratio of Slovak-Polish FAPDs.

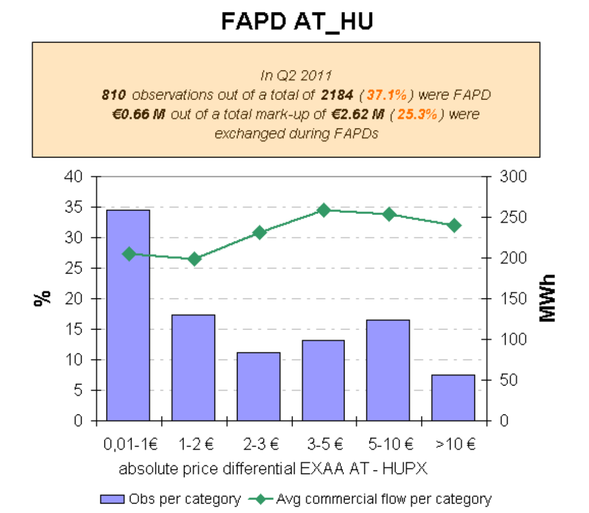


Source : OTE, PolPX,



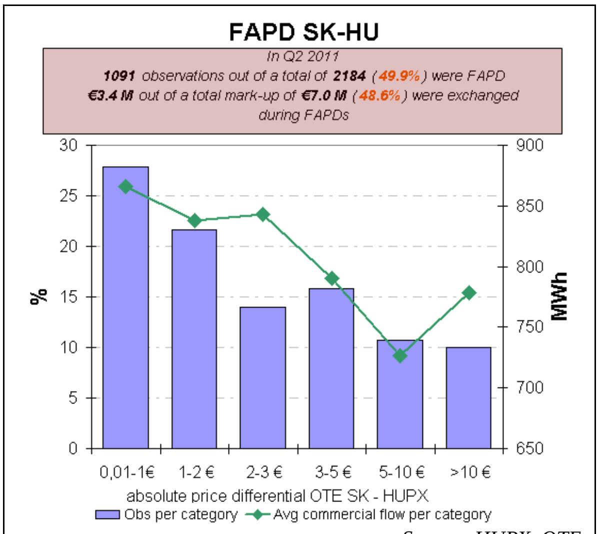
Source : OTE, PolPX

Power trade between Austria and Hungary could be characterised by an amount of power exports from Hungary to Austria being almost fivefold as high as Austrian power exports to Hungary. This was accompanied by a high ratio of adverse flows between the two countries. Both the ratio of FAPDs and the average amount of traded power in the higher price differential ranges were significant in Q2 2011, revealing a low level of integration between the two markets.



Source :Platts, HUPX

A similar picture could be observed between the Slovakian and the Hungarian power markets where a high overall adverse flow ratio, accompanied by significant amount of traded power in greater price differential ranges pointed towards the lack of market coupling between the two markets.



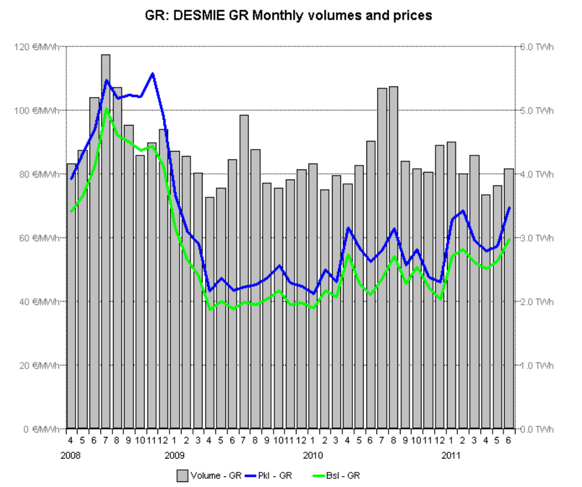
Source :HUPX, OTE

In the second quarter of 2011 no adverse flows could be observed in the Hungarian-Romanian power trade relation. In Q2 2011 the power trade was dominated by exports from Romania to Hungary (635 GWh), being significantly higher than the Romanian import from Hungary (3 GWh).

South Eastern Europe

Greece

Greek monthly average power prices in April and May 2011 were generally lower than those in the first quarter of the year. In contrast, in June 2011 both baseload and peakload power prices rose to an eighteen month high (59.6 €/MWh and 69.6 €/MWh, respectively). Meanwhile, traded volumes in Q2 2011 (11.55 TWh) fell to the a six year low, not independently from the economic situation (the Greek economy showed a 7.3% contraction of the GDP in Q2 2011 compared to the same quarter of 2010).

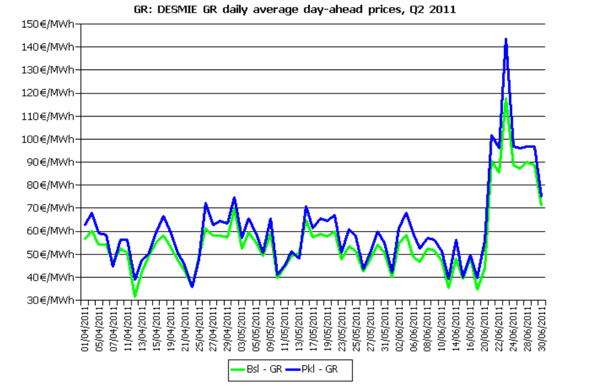


Source : Platts.

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

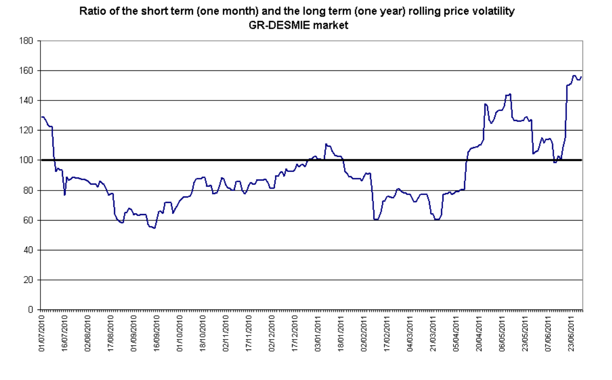
The next chart shows that the lowest daily average baseload price could be observed on the 12th of April (31.5 €/MWh). The reduced power demand during the Easter holidays and mild temperatures also pushed down prices at the end of April 2011. From the beginning of May, after rebounding from April's lows, prices fluctuated following a decreasing trend line until mid-June. In the last ten days of June daily power prices rose considerably and reached their peak on the 23rd of June (baseload: 118 €/MWh, peakload: 144 €/MWh). On this trading day the hourly power prices was 150 €/MWh for fourteen hours. After this spike power prices retreated but remained considerably higher than before.

The main reason for this sudden price increase was a nine-day strike that took place at the end of June 2011 and concerned about 20 power generation plants. The loss in power generation was replaced by putting some independent gas plants and hydro units on the grid and power import also increased, driving the prices up.



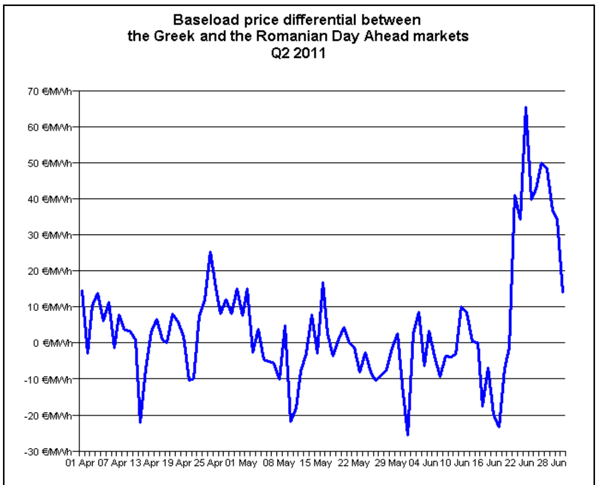
Source : Platts.

The short term volatility was higher than the long term trend during the most of Q2 2011 on the Greek market. In April short-lived price declines incurred higher volatility while by the end of June the sudden jump in prices resulted in a two year-high value of the RVI indicator.



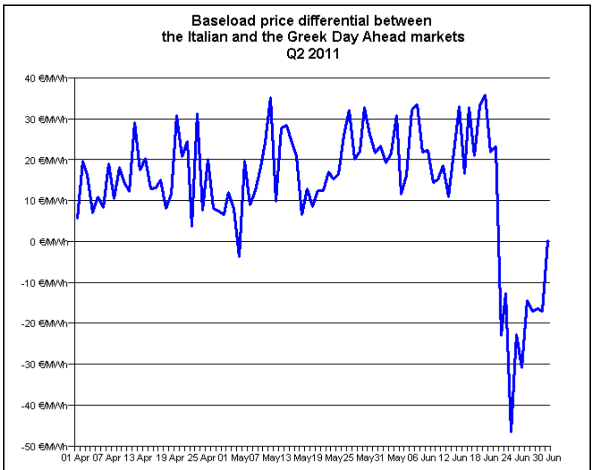
Source: Power price and volume data, own computations.

The above described spike in Greek power prices could also be followed on the evolution of price premium (or discount) to the Romanian and Italian prices. As Greek prices became cheaper in May and in the beginning of June the price premium to the Romanian market turned to discount. At the end of June 2011 the price discount suddenly turned to a double digit premium.



Source : DESMIE, OPCOM s.a.

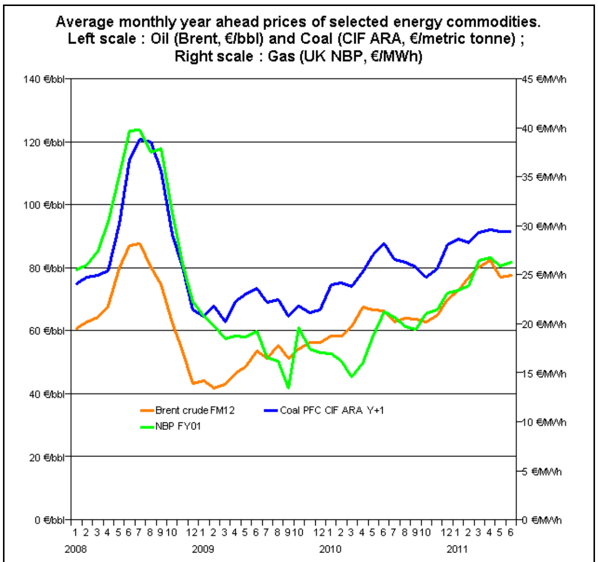
With the exception of a trading day of May Italian power prices showed a premium to Greek ones in most of Q2 2011. At the end of the quarter a huge discount appeared (-40 €/MWh on some trading days). This also reflects the relative stability of Romanian and Italian prices compared to those in Greece.



Source : IPEX, DESMIE.

A.1.2 Forward markets

In April 2011 the monthly average forward prices of the main energy commodities reached a level which has not been seen since 2008. One year forward oil price was more than 82 €/bbl, reaching the highest monthly average since July 2008. Monthly coal and gas prices were also on their highest levels since the fourth quarter of 2008.



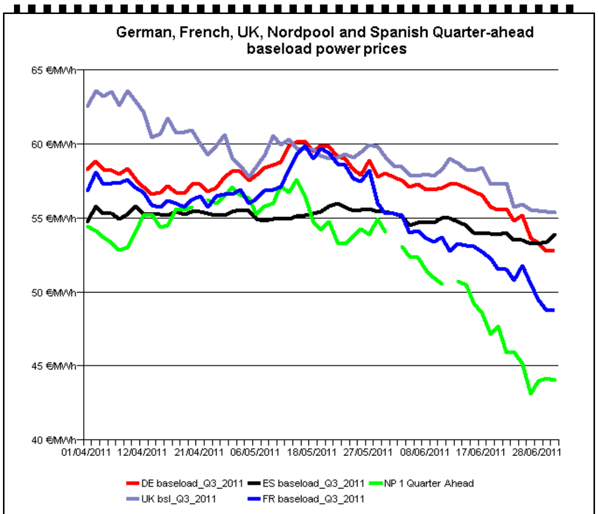
Source : Platts.

Oil supply disruptions in the Middle East, especially in Libya where military operations put an obstacle to the crude oil production, led to a decrease in the global oil supply, prompting higher market prices. Although crude oil forward prices retreated to a level of 77-78 €/MWh later in the second quarter of 2011, coal prices also remained close to their highs set in April 2011.

In the case of coal the unstable future of the European nuclear power generation might also have contributed to high prices as coal based generation seemed to offer an alternative on the short run to nuclear.

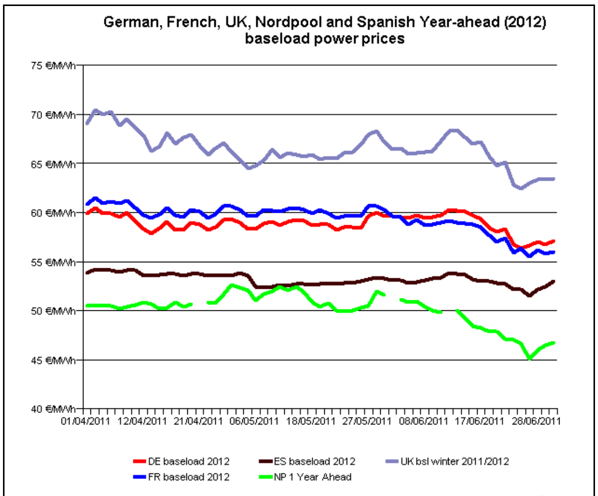
April monthly gas prices even managed to exceed the highs measured in March 2011 and they remained close to 26 €/MWh during the whole quarter. This development was mainly related to the surge of the global LNG demand.

Quarter-ahead power prices on the most liquid European exchanges showed a decrease between the beginning and the end of Q2 2011. While German and French power prices reached their quarterly peak in the second half of May 2011; reflecting the German decision on the future of the country's nuclear industry, the other markets showed stability or slight decrease in prices during April and May. In June 2011 the prices took a general downward direction; showing a correction of the upturn that took place during the earlier spring months.



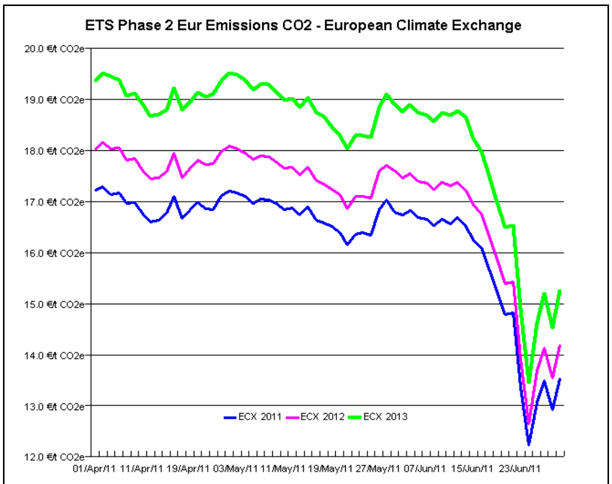
Source: Platts.

In the case of year-ahead baseload power prices a similar trajectory could be observed; although with less intensity of price decrease at the end of Q2 2011. The decrease in forward prices was influenced by the same factors that pushed down day-ahead prices (market sentiments about the economy, well supplied grids in many countries, higher hydro levels and abundant wind power generation).



Source : Platts.

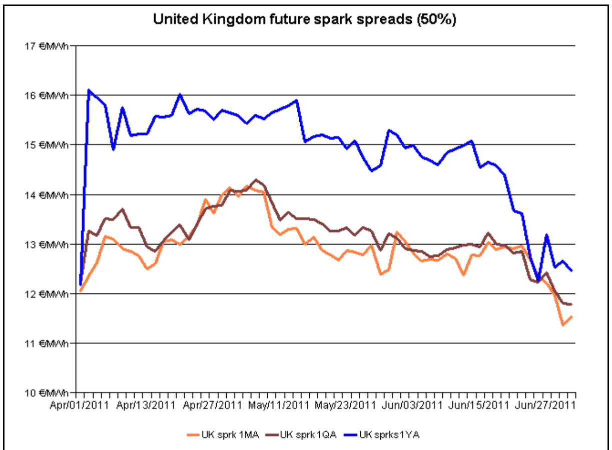
Forward emission prices only slightly decreased during most of Q2 2011; then in the second half of June a steep price fall could be observed.



Source : Platts.

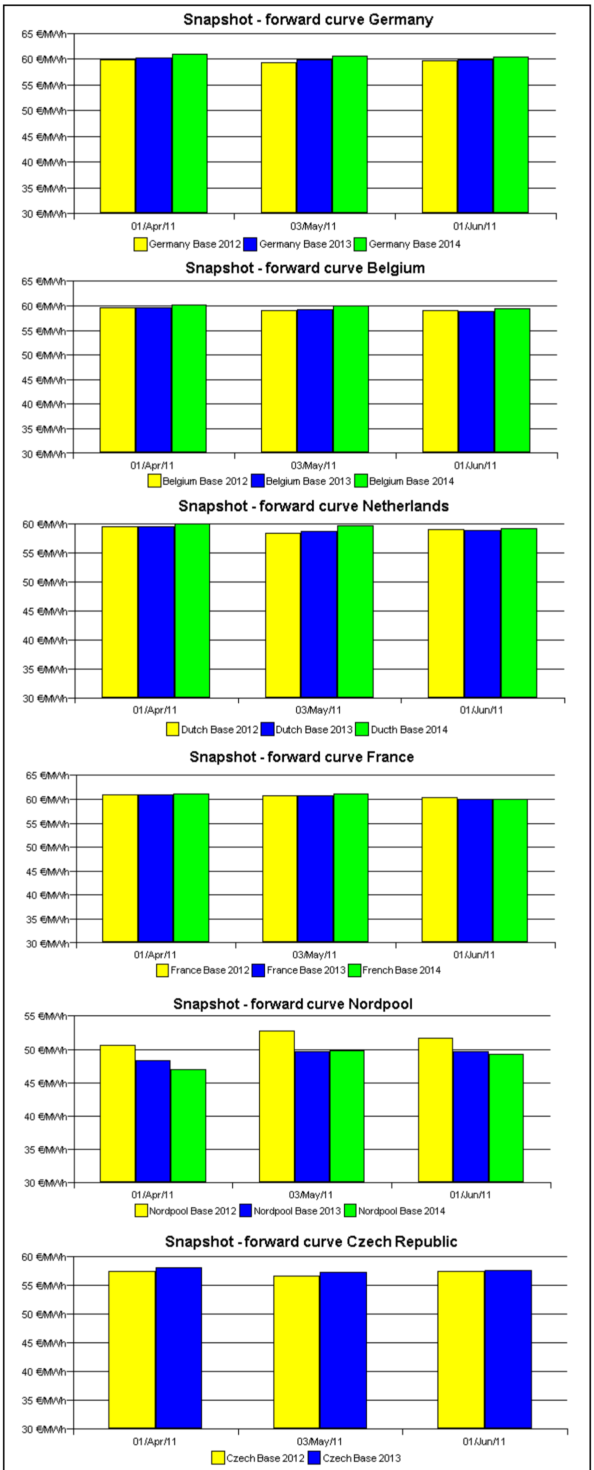
On the 24th of June December 2011 Emission contracts fell to 12 €/MWh, reaching a two year low value. This slide in prices was primarily owing to the renewed fears of an economic slowdown in the EU and market expectations that European Commission's recently revealed energy efficiency plans might assure a permanent oversupply on the carbon market; putting a pressure on the Emissions Trading System.

UK future spark spreads substantially declined during the second half of June 2011. This was mainly due to the decrease in power prices on the near-end of the curve and to the relatively stable gas prices during the whole quarter. The steepest decrease could be observed in the case of month-ahead power prices (and month-ahead spark spreads) as power demand and heating needs usually decline at the beginning of the summer period.



Source : Platts.

The forward contracts did not show a decisive direction (neither contango[9] nor backwardation[10]) on the markets of the Central West European region during the second quarter of 2011. In contrast, the Nordpool market the curve was in backwardation, primarily owing to high spot prices during the earlier periods of 2011 that put an upward pressure on the near curve.



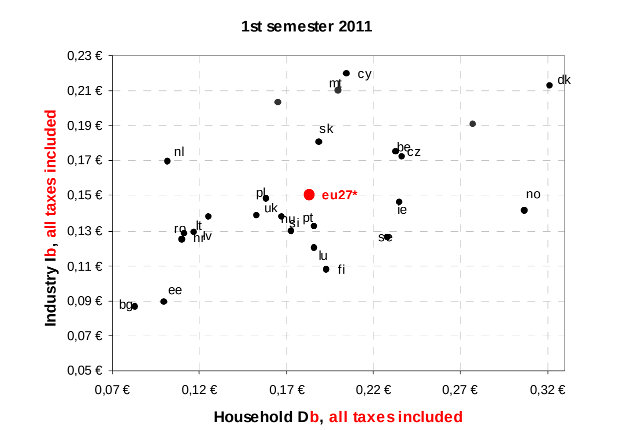
Source : Platts.

9 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.

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

A.2 Retail markets

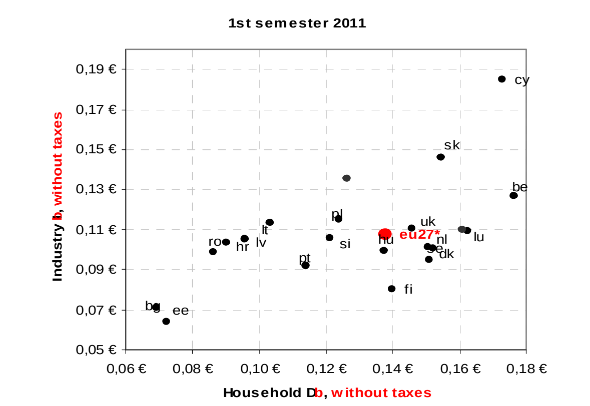
The next two charts show the electricity prices paid by household consumers from EU member states as well as from Croatia, Norway and Turkey that use between 1.000 and 2.500 kWh and industrial consumers that use between 20 MWh and 500 MWh annually (consumption bands *Db* and *Ib* according to Eurostat's 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).[11]



Source : Eurostat
Range for annual consumption of :
Household band Db : *[1.000 kWh – 2.500 kWh] ;*
Industry band Ib : *[20 MWh – 500 MWh]*

Notes: Data for Austria, Spain, France, Greece, Turkey are not available: eu27 is the last available weighted average, as of 2nd semester 2010.*

During the second semester of 2010 and the first semester of 2011 the ratio between the cheapest and most expensive gross prices for households increased, and at the same time it practically remained unchanged for industrial consumers. In absolute terms the range between the cheapest and most expensive net prices for household consumers amounted to 24 cents/kWh for households (2 cents increase with respect to second semester 2010) and 13,5 cents for industrial consumers (slight increase with respect to second semester 2010).



Source : Eurostat
Range for annual consumption of :
Household band Db : *[1.000 kWh – 2.500 kWh] ;*
Industry band Ib : *[20 MWh – 500 MWh]*

Notes: Data for Austria, Spain, France, Greece, Turkey are not available: eu27 is the last available weighted average, as of 2nd semester 2010.*

A.2.1 Price level

Households

As in the previous semester, Denmark and Germany were the EU Member States where household consumers had to pay the most for electricity, being 29 cents/kKWh and 25 cents/kWh respectively. The lowest price on the other hand was reported in Bulgaria, where households had to pay 8 cents/kWh.

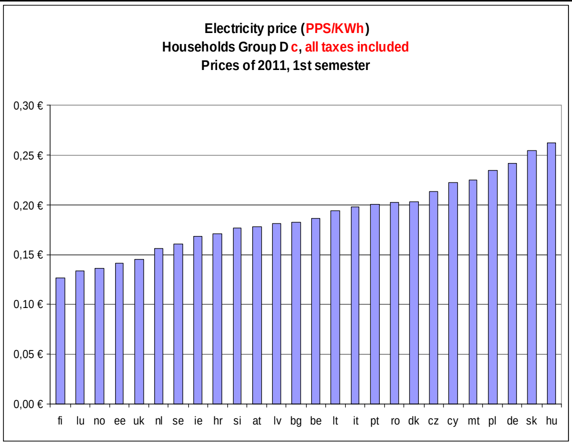
With the exception of Cyprus (21 cents/kWh), households in new Member States (NMS)[12] still paid less than the EU

[11] It should be noted that the indicative Eurostat categories of household and industry consumers are not necessarily representative of the average customer for a given Member State due to different consumption patterns across the EU.

[12] Member States than joined the EU in 2004 or 2007.

average (17 cents/mWh[13]) in absolute terms.

When correcting for purchasing power the picture changes: amongst the four most expensive Member States measured in PPS[14], only Germany is not a new member state, the other ones being Poland, Slovakia and Hungary. The same observation can be made at the lower end of the table, with the five out of six countries with the lowest prices in PPS all being old member states (Finland, Luxemburg, Netherlands, Sweden), and only one new member state (Estonia)[15].



Source : Eurostat
Range for annual consumption of :
Household band Dc : [2.500 kWh – 5.000 kWh] ;

Note: Data for Austria, Spain, France, Greece, Turkey are not available

Remarkably, the arithmetic average for NMS is 21 cents/kWh, versus a EU27 arithmetic average (of the available data) of 19 cents/kWh.

Industries

Industrial consumers in the EU27 paid 15 cents/kWh on weighted average, in line with the NMS average of 14 cents/kWh. The most expensive prices, as in the previous semester, were reported in Denmark (19 cents/kWh), whilst the lowest ones could be observed in Bulgaria (8 cents/kWh).

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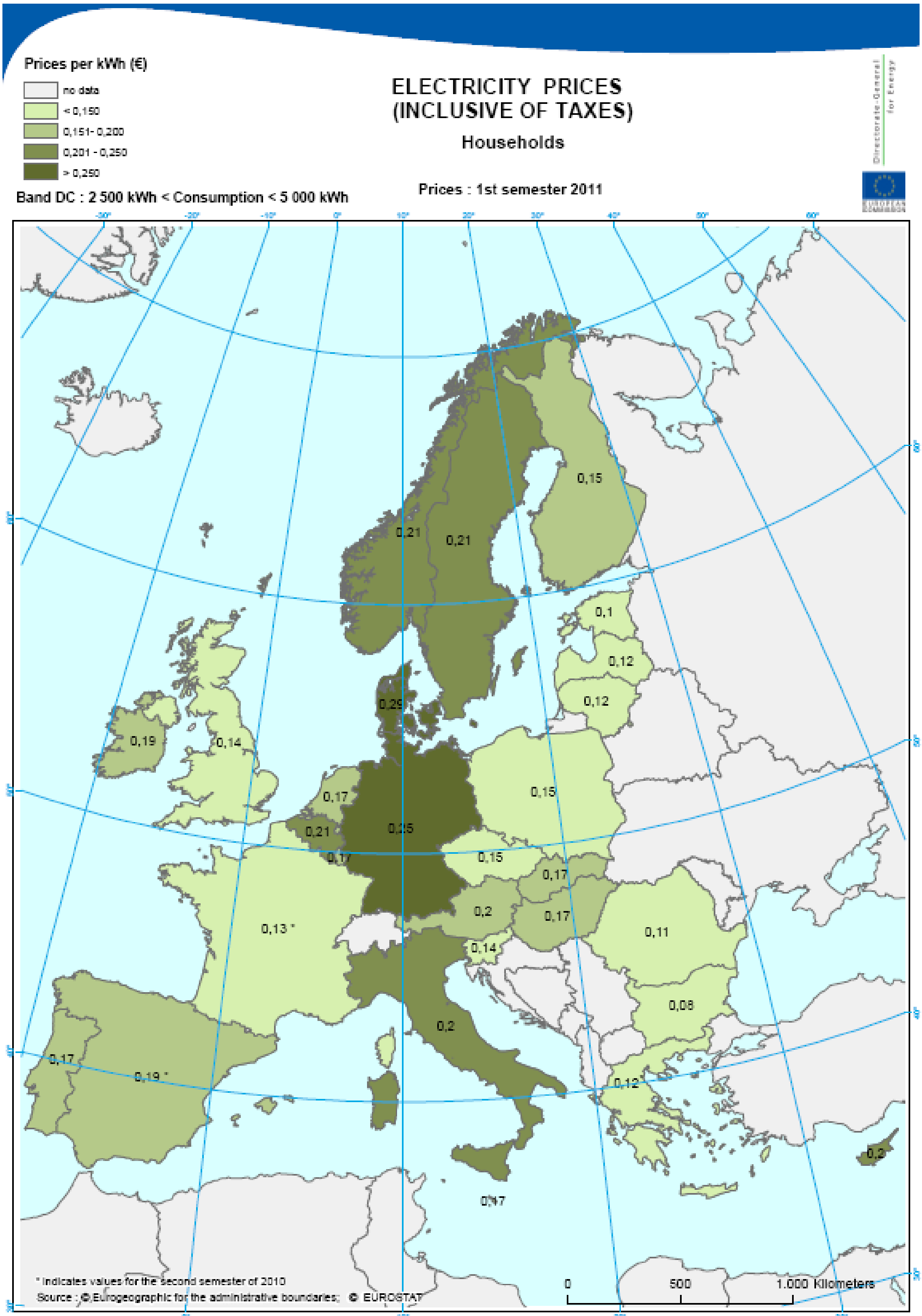
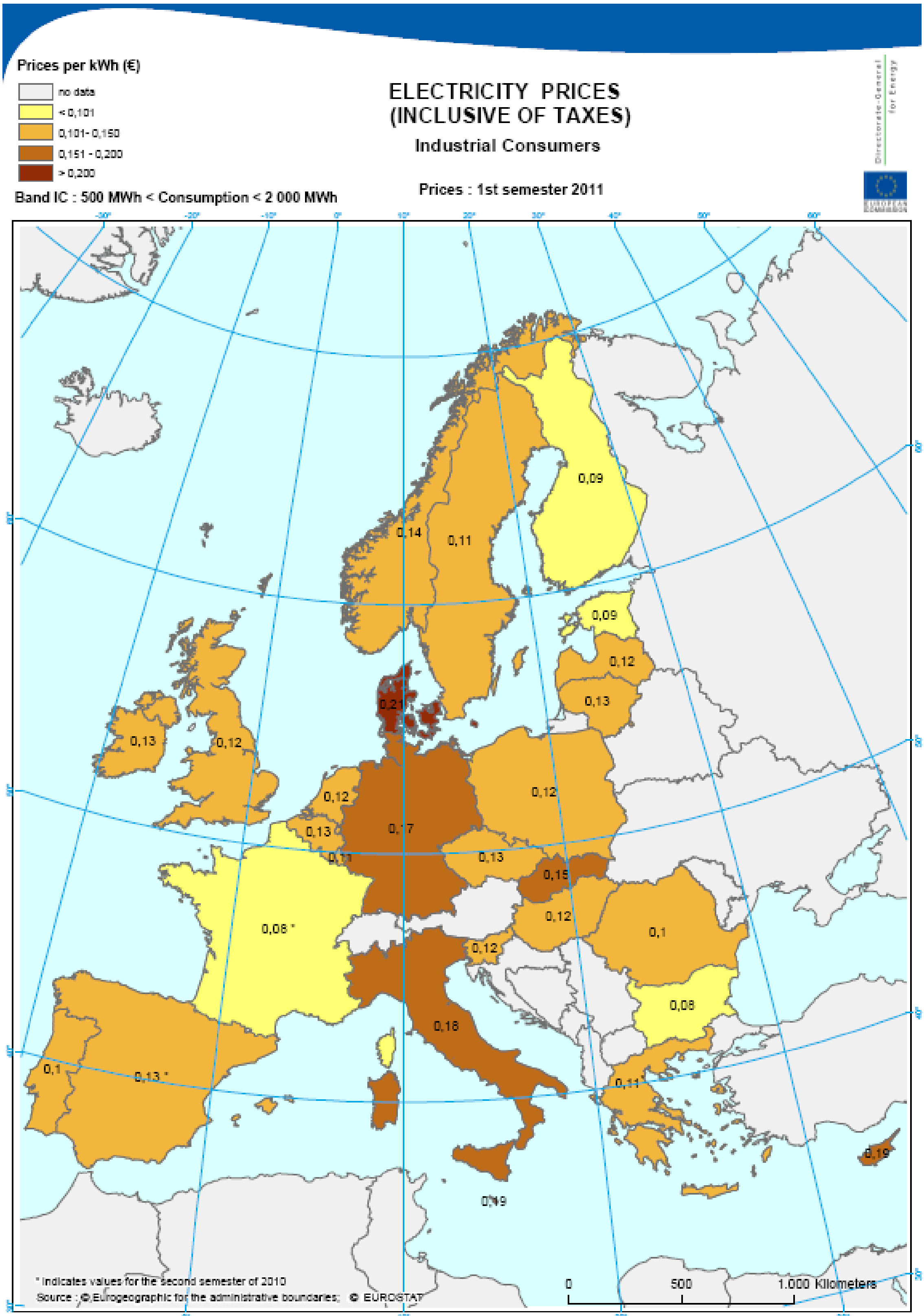
[13] EU27 average is not available for 1st semester of 2011. Throughout the report, the last available average was considered, as of 2010, 2nd semester.
[14] Purchasing power standards
[15] It is to be noted that France and Greece are not included (data not available). In the previous semester, they both figured amongst the lowest 4 prices.

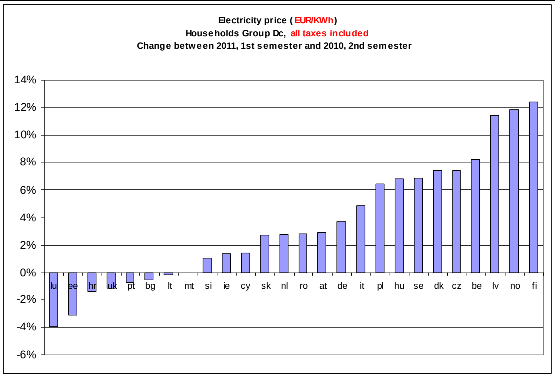

Prices per kWh (€)
no data
< 0,150
0,151 - 0,200
0,201 - 0,250
> 0,250
Band DC : 2 500 kWh < Consumption < 5 000 kWh
ELECTRICITY PRICES
(INCLUSIVE OF TAXES)
Households
Prices : 1st semester 2011
0,15
0,21
0,21
0,1
0,12
0,12
0,29
0,19
0,14
0,15
0,17
0,25
0,21
0,17
0,15
0,17
0,2
0,17
0,13 *
0,11
0,14
0,08
0,2
0,17
0,19 *
0,12
0,2
0,17
* indicates values for the second semester of 2010
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT
0
500
1.000 Kilometers

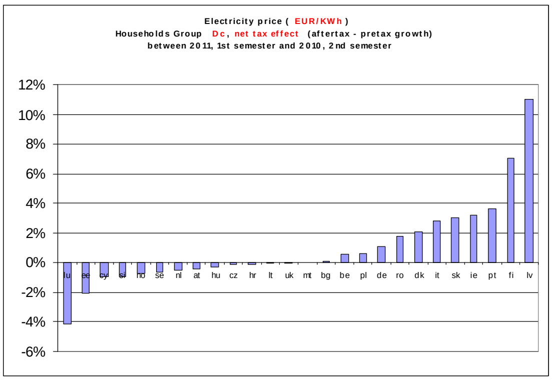

Prices per kWh (€)
no data
< 0,101
0,101- 0,150
0,151 - 0,200
> 0,200
Band IC : 500 MWh < Consumption < 2 000 MWh
ELECTRICITY PRICES
(INCLUSIVE OF TAXES)
Industrial Consumers
Prices : 1st semester 2011
0,09
0,14
0,11
0,09
0,12
0,13
0,21
0,13
0,12
0,12
0,12
0,13
0,11
0,13
0,15
0,12
0,08 *
0,12
0,1
0,08
0,18
0,1
0,13 *
0,11
0,19
* indicates values for the second semester of 2010
Source : © EuroGeographic for the administrative boundaries; © EUROSTAT
0
500
1.000 Kilometers

A.2.2 Price dynamics

Households

Electricity prices for household consumers rose on average by 3.5% in the first half of 2011, compared to the previous semester[16]. However, developments in the individual Member states have been quite diverse.





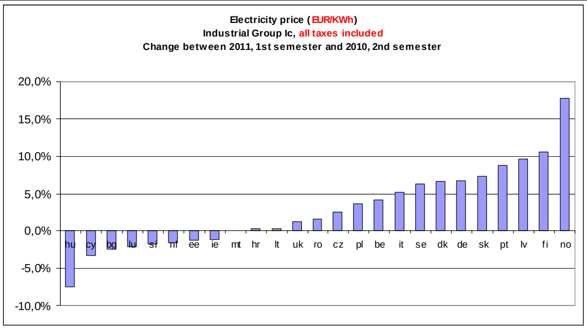
Source : Eurostat
Range for annual consumption of :
Household band Dc : [2.500 kWh – 5.000 kWh];

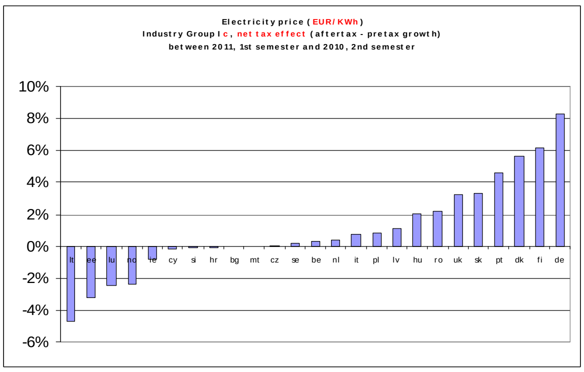
Note: Data for Spain, France, Greece and Turkey are not available

The steepest increases among EU Member States could be observed in Finland (12.4 %), Norway (11.9%) and Latvia (11.5%). The largest fall in prices on the other hand happened in the Luxembourg (-3,9 %).

The presence of a net tax effect[17] indicates that the level of taxation has changed during the period in question. The differentials for domestic consumers ranged from 11,7% (Latvia) to -4.1% (Luxemburg). Finland was the EU Member State with the largest net price effect (12.4%) for households. In Latvia, a major increase in after-tax prices of 11.5% coincided with a nearly stable gross price (net tax effect: 11%).

Industries





Source : Eurostat
Range for annual consumption of :
Industry band Ic : [20 MWh – 2000 MWh]

Note: Data for Austria, Spain, France, Greece and Turkey are not available

[16] In the remaining part of this chapter, unless otherwise stated, price changes are always compared to the previous semester (2nd semester of 2010)

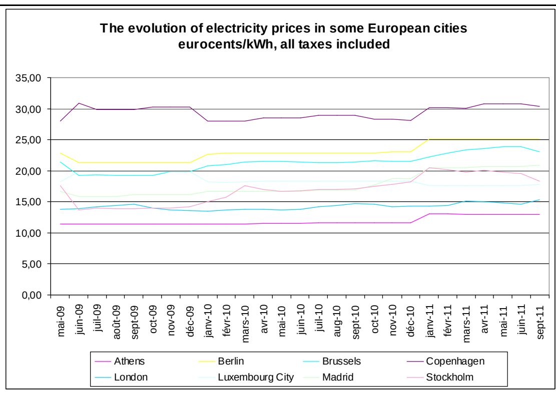
[17] Net tax effect is the difference between the percentage growth in after-tax prices and percentage growth in pre-tax prices.

Again, the developments in the individual Member States have been quite varied. Growth rates of over 10 % have been reported in Norway (17.7 %) and Finland (10.6 %). Falls in prices on the other hand could be observed in Hungary (-7.5%) and Cyprus (-3.3%).

When looking at the net tax effect rather than absolute price, the countries with the highest figures change. The highest net tax effect is found in Germany (8,3%), Finland (6,2%) and Denmark (5.7%). On the other hand, Lithuania (-4.7%) and Estonia (-3.3%) presented the smallest net tax effect.

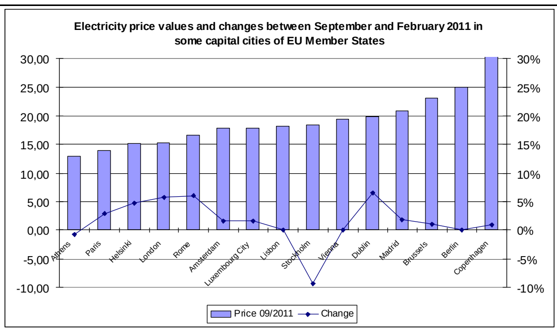
The next chart shows the evolution of all-inclusive retail electricity prices paid by households in some European capitals between May 2011 and September 2011. Price rose the most in Dublin (6,5%), Rome (6%) and London (5.7%).

The most significant price fall was in Stockholm (-9.3%), followed by Athens (-0.8%). All other cities presented either stable or increasing prices.



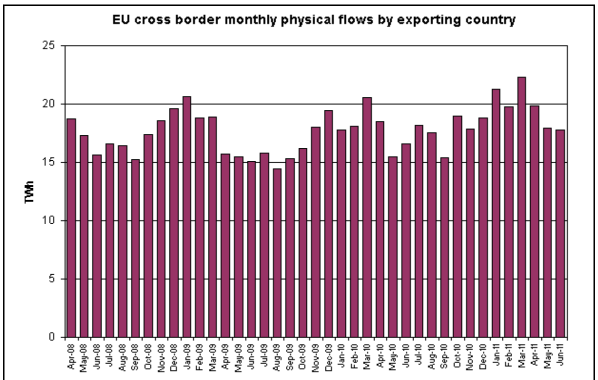
Source: HEPI

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.



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

In the second quarter of 2011 EU cross border physical flows decreased by 12% compared to Q1 2011, following the regular seasonal pattern as both electricity consumption and traded volumes diminished after the end of winter period. Meanwhile Q2 2011 cross border flow volume was up by 10% year on year, outpacing the 2.3% growth of the traded power volume on the EU markets.

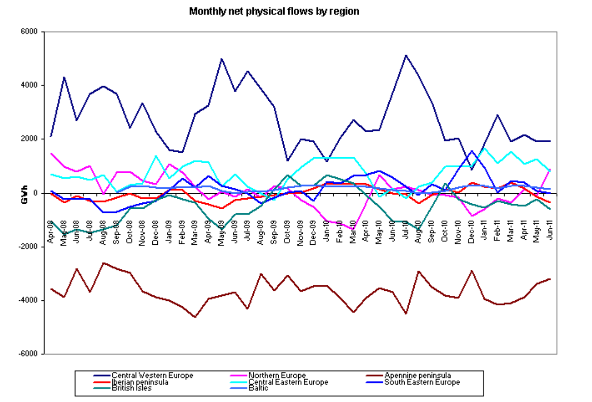


Source : ETSO

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.

This achievement points towards an increasing cross border trading activity that reflects a healthy evolution of the European electricity market.

Taking a look at the power flows between regions the net outflow of the Nordic region rebounded in May 2011 after high Nordpool power prices began to diminish. In the Central East European region the net outflow remained on high levels as many German nuclear plants were brought to a halt and this prompted an excess import power demand which was satisfied from the CEE region. The Central West European region retained its strong net outflow position while the other power regions remained on the net importer side.



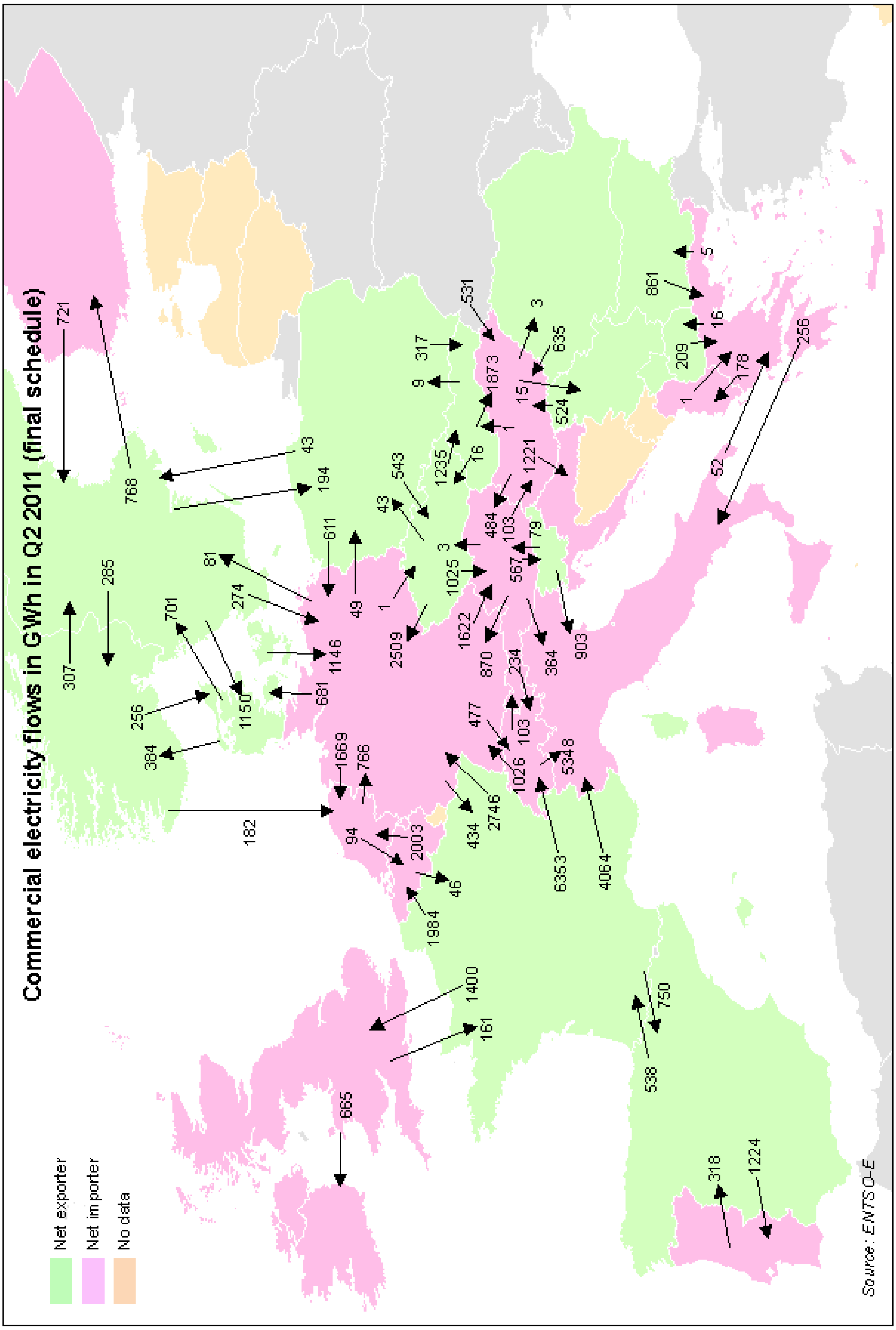
Source : ETSO.

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:

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 GWh in Q2 2011 (final schedule)
Net exporter
Net importer
No data
Source: ENTSO-E

C. *"Focus on Support schemes for renewable energy sources"*

Support schemes for renewable energies find their justification in the overall EU's 2020 package. This package contains the strategy to address climate change, increase EU's energy security and strengthen its competitiveness[18].

To reach those aims, in March 2007 EU leaders committed to the targets[19] to be met by 2020, the so-called 20-20-20 objectives:

- 20% reduction of greenhouse gas emissions in the EU with respect to 1990 levels;
- 20% of EU energy coming from renewable energy sources (RES);
- 20% reduction in primary energy use (with respect to projected levels), to achieve through energy efficiency.

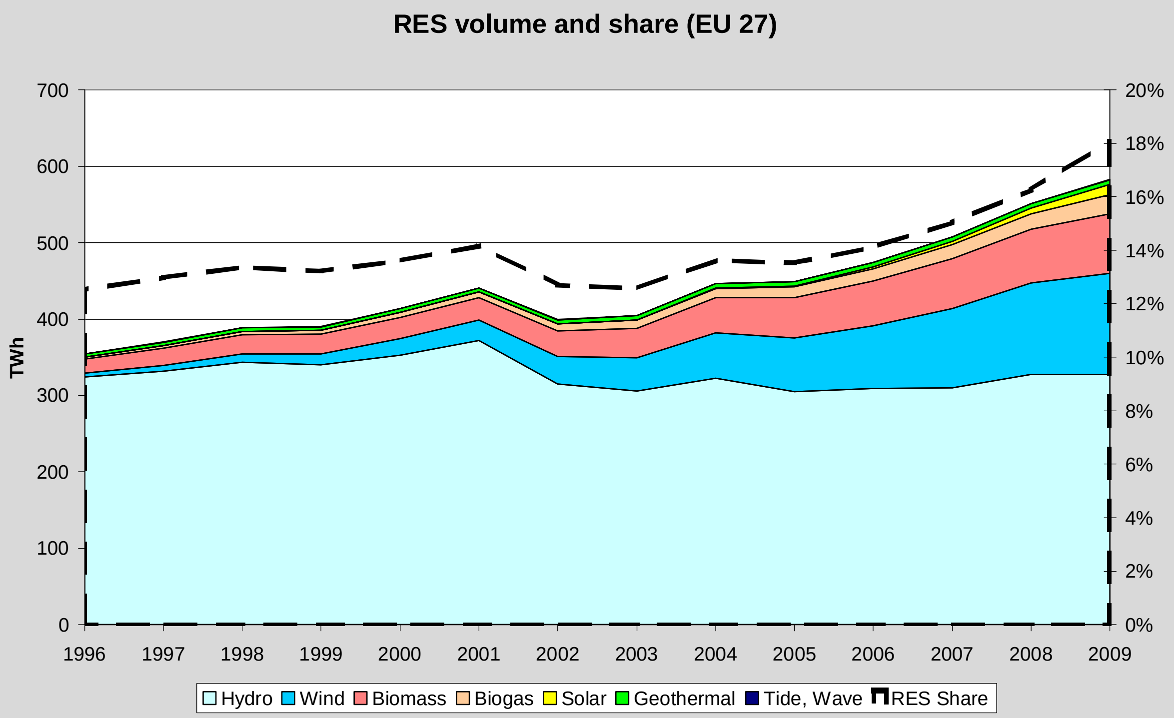
Renewable energy sources (RES) play a key role with respect to the first two objectives, but their adoption is not straightforward. In fact, energy coming from renewable sources has typically higher costs with respect to traditional sources such as fossil fuels and it is therefore less competitive on energy markets. This is due to the relatively new nature of the technologies adopted, which have not benefited from mass-adoption learning effects yet.

Hence, in order to promote the adoption of RES, support schemes are necessary to fill the gap with traditional sources while new technologies climb the learning curve, in order to become competitive in the long run without any further need for incentives.

The gap between the cost of producing energy from a renewable source and the market price is called "green spread". This indicator can be seen as a measure of the maturity of a renewable energy technology. In general, the bigger the green spread, the greater the support needed by a RES to be competitive on the market.

The following chart shows the progressive adoption of RES in the energy mix throughout the EU.

[18] See http://ec.europa.eu/energy/strategies/2010/2020_en.htm (last accessed on Oct 25th 2011)
[19] See http://ec.europa.eu/clima/policies/package/index_en.htm (last accessed on Oct 25th 2011)



Source: Eurostat

Price-based incentive schemes: Feed-in Tariffs and Feed-in Premiums

Incentive schemes can be rather diverse. They can be volume-based, such as compulsory RES quotas in the energy mix, limitations in the volume of CO_2 emissions, or tradable green certificates (TGCs)[20]. Incentives can also be price-based, such as Feed-in Tariffs (FiTs) and Feed-in Premiums (also called simply Premiums).

FiTs guarantee producers a fixed amount per generated kWh. Premiums guarantee producers a fixed price premium over market price per kWh sold. The difference is substantial: Premiums expose producers to demand fluctuations and therefore to market risk, putting uncertainty on the stream of subsidies for the producer. Hence, Premiums are more suitable for mature technologies which are expected to have a lower green spread. In general, the more stable (and risk-free) the incentive scheme, the more it is suitable for less mature technologies and vice versa. Another criteria of choice between those two types of price incentives is that FiTs do not require an established market price benchmark but only the volumes produced, while Premiums are calculated with respect to volumes and market price. This difference makes FiTs viable also in those countries which do not have an established market price benchmark,

[20] Tradable Green Certificates (TGCs) are a tradable certificate, proving that a certain amount of energy was produced from Renewable Energy Sources.

such as some member states in the South-East Europe.

The amount of the price incentive is normally set according to the type of technology, since different RES have different green spreads. For example, photo voltaic plants typically receive more incentives then wind plants[21]. Furthermore, the amount of the incentive often changes according to the specifics of the generating technology. For example, different wind plants may receive different amount of incentives per kWh according to their type of installation (onshore/offshore[22]), their generating capacity[23] and their installation year[24].
This type of scheme generally includes also other provisions, such as:

- long term guaranteed purchase contracts (15-20) years;
- gradual decrease of the subsidy over time.

It is to be noted that the EU law does not contain any specific provision with respect to the type of incentive scheme[25] to be adopted in order to promote RES. It however contains specific provisions which ensure "either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources"[26]. The regulation of grid access is of primary interest, especially given the intermittent nature of some RES (for example wind), which could generate additional costs for the network operator, which would have an impact on network tariffs[27].

Different approaches to RES incentive schemes have been historically adopted and it is rather difficult to assert in which manner the committed resources are more efficient in reaching the goal of promoting a sustainable development through renewable energies.

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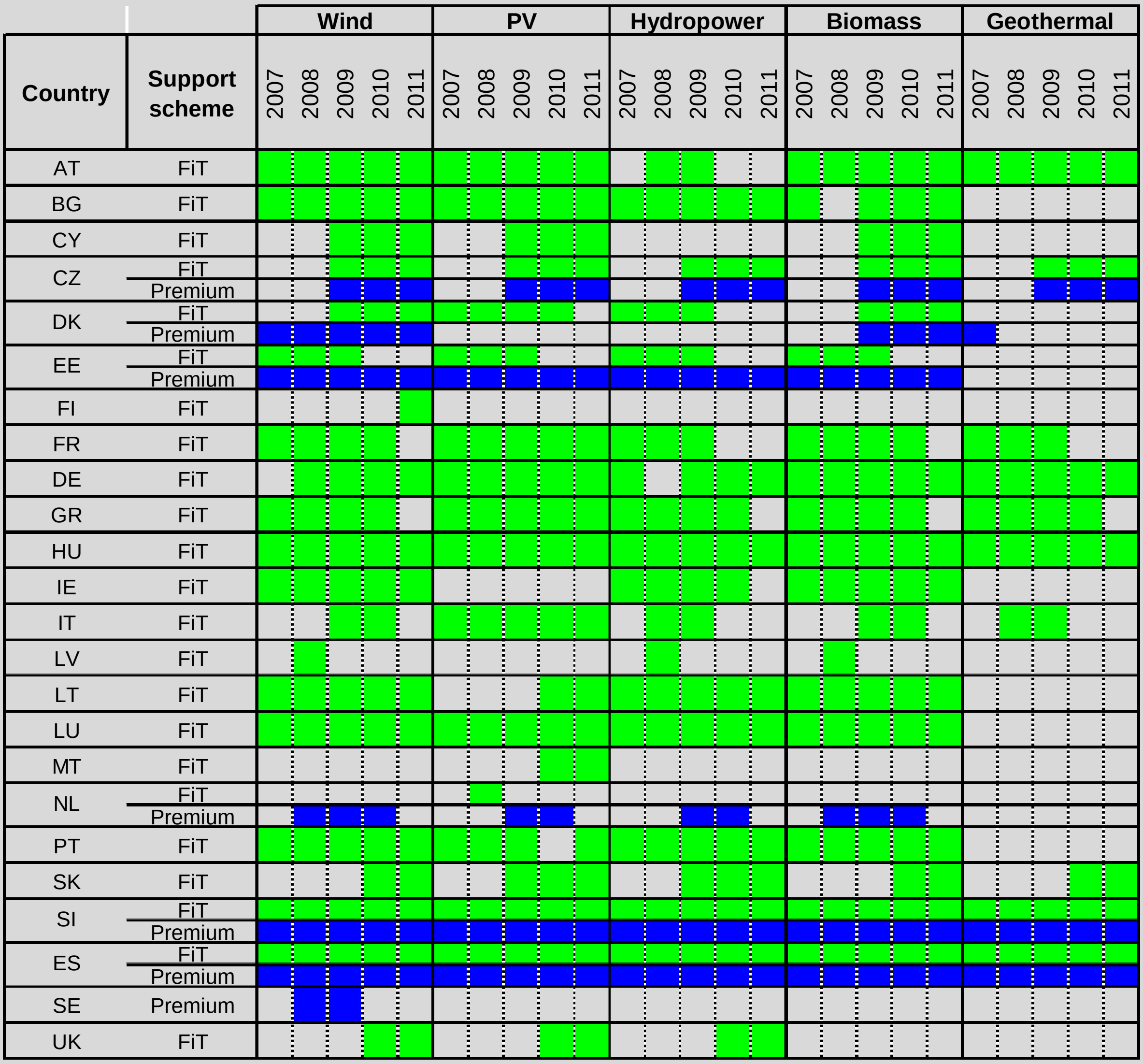
[21] Source: ENERDATA
[22] For example, for wind plants in Germay, the amount of the FiT is different if plant is onshore or offshore. See http://www.erneuerbare-energien.de/files/english/pdf/application/pdf/eeg_2009_verguetungsdegression_en_bf.pdf (last accessed on Oct 25th 2011).
[23] For example, for wind plants in Bulgaria, the amount of the FiT is different if the generating capacity of the plant is above or below 800 kWh. See http://www.mi.government.bg/eng/norm/rdocs/mdoc.html?id=212967 ; http://www.dker.bg/resolutions/res_c018_10.pdf (last accessed on Oct 25th 2011).
[24] For example, for wind plants in Czech Republic, amount of the FiT is different according to the year of commissioning of the plant. See http://www.eru.cz/user_data/files/cenova%20rozhodnuti/english/CR%204_2009%20EN.pdf (last accessed on Oct 25th 2011).
[25] See *EU Directive 2009/28/EC on the promotion of the use of energy from renewable sources*, Article 3, Par. 2, where it states "In order to reach the targets […] Member States may, inter alia, apply the following measures: (a) support schemes […]".
[26] See *supra*, Article 16, Par. 2.
[27] For example, an unforeseen drop in wind could lead to balancing problems for the electric network operator, which would face an unexpected shock in the supply.

The following table illustrates which countries have adopted incentives schemes which can be classified as FiT or Premiums.



Source: ENERDATA

The variety of the type of realized incentive schemes, together with the different specificities of each technology and country, suggest extreme care in comparing the data across countries and sources. Case studies on selected countries appear to be a more appropriate tool of analysis. For example, a recent article from IEA[28] compared the impact of Solar FiTs on consumer prices in Germany, France and Czech Republic. The three FiT systems analyzed were designed to be

[28] IEA (2011) – ENERGY PRICES & TAXES, 1st Quarter 2011, *Feed in tariffs in selected EU countries*, J. Kubat & A.Kennedy

self-sufficient, hence to pass the entire cost of the surcharge to the final consumers. The consumer surcharge per unit estimated showed a clear growing trend in all the three countries. Germany in particular exhibited a significantly high surcharge (up to 35€/MWh estimated for 2011).

In conclusion, FiT and Premium incentives are one of many tools available to promote RES adoption. The variety of the possible combinations of type of incentives, level of prices, together other provisions, suggests that the effectiveness of those policies is to be carefully evaluated on a case-by-case basis.

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