Quarterly Report on European Electricity Markets

MARKET OBSERVATORY FOR ENERGY

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Directorate-General for Energy

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DIRECTORATE A - General Policy
Unit A.1 - Energy policy, Programming & Observatory, Economic analysis & Infringements
Market Observatory for Energy

Dear readers,

The devastating earthquake that hit the Japanese coastline and the accident that took place in a nuclear power plant in March 2011 triggered some important developments that influenced the European Electricity Markets.

In the aftermath of Fukushima, the security of the European nuclear plants turned into a daily topic covered by the mainstream media. The European Commission launched a series of nuclear stress tests to underline its commitment to safeguard the highest safety standards. Some Member States took steps to reconsider the future of their nuclear power plants. The "*Focus on…*" section of the current reports develops this topic in more detail.

The completion of the internal energy market remains an overarching priority. In this edition of the *Quarterly Report* we analyse positive developments such as the significant reduction of adverse flows in the Central Western Europe after the day-ahead markets were coupled in November 2010. This development sends a strong message to the remaining electricity regions in Europe: market coupling delivers tangible results in the electricity market. It demonstrates what can be achieved when market participants, energy regulators, system operators, Member States and European institutions cooperate with each other.

However, the internal energy market cannot develop without investments in physical connections, as the case of the newly inaugurated interconnection between Sardinia and the Italian mainland demonstrates. This interconnector led to substantial decrease of the zonal price on the island.

I take this opportunity to thank you, dear readers, for participating in the on-line survey of the *Quarterly Reports on European Electricity Markets.* The replies we received were very encouraging and inspiring for our future work, where our objective is to keep the reports close to your needs.

For the editing team:
Dinko Raytchev

HIGHLIGHTS

- The number of heating degree days in January was lower than in December 2010, causing a drop in the pan-European price index.

- The outage of the power plant in Fukushima pushed up the prices of energy commodities in March. This accident and the following German decision to put off grid seven nuclear reactors exerted influence over European spot and forward power prices.

- French net exports increased considerably, but Norway was a net importer. The reservoir content in Nordpool area reached another record-low level. The Nordpool baseload was traded at a premium to the German baseload throughout the quarter. The "*Focus on*" section of the current report provides a more detailed analysis of these developments.

- The area prices in Italy converged significantly between the mainland and Sardinia after the completion of the new interconnector.

- In the first quarter of 2011 prices in the Central Eastern European region remained competitive compared to Western Europe which was also reflected in increasing power exports from the region to the western part of the continent.

- Greek prices returned from their very low levels measured at the end of 2010, primary owing to decreasing hydro- and renewable based power generation in Q1 2011.

- CO_2 emission forward prices closely followed the price hikes in forward power prices in mid-March 2011.

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QUARTERLY REPORT ON EUROPEAN ELECTRICITY MARKETS

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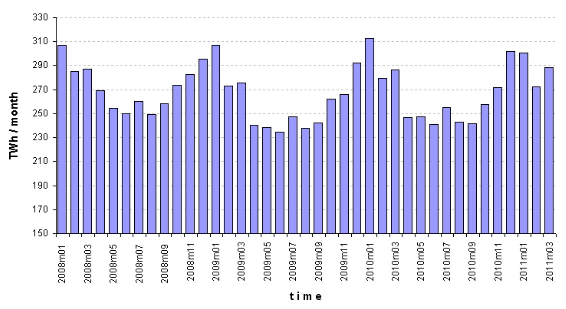
A. Recent developments in the electricity markets across Europe

The combined gross electricity consumption in the EU during the first quarter of 2011 was 861 TWh, around 2% lower than in the same quarter in 2010. The biggest decrease was observed in the region comprising Belgium, Germany, France, Luxembourg and Netherlands (close to 4.4%). The consumption also decreased in the Baltic countries (3.7%), the Nordic countries (3.4%) and on the Iberian Peninsula (1.9%).

EU27 gross electricity consumption



Source : Eurostat

Monthly consumption for Italy and Malta is estimated based on GDP data for the first quarter of 2011 from Eurostat's Principal European Economic Indicators.

In the South East European Region[1] considerable growth could be observed (2.9%), but also in Central European Countries and the British Isles (1%). In

[1] This region consists of Bulgaria, Greece, Cyprus, Malta and Romania.

several of the countries in these regions the number of heating degree days[2] was higher in Q1 2011 than in Q1 2010.

The table below shows, that February and March 2011 were on average colder than a year ago and much colder than two years ago. As presented in the charts in the section A.1.1, this did not have only an important impact on the consumption, but on the power prices as well.

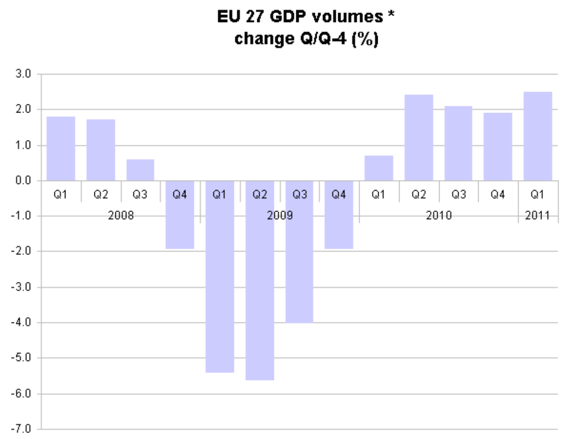
EU 27 Heating Degree Days in Q1
Values for 2009, 2010, 2011 and 1980 – 2004 average

	January	February	March
2009	555.66	476.34	405.00
2010	624.23	499.45	421.50
2011	551.74	509.88	423.14
LT avg.	545.97	471.03	412.40

Source : Eurostat /JRC

Besides the temperatures, the economic performance in the EU appeared to be another driver influencing the consumption. For the fifth time in a row the quarterly data show an economic growth, which reached 2.4% in the observed quarter (on a year-on-year basis).

[2] 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.

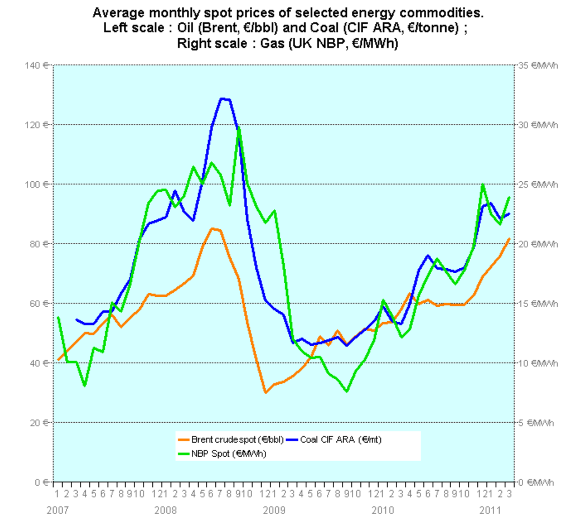


Source : Eurostat.
Selected Principal European Economic Indicators
** Gross domestic product (GDP) at market prices is the final result of the production activity of resident producer units. It is defined as the value of all goods and services produced less the value of any goods or services used in 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

In Q1 2011 the main fossil fuels showed some signs of decoupling.

After peaking at 25 €/MWh, a level last seen in October 2008, the NBP price dropped in January and February. As it appears this was a result of price corrections after the cold month of December and rising temperatures afterwards. The increase of the March average is linked to the high NBP price in the middle of the month, when it grew close to 26 €/MWh. This happened at the time of the nuclear accident in Fukushima, Japan.



Source : Platts.

The CIF ARA coal price followed a similar trajectory as the NBP price. After increasing to 92.7 €/tonne in December and 93.7 €/tonne in January, it dropped in February.

The reason why the coal price still increased in January can partly be found in the heavy floods in Australia (Queensland) in the beginning of the month which disrupted the production considerably. The subsequent increase in March can be, as in the case of gas, attributed to the events in Japan.

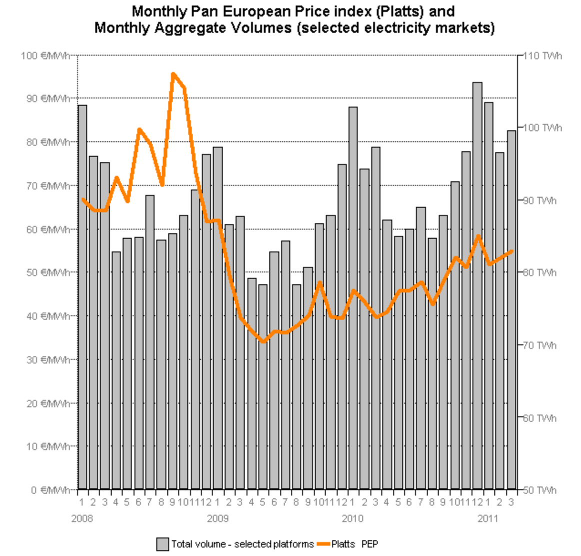
The spot price for Brent, on the other hand, grew almost constantly throughout the quarter. The increase at the beginning of the year was driven by positive economic expectations. Later other events contributed to growth, such as the closure of four production facilities in North Sea by Royal Dutch Shell due to an accident in mid-January. Uprisings in the Middle East, worries that shipments through the Suez Canal would be disrupted, fighting in Libya and the accident in Japan were other important drivers influencing the Brent price.

A.1.1 Day-ahead

EU wholesale markets

After the record in December 2010, the total traded volumes on European power exchanges were in January 2011 again above the level of 100 TWh.

Along with the trend in increasing volumes since 2009, same pattern can be observed in the prices. In the period from May 2009 to March 2011 the Platts pan-European price index increased by 62%.

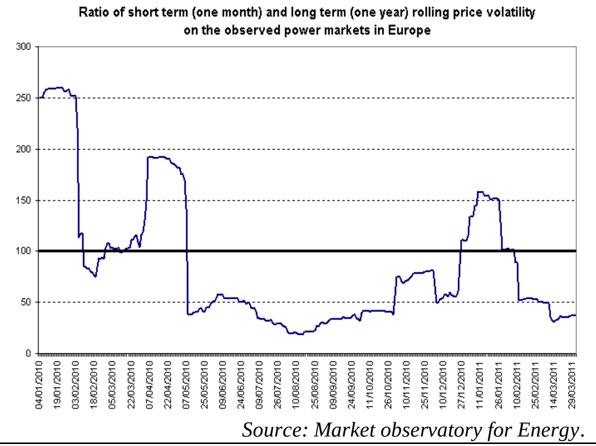


Source: Platts (price index) and selected European electricity wholesale markets (volumes). The selected markets are : Nordpool Spot A.S ; European Energy Exchange (EEX) ; Amsterdam Power Exchange (APX Power NL) ; Powernext Day-ahead S. A. ; Belpex Spot ; Energy Exchange Austria (EXAA) ; Gestore del 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 January 2011 a Europe-wide drop in prices was observed when compared to December 2010. December was a much colder month with 609.43 actual heating degree days, while in January 2011 there were 551.74 heating degree days as the table in the previous sections shows. The favourable prices were also supported by the French nuclear power production and consequently large French net exports.

In February and March the pan-European index increased. In February the number of HDDs was 8% above the long-term average. In March the prices were strongly affected by the nuclear accident in Japan and the following decision in Germany to put seven nuclear reactors off grid. This issue is developed further in the relevant regional section as well as in the "*Focus on*" part of this report.

The unrests in the Middle East also contributed to the price increase in February and March, mainly through the growing price of underlying fuels used for power production.



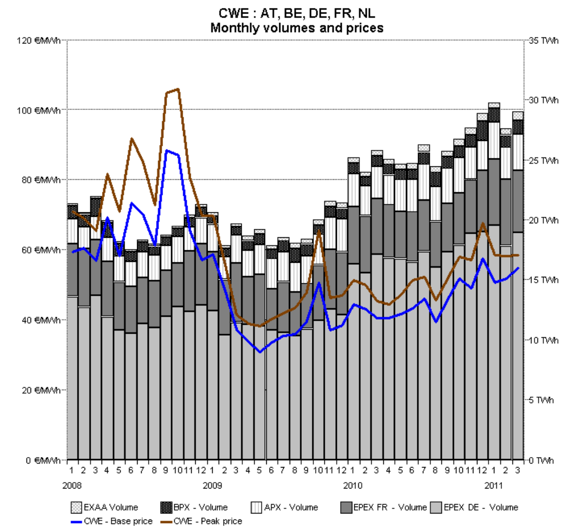
Source: Market observatory for Energy.

The Relative Volatility Index[3] (RVI) of the European power markets was at the beginning of the quarter still high. This situation began in December and continued in January due to changes in temperature. In February and in the first half of March the price movements stabilised. As the markets became volatile in the second half of March and the prices changed quickly, the volatility index increased slightly.

Regional markets

Central Western Europe

The combined trading volumes in Central Western Europe amounted to 86 TWh in Q1 2011, almost one quarter of the gross inland consumption of electricity in these countries.



Source : Platts.

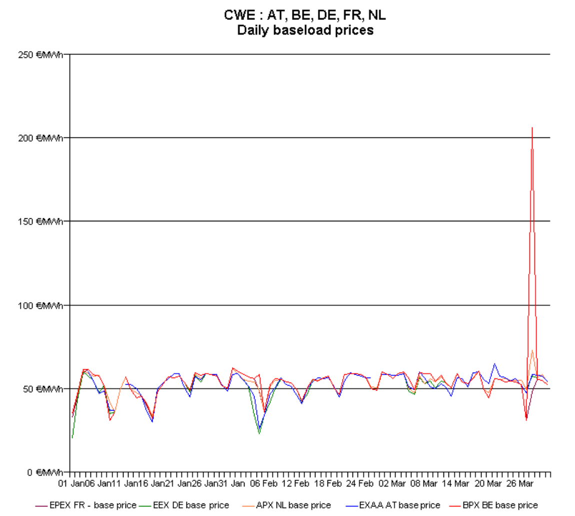
Higher than usual average temperatures in January caused the weighted CWE base and peak prices to drop. With 50.5 €/MWh the base price was close to the level of November 2010. At the end of January the price was pushed up due to decrease in temperatures and low wind power production in Germany. In mid-February the price was again supported by cold weather coming from northern Europe. Further in the quarter, the reduction of nuclear capacity in Germany after the accident in Fukushima gave support to high price levels in March[4].

On a daily basis the price movements showed close correlations with typical price drops on week-ends. There were also some cases of decoupled prices, like in the beginning of February, when there was a considerable difference between French, Dutch and Belgium prices on one hand, and German as well as Austrian prices on

[3] Relative Volatility Index (RVI) measures the relation between the short term volatility and the long term volatility on a given trading day. Short term refers to a one month backward looking volatility while long term period means a one-year time period. Volatility index is calculated from dayahead baseload wholesale daily average power prices on each trading day. If the RVI's value is greater than 100 the short term volatility is higher than the longer term volatility, implying that current market conditions are more volatile than usual. See more about the methodology of the RVI in 'Methodological description and interpretation of the volatility index for electricity markets' on the webpage:http://ec.europa.eu/energy/observatory/electricity/electricity_en.htm.

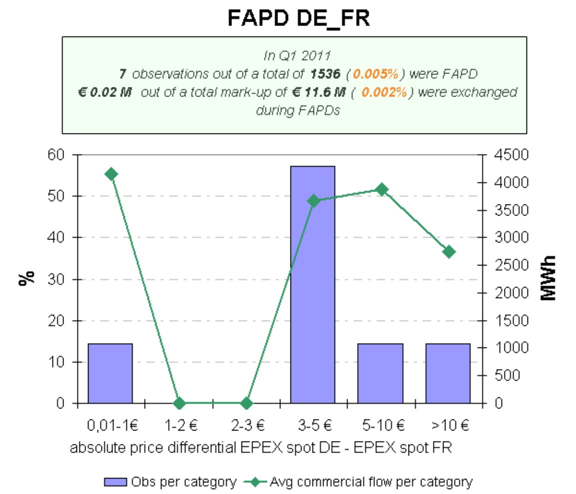
[4] The combined capacity of seven nuclear reactors (Neckarwestheim 1, Biblis A, Biblis B, Isar 1, Brunsbüttel, Philippsburg 1 and Unterweser) that were shut down is 7400 MW. Together with the reactor in Krümmel, which had due to malfunctioning been taken off the grid earlier, the total share of nuclear reactors being offline is 40%.

the other hand. Increased demand in France was the reason at first, but later in the second week of March (before the Fukushima accident) high levels of wind power production in Germany were the main driver for this difference. For balancing reasons these high wind levels also led to reduced cross-border flows from Germany to France and Benelux.



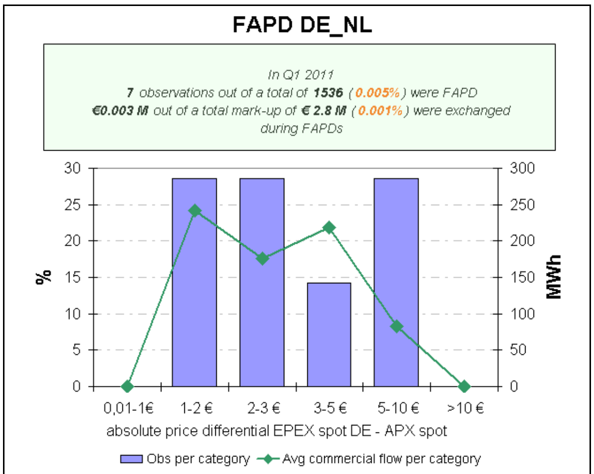
Source : Platts.

The steep increase on BPX end of March (up to 206.1 €/MWh) was caused by a short period of decoupling from the neighbouring power markets. This resulted in some observed adverse flows as seen on the following charts[5]. Adverse flows have not been observed anymore since the market coupling on the 9th of November 2010. In Q1 2011 there were not observed either, except at the end of March when the aforementioned brief decoupling of the Belgian market happened.

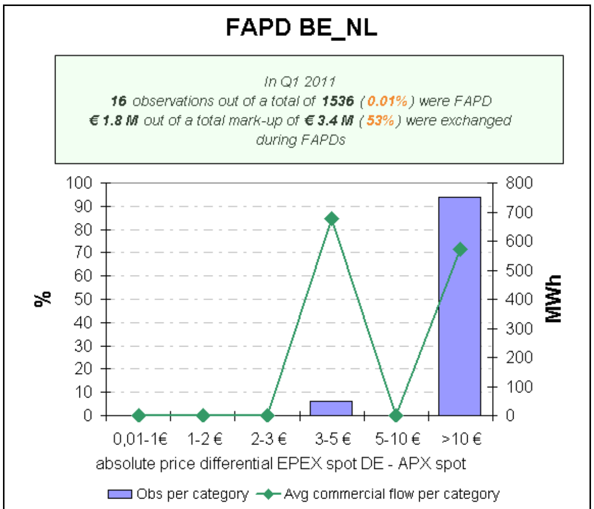


Source : Platts.

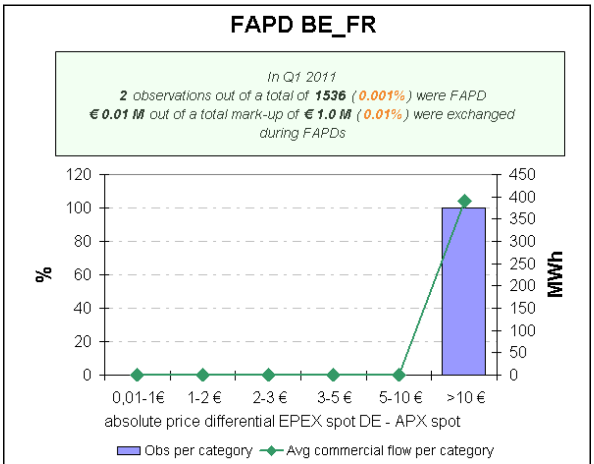
[5] By combining hourly price and flow data, FAPDs are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of electrical systems.
With the closure of the day-ahead markets (D-1), the prices for each hourly slot of day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



Source : Platts.

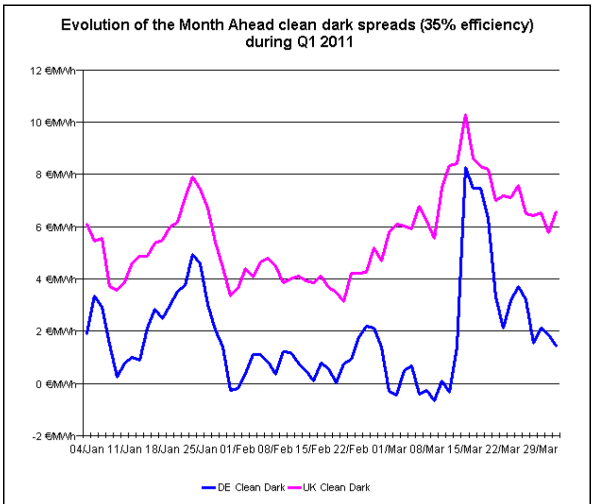


Source : Platts.



Source : Platts.

The next chart shows the evolution of clean dark spreads[6] in Q1 2011. The peaks can be explained with the electricity prices. At the beginning of January the temperatures were low, which increased the demand for power. At the end of January the spread reached a new peak for the same reason. In mid-March the German spread increased from 1.4 €/MWh to 8.3 €/MWh in one day. This coincided with the decision to in Germany to shut down the old nuclear reactors.



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

Source : Platts.

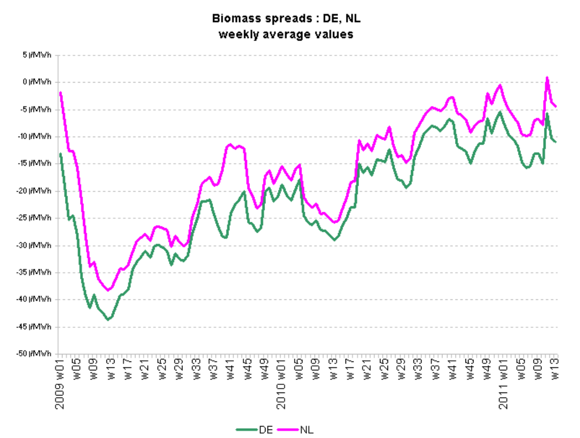
The **biomass spreads**[7] kept moving towards the break-even point. In mid-

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

[7] 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

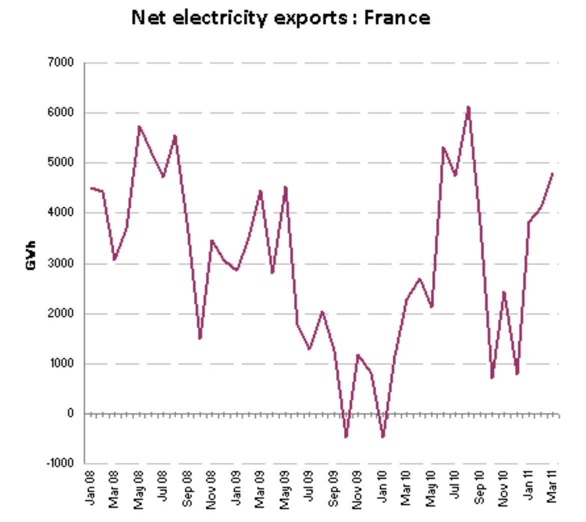
March the Dutch biomass spread even reached the positive value of 1 €/MWh.

As it appears, the movements of the biomass spreads within the quarter were to some extent influenced by the same events as the movements of the clean darks spreads in the chart above. Having lower power prices in February after low temperatures in January, they increased again in mid-March due to the German announcement on the nuclear power generation. However, the price of the emission allowances was increasing throughout the whole quarter, contributing to the increase of the spread (see section A.1.2 for further analysis of carbon prices).



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

Temperatures also influenced the French net electricity exports (due to the relatively large share of heating powered by electricity, the demand in France is highly elastic in relation to temperature). After the very cold period in December 2010 the French electricity exports began to increase in 2011. In March 2011 they reached 4800 GWh.



Source : ENTSO-E Vista

The exports were also supported by the high availability of the nuclear power plants, which were in January available at almost full capacity. Due to some unplanned outages the availability decreased in the second half of January and February. Nevertheless, it dropped most significantly in March, as the period of planned maintenance after the intense production season began. This however did not seem to affect the French exports, which were supported by the French discount towards the German and the Dutch spot price which lasted throughout the second half of March.

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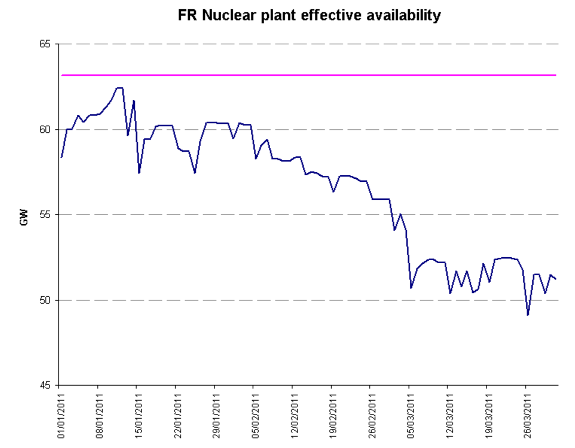
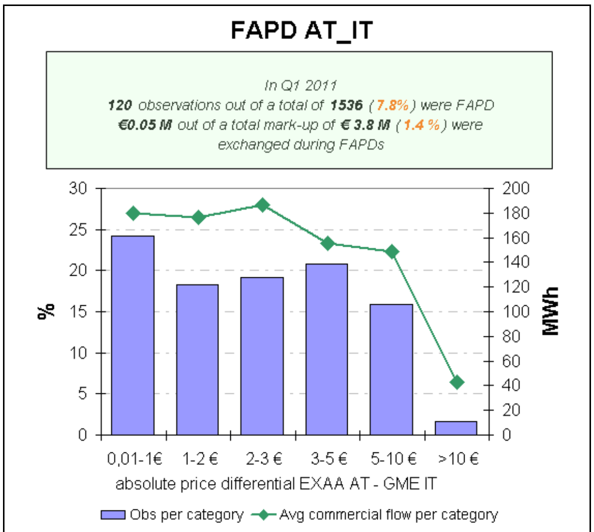
of industrial wood pellets (delivered month-ahead ex-ship at Rotterdam).
Biomass spreads do not include operation and maintenance costs. However, the German spreads include transport costs of shipping the pellets along the Rhine (Rotterdam – Cologne area).
Specific calculation assumptions: conversion 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*.



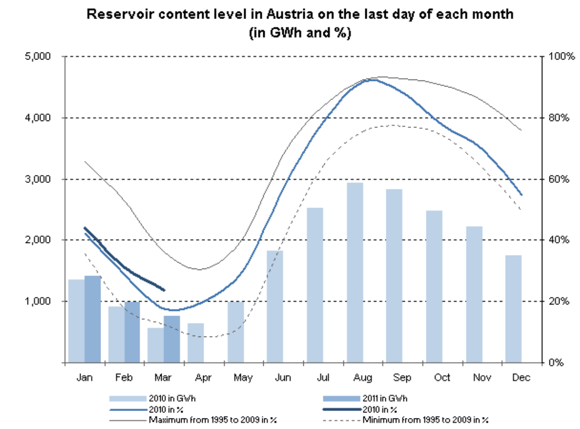
The installed capacity of the reference fleet is 63.13 GW.
Source :RTE France

Contrary to the countries which joined the coupling initiative in Western Europe and who as a result do not register adverse flows, the situation was different in Austria in this respect.



Source : Platts.

The adverse flows between Austria and Italy showed a similar statistics as in the previous quarter. Close to 10% of the observed flows were adverse flows and the average volume of traded MWh decreased as the price differential increased.

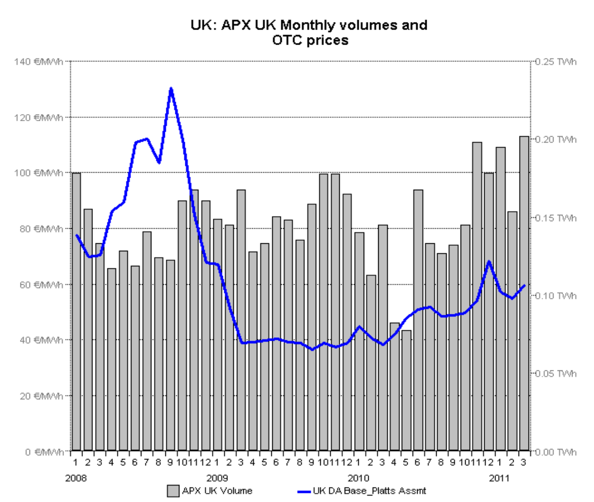


Source : E-Control GmbH, Austria

British Isles

UK

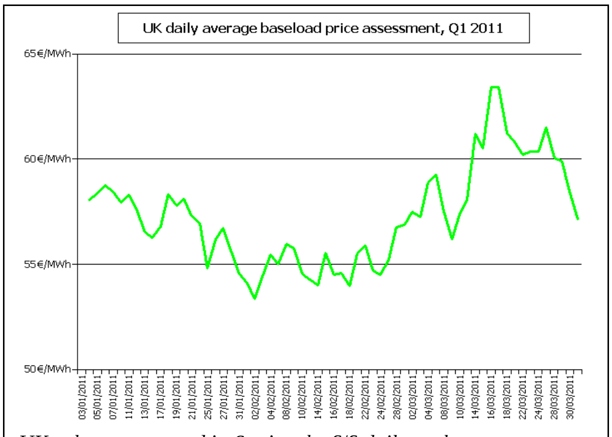
In January 2011 UK monthly average baseload power prices started to retreat from their two year highs measured in the preceding December. The average power price in the first month of 2011 was 57.2 €/MWh, 11 €/MWh lower than in December 2010. In February 2011 monthly average prices decreased a bit (to 54.9 €/MWh) and in March they were up again (59.5 €/MWh).



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

Source : Platts.

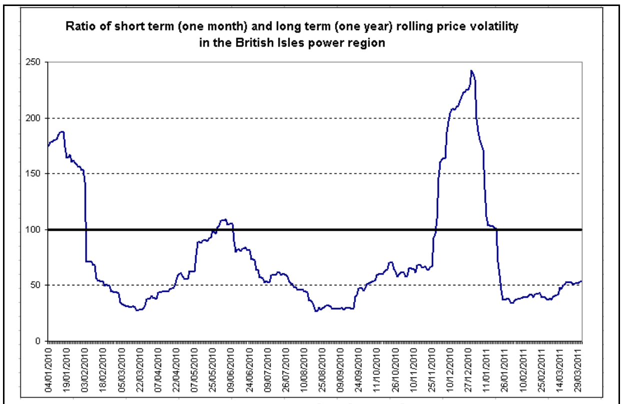
The next chart about the evolution of the UK day-ahead baseload power prices on a daily basis in Q1 2011 shows that in January 2011 prices were on a downward path. This must have been related to the relatively mild weather, decreasing gas and coal prices and the abundant power supply in the grid, which was also reinforced by the restart of some nuclear reactors. The lowest daily average price was recorded on the 2nd of February (53 €/MWh). From the second half of February 2011 as the Middle East tensions exerted an upward pressure on oil and gas prices, as the maintenance works began on the UK-France interconnector[8] and as the weather turned to colder than usual UK power prices began to rise steadily. They reached their peak in Q1 2011 on the 16th of March (63.4 €/MWh); on the week following the nuclear incident in Japan (that helped to lift gas prices) and after the announcement of the German government of its plans about temporarily halting some nuclear reactors.



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

Source : Platts.

In the remaining part of the first quarter of 2011 prices retreated as market tensions eased and natural gas prices went down.

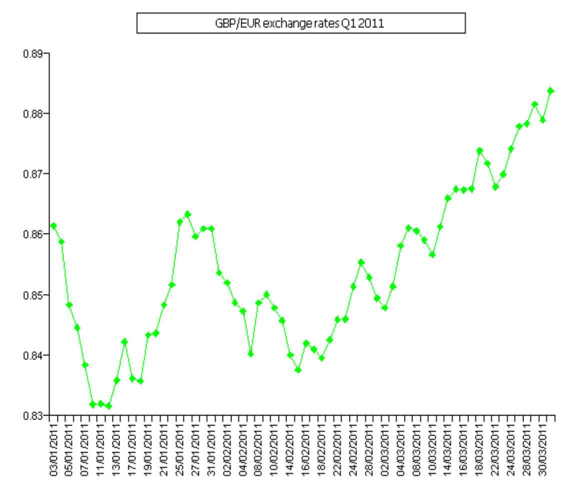


Source: Power price and volume data, own computations.

The relative volatility index of the UK power market returned to lower levels after reaching a three year high at the end of 2010. After extreme price movements in December 2010 the first quarter of 2011 brought a calmer period, although in March the market became more volatile again.

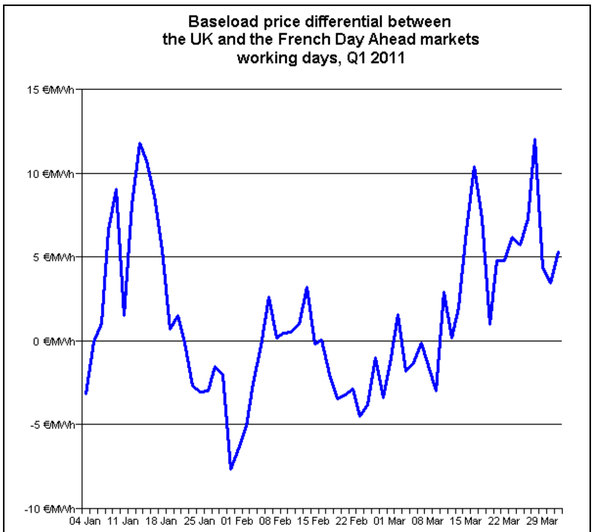
The increase in UK power prices in the second half of Q1 2011 measured in euros was also helped by the appreciation of the UK pound compared to the euro. While in mid-February 2011 the GBP/EUR exchange rate was slightly above 0.83, by the end of the quarter it rose to 0.88.

[8] The UK-France interconnector is a HVDC link with a capacity of 2000 MW. The ownership is shared between the National Grid and Réseau de Transport d'Electricité. It is 70 km long, with 45 km under water. (Source: National Grid)



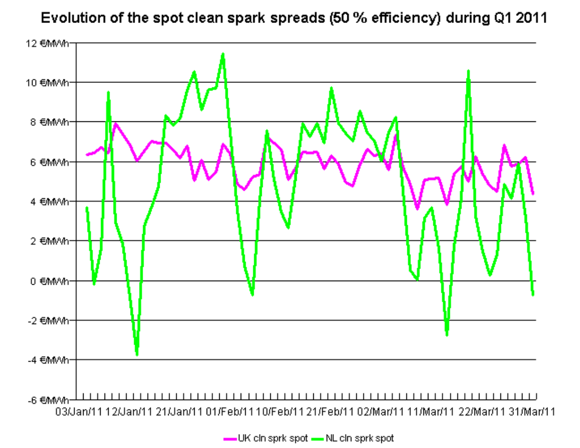
Source : ECB.

The next chart shows the evolution of the UK power price premium to the French market. In the consequence of cheap UK power prices the premium turned to discount in early February 2011. Afterwards, as UK prices started to increase the premium reappeared and started to grow. As UK indigenous power generation is primarily based on natural gas the rapid increase in the price of this fuel in the second half of Q1 2011 resulted in an increase in UK power prices that outnumbered those of France.



Source : Platts

The UK clean spark spread[9] was relatively stable in the first quarter of 2011, varying between 4-8 €/MWh. In the first half of the quarter UK power prices decreased which was accompanied by slightly decreasing gas prices on the NBP hub and increasing CO_2 emission prices. These all resulted in decreasing clean dark spreads. In the second half of the quarter all of these three factors (power, gas and emission prices) started to rise and as the price rise in the latter two factors outnumbered that of the rise in power prices, clean dark spreads continued to go down. On some trading in mid-March days they fell below 4 €/MWh, reaching their minimum during Q1 2011.



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

Source : Platts

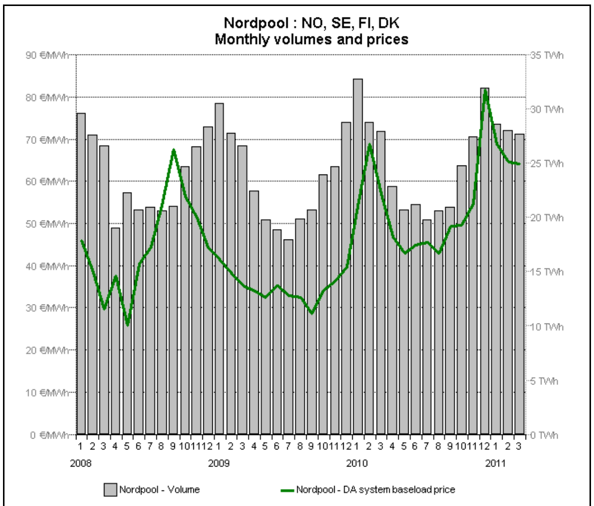
[9] Spark spreads are indicative prices showing the average difference between the cost of gas delivered on the gas transmission system and the power price. As such, they do not include operation, maintenance or transport costs. The spark spreads are calculated for gas-fired plants with standard efficiencies 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.

In contrast, Dutch clean spark spreads showed a high degree of volatility, primarily owing to the higher volatility of the Dutch daily power prices and their lower correlation with natural gas and emission prices.

Northern Europe

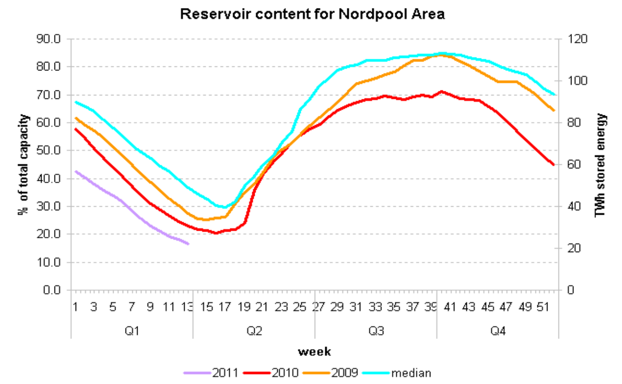
On Nordpool the average monthly baseload price decreased from its peak in December, from 81.7 €/MWh to 68.9 €/MWh in January. This price level was equal to the previous record level in February 2010 (see the report on Q1 2010 for a detailed explanation of the events during that time). In March the monthly average fell to 64.2 €/MWh, still being one of the highest observed price levels.

The sum of the traded volumes reached 84.4 TWh in Q1 2011, which was below the traded volume during the same period in 2010, but close to the volumes in 2009 and 2008. Nevertheless, the entire traded volume of five countries in the Central-Western Europe was 86 TWh in Q1 2011. Nordpool remains among the most liquid European power markets.



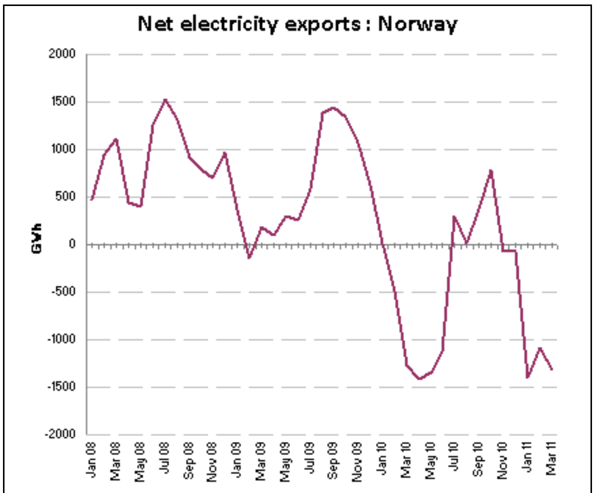
Source : Platts.

The high prices in Q1 2011 and especially in January 2011 were a result of low temperatures and low hydro levels. The total number of actual heating degree days in Denmark, Finland, Norway and Sweden was lower in Q1 2011 than in Q1 2010 (8379 vs. 9002) but higher than in Q1 2009 (7931 actual HDDs). The number of HDDs was in February slightly higher than in January, also due to the cold snap in the second half of February. At that time the Nordpool baseload grew to 69 €/MWh (whereas the monthly average in February was 64.5 €/MWh).



Source : NPS

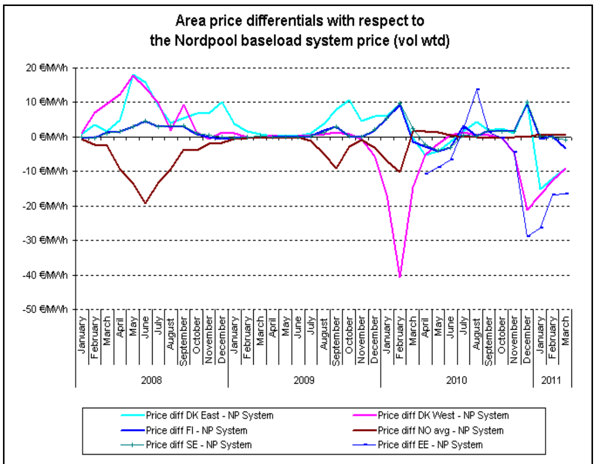
The reservoir content was even lower than a year ago, when it contributed considerably to the tight conditions in the system. This had serious implications especially on Norway, which relies almost completely on hydropower. Combined with high demand, Norway imported a net volume of 3.8 TWh in Q1 2011 (measured in physical flows), reaching the previous record net imports from 2010.



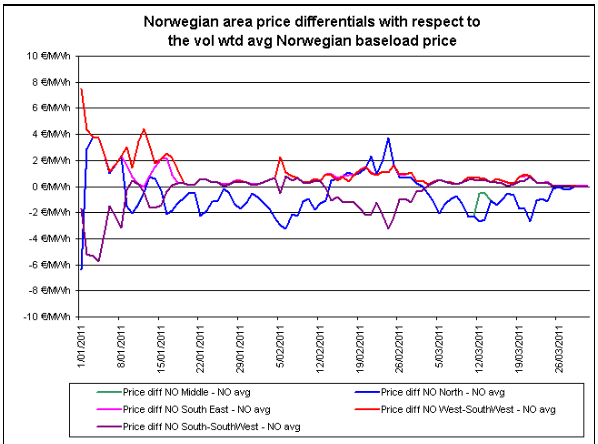
Source : ENTSO-E Vista

The high prices in Norway reflected this situation as well. They were above the average Nordpool system price during the entire quarter. The monthly difference was at the highest in January (0.9 €/MWh). Within the country the prices were above average in the price areas where there is in general more demand, i.e. in southern part of the country. The Northern and Central zones were priced at discount with regard to the Southern prices areas. This discount can be additionally supported when the hydro level is high in those areas.

High prices were also observed in Sweden and Finland, whereas in Estonia and Denmark the prices were below the Nordpool average. To some extent this can be explained with the fact that these countries were less affected by the low precipitation on Scandinavian Peninsula.

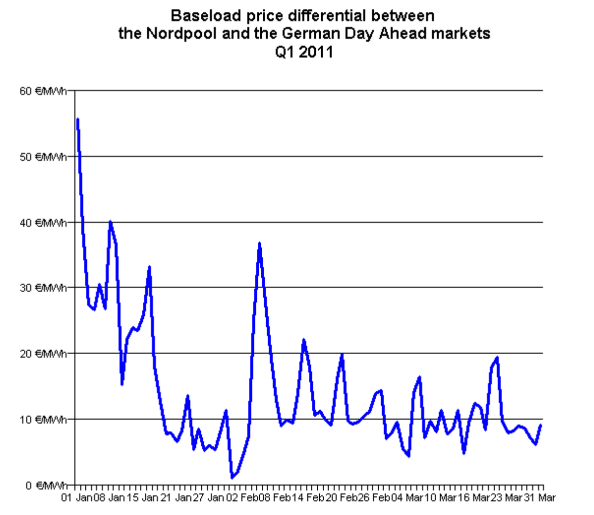


Source : Platts, NPS.



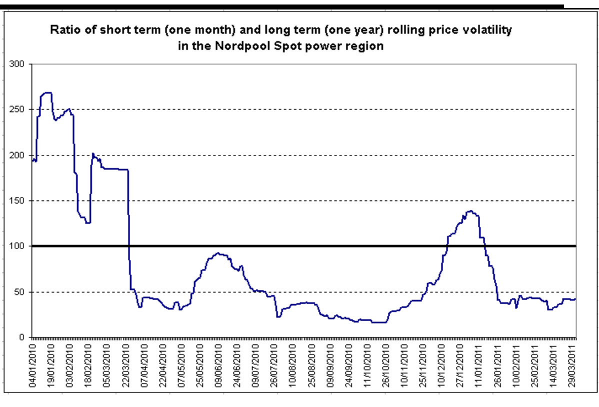
Source : NPS

As a result of unfavourable generation conditions on one hand and low temperatures on the other hand, the Nordpool baseload was traded at a premium to the German baseload throughout the whole quarter. Actually, the tight situation on Nordpool began already in the previous quarter and the premium had been in place ever since the beginning of November 2010. The preliminary data show that the discount reappeared only in April 2011.



Source: Platts.

The volatility which was high in the Nordpool Spot power region by the end of 2010 and in the first two weeks of January 2011 began to decrease gradually from mid January and stabilised on lower levels as the system price fluctuated in a range of 60-70 €/MWh in most of the first quarter of 2011.

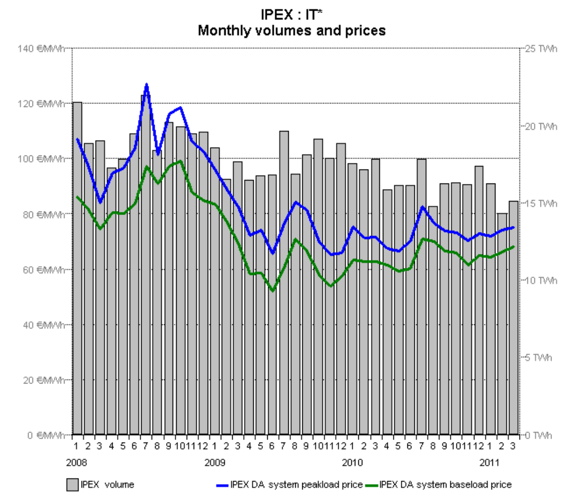


Source: Power price and volume data, own computations.

Apennine Peninsula

Italy

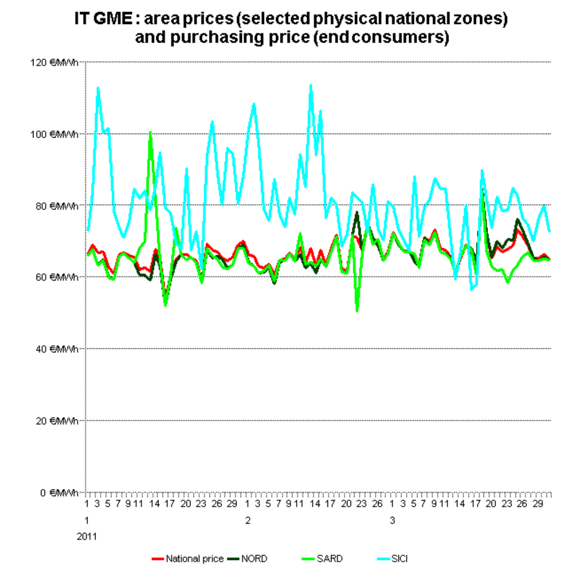
On IPEX the average monthly baseload price increased from December 2010 to March 2011 by 4.9% and the peakload price by 3.1%. The traded volumes decreased, most notably in February when they dropped by 16% year-on-year. As it seems this was to some extent related to the consumption in Italy which also dropped within the same period. The number of HDDs in February 2011 was 320.8, whereas in February 2010 it was 325.4.



Source : Platts.

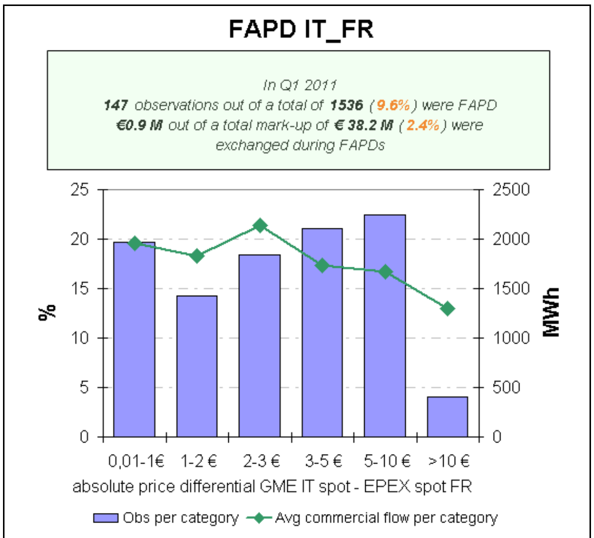
** Trade on Italian (IPEX) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

On average the Italian baseload price was in this quarter 14 €/MWh above the baseload price in Central-Western Europe, with all Italian area prices exceeding the average CWE price. The highest and the most volatile prices were once again registered in Sicily which was constantly above the national average, suggesting that the island may need further integration with the mainland. On average the Sicilian price was in Q1 2011 15 €/MWh above the national price.



Source : Gestore mercati energitici.

On Sardinia, the second important island, the prices had often been above the national average as well. However, in this quarter they were much closer to the national price, on average being 0.7 €/MWh below it. This can be partly explained with the new interconnector between Sardinia and the mainland called SAPEI, which became operational in this quarter[10].

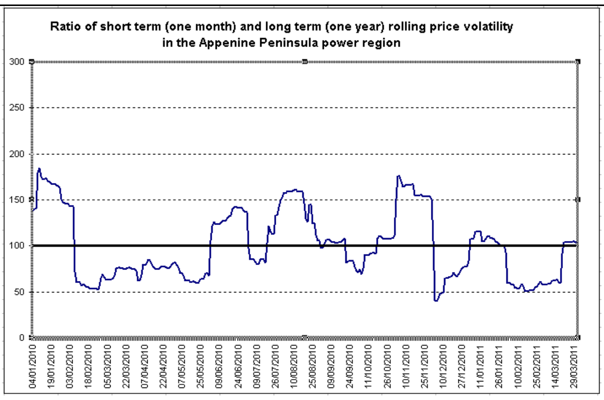


Source : Platts.

The number of observed adverse flows on the Italian-French border decreased considerably in Q1 2011. Consequently there were less than 10% of adverse flows in this quarter (compared to 30% in Q4 2010). The structure of the adverse flows changed as well. Whereas in Q4 2010 the majority of them were above the price difference of 3 €/MWh, this time most of them were below it. Nevertheless, the amount of adverse flows at the price difference higher than 3 €/MWh remains unusually high. This distribution confirms the importance of integration of the Italian market with the neighbouring countries.

Volatility on the Italian market decreased below its long term value at the beginning of the first quarter of 2011. By the end of March 2011 the RVI indicator was above 100 again, showing an increasing volatility at the end of the quarter. This was mainly due to a temporary price jump on the 18th of March, resulting in a daily average price higher by € 22/MWh compared to the previous day. On the following trading day the daily average price returned to the preceding levels.

[10] The first cable of SAPEI (meaning Sardegna-Penisola-Italiana – Sardinia-Italian Peninsula) was officially inaugurated on the 17th of March 2011 (with testing being carried out before this date). The investor and operator is the Italian transmission system operator Terna. With 435 km it is the longest submarine cable in the Mediterranean, reaching maximum depth at 1640 m. Together with the second cable the connection will have a total capacity of 1000 MW at 500 kV *(Source: Terna).*



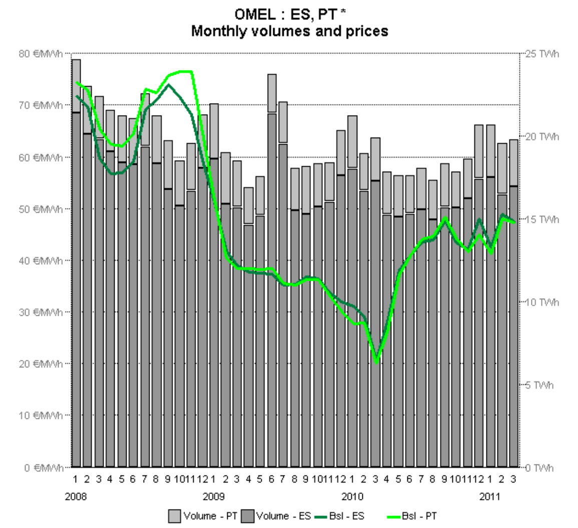
Source: Power price and volume data, own computations.

Iberian Peninsula

Spain and Portugal

The baseload prices on the Iberian Peninsula moved somewhat differently than the European average. After the drop in January, which was also observed elsewhere, the prices reached a new peak in February followed by a drop in March. In Feburary the Spanish monthly average grew to 48.8 €/MWh, the value last seen in January 2009. The Portuguese monthly average incrased to 47.9 €/MWh in the same month, but it did not exceed the peak in September 2010, when it stood at 48.4 €/MWh.

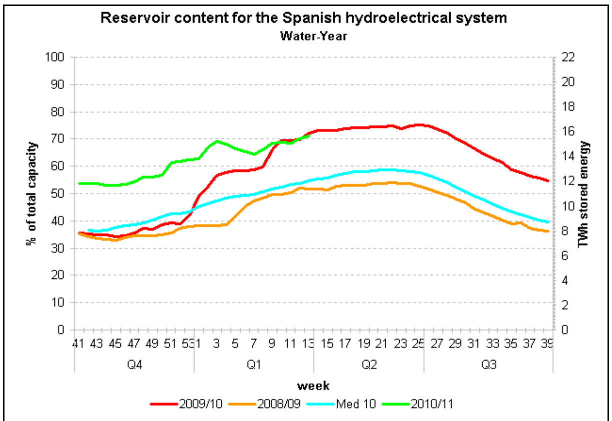
The OMEL prices were below the European and CWE prices most of the quarter. The Iberian Peninsula registers less heating degree days during the winter time, but the reservoir content of the hydroelectrical system was also above the average.



Source : Platts.

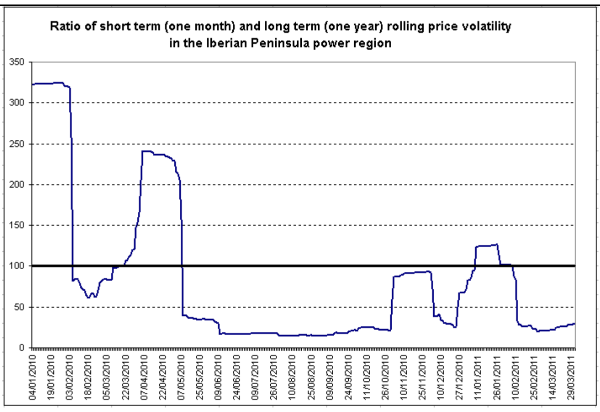
** Trade on Italian (IPEX) and Iberian (OMEL) electricity markets is incentivised by regulatory means.*

The increase in monthly average was related to the price growth which began already at the end of January and lasted till mid-February. The reason for it was a drop in temperatures, but also fluctuations in wind and hydro production. Although the reservoir content was in general favourable, it dropped slightly in the middle of the quarter due to less precipitation. As a consequence the Spanish producers had to increase the more expensive production in gas-fired power plants.



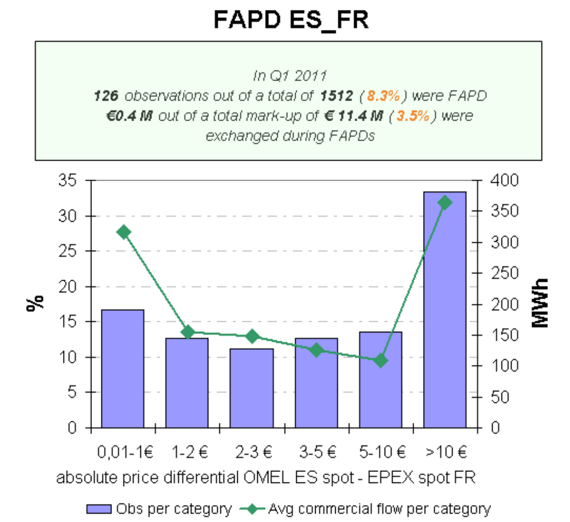
Source : Ministerio de Medio Ambiente, y Medio Rural y Marino, Gobierno de España

The short term volatility in the Iberian Peninsula power region was generally lower than that long term suggested in Q1 2011, with the exception of the first two weeks of January.



Source: Power price and volume data, own computations.

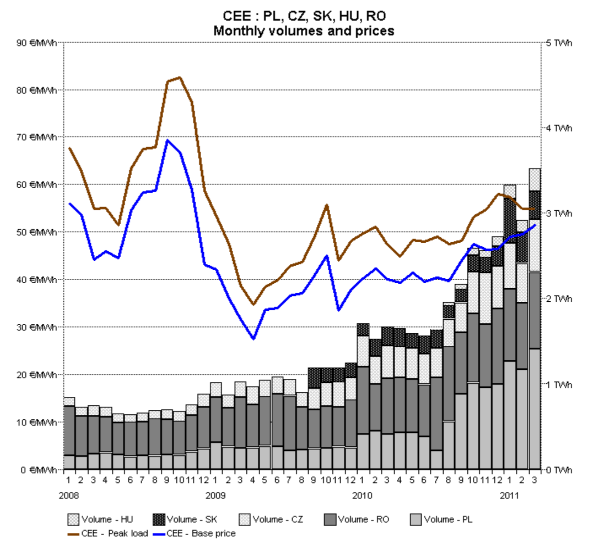
The share of observed adverse flows between Spain and France decreased considerably when compared to Q4 2010, with less than 10% of observations counting as adverse flows. On the other hand, the structure of the observations per category remained very similar. Up till the price difference of 10 €/MWh the observations were almost evenly distributed per category, whereas the adverse flows with the largest price difference represented the highest share of these flows. This is a peculiarity rarely seen on other borders and this report is going to continue to follow these developments. As it appears some of these events coincide with drops in Spanish wind power production.



Source : Platts.

Central Eastern Europe

The next chart shows the monthly traded-volume-weighted baseload and peakload prices in the Central Eastern Europe region and the evolution of the traded volumes on the Polish, Czech, Slovak, Hungarian and the Romanian markets.



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

In the first quarter of 2011 the traded volume of power grew by 24% compared to Q4 2010 and it was up by 99%

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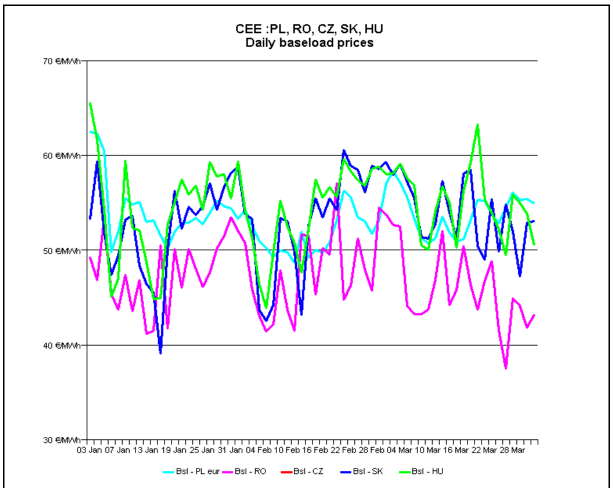
compared to the first quarter of 2010. This remarkable increase was mainly due to the change in the power trading regulation on the Polish market in the summer of 2010, however, the other four markets also showed a dynamic growth. The combined power traded volume of these five markets was 9.8 TWh in Q1 2010, which equalled almost 10% of the gross inland electricity consumption in these countries.

In March 2011 monthly wholesale baseload prices reached their highest level since early 2009. With the exception of Poland prices were higher in this month than in December 2010. The most significant price increase between December 2010 and March 2011 could be observed in Romania where prices went up by 46%. This was mainly due to a correction of relatively low prices measured by the end of 2010, primarily owing to the favourable impact of high hydro reserve levels in South Eastern Europe. These hydro reserve levels began to diminish in the first month of 2011 that helped to drive up Romanian power prices.

Monthly average baseload power prices (€/MWh)			
2011	January	February	March
Hungary	50.0	51.1	53.9
Poland	53.3	51.5	53.4
Czech Republic	47.8	50.0	53.1
Slovakia	47.8	50.0	53.1
Romania	44.1	45.7	46.0

In spite of this rapid price increase in Romanian power prices in Q1 2011, the price discount to other Central European markets prevailed; mainly due to a well-supplied domestic market and bottlenecks in power exports to the neighbouring countries.



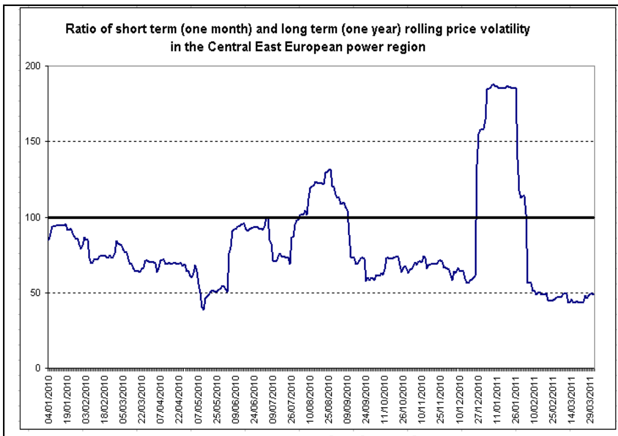
Source : TGE (PL),OTE(CZ, SK), OPCOM(RO), HUPX(HU)

Romanian prices were normally the cheapest among the observed five markets while Polish and Hungarian power prices were at the top in the region.

Both Czech and Polish prices closely followed the German prices. Short term price movements could usually be explained by wind and solar power generation forecasts in Germany. In January 2011 higher coal prices exerted an upward pressure on power prices in both Poland and the Czech Republic. From mid-February, as the political tension escalated in the Middle East, oil and gas prices began to soar which also put power prices on an upward trajectory on many European markets. After the Fukushima nuclear incident in Japan and the decision of the German government to halt seven nuclear power plants for three months (see the "*Focus on*" part on page 33) power prices turned up again. Nevertheless, day-ahead prices remained relatively stable compared to forward contracts (see page…).

The power inflows from South East European countries could also temporarily influence power prices in the region during some short periods. As Hungary is situated in the neighbourhood of the Balkans, power inflows from that region could put a considerable downward pressure on Hungarian power prices during the last week of March 2011. Decreasing Romanian prices in the second half of March could also be explained by power inflows from the Balkan countries.

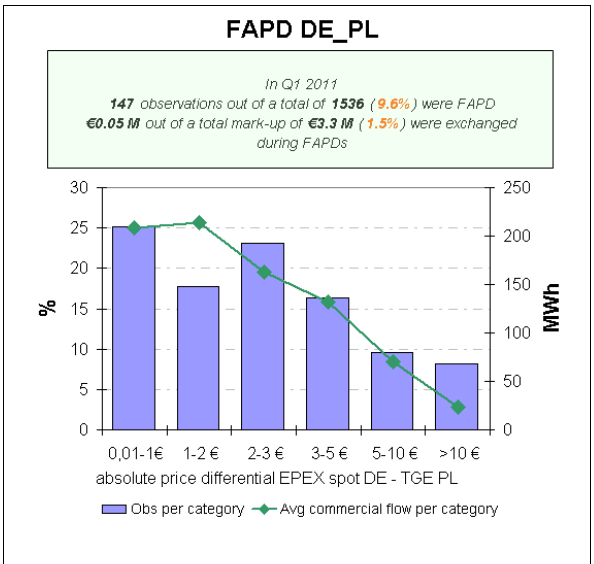
The relative volatility index in the CEE region that jumped to high levels in the last couple of days in December 2010 in the consequence of lower prices during the Christmas period, returned to usual levels by the end of January 2011. Lower volatility might be explained by the lack of tight supply margins in the power grids (and by less intensive sudden price changes). The impacts of the Middle East events and the Fukushima crisis with its aftermaths on European power generation exerted a minor impact on day-ahead prices in the region. These market developments rather inflicted significant price changes on the forward markets (see page 24).



Source: Power price and volume data, own computations.

As German power prices are pivotal to the markets of the CEE region, the next two charts show the frequency of the reverse power flows between the German and some regional markets. The existence of the FAPDs clearly indicates that Polish and Czech power markets' prices are not fully aligned with those in Germany and the Central West European power region.

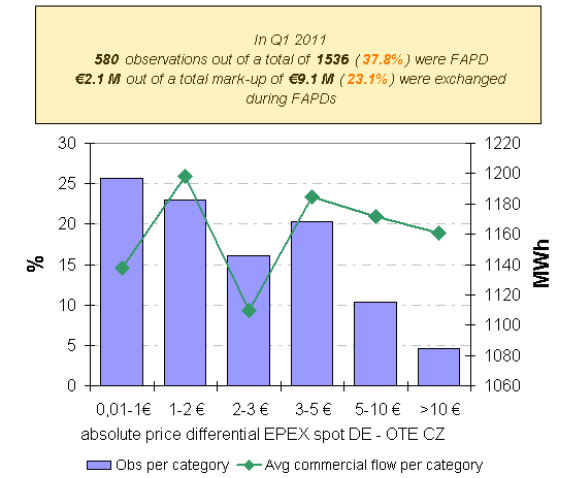
In the case of Polish-German FAPD relation only 10% of the flows could be considered as reverse flows, however, significant amount of reverse flows exist in each price differential category. The average amount of reverse flow power is lower in the higher price differential ranges, which is something that could be expected under normal competitive conditions.



Source : Platts

In the Czech-German power flow relation FAPDs are of higher importance than in the case of Polish-German relation. Almost 38% of all hourly observations were FAPDs while expressed in monetary terms 23% of all price mark-up was traded during reverse flows.

FAPD DE_CZ



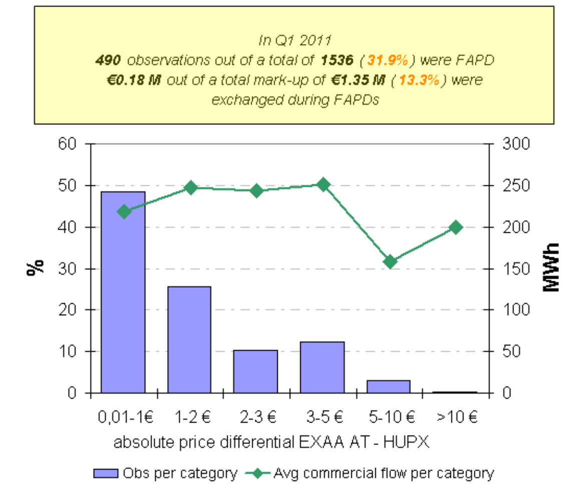
Source : Platts, OTE

As Poland is more affected by the so-called loop flows from the German grid arising from the excess renewable energy based power generation, Polish day-ahead power prices are generally more aligned to those of the German market. In contrast, the Czech-German market relation is predominantly based on the Czech power export to Germany.

In Q1 2011 the Czech power export to Germany amounted to 2.7TWh, while German export to the Czech Republic was less than 0.05 TWh. During the same period the German power export to Poland amounted to 0.86 TWh and the Polish power export to Germany was 0.12 TWh.

The higher share of FAPDs in the Czech-German relation can also be explained by the fact that while the Czech-German daily price differential hovered around zero during most of the time in Q1 2011, the Polish-German price differential remained mostly in the positive range.

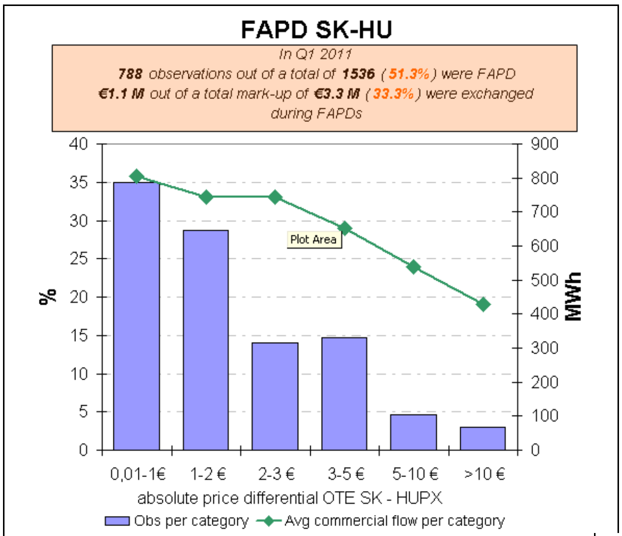
FAPD AT_HU



Source :Platts, HUPX

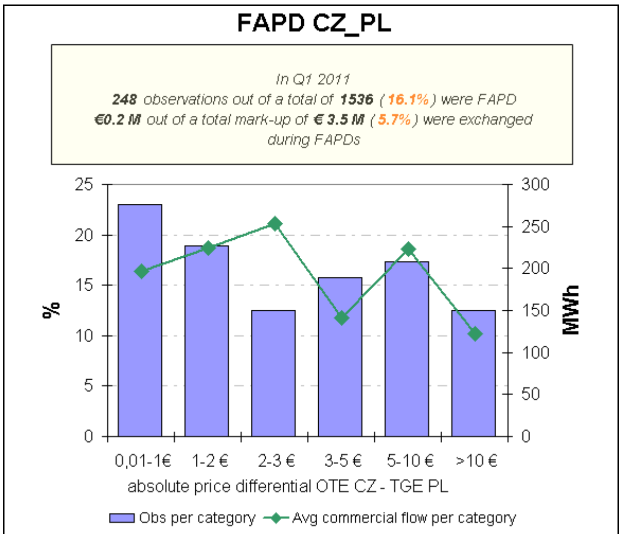
The share of FAPDs in the Hungarian-Austrian power market relations (32%) in the first quarter of 2011 could also be deemed relatively high. The overall majority of the hourly FAPD flows was concentrated in the lower price differential ranges (0-2 €/MWh). This coincides well with the evolution of the day-ahead price differential, being mostly close to zero during the whole Q1 2011. Power flows between the two countries can be characterised by a Hungarian export surplus (0.25 TWh Hungarian power exports to Austria vs. 0.11 TWh power imports).

In the Slovak-Hungarian power flow system, where the ratio of FAPDs were the highest in the region compared to the number of the total observations, low power price differentials played a key factor in Q1 2011.

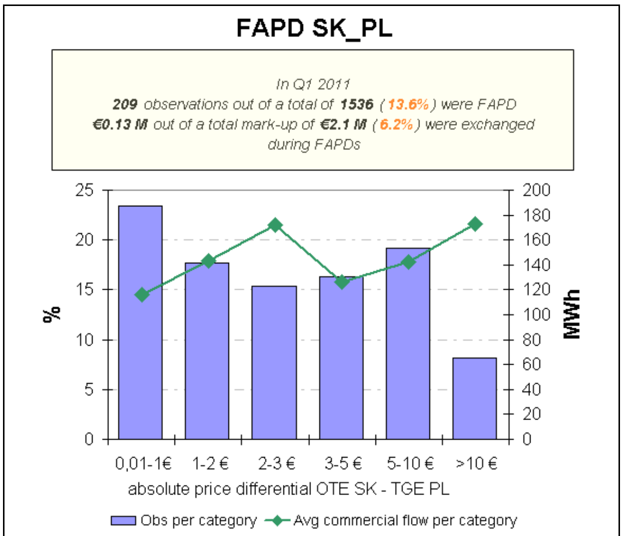


Source :HUPX, OTE

In the first quarter of 2011 in the Czech-Polish and in the Slovak-Polish flow system FAPD ratios were lower and the price differentials were higher than in the previous two cases. The distribution of FAPDSs among price differential ranges was more even than in the case of the Hungarian-Austrian and Slovak-Hungarian reverse flow relations.



Source : OTE, PolPX,



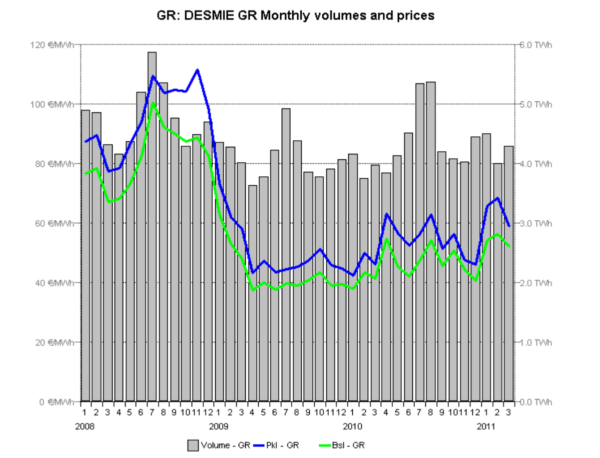
Source : OTE, PolPX

In the first quarter of 2011 no adverse power flows could be observed in the Hungarian-Romanian trade relation.

South Eastern Europe

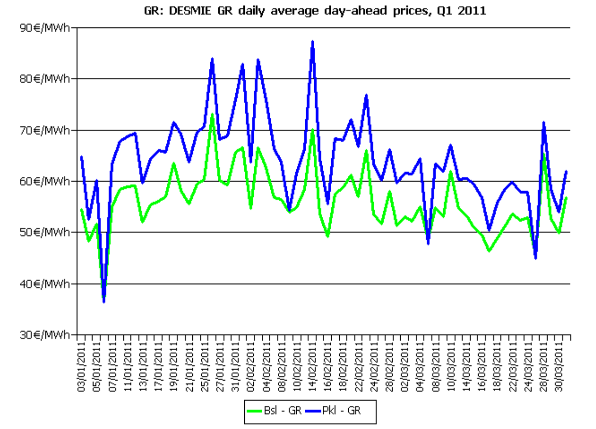
Greece

At the beginning of 2011 Greek wholesale power prices started to increase after twelve month lows measured in December 2010. Both monthly average baseload and peakload power prices rose by 28% between December 2010 and March 2011; reaching a peak in February 2011 (56.5 €/MWh and 68.4 €/MWh, respectively). In March 2011 power prices retreated compared to the February peaks.



Source : Platts.
** Trade on the Greek mandatory pool (DESMIE) is incentivised by regulatory means.*

The significant increase in power prices in Q1 2011 must have been influenced by decreasing hydro power generation. According to the data of the Greek Regulatory Authority for Energy (RAE) monthly power generation from hydro amounted to 942 GWh in December 2010 while in February and March 2011 it dropped below 300 GWh. In practice it means that the share of hydro decreased from 22% to 7% in the power generation mix in the December 2010 –March 2011 period. As a large share of hydro power is 'mandatory hydro' (which enters the market in a compulsory, non-priced, way and hence exert a suppressing effect on prices), decrease in hydro generation eliminated the oversupply from the grid and hence helped in lifting the prices. The share of renewable sources other than hydro in the power mix was also down from 5% in December 2010 to 2.7% in March 2011 mainly due to the drop in wind power output.

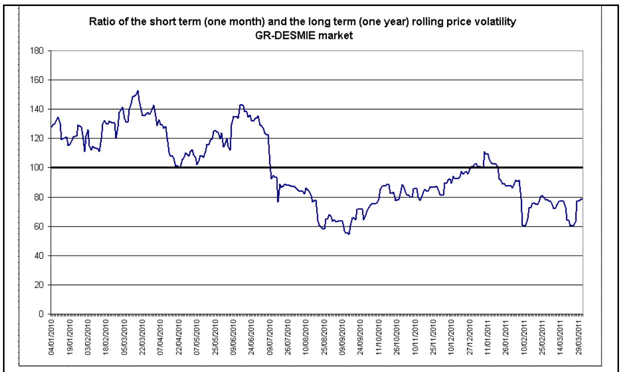


Source : Platts.

Besides current changes in the power mix the dominant power generation utility (PPC) probably intended to smooth the amount of hydro-based power generation throughout the year by using hydro reserves during the dry (summer) period, hence reducing the hydro generation in the first quarter of 2011.

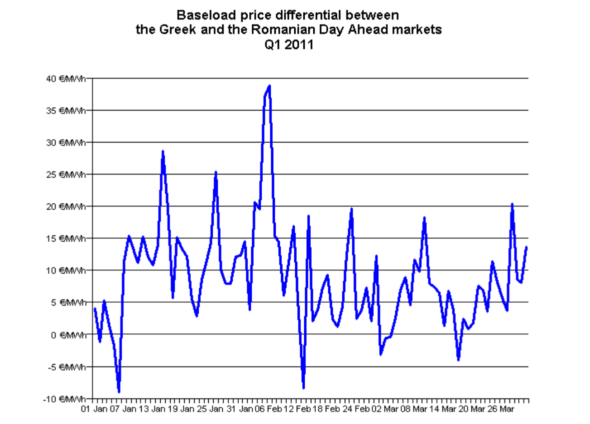
Looking at the chart of the daily power price evolution the upward trend culminated at the end of January with a daily baseload price of 73 €/MWh. The highest peak-load price could be observed on the 14th February (87 €/MWh). In the first half of February 2011 the gap between daily baseload and peakload power prices significantly widened; the reduction in hydro supply must have affected peakload prices more deeply. In the second half of the quarter daily power prices rather tended to decrease compared to their mid-quarter highs.

The Greek RVI indicator began to decrease after climbing above its long term level in the early days of January 2011. Decreasing trend of power prices was accompanied by less volatility as the reduced share of hydro power generation stabilised in the second half of Q1 2011.



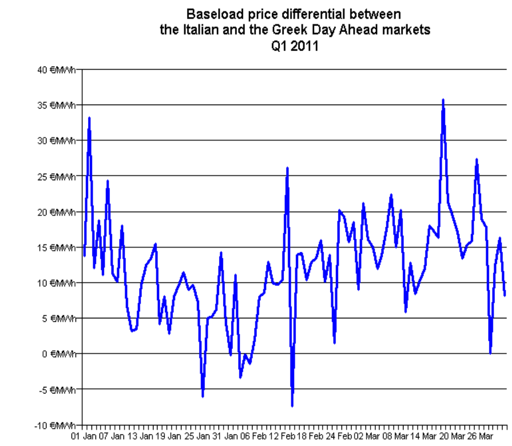
Source: Power price and volume data, own computations.

As Romanian prices remained stable and relatively low compared to their Greek counterparts in the first half of Q1 2011 and Greek prices were on an upward trajectory, the Greek price premium amounted to almost 40 €/MWh in the first week of February 2011. Following the retreat of Greek prices this premium began to diminish, but in the last week of March 2011 as Romanian prices moved to even lower levels it began to rise again.



Source : DESMIE, OPCOM s.a.

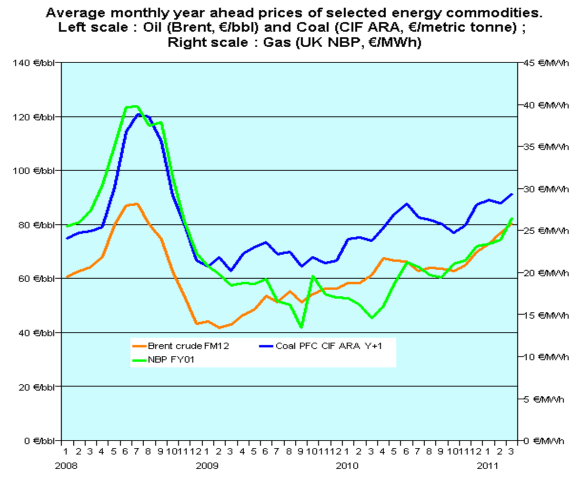
The increase in Greek power prices in January 2011 also reduced the Italian price premium, on some days the latter prices were even traded on a discount. From February 2011 the Italian premium returned in parallel with decreasing Greek prices.



Source : IPEX, DESMIE.

A.1.2 Forward markets

In the first quarter of 2011 the general upward trend of the year-ahead prices of energy commodities that started in the autumn of 2010 still prevailed. Year-ahead coal, oil and natural gas prices reached their highest levels since the fourth quarter of 2008.



Source : Platts.

One reason of the permanent rise in commodity prices was the good performance of the European economy that helped to boost demand for energy commodities. This growth of demand exerted an influence on both spot and forward fuel prices.

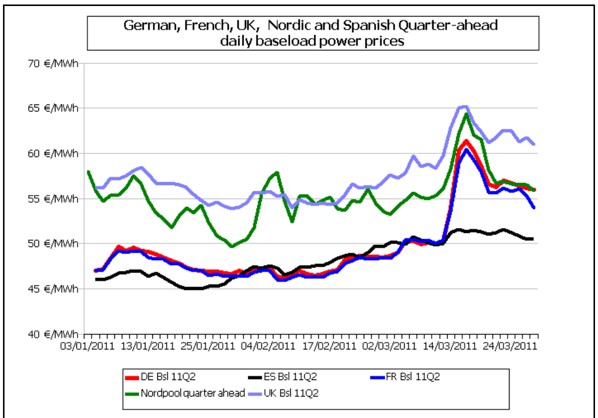
The other macro-economic factor that might have contributed to the rise in commodity prices was the supportive monetary policy conditions in many developed countries, providing a stimulus through increasing supply of money.

More specifically, the increase in coal prices was influenced by the serious floods on Australia's coal-mining sites (mainly in Queensland) in January 2011 that reduced the global supply of coal. Although the floods later retreated, coal prices remained on higher levels.

Crude oil prices were mainly influenced by the political tensions in the Middle East and by the supply disruption from Libya that put pressure on prices since mid-February 2011.

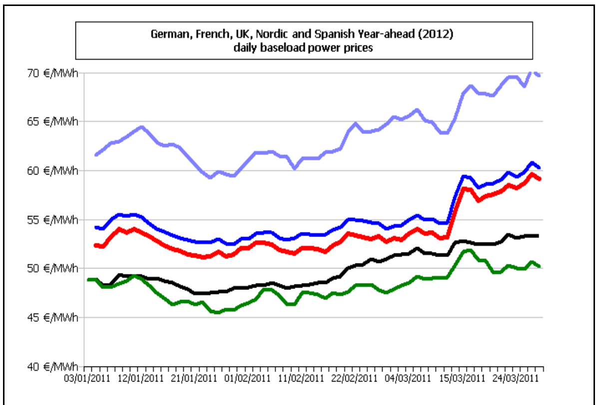
Natural gas prices were generally moving in parallel with the increasing oil prices. Besides the factors that affected the price movement of crude oil gas prices were affected by the nuclear incident in Japan through the increased demand for LNG shipments, being as a substitute fuel for nuclear-based power generation in that country.

As the next two charts show increasing fuel prices had a clearly observable impact on quarter-ahead and year-ahead power prices on many European markets until mid-March 2011.



Source : Platts.

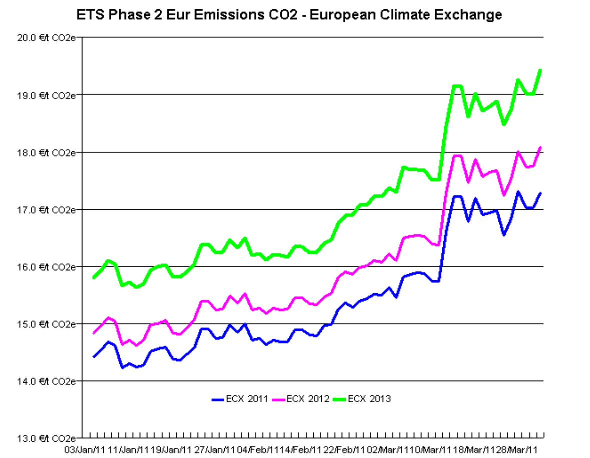
However, the decision of the German government about the future of nuclear power generation in mid-March 2011 had a direct impact on forward power prices. Quarter-ahead prices showed a steep rise after the announcement of this decision with the exception of Spanish prices, however in the last week of March they retreated a bit. In contrast, year-ahead prices remained on higher levels or rose even further until the end of Q1 2011.



Source : Platts.

Year-ahead prices in Spain and in the Nordpool area seemed to be more resilient to the German policy developments; probably owing to the higher share of renewable sources in their power generation mixes and/or weaker links with the German market.

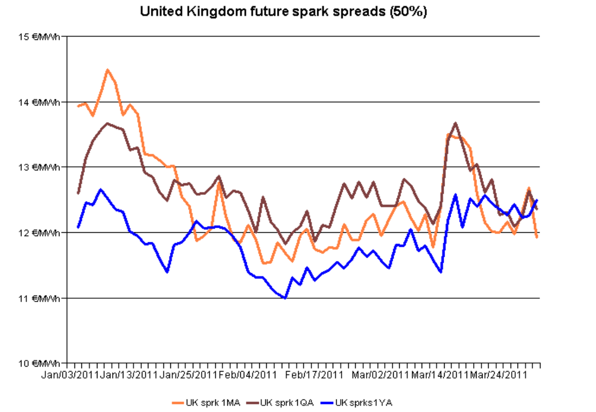
CO_2 emission forward prices seemed relatively stable in the first half of Q1 2011. A substantial rise began from mid-February; following the increasing energy commodity prices. The price jump in emission prices in mid-March 2011 mirrored that what happened to the year-ahead power prices on the majority of the European markets.



Source : Platts.

The decision of the European Commission in mid-January on the temporary closing of the EU emission trading registries for nearly three weeks in consequence of a hacker attack apparently had only limited impact on emission prices.

Decreasing forward power prices and relatively stable gas hub prices in the first month of 2011 contributed to the drop in future spark spreads in the UK. From the beginning of February as power prices started to rise, spark spreads began to slowly increase. The market events already mentioned in previous sections caused a spike in spark spreads in mid-March; the quarter-ahead contract proved to be mostly affected.



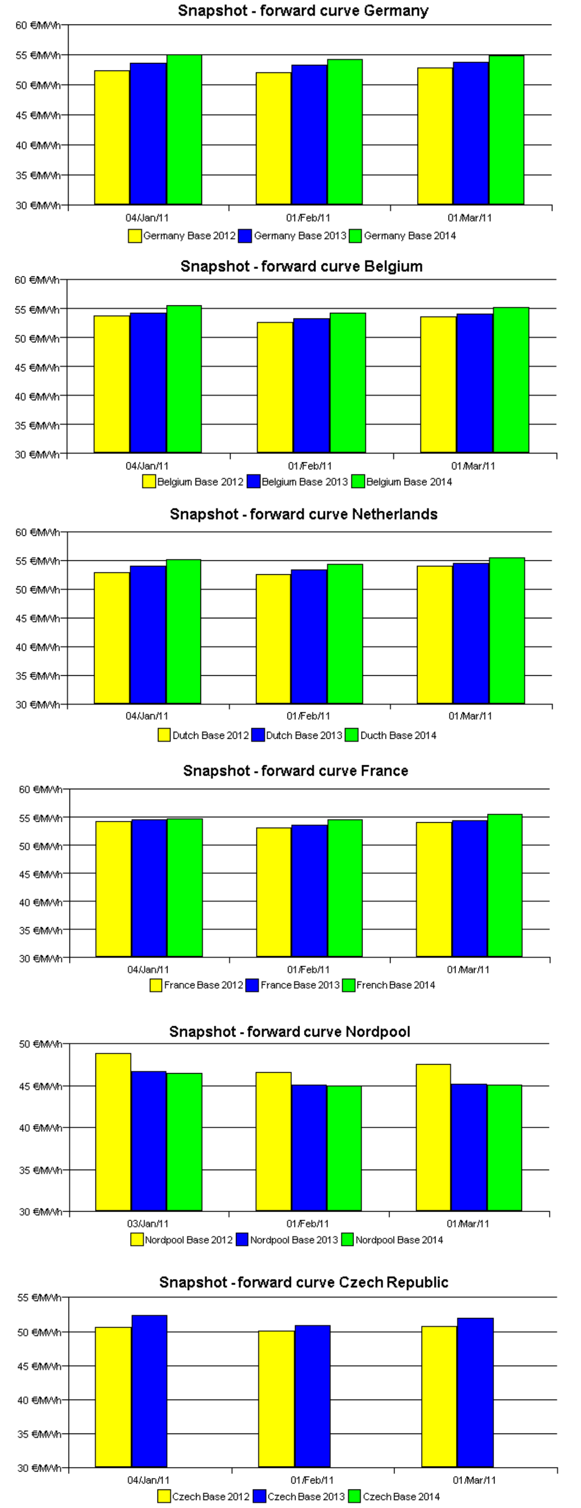
Source : Platts.

On most of the observed markets price curves were in contango[11] on the first trading days of each month in Q1 2011. The exception was the Nordpool power region where extremely high spot prices observed at the end of 2010 began to retreat; exerting a downward pressure on forward contracts.

In February and March 2011 economic and political developments caused rapid increases in forward power prices that turned contango to backwardation[12] on some markets (e.g.: in the UK on the 8th of March 2011 the full power curve was in backwardation). Nevertheless, after the change in the situation of German nuclear based power generation price curves returned to contango in mid-M arch 2011.

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

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



Source : Platts.

A.2 Retail markets[13]

The next two charts show the electricity prices paid by household consumers with an annual consumption between 2.500 and 5.000 kWh and prices paid by industrial consumers that use between 500 MWh and 2.000 MWh annually (consumption bands[14] *Dc* and *Ic* according to Eurostat's consumption categories) in the EU Member States and in Croatia, Norway, Turkey. The first chart shows household prices including all taxes and prices[15] for industrial customer without VAT (gross prices - final prices paid by the consumers), while the second one shows prices without taxes (net prices).

During the first and the second semester of 2010 the ratio between the cheapest and most expensive gross prices for households practically remained stable (at a ratio of 3.3). In the case of the industrial consumers this ratio slightly decreased (from 2.8 to 2.7). In absolute terms the range between the cheapest and most expensive net prices for households and industrial consumers amounted to 19 €cents/kWh and 11 €cents/kWh, respectively.

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13 Eurostat only provides data on retail market prices on a biannual basis. For this reason different annual consumption bands are chosen in each quarterly report in order to provide information on evolution of retail electricity prices for consumers having different annual electricity consumption.

14 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.

15 In order to best represent the final price households and industrial consumers pay prices including all taxes are taken into account for households while for the industrial consumers prices without VAT is given as they are subject to VAT reimbursement.

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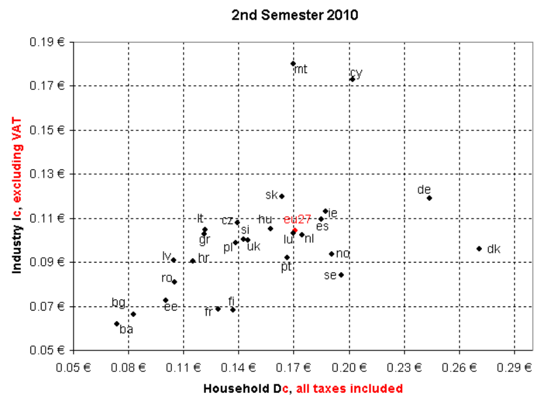
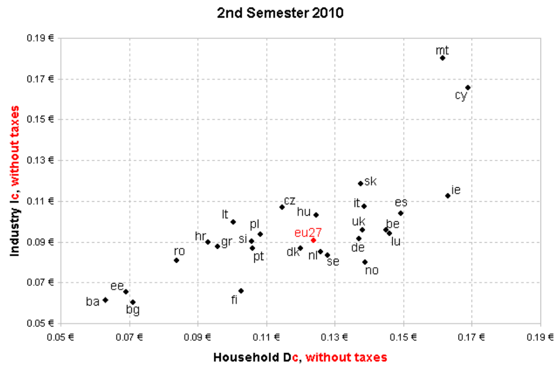


Source : Eurostat
Range for annual consumption of :
Household band Dc : [2.500 kWh – 5.000 kWh] ;
Industry band Ic : [500 MWh – 2000 MWh]

Note: Data for Austria are not available

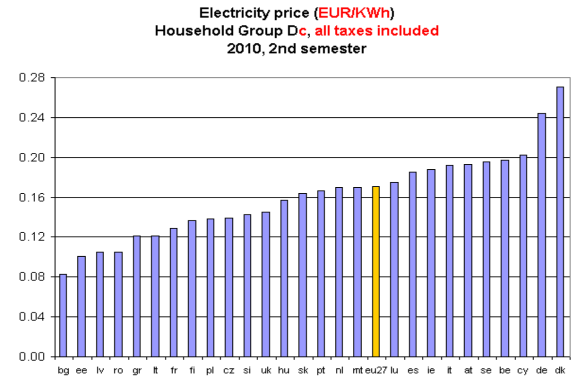


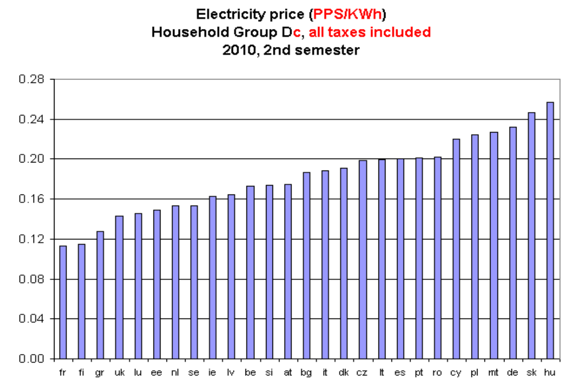
Source : Eurostat
Range for annual consumption of :
Household band Dc : [2.500 kWh – 5.000 kWh] ;
Industry band Ic : [500 MWh – 2000 MWh]

Note: Data for Austria are not available

A.2.1 Price level

In the second half of 2010 the EU-27 average gross price for electricity stood at 16 €cents/kWh for households in the Dc consumption band. Similarly to the previous semester, Denmark and Germany were the EU Member States where household consumers had to pay the most for electricity, being 27 €cents/kKWh and 24 €cents/kWh, respectively. On the other hand, the lowest price was reported in Bulgaria, where households had to pay 8 €cents/kWh.



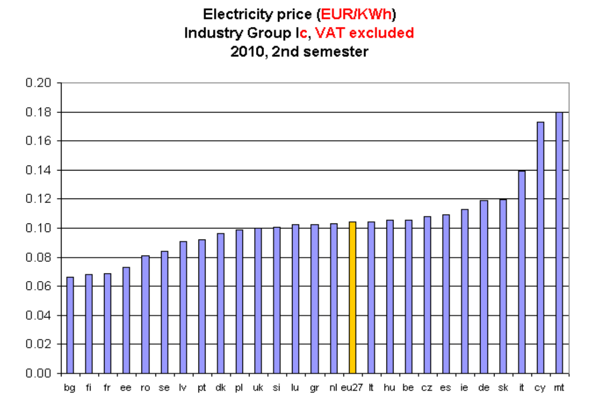


Source : Eurostat
Range for annual consumption of :
Household band Dc : [2.500 kWh – 5.000 kWh];

With the exception of Cyprus (20 €cents/kWh) Member States that joined the EU after 2004 still paid less than the EU average in absolute terms. The weighted arithmetic mean (using the 2010 annual gross inland electricity consumption as weights for each country) for these twelve Member States amounted to 13 €cents/kWh, which was almost 5 €cents/kWh less than the weighted average of the other fifteen EU countries.

However, in Greece, France and Finland household consumers paid less than the average of the twelve selected Member States.

The correction for purchasing power changes substantially the picture about the price ranking order of countries. Amongst the ten most expensive Member States measured in PPS[16], only Germany, Portugal and Spain belong to the group of 'old Member States'. In contrast, amongst the ten cheapest countries only Estonia and Latvia could be found from the group of the twelve new Member States. The PPS correction reduces both the ratio and the absolute difference between the most expensive and the cheapest countries. The price ratio was 2.3 (as opposed to 3.3 without PPS correction) and the absolute difference was 13 €cents/kWh (19 €cents/kWh without correction) in the second semester of 2010.



Source : Eurostat

Range for annual consumption of :

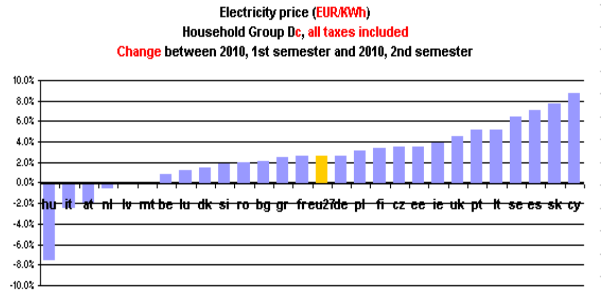
Industry band Ic : [500 MWh – 2000 MWh]

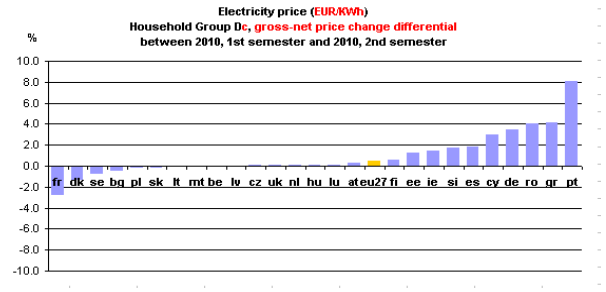
Note: Data for Austria is not available

Industrial consumers paid 10 €cents/kWh (without VAT) in the EU-27 on average. The most expensive prices were reported in Malta (18 €cents/kWh), Cyprus (17 €cents/kWh), and Italy (14 €cents/kWh) whilst the lowest ones could be observed in Bulgaria, Finland and France (slightly less than 7 €cents/kWh for each). High prices in Malta and Cyprus might be related to their geographically isolated nature (islands) while in Italy the traditionally high wholesale prices must have played an important role.

A.2.2 Price dynamics

Electricity prices for household consumers having a middle level annual consumption (band Dc) rose on average by a modest 2.6% in the second half of 2010, compared to the previous semester[17]. However, price developments in the individual Member States were quite diverse.





Source : Eurostat

Range for annual consumption of :

Household band Dc : [2.500 kWh – 5.000 kWh];

Note: Data for Italy are not available

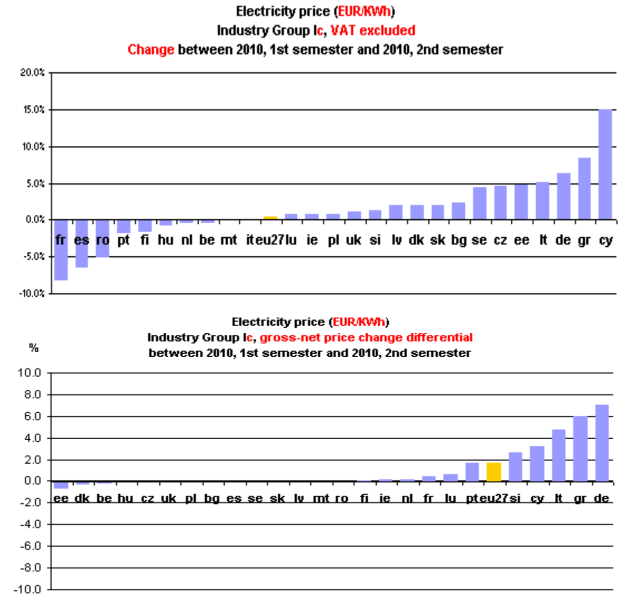
Substantial price increases could be observed in Cyprus (8.8%), Slovakia (7.7%) and Spain (7.1%) In contrast, prices fell in Hungary by almost 8% and in Italy, Austria and the Netherlands prices were slightly lower than in the first half of 2010.

[16] Purchasing power standards

[17] In the remaining part of this chapter, unless otherwise stated, price changes are always compared to the previous semester (1st semester of 2010)

Looking at the chart showing the difference between the evolution of gross and net power prices paid by households, it is reasonable to say that changes in taxation influenced substantially the increase in prices in Portugal, Greece Romania and Germany. The taxation effect added 8% to price growth in Portugal; in Greece and Romania this impact was more than 4% and in Germany it amounted to 3.5%. As the net price increase was lower than this gross-net difference in all of these countries, we can assume that without tax changes prices would have decreased. In Cyprus however, the big rise in prices was primary owing to the increase in net prices, although the impact resulted from the changes in taxation amounted to 3%.

On the other hand, in France and in Denmark changes in taxation helped to mitigate the impact of net price increase (by 2.7% and by 1.2%, respectively). For the remaining countries of the EU this gross-net price increase differential was below two percent, with the weighted EU-27 average standing at 0.5 %.



Source : Eurostat

Range for annual consumption of :

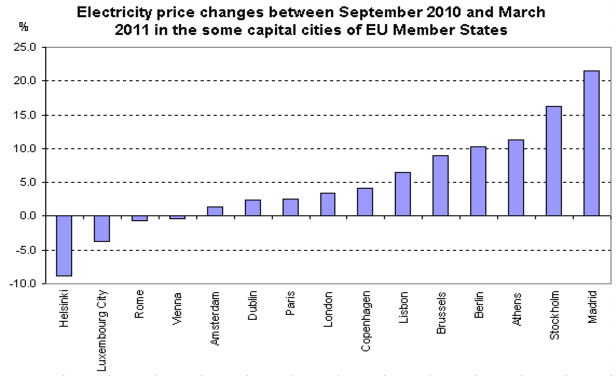
Industry band Ic :   [500 MWh – 2000 MWh]

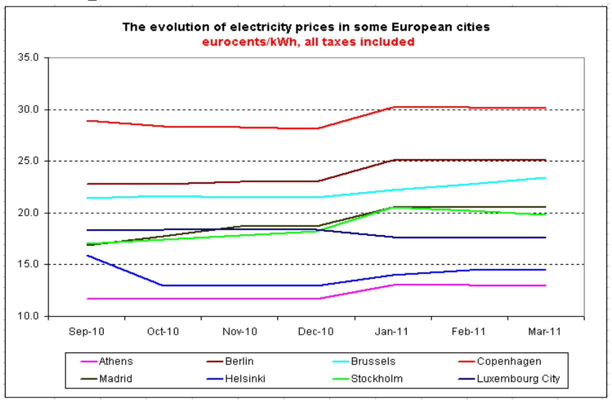
Note: Data for Austria and Italy are not available

Industrial consumers with an annual consumption between 500 MWh and 2.000 MWh (Ic consumption band) across the EU saw only a minor price increase of 0.5 % on average. Again, the developments in the individual Member States have been quite varied. In France, Spain and Romania consumers faced favourable price decreases (8%, 6.3% and 4.9%, respectively), while in Cyprus, Greece and Germany consumers experienced significant rise in prices (15%, 8.5%, 6.3%, respectively).

Similarly to the development of prices for household consumers, there were some countries in which changes in taxation resulted in a gap between the evolution of gross and net prices. The difference was the highest in Germany (7%), Greece (6%), Lithuania (4.7%), Cyprus (3.2%) and Slovenia (2.3%). With the exception of Cyprus, where the price growth for both household and industrial consumers was the highest in EU-27, price increases were mainly due to the changes in taxation in these countries.

The next chart shows the evolution of retail electricity prices paid by households in some European capitals between September 2010 and March 2011. Prices rose in the largest extent in Madrid (21.5%), Stockholm (16.2%) and Athens (11.3%). This coincides well with the price evolution in Sweden and Spain in the second semester of 2010. In contrast, retail power prices went down by 8.8% in Helsinki and by 3.7% in Luxembourg.



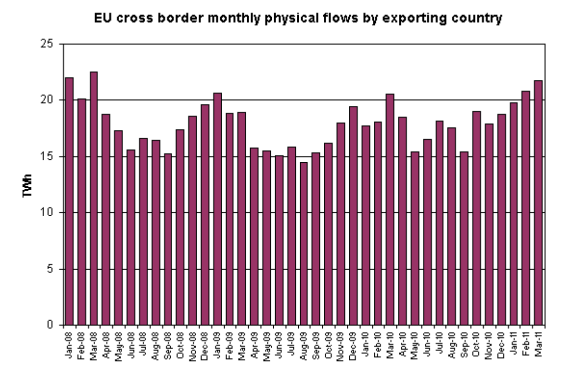


Source: HEPI

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 gas consumer prices in some selected capital cities of EU countries.

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

In the first quarter of 2011 the amount of cross-border power flow was 63.4 TWh, slightly less than 8% of the EU-27 gross inland electricity consumption. In March 2011 the monthly cross border flow volume (21.8 TWh) reached its highest level since March 2008, giving a good signal about the performance of the EU economy.

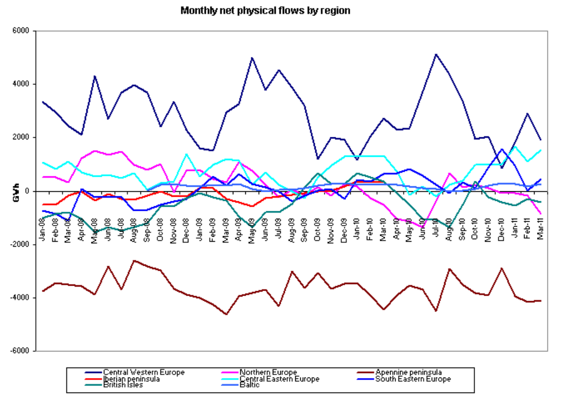


Source : ETSO

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.

In the Central Western European region, where net physical flows reached their lowest level in December 2010 in the consequence of increased domestic use of power, exports rebounded again.

In the Central Eastern Europe the net power export continued to rise (having Western Europe as primary export destination) and reached its three year high (1.55 TWh) in March 2011, providing an evidence for the improved competitiveness of power generation in the region. The main driver behind this competitiveness was the resilience of the regional price level to the general price increasing factors, such as energy commodity prices.



Source : ETSO.

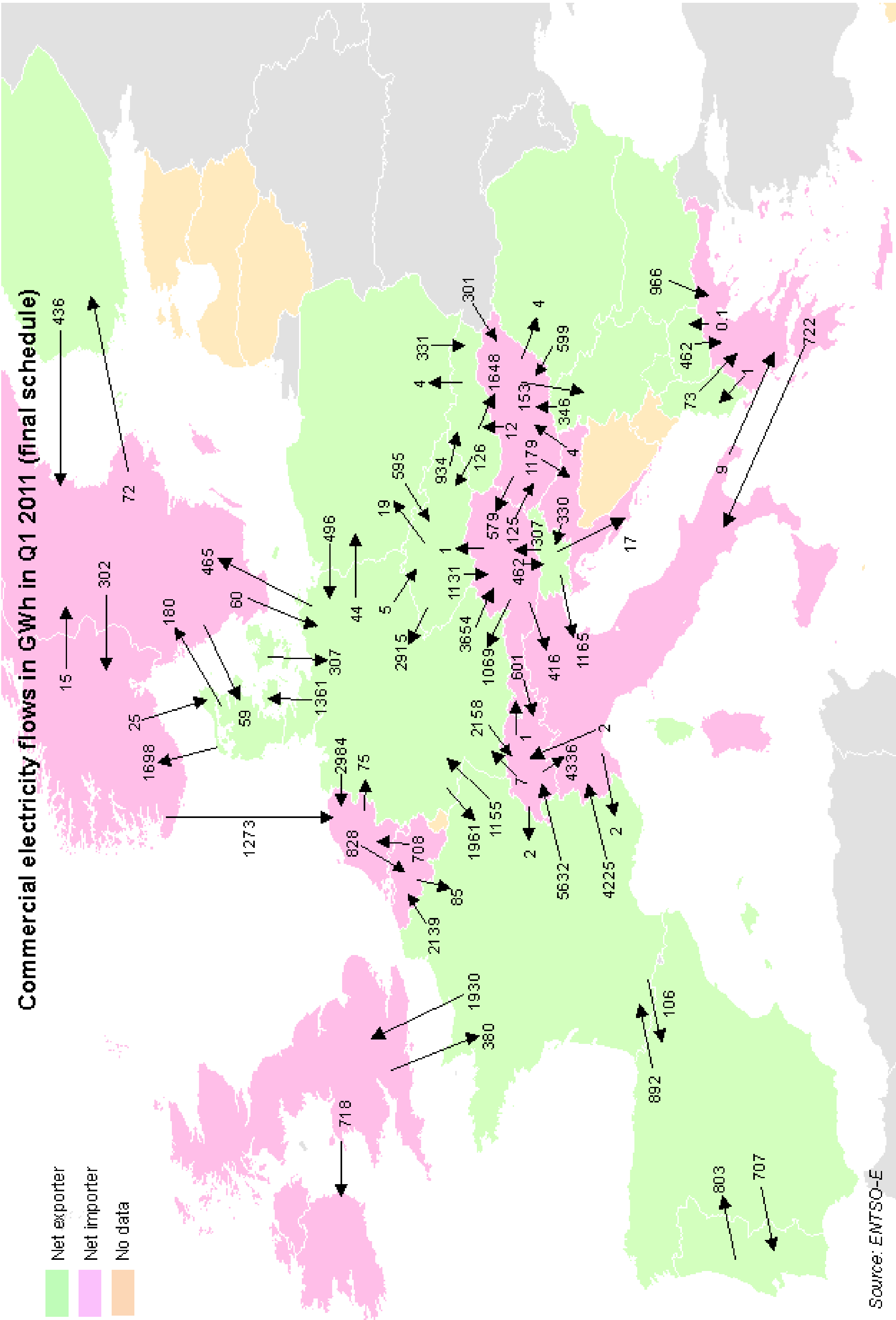
European countries are grouped in the following regions :

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*

After the market coupling took between the CWE and Nordpool regions place in November 2010 the net flow position of the latter remained close to equilibrium, although in March 2011 it turned to negative range.

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 Q1 2011 (final schedule)
Net exporter
Net importer
No data
Source: ENTSO-E

C. "Focus on Market reaction and stability of electricity grid following nuclear shut-down and revision schedule for power plants in Germany "

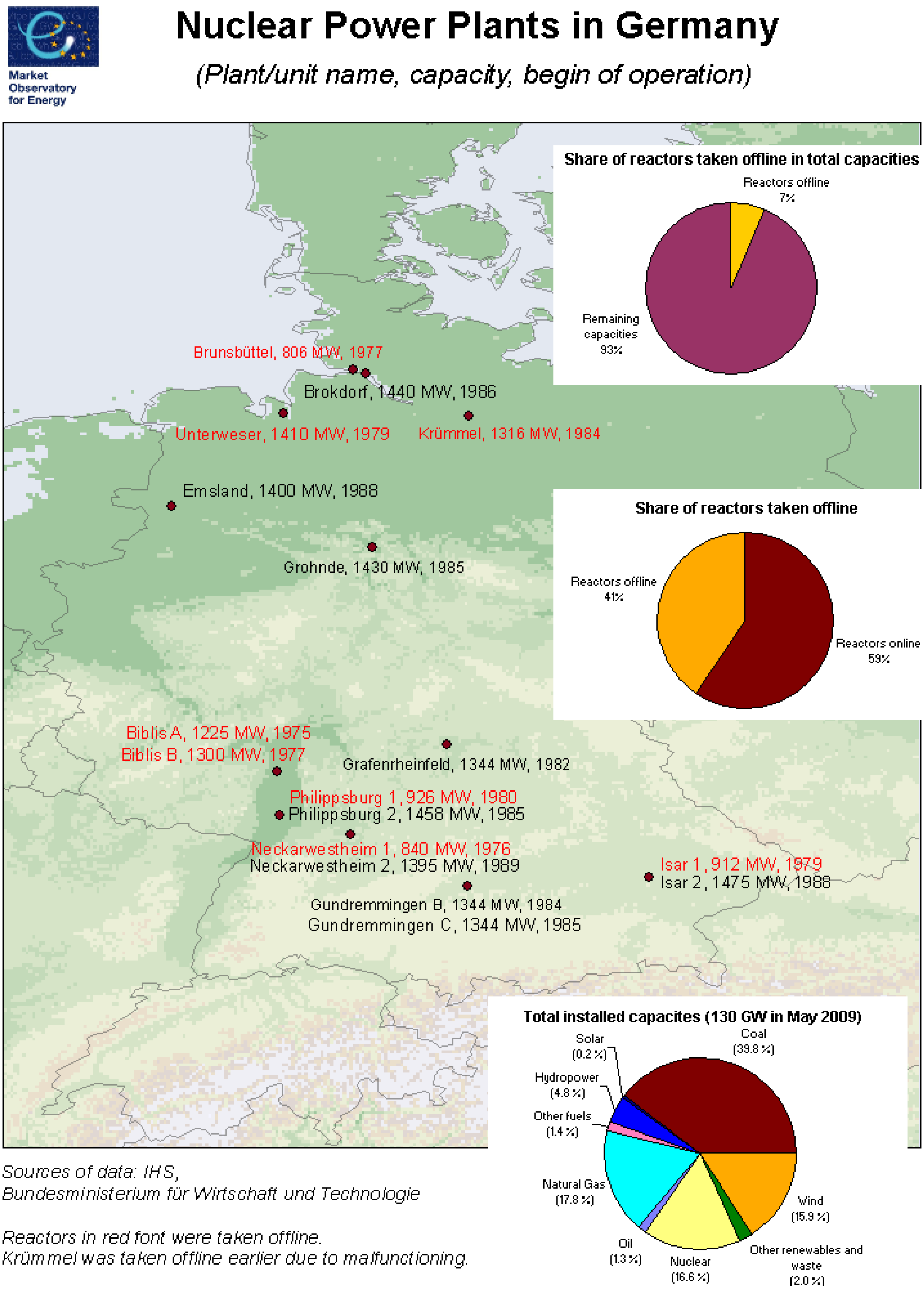
In June and July 2011 Germany’s lower and upper houses of parliament passed an amendment to the atomic energy bill sealing Germany’s exit from nuclear power by 2022.

Germany’s new energy strategy, prompted by Japan’s nuclear crisis at the Fukushima plant, reverses the extension of nuclear run-times, which became law earlier this year. It follows a three months moratorium which halted seven reactors that were built before 1980 for a safety review with a new risk assessment.

Seven[18] reactors built before 1980 as well as the Kruemmel reactor, which has not been online since 2007, will loose their license permanently. The nine remaining, more modern reactors will be gradually phased-out between 2015 and 2022. The map on the following page details the geographic position as well as the starting year of operation of the German reactors.

Together, Germany’s 17 reactors have a combined installed capacity of 20.3 GW and provided nearly a quarter of the country’s electricity generation in 2010. This is around 7% of German power generating capacity, according to IHS data. For comparison, Germany’s currently installed total green capacity is above 50 GW (Platts).

[18] These are Neckarwestheim 1, Biblis A, Biblis B, Isar 1, Brunsbuettel, Philippsburg 1 and Unterweser. As of the end of Q1 2011, the Brunsbuettel reactor had been on an extended maintenance outage since 2007. The 1.3 GW Biblis B reactor has been offline since February for maintenance. Neckarwestheim-1 is Germany’s oldest reactor and Biblis A had been scheduled to go offline for maintenance until the end of the year.

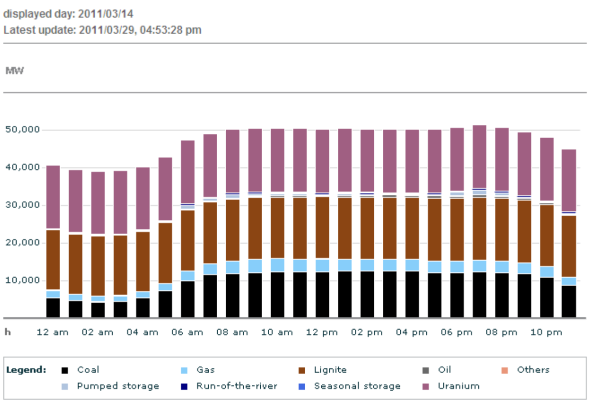


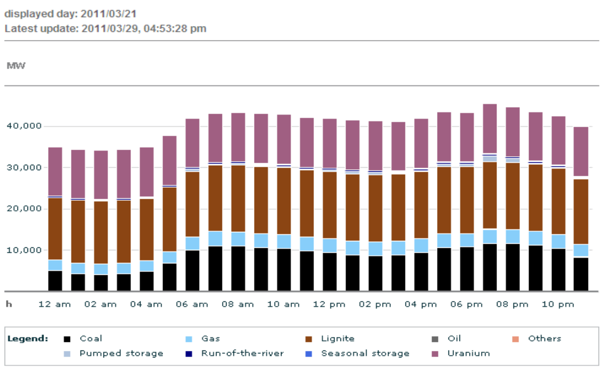
Sources of data: IHS,
Bundesministerium für Wirtschaft und Technologie

Reactors in red font were taken offline.
Krümmel was taken offline earlier due to malfunctioning.

The next charts show the effect of the retreat of the 7 nuclear power plants from the power generation mix. It compares the mix before the announcement of the moratorium (14.03.2011) with the mix for the same day of the following week (21.03.2011). As indicated by the data, about 5 GW of generation capacity was removed from the grid.

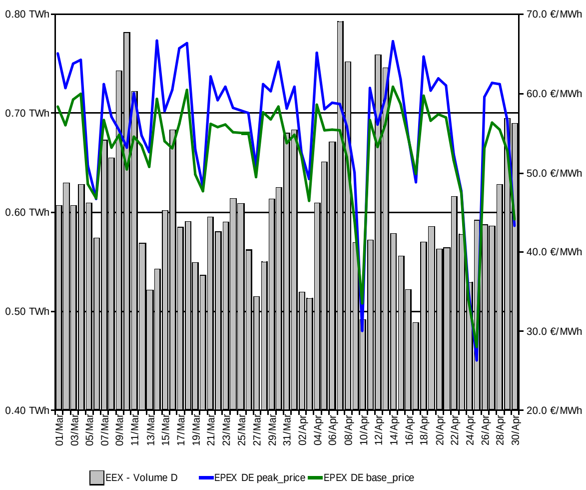
14.03.2011 **21.03.2011**

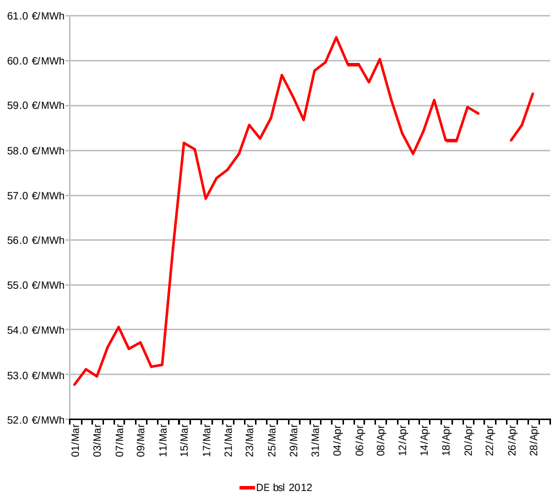




Source: EEX transparency platform

The announcement of the moratorium was by far the most significant event to affect European power prices in March 2011. It sent prompt and forward power contracts throughout the Continent to fresh highs, against a background of rising commodity prices. However, the effect on the day-ahead marked was short-lived as enough renewable generation capacity was available at that moment.



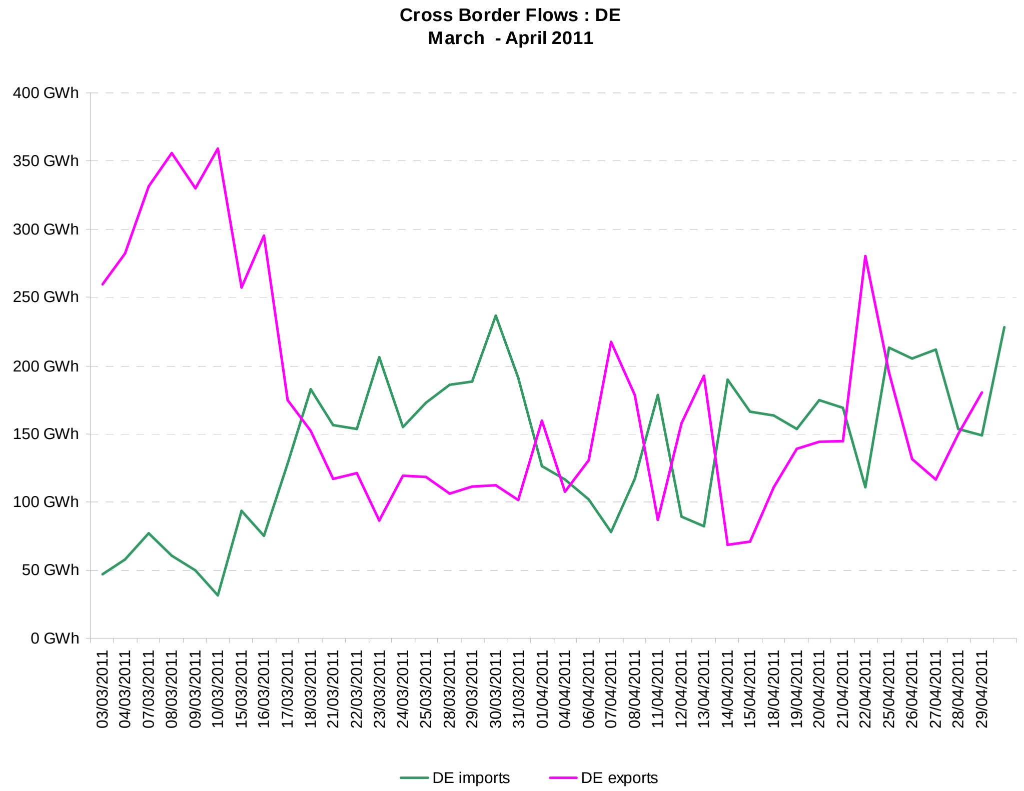


Source: Platts

The German front-month baseload contract appreciated strongly in March, with gains of 9% relative to the previous month, and 50% compared with a year ago, according to Platts data. The day-ahead baseload contract also rose by 5% compared with the previous month to Eur54.90/MWh, the data showed.

The decision took market participants by surprise and saw German power prices jump by more than 10%. In the following days market participants were scrambling to factor in all incoming information related to this decision – from speculation on the possible winners and losers, to analysis of the cost of early exit, the importance of the local election results in Baden-Württemberg and to the findings of the special commissions which would affect the Government decision on the future of the moratorium.

As illustrated by the next chart, Germany has turned from a power exporter to a power importer in the period following the announcement of the moratorium.



Source: ENTSO-E

The closure of the seven reactors and possibly also the consequences of stress tests for all European nuclear plants could reduce the available generation capacity and the security margin regarding generation adequacy. Whereas security margins in spring and summer periods may be sufficient, ENTSO-E and the European regulators are conducting further investigations on the effects of the closure with regard to regional grid stability during peak demand period in winter.

Regarding the network operation, the closure of the reactors is a regional challenge including all neighbouring countries of Germany. Congestion on interconnections will potentially increase as Germany will import more than before. This challenge applies in particular for Southern and South Western Germany which has been a deficit area already before closing down the nuclear plants. This increase deficit might put also the internal North-South connections to a high stress as they are already congested in periods of high wind production in the North Sea and Baltic Sea area.

Many of the operational challenges can be tackled by usual operational measures. For example, maintenance of power plants and transmission lines needs to be coordinated even more carefully. However, low grid margins increase the risk of serious disturbances such as voltage collapses in some areas. In the worst case, these incidents might propagate widely in the interconnected network.

Special measures, which are not always market oriented, may be need to ensure grid stability. System operators may be forced to use daily operation measures that are today reserved for special situations such as sudden breakdowns of power plants or lines. These special measures include for example extensive redispatching of the power plants, switching measures in the network to reconfigure its topology, curtailing wind in-feed and keeping a larger amount or reserve power available.

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