Quarterly Report on European Gas Markets

Directorate-General for Energy

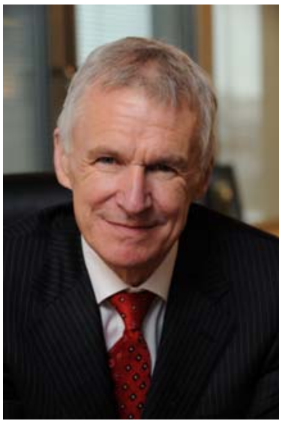
European Commission

- **MARKET OBSERVATORY FOR ENERGY**

VOLUME 4, ISSUE 2: April 2011 - June 2011

EUROPEAN COMMISSION
DIRECTORATE-GENERAL FOR ENERGY

Director-General



Dear readers,

Natural gas consumption in the EU in the first half of 2011 was 7% lower than in the same period in 2010. Rapid and significant increases in natural gas prices in 2010 may well have contributed to this drop in demand, as well as uncertainties about the recovery of the economy, provoked by rising fears of sovereign debt defaults in the eurozone.

Falling demand contributed to relative stability in prices during the period, alongside a number of gas market fundamentals, such as high levels of natural gas storage and increased supplies of LNG to EU markets. Initial fears that a post Fukushima surge in demand for gas from Japan to replace losses in nuclear capacity could immediately swallow up flexible LNG supplies to the EU did not materialise. The announcement in May of the retirement of all nuclear capacity by 2022 in Germany also had no apparent effect on day-ahead traded gas prices.

However, increases in the price of LNG deliveries offered the first signals of pressures likely to come from heightened Asian demand in the short to medium term. These price increases contributed to reducing the gap between day-ahead prices and prices of LNG deliveries to the EU, which in recent times have been low partly because of ample gas supplies in the US.

Continued increases in oil-indexed prices of Long Term Contracts (LTC) for gas alongside stable traded prices meant a reversal in the recently observed narrowing of the gap between the two pricing mechanisms. This means that the issue of renegotiation of LTC gas contracts between suppliers and EU importers of piped gas is still very much on the table.

Given recent economic and gas market developments and their influence both on the behaviour of EU consumers and on the level of traded gas prices, it seems justified that an effort is made by suppliers to take better account of such factors in their LTC price formulas.

Finally, this quarterly issue provides information on the legally binding guidelines on Congestion Management Procedures which the European Commission is in the process of preparing.

Philip Lowe

HIGHLIGHTS

- Two subsequent quarters of falls in natural gas consumption amounted to a year-on-year decline in first half 2011 consumption in the EU of 7%. This was likely the combination of mild weather in the second quarter of 2011, good levels of gas storage and ample supplies, especially of LNG, in spite of initial fears that large importers of flexible LNG (such as the UK and Belgium) would have to compete with post-Fukushima increases in Japanese demand for the commodity. Additional reasons (for a more moderate consumption of natural gas) may well have been as reactions to signs of a faltering economic recovery, with rising fears of sovereign debt defaults in the eurozone, and due to recent large (wholesale and retail) price increases of natural gas.

- This was the backdrop for falling prices of energy commodities in general over the course of the second quarter of 2011. Looking at natural gas and average quarterly prices on the EU's hubs in particular, prices in Q2 remained relatively stable compared to the previous quarter. At the beginning of the second quarter, North West European hubs traded in a tight range of between 23 and 24 €/MWh, while by the end of the quarter, the range remained tight at slightly lower levels: averaging between 22 and 23 €/MWh.

- In comparison to day-ahead prices quoted on NWE hubs, monthly average spot LNG prices in the EU in the second quarter of 2011 traded within a wider price range of between 18.1 and 29.6 €/MWh, and averaged at 22.4 €/MWh for the period across the seven countries for which data is available. This was above the previous quarter's average price of 21.6 €/MWh, and that of 2010's fourth quarter of 19.6 €/MWh. The rising trend of LNG prices as against one of stability/slightly decreasing hub day-ahead prices means that the gap between the two is slowly narrowing.

- Estimations of Long Term Contract (LTC) border prices for natural gas imports for the second quarter also show an extension of the upward trend witnessed in recent quarters. There are signs that some of these prices are being increasingly influenced by spot gas prices, as major importers are managing to get concessions from their suppliers to account for the oil-link/spot gas price divergence. But that such price mechanisms remain tightly linked to oil prices is apparent from the continued price increases, as 2011 Q2 price levels reflect oil price movements of either Q3 or Q4 of 2010, when the Brent crude was very much in an ascendancy phase.

- In the last couple of issues, it was observed that the rapid rise in traded day-ahead gas prices on European hubs in the fourth quarter of 2010 had contributed to a considerable narrowing of the gap between hub prices and border prices. Indeed, in December 2010 the monthly average of the NBP day-ahead price was equivalent to 95% of the NWE Platts Gas Contract Indicator (a theoretical, pure oil-linked index of LTC prices) for that month. By June 2011 however, the UK NBP average of 22.5 €/MWh represented 78% of the Platts NWE GCI.

- It can be expected that the renewed divergence of the long term and spot gas markets witnessed in Q2 of 2011 will put renewed pressure on the finances of the major European utilities - and therefore, on their suppliers - buying gas under long term, oil-indexed contracts, but asked by their own customers to sell at lower spot levels.

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QUARTERLY REPORT ON EUROPEAN GAS MARKETS

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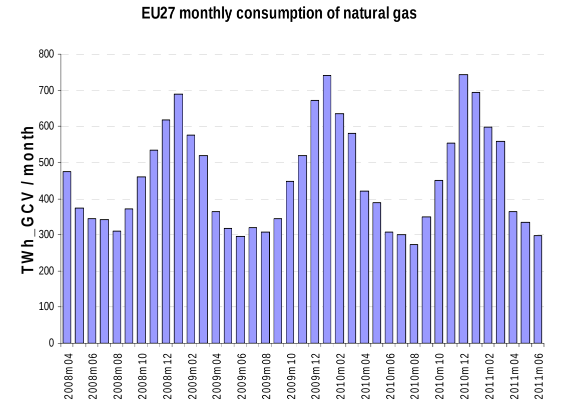
A. Recent developments in the gas markets across Europe

A.1 Gas consumption, production and imports



Source: Eurostat

2011 second quarter EU gas consumption amounted to 997 TWh, which represented little more than half of what was consumed in the preceding quarter and was 11% lower than gas consumption in Q2 2010. This follows a year-on-year fall of 5% registered in the first quarter of 2011. First half 2011 natural gas consumption in the EU was thus 7% below natural gas consumption levels in the first half of 2010.

To recall from the last issue, the number of heating degree days (HDD's)[1] in January 2011 were close to the 25 year long term average, while in February and March 2011, the number of heating degree days slightly exceeded the long term average. This suggests that weather conditions in Q1 do not explain the reductions in gas consumption that were observed.

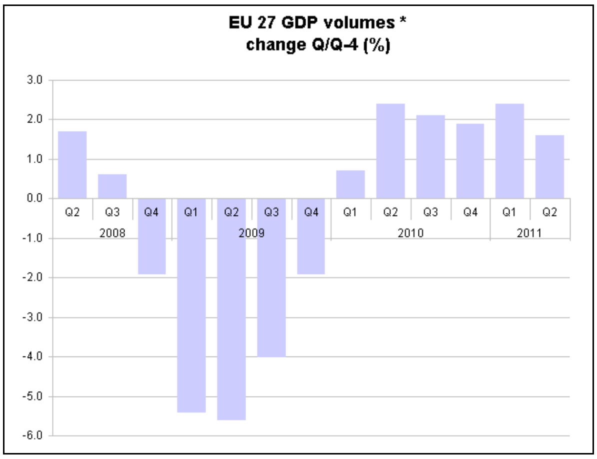
In Q2 however, it could be seen from the chart below that April had significantly less HDD's than the norm while May did not vary much from the norm. Thus Q2 2011 weather was relatively mild, which provides some explanation for the year-on-year fall in natural gas consumption for that period.

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

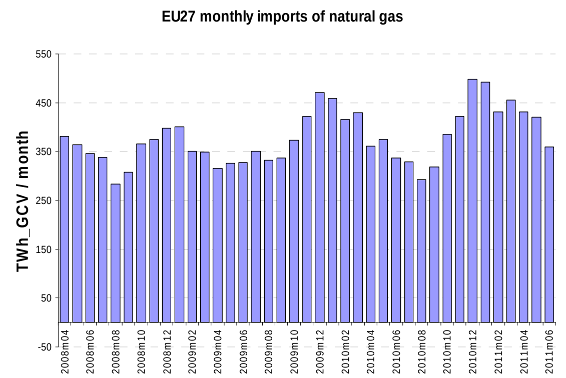
Source : Eurostat /JRC

Taking a look at economic growth, year-on-year GDP in the EU grew by a positive but modest 1.6%, which is somewhat lower than recent quarters. This contrasts with 2.4% growth recorded in the first quarter of 2011, which represented the highest rate of yearly GDP growth since the end of the recession.



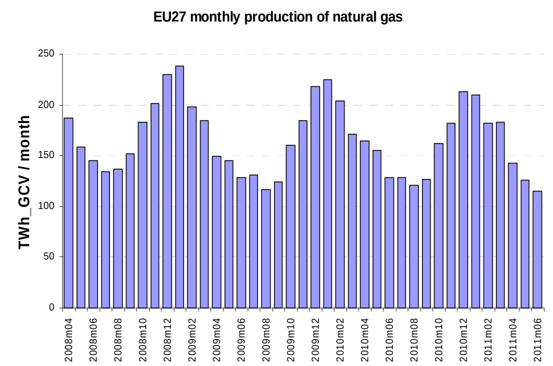
At 1,210 TWh, EU imports of natural gas in the second quarter of 2011 were well in excess of Q2 2010 levels (of 1,074 TWh), representing a growth of 12.7%. This follows a trend of quite significant increases in imports of natural gas into the EU, as witnessed over the last two quarters. Q2 imports however exceeded consumption for that quarter, such that the excess was available for gas storage re-injections. This explains the high levels of gas storages (see storage section) for the period.

[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.



Source: Eurostat

Parallel to increasing imports, EU natural gas production levels in Q2 2011 also fell year-on-year, by a significant 14% compared to Q2 of 2010. This was following a 6% y-o-y increase in 2010 and a 14% fall in 2009.



Source: Eurostat.

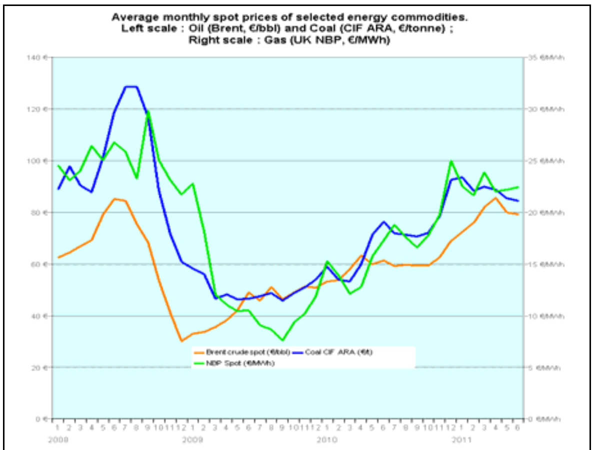
A.2 Wholesale markets

A.2.1 EU spot gas markets

A.2.1.1 Overview

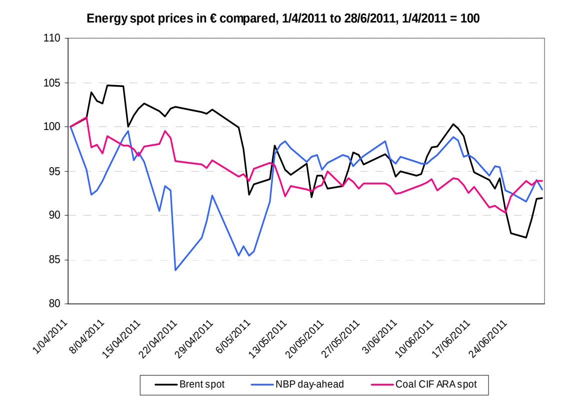
As highlighted in the last quarterly report, the effect of the nuclear outage in Japan resulting from a tsunami on the 11th of March seemed to have had only a temporary effect on the spot prices of energy commodities.

To recall with regard specifically to spot natural gas, though prices intially increased, they quickly came down again after it became evident a few days later that exports of LNG from Qatar and other suppliers could match the increasing demand from Japan in the short-term, supported by diversions of LNG from other parts of Asia, without any immediate impact on European LNG imports.



Source : Platts.

In the period succeeding the Japanese nuclear outage incident, the trend of energy commodity prices in the second quarter was a downward one, with coal, oil and gas prices falling by more than 5% over the course of the period. Gas prices (as represented in the graph below by the NBP day-ahead), experienced an upward correction in May (due to supply constraints resulting from pipe outages), only to fall back down again for the remainder of the quarter.

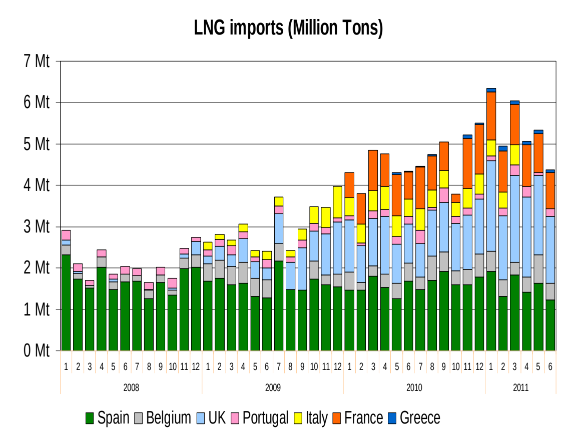


Source: Platts.

2011 Q2 EU imports of LNG were high, exceeding 2010 Q2 levels by 20%. In comparison to the 12.7% year-on-year growth reported in total imports of natural gas highlighted above, this suggests a growing share of LNG in natural gas imports.

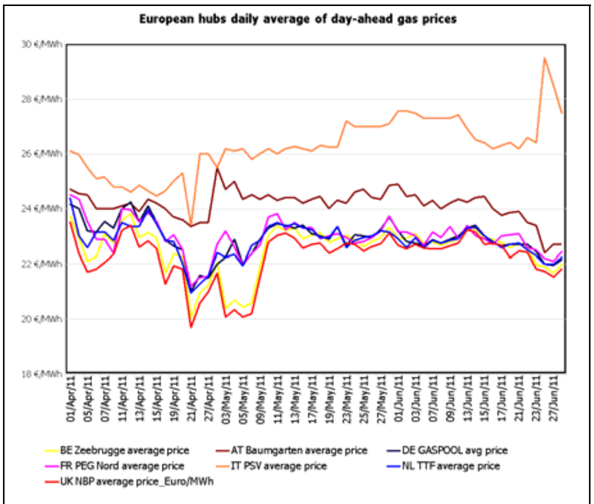
Looking specifically at the UK and Belgium, both dependent on high levels of flexible LNG imports, 2011 Q2 levels were well in excess of that for the previous year (by 67% and 30% respectively), and were only slightly less than import levels during the (cooler, and therefore with higher demand for gas) first quarter of 2011 for the UK (-6%), and even higher for Belgium (21%). Of the seven Member States for which LNG imports are reported, only Italy imported less LNG in Q2 2011 than Q2 2010.

It could therefore be seen that unrest in the Middle East and Japan's sudden need for large imports of LNG did not have a negative short-term impact on EU imports of LNG in the second quarter of 2011.
Examining the origin of imports more closely, it can be reported that imports from Qatar to the EU grew by 62% year-on-year compared to Q2 2010 levels. Interinstingly, events in Egypt did no prevent a yearly increase in imports to the EU of 29%. Equally, imports from Nigeria increased by 17%.



Source: Eurostat COMEXT
Italian data reported from January 2009.
French data reported from January 2010.

Plotting the evolution of European hub day-ahead prices, (in the graph below) it can be seen that, as usual, NWE (North-West European) hubs very much evolved in a similar fashion, while prices on the Baumgarten and the Italian PSV diverged from the rest.



Source: Platts.

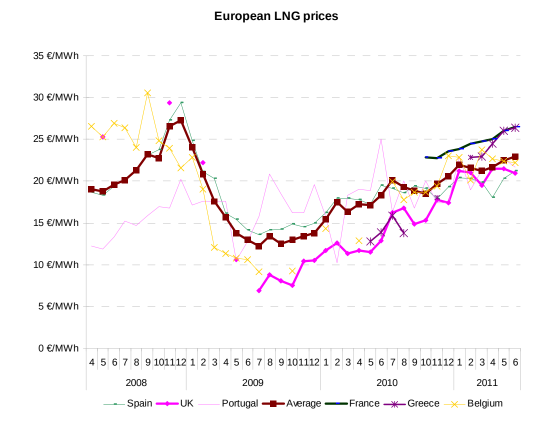
Italy is relatively more exposed to potential impacts on its natural gas imports by unrest in the Middle-East and North-Africa. This is on account of its dependence on Algerian and Libyan imports (together representing some 35% of Italian gas imports), which goes some way to explain the higher levels of Italian prices.

Though there were no reports of disruption of flow of piped gas from Algeria in Q1 or Q2 (Algerian gas flows through Tunisia and the Trans-Med pipeline), the flows of gas from Libya via the Greenstream pipeline were completely interrupted from the 22nd of February 2011 onwards.

With the exception of Italy, the trend across Europe's gas hubs in the second quarter of 2011 was one of relative stability in prices. At the beginning of the second quarter, NWE hubs traded in a tight range of between 23 and 24 €/MWh, while by the end of the quarter, the range remained tight at slightly lower levels: averaging between 22 and 23 €/MWh.

A.2.1.2 Gas contracts and pricing mechanisms

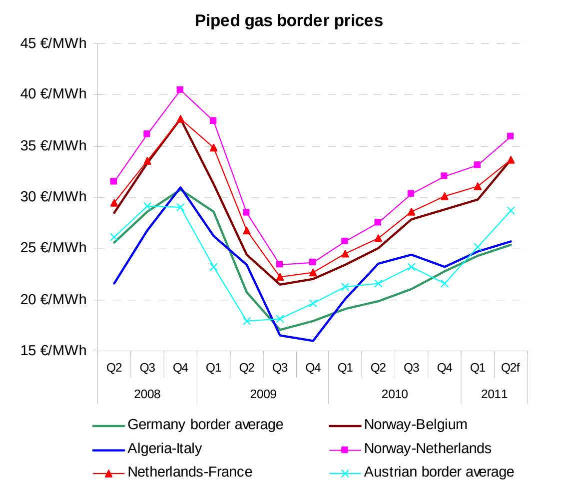
In comparison to day-ahead prices quoted on NWE hubs, monthly average spot LNG prices in the EU in the second quarter of 2011 traded within a wide price range of between 18.1 and 29.6 €/MWh, and averaged at 22.4 €/MWh for the period across the seven countries for which data is available. This was above the previous quarter's average price of 21.6 €/MWh, and that of 2010's fourth quarter of 19.6 €/MWh. The rising trend of LNG prices as against one of stability/slightly decreasing hub day-ahead prices meant that the gap between the two was slowly narrowing.



Source: Eurostat COMEXT

Looking at a selection of Long Term Contract (LTC) oil-indexed border prices for piped gas in Europe, shown in the graph below, reveals an average price of 30.5 €/MWh for the second quarter, from a range of between 25.4 and 35.9 € per MWh. This compares to average prices for the same selection of contracts of 28.03, 26.4 €/MWh and 25.9 €/MWh in the three preceding quarters. Based on *Gas*

Strategies data, LTC prices for gas imports from Norway and the Netherlands were among the highest prices for gas in Q2 2011.



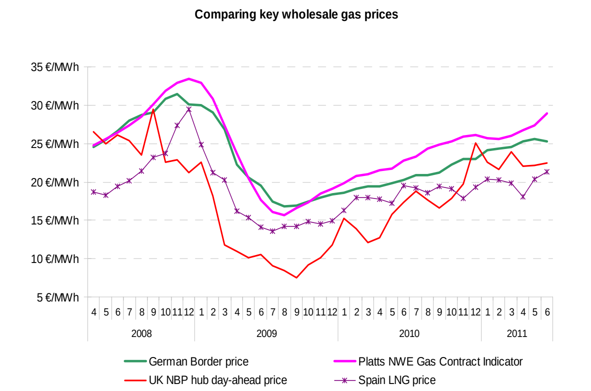
Sources: Gas Strategies, German Federal Office of Economics and Export Control (BAFA)

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

The trend of LTC prices is therefore very much an upward one, unsurprisingly given that they are oil price-indexed, with a 6 to 9 month time lag, such that today's LTC prices will partly reflect oil price movements 6 to 9 months ago. The relevant oil prices for LTC gas prices in Q2 were therefore oil prices in Q3 and Q4 of 2010, when the Brent was very much in an ascendancy phase (see chart in previous section).

The graph below shows a selection of different wholesale price contracts for natural gas in the EU for a closer comparison.



Sources: Eurostat COMEXT, Platts, German Federal Office of Economics and Export Control (BAFA)

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

The graph shows the UK NBP price for traded gas, which is the European benchmark, as well as the price of LNG delivered to Spain, Spain being the main importer of LNG in Europe, contributing some two thirds of Spanish gas supply.

The pink line shows the Platts North Western Europe gas contract indicator, which is a theoretical price calculated using a traditional “pure oil-link” formula, while the green line shows the price of actual gas imports at the German border, as published by the German customs agency (BAFA). This price has also traditionally been taken as an indicator showing the price of oil-linked gas into Europe.

Comparing these two lines, it can be seen that the German border price has increasingly been dropping away from the Platts NWE GCI oil-indexed price indicator towards the spot gas price. This suggests that the actual prices now being paid for gas in Germany are being increasingly influenced by spot gas prices, as major importers demand concessions from their suppliers to account for the oil-link/spot gas price divergence.

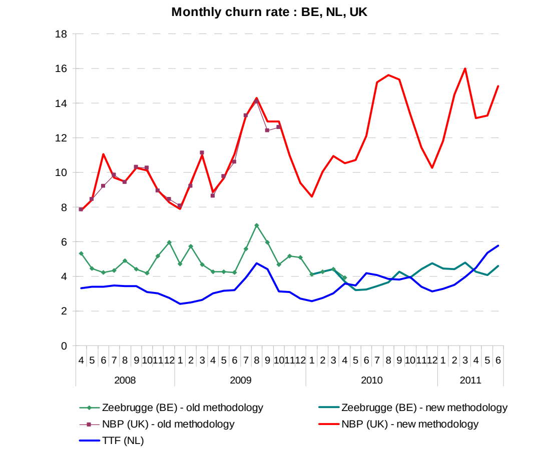
In the last couple of issues, it was observed that the rapid rise in traded day-ahead gas prices on European hubs in the fourth quarter of 2010 had contributed to a considerable narrowing of the gap between hub prices and border prices. Indeed, in December 2010 the monthly average of the NBP day-ahead price was equivalent to 95% of the NWE Platts GCI for that month.

By June 2011 however, the UK NBP average of 22.5 €/MWh represented 78% of the Platts NWE GCI.

It can be expected that the redivergence of the long term and spot gas markets witnessed in Q2 of 2011 may put renewed pressure on the finances of the major European utilities buying gas under long term, oil-indexed contracts, but asked by their own customers to sell at lower spot levels.

Liquidity in Europe's three biggest hubs (NBP, TTF and Zee) in the second quarter of 2011 evolved in different ways. While churn rates[2] at the UK NBP and the Belgian Zeebrugge hubs were slightly below the previous quarter, that of the TTF increased from an average in Q1 of 3.6 to a Q2 average of 5.20. This was due to a much higher than usual level of traded volumes (H1 2011 traded volumes on the TTF increased by 43% year on year, compared to H1 2010), which boosted liquidity.

The large increase in traded volumes in the Netherlands was at least in part due to a recent change (in April 2011) in balancing regimes there, with a switch to a system in which the market players are themselves responsible for keeping the national gas transmission network in balance. To keep in balance, market players can now either buy or sell gas themselves on the TTF, thereby increasing the hub's liquidity. Previously, only the national network operator was responsible for keeping the system in balance.



Sources: Huberator (BE), Gas Transport Services (NL), National Grid (UK), Platts.

Note: changes in methodology were implemented from November 2009 for NBP and from January 2010 for Zeebrugge.

[2] The churn rate is an indicator of the liquidity of a market/ hub. It represents the ratio between the total volume of trades and the physical volume of gas consumed in the area served by the hub.

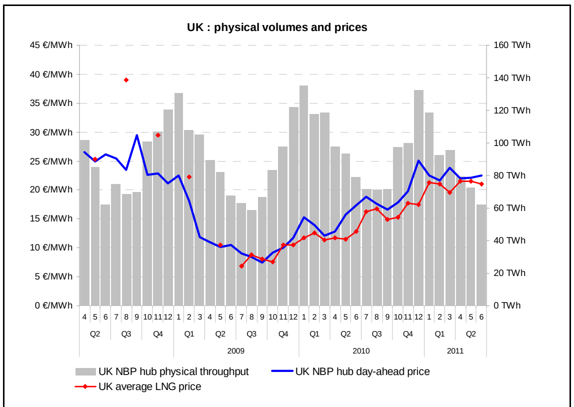
A.2.1.3 Regional markets

North and South Western Europe

United Kingdom

Physical day-ahead throughputs on the UK's National Balancing Point (NBP) in Q2 2011 fell by 30% relative to the previous quarter, while they were 21% less than levels recorded in Q2 2010. This was very much in line with year-on-year falls in gas consumption in the UK (of 19%).

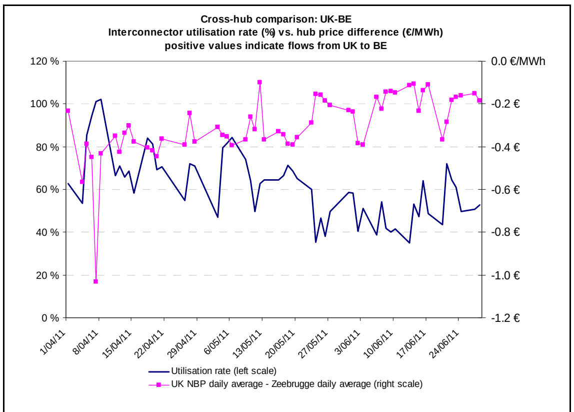
After recording a monthly average of 22.7 €/MWh over the first quarter of 2011, the NBP day-ahead averaged 22.2 €/MWh in Q2 2011. This compares to previous quarter averages of monthly prices of 20.9, 17.7, 15.3 and 13.8 €/MWh respectively for each of the four preceding quarters of 2010. Thus after a trend of increasing prices, the second quarter can on the whole be said to have been one of price stability.



Sources: National Grid (UK), Platts, Eurostat COMEXT.

As regards monthly averages of prices for UK deliveries of LNG, which had previously reached a historical high of 21.2 €/MWh in January 2011 and averaged 20.6 €/MWh over the first quarter, second quarter average levels reached 21.3 €/MWh. Thus, the gap between the UK hub spot and LNG price which had already been narrowing in the first quarter of 2011 (to 2.08 €/MWh), was even further reduced in Q2 (to 0.9 €/MWh).

Looking at interconnecting flows between the UK and Belgium, it could be observed that natural gas from the cheaper UK hub was being sent to the higher price continent throughout the second quarter of 2011. The day-ahead price on the NBP hub remained at a discount to that of the Zeebrugge hub for the whole quarter, such that gas continued flowing from the UK towards the continent. However, a gradual reduction in the discount between the two hubs was accompanied by falling UK-BE flowing utilisation rates of the the two-way flow Interconnector.



Sources: Interconnector, Platts

This contrasts with the first quarter of 2011, during which gas flow was largely UK bound from the continent (as was the case also in the first quarter of 2010), as the UK NBP traded at a premium to the Zeebrugge hub during most of the quarter. To recall, relatively lower prices at the UK NBP hub compared to other European hubs during the second and third quarters of 2010 had led to high levels of gas exports out of the UK into continental Europe. At the beginning of the fourth quarter, gas continued to flow from the UK to the continent via Belgium, but the flow rate decreased progressively as the discount of NBP day-ahead gas to the Zeebrugge day-ahead was slowly reduced.

It appears therefore that during the cooler months, more gas usually flows into rather than out of the UK, while the reverse is true in the warmer months of the year.

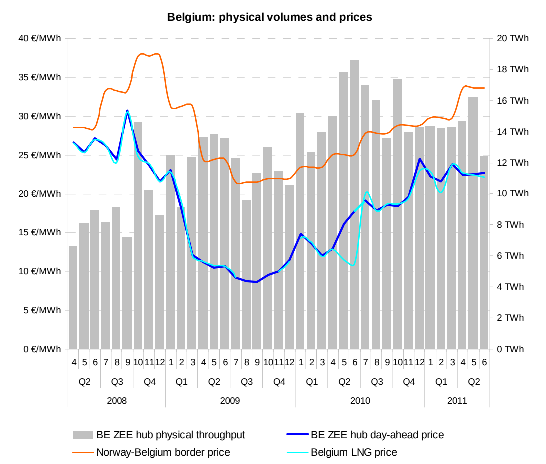
Examining the total gas volumes flowing through the interconnector in the second quarter of 2011, it is interesting to note that 32 TWh was exchanged between the UK and Belgium during that period, while only 12 TWh was exchanged in the previous quarter.

Belgium

2011 second quarter physical gas deliveries at the Belgian Zeebrugge hub (ZEE) were slightly higher than the equivalent quarter of the previous year, and in line with deliveries recorded in Q1 of 2011. This contrasts with falling throughputs both on a yearly and quarterly basis at the NBP hub and is to some extent explicable by the price differential over the quarter between the two hubs, which favoured flows out of the UK and into Belgium via the Interconnector (see section on UK for more details).

Traded volumes at the Belgian hub amounted to 186 TWh in the second quarter of 2011, relative to Belgian consumption of 96 TWh for the same period. This highlights the importance of the Zeebrugge hub not only to the Belgian market, but also as a key European hub.

Average monthly day-ahead prices on the ZEE hub were very stable throughout the second quarter after receding somewhat from average monthly levels in the previous quarter Q2 averaged at 22.5 €/MWh, exactly in line with the previous quarter. This is quite a bit below the historically high monthly average price recorded in the fourth quarter (of 24.5 €/MWh) of 2010.



Sources: Huberator (BE), Platts, Eurostat COMEXT, Gas Strategies.

At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

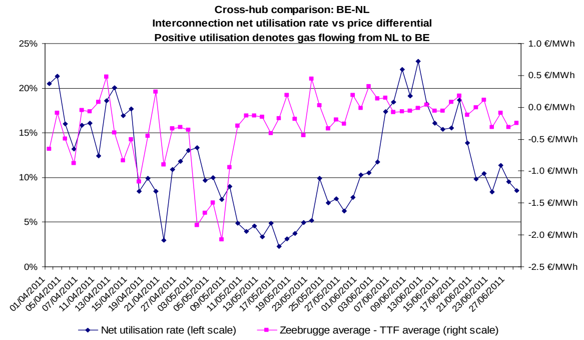
In comparison to Belgian hub day-ahead prices, spot LNG deliveries to Belgium increased slightly from a Q1 average of 22.2€/MWh to a Q2 average of 22.4€/MWh. Thus, as the UK, it could be seen that the gap between the price of LNG and that of the day-ahead in Belgium was narrowing.

LTC piped gas from Norway also continued to exceed both hub and LNG prices, and the gap which had been progressively narrowing during the course of 2010, has been increasing again. Based on *Gas Strategies* data, in Q2 2011 the average day-ahead price at the Zeebrugge hub was 33% less than the price of gas from Norway to Belgium, compared to 24% in the previous quarter.

The graph below provides a comparison of the evolution of the relationship between gas flows and day-ahead prices on the Belgian and Dutch TTF hubs in the second quarter of 2011. It can be seen that in the first part of the quarter, the trend was one of a growing premium of Dutch prices over Belgian prices, with corresponding falling utilisation rates of gas flows between the Netherlands and Belgium, as usual in such circumstances. Note that whatever the price differential, net gas flows between the Netherlands and Belgium are unlikely to become negative, given the much higher existing physical capacities of gas from the former to the latter, in contrast to capacities of gas from Belgium to Netherlands (5 times smaller).

After reaching a discount high of 2 €/MWh by the first week of May, Belgian prices then rapidly rose to close the discount to the TTF price to a level rarely exceeding 40 cents/MWh for the remainder of the quarter. Parallel to this development, Belgium-bound flows of gas from the Netherlands could be seen to increase again to some extent, even though Belgium continued to be a relatively cheaper gas area compared to the Netherlands.

These observations show that although price differentials between Belgium and the Netherlands do have a rational effect on the utilisation rates of interconnector flows between the two countries, widely different levels of flow capacities are preventing gas between the two markets to be constantly flowing from the relatively cheaper area to the more expensive area.



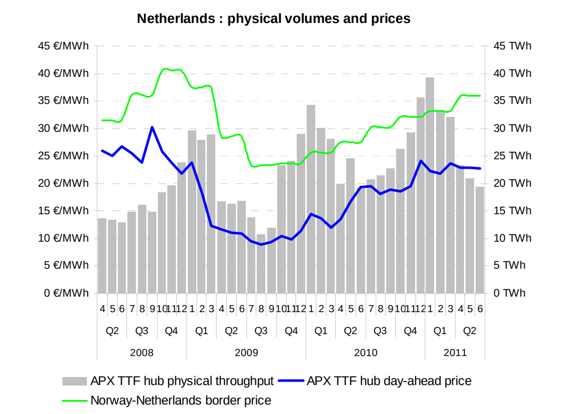
Sources: ENTSO-G, Fluxys, Platts

Netherlands

Q2 2011 physical throughputs of gas on the Dutch TTF hub were less than the previous quarter (by close to 40%) but in line with Q2 of 2010. In comparison, Dutch gas demand declined relative to the second quarter of 2010 by 14%.

Traded volumes on the TTF hub in the second quarter of 2011 attained levels of 328 TWh, relative to 238 TWh of natural gas consumed in the Netherlands in the same period.

Day-ahead prices followed exactly the same trend to that noted for the Belgian hub, keeping to a stable level over the second quarter, and equivalent to the previous quarter average of 22.6 €/MWh.



Source: Platts, Gas Strategies.

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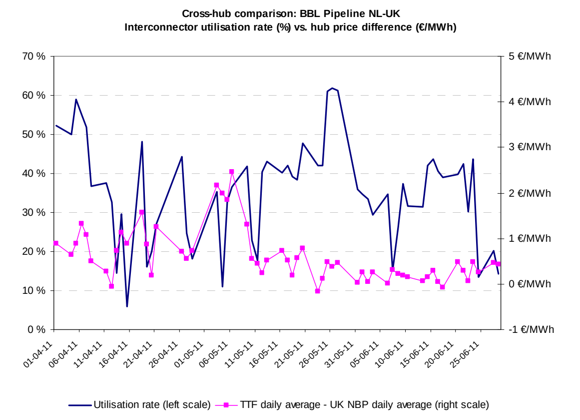
Compared to recent quarters, the second quarter of 2011 did not bring about a significant difference in the relationship between the Dutch day-ahead price and the price of LTC piped gas from Norway[3]. According to *Gas* Strategies data, in Q2, the price of Norwegian LTC gas deliveries into the Netherlands was 57% more expensive than the TTF day-ahead.

Looking at the graph below, it can be seen that the TTF day-ahead traded at a premium to the UK hub throughout the second quarter, with only isolated exceptions. The utilisation rate of the uni-directional BBL pipeline (in terms of physical flows, as it has acquired virtual reverse flow capacities since the first quarter of 2011) was however very erratic, with significant changes from day to day with no particular rationale vis-à-vis relative changes in prices.



Sources: BBL Company, Platts

Germany

Combined traded volumes on Germany's NetConnect (NCG)[4] and Gaspool[5] hubs for Q2 2011 amounted to 1.1 TWh, which was less than half of what was traded in the previous quarter (2.85 TWh) and also less than levels recorded in Q2 2010 (of 1.47 TWh). German traded volumes remain very modest compared to other hubs in North Western Europe, and also compared to German consumption of natural gas (of 169 Twh in the second quarter of 2011).

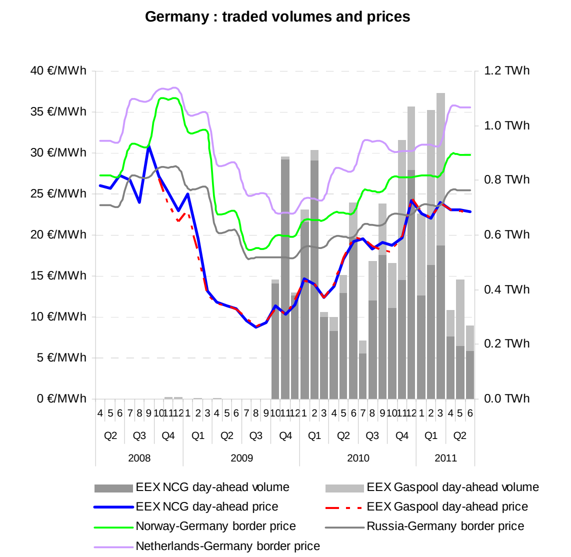
The evolution of NCG and Gaspool hub day-ahead prices in the second quarter of 2011 was comparable to that reported for other NWE hubs, averaging respectively 23 and 22.9 €/MWh, which represented stability compared to 22.9 and 22.8 €/MWh registered in the previous quarter.

[3] Norway is the main exporter of gas into the Netherlands, representing some 10% of total Dutch gas consumption.

[4] NCG is formerly known as *E.ON Gastransport (EGT)*.

[5] Gaspool is formerly known as BEB. The new market area started on the 1st of October 2009.

The graph also displays the evolution of a number of German border prices, alongside the German traded prices. It shows that the price of Russian gas paid by Germany was the lowest, while the price of Dutch gas was highest, and that of Norwegian gas was between Dutch and Russian gas. According to *Gas* Strategies data, the price of imported gas from the Netherlands averaged 35.6 €/MWh over the course of the second quarter, nearing a historic high of 37.7 €/MWh reached in 2008.



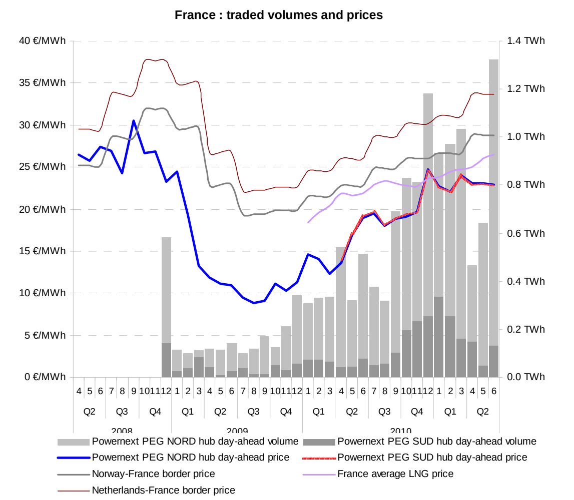
Source: Platts, Gas Strategies.

At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

France

Q2 volumes traded on France's Powernext Point d'Echange de Gaz (PEG) Nord and Sud increased on a yearly basis (by 179%), reaching a quarterly level of 2.8 TWh, compared to a 2010 Q2 level of 1.5 TWh. Though this represents a significant increase, the levels of day-ahead volumes traded on the French hubs remain modest in comparison to the levels traded in Europe's larger hubs such as the NBP, the TTF and the Zeebrugge hubs. It also only represents less than 4% of French natural gas demand in Q2 of 2011.

Similar to other hubs, Powernext assessments of PEG Nord and PEG Sud day-ahead prices show stability between Q1 and Q2, with quarterly average prices across both hubs registering levels of between 22.9 and 23 €/MWh.



Source: Platts, Gas Strategies, Eurostat COMEXT

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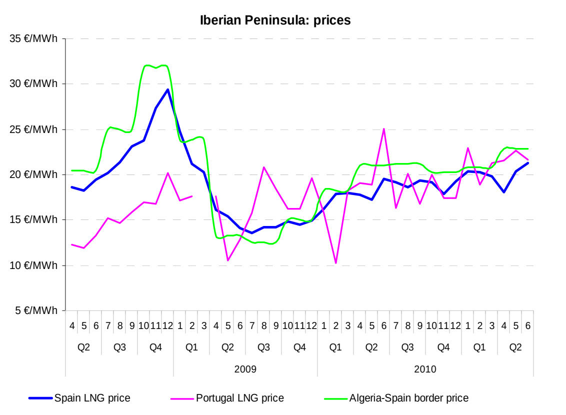
In comparison to other price mechanisms, LTC prices of imported gas at the French border were at relatively comparable levels to German border prices in the case of gas from Norway and the Netherlands, these being much less competitive than hub prices, or indeed to prices of LNG gas deliveries to France.

As for other LNG importing countries, prices paid in France for LNG also increased since the first quarter of 2011, thus reducing the gap between traded prices and LNG prices. At an average price of 25.9 €/MWh for the second quarter, the price of LNG imports paid in France in Q2 continued to exceed that of the UK, Spain, Belgium and Portugal, but was less than that paid by Italy and Greece.

Iberian Peninsula

Some two thirds of natural gas supplies to Spain and Portugal comes in the form of LNG. The price paid for LNG in the Iberian Peninsula is therefore a key determinant of the cost of imports of natural gas in that region of the EU.



Sources: Eurostat COMEXT, Gas Strategies, Platts.

At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

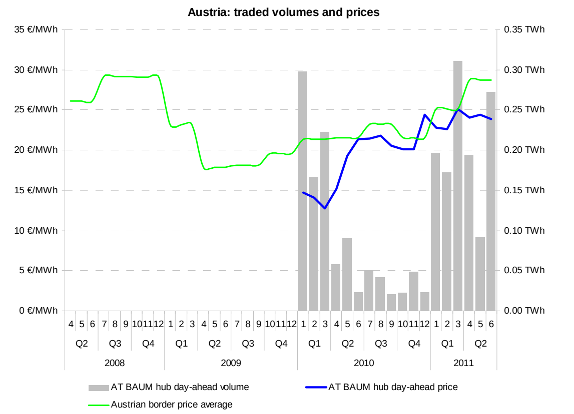
This continues to represent an advantage given the relative cheapness of LNG compared to pipe gas delivered under LTC. Relative to other importers of LNG, both Spain and Portugal pay low prices for their LNG imports. In the second quarter of 2011, the average quarterly price paid for LNG in Spain (of 19.9 €/MWh, compared to 20.2 €/MWh in the previous quarter) continued to be less than any of the six other Member States for which LNG prices are reported in this publication, while the Q2 average price of LNG in Portugal (22 €/MWh) was less than prices paid in Belgium, Italy, France and Greece for LNG in that quarter.

The price of LNG deliveries to Portugal did however continue to increase, by 4% since the last quarter, while that paid in Spain decreased by 1%. It is interesting to compare the evolution of prices for LNG in such countries, to those of the UK and Belgium (+4% and +1% respectively) given that the former countries purchase their LNG on long term contract (LTC) terms whereas UK, and to a lesser extent Belgium, purchase most of their LNG on the spot markets.

Central and Eastern Europe

Austria

Q2 2011 traded volumes (of 0.56 TWh) at Austria's Baumgarten hub represented an increase of more than 300% since the equivalent quarter of the previous year. This was an impressive yearly increase, even if these continue to represent a very small amount relative to Austrian natural gas consumption (which equalled 18 TWh in Q2 2011).

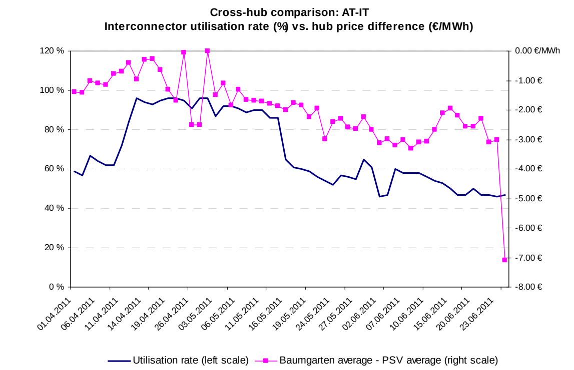


Sources: Platts, Gas Strategies

At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

As with other hubs, the evolution of the day-ahead price in Baumgarten was fairly stable, the average Q2 price (of 24.1 €/MWh) having incrased by only 3% compared to the previous quarter's average. It remained higher than North Western European hub prices, having traded at a an average premium of just below 2 €/MWh to the UK NBP monthly average over the second quarter, and 1 €/MWh compared to the Gaspool hub day-ahead monthly average.

After increasing quite rapidly at the beginning of the second quarter, the utilisation rate of the Austria-Italy gas interconnector then trended downwards for the remainder of the quarter, while at the same time the premium of the Italian PSV hub over the Austrian day-ahead increased.

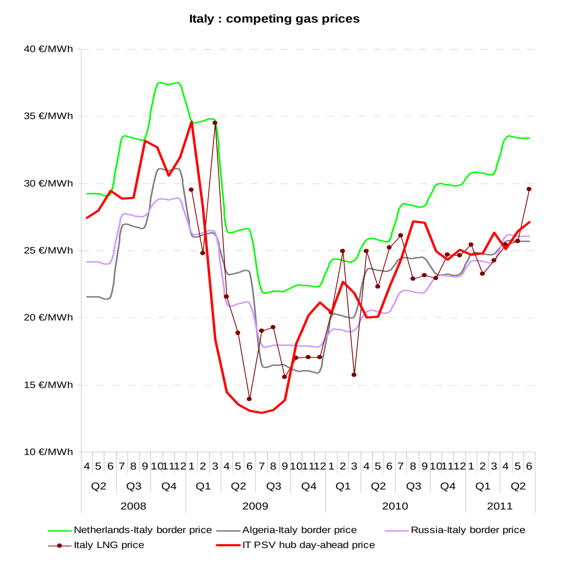


Sources: TAG, Platts

Italy

The quarterly average of the price of the day-ahead gas contract at Italy's Punto di Scambio Virtuale (PSV) increased from a level of 25.3 €/MWh in the first quarter to 26.2 €/MWh in the second quarter of 2011. As can often be observed, the PSV day-ahead which typically trades at a few Euros per MWh above NWE hubs thus followed a different direction to NWE hubs, which remained stable (Given that no trade volumes are currently available for the PSV, it is difficult to estimate how representative the spot price is for the Italian gas market).

As noted already in the preceding reports, this could however be deemed a relatively modest increase in prices given the high exposure of the Italian market to North-African markets such as Lybia and Algeria. While Algerian gas (which represents around a quarter of Italian imports) was not affected by the unrest in the region (in spite of transiting through Tunisia), the Greenstream pipeline bringing gas into Italy from Libya (and representing some 10% of Italian imports) remained closed throughout the second quarter.



Sources: Eurostat COMEXT, Gas Strategies, Platts

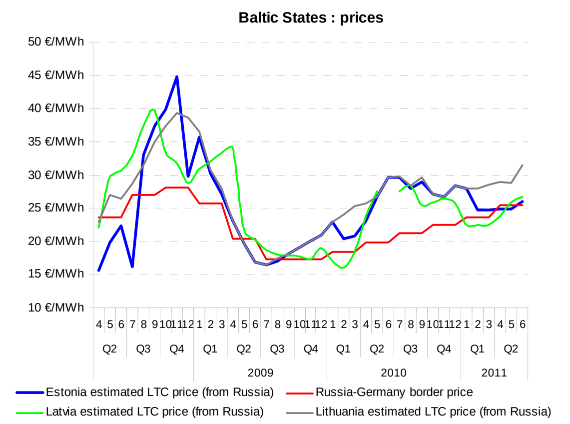
At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

Compared to other gas contracts, the Italian day-ahead traded at an average of 6 €/MWh discount to piped gas from the Netherlands and 3 €/MWh relative to Russian imports as reported by *Gas Strategies*. However gas imports from Algeria (25.7 €/MWh) were slightly cheaper than traded gas, while the price paid for LNG deliveries to Italy (of 26.9 €/MWh) was slightly higher than both.

Baltic States

Estimations of LTC prices of Russian gas to the different Baltic States of the EU for the second quarter of 2011 show that while Estonia continued to benefit from falling prices for the third successive quarter (down to 25.3 €/MWh), average quarterly prices went up in Latvia by 3 €/MWh (to 25.4 €/MWh) while Lithuania experienced a second successive increase, reaching a level of 29.8 €/MWh. In comparison, the average monthly German border price paid in Q2 was 25.5 €/MWh.

This was in contrast to general LTC contracts in NWE as well as other European markets, which stabilised in Q2.



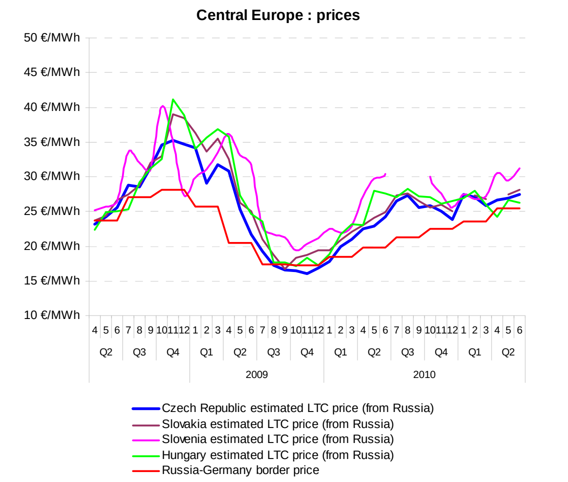
Sources: Eurostat COMEXT, Gas Strategies.

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

At the time of publication, Gas Strategies is in the process of reviewing its methodology for calculation of LTC prices. Any changes and explanations for changes will be provided and highlighted in the next issue of this publication.

Other Central EU Member States

The estimated monthly average LTC price of Russian gas in Central EU Member States in the second quarter of 2011 ranged from 25.7 €/MWh in Hungary to 30.4 €/MWh in Slovenia, in contrast to a price range in the previous quarter of between 22.2 €/MWh in Slovakia to 27.1 €/MWh in Slovenia. Thus the overall trend was one of increasing prices for Russian gas in Central EU Member States in the second quarter of 2011.



Sources: Eurostat COMEXT, Gas Strategies.

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts. Q3 2010 Slovenian border prices are not included as these are being reviewed.

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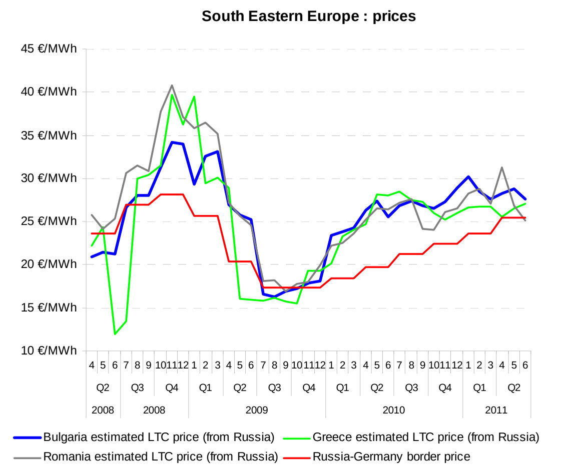
Other South-Eastern EU Member States

The average quarterly price of Russian gas in South-Eastern EU Member States in Q2 2011 varied between 26.4 €/MWh in Greece and 28.2 €/MWh in Bulgaria. On a quarterly basis, all three countries (Romania included) experienced decreases in prices relative to the previous quarter, after seeing rises between Q4 and Q1.

Observing the evolution of the estimations of LTC prices of Russian gas to these Member States in the graph below, in comparison to the price of German imports of Russian gas, it is interesting to note the increasing gap that could be seen during the course of 2010, which was then reduced to a certain extent in the latter part of the year. This observation is also valid for prices of Russian gas in Baltic and central European countries (see preceding charts).



Source: Eurostat COMEXT, Gas Strategies.

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

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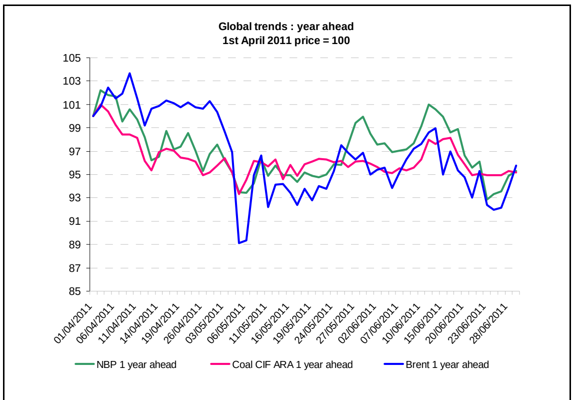
A.2.2 EU forward gas markets

After two quarters of continued increases in forward prices of energy commodities – driven initially in Q4 2010 by increasing demand supported by a recovering economy, and then in Q1 2011 by future energy supply uncertainties due to conflicts in the Middle East and Northern Africa – the trend in Q2 2011 was clearly a downward one.

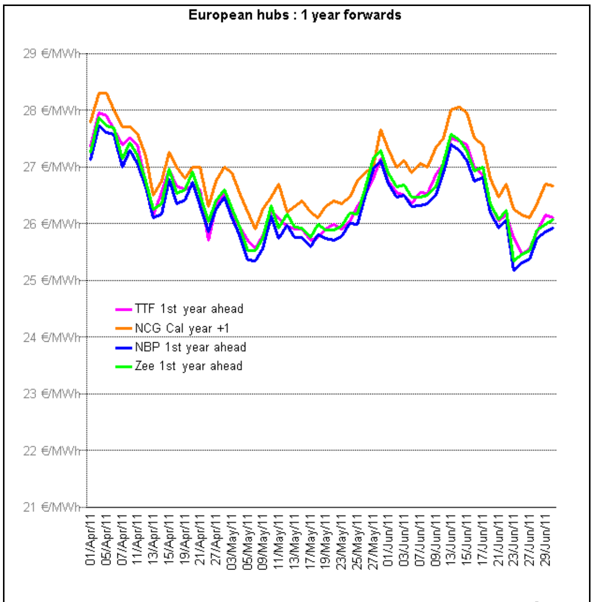
As was explained in the last report, expectations of rising gas prices came following expectations of probable diversions of flexible LNG from Europe in order to supply Japan following the nuclear outages. Another important factor pushing up gas prices was the uncertainty surrounding nuclear energy in the EU in the aftermath of the incidents in Japan in mid-March. Along with the decision to submit EU nuclear power stations to stress-testing, Germany decided in May 2011 to shut down all of its nuclear capacities by 2022.



Source: Platts.

However, the observation of falling EU gas consumption as well as rising fears of sovereign debt defaults in the eurozone geopardising the recovery appears to have weighed down on one year forward prices, with the consequence that the 4 to 5 €/MWh increase in one year forward prices of gas during the first quarter of 2011 gradually disappeared over the course of April and May.

Gas storage levels were also high relative to recent years, which reassured market participants that near-curve winter gas contracts would be supported by plentiful storage as back-up (see more on storage in the next section). Also, no diversion towards Asia of flexible LNG bound for Europe was actually experienced over the second quarter.



Source: Platts.

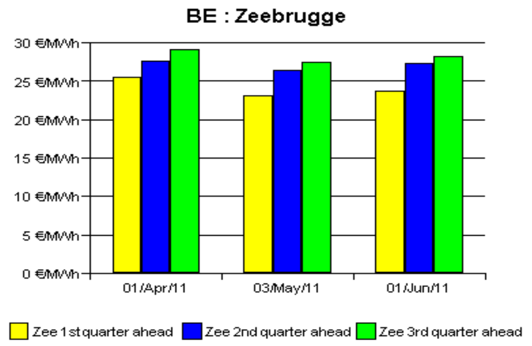
Forward prices were however quite volatile over the quarter, as can be seen in the graph above during the month of June when prices went back up again some 3 €/MWh, only to fall back down later in the month.

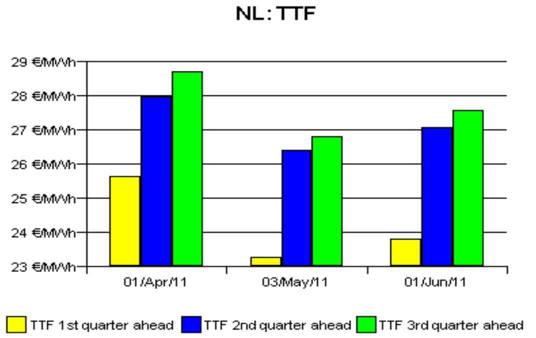
This volatility can also be observed in the charts below which show first, second and third quarter forwards for different hubs, with no clearly detectable trend in prices apparent. This contrasts with the first quarter, when a rising trend could be clearly observed, with higher prices being demanded, the further ahead the quarter.

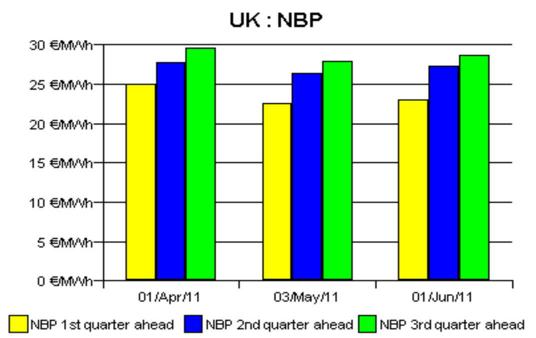
However, the near-forward gas curve continues to be in contango[6], as can be seen if first to third quarter ahead prices

[6] The 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.

are examined for any of the three dates shown in the graphs below. This is less surprising the further we go into the quarter, as cooler months lie ahead, but contango is less evident for early April and May, and may be explicable more by economic uncertainties.





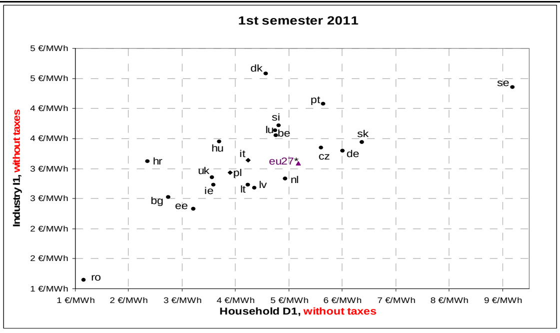


Source: Platts.

A.2 Retail markets

A.2.1 Price levels

The first two charts below show prices of natural gas paid by households and industrial customers in the 1st half of 2011. For both household and industrial customers prices of median level annual consumption bands (corresponding to household consumption band[7] D_1 and industrial consumption band I_1) are illustrated here. The first chart shows gas prices without taxes (net prices) in the EU Member States, Croatia and Turkey. The second chart shows prices including all taxes (gross prices)[8].



Source: Eurostat

Range for annual consumption of :

Household group D1 : [0 MWh – 5,56 MWh] ;

Industry group I1 : [0 GWh – 0,28 GWh];

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

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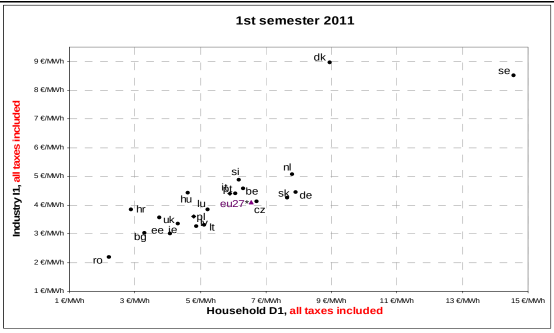
[7] It should be noted that the indicative Eurostat categories of household and industry consumers are not necessarily representative of the average customer for a given Member State due to different consumption patterns across the EU.

[8] In the case of industrial consumers prices without VAT are presented as gross prices while industrial consumers are subjects to VAT reimbursement and VAT free prices better represent the prices they actually pay.



Source: Eurostat

Range for annual consumption of :
Household group D1 : [0 MWh – 5,56 MWh] ;
Industry group I1 : [0 GWh – 0,28 GWh];
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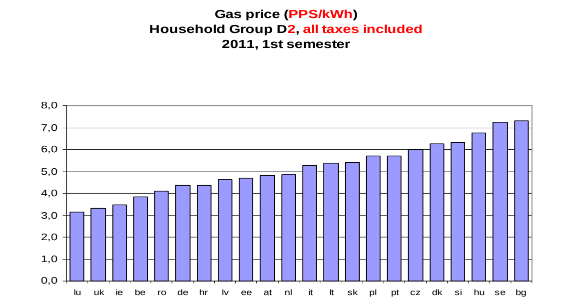


Household group D2 : [5,56 MWh – 55,6 MWh] ;
Notes; data for Spain, France, Finland, Greece, and Turkey are not available
Source: Eurostat

In the first half of 2011 the ratio of the highest and the lowest gross household natural gas price among the EU Member States was 7.9 (for category D_1), being almost identical to that of the second half of 2010 (8.0). The ratio was in both cases Sweden/Romania.

In the case of industrial consumers this ratio grew from 3.9 to 4.0 during the two semesters of 2010. The difference between the cheapest and the most expensive Member State for household consumers amounted to 8 €cent/kWh, while in the case of industrial consumers prices varied in a narrower range of 3.4 €cent/kWh in the first half of 2011.

The EU-27 average of household gas prices in consumption band D_2 was not available, hence through this paragraph the last available data is used (as of second half of 2010). The highest net prices could be observed in Sweden, Denmark and The Netherlands (respectively, 9.4 €cent/KWh, 9 cent/kWh and 5.5 €cent/kWh). On the other hand in Romania prices as low as 2.2 cent/kWh.

When correcting for purchasing power by measuring prices in PPS[9], Sweden could still be found in the group of the five most expensive countries, together with Hungary and Bulgaria. UK, Ireland and Luxemburg become the cheapest countries. Generally, calculations of prices for gas in PPS renders gas prices in 'New Member States' more expensive than in absolute terms and narrows the distinction between 'old' and 'new' Member States in the ranking order. In fact, the ratio between highest and lowest after-tax price for domestic consumers falls from 4.3 to 2.3 when correcting by PPS.

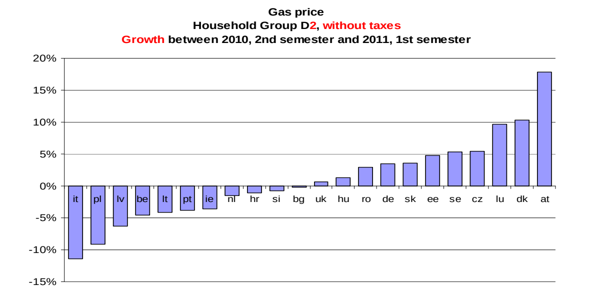
The price dispersion of industrial gas prices in the EU Member States was smaller than in the case of household consumers. The range of highest to lowest pre-tax price was 2.1 €cent/kWh, significantly smaller then the 3.9 €cent/kWh differential for household consumers (category D_2). Similarly to the household consumers the highest industrial consumer gross prices could be observed

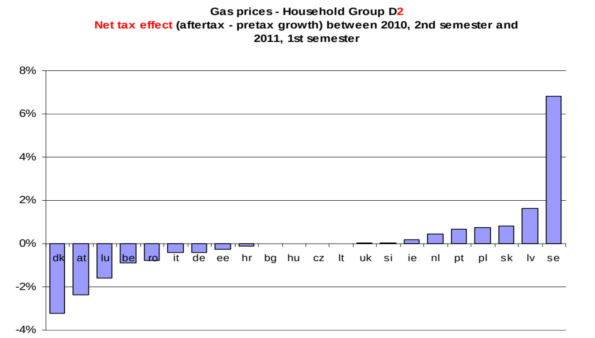
[9] Purchasing power standards

in Sweden (3.3 €cent/kWh) and the lowest one in Romania (1.2 €cent/kWh).

A.2.2 Price evolution

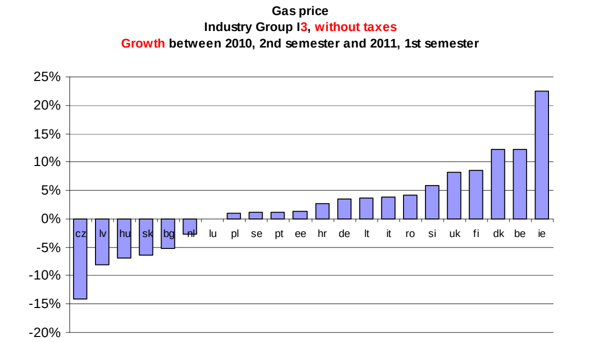
As the next chart shows there were some significant household gross price increases in some European countries with respect to the second half of 2010. Highest rises were in Austria (17.81%), Denmark (10.35%) and Luxembourg (9.66). The largest decreases in household gross prices were in Italy (-11.5%), Poland (-9.1%) and Latvia (-6.3%).

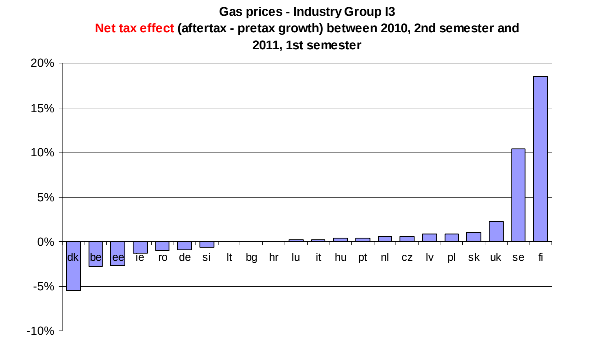




Household group D2 : [5,56 MWh – 55,6 MWh] ;
Data for Spain, France, Greece, Finland and Turkey are not available
Source: Eurostat

There were some significant values of the net tax effect[10], the largest (in absolute terms) being Sweden, where a pre-tax increase of about 5.3% was coupled with a tax increase which resulted in an after-tax price growth of 12.1% (net tax effect 6.8%).





Industry group I3 : [2,77 GWh – 27,8 GWh];
Data for Spain, France, Greece, Finland, Turkey and Austria are not available
Source: Eurostat

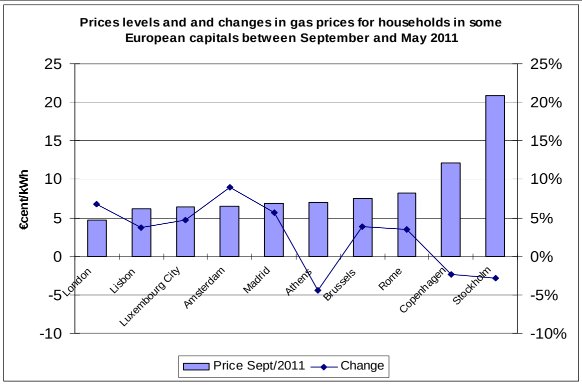
On the other hand, for industrial consumers, Finland and Sweden had the biggest positive net tax effect price differentials (respectively, 18.5% and 10.25%). In both countries, an increase in gross prices was coupled with a more-than-proportional tax increase.

On the other hand, the most significant negative net tax effect was in Denmark (-5.5%).

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

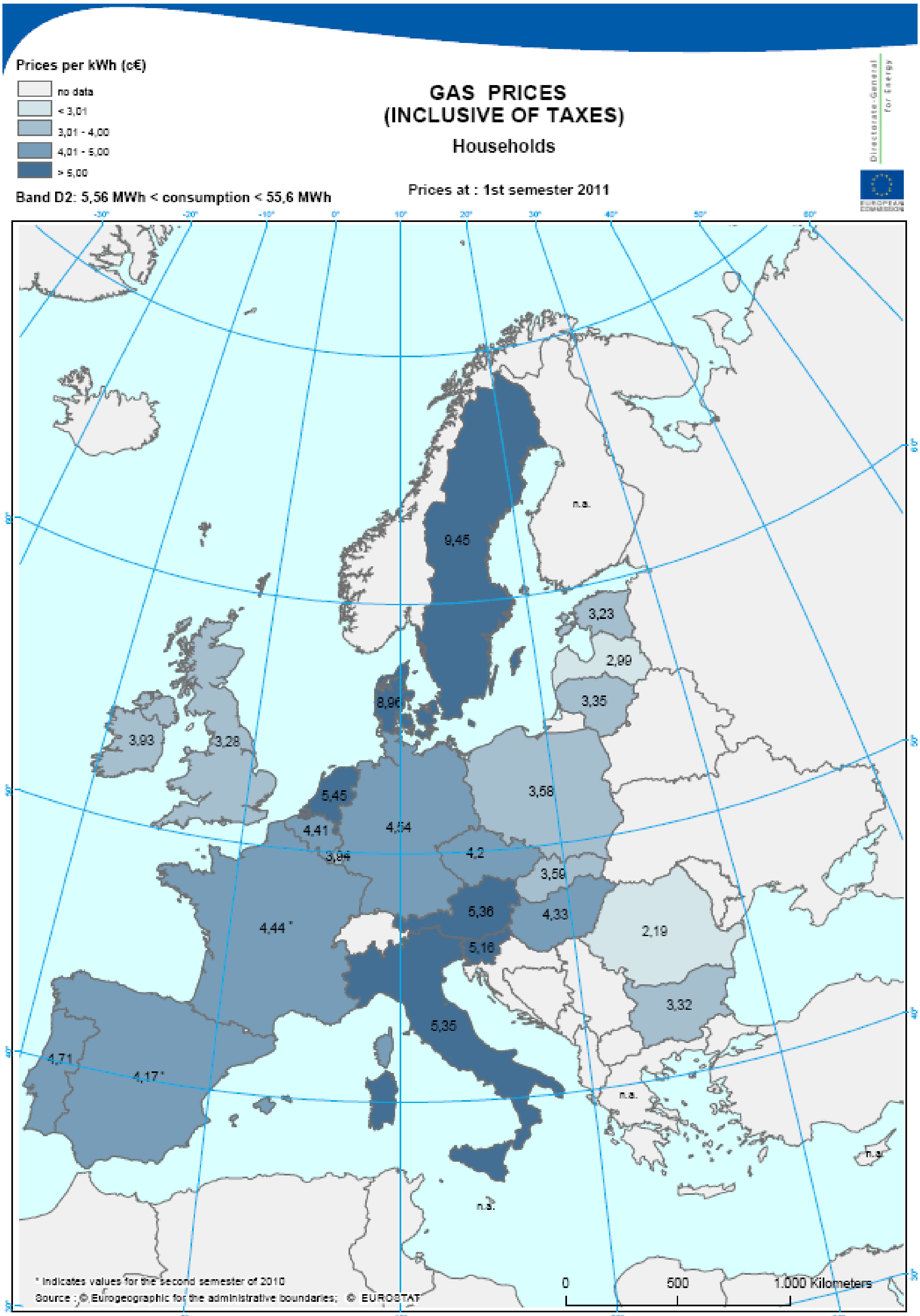
The next chart shows the evolution of all-inclusive retail gas prices paid by households in some European capitals between May 2011 and September 2011. Price rose in the majority of European capitals. The highest increase was in Amsterdam (8.94%), followed by London (6.76%) and Madrid (5.68%).

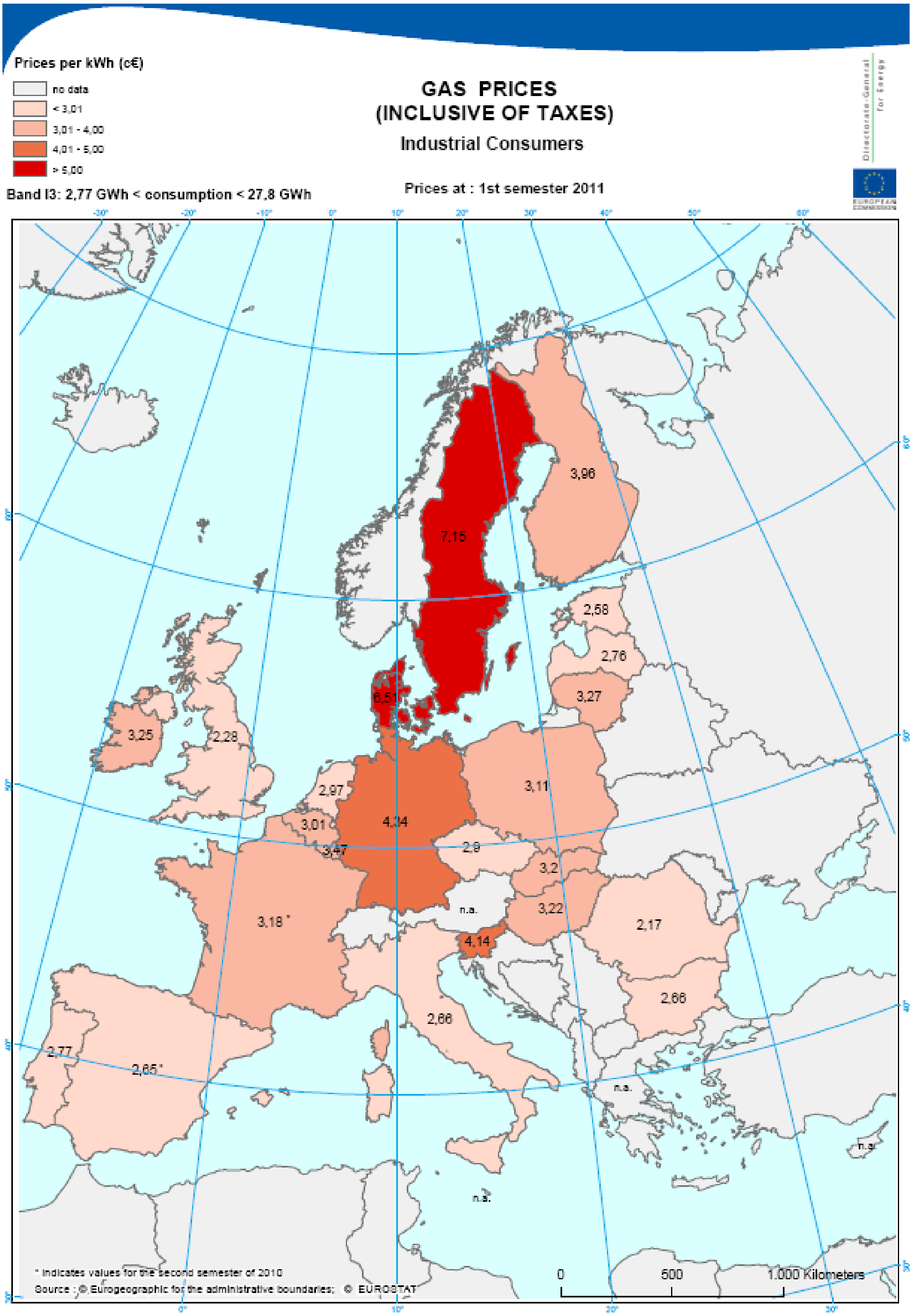
The most significant price decreases were in Athens (-4.4%), Stockholm (-2.8%) and Copenhagen (-2.33%).



Source: HEPI

The HEPI gas 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.


Prices per kWh (c€)
no data
< 3,01
3,01 - 4,00
4,01 - 5,00
> 5,00
Band D2: 5,56 MWh < consumption < 55,6 MWh
GAS PRICES
(INCLUSIVE OF TAXES)
Households
Prices at : 1st semester 2011
n.a.
9,45
3,23
2,99
3,35
8,96
3,93
3,28
3,58
5,45
4,54
4,41
3,94
4,2
3,59
5,36
4,33
4,44 *
2,19
5,16
3,32
5,35
4,71
4,17 *
n.a.
n.a.
n.a.
0
500
1.000 Kilometers
* Indicates values for the second semester of 2010
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT


Prices per kWh (c€)
no data
< 3,01
3,01 - 4,00
4,01 - 5,00
> 5,00
Band I3: 2,77 GWh < consumption < 27,8 GWh
GAS PRICES
(INCLUSIVE OF TAXES)
Industrial Consumers
Prices at : 1st semester 2011
3,96
7,15
2,58
2,76
3,27
6,51
3,25
2,28
2,97
3,11
3,01
4,34
3,47
2,9
3,2
3,22
n.a.
3,18 *
2,17
4,14
2,66
2,66
2,77
2,65 *
n.a.
n.a.
n.a.
* indicates values for the second semester of 2010
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT
0
500
1.000 Kilometers

B. Storage

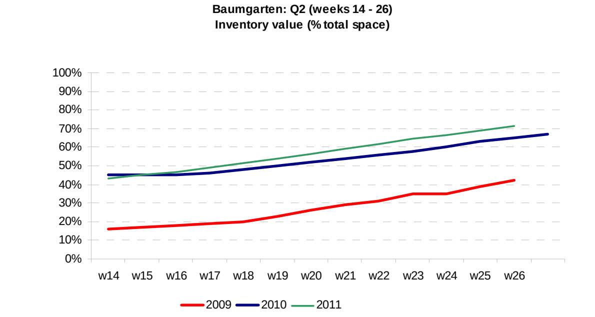
To put hub storage levels in the second quarter in context, it is useful to recall how storage levels evolved in the preceding two quarters. By the end of the fourth quarter storage levels had decreased considerably in a number of markets, as a result of low levels[11] at the start of the quarter and higher than expected demand for natural gas due to severe weather conditions especially in the latter part of the quarter.

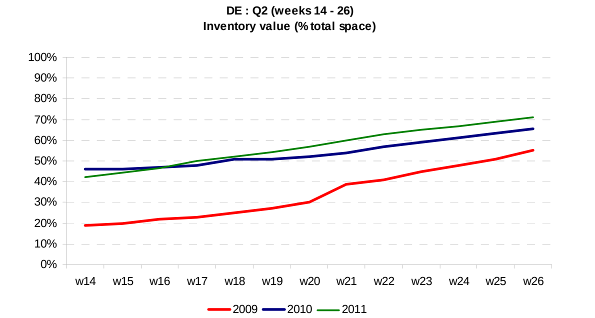
There was therefore concern by market participants over whether the necessary gas supplies could continue to be maintained during the remainder of the cold season in Q1. Such concerns were however allayed during the course of the first quarter as warmer than normal temperatures meant that levels of demand for natural gas were relatively low for that time of year, unlike at the end of 2010.

This allowed storage withdrawals of natural gas (common for that time of year to respond to high demand) to be relatively contained. Combined with the opportunistic reinjection of gas into storages which the contango situation[12] of day-ahead and near term hub prices incentivised, this meant that by the end of the quarter storage levels in a number of hubs were in fact higher than usual for this time of year.

Thus, by the start of the second quarter, gas storage levels were already high. This can be seen in the graphs below especially in the case of the NBP and the TTF.

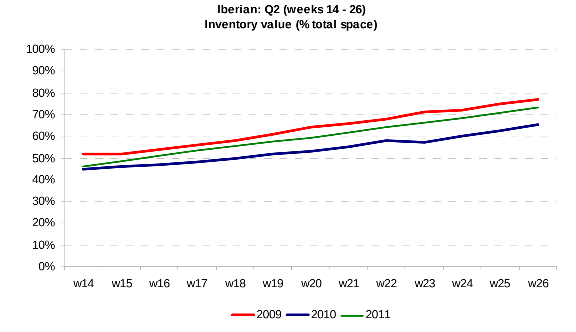
Warm weather during the second quarter also meant that storage injections boosted levels further as there was relatively little need for withdrawals. With falling demand for natural gas being observed across the EU, storage levels by the end of the second quarter generally exceeded levels recorded for that time of year in recent years.

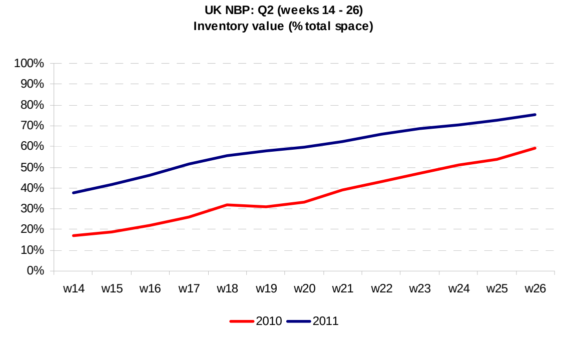


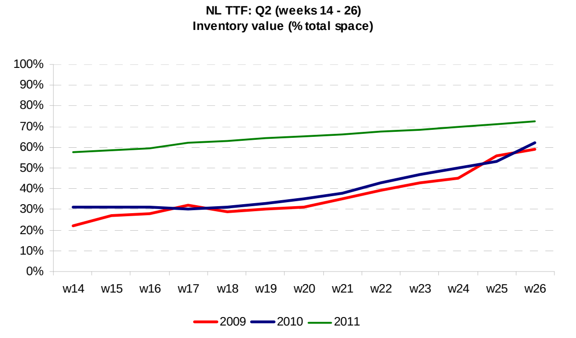


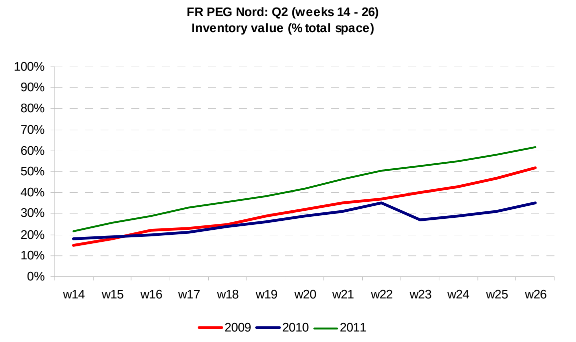
[11] The months of September and October usually mark the end of the summer injection period during which storages are refilled in preparation for the cooler months ahead.

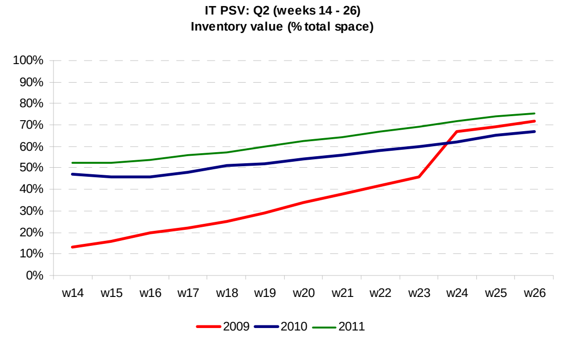
[12] The situation of *contango* arises when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.

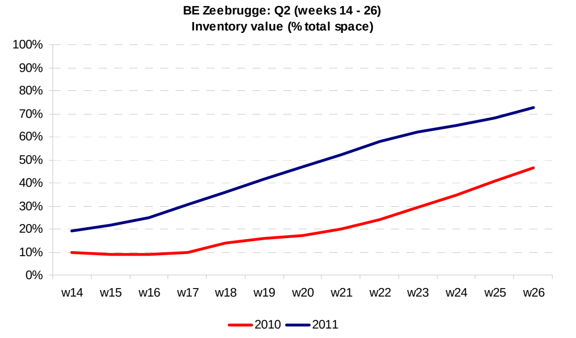












Source: Gas Infrastructure Europe

C. Focus on Congestion Management

The European Commission is in the process of preparing legally binding guidelines on Congestion Management Procedures which will be annexed to the Regulation (EC) No. 715/2009. In October 2011 it held workshops with Member States and industry representatives and is now finalizing the text for adoption through comitology procedure.

In close to 15 years since the first EU internal market legislation for the gas sector there has only been limited development of competition in the sector with national incumbents largely remaining in dominant positions on many national markets. The use of infrastructure in a network industry such as natural gas is non-substitutable. In trying to achieve the headline goal of creating a competitive, secure and sustainable internal gas market it is crucial that all players have access to capacity. Competition in the supply of commodity gas can only develop if market players are allowed equal and non-discriminatory access to transmission capacity. Only this equal access will provide the competitive platform from which gas customers across the EU can benefit.

Currently, the availability of cross-border capacities at many of Europe's interconnection points is low. This is partly due to the problem of contractual congestion, caused by the coincidence of - to a large extent - historic, long-term capacity reservations (at many points all the capacity is sold-out for many years into the future; see the table below) as well as increasing short-term capacity demand. Contractual congestion means that demand by the market for capacity is turned down by the network operator even if physically there is still space in the pipeline. This is the result of the fact that *contractually* the pipeline is fully booked but physically it is not fully used. This type of congestion undermines the creation of an integrated EU gas market, fragmenting it typically along national boundaries.

The Gas Regulation in force promotes a better use of the scarce interconnection capacity between countries through an improved handling of situations of contractual congestion. It enumerates several minimum actions (interruptible capacity and trading) to better manage contractual congestion but at the same time it also foresees further network codes or guidelines on congestion management to be developed through Comitology. These network codes should serve the purpose of providing the level playing field necessary for new entrants to take part in sustainable and successful competition with incumbents, either on the wholesale or the retail market.

Insofar as physical congestion is not a problem, before building new and expensive pipelines, it is more appropriate to optimize the use of existing capacity.

Legend for capacity sold:			
(black)	100%		
(dark grey)	>=90%	and	<100%
(medium grey)	>=50%	and	<90%
(light grey)	>0%	and	<50%
(dotted)	0%		
(white)	No data		

Figure 1 – Cluster analysis of long term capacity bookings (firm reservations as a share of technical capacity) at selected EU IPs (status of July 2011, for 2011, 2015, 2020, 2025, 2030 and 2035)[13]

IP Name	Country	Direction	TSO	Capacity category	2011	2015	2020	2025	2030	2035
Tarvisio	AT>IT	Exit	TAG	large	100%	>=90%	>=90%	>=90%	>=90%	>0%
Blaregnies Segeo	BE>FR	Exit	Fluxys	large	0%	100%	>=90%	>=50%	>0%	0%
Bacton	BE>UK	Entry	Interconnector	large	100%	100%	0%	0%	0%	0%
Waidhaus	CZ>DE	Entry	GRT. DE	large	>=90%	>=90%	>=50%	>=50%	>0%	0%
Waidhaus	CZ>DE	Entry	OGE	large	100%	100%	100%	100%	100%	100%
Medelsheim	DE>FR	Exit	GRT. DE	large	100%	>=50%	>=50%	>=50%	>0%	0%
Bunde	DE>NL	Exit	WIN	large	>=50%	100%	100%	0%	0%	0%
Bunde	NL>DE	Entry	WIN	large	>=50%	100%	No data	No data	No data	No data
Julianadorp	NL>UK	Exit	GTS	large	>=90%	100%	>=90%	>0%	0%	0%
Mallnow	PL>DE	Entry	WIN	large	>=90%	>=90%	>=90%	0%	0%	0%
Baumgarten	SK>AT	Entry	BOG	large	>=50%	>=50%	>=50%	>=50%	>=50%	>0%
Baumgarten	SK>AT	Entry	TAG	large	>=90%	>=90%	>=90%	>=90%	>=50%	>0%
Lanžhot	SK>CZ	Exit	Eustream	large	>=90%	>=50%	>=50%	0%	0%	0%
Bacton	UK>BE	Exit	National Grid	large	100%	100%	100%	100%	0%	0%
H. S. Kateřiny	CZ>DE	Exit	N4G	medium	>=50%	>0%	0%	0%	0%	0%
Lanžhot	CZ>SK	Entry	Eustream	medium	>=50%	>0%	0%	0%	0%	0%
Gravenvoeren	NL>BE	Exit	GTS	medium	100%	100%	>=50%	>0%	0%	0%
Bocholtz	NL>DE	Entry	ENI D.	medium	100%	100%	100%	>=90%	0%	0%
Zevenaar	NL>DE	Entry	OGE	medium	100%	100%	100%	>=50%	0%	0%
Hilvarenbeek	NL>BE	Exit	GTS	N/A	100%	100%	>=90%	>=50%	0%	0%
Winterswijk	NL>DE	Exit	GTS	N/A	100%	100%	>=50%	>0%	No data	No data
Oberkappel	AT>DE	Entry	GRT. DE	small	100%	>=90%	>=50%	100%	0%	0%
Oberkappel	AT>DE	Entry	OGE	small	>0%	100%	>0%	>0%	0%	0%
Eynatten	BE>DE	Entry	ENI D.	small	>=50%	>=50%	>=50%	>=50%	0%	0%
Eynatten	BE>DE	Entry	OGE	small	100%	100%	>=50%	>=50%	0%	0%
Eynatten	BE>DE	Entry	Thyssengas	small	100%	0%	0%	0%	0%	0%
Eynatten	BE>DE	Entry	WIN	small	>=50%	>=50%	0%	0%	0%	0%
Sidikastiron	BG>GR	Entry	DESFA	small	>=90%	>=50%	0%	0%	0%	0%
Oberkappel	DE>AT	Exit	GRT. DE	small	100%	100%	100%	100%	0%	0%
Oberkappel	DE>AT	Exit	OGE	small	100%	100%	>0%	>0%	0%	0%
Eynatten	DE>BE	Exit	ENI D.	small	100%	100%	100%	100%	0%	0%
Eynatten	DE>BE	Exit	OGE	small	100%	100%	>0%	>0%	0%	0%
Eynatten	DE>BE	Exit	WIN	small	100%	100%	100%	0%	0%	0%
H. S. Kateřiny	DE>CZ	Exit	Ontras	small	100%	>=90%	0%	0%	0%	0%
Medelsheim	DE>FR	Exit	OGE	small	100%	0%	0%	0%	0%	0%
Bunde	DE>NL	Exit	GUD	small	100%	>=50%	>=50%	0%	0%	0%
Bunde	DE>NL	Exit	OGE	small	100%	100%	>0%	>0%	0%	0%
Lasow	DE>PL	Exit	Ontras	small	100%	>=50%	0%	0%	0%	0%
Larrau	ES>FR	Entry	TIGF	small	100%	>=50%	>=50%	>0%	0%	0%
Badajoz	ES>PO	Exit	Enagas	small	100%	100%	100%	100%	>=90%	>=50%
Larrau	FR>ES	Entry	Enagas	small	>=90%	>=50%	>=50%	No data	No data	No data
Gorizia	IT>SL	Entry	Geoplin	small	>0%	>0%	>0%	No data	No data	No data
Bocholtz	NL>DE	Entry	OGE	small	100%	100%	100%	100%	100%	No data
Bocholtz	NL>DE	Entry	THY	small	>=50%	0%	0%	0%	0%	0%
Bunde	NL>DE	Entry	GUD	small	100%	100%	>0%	0%	0%	0%
Bunde	NL>DE	Entry	OGE	small	100%	100%	No data	No data	No data	No data
Zevenaar	NL>DE	Entry	Thyssengas	small	>=50%	0%	0%	0%	0%	0%
Badajoz	PO>ES	Entry	Enagas	small	>0%	0%	0%	0%	0%	0%
Gorizia	SL>IT	Entry	SRG	small	0%	0%	0%	0%	0%	0%

Background to the data

- Capacity data provided by TSOs via ENTSOG according to transparency provisions of Regulation (EC) No. 715/2009. (not all TSOs replied and, some data seems to be missing and some confidentiality claims have been made on the data)
- Calculations were done by ENTSOG and EC
- IPs selected largely on the basis of 2011 ERGEG Monitoring study on 21 Interconnection Points in the EU (http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Gas/Tab/E10-GMM-11-05_CAM-CMP%20Monitoring%20Report_2-Febr-2011.pdf)
- „Capacity category": Size of pipelines categorized based on 2011 firm technical capacity figures (GWh/d) [Small: 0-253 GWh/d (253 GWh/d is the median); Medium: 253-409 GWh/d (409 GWh/d is the mean); Large: 409-1870 Gwh/d]
- IPs with no 2010 flows were filtered out
- For IP entry-exit pairs capacity reservation data for the more congested (bottleneck) side of the border is displayed

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