Hungarian Energy Market REPORT

1st Issue 2012

Regional Centre for Energy Policy Research
REKK

REKK

The aim of the Regional Centre for Energy Policy Research (REKK) is to provide professional analysis and advice on networked energy markets that are both commercially and environmentally sustainable. We have performed comprehensive research, consulting and teaching activities on the fields of electricity, gas and carbon-dioxide markets since 2004.Our analyses range from the impact assessments of regulatory measures to the preparation of individual companies' investment decisions.

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- regional electricity and gas price modelling
- CO_2 allowance allocation and trade
- supports for and markets of renewable energy sources
- security of supply
- market entry and trade barriers
- supplier switching

Consultancy services

- price forecasts and country studies for the preparation of investment decisions
- consultancy service for large customers on shaping their energy strategy on the liberalised market
- consultancy service for regulatory authorities and energy supply companies on price regulation
- consultancy service for system operators on how to manage the new challanges

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Our training programmes:

- summer schools
- courses for regulators
- trainings and e-learning courses in the following topics:
  - price regulation
  - electricity markets
  - market monitoring
  - gas markets
- occasional trainings for companies based on individual claims

Nowadays, due to market opening, energy markets cannot be analysed without taking into account regional environment. We monitor the market situation and developments of the countries of the Central Eastern and South East European region. We have built a regional electricity market model including 15 countries to forecast regional electricity prices.

The experts of REKK with their energy regulatory experience and academic background can supply scientific solutions taking also into account the specialities of the given markets.

Our reference partners:

Regulatory authorities and ministries

HEO (Hungarian Energy Office), GVH (Hungarian Competition Authority), KVVM (Ministry of Environment and Water), GKM (Ministry of Economy and Transport), FVM (Ministry of Agriculture and Rural Development)

Energy companies and large customers

Mavir, E.ON, MOL, MVM, ELMŰ, Főgáz, Alcoa, DRV

International organisations

DG TREN, USAID, ERRA, CEER, NARUC

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Dear Reader!

We are delighted to present to you the first issue of volume 4 of our *Hungarian Energy Market Report.* We honestly hope that our readers have been satisfied with the earlier issues of the Report.

In addition to reviewing the last quarter of the electricity and gas markets, we publish four studies.

Our first analysis looks at changes that have taken place in the procurement method of system level reserves. Thanks to a more favourable methodology less capacity is reserved by the system operator, at a considerably lower cost, resulting in lower system level service fees for the customer.

Our second articles highlights a long term trend in the domestic demand for natural gas: since 2004 household, power plants and industrial consumption all declined.

The third piece covers trader switching activity within the retail electricity market. While, as a result of low universal service tariffs, households are still reluctant to switch traders, within the commercial segment 2011 brought about an increased willingness to switch and more intense retail competition.

Our fourth article describes the draft regulation of the Commission on electricity and natural gas network development, promising a faster and easier permitting process.

We hope the current issue continues to deliver a lot of useful information to our readers.

Péter Kaderják, *director*

ENERGY MARKET DEVELOPMENTS

During the last quarter of the year the price of crude oil, coal and natural gas slowly declined. Compared to the third quarter of 2010 the price of Brent oil became cheaper by 4 USD/barrel, the price of coal declined by 10 EUR on average, and futures natural gas cost 2 EUR less. The price of futures baseload and peak electricity declined by 3-5 EUR. CO_2 credits with December 2011 delivery were worth only 9 EUR/ton. The corrected electricity consumption of the last few months of the year was 1% less than 2010 consumption. 13.3% of the electricity use was based on import. During the quarter the price of cross-border capacities was typically high due to the capacity constraints starting in October on the Slovakian border section. The price of next day baseload products quoted by the exchanges of the region displayed a remarkable deviation: in December the price for the Hungarian market exceeded the German price by more than 14 EUR. The domestic futures electricity price also departed from the German, Czech and Slovak prices.

Due to the mild weather domestic gas consumption in the last quarter of the year was 370 million m^3 less than in the same period of the previous year. The difference between the oil indexed price and the price on the exchange continued to diverge, reaching 50 HUF/m^3 by the end of the year.

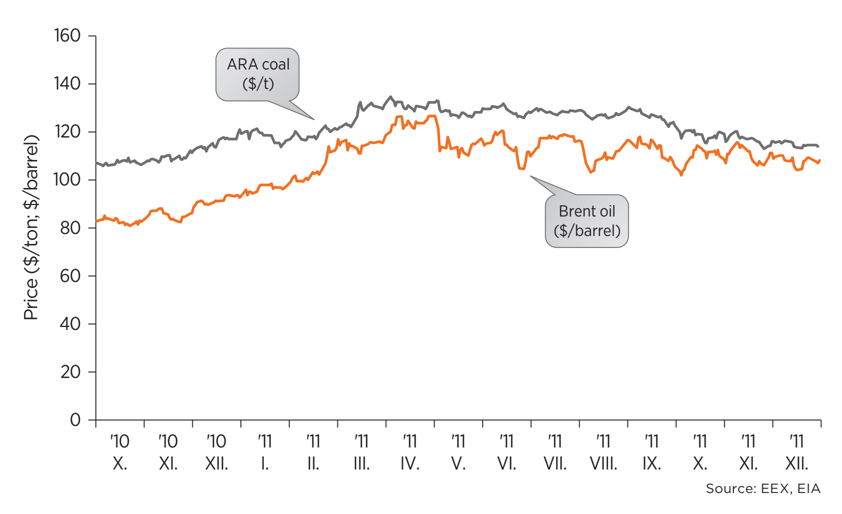


Figure 1. The price of 2012 ARA coal futures traded on EEX and the spot price of Brent Crude between October 2010 and December 2011

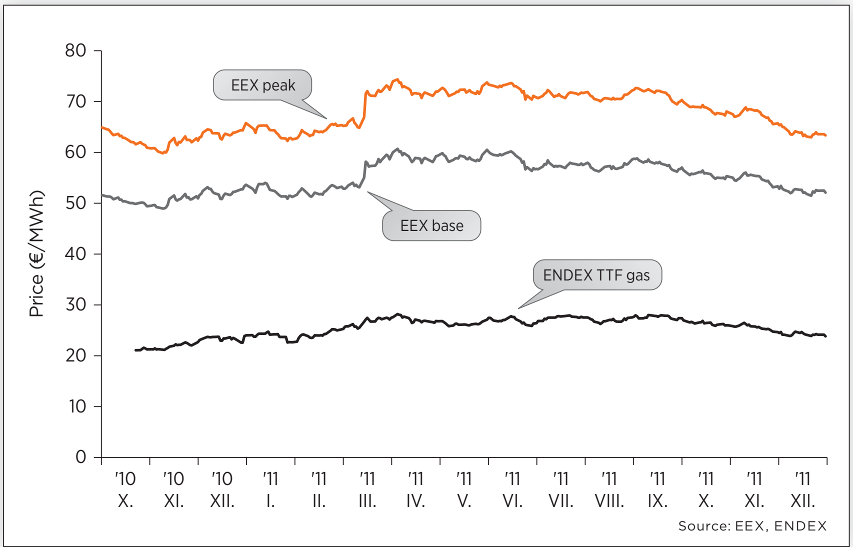


Figure 2. . The price of 2012 futures electricity and natural gas between October 2010 and December 2011

International price trends

In the 4th quarter of 2011 the crude oil and coal markets displayed a slow price decline. During the quarter the price of Brent Crude oscillated at around USD 110, delivering somewhat less price variation than in the previous quarter. The price of the 2012 futures ARA coal continued its slow decline, similarly to previous quarters, reaching USD 113 per traded unit by the last trading day of the year. Compared to the average September price a ton of coal in December was available at a discount of USD 10.

The price of 2012 futures baseload and peak electricity traded on the EEX declined by 5 EUR by the end of the period. The price of the baseload product varied between 51 and 56 EUR/MWh, a unit of this futures product in December was worth 52 EUR on average. Peak electricity was traded in a range of 63-69 EUR/MWh, with an average closing price of 64 EUR/MWh are the end of the quarter. The price of the 2012 futures natural gas listed on ENDEX also fell below the price of the previous quarter, being traded between 24 and 26 EUR/MWh on average, reaching 24 EUR/MWh during the last trading sessions.

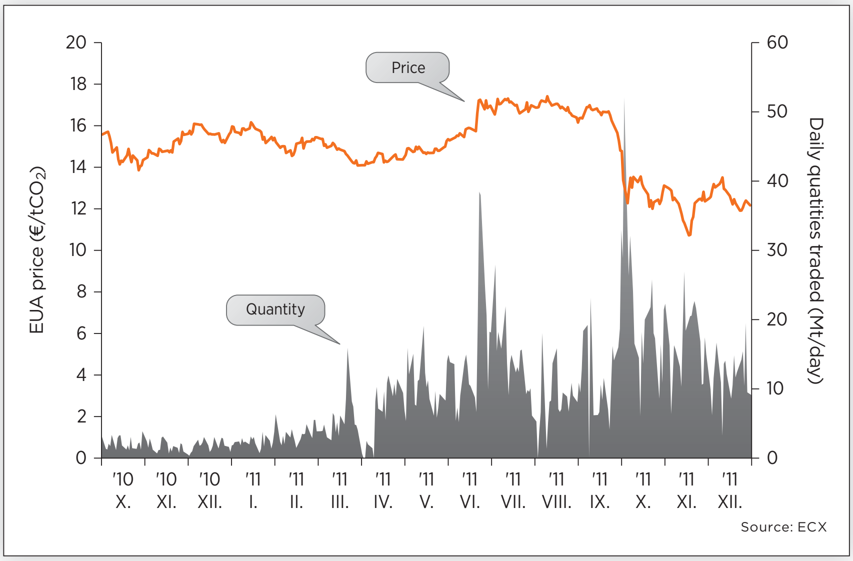
This was the last quarter when emission allowances with December 2011 delivery were traded. Prices continued to decline, during the period the average price of a ton of EUA was 9 EUR. In comparison to the previous quarter, volume declined by almost 30%.

Overview of the domestic electricity market

In the fourth quarter of 2011 the temperature adjusted power consumption, excluding seasonal impacts, was 1% below the figures of the same quarter of the previous year. The monthly variation within the quarter was significant: compared to the figures from the previous year, consumption in October was 1% lower, November displayed an increase of 2.2%, while December power use declined by 4.5%. Quarterly consumption was 2% higher than in 2009, and essentially the same as in 2008.

Net imports covered 13.3% of consumption, more than 5 percentage points above the net import ratio of the last quarters of the preceding two years.

In October and November on the Slovakian-Hungarian border section the allocated amount of cross border capacity was less than usual, but in December the volume of



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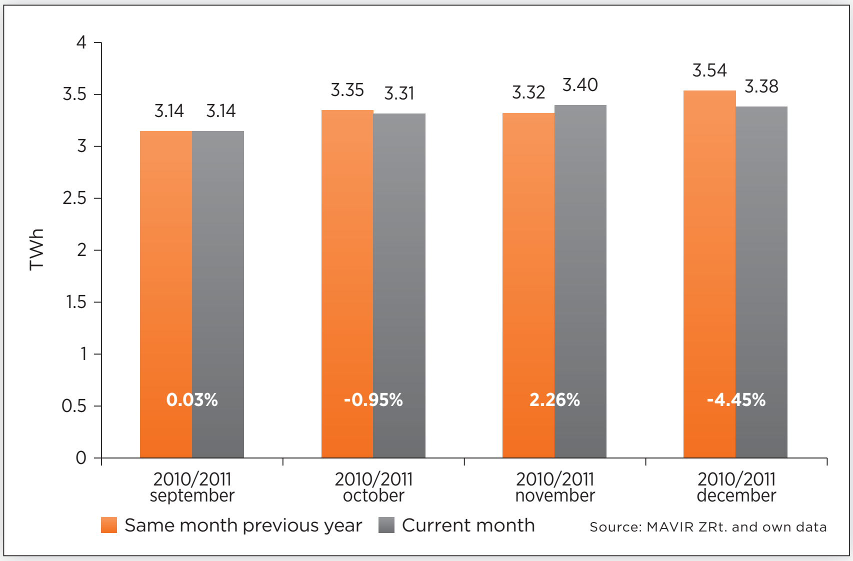


Figure 4. Adjusted electricity consumption between September 2010 and December 2011 relative to the same period of the previous year

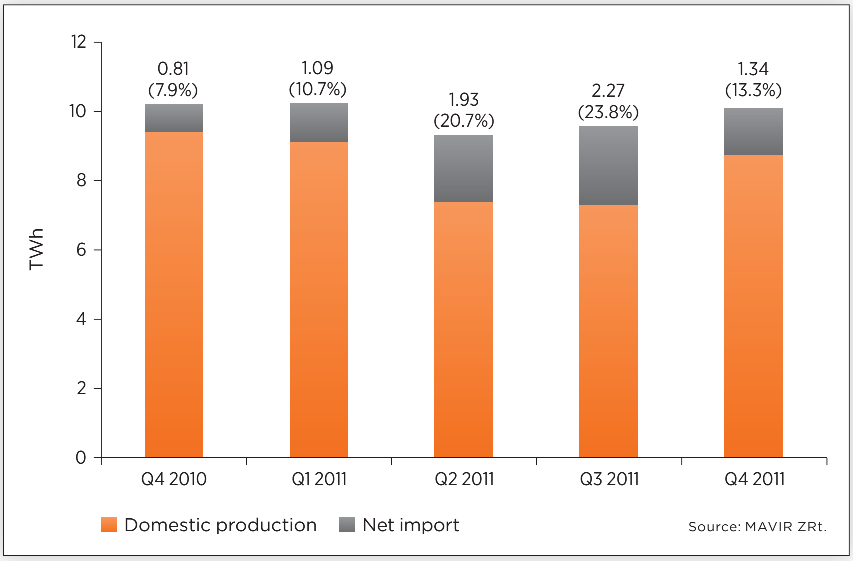


Figure 5. Quarterly domestic electricity production and net imports between Q4 2010 and Q4 2011

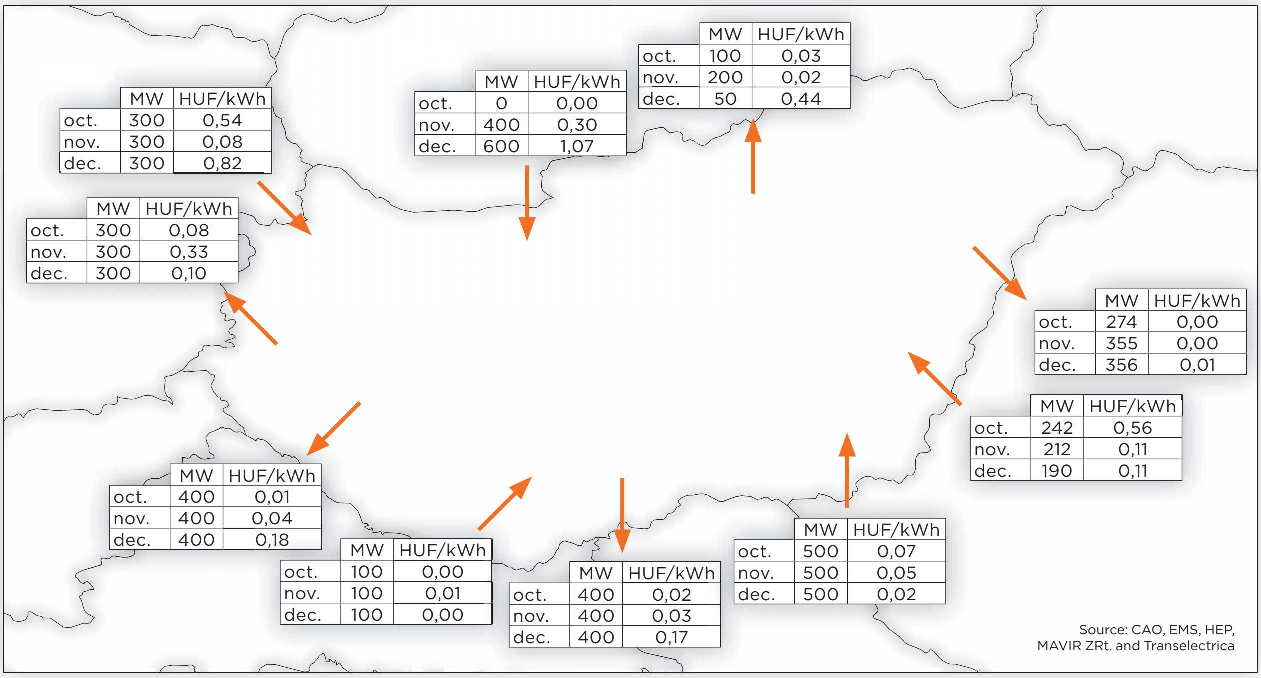


Figure 6. Results of monthly cross-border capacity auctions in Hungary, Q4 2011

Capacities above mean capacities offered for auction. Capacities were not sold fully in the period under review in the event of oversubscription at a specific price, because in such cases the system operator considers the next highest price as the auction price.

baseload power imported from our Northern neighbour was again 600 MW. In December the auction price on the Austrian-Hungarian border section came close to 1 HUF/kWh, while on the Slovakian-Hungarian section it exceeded it.

The average monthly price of electricity with next day delivery, traded on the regional exchanges, slightly declined in October, and then strongly rebounded in November on all four exchanges. By December OTE and EEX fell to annual lows of 40-42 EUR/MWh, while the average monthly price on HUPX and OPCOM turned out to be 57-59 EUR/MWh. The average monthly price of the product with next day delivery traded on OPCOM – the exchange which likes to pride itself as having the lowest prices – steadily rose for the last half year, exceeding the average monthly price of the German product with next day delivery by 17 EUR in December.

The wholesale price of electricity is influenced by the costs of deviations from the schedule and the balancing energy prices as well. The system operator sets the settlement prices of daily upward and downward regulation based on its procurement costs of energy from the balancing market. The financial costs of balancing for the balance circles are determined by the balancing energy prices and the spot price of electricity in the settlement period. The higher the difference between the price of upward and downward regulation and the spot wholesale price, the more it costs to acquire the required amount from the balancing market. The price of positive balancing energy increased to 30.53 HUF/kWh during the quarter, while the price of negative balancing energy was –1.22 HUF/kWh.

The decline of the price of the 2012 futures baseload products on the German, Czech, Hungarian and Slovakian exchanges was only

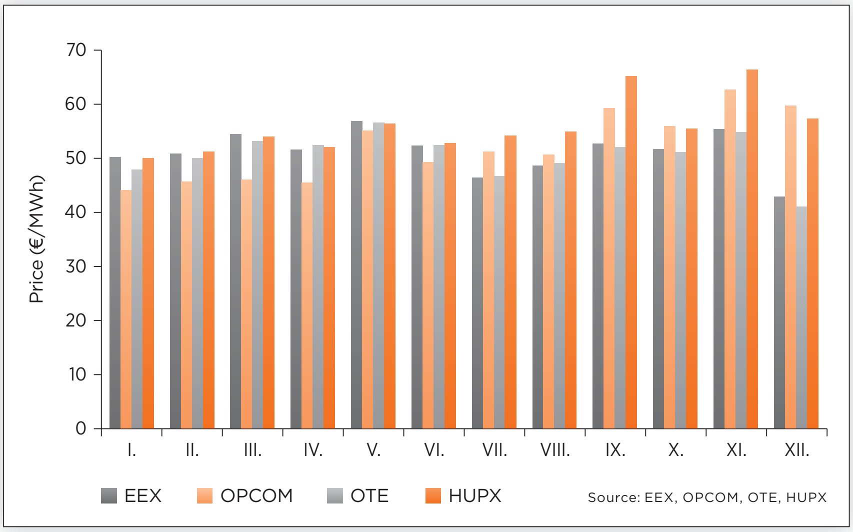


Figure 7. Comparison of next day baseload power prices on EEX, OPCOM, OTE and HUPX between January 2011 and December 2011

partially mitigated by the November price increase. The spread between the German and the Czech and Slovakian markets continued to decline, the price advantage of the Czech and Slovakian products dropped from an average 2 EUR in the previous quarter to 1.5 EUR. During the same period the decrease of the Hungarian baseload futures price was more restrained, therefore by December the spread between the prices of the German and the Hungarian product increased above 3.5 EUR.

The annual cross border capacities were sold during the quarter, and the 2012 baseload electricity was also auctioned through the tenders of the MVM. Compared to 2011 the size of available annual cross border capacities did not change, but the price for Austrian and Slovakian import increased by 1 HUF/kWh. In 2011 MVM Trade sold a total of 4.5 TWh of electricity through three auctions, of which 4.2 TWh was baseload power, sold

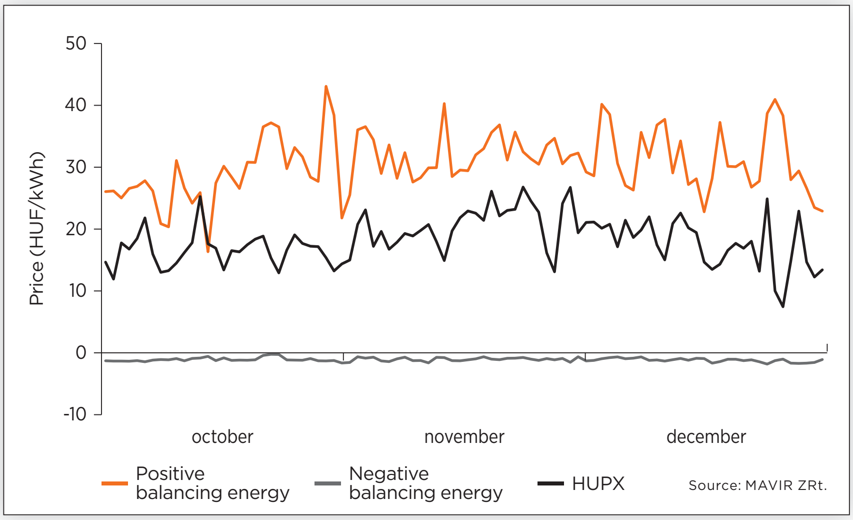


Figure 8. Daily average of balancing energy and spot prices, Q4 2011

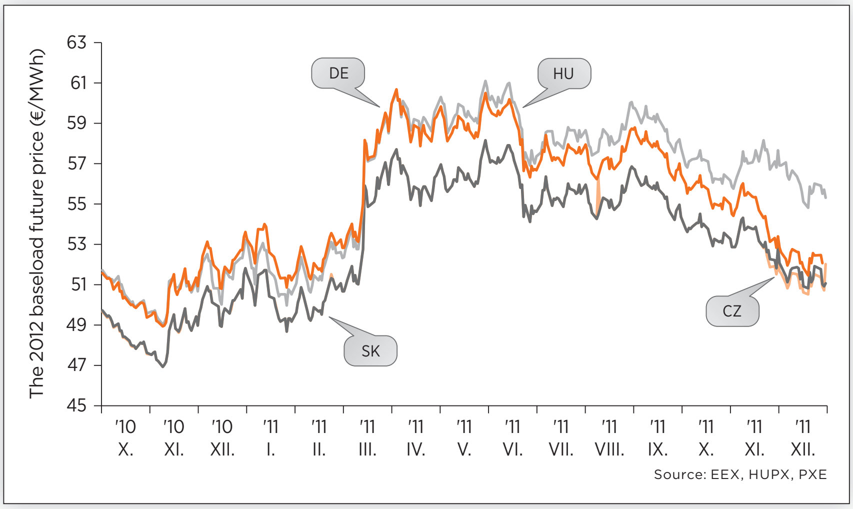
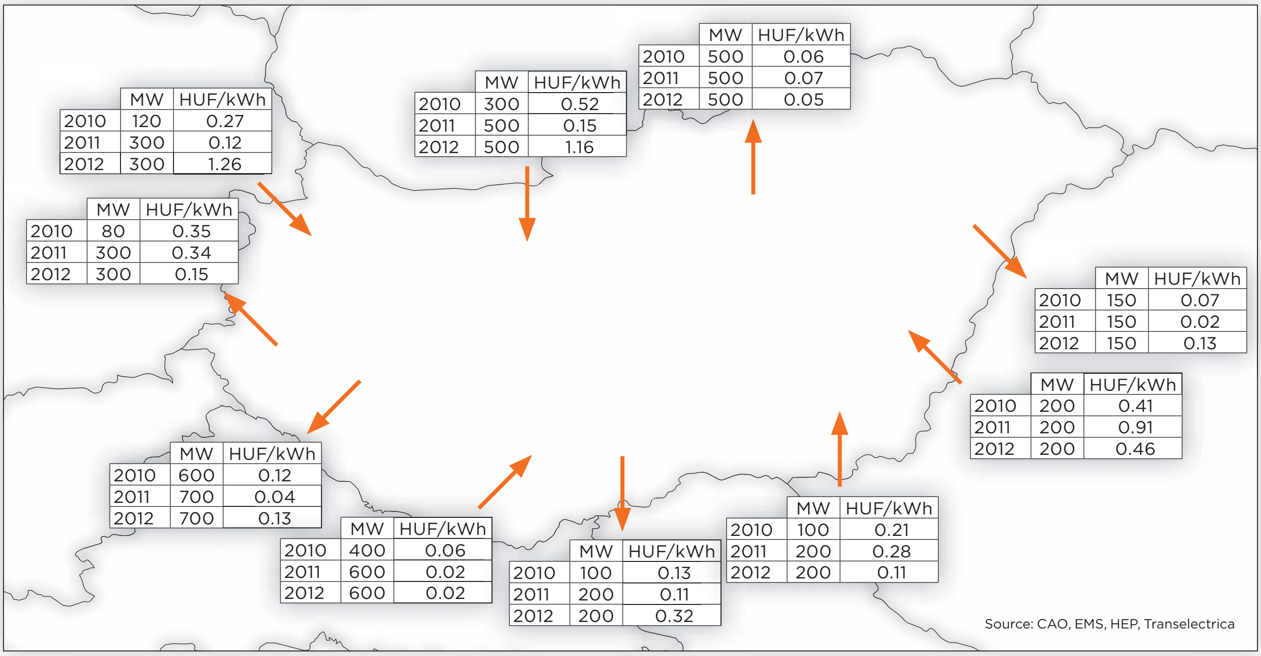


Figure 9. 2012 baseload futures prices in the countries of the region between October 2010 and December 2011



	MW	HUF/kWh
2010	120	0.27
2011	300	0.12
2012	300	1.26

	MW	HUF/kWh
2010	300	0.52
2011	500	0.15
2012	500	1.16

	MW	HUF/kWh
2010	500	0.06
2011	500	0.07
2012	500	0.05

	MW	HUF/kWh
2010	80	0.35
2011	300	0.34
2012	300	0.15

	MW	HUF/kWh
2010	150	0.07
2011	150	0.02
2012	150	0.13

	MW	HUF/kWh
2010	200	0.41
2011	200	0.91
2012	200	0.46

	MW	HUF/kWh
2010	600	0.12
2011	700	0.04
2012	700	0.13

	MW	HUF/kWh
2010	400	0.06
2011	600	0.02
2012	600	0.02

	MW	HUF/kWh
2010	100	0.13
2011	200	0.11
2012	200	0.32

	MW	HUF/kWh
2010	100	0.21
2011	200	0.28
2012	200	0.11

Figure 10. Results of the 2012 annual cross border capacity auctions in Hungary

The capacity values displayed in the figure represent the total volume auctioned by the two system operators together. Joint auctions took place on all border sections.

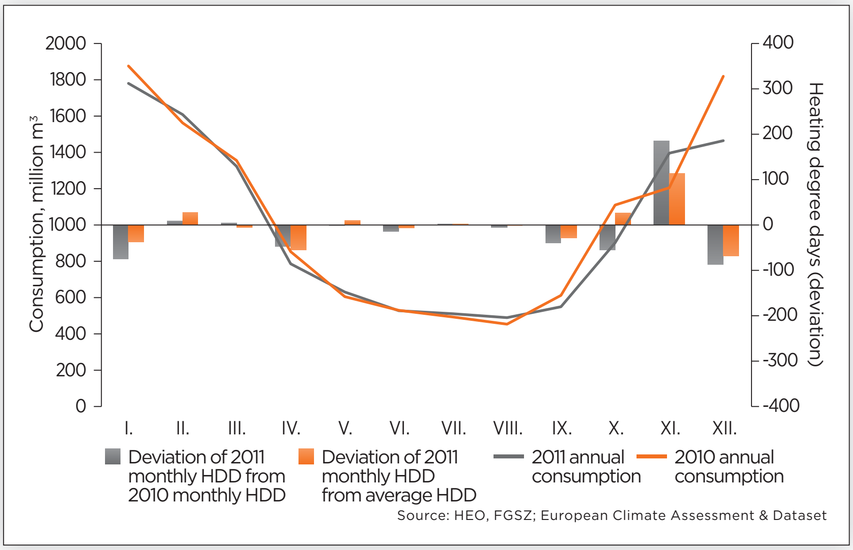


Figure 11. **Monthly natural gas consumption in 2011 compared to the natural gas consumption in the same months of the previous year, and compared to the difference between the monthly heating degree days and the multi-year average hdd figures and those of the previous year**

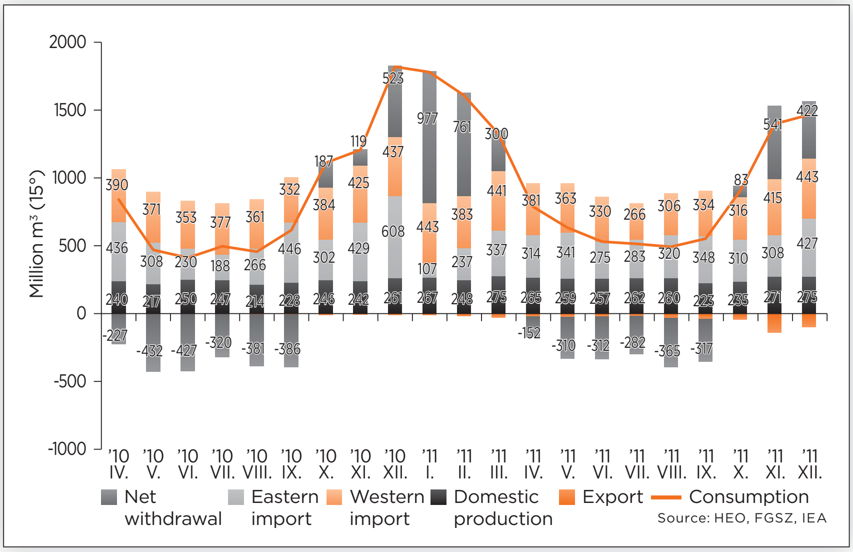


Figure 12. **The source structure of the gas market of Hungary by month**

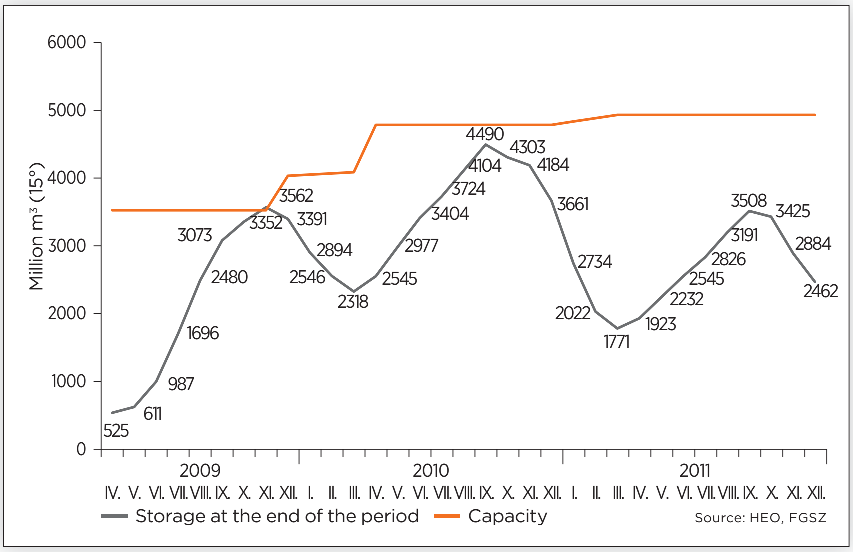


Figure 13. **The mobile gas storage capacity of commercial storage facilities and their stocks by month**

at an average price of 17 HUF/kWh. Using an exchange rate of 300 HUF/EUR this is equivalent to an average price of 57 EUR/MWh, 5 EUR higher than the futures price of baseload electricity obtainable at the EEX.

Overview of the gas market in Hungary

The first month of the 2011/2012 heating season was milder than a year ago, also confirmed by the lower level of consumption. November 2011, on the other hand, was much colder than last year – or even compared to the average November temperature -, therefore almost 200 million m³ more natural gas was used. Quarterly gas consumption, nevertheless, was still 370 million m³ less than in 2010 thanks to milder than usual December temperatures.

The volume of imported Russian gas arriving through the Beregdaróc entry point fell by almost 300 million m³ in November and December compared to last year. In parallel with the declining import, export grew considerably, with 250 million m³ compared to the same quarter a year ago. The reduction in import and the additional export was enabled partly by the already mentioned reduction in consumption, and partly by the increased withdrawal from the storage facilities: during the quarter 200 million m³ more gas was extracted from the commercial inventories than during the first three months of the previous heating season a year ago.

The withdrawal period started in October, and during the quarter 200 million m³ more gas was withdrawn than a year ago. The increase of the storage intensity is due to lower imports from Russia, increased exports and the cold November weather: in November 100 million m^3 less natural gas arrived from the direction of Beregdaróc, our export to our Southern neighbours grew from 30 million m^3 last year to 290 million m^3, while withdrawal was 4.5 times higher than in November 2010. The capacity utilisation of our commercial storage facilities reached a multi-year low in December: it was almost 1 billion m^3 less than the mobile gas inventory at the end of 2009, and 1.2 billion m^3 less than last year. For the sake of completeness let's not forget that according to Decree 13/2011. (IV. 7.) of the NFM in gas year 2011/2012 the MSZKSZ may sell 200 million m^3 of natural gas to MVM and 85 million m^3 to universal service providers at the average purchase price. Concerning the fate of the 285 million m^3 of strategic natural gas inventory that was reclassified for commercial purposes based on the Decree, we know that in 2011 the eligible parties had not fully used the inventories reserved for them.

The gas flow arriving from the West exceeded the non-interruptible capacity. 1.2 billion m^3 of gas came through Baumgarten, almost 200 million m^3 more than from the East. In 2011 4.4 billion m^3 of gas was imported through the Western border, equal to 55% of the total import. Quarterly import decreased by 6% compared to last year, while the annual import declined by 5.5%.

52% of the capacity at the Eastern border section was booked, and gas flow comprised 38% of booked capacities. Natural gas from the East made up 47% of import, equal to 1 billion m^3. In 2011 3.6 billion

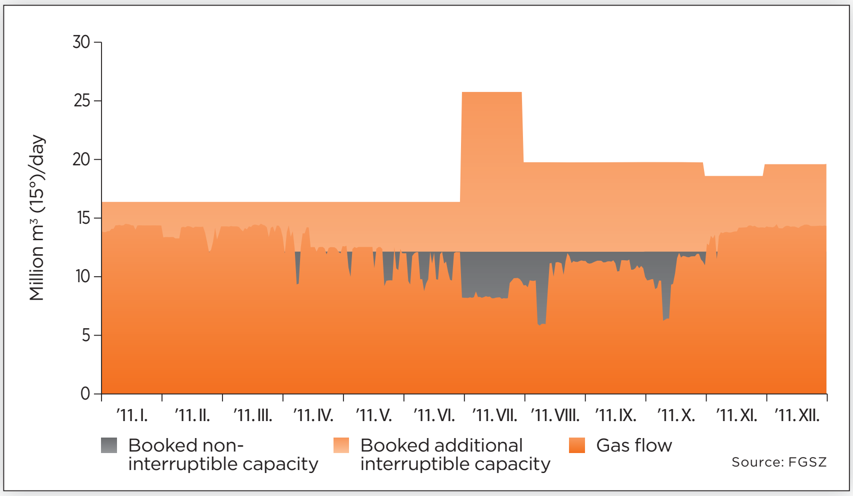


Figure 14. **Transmission at the Baumgarten entry point in 2011 together with booked interruptible and non-interruptible capacities**

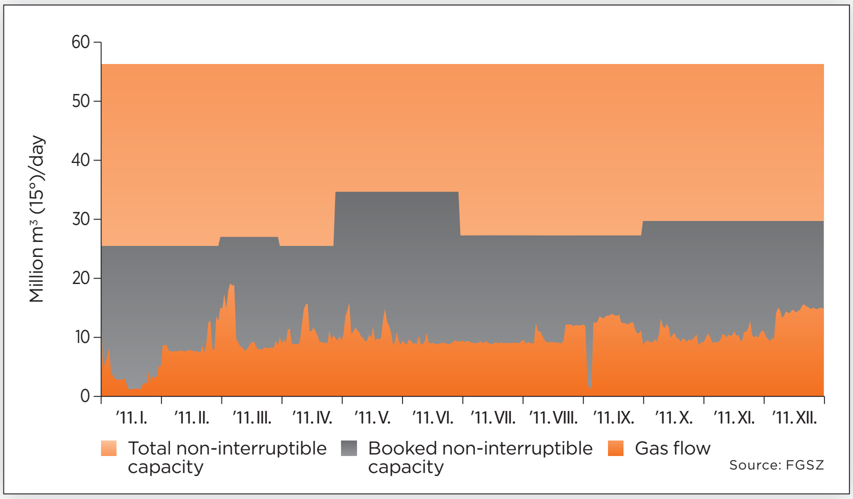


Figure 15. **Transmission at the Beregdaróc entry point in 2011 together with total available capacity and the booked non-interruptible capacity**

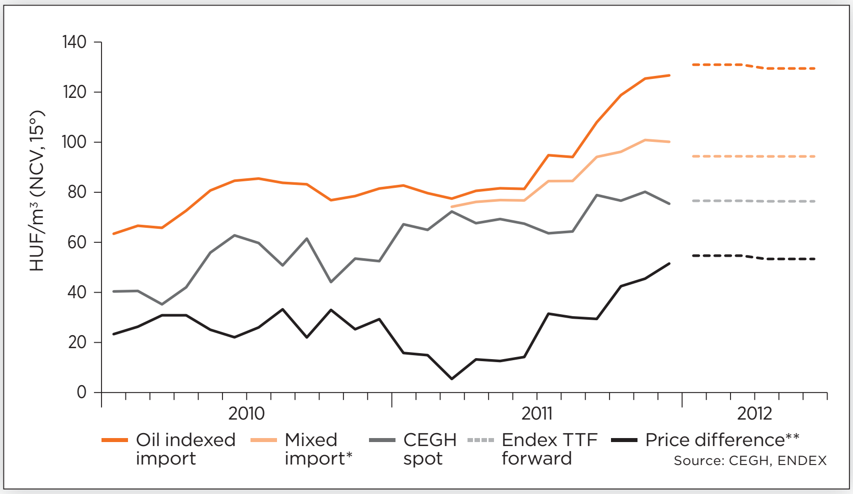


Figure 16. **Past and forecasted future international and domestic wholesale gas prices**

* *60:40 weighted average of the oil indexed and the ENDEX TTF gas price on the power exchange*

** *The price difference between the oil indexed and CEGH for past prices, and the oil indexed and corresponding quarterly futures ENDEX TTF prices for future gas prices. The spread between the spot prices at the Dutch and Austrian exchanges has become very small recently. This is why the futures ENDEX gas prices are considered relevant for the Austrian market as well.*

m^3 of gas, or 45% of all import arrived from the East. During the inspected period import from the direction of Ukraine was one-fifth of the year ago figure, while the annual import declined by 25%. The source structure of import changed in 2011: while in 2010 the volume of natural gas arriving from the East and the West was about the same, in 2011 55% of the import came from the West.

The price difference between oil indexed import and exchange based prices considerably increased: in December a m^3 of gas cost HUF 50 less on the CEGH exchange.

ENERGY MARKET ANALYSES

The results of the procurement of year 2012 system level reserves

The methodology for securing system level reserves underwent substantial change last year, positively impacting the level of purchase costs. In our article, for the most part, we address the procurement of secondary and tertiary regulatory reserves for year 2012. We present the new developments concerning the method applied by MAVIR, then we review and evaluate the results of the tender procedure held at the end of last year.

The task of ensuring the uninterrupted operation of the electricity system, and the constant balance of production and consumption lies with the system operator. The reserve capacities (primary, secondary and tertiary system reserves) necessary to ensure system level services, the voltage and reactive power controlling services and black start services are obtained by MAVIR through annual tenders. In previous years the capacity making up for the loss on the transmission network was also (partially or fully) acquired this way, but starting this year all of this quantity is purchased by the system operator on the Organised Electricity Market (HUPX), either on the physical futures (PhF) market, or on the next day spot market.

Based on the peak load of the system the Operation Handbook of the ENTSO-E determines the minimum capacity to be secured for each reserve type within the country. The system operators supplement this with the additional volume that is required for safe operation considering the condition of the country's network and the gradient values.

Last year the method of acquiring the reserves necessary to guarantee system level services went through a profound change. One of the most important new developments is the introduction of a multi-round electronic reverse bid auction executed separately for each product. During the auction bidders are obliged to organize their available capacity in increasing 10 and 5 MW units (bundled block offer) for secondary and tertiary system reserves, respectively. Next, the system operator determines the total score for each offered unit, by appropriately weighting the capacity fee, energy fee and gradient value belonging to the unit. An interesting feature of this year's tender is that (and this will be covered in more detail later) the weight of the different factors was modified during the tender procedure. For the first announced tender the capacity fee carried a 65%, the energy fee a 5% and the gradient a 35% weight within the total score, then later on the weight for the capacity fee was increased to 80%, while for the gradient it was reduced to 15%.

The next step consists of a process of optimisation during which that combination of the offered capacity units is selected the sum of which supplies the needed quantity while the total score is the highest. At the end of each round bidders get to know which one of their offers would be accepted if no more changes took place during the upcoming rounds, and they are also informed about the tender price and the total score of the worst offer that was still selected during the round. Equipped with this knowledge in each new round bidders have a chance to amend their offer in the direction favourable for MAVIR, lowering their prices with at least a preset minimal value. New rounds are announced as long as there is any bidder whose most recent offer changed the selected order of the previous round on at least one day. If the results in a round stay unchanged for all of the days or all bidders have submitted their final offers, then the auction is completed.

Compared to the practice of the previous years, the price negotiation phase of the tender procedure therefore became more complex in several ways. First, in contrast with bidding for a specific volume the obligation to make bundled block offers has been introduced. This is certainly favourable for MAVIR as it is now not forced to break offers (in case it wishes to accept only a fraction of the offered quantity), while beforehand every such case required a unique price negotiation with the power plant in question. Secondly, the reverse bid process consisted of multiple rounds this year (for one product the number of bidding rounds exceeded 20) as opposed to the practice of the previous years when amending already submitted bids was allowed only once. This method explains why some power plants, under the previous regime, submitted an extremely high price for the first round, and then as a function of the initial results they lowered the bid with as little as their assessment commanded. Employing multiple rounds, on the other hand, lets the power plants submit lower and lower bids, significantly lowering prices and thereby increasing the efficiency of competition. Having the option of inspecting the winning bids, and the underlying

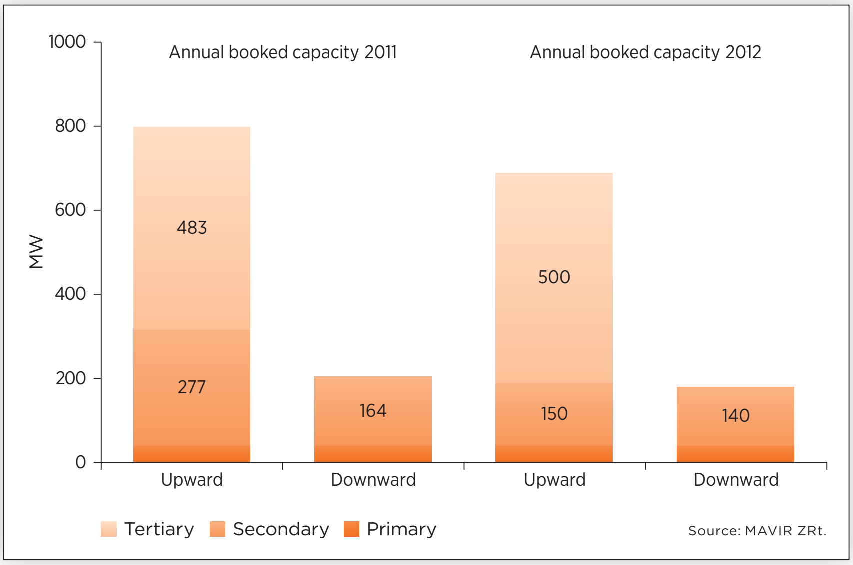


Figure 17. **The size of regulatory reserves secured through the annual tender in 2011 ad 2012**

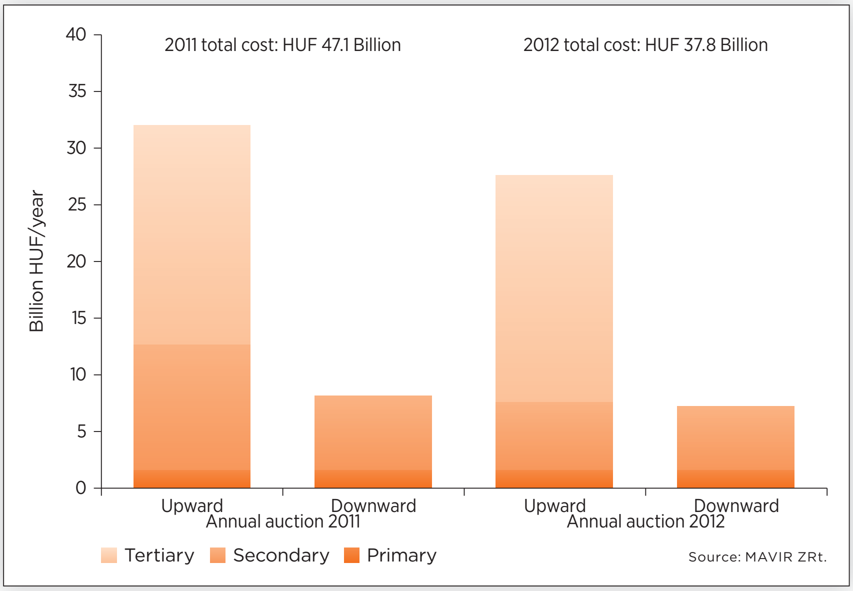


Figure 18. **The cost of securing reserves for 2012 and 2012**

strategies of the competitors in multiple rounds, nevertheless, may increase the chance of collusion among power plants.

Another important innovation from last year is that concerning the secondary, upward regulatory reserve MAVIR secured only a portion of its reserve demands (barely more than the quantity required by ENTSO-E, only 150 MW) through the annual tender, the rest is acquired through intra-year, quarterly auctions. Under this framework for the first quarter the system operator concluded 110 MW per day of market maker contracts.

Figure 17 describes the size of primary, secondary and tertiary regulatory reserves secured through the annual tender, also in comparison to the previous year.

The figure includes only the quantity secured through the annual tender, therefore the 110 MW of secondary upward regulatory reserve acquired for the first quarter through the quarterly tender is excluded, similarly to the volumes that are expected to be procured through the future quarterly tenders. However, even if all this is taken into account, apparently MAVIR was successful in reducing the contracted quantity of secondary regulatory reserves thanks to its reassessment of the real reserve requirements. Nevertheless, acquisition of reserves continues to be characterised by the dominance of upward regulation. Downward regulatory energy continues to be acquired through the annual tender only, and not more than the recommended minimum quantity. This is explained partly by the lack of resources, and partly by the fact that the system contains reserves in the downward direction (thanks to the operation of the Mátrai power plant, for example), therefore downward regulation can, to a degree, be managed by modifying the generation schedule of the plants. With regard to tertiary downward reserves this year again MAVIR made only contracts on options (for an annual average value of 130 MW).

Figure 18 describes the cost of securing primary, secondary and tertiary regulatory reserves through the annual tender, also in comparison to the previous year.

Comparison of the costs is made difficult by the considerable transformation of the purchase methodology. The large difference portrayed in the figure may be misleading, since the 2012 data doesn't include the cost of securing secondary upward regulatory reserves through the quarterly tenders. For the first quarter this item cost about HUF 1.4 billion for MAVIR, if this value is projected to the whole year the cost reduction in case of secondary upward reserves is still likely. The total cost for secondary downward reserves significantly decreased, while the cost of tertiary upward reserves increased, partly due to higher contracted volumes.

In addition to the introduction of the new method of optimisation, the launch of quarterly tenders probably also contributed to the reduction of the average capacity fee for the most critical direction of balancing regulation, the secondary upward direction. Thus more frequent tenders should be viewed as advantageous. Since part of the required quantity is acquired only through quarterly tenders, the quantity secured through the annual tender most likely represents a demand that is limited enough to trigger more aggressive price competition among the bidders due to the excess supply of their overall capacities. The legitimacy of quarterly tenders is also supported by the launch of the market for long-term products on HUPX, which may reduce the risk for power plans (since when they make a decision on their tender price they may already know the futures price of the underlying products for the period in question), which may in turn reduce prices.

An interesting feature of the tender for this year is that the results pertaining to the originally issued bid were invalidated with the exception of the tertiary downward direction. This is probably explained by the deficiencies of the scoring procedure. Since scores for the bids are calculated by comparing to the best offer for the given factor, when the capacity fee within a bid is much lower than in the other bids, the scores for the capacity fee of the other bids may fall in a narrow range even in case of relatively large differences among these fees. As a consequence, the order of selection may practically be determined by the energy fee and the gradient. Therefore bids with extremely large capacity fees could also have been selected as winners. This is the likely reason why MAVIR – with one exception – cancelled the results and decided to announce new bids, before which it amended the scoring procedure in order to prevent similar defects. This, nevertheless, happened in a rather ad hoc way: a constant was added to the formula calculating the score for the capacity fee, the value of which is arbitrarily determined by MAVIR as either zero or ten-thousand. Moreover, the weight for the capacity fee within the total score was increased from 65% to 80% at the expense of the weight for the gradient.

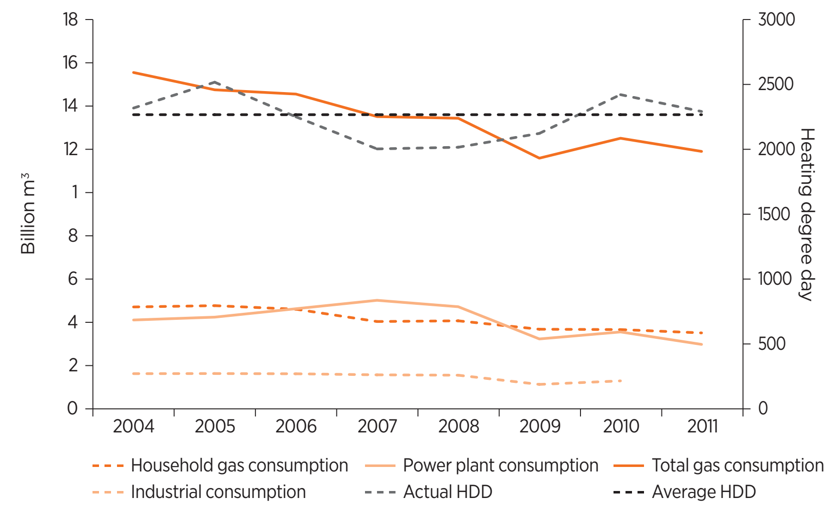
Another problem with the current process of optimisation is that it allows situations under which the purchase cost becomes higher in a new round compared to the previous one, which is obviously not a favourable outcome. As a consequence, the methodology of the procurement process is likely to be further amended in the future.

The pricing behaviour of the AES Tisza Erőmű was another really interesting experience of the tender at the end of the last year. Due to its low capacity fee on the annual tender the power plant became the exclusive winner for all the days of the first quarter, with the maximum allowed 150 HUF/kWh energy fee for each day. Furthermore, on the first quarter tender 20 MW of its daily capacity was secured at a capacity fee below that of its competitors, but also at the 150 HUF/kWh maximum energy fee (while all the other bidders offered a substantially lower energy fee with an average value of 64 HUF/kWh). While this pricing strategy is advantageous from the perspective of lower capacity fees, it may negatively impact the price of balancing energy. Even though these offers, containing high energy fee, may not necessarily be used - since the order of utilisation and the price of balancing energy is determined by the energy prices of the daily offer (which are limited by the energy fees submitted to the annual and quarterly tenders) -, as a result of the extremely high energy fees there is a danger that balancing energy prices in the first quarter escalate. Based on the balancing energy prices for January we can affirm that the average value of the settlement price for upward balancing regulation does not seem to be particularly high, but there is substantial volatility (in case of 5 fifteen minute periods the upward settlement price exceeded 80 HUF/kWh, with a maximum value of 97 HUF/kWh, and the last three years have been without such precedent).

To conclude, the procurement method for system level regulatory reserves (especially the new methodology applied within the process of price negotiation, and the division of secondary upward reserves to annual and quarterly products) has proved to be successful, since the costs of securing reserves for the system operator decreased, which may also lower the network access fees. The current system, nevertheless, is not without deficiencies the remediation of which would be certainly worthwhile, and this may trigger further amendments in the coming years. Furthermore, quarterly procurement for tertiary reserves and downward regulatory reserves should also be considered.

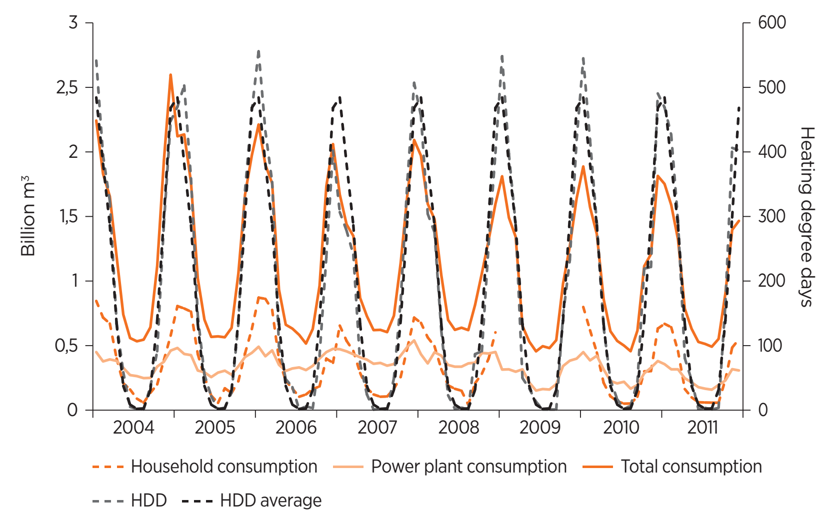
Diminishing opportunities – almost a quarter of the gas market evaporated since market liberalisation

Following the mild, almost spring-like weather of November and December the troubles of the gas sector reached the headlines and "Have a cold winter!" became the choice of farewell wish



Source: Total gas consumption and power plant gas use: data release of HEO; household gas consumption: Statistical Yearbook of Network Energy Sources, 2010 and data release of HEO; industrial gas consumption: EUROSTAT; heating degree days: European Climate Assessment & Dataset, REKK calculations.

Figure 19. **National and sector specific annual natural gas consumption (billion m³), and actual and 20-year average values for heating degree days (°), 2004–2011**



Source: Total, household and power plant gas consumption: data release of HEO and EUROSTAT; heating degree days: European Climate Assessment & Dataset, REKK calculations.

Figure 20. **Monthly household, power plant and total national gas consumption, and actual and 20-year average values for heating degree days, January 2004 – December 2011**

HDD = heating degree day: The impact of temperature on gas consumption is measured by the so called heating degree day (HDD). The method to determine the heating degree day of a particular day is as follows: if the mean temperature of the day exceeds the threshold value (about 16 °C in Hungary) then the HDD is 0. If the temperature is below this level, then the difference makes up the HDD (e.g. in case of 13 °C of mean daily temperature the HDD is 16 °C – 13 °C = 3 °C). The HDD of a month is the sum of the daily HDD values

at many natural gas conferences. Therefore, we thought it's worthwhile to review the domestic natural gas consumption of the last few years, if there is any clearly visible tendency, and whether everything can be explained simply by the vagaries of the weather, or even contracting a shaman to assure a cold winter is not any more sufficient to return to the consumption level of the "good old times".

Figure 19 shows the annual gas consumption from 2004 on. Apparently, consumption decreased almost on a straight line from 15.5 billion m³ to less than 12 billion m³ in 2011. Moreover, for the same period the figure also shows the relationship between the actual and the 1990-2011 average value of the heating degree day, the most appropriate measure of the impact of temperature on gas consumption – the higher its value, the higher the expected gas consumption is. The heating degree days for 2004 and 2011 are almost identical – there is a difference of about 1% -, in other words, weather alone does not justify a significant difference between the consumption of the two years. The heating degree days for the rest of the years also confirm that the radical contraction of the market through this 8 year period is due not to progressive warming, an occasional warmer year may only have provided further impetus to the on-going process.

Behind the drop in gas consumption therefore we need to look for factors which - independently of the weather – determine the consumption of the three dominant segments: households and other small consumers, large industrial consumers and power plants. The figure contains the annual level of consumption for households, industry and power plants. (Unfortunately, complete, publicly available data on the domestic natural gas market in a sector breakdown for the inspected period is not available, therefore we can present the consumption of only specific segments which have better records). During the period household consumption steadily decreased, from 4.69 billion m³ in 2004 to 3.48 billion m³ in 2011. The same tendency is valid for other developed countries as well, and we expect a similar, but somewhat milder trend in the future, too. The number of households connected to the natural gas network will not any more increase significantly, while price sensitive consumers will continue to reduce their consumption as they switch to other fuels, improve energy efficiency and introduce renewable technologies.

The consumption of power plants, on the other hand, still increased during the first half of the period, then a slight decline was followed by a larger drop in 2009. This drop was primarily explained by the January gas crisis. Nevertheless, the fact that power plant consumption never bounced back to previous levels demonstrates the impact of the economic crisis on the electricity market: during periods of low electricity demand gas based power plants operate at reduced capacity. Another factor may be that domestic natural gas prices are high in a regional context, resulting in competitive disadvantage for domestic gas based plants, getting partly replaced with import.

In addition to temperature, industrial gas consumption is sensitive to changes in the economy. As a result, the current crisis brings about lower industrial consumption, the gas consumption of large industrial users decreased from 1.6 billion m^3 in 2004 to 1.26 billion m^3 by 2010.

Figure 20 shows the same data in a monthly breakdown. It appears that it is the winter gas consumption that continuously and remarkably decreased. While close to 2 billion m^3 was used in December 2005, gas use for December 2011 was less than 1.5 billion m^3. As a matter of fact, the extremely mild weather also contributed to the latter figure.

Even the simple analysis above makes it clear that while a mild winter may substantially reduce gas consumption, the recently shrinking market is primarily a result of not the Mediterranean-like weather of late, but other factors, such as the economic crisis, price elasticity, and regional price competition. Our shaman, therefore, will face a difficult task, and even if he was capable of stimulating the economy, he is unlikely to be able to reverse certain other trends, such as the reduced gas use of small consumers.

Abbreviations int he report

ACER	Agency for the Cooperation of Energy Regulators
APX	Amsterdam Power Exchange
ARA	Amsterdam–Rotterdam–Antwerpen
CEGH	Central European Gas Hub
ECX	European Carbon Exchange
EEX	European Energy Exchange
EUA	European Union Allowance
HAG	Hungary–Austria Gasline
HDD	Heating Degree Day
OPCOM	Operatorul Pietei de Energie Electrica
OTE	Operátor trhu s elektřinou
PXE	Power Exchange Central Europe
SEPS	Slovenská elektrizačná prenosová sústava
UCTE	Union for the Coordination of Transmission of Electricity

HOT TOPICS

Trader replacing activity within the power sector

For the last year or two retail and wholesale competition within the Hungarian electricity market became considerably stronger than in prior periods, even though the trader replacing activity within the retail power market continues to be much weaker than in the wholesale segment. In our article we take a look at the activity of switching service providers for the last few years, also considering retail competition as it evolves under the current regulatory and market framework.

The trader replacing activity of domestic electricity consumers is rather low in an EU context. According to a research project ordered by the European Commission, between July 2008 and June 2010 5.7% of the household customers in the EU switched service providers, while in Hungary the same ratio was a mere 0.2%[1]. The low activity is due to two reasons: on the one hand, since the market only opened up in 2008, consumers are not yet aware of their options, and on the other hand, regulated prices in the segment in question are relatively low. Enterprises – to whom the right to move from one trader to another was already granted in 2003 or 2004 – are much more active in switching between traders. Another contributing factor has been the intensifying competition in the retail segment due to weakening demand brought by the economic crisis. In 2011 the competition for customers was also boosted by the fact that the final consumer prices in the competitive market fell below the regulated price in the universal service segment. Given that the trader switching activity is strongly related to the intensity of competition in the market, and therefore to the structure of the market, next we provide a brief overview of the recent history of the retail electricity market.

The domestic retail market consists of two parts with distinct regulatory and operational environments: the universal service segment which has regulated prices, and the competitive market segment. The share of the latter notably increased from 2008 (in 2010 it made up about 61% of the retail market), primarily because starting in 2008 public utility service was replaced by universal service for which far fewer market participants are eligible. As a result, approximately a hundred thousand small and medium sized electricity consumers were placed within the competitive market segment.

Supplying the consumers eligible to universal service is the task of the universal service providers, who are the successor companies of the former public utility service providers (E.ON Energiaszolgáltató, ELMŰ, ÉMÁSZ, DÉMÁSZ). Within this segment the lack of competition is discernible: neither have the universal service providers attempted to penetrate each other's service areas, nor have those traders, who previously had not carried out universal service, applied for such a permit, even though the regulations make this possible.

Among traders serving the customers of the competitive market, again, those multinational companies (E.ON, RWE and EDF) hold the largest market share (approximately 64%) which also control the universal service segment. Besides them the trading companies of the MVM group (MVM Trade and MVM Partner Zrt.) and a growing number of "independent" trading companies (which are represented by considerable interests only within the retail portion of the domestic electricity sector) are active in this business.

Next we review the average sales price[2] and the market share of the universal service providers and the traders active in the competitive segment between 2009 and 2011.

The final consumer prices depicted by Figure 21 have gone through a significant change for the last three years. The competitive market price, paid for by commercial entities, decreased by an average value of 6.6 HUF/kWh. This was driven by two factors. First, during this period the average purchase price of retailers decreased by about 4 HUF/kWh due to the strengthening of the wholesale competition. Secondly, stronger competition among traders resulted in lower retail margins. The scale of the price decline, however, varies among different customer groups. The biggest price decline is observable in the SME sector characterized by annual consumption of 20 to 20,000 MWh, while the

[1] ECME Consortium: The functioning of retail electricity markets for consumers in the EU, 2010 november
[2] Prices are not reflective of the full final consumer price, only its energy fee component.

decline is less than average for small consumers, and average for consumers with power use in excess of 20,000 MWh/year. All this indicates that there is already real competition among traders to acquire the business opportunities of SMEs with low and medium levels of electricity consumption.

In contrast with this, in the market segment with regulated prices the average energy fee of commercial customers has increased for the last three years, thanks to the higher purchase prices of universal service providers. The scale of the price increase, nonetheless, also varies here: the energy fees of larger customers increased by less, those of medium sized and small customers increased at a higher rate. This again suggests that the competition for clients also extends to the commercial customers eligible for universal service.

As depicted by Figure 22, the change in the market share of universal service providers and traders is in line with the change of relative energy fees. The share of universal service providers in electricity sales to commercial clients decreased from 13% to 9.5% in 2011, as competitive market prices dropped below regulated prices, which prompted more customers to switch traders. A similar, but very slow shift is also present among households: while in 2009 only 0.1% of households obtained electricity from the competitive market, the same figure was already 0.3% for 2011.

Due to lack of publicly available data we do not know how

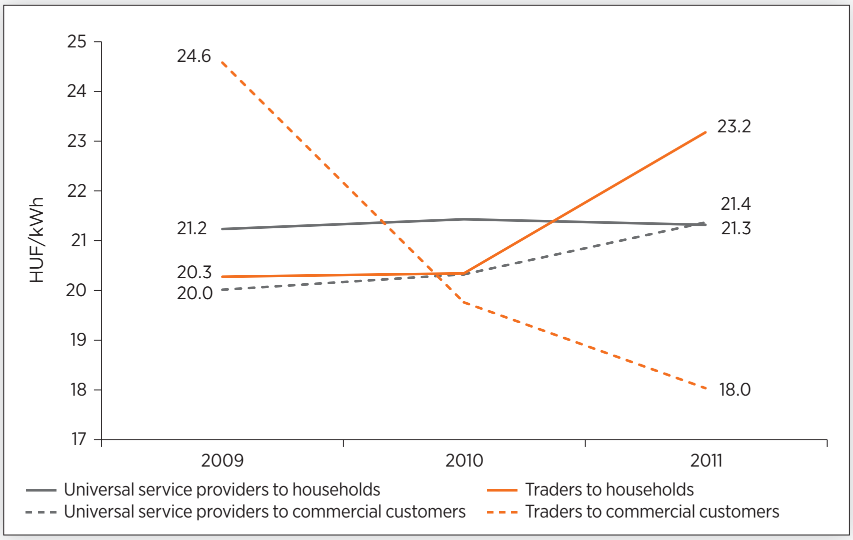


Figure 21. The average value of the product price component of sales prices within given customer segments, 2009-2011[3]

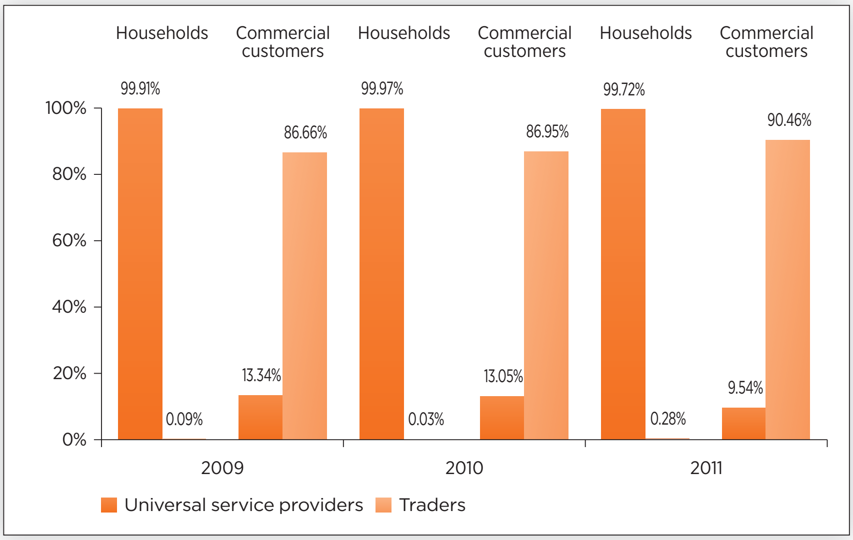


Figure 22. The market share of universal service providers and traders within specific consumer segments, 2009-2011[4]

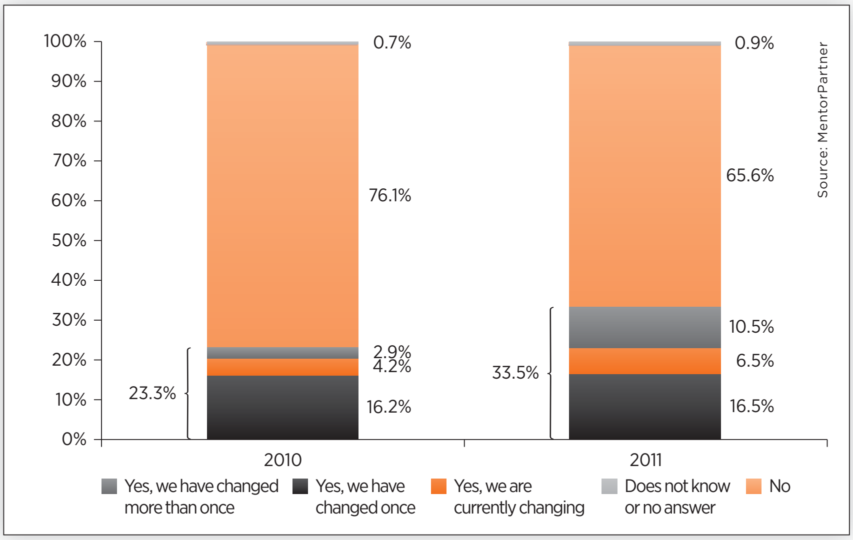


Figure 23. The distribution of the answers to the question: "Have you changed a trader?"

[3] 2011 data is available for the January-September period
[4] Year 2011 data is available for January to September

many actual changes of service providers these shifts in market share are equivalent to. According to our rough estimates during 2011 between 1000 and 2000 commercial customers may have switched from a universal service provider to a competitive market trader.

Next we summarise the trader replacing experience of the domestic SMEs building on a questionnaire based survey of MentorPartner. Of the sampled companies 559 had a direct contractual relation with an electricity trader. These companies were asked in 2010 and 2011 whether they had already switched traders. The distribution of their answers is depicted by Figure 23.

We can see that the trader replacing activity became slightly stronger during the inspected period. Whereas in 2010 23.3% of the surveyed companies had already replaced traders at least once, the same figure for last year was already 33.5%. While the number of instances in which traders were replaced during a year can only be roughly estimated, the information at hand reveals that in 2011 the number of customers replacing their traders at least once increased by 3100, while the number of customer with multiple trader replacements increased by 2300, equivalent – on an annual basis - to almost 18% of SMEs directly present on the power market, and about 1.5% of all commercial consumers.

We can infer the magnitude of savings that can be realised through the replacement of traders based on an autumn 2010 survey of ALTEO Energiaszolgáltató Nyrt among SMEs[5]. As indicated by the analysis, the largest saving opportunity is available for companies consuming 100-200 MWh of energy, which on average achieved 9% of cost savings by replacing their existing trader. Interestingly, it is not the largest consumers that can attain the biggest savings. This is likely because these consumers are more intensively competed for, therefore the variation of prices, along with the saving potential, shrinks.

To conclude, even though the trader replacing activity in the domestic power retail market is rather restrained, last year the number of replacements increased due to the favourable shift in market practices and the intensification of retail and wholesale competition. As competition in the retail segment is becoming stronger, there are more independent traders, the energy fees paid by commercial customers keep on declining, and the final consumer price in the competitive market fell below the regulated price.

Regulation of infrastructure development: EU vs. member state competencies

Last year a number of new EU initiatives on the regulation of infrastructural investments were brought to light: the aspiration of the European Commission to boost the development of the electricity and natural gas infrastructure was escorted by a series of policy declarations and amendments of regulation. These initiatives elicit an important shift in emphasis concerning the competence on transmission networks (and within that, in the first place, on cross-border lines): the power of member states to authorise investment plans becomes gradually superseded by certain normative rules and the Commission's rights of decision.

The draft order of the Commission on Trans-European energy infrastructure, which was presented to the legislative bodies of the EU (the European Parliament and the Council) in October 2011, is in line with this process. Below we review how much further will the sharing of competences between Member States and the Commission shift as a result of the regulatory initiative, in comparison to earlier regulations.

The challenges of infrastructure development

The quick expansion of renewable based generating capacities and the energy policy targets to curb greenhouse gas emissions require network extensions that are larger than ever. The electricity produced by the flourishing wind farms along the North Sea already creates serious tension between the countries exposed to the flow of this energy: the networks of Poland and the Czech Republic are so heavily burdened by the periodic peak loads generated by German wind power plants that – referring to the protection of their networks - the concerned system operators started to consider the installation of phase-shifters to prevent the flow of electricity. The continued rise of weather dependent renewable electricity generation (and the transmission of surplus energy produced during peak production to pumped-storage reservoirs), nevertheless, not only increases the burden placed on electricity networks, it also affects natural gas networks.

Even if they made large new investments, European electricity networks would not be able to manage the problems related to system

[5] ALTEO press release, October 2010

operation and balancing caused by the fluctuating renewable generation. Adjustment to sudden variations of the load requires a substantial expansion of gas based generating capacities, and this obviously calls for the enlargement of the capacity of the current natural gas transport networks as well as increased flexibility of the systems (by constructing storage facilities and LNG terminals).

The above changes, nevertheless, do not merely stem from the current renewable targets. In the wake of the European commitment to reduce greenhouse gas emissions (partly endorsed in international treaties) the European electricity sector will be burdened by extremely heavy obligations to decarbonise. Further dramatic increase of the 20% renewable target for 2020 is projected: the 80% CO_2 reduction considered by the EU would dictate a 50-60% renewable share by 2050, even under conservative assumptions. The expansion of renewable generation on this scale may require extraordinary network development (50-100% capacity enlargement).

According to the calculations of the Commission approximately 50% of the network development investments needed by 2020 will not be realised due to the present regulatory shortcomings on permitting and financing deficiencies. Considering the speed at which construction and environmental permits are issued, building some of the transmission lines may take as long as 10 years, while a wind turbine is erected in 2-3 years, including the acquisition of permits. In addition to the administrative obstacles that delay the investments, in case of crossborder lines more serious problems may also arise concerning the sharing of costs among the involved member states and system operators.

Most regulatory authorities exhibit a rather conservative approach to permitting and within the tariff they recognise mainly those investments which serve to satisfy proven domestic demand. In case of transmission lines largely devoted to transit or export flows regulators are hesitant to recognize part – or even any - of the investment costs in network tariffs. The completion of these investments would be much smoother if involved/beneficiary member states also took part in financing. Regulatory authorities, however, rarely recognise the cost of capacity development within the cost base of the domestic system operator in case the investment takes place across the border (initiated by a neighbouring system operator) even if it also has a role in supplying domestic consumers.

Regulatory changes

The adoption of the 2009 energy related legislative package (the so called “third package”) was the first major step towards the normative regulation of the competence of Member States on infrastructure development and the harmonisation of developments. The amended directives on electricity and natural gas obliged TSOs to prepare 10 year network development plans aligned with the future balance of demand and supply. The preparation, elaboration and approval of the network development plan is conditional on regular, open consultations with a wide range of system users. When demand is forecasted, which is absolutely crucial in “calibrating” the network development plan, and during the specific need assessments in which individual developments are rooted, it is essential that the needs articulated by market participants are incorporated. These measures aim to limit “strategic under-investment” (artificially under-planned crossborder capacity development in order to protect the market) by the system operators belonging to the same group of owners as the incumbent natural gas suppliers.

The task of harmonising the network development plans of the member states was imposed on the newly established EU bodies by the third package. The ENTSO-E and ENTSO-G, bringing together European TSOs, were obliged to draft a 10 year network development plan for the EU. While these EU level plans do not override national development plans, the regulator can approve a network development plan only if it is in harmony with the EU level network development plan. If the national and EU level network development plans are not consistent with each other, the regulatory authority of the EU, the ACER may propose that a national authority amends its network development plan.

Regulation 994/2010/EU on the security of gas supply represented the next step for the EU regulation on infrastructure development. The legislation imposes normative requirements on the security of supply (by setting so called infrastructural standards) of the national natural gas systems. By December 2014 at the latest concerned Member States have to complete the infrastructural developments necessary to fulfil the requirements.

The Trans European energy infrastructure regulation

The possibility for the Commission to override national network development plans is essentially established by the draft regulation on Trans European energy infrastructure. The draft legislation is anchored in the Project of Common Interest (PCI) terminology. These are infrastructure development plans with substantial crossborder impacts, the completion of which is necessary for the development of the priority infrastructural corridors. The definition of PCI is so broad, and the characterization of the priority infrastructural corridors in question is so general, that in practice almost any major infrastructural development plan can be classified as of common interest.

Member states have to provide a one-stop shop permitting procedure to projects of common interest. In accordance, each member state is obliged to designate an authority responsible for the coordination of the permitting procedures of the projects in question. The simplification of the procedures, however, is also steered by a tangible criterion: the permitting procedure of PCIs must be completed within 3 years. In light of the fact that transmission line projects under the current circumstances often take 10 years to complete, keeping this deadline will require extraordinary efforts and likely special procedural rules on the part of the Member States.

The provision, according to which system operators are obliged to incorporate the projects of common interest into their 10 year network development plan, may be even more far-reaching than the acceleration of the permitting procedures. Since the electricity and gas directives utilise several instruments to enforce the execution of the network development plans (such as the compulsory tendering of developments not executed by the system operator), this step eliminates the other key obstacle to the realisation of the developments in question, the lack of approval by the regulator.

Including the projects of common interest within the national network development plans, however, does not solve a key problem, namely, the sharing of the investment costs of transit lines and those cross-border capacities which are particularly important for other countries. Indeed, national regulators can prevent investments not preferred by them (investments that are less critical from the perspective of domestic consumers) through the rules on tariff setting. The draft regulation therefore declares that in case the regulators of the countries involved with a given investment cannot reach an agreement on the sharing of investment costs (and the subsequent adjustment of network tariffs) within 6 months, then the decision is to be made by ACER.

The conservative tariff setting practice of national regulators is to be reformed by the provision according to which the incentives provided to projects of common interest should be commensurate with expected risks (e.g. recognising the costs incurred before the investment is executed, higher rate of return). The ACER has to prepare a guidance on actual incentives and risk assessment for the national regulators, which are obliged to publish the methodology to be applied for project appraisal based on this guidance.

The above proposals provide a more effective catalyst to develop projects of common interest than previous regulations. The most important question, however, remains to be answered: who determines the group of PCIs – the projects that require special treatment. Those who have kept a close eye on the EU energy regulation of the last few years will not be surprised at the answer: the final decision on projects of common interest will be made by the Commission, according to the present proposal by the middle of 2013 at the latest.

A prominent role within the process of selecting infrastructural projects of common interest, nevertheless, will be given to the so called Regional Groups that are still to be established. These bodies will be responsible for assembling the list based upon which the Commission will make its final decision. Concerning the structure, operation, and decision making process of the Regional Groups, nonetheless, only very limited guidance is provided by the draft regulation. What is certain is that the member states, the national regulators and the system operators, as well as the ENTSO, the ACER and the Commission will be represented within the groups. Regarding the border of specific regions, and the relations of the groups that are to be established to other, already existing regional bodies, not much is revealed by the proposal.

The competence of member states with regard to future network developments is of course not transferred completely to the Commission: to be added to the list of projects of common interest is conditional not only upon being part of the 10 year EU network development plan of the ENTSO, it also has to be supported by the affected member state. The above provisions, however, clearly show that the exclusive competences of national regulators over network development plans are gradually narrowed down, while the influence of EU institutions is steadily increasing.