Dear Reader!

We are delighted to present to you the third issue of volume 4 of our Hungarian Energy Market Report. We sincerely 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.

Using the REKK Danube Region Gas Market Model in our first study we quantify the impact of potential gas infrastructural investments on the natural gas bill of the countries in the Danube Region.

One year after the decision was made, our second article looks at the country specific impact of the German nuclear shutdown on wholesale prices, based on a literature review as well as the results of the REKK European Electricity Market Model.

Our third piece examines a new tendency that has been accelerating for the past year: as a result of growing photovoltaic capacities, the spread between peak and baseload products has substantially decreased. The influence made on the generating mix and the long term development of the electricity market is described in our article.

Our fourth analysis takes a look at the alternatives to the long term gas import contract that will expire in 2015, evaluating, in particular, the merits of the TOP contract.

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ENERGY MARKET DEVELOPMENTS

The decline of prices that had started in March on the key markets continued during this quarter as well, with the price of coal and oil reaching new lows. The price of crude oil fell by USD 30 per barrel, while the price of coal decreased by USD 15 per ton. The futures price of baseload and peak electricity with next year delivery decreased by 3 €/MWh, while the price of futures natural gas with next year delivery declined by 2.5 €/MWh. The price of December 2012 emission credits stayed below EUR 10, fetching on average 7 EUR per ton.

The existing trend of domestic electricity consumption continued, the share of import increased from the previously characteristic 20% to 27%. Exchange quoted day-ahead prices of baseload power fell below 40 €/MWh, the price spread for the recently more expensive Hungarian and Romanian day-ahead markets shrank to 2-4 EUR compared to the German and Czech markets. The price of the Hungarian baseload product with next year delivery got even more detached from the German, Czech and Slovakian markets.

The period of injection for storage started in the natural gas markets. Commercial gas storage facilities were depleted to 1.2 billion cubic meter, which is 0.5 billion cubic meter less than in last April. Until June the injected volume was 200 million cubic meter below the value from last year, and an increasing proportion is stored at the MMBF facility. A little over half of our import came from the East.

International price trends

The price increase of the Brent oil that started during the previous quarter reversed in the middle of March, and after the earlier 9-month high, during the quarter the price registered a nine-month low: while at the end of March the price of crude oil was still above 120 $/barrel, it dropped even below 90 $ by the end of June. Meanwhile the price of ARA coal also declined: less coal was consumed due to a mild winter, furthermore, the worldwide supply of coal substantially increased, since the US started to export its surplus production while gradually switching to shale gas. The formerly sustained 110-120 $/ton price of coal declined below 100 $.

The decrease in the price of coal was on the whole exceeded by the drop of the oil price, as a result the Brent crude became the cheaper fuel again.

Compared to the previous quarter the quarterly price of the EEX traded futures baseload and peak product with next year delivery decreased by

![Figure 1. The price of 2013 ARA coal futures traded on EEX and the spot price of Brent Crude between April 2011 and June 2012](image1)

![Figure 2. The price of 2013 futures electricity and natural gas between April 2011 and June 2012](image2)
3 EUR on average. The base-load product was traded for 48 to 51 €/MWh, with an average price of 49.5 €/MWh. The peak product was sold for 58 to 64 €/MWh, with an average of 61 €/MWh. The price of the TTF gas quoted on the APX-ENDEX exchange fell from 27.5 €/MWh at the end of March to 25 €/MWh.

During the quarter the average price of a ton of emission credit (EUA) with December 2012 delivery was 7 EUR on average. In March it reached a new all-time low, as a ton of credit was already available for 6.2 EUR. In addition to the excess supply on the market, depressed prices were also stabilised by the prolonged crisis of the European economy. At these low prices 835 million tons of CO2 credits were traded during the quarter, 200 million tons below the volume registered for the first quarter of 2012.

### Overview of the domestic electricity market

During the second quarter the 9.3 TWh of temperature and working day adjusted electricity consumption was the same as the value from the second quarter of last year. Within the quarter consumption in May was 3% below, while in June it was almost 3% above the values from last year. Quarterly consumption is not only close to the figures from a year ago, it was also in harmony with the electricity use of the same quarter of 2010.

More than a quarter of electricity consumption was supplied from import. For the previous two years the import share for the months of April, May and June stayed steadily at around 20%.
Monthly cross border capacity auctions generated prices that were even higher than in the preceding quarter. In May the price of cross border capacity on the Austrian-Hungarian border section rose to 4.5 HUF/kWh. The continued contraction of import capacities on the Slovakian border produced another price increase, the monthly price for cross-border capacity approached 3 HUF/kWh. On our Southern and Eastern border sections capacity fees were negligible.

Relative to the previous quarter the price of the day-ahead wholesale baseload product decreased by 5-6 EUR in the German and Czech markets, and by 15-16 EUR in the Hungarian and Romanian day-ahead markets. In the regional markets in April the settlement price sometimes spiked to almost 100 €/MWh, but in May and June the market calmed down again – it was most likely relieved by the return of the Balkan hydro generating capacities and the low quarterly demand. The Romanian and Hungarian day-ahead wholesale electricity prices approached the price of the German and Czech day-ahead products. In comparison with the Romanian and Hungarian markets the price advantage of the German and Czech wholesale markets shrank to 2-4 EUR by the end of June. The price of baseload energy typically stayed at around 40 €/MWh. Of the regional exchanges, once again HUPX turned out to be the most expensive and most volatile, followed by OPCOM, OTE and EEX.

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. During the quarter the price of positive and negative balancing energy was 21.7 and -7.6 HUF/kWh, respectively. The price of positive balancing energy stayed further below HUPX prices than during the previous quarters.

The price of 2013 delivery baseload electricity has been slowly drifting lower in the German, Czech and Slovakian markets. The Hungarian futures price, on the other hand, rose to 60 EUR in April, and then dropped to 54 EUR in May. The price difference between the Hungarian and the German exchanges, summed for the quarter, has almost doubled compared to the previous quarter. The spread between the Czech-Slovakian and the German exchanges contracted to a euro and a half, while on some June days the Hungarian market was 10 EUR more expensive than the German market, and the quarterly average price difference was 7 €/MWh.

**Overview of the gas market in Hungary**

Natural gas consumption during the second quarter was 260 mcm less than that of the same period of 2011. The monthly heating degree days slightly surpassed the figures from last year only in April, otherwise they are the same as the average and the hdd values specific to last year. Looking at the gas consumption data of recent years, we can note...
that 54-56% of the annual consumption took place during the first half of the year in each instance. The 6.1 bcm natural gas consumption from the first half of 2012 forecasts an annual gas demand of 11 bcm, indicating a 5% reduction of demand compared to 2011, and a 10% drop compared to 2010 consumption. Considering that the heating degree days for the first half year of 2012 even exceeded the figures from the same period of 2011, the decline in demand is clearly a sign of lower household consumption and decreasing industrial production.

Domestic natural gas production further contracted during the quarter: in June, for example, it fell to a modest 170 mcm. The total quarterly production fell by 190 mcm to 592 mcm. The tendency observed during the previous quarter, namely that the absolute production of residual producers declined, was also present in the months of April to June. In addition, the production of MOL also fell: the usual quarterly production of 250 mcm declined to 170 mcm. The volume of our import did not change much since the last quarter, but within its composition Eastern import became dominant again: 51% of the import arrived through Beregdaróc.

In April the heating season ended and the period of injection to the storage facilities started. Commercial storage facilities were depleted to 1.2 bcm, and then by the end of June filled up to 2 bcm. Compared to 2011, this is a 200 mcm lower storage level, and downright 1.4 bcm less than in 2010. The commercial portion of the Szőreg facility of the MMBF already makes up a quarter of the total...
storage capacity, while last June it provided only 13% of the stored volume.

During the 2nd quarter of 2012 1.1 bcm, or 49% of the import arrived from the Western direction. Eastern import was only 50 mcm higher. 60% of the capacity was reserved by market participants, and these reserved capacities were fully utilised in each instance.

48% of the natural gas arriving through the Eastern border was reserved, and the gas flow made up 46% of the reserved capacities. The total quarterly import exceeded the import of the same period of last year by 260 mcm.

During the quarter the average price of the oil indexed import was 129 HUF/m³. The difference between the oil indexed price and the price at the Austrian exchange was 46 HUF/m³, this has not changed meaningfully since October 2011. The price difference between the mixed import and the Austrian gas hub was on average 12 HUF/m³ during the quarter, slightly less than a quarter ago. According to our forecast the oil indexed import will on average be sold for 130 HUF/m³ during the next six months, while the price difference between the oil indexed import and the exchange based gas prices will stay above 50 HUF/m³.
ENERGY MARKET ANALYSES

How could gas become cheaper in Central and Eastern Europe?

In connection with the Ukrainian-Russian gas dispute of January 2009 the transit pipeline leading to Central Europe was turned off for a few days, instantly bringing the security of supply related exposure of the former Socialist countries to spotlight. Since then it has been expressed on many occasions (Kaderják, Piebalgs, ERGEG letter, Pirani et al.) that the gas dependency from the Russian partner carries serious risks, that can be eased through the diversification of sources, strengthening the infrastructural connection to the Western European gas network, establishing physical connections among Central European countries, and developing existing pipelines to be bi-directional. In part, these are made compulsory by the 2010 security of gas supply regulation of the EU (e.g. making all connecting pipelines between any two member states bi-directional by December 2013), while the 10 year network development plans contain the proposed investments of Member States on the development of cross-border and storage capacities. In addition to security of supply considerations, another noteworthy benefit generated by network development is that the natural gas wholesale purchase price of the region comes closer to Western European prices (represented by the spot prices of the Dutch exchange [TTF prices] in our model), which, for recent years, have been substantially lower than the wholesale prices of the Danube Region (the markets of which are heavily influenced by TOP contracts).

Based on its modelling work REKK set out to identify the infrastructural projects, or combinations of projects that could reduce the annual gas bill of the whole region by the largest proportion, and also examined in which case would the incorporation of new sources generate the most saving for the region.

New, non-Russian gas can be transported to the region by LNG (liquefied natural gas shipped by sea) tankers, or through a high-pressure pipeline, assuming that appropriate investments are undertaken to make the connection between the gas fields and the consumers. For these two different methods of transport we separately evaluate the likely impact on regional prices. During the analysis we apply the gas market model of REKK to compare the annual average marginal prices computed for the countries of the region before and after a new piece of infrastructure is added.

The impact of LNG investments

With the exception of Slovenia, all Central European coastal countries have developed LNG investment plans, but construction started only in Poland. As depicted by Table 1, the latter is indeed the most promising LNG project in the region.

<table>
<thead>
<tr>
<th>LNG</th>
<th>Maximum capacity</th>
<th>Annual saving for the region as a whole</th>
<th>Estimated investment cost</th>
<th>Break-even time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location of the investment</td>
<td>mcm/day</td>
<td>million €</td>
<td>million €</td>
<td>year</td>
</tr>
<tr>
<td>LNG-PL</td>
<td>13.70</td>
<td>872.30</td>
<td>470</td>
<td>0.54</td>
</tr>
<tr>
<td>LNG-HR</td>
<td>16.44</td>
<td>281.39</td>
<td>240</td>
<td>0.85</td>
</tr>
<tr>
<td>LNG2-RO</td>
<td>21.92</td>
<td>205.51</td>
<td>470</td>
<td>2.29</td>
</tr>
<tr>
<td>LNG2-BG</td>
<td>6.85</td>
<td>41.77</td>
<td>470</td>
<td>11.25</td>
</tr>
</tbody>
</table>

Table 1. LNG investment project plans and their profitability as calculated by REKK

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3 ERGEG Letter to Commissioner Piebalgs advising on lessons from Russia–Ukraine gas dispute
6 The Danube Region is a regional initiative launched during the Hungarian presidency of the Council of the European Union, the energy pillar of which is co-chaired by the Hungarian and Czech governments. In spring 2012, following the request of the Hungarian Ministry of Foreign Affairs, REKK developed a regional gas market model, covering the following countries: Albania, Austria, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Greece, Hungary, Kosovo, Macedonia, Moldova, Montenegro, Poland, Romania, Serbia, Slovakia and Slovenia.
7 TOP = „take-or-pay” is a long term gas purchase contract, under which the buyer is obliged to pay for the contracted volume even if it has not actually taken over the full amount.
8 The result is, of course, slightly deceptive, as only part of the benefits is retained directly by the investor.
LNG in Western Europe is also sold through two main channels: on the one hand, investment into the construction of LNG ports usually requires signing long term contracts that are mostly oil index based, just like the Russian long term contracts. On the other hand, a lower share is sold in the spot market, the price of which has, for the last few years, turned out to be lower than the price within long term contracts. While running the model we assumed that the LNG shipped to the Polish and Croatian LNG ports is sold at the spot price, while for the Romanian and Bulgarian terminals the spot LNG price does not apply, as these facilities can only receive tankers arriving from Georgia. Therefore for these two locations we presumed a gas price that is 5% lower than the Russian import price. Model calculations show that all the LNG terminals most benefit from the region is delivered by the Polish investment: this is because as a result of constructing the Polish terminal, the annual average marginal price of Poland, which counts as a large consumer within the region, decreases to 24.8 €/MWh compared to the 30.8 €/MWh value of the reference scenario, and this alone generates massive savings on a market with 10 bcm of annual consumption.9

The project, however, does not have regional impacts, since the connecting pipelines that would enable trading with the neighbours are absent (Figure 16). In the map the arrow circled in yellow indicates the investment that is realised, and its impacts are signalled by the background colours of the countries. For white coloured countries the marginal price is not impacted by the investment, in case of grey coloured countries the regional marginal price declines by between 1 and 5 €/MWh, while in countries with an orange background the price drop exceeds 5 €/MWh. We can also note that the Croatian investment – while delivering lower savings on a regional scale (see Table 1) – has a much wider geographical reach, as practically the whole region is covered through the existing infrastructure.

**The impact of the high pressure transit pipeline investment**

Another potential means of source diversification is the transmission of non-Russian gas to the region through a pipeline. In this respect, we made an ad hoc assumption that a pipeline with an annual capacity of 10 bcm transports gas (with a 5% discount compared to the Russian import price) from Azerbaijan to Baumgarten based on a TOP contract, from where it is dispatched to other countries within the region using commercial transactions (version 1), or the same quantity is reserved through a number of smaller contracts along the transit route (version 2).10

In our exercise the model was run for the assumed 2020 scenario,11 where the modelled 2011 regional wholesale price premium of 21.51%...
over the TTF price jumps immediately to 30%. In other words, the absence of new investments will increase the gas bill of the region by 41% (see Table 2). This is because the gas demand of the region will escalate by this time, and we assumed that the expired TOP contracts are renewed for 80% of the originally contracted volume. Even though the portfolio consisting of diversified contracts is expected to deliver almost 8 times more savings than transmitting gas to the Austrian hub under one large contract, the 10 bcm of new source in itself has a modest impact in the region, considering the giant leap in regional demand by 2020. In case of V1 the gas delivered to the Austrian market cannot return to the region due to the limited cross border capacities, therefore it is not in a position to lower the price of the neighbouring markets (Hungary, Slovenia), even if a discount is assumed compared to the Russian import price. Under the more diversified contractual structure a lower quantity “gets stuck at Baumgarten” as a result of the capacity constraints at the Austrian border.

As the above descriptions reveal, source diversification, in addition to the obvious improvement of the security of supply, also generates financial savings for the region. Of all the possible sources, connection to Western European spot markets and the global LNG market is the most attractive given the current spot and contracted TOP prices. In balancing price differences. With the Danube Region Gas Market Model of REKK we ranked each cross border infrastructural project included in the regional development plans based on the extent to which they help the average regional wholesale marginal price to approach the Western European spot price, and thereby generate annual cost savings to the consumers of natural gas in the region. If we inspect the six best projects from Table 3 as a package, then the regional wholesale premium (compared to the TTF price) falls to 11.94% compared to the initial 21.51%. Regional savings amount to 1,834 million €/year. This clearly shows that constructing regional connections is necessary not only from the perspective of security of supply, but they also make economic sense. The intuitive hypothesis that the planned connections as a package deliver a much larger impact

<table>
<thead>
<tr>
<th>Cross border pipeline project</th>
<th>REP14</th>
<th>Annual saving</th>
<th>Estimated investment cost</th>
<th>Payback time</th>
</tr>
</thead>
<tbody>
<tr>
<td>CZ-PL2</td>
<td>17.10%</td>
<td>841.75</td>
<td>28</td>
<td>0.03</td>
</tr>
<tr>
<td>SK-HU</td>
<td>18.35%</td>
<td>598.51</td>
<td>150</td>
<td>0.25</td>
</tr>
<tr>
<td>TR-BG</td>
<td>21.29%</td>
<td>41.77</td>
<td>75</td>
<td>1.80</td>
</tr>
<tr>
<td>GR-BG</td>
<td>21.13%</td>
<td>73.49</td>
<td>160</td>
<td>2.18</td>
</tr>
<tr>
<td>SB-BG</td>
<td>21.39%</td>
<td>22.98</td>
<td>95</td>
<td>4.13</td>
</tr>
<tr>
<td>RO-MV</td>
<td>21.47%</td>
<td>7.73</td>
<td>50</td>
<td>6.46</td>
</tr>
</tbody>
</table>

Source: REKK gas market model

Table 3. The impact of the cross border pipelines within the region on the average regional marginal price and the estimated return profile of the projects (2011)

12 In the absence of reliable data on the costs of large transit pipeline projects, we have not calculated the return profile. In all likelihood, the investment costs of version V1 are many times higher than the costs of V2. Nevertheless, in June 2012 the BP consortium selected the Nabucco West project, that is similar to the V1 version, as the transit path to compete with the TANAP corridor. Whether the Nabucco West or the TANAP will transmit the gas from Azerbaijan, will be decided by late 2012.

13 The starting reference scenario is the 2011 modelled baseline.

14 REP (Regional Excess Price) = Σ(P modeloled*Q regional)/(P spot*Q regional). The index quantifies the premium to be paid by the countries of the Danube region in excess of Western spot prices.
than the sum of individual impacts (1586 million €/year) has now become quantifiable with the help of the model.

Another lesson that can be drawn from the analysis is that the construction of cross border connections and the convergence of prices within the region generates more savings for the region as a whole than the construction of new transit pipelines.

Long term impacts of the closure of German nuclear facilities

In issue 3/2011 of the Hungarian Energy Market Report we have already analysed the short term impacts of the closure of the German nuclear power plants – in particular, how electricity prices, foreign trade and the Hungarian electricity market are affected. More than a year has passed since then, making it possible to review the impacts made on the German and the regional electricity markets, now with a longer data set. Moreover, using the results of the European Electricity Market Model developed by REKK, we can also inspect the implications on an extended time horizon. The model is capable of simulating the electricity markets of 36 European countries.

Hence, the article will first review the new developments within the German electricity market since the middle of last year, also covering those analyses that addressed the questions surrounding the reduction of nuclear capacities. The evaluation of modelling results will come afterwards.

The direct impacts of the nuclear shutdown

The final decision to close down German nuclear facilities was passed by the Bundestag at the end of May 2011. This, however, had been preceded by the mid-March announcement of Chancellor Merkel on a temporary halt of generation lasting for three months. According to the decision, 48% of the German nuclear capacity was closed in last March, while the rest of the capacity is scheduled to gradually wind down by 2022. The facilities closed last year used to generate a non-trivial 5-7% of German electricity production. As a result, in the short run the price of electricity increased by 6-7 €/MWh in the German markets, and this increase more or less spread to the rest of the EU, including the Hungarian market. (For more details please see issue 3/2011 of the Hungarian Energy Market Report.)

Concurrently with the closures, opinions and studies on the impacts were published, focusing on the following issues:

- The impact on the German electricity market, including the effects on price change, the capability for the self supply of the country, and the foreign trade of electricity.
- The likely GHG emissions trajectory of the power generating sector (as a result of the nuclear shutdown the increase of German and European emissions were forecast by many sources).
- Concerns appeared in relation to nuclear generation, namely, that the surplus demand due to the closure of the German facilities may be met with nuclear energy produced elsewhere, e.g. in France. Therefore the impact on the European nuclear energy sector is also examined.

Most reports forecast rising prices and increasing German import for the short run. According to nearly all studies, on the longer term the German electricity system will be able to handle the shutdown of nuclear plants with a moderate increase of price and a slight shift in foreign trade. Only the Bundesnetzagentur study indicated that network difficulties may take place during the winter season. We will return to the GHG emissions and the impacts on European nuclear generation when evaluating the modelling results.

At present we have a full year of data on German electricity market developments, making it possible to analyse the extent to which predicted trends materialized. Figure 17 displays the net foreign trade of electricity on German border sections in a monthly breakdown between April 2010 and June 2012.

Figure 17 provides a versatile view of German crossborder flows. The data accurately reflects the large seasonality of foreign trade: while during the summer months Germany is typically a net importer, it has a net exporter position for the rest of the year. Looking at annual data we can see that Germany, which has been a net exporter since 2003, continued to be a net exporter in 2011, the year in which nuclear generation was scaled back, but its export substantially dropped. In contrast with the preceding 5-year average export of 14 TWh, 2011 net export was a mere 2.4 TWh, signifying the growing electricity imports and decreasing exports of the country. In essence, the 37 TWh of annual average generation of the power plants decommissioned in 2011 was replaced mainly with domestic production.

1 See the References at the end of the article.
From the perspective of the analysis an important message offered by the figure is that the substantial export decline in the summer of 2011 will probably not be repeated this year, in other words, the German foreign trade balance may possibly even return to the previous level.

German foreign trade has also been characterized by the rather firm positions of the key players: France and the Czech Republic were the main import partners, while the rest of the countries were net recipients of German export. To some extent, Austria and Denmark are exceptions, the foreign trade positions of which switched from net export to net import. A specific tendency observed last year, nevertheless, is that the German import became more diversified, partly as a result of import from Sweden – an inactive border section prior to October 2011 –, and partly due to the commencement of net import from Denmark and Switzerland.

The only feasible avenue to get a sound estimate for the price impact is through modelling, during which we can explore the alleged interrelations by comparing different scenarios. We accomplished this analysis with use of the REKK European Electricity Market Model.

Modelling results of the German shutdown

The long term impacts of the German nuclear closure have been analysed with the Electricity Market Model that has been extended to include Europe. We compared two scenarios to examine the impacts of the nuclear shutdown. We have contrasted the current German schedule for closure (baseline scenario) with the schedule that had been envisaged before the Fukushima disaster (nuclear scenario), and analysed the results for the period between 2012 and 2020. Keeping all other modelling variables – such as capacities and fuel prices – constant, we can quantify the short and long term impacts of the closure. The ensuing results are concisely summarised by Figure 18.
The model presents the wholesale prices (for both peak and off-peak periods) and the traded volume for both scenarios, with the difference between the scenarios being equivalent to the effects of the nuclear shutdown. In Figure 18 we display these differences for year 2012, where the figures within the boxes indicate the difference between the off-peak prices of the two scenarios, while the arrows show the difference between the commercial flows of the two scenarios. It is important to note that the arrows do not show the actual flows, they represent the changes induced by the shutdown. The colour codes applied to the map illustrate the magnitude of the price change: white for 0-1 €/MWh of price change, light grey for 1-3 €/MWh, dark grey for 3-5 €/MWh, while orange for above 5 €/MWh. We subtracted the prices of the nuclear scenario from the figures of the baseline scenario, therefore positive values signal higher prices for the current scenario (post-shutdown) in comparison to the pre-Fukushima vision.

As a short term effect, the model anticipates an almost 7 €/MWh price hike in Germany, less than 5 € in the Czech and Slovakian markets (and also in case of the Ukrainian island production, linked to the ENTSO-E region), between 1 and 2 € in our region, in the Nordpool and in France. The price change is less significant for the rest of the EU member states. While French and Czech exports to Germany increase by about the same percentage, this prompts a much larger price change for the latter, clearly as a result of the size of the market and the particularities of the power plant portfolio.

The impacts have spread throughout our region, triggering a noticeable price increase even in the Balkan countries. As we already noted, the arrows do not stand for actual flows, they signal decreasing German exports to the region. Modelling results demonstrate that the German decision – through the substantial weight of the country in foreign trade – significantly impacts the electricity markets of almost the whole continent. The higher modelled German import originates mainly from the French, the Czech and the Danish electricity systems.

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In order to be able to quantify the longer term impacts, we need to make some assumptions on specific factors: in case of the capacity extension of power plants and cross border transmission lines, based on presently available information those plants and transmission network items were incorporated into the simulation – together with their respective development schedules –, which have already entered the national permitting pipeline, or appear within the ENTSO-E Ten Year Network Development Plan in case of border sections. For renewable generation our assumptions have been based on the National Renewable Energy Action Plans. It is important to note that these
plans had all been developed before the decision on nuclear closure was made, but in the absence of more recent, official targets we did not have anything else to use.

Results for 2020 show a slightly different picture of the European electricity market (see Figure 19).

Further down the road the price effect will alleviate in the countries of the continent, but it will not disappear completely. This will be the net result of two forces. Newly developed generating capacities (both renewable and conventional sources) may ease the price effect, while the continuously reduced German nuclear generating capacity will keep pressuring prices. The impact on the United Kingdom and the Nordpool will be even stronger due to further developed network connections, the price effect in these countries will be more profound than in the countries of the continent. In the long run, nevertheless, the Czech, the Slovakian and the Ukrainian electricity systems will continue to be the most price sensitive to the German decision.

Modelling results also reveal that the impact on GHG emissions on the 2020 time horizon is non-negligible. The new shutdown scenario will increase emissions by 4.5% in Germany, and 2.5% for the EU as a whole. This is not surprising since much of the terminated capacity is replaced by fossil fuel based generation in Germany and the Czech Republic. With respect to the other foreseen problem – nuclear generation shifting to other countries –, modelling results indicate that the difference between the all-European nuclear production of the two scenarios is below 1%, therefore this impact is not likely to be relevant. Without the entry of a new nuclear power plant, and due to the full capacity utilization of the existing ones there is essentially no room to increase nuclear generation.

References
CURRENT EVENTS

INCREASING PHOTOVOLTAIC PRODUCTION AND THE ELECTRICITY MARKET

For the last two years the difference between the price of baseload and peak products (peak spread) quoted on electricity exchanges has substantially narrowed for several European countries, including Germany and Spain – and this trend seems intact in 2012 as well. The key explanation for this phenomenon is the soaring photovoltaic (PV) production: solar PV plants can generate abundant energy during the day-light peak hours, and the feed-in-tariff scheme brings about significant additional supply, suppressing the price of peak load energy. In the article we explore the price lowering impact of the PV plants, primarily in the case of Germany, and we also inspect the influence that lower spreads may make on the generating mix and hence the longer term development of the electricity market.

Photovoltaic penetration in Europe

As a consequence of a favourable regulatory environment, attractive subsidy schemes and fast eroding PV panel prices, photovoltaic generating capacities have, for the last few years, expanded impressively in a number of European countries – most importantly in Germany, Spain, Italy and the Czech Republic. A good indication for the direction of the market is that in 2011 in Europe the 21.9 GW of newly installed PV already made up 47% of the total power generating capacity created during the year, while the respective figure from the previous year was only 22% (13.4 GW of PV). In 2011 the quick expansion of capacities continued in Germany, but its previous first place with regard to newly installed capacities was still lost to the dynamically advancing Italy. Meanwhile in Spain, where subsidies had already been substantially cut following the accelerating growth of 2008, stable, but modest expansion was observed for 2011. In the Czech Republic, where 2009 and 2010 were characterised by a remarkable increase, the expansion of PV capacities almost completely stopped as feed-in-tariffs were heavily cut at the end of 2010. In terms of PV capacity per capita, last year Slovakia, Greece and Belgium all demonstrated a quick rise, with Belgium having already surpassed Spain (Table 4).

Today these capacities can provide most of the peak consumption of some of the countries. Currently solar photovoltaic generation can, on average, deliver over 4% of European peak consumption; the same figure is 10% in Italy, 8% in Germany, and even Spain can pride itself with a value above 5%. The case of the largest European economy, Germany, is especially intriguing: German photovoltaic capacities are estimated to have surpassed 28 GW, equal to 18-19% of the total electricity generating capacity of the country. Thus, since May this year the PV based midday production of Germany has typically been between 10 and 15 GW, but on 26 and 27 May it exceeded 22 GW: on these two sun-soaked afternoons PV plants supplied 31% of the peakload power consumption of the country.

The impact of photovoltaic production on the merit order

In a number of countries, including Germany, electricity produced from renewable sources is subject to obligatory purchase: the operator of the distribution network usually pays a fixed price.

<table>
<thead>
<tr>
<th>Country</th>
<th>PV capacity (MW), 2011</th>
<th>PV/capita (MW), 2011</th>
<th>Total generating capacity (MW), 2011</th>
<th>PV/total capacity, 2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>24,678</td>
<td>302.8</td>
<td>145,112*</td>
<td>17.1%*</td>
</tr>
<tr>
<td>Italy</td>
<td>12,754</td>
<td>212.6</td>
<td>118,432</td>
<td>10.8%</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>1,959</td>
<td>185.4</td>
<td>18,981</td>
<td>10.3%</td>
</tr>
<tr>
<td>Belgium</td>
<td>2,018</td>
<td>183.5</td>
<td>20,027</td>
<td>10.1%</td>
</tr>
<tr>
<td>Spain</td>
<td>4,400</td>
<td>93.6</td>
<td>96,904</td>
<td>4.5%</td>
</tr>
<tr>
<td>Slovakia</td>
<td>468</td>
<td>85.1</td>
<td>8,152</td>
<td>5.7%</td>
</tr>
<tr>
<td>Greece</td>
<td>631</td>
<td>58.9</td>
<td>14,773</td>
<td>4.3%</td>
</tr>
<tr>
<td>Hungary</td>
<td>4</td>
<td>0.4</td>
<td>9,497</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

*The total generating capacity and the PV/total capacity values for Germany are estimates

Source: EPIA, ENTSO-E

Table 4. PV capacities of Hungary and the European countries with the highest capacity per person
(feed-in-tariff) to the power plant in exchange for the renewable electricity, and subsequently it is required to transfer the electricity to the transmission system operator. Furthermore, since January 2010 the system operator in Germany also has a legal obligation to sell the acquired renewable energy on the Leipzig EEX exchange for day-ahead delivery. Renewable electricity – including, in particular, the intermittently produced solar and wind energy – is therefore always fully sold on the exchange, independently of the actual demand in the market.\(^2\) This additional supply displaces the production of relatively expensive power plants (those situated on the right hand side of the merit order), thereby reducing the day-ahead price on the exchange. This so called merit order effect is typically the most critical in case of solar power plants, since the bulk of their production takes place during the daylight period of peak demand.

**Decreasing peak spreads, decreasing price volatility**

As Figure 20 shows, all along since March this year on the day-ahead (EPEX) market of the EEX power exchange the peak-baseload spread has stayed low, with an average value of 5 EUR/MWh, and as a new phenomenon, more and more frequently even negative spreads have taken place on certain days (weekends and holidays). Meanwhile, in the case of baseload prices we have not observed an increasing trend, therefore the shrinking spreads are not explained by a change in baseload prices. We thought that the impact of higher PV generation on day-ahead electricity prices was worth exploring. We did this by analysing the day-ahead prices for the German-Austrian control zones of the German EEX exchange (the day-ahead auction is already influenced by the number of sunny hours, since the latter can be well forecasted for the day ahead) as well as the daily German photovoltaic generation between 1 May and 19 July, 2012 (the last available data). After filtering out the price lowering impact of weekends and holidays, we estimated that a 1% increase in peak period (between 11 AM and 2 PM) PV production results in 0.46% lower day-ahead daylight peak prices.

\(^1\) We should note that German renewable producers can sell their generated electricity not only within the obligatory purchase regime, based on feed-in tariffs, but they can also choose to sell the electricity in the market, at a market price, while fetching a feed-in premium that supplements the market price. This duality does not have a major impact on our analysis.

\(^2\) In general feed-in tariffs are fully financed through a fee component included within the invoiced amount to consumers – this is the practice in Germany as well. Therefore system operators can sell the received power at any price – even very low prices – on the exchange, the price does not have to be in harmony with the feed-in tariff, since the costs associated with the obligatory purchase will eventually have to be reimbursed.
on average. In short, during the most critical summer season the operation of photovoltaic power plants exerts a substantial influence on the price of exchange traded peak products.

Figure 21 illustrates how the day-ahead price on EPEX for the May-June period changed between the average of the 2009-2011 period and 2012. Apparently by 2012 prices fell for almost every hour of the day, with the biggest price drop observed for the early afternoon peak period: exactly when photovoltaic power plants operate with maximum capacity. The larger intraday price drops reinforce our view that the price reducing impact of the growing PV penetration is substantial, while at the same time intraday price variation is also trimmed: on sunny days the hourly prices get more even, that is, price volatility declines.3

**Gas based power plants getting crowded out**

Presently it is specific to Germany that gas fuelled power plants, operating at a higher marginal cost, on some days get crowded out by photovoltaic power plants which enjoy a guaranteed price and obligatory purchase. This summer low German peak spreads are already escorted by sustained negative clean spark spreads (CSS), while worsening summer margins can hardly be offset by the overcast autumn-winter periods.

A noticeable tendency for the growing preferred (must-run) capacities – such as nuclear power plants, renewables, including PV capacities, and to a lower extent cogeneration power plants – is to crowd out conventional (that is, market based, primarily fossil fuel fired) generation. According to our estimates, if Germany, in line with recent government messages, lets renewable energy replace the nuclear plants that are to be closed, then the weight of conventional power plants within the German generating mix may, by 2020, sink from the current approximately 28% to 15.9% during peak, and 20.4% during off-peak periods (Figure 22). If we want to determine the room left for conventional power plants in different periods, then an even more interesting picture emerges: while in 2012 the peak period generation of conventional plants is on average 2 GW above their annual average production, by 2020 this is expected to reverse, and their peak period generation will only trail off-peak production.

If pure market logic holds, in the long run low profitability should also be reflected in declining investments into gas fired power plants. This implies lower gas based capacity, which, however, carries a risk as the flexibility offered by gas turbines will be missed in some periods, and every now and then unusually high demand will lead to spikes in prices. At present, nevertheless, conventional capacities in the countries of Western Europe are 10-25% in excess of peak period demand, and markets are characterised by reasonably low hourly price volatility. For the last couple of years, for instance, day-ahead EEX prices edging above 100 €/MWh have been rarely witnessed – the last time this happened was amid the extreme cold weather of early February. What is much more typical is that during the morning and late afternoon peak hours of summer days, when PV production is low, and the gas fired power plants – crowded out for the daylight hours – are not really economic to start, prices become relatively high. It is worth noting, however, that power plant investments, in addition to market based profitability are also guided

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3 Electricity consumption in 2012 has not declined significantly in comparison with the average of the previous three years. This is explained neither by the business cycle (German GDP has been on the rise since 2010, without an economic decline that could have triggered a drop in electricity consumption), nor by the increase of the average temperature (while in 2012 the May period was warmer than the 2009-2011 average, June was somewhat colder, and even if we restrict our analysis to June the results will be similar to that of the whole May-June period).
by several other factors – e.g. considerations of system security –, which makes it more difficult to predict the actual volume of gas fired power plant capacities available in the future. Analysing the impact of such market distorting factors, nevertheless, is beyond the scope of our article.

**TOP or TOPless beyond 2015?**

The long term Take-or-pay (TOP) contract that was signed between Gazprom and MOL in 1996, and which even today serves as the backbone of the supply side of the domestic natural gas market, will expire in 2014-15, opening up the opportunity to meaningfully reorganise the structure of the gas wholesale market. The current article raises a number of vital questions concerning the future structure of the Hungarian natural gas sector, essential from the perspective of the competitiveness of domestic power plants and the economic position of the households. First and foremost, we inspect if it is reasonable to make a new TOP contract – similar to the current one – specifically for the Hungarian market, considering the expected domestic and regional gas market developments.

### The state of domestic gas market competition

The expansion of competition within the domestic natural gas market has been unabated since market liberalisation was launched in July 2004. An important indicator for the development of the competitive market is that in 2011 three-quarter of total domestic consumption was supplied through competitive market contracts. For the last three years a critical factor that strengthened competition has been the operation of the HAG pipeline enabling Western import competition. Thanks to the favourably priced Western-European gas supply, in 2011 the share of imports from the West within total natural gas import rose above 50%. The willingness of final consumers to switch traders as well as the actual replacement ratio is relatively high, and this tendency can be spotted even among the universal service providers that are otherwise protected with regulated prices.

From the perspective of future gas wholesale competition it is an encouraging and notable sign that in addition to MOL, of the European market participants with the largest gas resources five (EON, RWE, ENI, GDF-Suez, Gazprom) are also present in the Hungarian market, several of them with vertically integrated interests. Furthermore, the Hungarian government apparently wants MVM to also turn into a noteworthy gas market participant. The number of licensed gas traders is altogether 42.

The impressive expansion of the infrastructure of the Hungarian gas industry between 2008 and 2010 is also a favourable development from the perspective of wholesale competition. In this period the capacity of pipelined gas import grew by 72%, while the mobile gas capacity of subsurface storage facilities increased by 65%.

### The importance of year 2015

In addition to the expiration of the TOP contract, the significance of year 2015 is enhanced by the fact that the new Slovakian-Hungarian, bi-directional cross border pipeline, with annual capacity of 5 bcm is also planned to be completed by this year. This will increase our total gas import capacity from all non-Russian directions (that is, the Slovakian, Austrian and Croatian cross border capacities, and the Romanian connection once it is developed to be bi-directional) to 10 bcm a year, equal to the total expected Hungarian import demand.

<table>
<thead>
<tr>
<th>Annual transport capacity, bcm/year</th>
<th>Import</th>
<th>Export</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ukraine</td>
<td>22.2</td>
<td>-</td>
</tr>
<tr>
<td>Austria (HAG)</td>
<td>4.4</td>
<td>-</td>
</tr>
<tr>
<td>Croatia*</td>
<td>6.5</td>
<td>6.5</td>
</tr>
<tr>
<td>Serbia</td>
<td>-</td>
<td>(transit)</td>
</tr>
<tr>
<td>Romania**</td>
<td>-</td>
<td>1.6</td>
</tr>
</tbody>
</table>

* For the time being, the Croatian import capacity is only nominal, as a considerable volume of alternative natural gas is not likely to be available from this direction in the medium term.

** Source: REKK gas market model

**Table 5.** Key attributes of the connecting gas pipelines between Hungary and its selected neighbouring states (2012 status)

1 Concerning the domestic partner the contract changed hands in 2006 when E.ON Ruhrgas AG purchased the stake of MOL.
Thereby the physical-infrastructural basis for more efficient gas import competition is created, as the supply of Western European gas markets will not any more be restricted by transport capacity constraints from reaching the Hungarian market. If we also add a regulatory and institutional environment that supports competition, then after 2015 we may witness a domestic gas wholesale market that is much more competitive than today. The essential components of the quoted regulatory and institutional environment encompass a system for discrimination free network capacity reservation and access (including, of course, cross border capacities),2 a regulated network access tariff scheme that is equitably priced by the Hungarian Energy Office, and a domestic storage market free of distortions. The consistency and credibility of competition may be further fortified by a trustworthy gas exchange offering price transparency – expected to be operational by 2015. Lastly, it should be guaranteed that wholesale price development can be influenced only through the supervision of competition authorities.

If, during the second half of the decade, additional sources of gas appear within our region in the form of LNG, a new international long distance gas pipeline or non-conventional gas extraction, then the efficiency of wholesale competition may further improve due to the expansion of supply. This process may be further facilitated by the attempt of the European Union to strengthen the connection between the gas markets in our region.3

Model alternatives and the feasibility of a new TOP

The above contemplation suggests that once the current TOP contract is completed, we would have a reasonable opportunity to devise a multi-party, efficient and competitive wholesale natural gas market in Hungary. This could be instrumental in passing a growing share of the benefits of intensifying competition in the European core market to domestic consumers, and in replacing the prevailing Hungarian practice of oil index based price setting for natural gas by market based pricing.

In contrast, signing a new, long term TOP contract similar to the one in effect today would severely restrict or even prevent the development of the competitive model by securing a disproportionately large share of the supply to one market participant. Given that the international gas market environment seems to be favourable in the long run and considering the above described encouraging conditions that characterise the domestic gas market, one wonders what other factors are sensible to assess before another TOP contract is signed with the Russian partner? Next, this question will be investigated.

Table 6 provides a summary of the key features of the TOP contracts signed between Russia and those EU member states in the region that used to belong to the Socialist regime.

As the table shows, besides Hungary, Bulgaria is the only country that has not yet extended its former TOP contract with Russia. Also, with the exception of Romania, which has a lot of domestic production, the annual volume reserved for the next 20-25 years under the new TOP contracts makes up 60-100% of annual consumption, therefore in terms of volume the countries of the region have decisively and directly committed themselves to the Russian supplier.

The typical components of a TOP contract comprise the annual contracted quantity (ACQ), the indicator of the supply flexibility (swing), and the

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2 On the present distortions of the system please see our earlier piece titled The Baumgarten-saga (Issue 3/2011 of the Hungarian Energy Market Report)

3 See especially the initiatives presented by the European Infrastructure package (COM(2011), SEC(2011) 1233 and COM(2011) 665), and the December 2011 report of the working group on North-South gas connections.
method for setting the price of the product. While we lack information on the latter component of the new contracts, we have reasons to believe that indexing to oil products continues to be an important constituent of natural gas pricing.

In our view, principle three key arguments may be made for signing a TOP contract with a duration and volume similar to the current one, namely: management of the volume risk associated with supplying the Hungarian market, management of the price risk, and lastly, assisting the market entry of a new participant by ensuring that the contracted gas volume is available.

Management of the volume risk and guaranteeing the security of supply

An argument in support of signing a new TOP contract may be that for the duration of the contract the availability of sufficient gas to meet the demands of domestic consumers or a well defined subset of them (e.g. household consumers) is assured. In other words, the contract would offer a volume / security of supply type of guarantee.

A properly functioning gas wholesale market, nevertheless, can offer a similar volume based guarantee. As we have seen, in the Hungarian market there are at least seven large, active participants, with a European natural gas portfolio behind each of them. It is difficult to imagine that – in case prices reflect demand and supply – these participants would not have the 1-2 bcm of natural gas to be sold in this market. In addition, Western European spot markets also become accessible through the construction of the Slovakian-Hungarian connection.

The price signal of a distortion free market and the availability of sufficient storage capacity enables the management of temporary cases of short supply, but not necessarily emergency situations. It would be good to know if a Russian TOP contract tailored to the national market is the best tool to take care of the risk associated with supplies under an emergency situation. The answer is probably “no”, since past crises of supply were, in fact, caused by the partial fulfilment or complete neglect of the contractual obligations by the Russian partner. Strategic storage, a commercial storage obligation to handle emergency situations, demand side solutions or the establishment of a regional cooperation to manage emergency situations all seem to be better and cheaper answers.

What is more, the crisis of 2009, for instance, demonstrated that in Austria the supply shock triggered a large enough price increase to generate adequate additional supply for the Austrian market, without any intervention of the authorities – that is, a market with efficient pricing mechanisms is also one of the most efficient solutions to manage emergency situations of gas supply.

Management of the price risk

According to the other common argument in support of long term contracts these agreements ensure (also) for the buyer that prices are foreseeable, and market based price volatility is pacified. Under the current market conditions, nevertheless, it is exactly the maintenance of oil indexed gas pricing, favoured by the Russian partner, that poses a significant price risk. For European customers the preponderance of such transactions results in prices that exceed the American exchange based price by five times (!). Meanwhile, compared to the Western European price, Hungarian consumers pay another substantial premium (see Figure 15 of the article on Energy market developments). The separation of oil and gas market trends is unlikely to reverse any time soon, and in contrast with the gas market, within the oil market the price increasing forces seem to win the day. Consequently, when working on the post-2015 gas model, it makes a lot of sense to fade oil index based pricing, and prefer solutions that support market based price setting. In addition to efficient competition, a TOP contract giving maximum priority to market based pricing can also suffice – as long as there is a seller willing to engage in it.

A politically sensitive question to be distinctively addressed is how the consistency and stability of the gas price for universal services can be guaranteed under a predominantly competitive wholesale market model. Here the Croatian experience of INA, a subsidiary of MOL, may offer valuable lessons. In 2010, after the previous TOP contract had expired, the company issued a public procurement tender for the three year gas supply of Croatian consumers. The contract was granted to ENI, which submitted the most attractive price offer. The bid of the supplier and the pricing method for final consumers that is based on the bid allows for a predictable, stable, and at the same time also market based setting of consumer prices.

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4 Nevertheless, in January 2009, for example, to ease the problems after the Ukrainian pipeline had been turned off, gas was imported from the West, and much of this gas – indirectly – probably originated from Russian TOP gas transported to Europe through other pipelines.
While the domestic universal service market is almost three times larger than the whole Croatian gas market, in the case of this market segment frequent public tendering – every 1-3 years – can prove to be an appropriate method. This, however, may require the appointment of a wholesaler that would issue the bid.

**Assisting the market entry of a new participant**

A new TOP contract may assist a domestically owned participant, for instance MVM, to join the market along with the large international players that have sizeable gas portfolios. A non-market based contract that can handle volume with reduced flexibility, nevertheless, can also pose substantial risk to the new market entrant, easily digesting the net revenues of its other activities. A 20% price advantage compared to the TOP price would consume the full 2011 after-tax profit of the MVM group, even in case of a 3 bcm/year contract, equivalent to one-third of the present volume – and the developing European gas market certainly carries pricing uncertainties on this scale. The wholesaler role of the universal service market segment could offer some assurance to a new entrant like this – but even in this case, if the universal service pricing is unfavourable relative to the market, the migration of consumers to the competitive market should be expected.

In a nutshell, we assume that the character and role of future TOP contracts will be in the center of professional discussions on the post-2015 domestic gas wholesale market.

**Abbreviations in the Report**

- **ACQ** Annual Contracted Quantity
- **APX** Amsterdam Power Exchange
- **ARA** Amsterdam-Rotterdam-Antwerpen
- **BCM** Billion Cubic Meters
- **MCM** Million Cubic Meters
- **CEGH** Central European Gas Hub
- **ECX** European Carbon Exchange
- **EEX** European Energy Exchange
- **EUA** European Union Allowance
- **FIT** Feed-In Tariff
- **HAG** Hungary-Austria Gasline
- **HDD** Heating Degree Day
- **LNG** Liquefied Natural Gas
- **HEO** Hungarian Energy Office
- **OPCOM** Operatorul Pieteii de Energie Electrica
- **PV** Photovoltaic
- **PXE** Power Exchange Central Europe
- **SEPS** Slovenská elektrizačná prenosová sústava
- **TOP** Take or Pay
- **GHG** Greenhouse gas
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- KVVM (Ministry of Environment and Water),
- GKM (Ministry of Economy and Transport),
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