REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q1 2015

REKK REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

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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- ERRA summer schools
- Regulatory trainings
- Price regulation
- Electricity market trainings
- Market monitoring
- Gas market trainings
- Tailored trainings upon request

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Geographically, our key research area is the Central Eastern European and South East European region:

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- Renewable energy support schemes and markets
- Security of supply
- Market entry and trade barriers
- Supplier switching

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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 all countries of the EU to forecast regional electricity prices. In 2012, we have developed a regional gas market model for the Danube Region countries, which was expanded to a model covering Europe.

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.

Dear Reader,

The first article of our current issue inspects the consequences of the dramatic fall of the price of Brent crude on natural gas and electricity markets. We describe in detail the channels through which the drop in oil prices influences the price of natural gas (above all, the price of long term oil price indexed contracts), and consequently the marginal cost of gas based electricity production and electricity market prices. We want to know if the unfolding price developments within the natural gas markets are sufficient to re-establish the competitiveness of natural gas fired power plants - which have been uncompetitive and unprofitable for a good number of years now - making their operation a profitable activity again.

In our second article we take a look at the capacity allocation of the Slovakian-Hungarian cross border gas pipeline. While the long awaited pipeline has been completed, transmissions have still not started as there continues to be uncertainty as to when and how system users can get access to the capacities. In the article we briefly appraise the motives and circumstances of the inception of the project, examine the factors hindering the creation of capacity allocation rules that are acceptable to all stakeholders, and finally review the key principles based on which capacity allocation rules should be devised so that the pipeline can function as it was intended: increasing security of supply, enhancing source diversification and robust competition in the natural gas market.

Our third article is devoted to inspect the new security of supply and infrastructure challenges imposed upon Hungary and the Central and South-East European region following the termination of the South Stream development plans and the new gas delivery strategy foreseen by Gazprom. We recall the reasons behind the gradual impediment of the large transit pipelines (Nabucco and South Stream), analyse the rationality of the Russian transport strategy focusing on the elimination of the Ukrainian transit and the construction of the Turkish Stream, i.e. the viability of substituting shipping via Ukraine, and finally we review the infrastructural prerequisites necessary to sustain the security of supply of the affected countries following the collapse of the transit plans.

Out last article was prompted by the reopening of the Mecsek coal mine last December. After reflecting on the history of the project, we describe the ideas behind its launch. Then we assess the future role of coal mining and coal based energy production as anticipated by the domestic mineral resource and energy strategies, and we analyse the environmental impacts of coal based energy generation, with special attention to household heating.

Péter Kaderják,director

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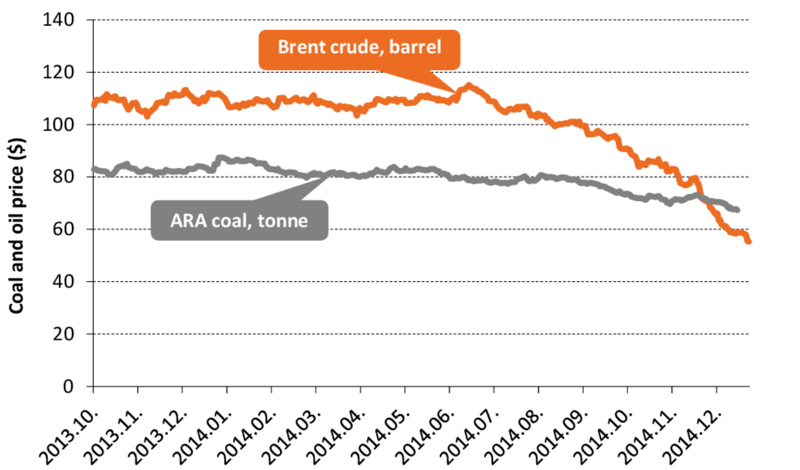
Energy market developments

Oil prices collapsed in the last months of 2014, to as low as 55 $/barrel by the end of December. While Japanese natural gas prices rose by 2.4 €/MWh, the Henry Hub price remained the same in the fourth quarter. While TTF spot prices – used as a barometer for continental European price – stabilised at 21 €/MWh, long term contract prices varied between 28 and 29 €/MWh. The clean spark spread, measuring the profitability of gas-fired power plants – which has remained negative for years – declined further.

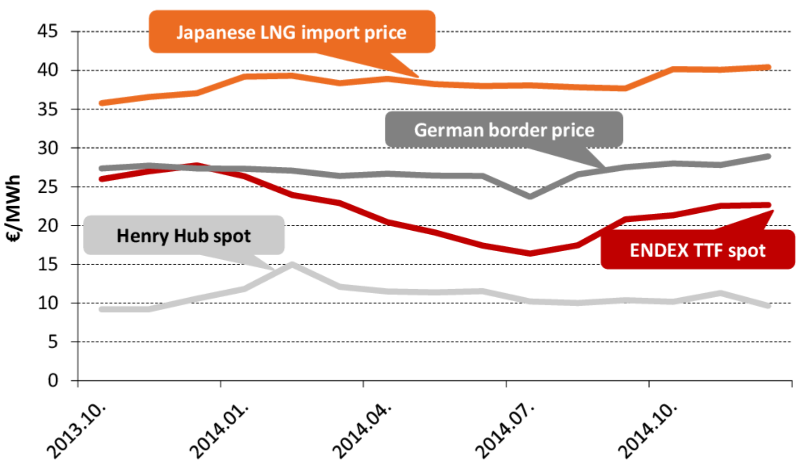
The Hungarian quarterly electricity consumption was largely equal to that of the comparable period of 2014. Monthly cross-border capacity prices ranged between 7 and 10€/MWh on the Austrian, Romanian and Slovakian interconnections. Hungarian year-ahead prices remained 8.5 €/MWh higher than other prices on the futures market. There was a radical split between day-ahead prices, with the Czech day-ahead prices following closely the German market and moving away from Slovakian prices. The Slovakian market was more influenced by Hungarian market developments. With the launching of 4M market coupling, Hungarian day-ahead prices declined and approached Romanian market.

Figure 1 **Prices of year-ahead EEX ARA coal and Brent crude oil futures from October 2013 to the end of December 2014**



Source: EEX, IEA

Figure 2 **Prices on select international gas markets from October 2013 to December 2014**



Source: Statistical Office of Japan, EIA, Gaspool, IMF

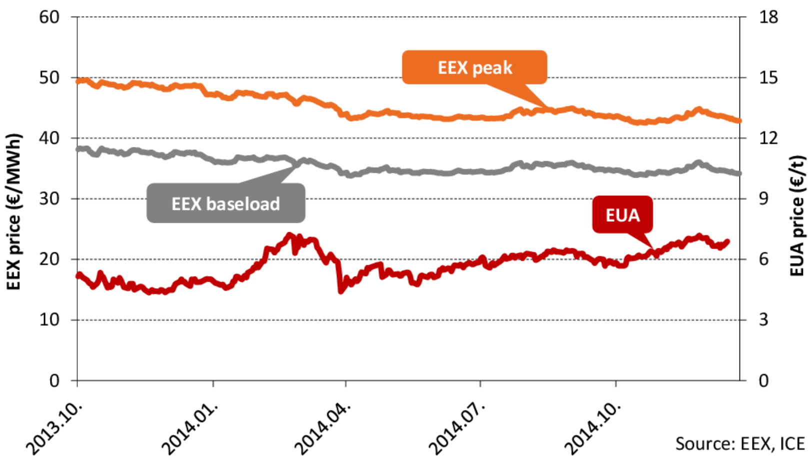
The mild winter triggered a drop in quarterly natural gas consumption relative to the average in past years. Natural gas transports were not restarted to Ukraine until the end of December. In this quarter, Gazprom had injected 600 million m^3 of natural gas into the storages of the Hungarian Gas Storage Ltd. – through the Ukrainian-Hungarian transmission pipeline. This resulted in the extention of the injection period to as late as the end of November.

International price trends

In the last quarter of 2014, there was a significant drop in oil prices: key markets witnessed a fall similar to 2008. Brent crude oil plummeted to 55 $/barrel by the end of the year. The steepest decline took place in December, when oil prices amounting to 80 $/barrel at the beginning of the month dropped to 25 $/barrel. At the same time, there was a moderate decline in prices of year-ahead ARA coal futures, which meant a 7 $/t lower price compared to the previous quarter (i.e. a nearly 10% drop) (*Figure 1*). The drop in Brent oil prices was decisive for the whole energy sector, since a significant part of the price of natural gas sold in the framework of long-term purchase contracts is linked to oil. The impact on natural gas and electricity prices is analysed in detail in the article *Light at the end of the tunnel? Possible effects of fall in oil prices on the profitability of natural gas-based electricity generation*.

Figure 2 depicts the international markets, with representative Japanese LNG import, Henry Hub spot, the German border price and TTF. In the world market, imported Japanese LNG tends to represent the upper bound of natural gas prices while the lower limit is set at Henry Hub in the US. Japanese LNG import prices increased by 2.4 €/MWh relative to the second quarter of 2014. The average quarterly price of the North-American Henry Hub remained unchanged – in November it shifted by 1 €/MWh from October and then fell back again. The reason behind the price growth in November was colder than average weather, followed by a December with above-average daily average temperatures. After catching up in the third quarter, the day-ahead Dutch TTF natural gas prices varied between 21 and 22 €/MWh on average in December. Russian import prices paid at the German border and representing long-term purchase contracts moved with TTF prices but on a much higher level, ranging from 28 to 29 €/MWh.

Figure 3 **Prices of EEX year-ahead futures and CO2 allowances (EUA) with December delivery from October 2013 to the end of December 2014**



Source: EEX, ICE

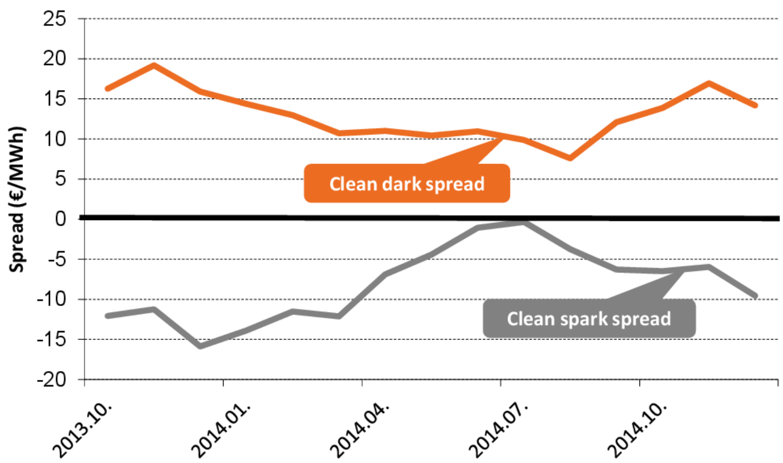
There were not any significant changes in the German year-ahead baseload prices which remained at 34.5 €/MWh, which was the same both in the second and the third quarter. Peak power prices did not move from the previous quarter's range of between 43 and 44 €/MWh. EUA futures with December 2014 delivery showed a slight increase when approaching to its expiration, and exceeded 7 €/MWh in the second half of November (*Figure 3*).

The profitability of gas- and coal-fired power plants can be measured by two kinds of price differences: with the clean spark spread for gas-fired plants, and with the clean dark spread for coal-fired generation. Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, represented by the cost of gas (spark spread) or coal (dark spread) needed for generating 1 MWh of electricity and the additional cost of CO_2 emission allowances. *Figure 4* shows the monthly averages of these two indicators, which are calculated using spot baseload power prices on the German EEX exchange and on the basis of the Dutch TTF spot prices as well as ARA coal prices.

The clean dark spread has not exceeded 0 €/MWh in previous years, remaining at an average price of -6-6.5 €/MWh in October 2014, which is the loss resulting from the generation of one MWh electricity for a gas-fired power plant if sold at the baseload price. In December, the loss approached 9.5 €/MWh, which was caused by the low demand typical for the month and the negative power prices around Christmas.

Meanwhile, the clean dark spread for coal-fired power plants was grew from 10 €/MWh in the third quarter to 15 €/MWh in the fourth quarter. Although it is lagging behind the spread of the fourth quarter of 2013 (17 €/MWh), and that of 2012 (18 €/MWh) respectively, coal-fired power generation has a sizeable profitability advantage over gas-fired generation. The main reason behind the difference is the failure of the European emission allowances market, which does not to fully represent climate costs.

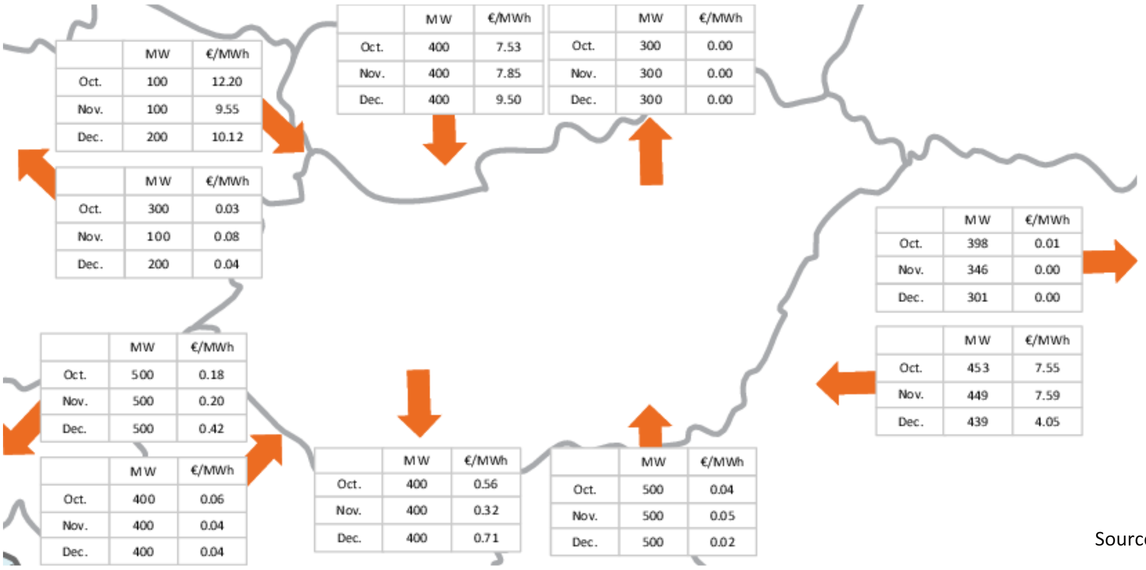
Figure 4 **Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from October 2013 to December 2014**



Source: REKK calculation based on EEX, ICE and Gaspool data

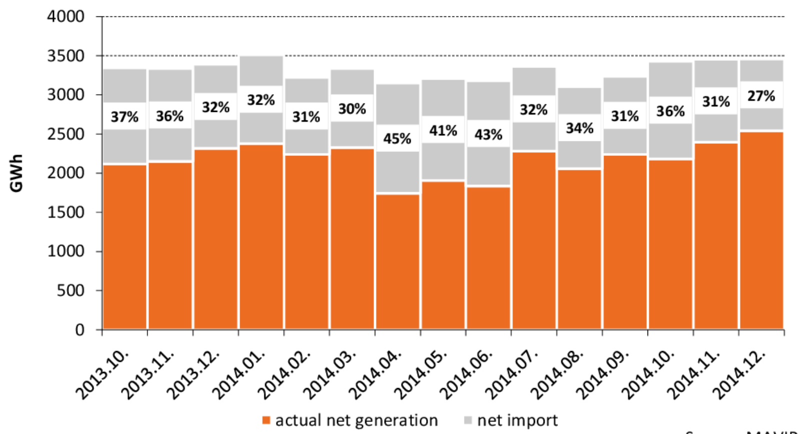
Note: in our calculations we assumed an efficiency of 50% for coal-fired and 38% for gas-fired power plants.

Figure 5 **Net electricity production of Hungary's power plants, and monthly net electricity import of Hungary, Q4**



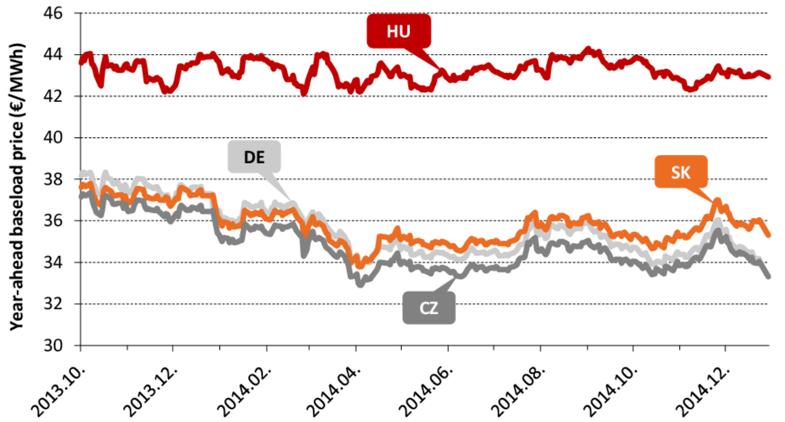
Source: CAO, EMS, MAVIR

Figure 6 **Net electricity production of domestic power plants and monthly net electricity import between October 2013 and December 2014**



Source: MAVIR

Figure 7 **Year-ahead baseload futures prices in given countries of the region, between October 2013 and end of December 2014**



Source: EEX, HUPX, OTE

Overview of domestic power market

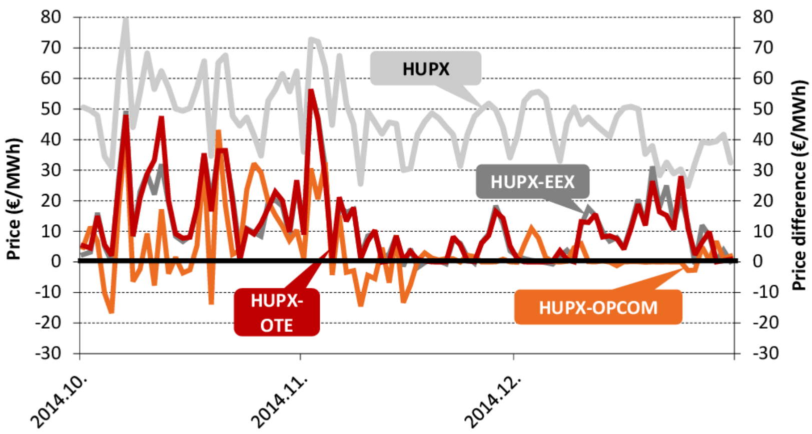
The last quarter again saw high cross-border auction prices on Slovakian, Austrian and Romanian borders: although prices on the Austrian-Hungarian intersection levelled-off compared to the previous quarter, prices still reached 10 €/MWh. Slovakian-Hungarian capacity prices were somewhat lower, amounting to 7.5-9.5 €/MWh in the last quarter. After Slovakian cross-border capacity prices, Romanian import capacity prices ranked third. These border prices fell from 7.5 €/MWh to 4 €/MWh only in December, pressumably due to the declining demand for imports. Cross-border prices remained below 1 €/MWh on the Croatian and Serbian intersections (*Figure 5*).

Annual cross-border auctions were also held in the fourth quarter, costing an extra 1.5 €/MWh on the Austrian border and 1 €/MWh more on the Slovakian border than in the previous year (*Figure 9*).

The electricity consumption of the fourth quarter accounted for 10.3 TWh, which was largely the same as in the fourth quarter of the previous year (10 TWh). Although nearly one third of the Hungarian consumption is met through import, this changed slightly compared to the same period of the previous year. In comparing data from 2014 and 2013, however, we found that apart from the moderate decline in the forth quarter the share of imports continued to increase in 2014 to the detriment of Hungarian power plant production: while the share of Hungarian power plants in the Hungarian electricity consumption accounted for 69% in 2013, this share dropped to 66% in 2014 (*Figure 6*).

On regional energy exchanges, year-ahead baseload power was traded at 34-36 €/MWh. Similarly to previous quarters, the Czech market was the cheapest in the region, followed by the German and then the Slovakian year-ahead baseload. The German year-ahead baseload got closer to Czech markets, with a price gap that shrank below 50 eurocents in the fourth quarter compared to the price gaps amounting to 75-100 eurocents in the previous quarters. At the same time, the divergence between Slovakian and Czech prices grew in the quarter, with Czech prices on average 1.5 €/MWh higher than Slovakian prices in the fourth quarter. Hungarian prices were much higher than other exchanges in the region with a 8.5 €/MWh price premium on average: the average baseload price was 43 €/MWh in 2015 (*Figure 7*).

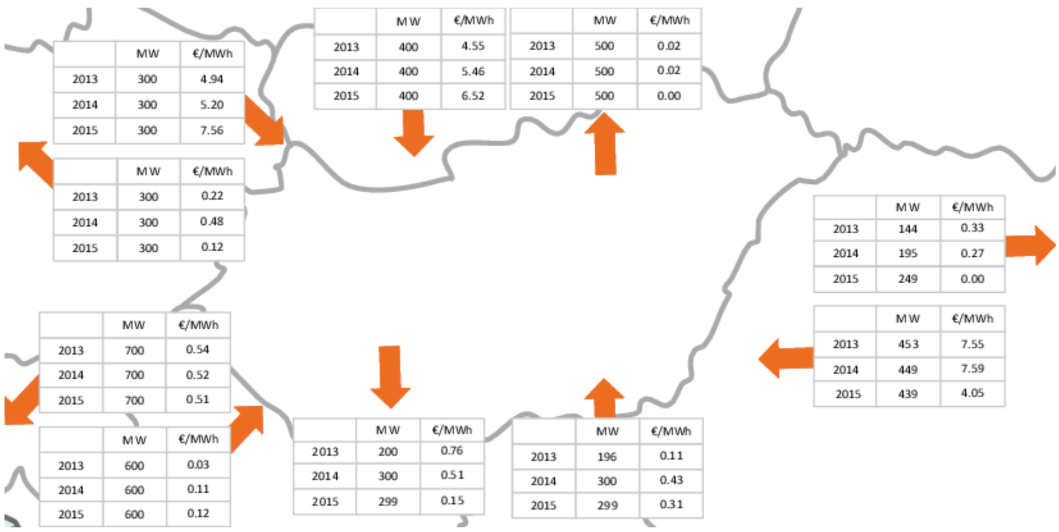
Figure 8 **Comparison of day-ahead baselaod prices on the EEX, OPCOM, OTE and HUPX exchanges between October and December 2014**



Source: EEX, OPCOM, OTE, HUPX

Figure 8 depicts day-ahead HUPX baseload prices and the various price differences of regional power exchanges compared to the Hungarian power prices. Hungarian day-ahead baseload prices varied considerably in October with an average of 53 €/MWh. In November, the average price was down to 46 €/MWh and HUPX prices became more predictable, displaying a weekly seasonality. The price in December was as low as 41 €/MWh, however this was strongly affected by low system load at the end of December and the close-to-zero prices. Since the 4M market coupling on 19 November 2014 (when Romania joined the coupled day-ahead markets of Czech Republic, Slovakia and Hungary), there has been a clear decline in the gap between Romanian and Hungarian prices. Despite this fact, the Czech day-ahead market was more closely following German day-ahead prices than those of the the coupled Hungarian market – October even witnessed a premium exceeding 50 €/MWh. In the middle of November, the price difference between Hungarian and German-Czech markets disappeared for a short time, and in fact for a few days Hungarian day-ahead prices were lower than German prices, but the spread was up again beyond 10 €/MWh in December. The parity in November resulted from the favourable hydro power plant production, while the divergence in December was triggered by the fact that the low demand in German markets led to negative prices for several hours due to renewable production. This effect, however, failed to fully reach Hungarian markets due to cross-border capacity congestions.

Figure 9 **Results of monthly cross-border capacity auctions in Hungary, 2014**



	MW	€/MWh
2013	300	4.94
2014	300	5.20
2015	300	7.56

	MW	€/MWh
2013	300	0.22
2014	300	0.48
2015	300	0.12

	MW	€/MWh
2013	400	4.55
2014	400	5.46
2015	400	6.52

	MW	€/MWh
2013	500	0.02
2014	500	0.02
2015	500	0.00

	MW	€/MWh
2013	144	0.33
2014	195	0.27
2015	249	0.00

	MW	€/MWh
2013	453	7.55
2014	449	7.59
2015	439	4.05

	MW	€/MWh
2013	700	0.54
2014	700	0.52
2015	700	0.51

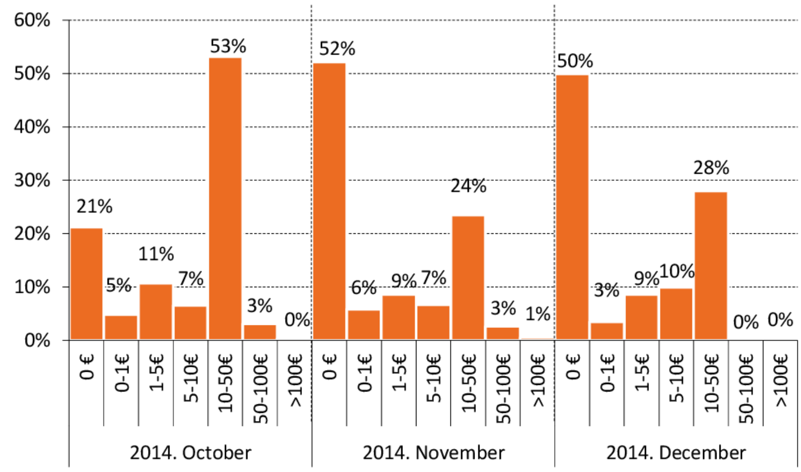
	MW	€/MWh
2013	600	0.03
2014	600	0.11
2015	600	0.12

	MW	€/MWh
2013	200	0.76
2014	300	0.51
2015	299	0.15

	MW	€/MWh
2013	196	0.11
2014	300	0.43
2015	299	0.31

Source: CAO, EMS, MAVIR

Figure 10 **Frequency of various levels of price difference between the Hungarian and the Slovakian exchanges between October and December 2014**



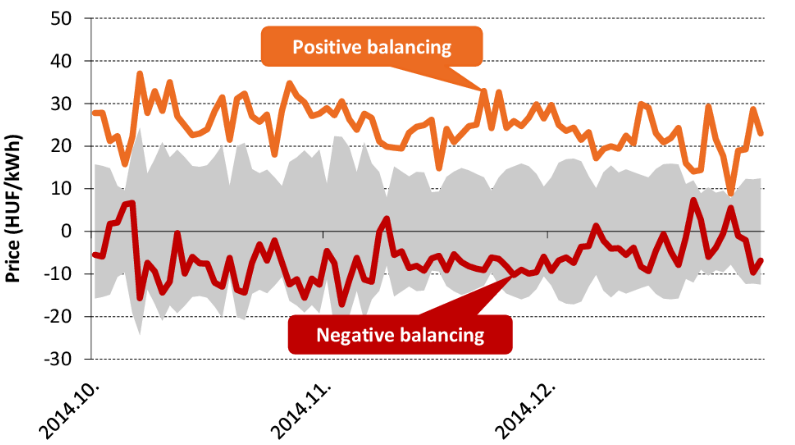
Source: REKK calculation based on OTE data

The outcome of market coupling is depicted in *Figure 10*. The divergent market trend in October is well illustrated by the fact that the price gap between Hungarian and Slovakian markets was below 1 €/MWh for more than a quarter of the month and the difference exceeded 10 €/MWh in half of the period. The situation reversed in November and December, when markets moved together in half of the period and split significantly in a quarter of the period. There was even a split between Slovakian and Czech markets in November and December. Consequently, should the 'goodness' of market coupling be shown/indicated on the Czech market, it would result in a decrease of 5 percent. This hightlights the phenomenon that the Czech day-ahead market adjusts to the German market more so than Slovakia and Hungary despite their coupling, while the Slovakian day-ahead market moves in closer correlation with Hungarian day-ahead markets.

The wholesale price is affected by the costs incurred from the deviation of energy prices from normal schedule and balancing. The system operator determines the accounted unit price of upward and downward regulation based on the energy tariffs of the capacities used for balancing. The order for using these capacities is established based on the energy tariffs offered on the day-ahead balancing market. The system for charging and balancing energy has been developed by MAVIR so that it provides incentives for market participants to try to manage foreseeable deficits and surpluses through exchange based transactions – in other words, covering the expected deficit and surplus by balancing the energy market should not otherwise be attractive for them. For this purpose, the price of upward balancing energy cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing energy than the price at the exchange. In the fourth quarter, the average price of the positive balancing energy accounted for 24.88 HUF/kWh, which exceeded the previous quarter's value of 20.1 HUF/kWh. The price of negative balancing amounted to -6.37 HUF/kWh compared to the previous quarter's price of -3.4 HUF/kWh (*Figure 11*).

MVM sold baseload electricity in two auctions in 2014: 0.613 TWh in June and 0.876 TWh in November. The average selling price of baseload was 43 €/MWh (assuming a 308 HUF/EUR exchange rate), which equals the average price of 2015 HUPX futures.

Figure 11 **Daily average of balancing prices and spot HUPX prices, Q4 2014**



Source: MAVIR, HUPX

Overview of domestic gas market

Similar to the fourth quarter of 2013, the last quarter of 2014 brought mild weather. Natural gas consumption lags behind the consumption of the fourth quarter of the previous year by 100 million m^3. However, with a temperature adjustment, the demand effect is just the reverse: adjusting for temperature, natural gas consumption in 2014 would exceed that of 2013 by 100 million m^3 (*Figure 12*).

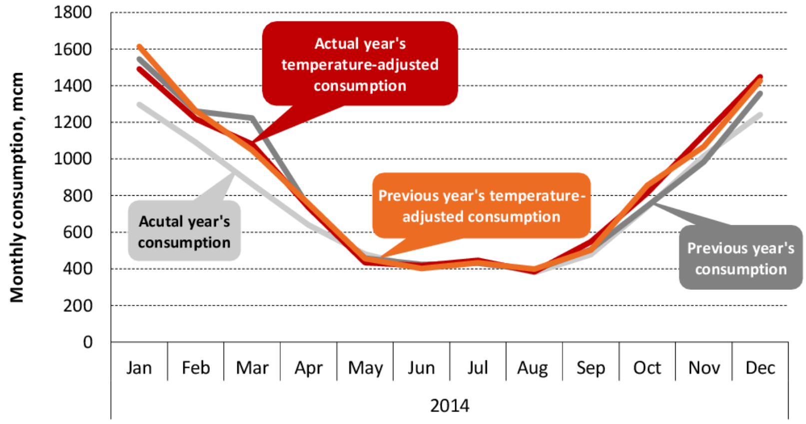
Natural gas production accounted for 651 million m^3 in the fourth quarter, which equals the production of the fourth quarter of 2013 but lags behind that of 2012 (749 million m^3) and of 2011 (781 million m^3).

While Hungarian natural gas imports amounted to 2.8 billion m^3 in the last quarter, natural gas export was 0.54 billion m^3 – reflecting a similar trading structure to the previous quarter. However, imports accounted for 2.4 billion m^3 in the fourth quarter of 2013 and hardly reached 2 billion m^3 in 2012. The import growth occured on the Ukrainian entry point where 1.9 billion m^3 of natural gas was transported instead of the usual 1.3 billion m^3. This import supplanted other sources: while the average size of flows coming from Austria accounted for 1.175 billion m^3 in the third quarter, just 1 billion m^3 came from the Western direction in the fourth quarter of 2014.

The reason for the unusual import level coming from Ukraine is that Gazprom had 600 million m^3 of natural gas injected into Hungarian storage facilities in the fourth quarter. Injection into the storage facilities of the Hungarian Gas Storage Ltd. (MFGT) lasted as late as 27 November (interestingly, there was a simultaneous physical withdrawal from other storage facilities of the MFGT into the natural gas transmission system). Due to this fact, storage levels grew from 46% measured at the end of the injection period in 2013 to 71% during 2014. In the quarter, the export was lower than that of the comparable period of the previous year by nearly 100 million m^3 (*Figure 13*). The construction of the Slovakian-Hungarian interconnector with a daily capacity of 12 million m^3 (4.38 billion m^3/year) was completed in this quarter. Although the way of access remains unknown and there have only been test transports conducted on the pipeline, it will significantly enhance Hungarian security of supply and promote the European integration of the Hungarian natural gas market. Details on the third party access to the new pipeline are disclosed in our article *Mysteries of the allocation of transmission capacities of the Slovak-Hungarian interconnector gas transmission pipeline*.

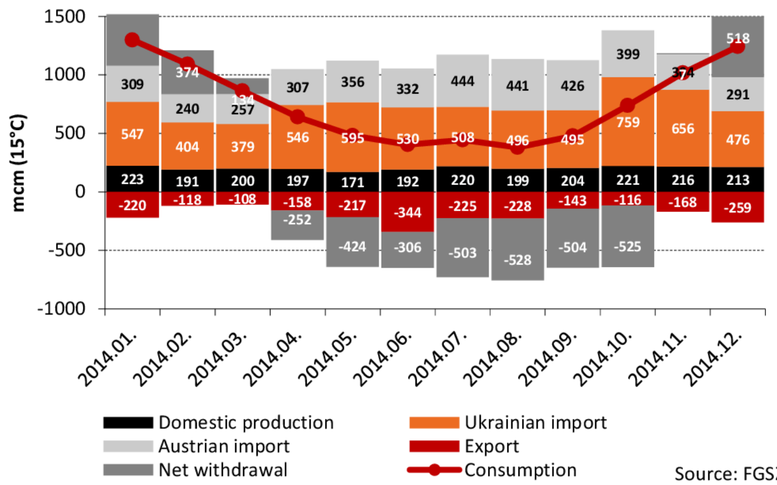
In the fourth quarter, 995 million m^3 of natural gas arrived in Hungary via the Mosonmagyaróvár entry point, which is 25% lower than the previous quarter's import and 15% less than the third quarter of 2013. The underutilisation of

Figure 12 **Raw and temperature-adjusted monthly gas consumption between January 2014 and December 2014 compared with the respective data in the previous year**



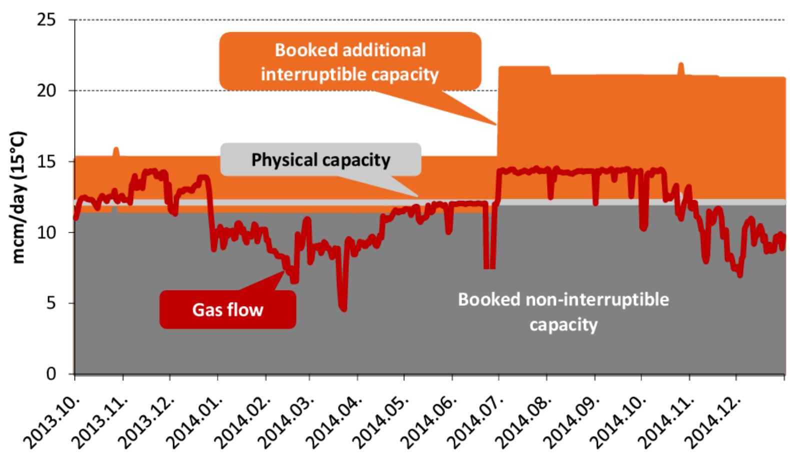
Source: FGSZ, European Climate Assessment & Dataset and REKK calculation

Figure 13 **Source structure of Hungarian gas market by month between January 2014 and December 2014**



Source: FGSZ

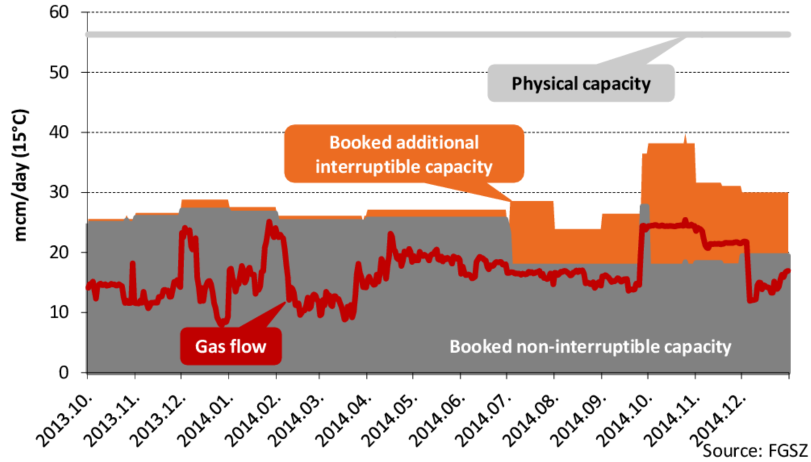
Figure 14 **Transmission at the Mosonmagyaróvár (Austrian border) entry point between July 201 3 and December 201 4, together with booked interruptible and non-interruptible capacities**



Source: FGSZ

Note: the depicted value of physical capacity is provided by FGSZ

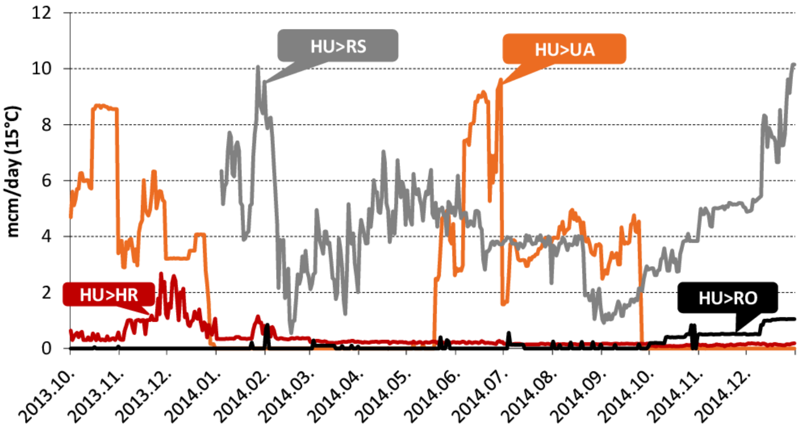
Figure 15 **Transmission at the Beregdaróc (Ukrainian border) entry point between October 2013 and December 2014, together with booked interruptible and non-interruptible capacities**



Source: FGSZ

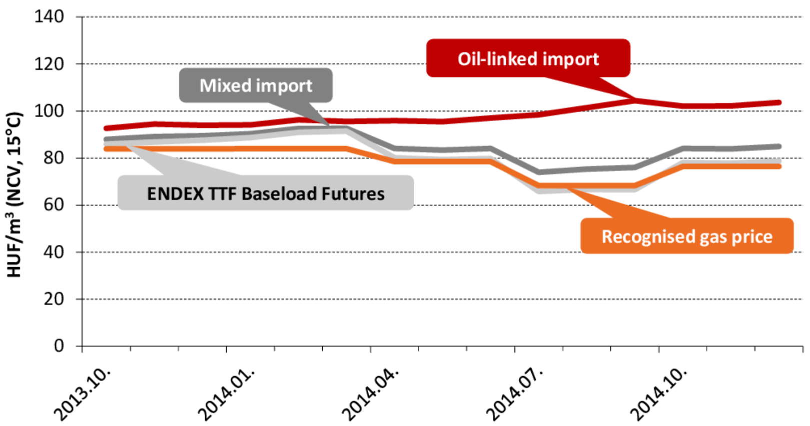
Note: the depicted value of physical capacity is provided by FGSZ. From January 2014 data also contains transit gas flows entering Hungary via Ukraine and leaving in the direction of Serbia and Bosnia-Herzegovina.

Figure 16 **Hungary's natural gas exports to Ukraine, Romania and Serbia from October 2013 to December 2014**



Source: FGSZ

Figure 17 **Recognized natural gas selling price of universal service providers, and factors of the gas price formula between October 2013 and December 2014**



Source: REKK calculations based on EIA and ICE data

Note: The "recognized natural gas price" is an estimate by REKK for the regulated price calculated by the Hungarian energy regulator (MEKH) every quarter – the estimation is based on the regulated gas price formula and the EUR and USD exchange rates used by the regulator, using publicly available information. The estimate does not take into accoun the effects of natural gas from storage facilities on the recognized price, which is also part of the gas price formula. We calculate the price of "mixed import" similarly, but in this case we use market exchange rates instead of those set by the price regulation decree.

the entry point (physical/total capacity) dropped to 89% in the quarter, while traders used 52% of the total contracted capacity; thus there was no overbooking on the intersection in December (*Figure 14*).

In total, 1.9 billion m^3 of gas were imported on the Ukrainian border, which is 25% more than in the previous quarter, and 45% more than in the fourth quarter of 2013. In 2014, transports were not restarted to Ukraine. In the quarter, 37% of physical capacities and 62% of the contracted capacities were utilised. Additional interruptible capacities were booked for the additional gas flows amounting to 600 million m^3, which required some modifications in the system access regulation since the system operator cannot allocate interruptible capacity as long as uniterruptible capacity is available (there is a jump in uninterruptible capacities for a few days in October 2014, which is followed by a shift to interruptible capacities). It is clearly visible that this flow coincided with the fall in flows on the Western interconnections (*Figure 15*).

Figure 16 shows Hungarian gas export to neighbouring countries (excluding transit). In the quarter under review, 88% of export went to Serbia, 10% to Romania and 2% to Croatia. The most striking change, which has fundamentally restructured Hungarian exports, was the absence of export to Ukraine at the end of September.

Figure 17 shows an estimation on Hungarian household gas product prices. Oil-linked import prices did not yet include the fall in oil markets, thus prices remained beyond 100 HUF/m^3 in the last quarter. Oil-linked prices might have only a limited effect on combined import and recognised gas prices, since the regulator has calculated the gas price recognised for universal service providers as the weighted average of 75% spot and 25% oil-linked prices since April. Consequently, the effect of the fall in oil prices is a quarter less, and appears more significantly in gas prices only once the effect of oil-linked prices is also evident in TTF prices. In the fourth quarter, recognised prices were below TTF, which resulted from the difference in real exchange rates and those regulated in decrees: at the real exchange rate, quarterly household gas prices would amount to 84 HUF/m^3 instead of 76.5 HUF/m^3.

Light at the end of the tunnel? Potential effects of the fall in oil price on the profitability of natural gas based electricity generation

Brent crude price displayed an unstoppable fall from July 2014, which was still ongoing in January 2015. The cause of the price drop was fundamental supply and demand: shale oil producers in North America produced an oversupply in oil, which was matched with dwindling global crude oil demand (notably in China). Despite the oversupply, OPEC (Saudi Arabia) was reluctant to cut its production, since they were protecting their market positions. The crude price, which was floating at 100-110 $/barrel in the first half of 2014, was traded as low as $46 /barrel in January 2015, a level that has not been seen since the financial crisis in 2008 (42 $/barrel).

Losers of the falling prices are the oil producing countries and those natural gas producers who market their product via oil-indexed long-term contracts. Winners are obviously natural gas importers and end users paying at oil indexed prices. Natural gas based electricity generation has faced low power prices due to the spread of renewable power generating capacities and the economic crisis in Europe. Since mid-2011, the low baseload electricity prices failed to cover even the variable costs of power generation (See *Figure 4.*). Sooner or later, the recent plunge of Brent crude price will take effect in the long term oil indexed gas contracts. The main question is if this price effect will be sufficient to shift the short-term marginal cost of power generation below the wholesale electricity price. In our short analysis, this is what we are trying to discover.

Effect of the Brent crude oil price on the oil-indexed long-term contracts

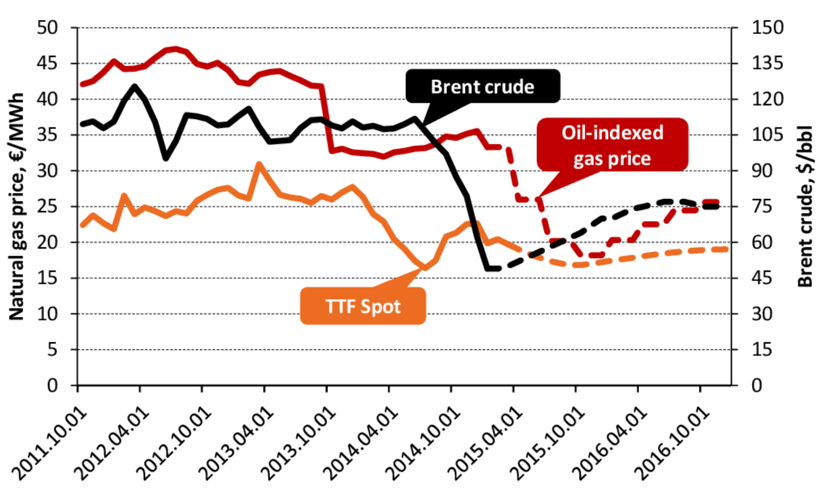
Oil-indexed gas contracts traditionally peg the quarterly gas price to the price change of two oil products – gas oil and heating oil. The price of oil products and thus the price of oil indexed natural gas may be estimated with high confidence based on the Brent crude price. Oil-indexed gas contracts apply a 9-month lag moving average of oil products for the quarterly price. Thus the 2014 price drop of Brent will be experienced in Q2 2015, since for this index, we use Q1 2014-Q2 2015 oil prices.

Nowadays natural gas long-term contracts are not purely oil indexed contracts, but include some indexing to hub-priced natural gas in even greater share. We based our analysis on the Hungarian long-term contract, which applies roughly 45% of hub-priced natural gas. To be able to give an estimation for the 2015 gas price, we have to make some assumptions beginning with the future development of the oil price and extending to the hub-based (TTF) prices.

A number of projections have been published on the future of the Brent crude. In January 2015, these projections could be categorized into two groups:

- Energy agencies (IEA and EIA) expected the oversupply to diminish in late 2015: the Brent will hit the floor in January-February 2015. Global demand for crude oil will recover slowly by the end of 2015 and match supply, which will result in a price hike with supply unchanged. However, the new price level will be considerably lower, 70-80 $/barrel compared to the previous 100-110 $/barrel.
- Financial analysts and investment consultants expect the price fall to continue in 2015. The reason for this is the fact that oil commodities tended to be a low-risk investment since 2008 (floating in the 100-120 $/barrel range), which caused investors to move long positions to this commodity. Due to the price fall, a quick withdrawal of these positions started, which has not stopped yet.

Figure 18 **Forecasting Brent crude, oil indexed gas price and TTF hub prices**



Source: EIA, Gaspool, REKK estimation

In our short analysis we assumed the forecasts of EIA, that is the recovering of oil demand by the end of 2015 and the stabilisation of prices (see *Figure 18*). Based on the oil price forecast, we calculated the oil-indexed gas price for each quarter to the end of 2016. E.On, the wholesale trader at that time of natural gas managed to negotiate a 20% price discount on the oil indexed price component in October 2013, which we included in our oil indexed prognosis. We used the oil indexed price forecast to project corresponding TTF hub prices (see *Figure 18*). We expect TTF hub prices to provide a floor for oil indexed prices because on a gas hub oil indexed and no-oil indexed products are traded together at the same point. Thus when the oil indexed price is lower than the hub price, oil indexed volumes would appear on the gas hub and trade at higher hub prices – which would then put downward pressure on spot prices and result in parity. Based on expectations of the future oil indexed and TTF gas price, we can forecast Hungarian natural gas prices. The 50% Brent crude price drop from 2014 to 2015 will appear in the LTC contract index in Q3 2015, resulting in a 27% price fall in long-term contract prices.

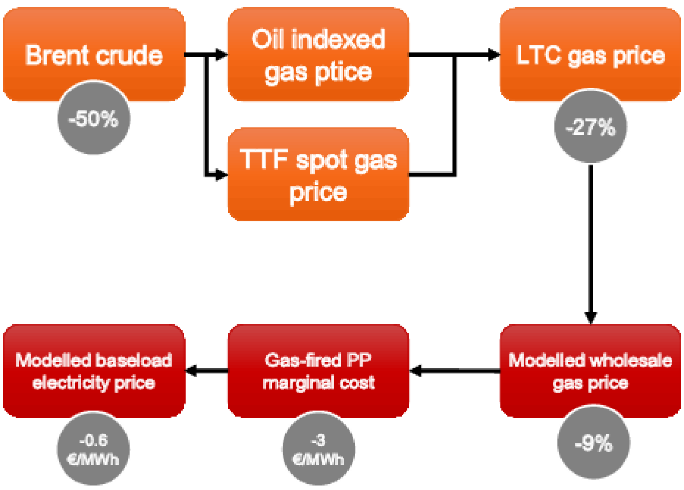
The effect of natural gas price on gas based power generation

Natural gas long term contracts apply unique pricing formulae, which may result in different prices for long-term contracted shipments to neighbouring countries. This price difference may be traded between the countries up to the capacity of cross-border interconnectors. Besides long-term contract priced natural gas, domestic consumption may be made up of purely hub-based gas. These two factors further dampen the effect of oil price drop on the natural gas price in Europe. To quantify these issues, we utilised REKK's gas market model (EGMM), inputting the long-term contract price calculated in the previous step and assuming 2015 network infrastructure. From 2014 to 2015, the 27% LTC price drop in wholesale natural gas prices for Hungary means only a 9% gas price drop.

The country prices calculated according to this method were then used for electricity market analysis. A low gas price may result in surging power station consumption – to capture this effect, we modelled a scenario in REKK's electricity market model (EEMM), assuming the 2015 power plant portfolio and network infrastructure.

According to electricity market analysis, short-term marginal cost of gas-based power generation will decrease by 3 €/MWh in Hungary due to the 50 $/barrel Brent crude oil price drop. Since gas-based power producers are situated at the higher price level of the merit order curve, it is not probable that production will take place during the whole year. Thus the 3 €/MWh price drop will induce merely 0.6 €/MWh price decrease in the annual baseload prices. Since the clean spark spread was below -6 €/MWh in the second half of 2014, a 3 €/MWh cut in marginal costs will not shift the spread into positive territory.

Figure 19 **Effect of Brent price drop on natural gas and electricity prices**



Source: REKK

Summary

In our short study we showed the channels through which oil prices affect natural gas prices and the short-term marginal cost of gas-based power generation. Our expectation is that a 50% oil price drop casuses a 27% price fall in the long term contracts. However, this effect will be moderated to 9% when we consider the wholasale natural gas price for Hungary. This resulted in a 3 €/MWh price fall in the short-term marginal cost of gas-based power producers, which had a meagre 0.6 €/MWh effect on the wholesale baseload power price. The point of the study is to illustrate that the trickle-down effect of a significant oil price decline on the fuel price of power plants and the electricity price is quite limited. Consequently we expect the clean spark spread to remain negative in 2015 with gas-fired power plants mostly uncompetitive in power generation.

Mysteries of the allocation of transmission capacities of the Slovak-Hungarian gas interconnector pipeline

The construction of the long-awaited Hungarian-Slovak gas interconnector pipeline is now completed. Although there are still technical issues to resolve, they cannot be blamed for why the commercial operation has not commenced yet. In January 2015, once set as target commercial operation date, systems users still do not know when and how the capacities will be allocated. In order to arrive at a proper understanding of this halt in the allocation of interconnector gas transmission capacities, we need a brief review of the conditions that existed at the birth of the project. After that, the principles of capacity allocation can be applied to help achieve the goals of the gas transmission pipeline.

The plan to build a Hungarian-Slovak gas transmission pipeline was first conceived after the Russian-Ukrainian gas debate. According to the concept developer FGSZ together with its Slovak partner Eustream, the interconnector improves security in gas supply and strengthens competition. First the Hungarian and Slovak TSO announced a non-binding open season procedure in autumn 2009, followed by a binding one in spring 2010 on the future capacity of the transmission line (14.4 mcm/day, two-way). Because of the bids received in the first round the latter phase was cancelled and re-launched with updated conditions to accommodate market needs. However, the total value of binding bids submitted for the Slovak and Hungarian interconnector remained below the rate of return, and FGSZ stopped the joint project. The government contracted MVM Hungarian Electricity Plc to construct the gas transmission pipeline, which together with MFB Invest Plc established a new affiliate Magyar Gáz Tranzit Zrt (Hungarian Gas Transit Plc, "MGT") to implement the project.

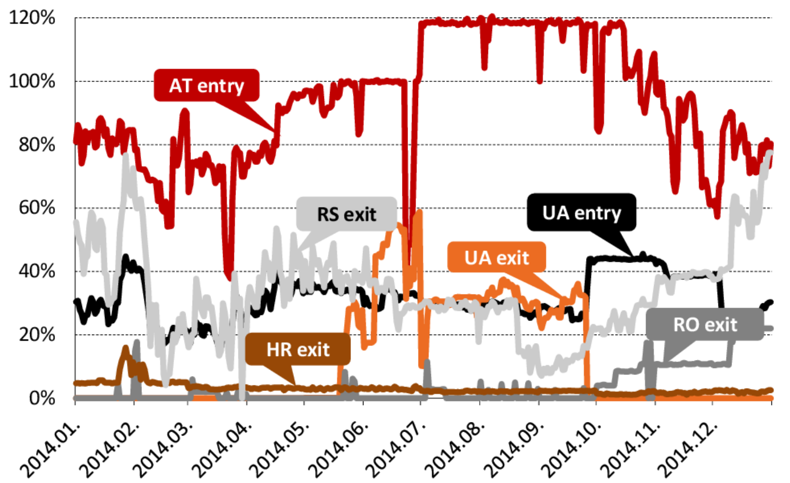
In order to accelerate the licensing procedures the government ranked the pipeline construction a high-priority project in November 2011. Prior to this, the European Commission had decided to secure a non-reimbursable financial loan of € 30 million (project cost of € 150 million) under the framework of the European economic recovery plan and it was subsequently added to the EU list of energy infrastructure projects of common interest (PCI).

The significance of the project at the EU level demonstrates that the interconnector pipeline improves the integration of the internal gas market and strengthens security of supply in the region as a part of the North-South Gas Corridor in Central Europe. It provides the Hungarian market with a direct connection to the German market and especially focuses on presenting market players and natural gas sources competing with gas delivered under the Russian-Hungarian long-term gas supply contracts ("LTC") an opportunity to enter the market.

There would be much demand for it in the market indeed, since according to last year's figures the average capacity utilisation rate at the Austrian entry point (Mosonmagyaróvár) responsible for connection with the western market was 93%. This figure is extremely high considering that the average capacity utilisation rate among the most relevant interconnector points in the EU was 60% according to ACER (ACER 2014 Monitoring Report, p. 187). The annual utilisation rates of Hungarian border points in 2014 are seen in *Figure 20*.

Considering that the annual average capacity utilisation rates to Romania and Croatia were 3% and 4%, and the Ukrainian entry and Serbian exit points run at 31% and 33% respectively, it is striking that during winter months the AT entry operates at 120%, above its physical capacity. It is a meaningful indication that the market is on tap to transmit gas through the new Slovak-Hungarian entry.

Figure 20 **Capacity utilisation rates at the interconnection border points of the Hungarian gas transmission pipeline in 2014 (%)**



Source: REKK on FGSZ data

In March 2014 the gas transmission pipeline between Hungary and Slovakia was inaugurated with a target commercial operation date set to January 2015 following the test operation. The capacities, however, have not been allocated yet. Although there was an open season procedure announced on the owner MGT's website in December 2014, it was withdrawn due to reasons beyond MGT's control (pressure from MEKH (Hungarian Energy and Public Utility Regulatory Authority)). It is strange that MGT wanted to sell the capacities of the completed transmission pipeline in an open season procedure, since open season functions as a preliminarily survey of demand to source funds for long-term operation. The Slovak-Hungarian gas transmission pipeline has not been built to operate under long-term contract, but to encourage market integration and improve security of supply. A regular fee included in the end-consumers' tariff, announced by MEKH in July 2014, ensures the project remains financially viable. As the parties implementing the project had not requested derogation from the Commission to exclude access of third party, all criteria was met for market players to participate.

What is the problem then?

From the moment the state entered as an owner, the project began to struggle with compliance to the rules of the 3rd energy package concerning ownership unbundling , as MVM became a dominant player in the gas trade market too by purchasing of E.ON Földgáz Trade Zrt. in 2013. In this situation the gas transmission pipeline owner is at the same time a key trader in the Hungarian gas wholesale market. The Commission's proposal encouraged FGSZ to keep the system in operation, which, by preserving the single-TSO model, provides traders an easier access to the market. MGT, however, did not want to transfer system operation licences to FGSZ, and it became a state-owned company through the Hungarian National Asset management Inc. in October last year. In the government's view the unbundling rules were fulfilled since although MVM is also a state-owned company, it is MNV that exercises the ownership rights, whereas for MGT the same rights belong to the Ministry of the Interior.

MGT cannot be granted a TSO licences until the European Commission's relevant statement is issued, and therefore it is not authorized to allocate the capacity of the Slovak-Hungarian interconnector. To evade this problem, instead of auctioning the company announced an open season procedure because it did not require TSO licence. Thanks to the pressure from the Hungarian regulatory authority they withdrew the call for bids under the former Open Season procedure in December. One of the most self-evident reasons is that in the course of capacity allocations the provisions set forth in the Commission Regulation 984/2013/EU on establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (effective date: November 2015) shall also be considered. For that very reason MEKH prefers auctions to allocate capacities, and has been consulting the Slovak regulator as well.

At present the Hungarian Gas Act, currently under re-examination, is unable to keep the capacity allocation mechanisms of the remaining interconnection border points in line with the schedule specified in the European Network Codes because of a delay in the planned timeline of legislation. Even in the best-case scenario it will be impossible to meet the auctioning deadline set for the beginning of March since the new legal rules will not have been announced by that time either. Another difficulty is meeting the unbundling requirements, and there is hardly any chance to make further progress. As long as the pipeline is empty, it produces nothing but losses to the owner, which are passed on through a state guarantee on return for the rest of the gas transmission pipeline. It is the end-consumer who pays this cost in the form of tariffs charged in network operated by FGSZ. Moreover, it is not to the end-consumer's benefit that there is no competing gas arriving at the Hungarian market, which could reduce prices. Although it is often emphasized that prices under the Hungarian long-term gas contract are competitive in the region, the wholesale gas prices published in the European Comission's Quarterly Report contradict it, and so far we have not been able to join the German price zone. This is precisely the purpose of the Slovak-Hungarian interconnector.

What would be the ideal capacity allocation?

The first issue stakeholders need to reach an agreement on is whether the two TSOs will allocate transmission capacities separately or together. It would be optimal if they allocate all their capacities in a common procedure, but this is is not ensured in the current situation. It could happen that by the time capacities at the Hungarian entry point become available, the Slovak partner will have sold all and they will have run out of capacities. As a minimum target,each system operator should aim to allocate 50% of the capacities separately while mutually accepting the other party's decisions. The failure mentioned above can also be prevented if, for instance, players who have been allocated exit from Eustream in the SK>HU direction would automatically get entry in the Hungarian system as well.

The second important issue is whether to use market-based allocation or not. In Hungary there is no a particularly strong argument against non-market-based allocation (pro rata or first-come-first-served) which leaves congestion rent with the traders. In case of market-based allocation the congestion rent is collected by the TSOs and can be transferred by the regulator to the final consumer through the reduction of transmission tariffs, for example. In the electric power industry non-market-based allocation has become completely obsolete in Europe according to the new rules of the internal gas market that prohibit it. Consequently, a simple auction procedure resolves the entire problem of capacity allocation. The allocation mechanism put forth under the new Gas Supply Act prepared by MEKH complies with those requirements and provides opportunities to book annual, quarterly, monthly, and daily capacities. It is important that these rules should apply to the Slovak-Hungarian interconnector as well.

The gas market distortion effects caused by administrative allocation of HAG capacities have been discussed in detail (Baumgarten saga PJ 2011/3). In order to prevent such intervention at the Slovak-Hungarian interconnection border point, transparency must be strengthened. In addition, a report by ACER found that contractual congestion is a major problem across the Western European market. Congestion occurs when transmission pipeline capacities are booked by long-term contracts but are not utilized, and it is impossible for other players to access capacities in the form of annual or quarterly non-interruptible allocations.

To address this problem the EU regulation is proposing a few simple measures: the use-it-or-lose-it (UIOLI) principle, a secondary capacity market, and overbooking. Such measures only attempt to mitigate the detrimental effects of obstructing the market, as their long run efficiency is still in question. For the moment 80% of the gas supplied under long-term contracts to the Hungarian market arrive at the Ukrainian entry point and 20% passes through the Austrian entry point. In the event this clause changes in the contract and transmission is transferred from the Ukrainian entry point – a point otherwise impossible for other players to access – to the Slovak-Hungarian interconnection border point, then it will limit the available capacities that other traders in the gas market can book in the manner discussed above, thereby restricting competition in the Hungarian gas wholesale market. In the process of capacity allocation it is necessary to restrict the market players with access to the Ukrainian-Hungarian gas transmission pipeline (UA-HU) from booking capacities of the pipeline built with the goal of strengthening competition. Such discrimination would not necessarily lack legal ground, as point 5 of Article 2 in the Commission Regulation (EU) No. 984/2013 states that competent national authorities may decide to take proportionate measures to limit up-front bidding for capacity in order to prevent foreclosure of downstream supply markets. Another way to prevent the obstruction of new gas transmission routes is for competent authorities to limit the share allocated to each trader from long-term non-interruptible capacities left after certain capacities are reserved for short-term trading.

The fact that MEKH has actively intervened in the allocation process is an encouraging sign that the capacities will soon be allocated by auction, a true market-based approach together with the Slovak partner.

The end of the mega-pipeline era: Post-South Stream implications for Central and South Eastern Europe

Shortly after the sudden cancellation of South Stream, Gazprom CEO Alexey Miller announced it would be replaced by a pipeline of the same capacity (63 bcm) delivered to Turkey across the Black Sea (13 bcm to the Turkish market replacing the trans-Balkan pipeline and 50 bcm to the Turkish-Greek border for southeast European customers). Whether the subsea section follows Blue Stream or the proposed South Stream route initially is still uncertain. Gazprom has already invested $4.7 billion - mostly toward the offshore pipe and charter of the barge – of the approximately $20 billion required for the first two lines (about 30 bcm).

In concert with this major policy shift, Miller asserted that Gazprom will stop supplying gas to Europe through Ukraine in three years' time. While this is highly unlikely because of infrastructure constraints, it reflects the steadfast determination of Russia to remove Ukraine from its gas transit seemingly at all costs, and leaves central and southeast Europe in another gas supply vacuum.

Background

The cancellation of South Stream was abrupt and symbolic, likely drawing to a close the era of the mega project that has dominated central and southeast Europe's (CSEE) energy security landscape for the past 15 years. South Stream was always an uneasy proposition for Europe as a whole; while it would have promised deliveries uninterrupted by Russia-Ukraine price disputes it thereby left Ukraine isolated, and while it would meet the demand of the countries it traversed it also deepened their reliance on a single supplier, suffocating prospects for market development. In this sense it was never the panacea that Nabucco (private financing aside) promised to be. From this point forward not only will there never be a direct external source physically traversing CSEE, but the region will depend on volumes from even greater distances delivered from Greece or Germany rather than directly across a shared border with Ukraine.

Like its predecessors Nabucco and Nabucco West, the economics of South Stream never justified the investment for a region that has relatively low consumption across a continent where gas demand will be stagnant for the remainder of the decade. According to the IEA, CSEE natural gas consumption will only rise by 7 bcm during from 2013 to 2030. For the Western Balkans in particular a lack of key distribution infrastructure has resulted in pervasively weak demand for gas. In central Europe the share of gas in electricity generation is lower than in northwest Europe because of longstanding import dependency and subordination to higher monopolistic prices. In 2013 Gazprom regained its footing in the European market after lower deliveries from 2009-2012. This is mostly reflective of a year to year surge in the UK, Italy and Germany whose imports from Gazprom have are higher than in 2008. At the same time, overall CSEE countries imported less gas in 2013 than in the early 1990s due to reduced demand, economic restructuring and higher prices. Russian imports fell modestly from 43 bcm in 2008 to 40.8 bcm in 2013, with country-level demand remaining flat or declining slightly in most cases.

Nabucco West and South Stream were essentially identical proposals that carried profoundly different implications for energy security according to their ownership and sourcing, competing directly and indirectly. The Nabucco consortium had to first battle with the Trans Adriatic Pipeline (TAP) over the rights to Caspian supply while at the same time Gazprom demonstrated a willingness to serve the same markets at its own cost with South Stream. Obviously the 2013 demise of Nabucco was a victory for Russia and its gas major, with or without South Stream.

The original Nabucco project discussed in 2002 envisioned a direct link for CSEE to the Southern Corridor, a vast pipeline between Georgia and Austria, accessing Azerbaijan's offshore Shah Deniz II gas field which was to begin production the latter half of this decade. It would have provided tangible diversification to the region's small Russia dependent countries and disrupted Gazprom's monopoly position. Yet at 31 bcm, there was a growing belief that there would not be enough gas to justify the 8-10 billion euro price tag, considering Turkey's growing demand and uncertainty over future contributions from Turkmenistan, northern Iraq and Iran despite their abundance of reserves. The backing of the Trans-Anatolian gas pipeline (TANAP) by state champions SOCAR and BOTAS of Azerbaijan and Turkey respectively was the final death knell for Nabucco. It is to be constructed across Turkey with a capacity of 16 bcm, linking Azerbaijan to Europe. The consortium responded with Nabucco West, an abridged proposal that was to connect with TANAP and run from the Turkish/Bulgarian border to Baumgarten.

Instead the Shah Deniz consortium selected its competitor TAP in what was seen as a politically influenced decision, ultimately bringing the Southern Corridor's EU landing point to Italy.

The gas field's operators claimed that they would receive higher gas prices in the Italian and Greek markets, but at the same time Moscow clearly opposed a direct link between central Europe and the Caspian Sea that would undermine Gazprom's market share (some experts still believe that South Stream was an empty proposal aimed entirely at countering Nabucco). Thus the selection of TAP allowed Azerbaijan to avoid a direct confrontation with Russia while still bringing its gas to the European market. But commercial considerations should not be discounted, and TAP was less costly and easier to finance compared to Nabucco. Furthermore Nabucco could not secure bank guarantees or promise customers in advance, something that the operators needed to see. One could conclude that geopolitics and economics favored TAP and the possibility of South Stream over Nabucco.

After the 2009 cut-off to Ukraine South Stream was perceived as a welcome lifeline for governments of central Europe, further incentivized by associated price discounts, transit fees and economic stimulus. Bulgaria, Hungary, Greece, Slovenia, Croatia and Austria reached IGAs with Russia in spite of the pipeline's blatant obstruction of EU gas market legislation and regulation, namely state-aid and competition rules. This was a glaring example of national self-interest defying the notion of a collective EU energy union. In the end, the economics of the project finally caught up with the politics, and although the announcement was unexpected it should not come as a surprise.

Post-South Stream

For the CSEE region, the post-South Stream world requires an entire rethinking of energy security. The first step was a 9 December meeting between representatives from the South Stream consortium and the European Commission's Vice-President for Energy Union Maros Sefcovic, who reiterated the importance of integration and diversification.

Conceptually, the longstanding prospect of a North-South corridor is representative. It is the amalgamation of a number of internal transmission and distribution projects and interconnectors, identified by the European Commission as projects of common interest (PCIs) that will enable the delivery of gas from the Baltic to the Aegean Sea and back according to market signals. Even though the projects are fast-tracked they are complex, requiring a combination of public, private and EU financing as well as strong support from TSOs, regulators and governments – and thus time horizons vary widely. The corridor has been mused over in conferences and forums across Europe for the past decade, but on the ground the vision remains far from being realized. This is not to say that there has not been progress, because there certainly has. While guidance from Brussels will remain crucial, project realization is still determined by the interest and initiative at the member state level. Aside from inherent complexities that obstruct development of these cross-border undertakings (e.g. limited public financing, cost sharing, creation of winners and losers, market protection etc.), South Stream was a significant distraction that created friction between Brussels and member state governments. Now removed from the equation there is space for a realignment of priorities. Rather than depending on an external energy security solution, the region will have to look within and cooperate over infrastructure.

The methodology of Gazprom's plan to meet all of its European contractual obligations while bypassing Ukraine remains unclear. First there is the matter of getting these extra volumes to the EU border, and then delivering them within the constraints of existing EU internal infrastructure. Although Miller did not mince words stating "it is up to them (Europe) to put in place the necessary infrastructure starting from the Turkish-Greek border," the supplier is actually responsible for its delivery obligation, and historically Gazprom has a good track record. In this sense Gazprom cannot and will not act unilaterally in redesigning its export routes around Ukraine.

We can make a rough estimate of Gazprom's current ability to displace the Ukrainian volumes by looking at available capacities of its other existing pipelines. The chart below lists Gazprom's existing options outside of Ukraine transit 2014, with available capacity near 24.5 bcm. In 2013 about half or 80 bcm of European imported Russian gas transited Ukraine which fell 28% to 62 bcm in 2014. A significant amount of this was diverted to Nord Stream, which experienced an increase of 10 bcm in 2014. Already in 2013 the flow of Nord Stream was up to 23.5 bcm, more than doubling the 11.3 bcm flow in 2012. With full capacity utilization of all other export pipelines there would still be about 38 bcm stranded without Ukraine transit. Therefore Turkish Stream would have to be built for Russia to have the possibility of completely subverting Ukraine (*Table 1*).

Table 1 **EU entry points for Russian gas excluding Ukraine**

EU Entry Point	Capacity (bcm)	2014 Flow (bcm)	Spare Capacity (bcm)
Poland (Wysokoje)	5.8	2.5	3.2
Poland (Kondratki) - Yamal	35.6	34.0	1.5
Poland (Tietierowka)	0.3	0.1	0.2
Germany – Nord Stream	53.2	33.9	19.2
Total	**94.8**	**70.6**	**24.2**

Source: IEA

There is further uncertainty as to how well transit can be facilitated through the Western Balkans from Greece without the completion of a number of priority Energy Community projects, notably: Interconnector Greece-Bulgaria (IGB) Interconnector Turkey-Bulgaria (ITB), the Ionian Adriatic Pipeline (IAP) and the Interconnector Bulgaria-Serbia (IBS). Public information is limited but only IGB is near a final investment decision, having received environmental approval and been awarded EU funding.

Reaching customers within the EU would be another challenge for the company, especially if in fact significant deliveries are destined for the Greek border. Existing contracts specify a point of delivery and can only be changed with agreement between buyer and seller. Assuming the delivery points are renegotiated, perhaps in return for a price discount, this would increase supply risk for a countries like Hungary, Bulgaria and Serbia. Instead of receiving direct deliveries at Beregdaroc the gas would need to transit multiple countries from Germany or Greece. In the near term, Central Europe will lean on Nord Stream's onshore connection to Opal, which can carry up to 35 bcm to the Czech border. However current EU regulation requires its operator Opal Gastransport to carry out a gas release program of 3 bcm/year if it wants to book more than half of the Czech border capacity, even though it remains unused. In 2014 the Commission repeatedly delayed an exemption decision requested by Gazprom that would allow it to book the full capacity. Even if the matter is resolved in Gazprom's favor, there will need to be some additional gas delivered fromTurkey through southeastern Europe where infrastructure is particularly poor.

The following chart outlines the cross-border projects that are expected in the short to medium term with the most significance to regional integration. The medium term projects from 2017 are still in the planning stage and do not have FIDs or secure funding, so the estimated date of commissioning is representative of a best case scenario with respect to permitting and construction (*Table 2*).

There are a number of large internal project proposals supported by governments that want to ensure their country's prominence in a transit role and further ensure security of supply. Eustream of Slovakia stands to lose the most with Russia's change of policy as a transit country, which is why it is pushing for financial support for the Eastring project. The centerpiece is a new segment built across Romania that connects Eustream's Brotherhood artery with the Trans-Balkan pipeline. While the motivation for Eustream is clear - to lock in future transit as flows from Ukraine continue to decline - the project is promoted as an alternative to South Stream. Meanwhile Hungary supports a pipeline running from Greece through Macedonia and Serbia connecting to Baumgarten, and Bulgaria continues to claim it is ideally situated to serve as a regional hub. Ultimately these projects will be competing to secure financing and a final investment decision, not necessarily according to the economics alone.

Table 2 **Key cross-border projects in the CSEE region**

Expected Commissioning	Project	Capacity (bcm)
2015	HU > SK bi-directional	4.3 and 1.7
	Yamal reverse flow (Poland)	7.4
	Interconnector Bulgaria – Serbia (IBS)	1.7
2016	Interconnector Turkey – Bulgaria (ITB)	3.1
	Interconnector Greece – Bulgaria (IGB)	2.8
2017	GR – BG reverse flow	2.4
2019	CZ – AT	8.7
	PL > SK bi-directional	4.9 and 9.9
2020	Ionian Adriatic Pipeline (IAP)	5.1
2022	AT > HU reverse flow	5.2

Source: ENTSO-G

Conclusion

Even if some of the individual PCIs that would contribute toward the realization of a North-South corridor are now more vigorously advanced in the absence of South Stream – as they likely will be - the effects will be gradual and not fully captured until well into the next decade. Over the past six years most of the low hanging fruit has been picked - relatively cheap expansions and reverse flow capacities vastly improving west to east flows of natural gas in central Europe.

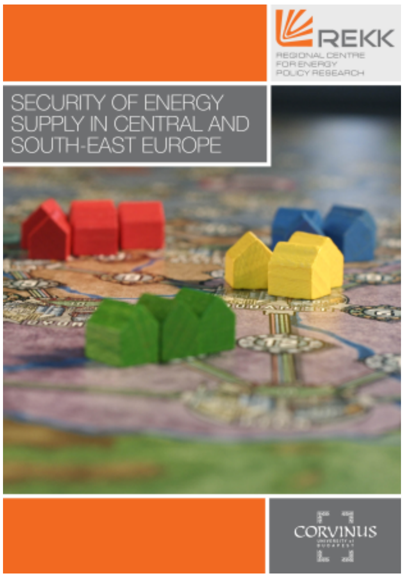
Meanwhile greenfield infrastructure (interconnectors) that require financing, feasibility studies, environmental assessments and cost allocation between beneficiaries, face long time horizons and varying degrees of uncertainty for commissioning.

Three years from now the current infrastructure landscape will not change significantly, meaning that Gazprom will have to facilitate deliveries under similar constraints. Russia appears to be pressuring Europe to accelerate internal infrastructure projects that will allow for rerouting options so Gazprom can bypass Ukraine, but Miller's threat is not credible given the existence of multiplelong term contracts well into the next decade. Ukraine will almost certainly play a significant transit role at least until 2020, at which point a form of Turkish Stream might realistically be completed, and probably even beyond.

Should Turkish Stream be built, it will have to be matched with significant infrastructure upgrades in the Western Balkans to facilitate transit from the Greek border. Until then, Ukraine will remain vital for Gazprom to meet its contractual obligations.

In the absence of South Stream, CSEE will have better focus and determination towards integration and the realization of a North-South corridor. While it is a slow, challenging and expensive process, it is the only way to improve security of supply and create legitimate markets and price signals across the region.

Security of Energy Supply in Central and South-East Europe



REKK has published the volume containing the studies of the SOS project started in 2009. The papers of this book were motivated by the wish to get a better understanding of the threats and challenges to gas and electricity supply security in a number of countries in Central and South Eastern Europe (CSEE). We very much hope that the reports of this volume, which have been prepared in an exceptional collaborative effort by the colleagues of the Regional Centre for Energy Policy Research, will be helpful for the executives of those companies interested in investing into the energy sector of the region and can also provide food for thought for European and local policy makers and regulators concerned about energy supply security in CSEE.

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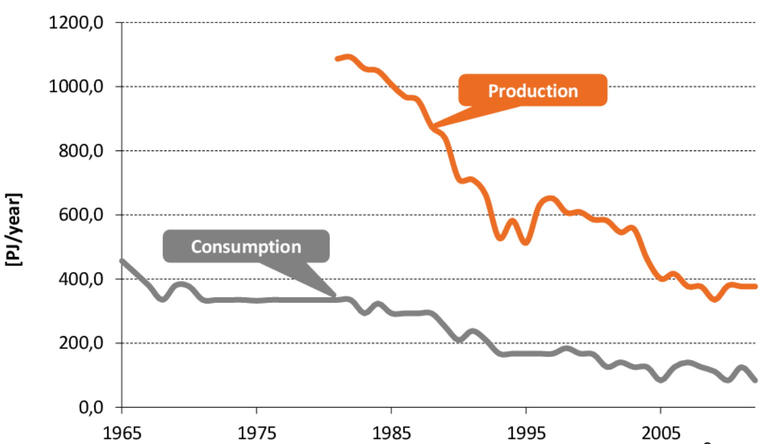
Mecsek coal mining relaunched

Last December the Pannon Thermal Power Plant Inc. restarted production at the open pit Pécs-Vasas coal mine. Surveys suggest that the 4.2 km2 site shelters about 3 million tons of extractable coal, of which over 100 thousand tons are directly accessible based on the reopened quarry, without expanding the mine or carrying out any substantial additional investments. According to the current plans of the company, 15 thousand tons of coal will be mined annually at a discount to imported coal as a result of the low cost of production.

The coal assets of the Mecsek mountains, including partly and fully explored areas, are estimated to be 500 million tons, enough to cover the total coal consumption of the country for over 90 years – based on 2012 consumption figures. This is the only place in Hungary with coal suitable for coke production: after volatile compounds (e.g. water) are removed through heat exposure, the remaining coal blends as a hard substance that continues to be suitable for combustion. So far about 220-240 million tons of coal have been mined from the Mecsek coal bed, extracted between 1782 and the coal mine bankruptcies of the 1990s.

During the early 1980s the annual production of all facilities of the former Mecsek Coal Mines (Mecseki Szénbányák) together still amounted to 3-4 million tons. Under the „Lias" program the State Planning Commission would have radically increased this volume by 1990, however, by 1986 the company was unprofitable and had to be bailed out by the state - the program was cancelled. By the end of the decade the Pécs Power Plant of MVM was reluctant to accept coal and the Danube Ironworks switched to cheaper import sources, which led to the collapse of the domestic coal market. Under these insurmountable circumstances, in 1991 Mecsek Coal Mines initiated bankruptcy proceedings. Following liquidation, close to 7,500 jobs were terminated. With the decline of coal mining, Hungary's coal production fell by a third during the decade between 1996 and 2006. Although decreasing consumption remains below the level of production (*Figure 21*), cheap imports pose an ever intensifying competition for the remaining mines. In 2013 Hungary imported almost 1.6 million tons of coal (about half of which came from the United States).

Figure 21 **The coal production and consumption of Hungary for the recent decades**



Source: BP

The Pannon Thermal Power Plant has, meanwhile, completely abandoned coal fired combustion. The fuel switch was explained by environmental necessities: following the EU directive on the restriction of pollutant emissions from large combustion plants (2001/80/EC), starting in 2005 the regulation on the emissions of particulate matter, sulphur-dioxide and nitrogen-oxides from power plants became substantially more stringent in Hungary. KvVM[1] decree 10/2003 (VII. 11.) adoption of the directive triggered fundamental changes for Pannon Thermal Power Plant, which had been burning coal with a high sulphur content.

In the early 2000s, two coal fired boilers were refurbished to be gas fired with some support from the World Bank, while one boiler was converted to biomass (burning wood chips). The biomass based power plant, with 49.9 MW of electricity and 85 MW of heat generating capacity, started to operate in 2004. In a few years' time the company – since purchased by French owned Dalkia Energia Zrt (Veolia Energia Magyarország Zrt. as they are called today) – launched a brownfield investment plan to build a straw fired power plant with a capacity of 35 MW of electricity and 72 MW of heat generation. This investment was completed at the end of 2013. The two new units are capable of fully supplying the heat demand of the district heating system of the city of Pécs while the two natural gas based boilers merely serve as reserve capacity.

[1] *Ministry of Environment and Water*

The preparations for the December reopening of the Pécs-Vasas coal mine started years ago; the environmental permit was received by the power plant in the summer of 2014. The extracted coal is planned to be sold primarily to the households of the South Transdanubian region, consisting of Baranya, Somogy and Tolna counties. A number of industrial players have also been contacted, and if preliminary expectations are confirmed by the market then production may be augmented. With respect to increased volumes and sales to industrial facilities, the company still lacks an actual market survey, thus potential volume expansion may fall anywhere between 50 and 300 thousand tons per year. With the permitted expansion of the mine pit even up to 20 times the current volume, between 100 and 300 thousand tons of coal can be extracted annually. Obviously this volume would be sufficient to supply fuel not only to household consumers, but also to the prominent industrial users of the region and the country.

Initially mining 15 thousand tons per year supports 8-10 workers, but additional jobs may be created through the expansion of capacities. If the market meets the preliminary expectations of the company, acquisition of the necessary permits would start this year. The restart of production also makes it possible for the students of the collier school launched by the Municipality of Komló to acquire skills of open pit mining.

Since the exploitation of the domestic coal stock is also spelled out in the energy strategy of Hungary, the reopening of additional coal mines is plausible. According to the Mineral Resource Utilisation and Stock Management Action Plan, published in 2013, the annual volume of primary energy from domestic coal mining (73.4 PJ) can be doubled, increasing the role played by domestic coal in electricity generation. At present the document, however, considers the domestic coal and lignite stock only as a “strategic reserve of our energy supply”, the utilisation of which depends on the availability of proper environmental technologies. As foreseen by the vision, domestic coal may play an increased role as the fuel input of new, highly efficient power plants with low carbon emissions, while also highlighting that even until then it makes sense to maintain coal mining and the existing infrastructure.

Similar targets have been set by the National Energy Strategy, adopted in 2011, assuming sustained levels of coal based energy generation under the Nuclear-Coal-Green scenario. To reach this, the economic impact assessment supporting the document envisions the entry of 400 MW of new coal fired power plant capacity. According to the strategy, however, the precondition to large scale coal use is the application of clean coal and CCS technologies, which are not economically viable at present. This statement still holds today: there is not any operational power plant facility anywhere in the World with capacities to capture, transport and store carbon-dioxide.

The most recent coal fired power plant investment in Hungary was announced in 2006: MVM and Mátrai Power Plant planned to build a 440 MW lignite unit as a mutual enterprise. According to the original concept the new unit would have started operation during the second half of this year, the owners, however, decided to stop the development in 2010. They claimed that following the economic crisis the HUF 300 billion project became financially unstable due to developments in financial markets, the price of electricity and the additional environmental costs anticipated to take place after the completion of the unit due to more stringent EU regulations.

While the revitalisation of the sector contributes to both the lower energy dependency of the country and job creation, environmental impacts are also worth to scrutinizing. The 15 thousand tons of coal planned to be extracted from the Vasas mine has a calorific value of 15.5 MJ/kg on average, sufficient to replace 7 million m3 of natural gas in a year. The ash content of the Mecsek coal is 50-60% without washing, while it has a sulphur content of 2.5-3%. These values indicate substantial pollution: since ash cannot be combusted, the calorific value of the Mecsek coal remains below the average figures of 17-33 MJ/kg typical for black coal. The high sulphur content, on the other hand, makes compliance with sulphur-dioxide emissions more difficult as desulphurisation involves additional costs. In contrast, natural gas contains practically zero particulate matter or sulphur, and due to its higher hydrogen content its combustion results in 22.5% lower carbon-dioxide emissions (and more water vapour) than coal, thus it should be correctly considered as much cleaner. As a result of the penetration of renewable energy sources, and even more importantly, the collapse of industrial activities following the change of regime, at present Hungary exceeds its CO_2 emission reduction obligations. But as the climate policy of the EU becomes more stringent, the expansion of coal based power generation can cause serious problems in the long run.

The particulate matter emitted from coal fired by households delivers its adverse health effects in the immediate environment, while sulphur-dioxide emissions – through acidic deposition – generate health problems and financial damage on a larger territory. While the quantity of emitted sulphur-dioxide and particulate matter from coal fired power

Table 3 **Emissions from the combustion of 15,000 tons of coal in a power plant, in households and from the combustion of natural gas of the same fuel content (232.5 TJ)**

	Natural gas	Coal	
		Households	Power plant
Particulate matter	0.0	1237.5	3.7
SO_2	0.0	825.0	41.3
CO_2	12787.5	16500.0	16500.0

Source: REKK calculation

Note: based on the content of pollutants in each fuel

plants can be substantially reduced through the application of appropriate equipment (bag filters, electrostatic precipitators, and lime injection), coal burned by households leads to an environmental burden that is a magnitude higher (see *Table 3*). Moreover, a modern coal fired power plant is also capable of utilising the heat from flue gases, therefore its efficiency is also much higher than that of household coal combustion.[2]

The coal market of Hungary has substantially shrunk since the change of regime in1989, with large industrial consumers absent today and the remaining former coal fired power plants (Bakonyi Power Plant, Mátrai Power Plant, Oroszlányi Power Plant, Dorogi Power Plant) partly or fully switched to alternative fuels (mainly biomass or gas). The revitalisation of Mecsek coal mining therefore can become economically and environmentally sustainable only with the advent of well capitalised users that can utilise the coal stock of the region efficiently and in compliance with the environmental standards of the EU.

[2] *Power plant air heaters help to reduce flue gas losses as - through a heat exchanger - they pass the flue gas heat to the air entering the boiler. Thereby during combustion less fuel is needed to reach the same temperature, thus the generation of a given quantity of useful energy requires less energy stored in the chemical bonds of the fuel. In other words, efficiency is higher.*

Renewable Energy and Energy Efficiency Quarterly

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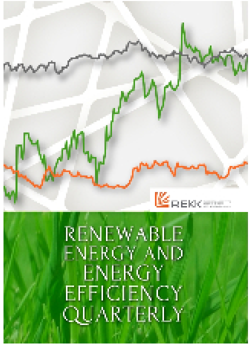

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