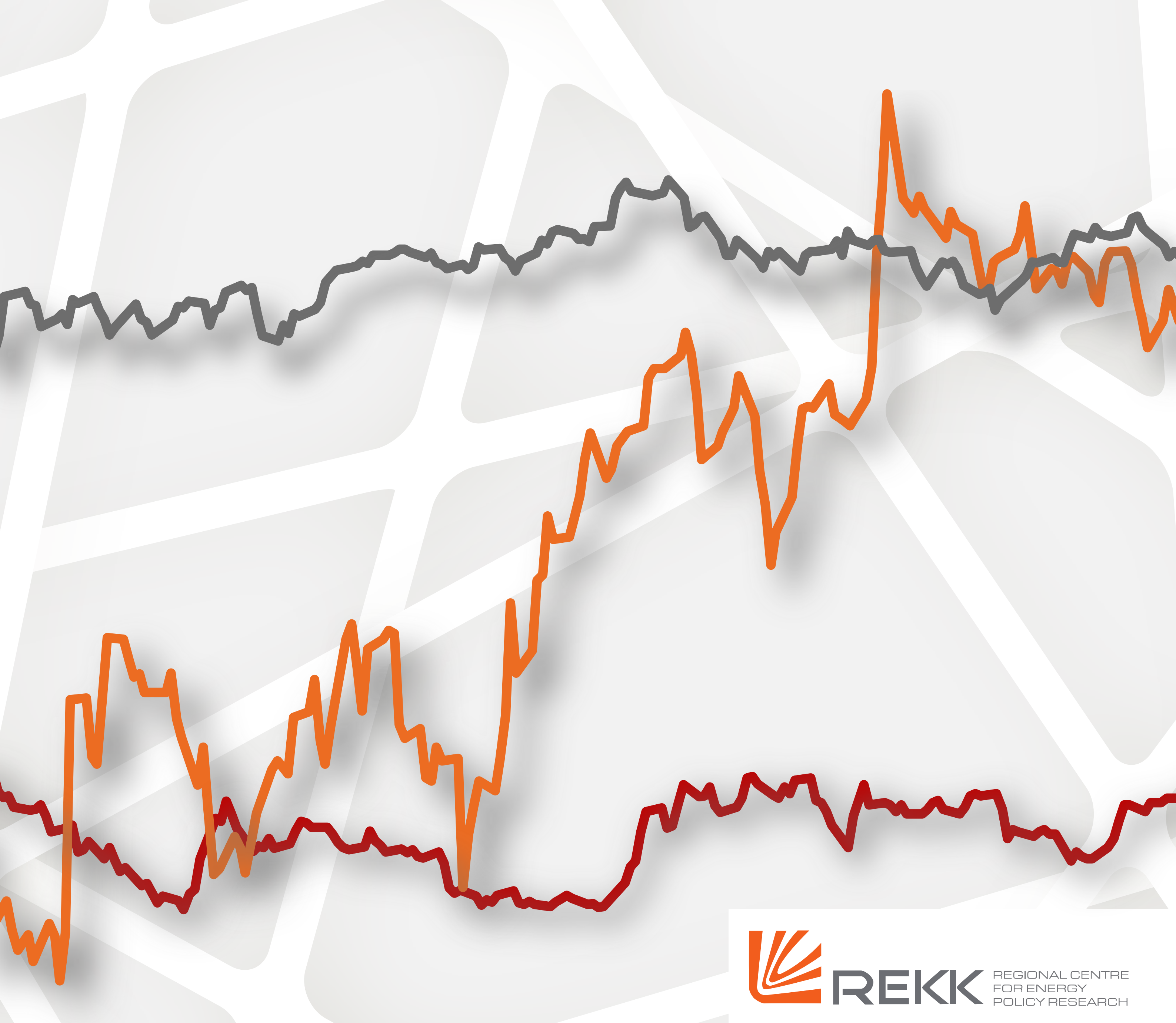

REKK REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q3 2015

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.

Training programs

- Energy market economist post-graduate training
- ERRA summer schools
- Regulatory trainings
- Price regulation
- Electricity market trainings
- Market monitoring
- Gas market trainings
- Tailored trainings upon request

Research

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

- Regional electricity and natural gas modelling
- CO_2-allowance allocation and trade
- Renewable energy support schemes and markets
- Security of supply
- Market entry and trade barriers
- Supplier switching

Consultancy

- Pride forecasts and country studies to support investment decisions
- Consultancy service for large customers on shaping their energy strategy on the liberalised market
- Consultancy service for regulatory authorities and energy supply companies on price regulation
- Consultancy service for system operators on how to manage the new challanges
- Preparing economic assessment for strategic documents

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,

In addition to the article that reviews the second quarter developments of energy markets, our current issue contains three more articles.

In the first piece we inspect the opportunities and risks inherent in the long term agreement to be signed after the Gazprom contract - a decisive element of the domestic natural gas market - expires. The contracted volume and the choice of cross-border capacities ensuring access to the domestic market may both considerably influence domestic consumer prices as well as the income of MVM. Within the article we briefly introduce the European stage and show the impact that different combinations of contracted volumes and entry points deliver to the market price and the level of loss faced by the importer.

Our second article describes the social welfare augmenting impact of the natural gas infrastructure development plans that are meant to alleviate the physical isolation of the Central and South East European region (CESEC). During the summer of 2015 the countries of the region agreed to accelerate the construction of the missing natural gas interconnection lines that would improve the safety of supply and contribute to the evolution of a competitive regional energy market. In an individual study REKK quantified the natural gas price reducing impact of the potential infrastructure development options and the magnitude of the resulting increase in social welfare, aiding the selection of those projects that offer the most attractive outcome. In our article we summarise the results of these analyses and the key conclusions.

In our third article we review the package of proposals to amend the regulation of the energy markets published by the European Commission in July 2015. The “summer energy package” includes the modification of regulations governing the operation of the emission trading system and the application of energy labels, proposals contributing to the protection of consumers as well as their market participation, and the transformation of the operating model of the electricity market. In the article we introduce the most important elements of the package and evaluate their likely impact.

First the elements of the new electricity market design drafted by the Commission are summarised, then we introduce the recommendations that aim to enhance the market participation of consumers via the distributed renewable energy that they produce and consume. Then we take a look at the climate change regulation: after reviewing the voluntary emission reduction commitments released before the Paris climate conference, the regulatory proposals meant to guide the EU to its 40% emission abatement target are assessed.

Peter Kaderják, director

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Energy market developments

The second quarter of 2015 saw a rise in world market oil prices, while the effect of the earlier decline appeared in European gas prices. That resulted in a 20% decline in the average price of oil-linked Russian gas at the German border, while Hungarian oil-linked import prices sank below 80 HUF/cubic meter from what was typically more than 100 HUF/cubic meter. Despite falling gas prices the clean spark spread continued to decline, with May production of 1 MWh electricity costing more than a 17 EUR loss for natural gas fired power plants, which was a two-year low. Hungarian net power generation in the second quarter lagged behind the previous quarter by 20% and met 58% of consumption, which was down 10%. There was more than a 10% drop in gas production in the period from April to June, which accounted for one third of consumption. Since this coincided with a fall in import, the source structure shifted towards declining net injection and export.

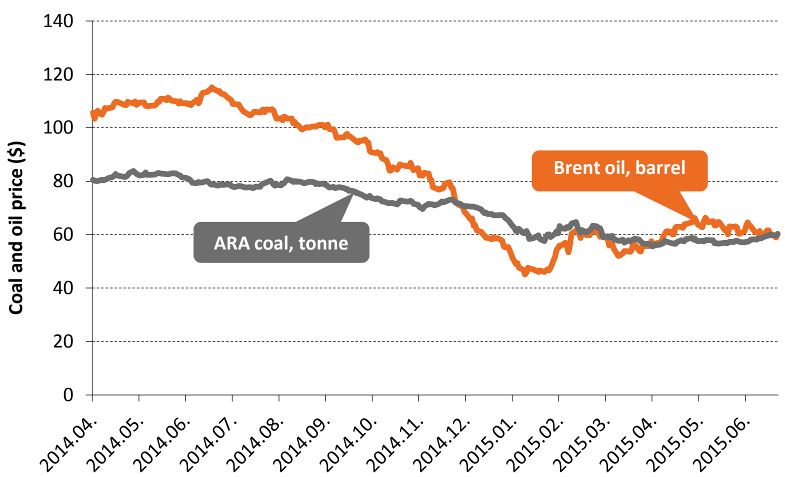
International price trends

After a period of stabilization in the first quarter, Brent prices rose between April and June. The average price amounted to 62 USD/barrel, which is more than 14% above the January-March period, and far exceeding the January low of 46 USD (*Figure 1*). Prices peaked at a monthly average of 64 USD in May, which was followed by a drop to 61.5 USD in June. In the meantime coal market prices, which have been decreasing for two and a half years, continued to fall. The average ARA price fell below 58 USD per ton, which lags more than 40% behind the prices in the first quarter of 2013.

Henry Hub saw the continuation of moderate gas prices counted both in EUR and in USD (*Figure 2*). Meanwhile TTF spot prices lagged behind the first quarter by a mere 1.5%. As mentioned, German border prices fell by 20% quarter on quarter. In fact, the monthly average of the German border price has fallen by 35% over the last three years (between June 2012 and June 2015). The quarterly EUR average price of spot LNG exported to Japan dropped 10%, and considering the period between March 2014 and June 2015 the price has nearly halved. The fall calculated in USD average prices is even more drastic, 60%. The downward trend can be explained mostly as a coneqeunce of declining oil prices since a significant part of Japanese LNG contracts are oil-linked. In addition, there was a drop in demand due to the mild winter of the last two years and Japanese nuclear restarts will begin to displace some LNG demand. According an estimate of Tokyo Gas, the displacement by nuclear restarts may reach 20 million tons by 2020.

German electricity prices stagnated in the second quarter: EEX year-ahead baseload futures stabilized at around 32 EUR/MWh, while year-ahead peak futures arrived close to 40 EUR/MWh (*Figure 3*). At the same time, there was a slight increase in the EUA market: EUA futures fluctuated around 7.5 EUR per ton by the end of the quarter, while in the previous quarter, the average price was 7 EUR. The slow rise in EUA prices appears stable since they were below 4 EUR two years ago. This slow rise could have also been influenced by the European Commission's Decision of 2011, which reduces 2014 and 2015 allowances by 400 and 300 million respectively, and cuts another 200 million units next year. However current prices still reflect a significant oversupply in EUAs, and because the overall number of EUAs available until 2020 will not decrease actions on the part of the Commission will not have short term effects.

Figure 1 **Prices of year-ahead EEX ARA coal and Brent crude oil futures from April 2014 to June 2015**



Source: EEX, IEA

The profitability of gas and coal-fired power plants can be measured according to the clean spark spread and the clean dark repsectively. 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, Dutch TTF spot prices and ARA coal prices.

The clean spark spread has not exceeded 0 EUR/MWh over the previous three years and it fell further in the second quarter. In May gas-fired power plants produced more than a 17 EUR loss by generating 1 MWh electricity, a two years low. The competitiveness of gas fired power plants has been deteriorating since July 2014, from which point TTF prices rose by 26% until this May and ARA prices declined by 11%. To the detriment of gas-fired power plants, renewable-based power production has played an increasing role. In Germany, solar energy based power production – with a system load exceeding 25 GW – broke a record in April. Based on the report of the German energy regulator, the conventional power generation capacity shrank by 1.5 GW in the last year, while renewable capacities grew by 6.4 GW.

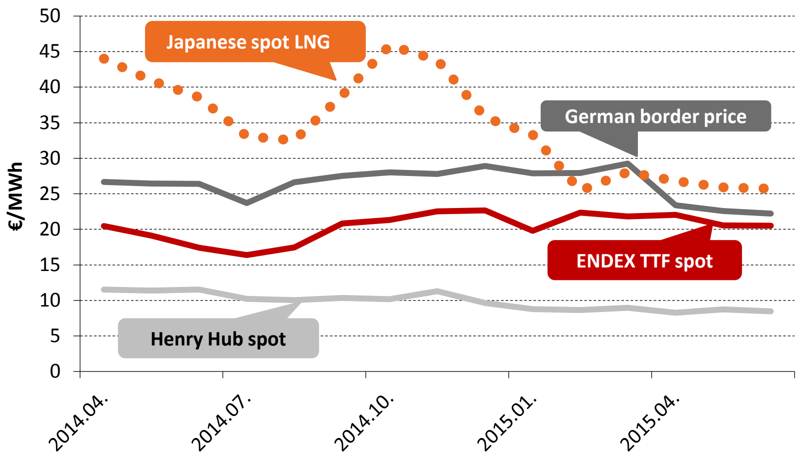
Although the loss of natural gas fired production stabilized at 12 EUR, it still exceeded the average of the previous quarter (8.4 EUR). Movements of clean dark spread were similar to those of clean spark spread but in the positive range: a retreat in May was followed by a rise in June, when the profit for coal based power generators producing 1 MWh electricity approached 8 EUR at the end of the quarter. This resulted in a difference of more than 20 EUR between clean dark and clean spark spreads, similar to the results of the previous quarter.

Overview of domestic power market

As opposed to the last quarter of 2014 and the first quarter of 2015, the most expensive interconnection was not at the Austrian border but the Slovakian border (*Figure 5*). The Slovakian interconnection capacity fee amounted to 7 EUR in April and 5 EUR in May. In April the Romanian interconnection capacity was also expensive, approaching 6 EUR compared to fees ranging from 2 to 3 EUR in the first quarter. While the Serbian import capacity prices jumped to 0.5 EUR in June, the Croatian and Ukrainian import capacity continued to tread at a few eurocents.

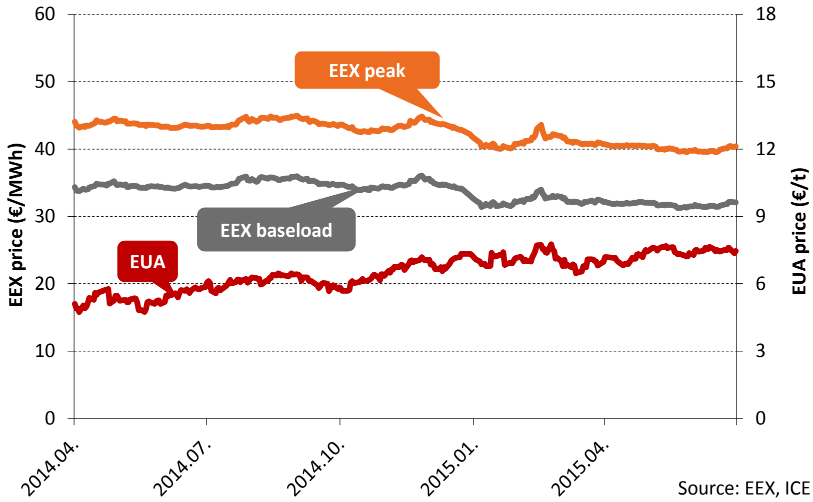
The domestic net power generation lagged behind the previous quarter's output by 20% and covered up to 58% of consumption, which was down 10% (*Figure 6*).

Figure 2 **Prices on select international gas markets from April 2014 to June 2015**



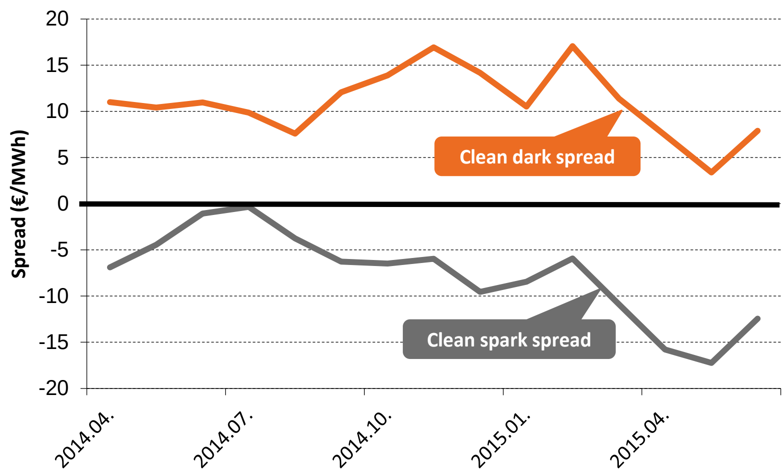
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 **Prices of EEX year-ahead futures and CO2 allowances (EUA) with December delivery from April 2014 to June 2015**



Source: EEX, ICE

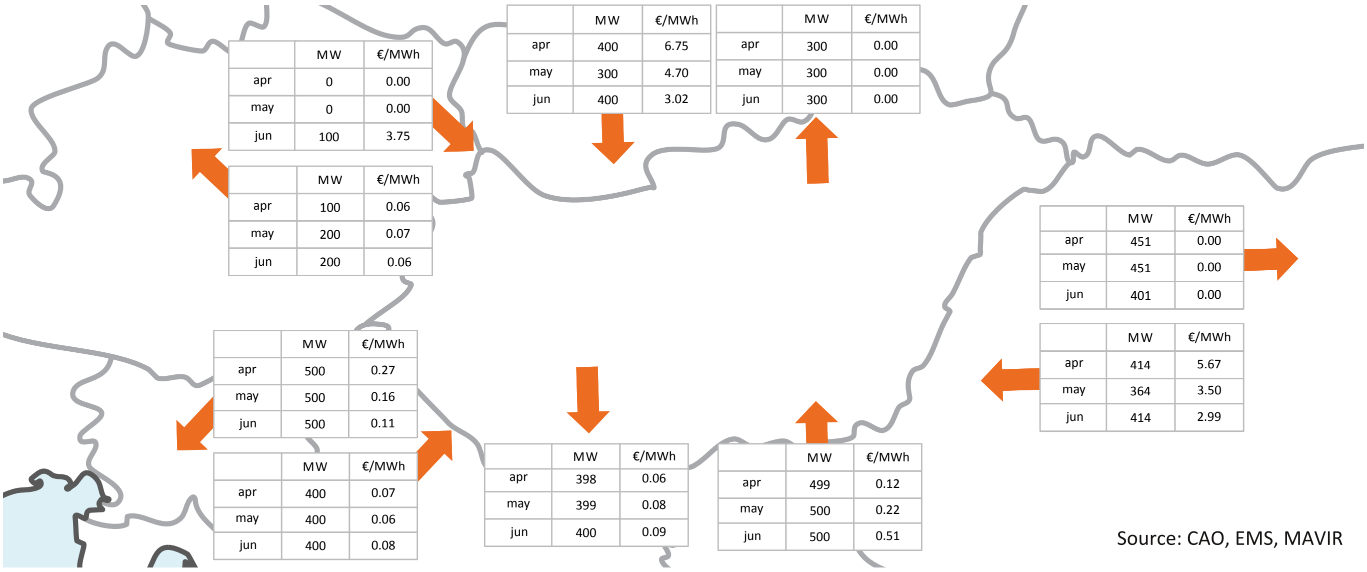
Figure 4 **Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from April 2015 to June 2015**



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

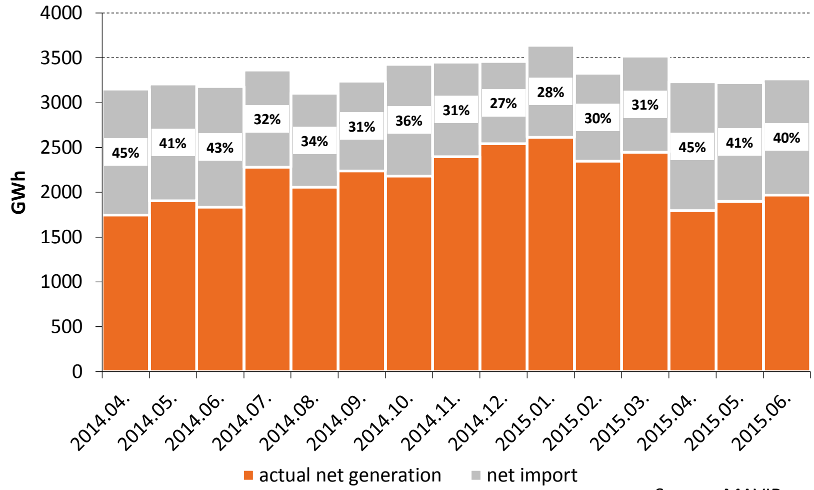
Note: In our calculations, we assumed a 50% efficiency for gas power plants and a 38% efficiency for coal power plants.

Figure 5 Results of monthly cross-border capacity auctions in Hungary, Q2 2015



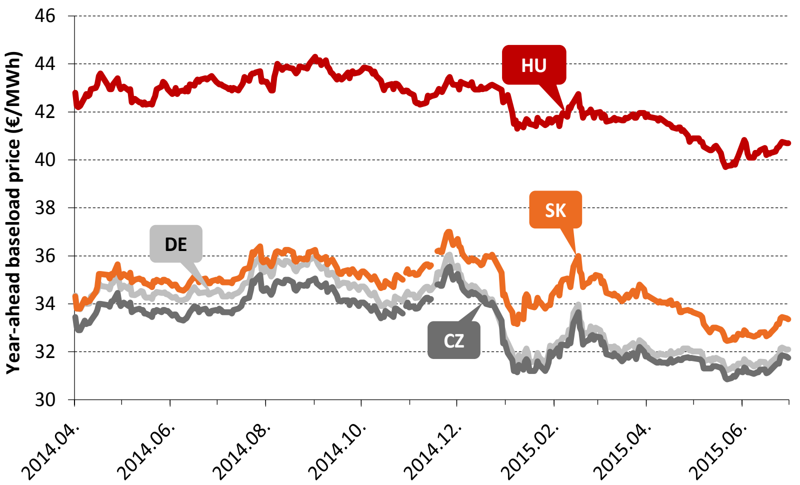
Source: CAO, EMS, MAVIR

Figure 6 **Net electricity production of Hungary's power plants, and monthly net electricity import of Hungary between April 2014 and June 2015**



Source: MAVIR

Figure 7 **Year-ahead baseload futures prices in given countries of the region, between April 2014 and June 2015**



Source: EEX, HUPX, OTE

The 42% import share accounts for a significant growth compared to the 29% share in the first quarter, while more or less equaling the share during the same period of the previous year.

On Central European power exchanges, year-ahead baseload futures continued to fall. The quarterly average of HUPX futures declined by more than one euro to 40.7 EUR (*Figure 7*). The spread between HUPX and EEX futures closed slightly but still approached 9 EUR. The cheapest baseload futures in the region are sold on the Czech exchange, which were 9.3 EUR below than HUPX futures, while Slovakian futures lagged behind HUPX futures by nearly 8 EUR on a quarterly average. There was a more noteworthy reduction in the long standing spread between Hungarian and German prices on day-ahead markets, with HUPX futures averaging only 4.2 EUR higher than EEX in the second quarter compared to 7.7 EUR in the first quarter. The quarterly average Hungarian day-ahead price was less than 4 EUR lower than Czech prices, while the difference between the Romanian OPCOM and HUPX day-ahead prices remained essentially unchanged during the quarter (*Figure 8*).

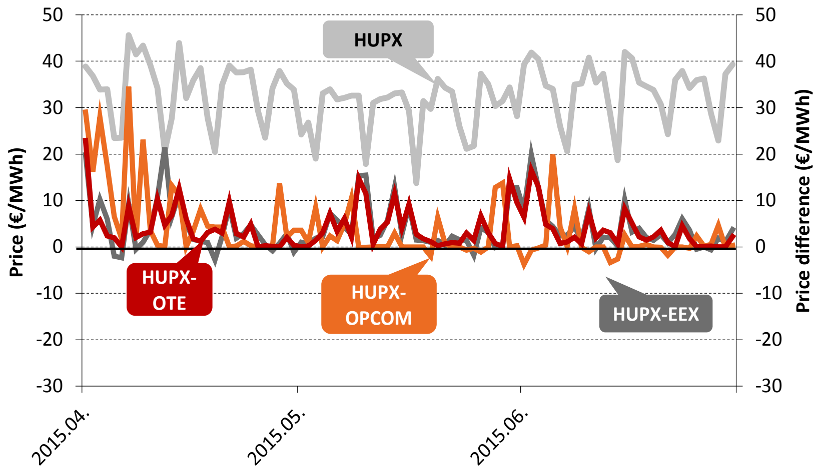
Figure 9 illustrates the frequency and size of spreads under HU-SK market coupling, revealing a strong alignment of HUPX and the Slovakian power prices in June. There was no difference between HUPX and Slovakian prices in 60% of the hours and a difference exceeding 10 EUR in only 10% of the hours. Similarly, June was the month in which HUPX prices aligned most closely with the Romanian and the Czech prices. The difference between OPCOM and HUPX exceeded 1 EUR in only 14% of hours, while the difference was 38% with respect to OTE. Compared to previous months, Hungarian prices in June were lower than Romanian prices somewhat more frequently in 8% of the hours.

The wholesale price is affected by the costs incurred from the deviation of energy prices from the normal scheduling 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 regulated market. The system charges for 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 would not otherwise be desirable. 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 second quarter, the average price of positive balancing approached 25 HUF compared to the average of the period from January to March reaching 19.3 HUF. The quarter saw that negative balancing energy prices strongly exceeded exchange prices, which suggests significant overproduction: balance circle managers could transfer the redundant electricity to MAVIR by paying for it at a price that significantly exceeded exchange prices.

Overview of domestic gas market

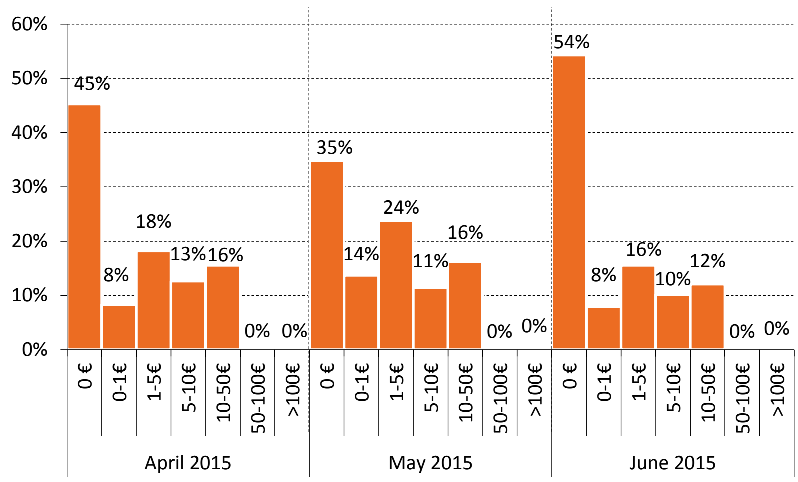
Due to the weather in April, which was colder than in the previous year, the second quarter's average monthly gas comsumption was not significantly lower than one year ago. This quarter's consumption of approximately 498 mcm is just under 10 million cubic meters lower than April-June 2014. (*Figure 11*). At the

Figure 8 Comparison of day-ahead baselaod prices on the EEX, OPCOM, OTE and HUPX exchanges between April and June 2015



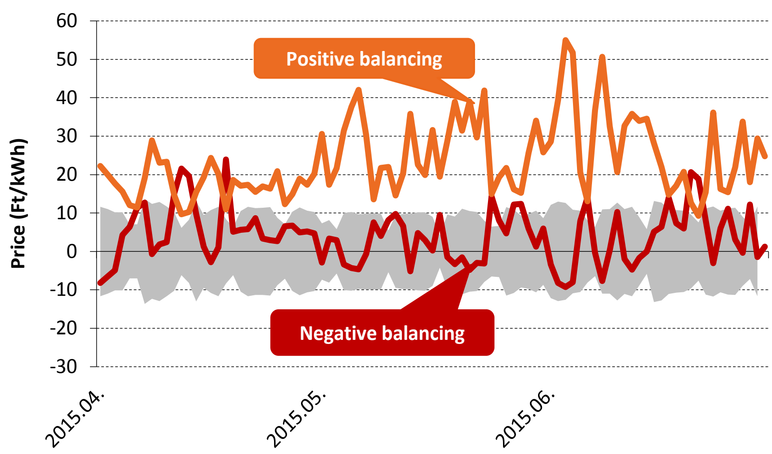
Source: EEX, OPCOM, OTE, HUPX

Figure 9 Frequency of various levels of price difference between the Hungarian and the Slovakian exchanges between April and June 2015



Source: REKK calculation based on OTE data

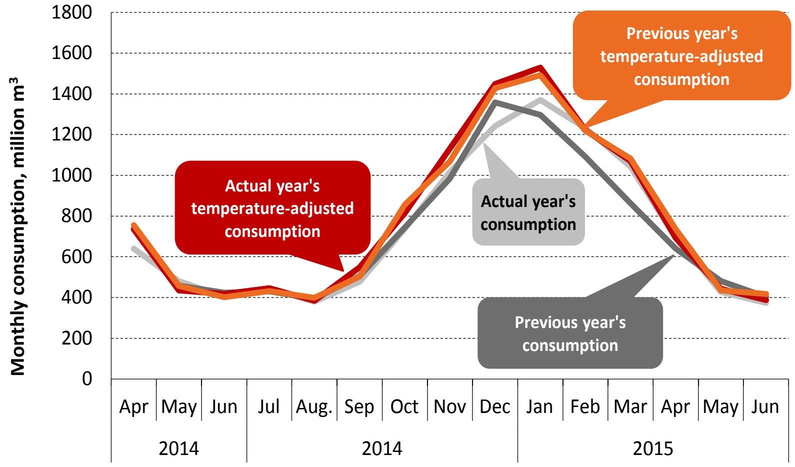
Figure 10 Daily average of balancing prices and spot HUPX prices, Q2 2015



Source: MAVIR, HUPX

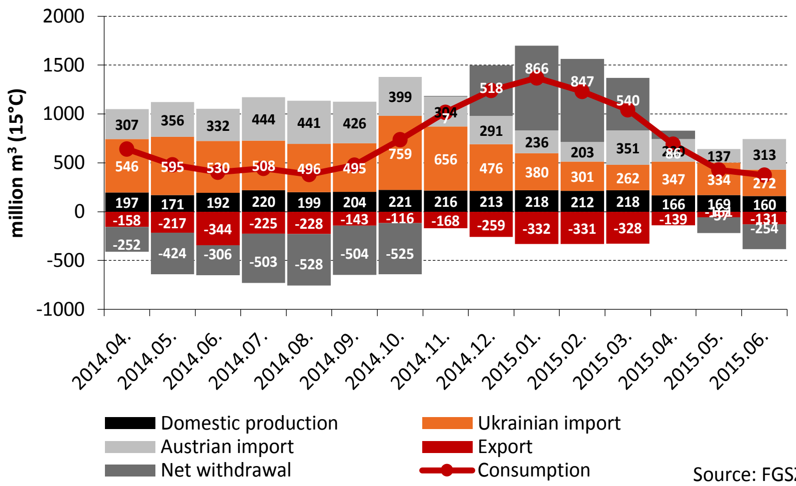
Note: the upper treshold of the gray area denotes the HUPX day ahead price, while the lower treshold indicates the HUPX price multiplied by -1. According to the Commercial Code of MAVIR, this is the upper and lower minimum of balancing energy price.

Figure 11 Raw and temperature-adjusted monthly gas consumption between July 2014 and June 2015 compared with the respective data in the previous year



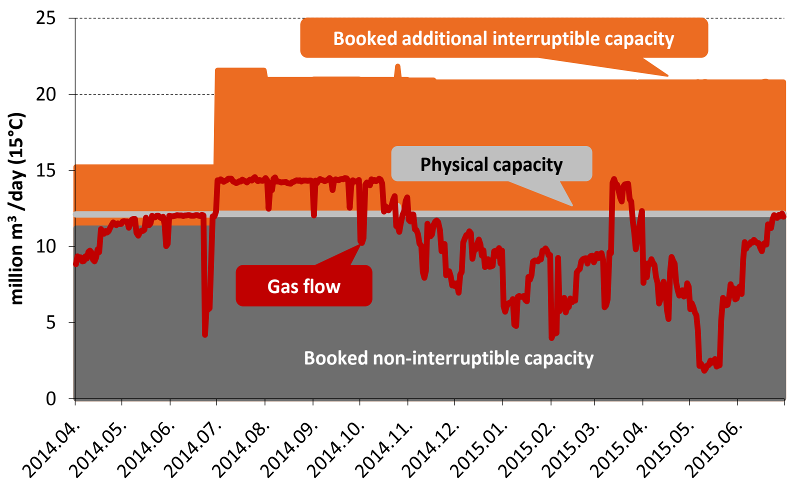
Source: FGSZ, European Climate Assessment & Dataset, and REKK calculations

Figure 12 Source structure of Hungarian gas market by month between July 2014 and June 2015



Source: FGSZ

Figure 13 Transmission at the Mosonmagyaróvár (Austrian border) entry point between April 2014 and June 2015 together with booked interruptible and non-interruptible capacities



Source: FGSZ

Note: the illustrated physical capacity is the value provided by the FGSZ.

same time, temperature adjusted consumption was more than 20 mcm less than in the second quarter of previous year.

While domestic gas production grew by 4 % in the first quarter, it declined by more than 10% in the second quarter, and accounted for one third of total consumption (*Figure 12*). Similarly, Ukrainian imports in the first quarter were significantly lower than one year ago, falling by nearly 45% (to 950 mcm) on a yearly basis. Since the Austrian imports dropped by more than 30%, the source structure shifted towards net injection and decreasing exports. Falling import and injection data can be explained by the action of traders in response to the Ukrainian crisis. In anticipation of the need for winter supply, they began accumulating reserves in the beginning of summer. At the end of this last June the saturation of domestic storages exceeded 35% while it did not even reach 28% this June owing to easing security supply concerns.

Falling imports are also reflected in gas flow data at entry points. Interconnection capacity utilization of the Mosonmagyaróvár entry point amounted to 62% in the second quarter, while it was 90% in the same period of the previous year (*Figure 13*). The month of May witnessed the biggest „sluggishness," including a day when only 15% of contracted and non-interruptible capacities were used. In this month, the average utilization of the interconnection capacity was only 36%.

Due to long term Russian gas import agreements, Beregdaróc entry point flows appear more balanced compared to Mosonmagyaróvár. Within the average utilization rate of 19% there were no significant fluctuations during the period under review (*Figure 14*). However, the decline from a 33% utilization rate in the second quarter of last year shows the weakening importance of Ukrainian imports.

In the second quarter, gas exports to Romania were slowed considerably, dropping from 53 mcm to 20 mcm in the course of the three months (*Figure 15*). Romania's strategy is to offset its import needs by ramping up domestic production. There was also a fall in exports to

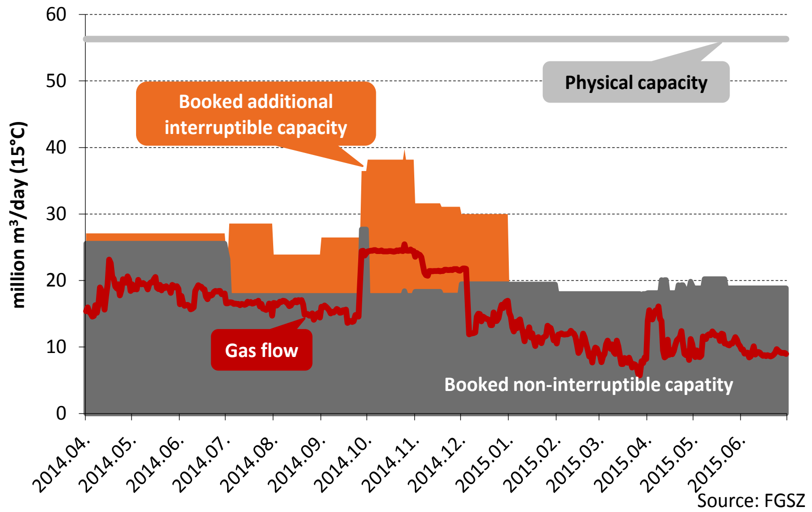
Serbia that exceeded 250 mcm in January and dipped to 43 mcm by June. Even so Serbia's share of Hungarian exports, totalling 327 mcm, was 67%, exceeding the first quarter's share of 63%. After agreeing with Russia in a 25% price decreasing for the second quarter, Ukraine had very little need to purchase gas from Hungary in March and April. Still, 72 mcm natural gas left Hungary at Beregdaróc in June. While Ukraine received 34% of the total Hungarian exports in the first quarter of 2015, this share was down to 24% in the second quarter.

A restart of Ukrainian shipments in June 2015 was followed by an agreement in May between FGSZ and Ukrtransgaz on bidirectional natural gas transport. FGSZ iniitally made shipments to Ukraine in March 2013 in the framework of temporary agreements. The interconnection capacity from Ukraine to Hungary amounts to 26 bcm/year, while 6.1 bcm/year from Hungary to Ukraine. Yet FGSZ maintains that further developments are needed on the transmission network in the latter direction at both sides of the border in order to ensure non-interruptible capacities.

Figure 16 shows that the effect of the drop in oil prices at the end of 2014 appeared in oil-linked import prices this past March, falling from what was a steady 100 HUF/cubic meter to less than 80 HUF/cubic meter. However the decline in oil prices had only a limited effect on Hungarian domestic gas prices that since April have a predefined weighted average of 75% spot and 25% oil-linked prices as prescribed by the regulatory body. Although TTF prices were lower compared to the first quarter, the decline was just 10% compared to oil-linked prices that fell neary 30%.

The regulatory decree overseeing the function of the gas price setting used for universal service as well as EUR and USD excange rates was modified on the first of April. As a consequence, the loss of universal service providers resulting from the difference in real exchange rates and those regulated in the decree has declined. Thus, recognised natural gas prices rose slightly above TTF prices in April and May and fell back in June, while TTF prices increased.

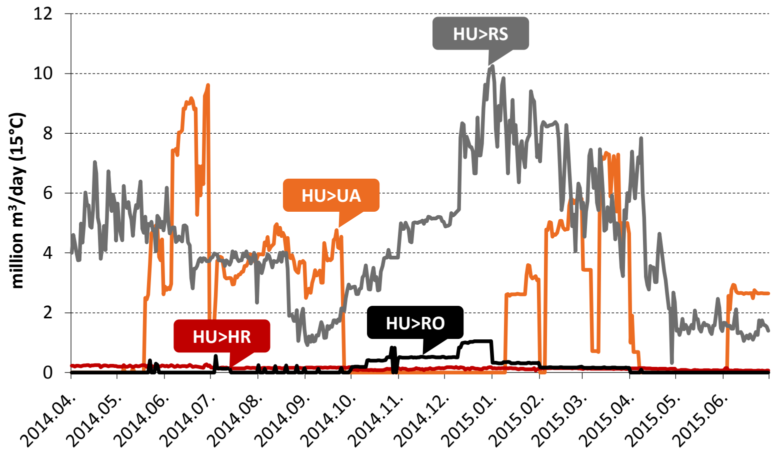
Figure 14 Transmission at the Beregdaróc (Ukrainian border) entry point between April 2014 and June 2015, together with booked interruptible and non-interruptible capacities



Source: FGSZ

Note: The illustrated physical capacity is the figure provided by the FGSZ. The data also contains the transit gas flow arriving from Ukraine, directed to Serbia and Bosnia

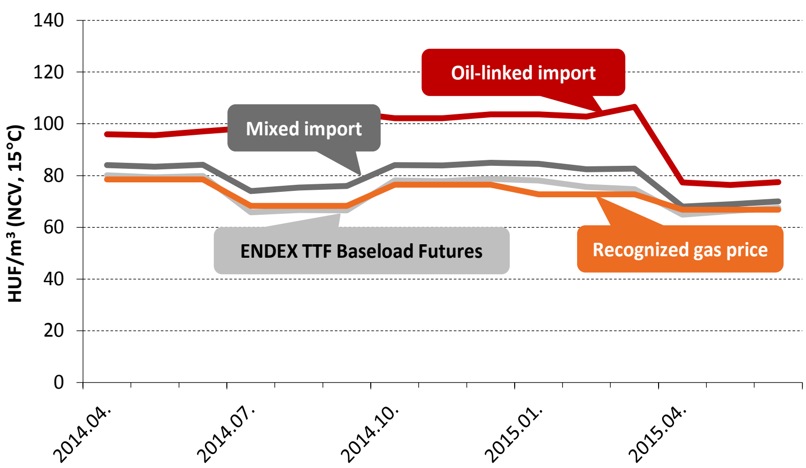
Figure 15 Hungary's natural gas exports to Ukraine, Romania and Serbia from April 2014 to June 2015



Source: FGSZ

Note: FGSZ publishes the transit gas flows that exit on the HU>RS (Kiskundorozsma) point and are directed to Serbia and Bosnia.

Figure 16 Recognised natural gas selling price of universal service providers and factors of the gas price formula between April 2014 and June 2015



Source: REKK calculations based on EIA and ENDEX data

Note: The 'recognized natural gas price' is the REKK estimation of the quarterly MEKH figure of the accepted weighted natural gas price, which relates to the universal service provision, and is based on the decreed gas price formula and the decreed EUR and USD foreign exchange rates, using publicly available information. The estimation does not take into account the effect of the storage gas featured in the gas price formula. The 'mixed import' was calculated with a similar estimation, but in this case foreign exchange market rates were used instead of the rates set by decree.

Looking ahead to Hungary's next gas deal with Russia

Hungary's natural gas market has been singularly dominated by the Panrusgaz legacy contract since 1996, and although its expiration is delayed until closer to 2018, it is easy to see that the new agreement will be negotiated on entirely different terms. This is due to an ad hoc agreement between Hungary and Russia that will extend the terms of the contract for Hungary to purchase the take-or-pay (TOP) deficit that accumulated over the past few years. Like other Central and Southeast European (CSEE) countries, Hungary has benefited from the rising tide of interconnectivity and hub-based trading across Europe that has enabled diversification of supply in Hungary and undermined the utility of long term buyer-side commitments of the past. With demand unlikely to rebound to pre-crisis levels in the medium-term and more competitive import capacity than ever before, Hungary must consider how a new arrangement with Gazprom will contribute toward the reshaping of its domestic market.

For now as in the past a majority of Hungary's annual gas consumption has been met with the Panrusgaz legacy contract, albeit a declining majority. Before the crisis, this met some 80% of Hungarian demand but in 2013 this was down to 59%, with only 5.52 bcm imported under contract and reflective of the continually downward adjusted annual contracted volume (ACQ). The ACQ is the agreed amount of natural gas that must be purchased each year on a take-or-pay basis, usually with a +/- 15% range that the buyer can ramp up or down depending on market conditions. The problem with traditional long term natural gas take-or-pay (TOP) commitments of this nature is that they do not readily adjust to changes in the market. A clause for ex-post market re-evaluation every three years should not be mistaken for a market mechanism, and likewise pursuing arbitration in an effort to reconcile contracted and market-based prices comes at a tremendous cost and can take years to resolve. Even after E.ON secured concessions from Gazprom that transmitted through all of its subsidiary contracts in 2012, the sales position of E.ON owned EFT, the Hungarian contract holder at the time, continued to worsen because of declining demand and increasing spot competition through the Hungary-Austria pipeline. This forced a unique settlement in 2013 that allows for unpurchased TOP volumes from this period to be rolled-over for repurchase by the current contract holder Magyar Foldgazkereskedo Zrt (MFGK), a subsidiary of MVM, after 2015. Now the contract will effectively govern a significant portion of Hungary's gas consumption possibly until 2018 before a new agreement is signed. While this form of ex-post restructuring helped E.ON EFT at the time, financial losses associated with the contract were merely backlogged and will reemerge for MFGK.

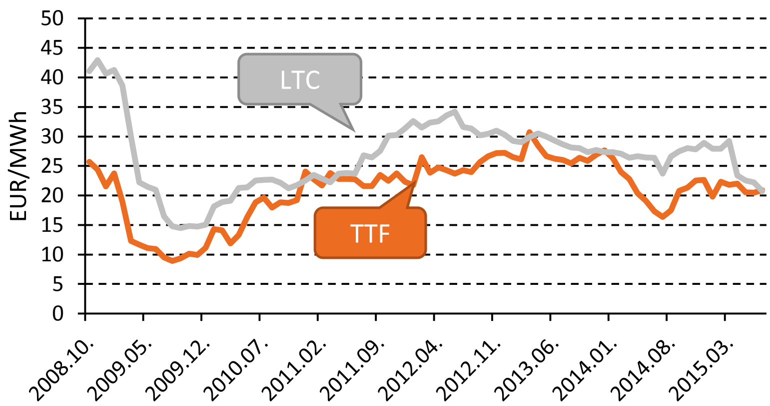
European scene

The challenges faced in Hungary by E.ON EFT were not unique, as the financial crisis and subsequent economic malaise inflicted carnage on all major European utilities under the weight of oil-indexed obligations and, for the most part, demonstrated that traditional TOP commitments and mechanisms were no longer a feasible model. In this sense, the crisis inadvertently added momentum and legitimacy to the Third Energy Package that was unveiled in 2009. Thus traditional non-market pricing mechanisms imposed by monopolistic producers will continue to face pressure from more open and interconnected markets and exposure to gas-to-gas competition. Now well over 50% of European demand is met by short-term transactions across hubs or spot indexation, and even though the share of market based volumes is much higher in NW Europe than in CEE, liquidity is increasing across the board. Thus flexibility in the form of shorter length, reduced TOP volumes and increased spot TTF indexation have more value to major incumbents that must compete in the marketplace.

Even though it has been the trend thus far in the early stages of Europe's energy market liberalization, the assumption that spot prices are always cheaper than oil-indexed prices is not always accurate, particularly in times of high demand or shortage, the prolonged discrepancy we observed was largely a product of exceptionally weak demand and high oil prices. While there is great uncertainty over natural gas demand outlook for Europe, but oil prices are unlikely to reach their recent peaks anytime soon.

In 2008 as TTF continued to sink on poor fundamentals (low economic growth plus coal and RES-E competition), Brent crude began to surge from under $50/bbl in 2009 to well over $100/bbl in 2011, propping up oil-indexed prices after the normal 6-9 month lag. In spite of declining demand, TTF prices not only held from the 2011 winter but increased and stabilized (unusual for cyclical seasonal demand) into 2014 before dropping precipitously in the summer as seen in *Figure 17*. This peculiar dynamic can be attributed to an exogenous shock; the sudden spike in Japanese LNG demand following the

Figure 17 **LTC and spot TTF gas prices**



Source: Gaspool, IMF

to spot prices. In defense of market share, a majority of Russian legacy contracts have been readjusted in the past few years to include a standard of 15-20% spot indexation towards what is becoming a hybrid pricing system.

As long as spot prices are lower than oil-indexed prices, European retailers will offload the minimum TOP volumes (-15% of ACQ) and attempt to fulfill the rest of their sales through what is available on the market. This has been the norm in the previous low growth/high oil price environment. When hub-based prices spike above the LTC price, retailers will do the opposite and take the prescribed maximum level above the ACQ to sell to into the market. As these extra volumes are released into the market, spot prices come down. Both of these actions affect market prices and bring them closer to contracted prices, but in the absence of a viable market, like in most CSEE countries, adjustment to persistently lower market prices are dealt with in the parameters of the contract – typically through agreements for higher spot exposure and an easing of TOP levels.

On the whole there remains great uncertainty surrounding the future EU gas landscape. The sudden collapse in oil price helps gas importing countries under contract in the short term but demand remains weak and difficult to forecast, to a large extent dependent on policies governing renewable energy subsidies and the reform of Europe's Emissions Trading Scheme (ETS). Through the rapid expansion of global LNG spot trade the EU market now interacts with Asia and Latin America, making price spreads consequential for the direction of cargo movements.

Scenario analysis

Obviously Hungary is in a far improved position vis-à-vis Russia as it enters into negotiations for its next natural gas supply deal. More Austria-Hungary (HAG) capacity has been opened to competition, the Slov-

gary interconnector began operations in
d Central East South Europe Connectivity
ıas prioritized Krk LNG for its 2020 agenda.
e current context (not considering Krk LNG),
ine Hungary's renegotiation strategy by us-
ıario analysis of potential TOP volumes and
ıpacity utilization against market price and
ity outcomes. This specifically accounts for
ve effects of contracted volumes (high and
ario) and their point of cross-border deliv-
ιU, SK and/or UA) on wholesale price and
profit in Hungary to better illustrate this
us we can assess MVM's options for a new
nt with Gazprom that is expected to take
2018.

The estimated minimum universal supply threshold for household consumers In Hungary is assumed to be 2-3 bcm in this exercise. This represents the lowest level that must be secured even at a higher contracted price. A completely liquid market might obviate the need for even this threshold, but Hungary's marketplace is in its early stages and the promise of available alternative supplies still needs to be established. This underlines the counter risks for failing to secure a sufficient proportion of the total demand, including the volatility and uncertainty of the TTF price and regulatory risk limiting open and transparent access to interconnection capacity.

We can measure the relative effect of contracted ACQ levels and capacity options by comparing market price outcomes and profitability levels of the LTC holder. The following tables uses a high (8 bcm) and low (3 bcm) volume scenario against contractual delivery (a) limited to Ukraine and (b) available via all interconnectors, Ukraine plus HAG and SK>HU. The assumption reflective of this period and the preceding years is a competitive spot price that is lower than the long term contract price.

In *Table 1,* the values are defined as the spread between Hungarian and German market prices, meaning that smaller values are representative of more competitive and lower Hungarian prices. The table illustrates that the best outcome for consumers is a low volume contract that is limited to the

Table 1 **Estimated spread of Hungarian and German natural gas price**

Hungarian-German price spread (€/MWh)	3 bcm	8 bcm
Contract holder restricted to the Ukrainen entry point	2,7	3,3
Contract holder have access to SK>HU or HAG entry point	4,2	4,3

Table 2 **Profitability of LTC contract holder**

Profit level (m€)	3 bcm	8 bcm
Contract holder restricted to the Ukrainian entry point	-152	-574
Contract holder have access to SK>HU and HAG entry point	-29	-267

Ukrainian delivery point. This allows for the maximum capacity of competitively priced gas to be booked via HAG and SK>HU, while the contract holder would be restricted to the Ukraine entry point. Alternatively, the worst case scenario shown in the red box combines the high contract scenario with the use of all interconnectors, which allows the contract holder to crowd out competitively priced gas via HAG and SK>HU.

In *Table 2*, the company profit levels are approximated. The contract holder is losing money in every scenario because it is paying a higher wholesale price than it is selling to the market. Its optimal profit level is low volume procurement with the use of all available interconnectors. This limits exposure to wholesale purchases and still displaces some of the cheaper western gas by using HAG and SK>HU. On the other hand, the high contract volume limited to delivery via Ukraine results in significantly higher losses for the company since all other capacities are fully dedicated to competitively priced gas which undercuts the position of the contract holder. The important point is that a low volume contract limited to Ukraine delivery is still a significantly better alternative than either of the high volume scenarios.

Thus the low volume scenario limited to the Ukraine entry point would provide the lowest price and still minimize some of the losses of the contract holder. If this is the desired outcome, it would require intervention that significantly curtails or completely prevents the contract holder from booking HAG and SK>HU capacity for its imports.

Looking ahead, Hungary can also consider the potential for meeting part of its 3 bcm (minimum) long term needs from the Krk LNG terminal, which will compete directly with Russia's pipeline offerings. This is one of a group of priority projects that the CESEC working group has defined for accelerated infrastructure investment and is schedule to come online in 2020. The binding open season procedure was released in July and bids are to be submitted by September. It is an opportunity for diversification that MVM will have to take into account as it continues negotiations with Gazprom. There is certainly an opportunity for Hungary to diversify into this LNG, but the costs of this option still need to be studied and assessed.

Gas infrastructure – Regional priority projects in Central and South Eastern Europe

There are several EU documents declaring the need for more interconnectivity of the European gas networks, especially in South East Europe. Starting with the TEN-E Regulation[1], which sets the framework for defining projects of regional interest, to the more policy oriented and strategic documents like the Energy Union proposal[2] of 25 February 2015 or the Commission's European Energy Security Strategy[3] of 28 May 2014 that was followed by the Stress Test[4] in October 2014 - all point out the need for more gas sources and more interconnectivity for the European gas networks. The identification of the most important projects from a European and regional point of view also has a long history.

The Commission has drawn up a list of 248 PCIs[5] which may benefit from a streamlined licensing process / preferential regulatory treatment by national authorities and financial support from the EU's Connecting Europe Facility between 2014 and 2020. The European Energy Security Strategy has reduced the list to 33 key projects[6] that serve security of supply purposes and divided them into two groups: short term and mid-term priority projects. Two regions have specific attention because of their physical isolation: the Baltic states (BEMIP) and Central and South Eastern Europe (CESEC).

There has been substantial development in the Baltic states with commissioning of the Klaipeda LNG terminal in Lithuania in 2014 (not a PCI listed project) and there are works underway to connect Lithuania to Poland with strong EU involvement not only in financing but also in regulation. That project was the first example where neighboring states could not agree on cross border cost allocation, and ACER had to decide.

In the Balkans the South Stream and the Nabucco projects were aiming to open a new transmission corridor, but both of them failed in 2014 for different reasons: Nabucco could not secure a gas source and South Stream could not agree on the regulatory issues. In Dubrovnik on 10 July, 2015 15 EU and Energy Community countries in the Central and South Eastern European (CESEC) region[7] have agreed to work together to accelerate the construction of missing gas infrastructure links and to tackle the remaining technical and regulatory obstacles which hamper security of supply and the development of a fully integrated and competitive energy market in the region. There are 7 priority projects defined in the action plan:

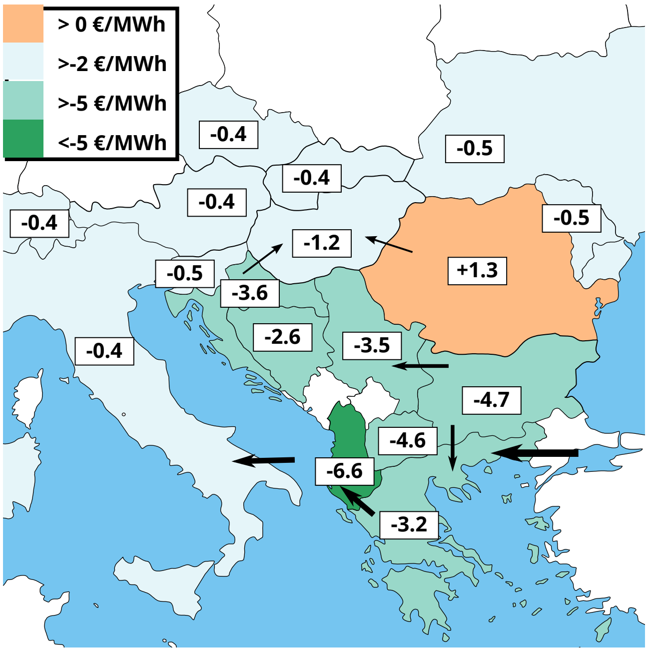
- Trans-Adriatic Pipeline (TAP).
- Interconnector Greece – Bulgaria,
- Interconnector Bulgaria – Serbia,
- Phased Bulgarian system reinforcement (reinforcements necessary to allow utilization of existing interconnections and new / additional interconnections being developed),
- Phased Romanian system reinforcement (reinforcements necessary to allow utilization of existing interconnections and new / additional interconnections being developed; including necessary reinforcements at those interconnection points in adjacent systems,
- LNG terminal in Croatia (with phasing potential),
- LNG evacuation system towards Hungary (corresponding necessary system development in Croatia)

The selection of these projects was supported with REKK gas market modelling. There have been four potential new gas sources identified for the region, which is now dominantly supplied by Russian gas. These new sources are: reverse flow via existing pipelines (from Western Europe), LNG (through Croatia or Greece), new Romanian offshore gas and Azeri gas through Turkey and distributed by the TAP project.

The modelling methodology compared the welfare increase created by these new sources when they are connected by new infrastructure to the markets where prices are the highest (indicating that there is a need for gas). Cluster A represents the corridor through a new LNG terminal on Krk (6.5 bcm) and related projects (interconnectors to the neighbors:

1 http://eur-lex.europa.eu/legal-content/HU/TXT/HTML/?uri=CELEX:32013R0347&from=HU
2 http://eur-lex.europa.eu/legal-content/HU/TXT/PDF/?uri=CELEX:52014DC0330&from=EN
3 https://ec.europa.eu/energy/sites/ener/files/documents/2014_stresstests_com_en_0.pdf
4 http://eur-lex.europa.eu/resource.html?uri=cellar:1bd46c90-bdd4-11e4-bbe1-01aa75ed71a1.0010.02/DOC_1&format=PDF
5 The map of PCI's is available at: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/
6 See the list in the annex of the Energy Security Strategy.
7 CESEC region consists of the following countries: Austria (AT), Bosnia Herzegovina (BA), Bulgaria (BG), Greece (GR), Croatia (HR), Hungary (HU), Italy (IT), Macedonia (MK), Moldova (MV), Romania (RO), Serbia (SB),Slovenia (SI), Slovakia (SK).
8 We define security of supply scenario as a loss of gas source due to supply cut (eg. a 100% curtailment of Russian flows via Ukraine in January) or extreme high demand (exceptionally cold winter)

Figure 18 **Modelled wholesale gas price change in the region due to CESEC priority projects (€/MWh) in a normal scenario**



The numbers depict the modelled yearly average wholesale gas prices change due to the implementation of the priority projects. The coloring of the countries indicate the magnitude of change in price level.

HR-SI, HR-HU, HR-RS and HR-BA). Cluster B is assuming 6 bcm/year new gas source from offshore gas fields in Romania, and related infrastructure to the neighboring countries (RO-HU, RO-MV, RO-BG and RO-UA). Cluster C is the Azeri gas delivered on TAP and connected to Bulgaria (GR-BG) and further to Serbia (BG-RS). Cluster C2 is the existing Greek LNG terminal connected to Bulgaria (GR-BG) and to Serbia (BG-RS). Top-down approach assumes all sources and all proposed (21 new) infrastructure projects in the region. Those projects that are underutilized in the modelling (no or close to zero flow) were excluded. Bottom-up scenario assumed all sources except for the Romanian offshore, since there is a risk of availability of gas from that source. In the bottom up scenario the most important projects were defined by modelling: the countries with the highest price difference were connected up to the point where transmission tariff between two adjacent markets exceeded the modelled wholesale price difference. The bottom up modelling identified those projects which are the most important from the priority project list outlined in CESEC's action plan.

The consumer welfare change was measured for each cluster of projects as a result of price decrease in the analyzed countries due to the new infrastructure. The results of the modelling are summarized in *Figure 19*.

LNG as a singular additional source (Cluster A and C2 only have LNG sources) brings substantially smaller consumer welfare surplus change than pipeline gas (Cluster B and C). Even though connecting the cheap Romanian market to its neighbours without additional offshore gas in Romania (Cluster C and the last column with bottom-up priority projects) results in a negative consumer welfare effect for Romania, the overall consumer benefits for the region are much higher than in case of LNG scenarios. It is important to note, that this is only one side of the equation: the cost of investment in offshore production + additional pipeline construction probably also exceeds the LNG terminal + evacuation pipeline costs. Implementation of all projects that are proposed to the Commission would result in huge consumer welfare gains (top down), but would result in underutilized infrastructure at a huge cost. When selecting the priority projects the Commission has also taken the maturity of the project and the cost of the infrastructure into consideration.

Figure 18 illustrates the regional price effect of implementing the CESEC priority projects (mentioned as bottom-up scenario before): except for Romania, where prices would increase slightly (1,3 €/MWh) as a consequence of ending the existing isolation of the Romanian market, in all other countries consumers would benefit from the price change. The largest price decrease arises in the Balkans: Bulgaria, Serbia, Macedonia and Greece experience 3,2-4,7 €/MWh decrease in the yearly average wholesale gas prices. These markets are relatively small, so the consumer welfare change is limited by the size of the market (see Table 1). Italy and Hungary, to the contrary, gain significantly in consumer surplus despite the moderate price decrease. Romanian consumer welfare losses are on the magnitude of 150 million € /year but the total consumer welfare change in the rest of CESEC is positive and nearly seven times higher (*Table 3*). It is also important to note here that Ro-

Figure 19 **Consumer welfare change due to the different project clusters**

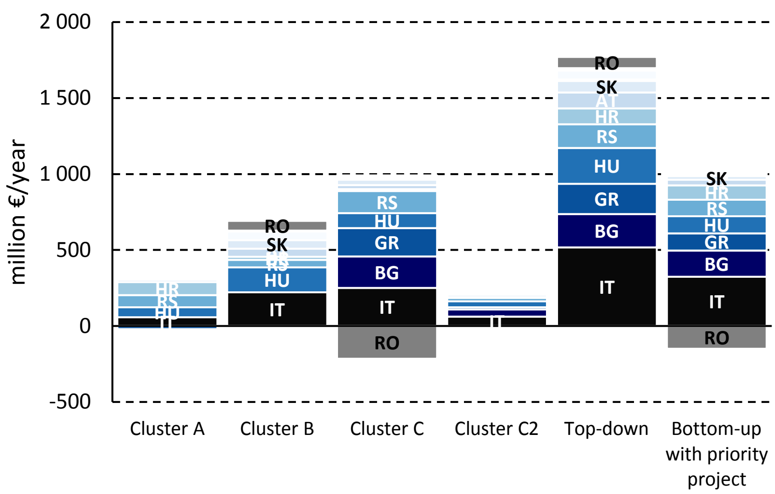


Table 3 **Yearly average wholesale gas price without the new CESEC priority projects (in the reference 2015) and in the modelled scenario with CESEC priority projects; and the consumer welfare change generated by the new infrastructure under normal market circumstances**

	Price (€/MWh)		Consumer surplus change in normal scenario (millio €)
	Reference	With the new projects	
AT	22.1	21.7	36.2
BA	27.0	24.4	4.2
BG	26.2	21.4	173.4
GR	23.3	20.1	112.3
HR	25.6	22.0	94.3
HU	24.7	23.5	111.9
IT	22.9	22.4	323.9
MK	27.9	23.3	7.3
MV	27.7	27.2	4.8
RO	20.5	21.9	-150.0
SB	26.7	23.3	109.8
SI	23.2	22.7	3.8
SK	22.7	22.3	24.4
CESEC total	23.0	22.2	856.2
UA	23.9	23.4	295.5
EU	22.1	21.4	1 377.0

mania is not entirely a victim of this co-operation: the Romanian producers would earn more due to the price increase, and this gain in producer surplus can be re-allocated – by taxation for example - partly to the consumers.

In *Table 3* the first column lists the yearly average marginal wholesale gas price for the modelled countries. In the reference there is only the existing pipeline, storage and LNG infrastructure in place (plus those that are in the last phase of construction, eg. the Polish LNG). In our modelling we experience a slightly higher gas price in the CESEC region than in the EU, which is in line with the reality that we experience. We also see that those markets that are better interconnected to the Western European market (AT, SK) and those that have access to the LNG market (GR) have lower prices, while those that rely on one single source are more expensive. In the second column, with new infrastructure and sources in place, the 4,1% margin of CESEC prices above the EU average price in the reference is reduced to 3,7%. In the last column the consumer welfare is measured as the price decrease multiplied by the gas consumption in the country, which is the monetization of the consumer surplus change for one gas year. Although the majority of the consumer welfare gains are realized in the CESEC region, Ukraine would also benefit from the new infrastructure. It is important to note that in larger markets the benefits are usually magnified.

In order to test the results in the case of a supply disruption we monetized the effect of new infrastructure investment using a simulated disruption scenario. In this so called security of supply (SOS) run, we assumed a 100% disruption of gas supplies through Ukraine in January. The results are similar to the normal run; the new projects help mitigate the price effects of the supply shock and the same countries that benefited in the normal run also benefit here (*Table 4*). In the SOS run we compare the annual and the January price under the disruption scenario without the projects (reference SOS) and with the projects. Without the projects in January, the price in Bulgaria, Macedonia, Serbia and Bosnia would sharply increase (above 40 €/MWh) as a result of supply disruption, but with the projects no country would experience a January gas price above 35 €/MWh in the CESEC region. The results show that the projects have an important role to play in a SOS situation. Several sensitivity runs were executed to

Table 4 **January average wholesale gas price without the CESEC priority projects (the reference SOS 2015) and in the SOS scenario with CESEC priority projects and the consumer welfare change generated by the new infrastructure under 100% supply disruption in January through UA**

	SOS yearly reference price (€/MWh)	SOS reference price in January (€/MWh)	SOS yearly price with projects (€/MWh)	SOS January price with projects (€/MWh)	Consumer surplus change in SOS scenario (millio €)
AT	23.1	28.6	22.6	27.8	42.0
BA	29.6	42.3	26.0	32.5	5.9
BG	32.3	50.4	22.8	27.0	361.1
GR	23.7	26.8	20.7	25.0	106.7
HR	26.0	27.9	22.9	27.1	80.4
HU	27.3	37.4	24.7	29.1	254.7
IT	23.4	26.9	23.1	26.9	236.0
MK	32.3	53.4	24.9	30.0	12.1
MV	30.6	38.4	29.3	35.0	12.4
RO	21.2	25.3	22.8	27.1	-180.3
SB	28.6	40.3	24.5	30.5	131.4
SI	24.1	29.9	23.6	29.1	4.3
SK	23.8	27.7	23.4	26.9	23.8
CESEC total	24.0	28.5	23.2	27.3	1 090.5
UA	27.3	34.5	25.9	31.1	848.6
EU	23.1	27.1	21.9	24.9	1 679.6

test the robustness of the results, and some general conclusions can be easily drawn:

- It was always a small number of projects that generated the bulk of the benefits. There is no need to build too much infrastructure, but the right ones have to be built.
- The market integration effect of the new interconnectors alone justifies their need. The same projects that bring market integration would also solve the huge dependency problem of the CESEC region on one single supplier and route.
- The more sources that are available the larger consumer welfare can be generated.
- LNG is competing with pipeline sources in Greece: TAP delivered Azeri gas might crowd out the LNG, especially when long term contract obligations prevent trade reaction to market price signals.
- The top down approach leads to the same list of prioritized projects as the bottom up, except for interconnectors between Romania and its neighbors. The difference between the welfare gains is due to the availability of different new sources and the substantial increase in supply in the former.
- Some projects have similar regional effects: connecting Hungary with new Romanian offshore gas (RO-HU) or with the Croatian LNG (through HR-HU) are similar in the terms of regional consumer's welfare effect. The same applies for Serbia: the option of a new Azeri (or LNG) source from Greece through Bulgaria would have a similar effect as HR-LNG plus HR-RS. Again the availability of the new sources and the cost of building the necessary infrastructure should be instructive in making the final determination.

We hope that arriving at a regional agreement on the list of priority projects will be followed by implementation of these projects.

A fourth energy package? Summer proposals to amend EU energy market regulations

In July 2015 the European Commission published a package of proposals to amend the regulation of the energy markets. The "summer energy package" includes the modification of regulations governing the operation of the emission trading system and the application of energy labels, proposals contributing to the protection of consumers as well as their market participation, and the transformation of the operating model of the electricity market. Below we introduce the most important elements of the package and evaluate their likely impact.

First the new electricity market model drafted by the Commission is examined, focusing on recommendations that aim to enhance the market participation of consumers via distributed renewable energy that they produce and consume. In the second part of the article we inspect the climate change regulation. After reviewing the voluntary emission reduction commitments released before the Paris climate conference, the individual regulatory proposals meant to guide the EU to its 40% emission abatement target are assessed.

New electricity market design: vain hope or reality?

Early in the spring the European Commission (EC), still busy with the integration of national energy markets, indicated that it would soon draft a regulatory amendment to transform the operating model of electricity markets. In its February communication on the creation of the Energy Union the EC anticipated the reinforcement of the powers of ENTSO-E and ACER, the termination of regulated tariffs and the liberalisation of market mechanisms based on free price signals. At the same time it revealed its reservations with respect to capacity markets.[1]

The more detailed concepts regarding the transformation of the market model were published in the communication on „the new energy market design" this June.[2] Before reviewing the main elements of the proposal, it would be appropriate to make two statements concerning the publication. First, the schemes referred to in the communication are too immature to be considered as concrete regulatory proposals. Second, these ideas essentially contain nothing new when compared to prior statements made by the Commission. They should be viewed as the reinforcement of the current market model (brushing up previous proposals) rather than the introduction of a completely new scheme.

The need for a new market design is justified by the explosive growth in the share of renewables and the challenge posed to system operation that is more and more difficult to manage. Owing to weather dependence the unpredictable nature of wind and PV capacities are difficult to fit into a system where traditionally it has been the task of baseload and peak power plants to align actual electricity production with the passive consumption curve. This is even more problematic as the profitability of flexible capacities is undermined by the suppressed electricity prices and the low capacity utilisation rates driven by the increasing share of renewables, ultimately hindering investments into those power plant capacities that would offer much needed flexibility. At the same time the expansion of renewable generating capacities is feasible only through immense state subsidy programs. The required investment is not ensured on a market basis due to the difficulties of keeping the schedule and selling the generated electricity in the market.

The above problems can be addressed in two distinct ways. The first is the answer applied in the Anglo-Saxon world which creates capacity markets (or brings some other capacity mechanism to life) to ensure that there is always sufficient flexible generating capacity to maintain the security of supply. The alternative solution makes the markets more flexible by increasing the role of intra-day markets - connecting national balancing energy markets that provide sharp price signals to facilitate demand side adaptation.

The Commission chose the latter option, which is often perceived by casual observers as a sign of further liberalisation of electricity markets and the curtailment of market distorting regulatory interventions. This characterisation, however, is rather inaccurate as it becomes evident from the more detailed description of the proposal; the flexibility of the markets cannot be achieved without powerful - and sometimes market distorting - regulatory interventions.

1 A Framework Strategy for a Resilient Energy Union with Forward-Looking Climate Change Policy. COM(2015) 80 final. Brussels, 25.2.2015
2 Launching the public consultation process on a new energy market design. COM(2015) 340 final. Brussels, 15.7.2015

The old-new market design intends to alleviate the problems associated with the fluctuation of weather dependent renewable capacities by stimulating cross-border electricity trade, bolstering intraday markets, integrating balancing energy markets and triggering demand side adjustment through spot price signals. The application of the above instruments can, in principle, ensure that an electricity market balance is sustained, allowing for the market-based installation of renewable generating capacities and thereby rendering capacity mechanisms and state subsidies as unnecessary.

The above concepts rest on the assumption that consumers equipped with smart meters and bound by contracts react to available real time price signals, reducing consumption when prices surge due to low renewable production or high consumption and shifting this missing consumption to periods of oversupply and low prices. Such consumer adjustment, however, is premised on market based prices and the abolition of retail price regulation, which is why it is referred to as the full liberalisation model.

On top of consumer adaptation, the second important element of system balancing is the substantial expansion of cross-border capacities and the growth of international electricity transmissions. This ensures that the excess production of renewable power in one region can reach another region with a low renewable ratio consequently reducing the need for intervention by system operators

The third pillar of the model is the development of liquid intra-day markets that enable real time trading which reduces the schedule-following disadvantage of renewable producers. They can also react to real time market prices by maintaining (even increasing) or reducing their level of production, further improving the stability of the system. In parallel with the establishment of intra-day markets that enhance the flexibility of supply, the integration of balancing markets and the development of regional system operator structures are also important elements of the Commission's initiative. Cross-border (regional) balancing markets allow for more optimal utilisation of existing reserve capacities, while raising system operation to the regional level (through the expansion and reaffirmation of the powers of ENTSO) is helpful for the more efficient execution of related tasks.

While the Commission encourages the model based on the above principles, it also firmly opposes the application of capacity mechanisms. The Commission does not have a legal basis to reject the decisions of member states concerning capacity markets that are backed by security of supply analyses as long as they do not create undue market distortion, especially in the British case which was approved by DG Competition. The Commission, nevertheless, puts two forms of pressure on members that intend to introduce capacity markets: first, it launched sectoral inspections to evaluate the capacity mechanisms under design or operation and, secondly, it urges the application of a uniform EU level security of supply assessment methodology.

The model that is dismissive of capacity markets and market distorting state subsidies, in fact, requires a number of regulatory interventions that can hardly be misconstrued as market liberalisation. One such piece is the expansion of cross-border capacities, whereby according to the prevailing regulation TSOs are mandated to make investments to meet the demand of market participants according to direction and capacity. Otherwise the Commission has limited tools to compel the electricity consumers of the member states to carry out and finance further investments. The other intervention addresses the creation of liquid intra-day markets: while in most member states the development of day-ahead markets already required substantial regulatory pressure (and in most cases TSO financing), what can we expect with respect to the intra-day markets offering even slimmer returns?

Capacity mechanisms created due to regulatory pressure clearly provide additional revenue for traditional power plants, and therefore their application is considered as state aid. In this sense, such markets are similarly artificial compared with the emission allowance markets, with prices heavily influenced by the regulator. The Commission, nevertheless, still rejects their introduction, primarily because they provide an advantage to traditional (fossil fuel based and nuclear) power plants and because there is a risk of market distortion due to the heterogeneous practices followed by the member states.

In the case of a properly operating CO_2 market, however, concerns related to fossil fuel based power generation are unfounded, since decarbonisation targets are automatically fulfilled in accordance with emission limits. Moreover, impairing the suite of instruments available for member states to guarantee their security of supply is not entirely fair. Ensuring the security of supply is the responsibility of member states, therefore it is understandable that accountable national governments resent the Commission's pursuit of its energy policy with EU instruments that are outside of the control of member states.

The most uncertain piece of the model envisioned by the Commission is demand side adaptation. While communications praise the new agreement with consumers, their empowerment and their active role in electricity markets, it is quite uncertain whether consumers are indeed ready and able to assume this role. If demand side adaptation, network development and the deployment of market infrastructure fail to meet expectations while the power plant capacities providing flexibility are not pursued either, the EU will pay a heavy price for its mistake.

"Own consumption?" Commission recommendations concerning renewable energy produced for self-consumption

As a result of renewable energy support policies, the volume of decentralised electricity produced in small, often household size power plants has escalated in a number of countries in the past few years. A large portion of this growth - among others, also in Hungary - is provided by photovoltaic (PV) units connected to medium and low voltage distribution networks.[3] As a result of the price decline of the technology, the unit cost of PV generation crosses the level of grid parity in an increasing number of countries. Therefore the unit cost of electricity production per kWh - including investment costs - falls below the price of electricity purchased from the grid.[4] In such cases it makes more sense for the consumer to use the electricity generated by its own small power plant than buying power from the grid, but this also assumes that the subsidy scheme provides incentives for own production by offering a lower compensation for electricity fed into the network than the volumetric component of the retail electricity price. This is because consumers with a small power plant are not exempted from paying the fixed network fees, and the cost savings due to own generation combines the energy fee and the volumetric network usage fee. As an annex to the summer energy package, the European Commission made recommendations by describing best practices with respect to three self-consumption related questions: 1) facilitating the active participation of consumers in the electricity market, 2) contribution to network costs, and 3) compensation for self-consumed electricity and power fed into the grid.[5]

According to the recommendations, the active participation of consumers in the power market can be encouraged by the simplification of permitting processes and by the support of investment funds where needed. The flexibility of the consumption of prosumers (consumers that generate electricity with micro power plants) can be enhanced through instant price signals and the establishment of local storage systems. Utilising the services made available by smart meters and smart networks can boost the network integration of small power plants, in addition to increasing the demand side flexibility of consumers.

The relevance of the second issue is highlighted by the fact that system operators in countries with a higher share of PV penetration are losing network-use revenue because of the increasing ratio of electricity produced for own consumption. An argument in support of the exemption from the payment obligation of volumetric network use fees is that locally produced and consumed electricity does not impact the grid, while large power plants do not have to pay network use fees after they feed energy into the network. An argument against the exemption, however, is that the revenue of DSOs declines with the surge of PV generation (especially, when the ratio of fixed fee components is low), while in transformation districts with higher PV penetration additional investments may be needed to facilitate the network integration of PVs. Meanwhile - with a delay corresponding to the period of price regulation - the missing revenues have to be made up by the consumers without PV, likely comprising the lower income segment of society. In order to confront this problem, a number of member states have recently introduced measures that force PV producers make a higher contribution to network costs. In the Flemish region of Belgium and in Italy, for example, a capacity based network fee was introduced for specific categories of size, while in Portugal a payment obligation based on a pre-set formula is introduced immediately after PV capacities exceed 3% of the total capacity.[6] The document recommends the development of a tariff structure that contributes to the achievement of both renewable and energy efficiency targets. This is not an easy task since the more equitable network contribution of PV systems is incentivised by the fixed fee component, while energy efficiency measures are triggered by the volumetric fee component. A contribution scheme set as a function of network impacts is deemed acceptable by the Commission if it considers both the positive and the negative network effects of decentralised generation. As long as the level of their penetration

3 At the end of 2014 PV made up 99.8% of the 69 MW of household size small power plant capacity. Source: MEKH (2015) 2008-2014 data for small power plants not requiring a permit („Nem engedélyköteles kiserőművek adatai 2008-2014.")
4 http://www.leonardo-energy.org/sites/leonardo-energy/files/documents-and-links/pv_grid_parity_monitor_-_residential_sector_-_issue_3.pdf
5 Best practices on Renewable Energy Self-consumption, SWD(2015) 141 final, 15.7.2015
6 Best practices on Renewable Energy Self-consumption, SWD(2015) 141 final, 15.7.2015, page 8.

is low, the operation of small power plants is beneficial for the distribution system since it reduces the load on transmission lines and network loss. The installation of larger scale, locally concentrated PV, however, may face technical limitations, possibly requiring reinforcement of the network with the replacement of specific network elements and appliances.[7] The technological challenges and the additional costs burdening distribution companies can be mitigated to a degree by maximizing the local consumption of this generated electricity, especially during peak hours, since the sizing of networks is based on maximum system load.

Finally, the document makes recommendations regarding the support mechanisms that are today still indispensable for the installation of small power plants. Among the member states at the moment there are two basic approaches governing the support for the small power plant segment, which are in constant flux following the fall of PV system prices. Feed-in-tariff (FIT) systems are applied in Germany and the UK, while in Romania the green certificate system will also be replaced by this scheme in the near future for the capacity category below 500 kW. In addition to the tariff provided in exchange for the power fed into the network, an initial premium is also paid after the generated electricity that is directly consumed, prompting PV operators to produce primarily for self-consumption. As grid parity is reached, the premium can be abolished, while the value of FIT can also be gradually reduced below the retail price.

The other widely applied support scheme is net metering, under which the electricity beyond immediate consumption that is fed into the network can be "withdrawn" within a specific period (e.g. a year or a month), and the payment obligation is calculated based on the balance of supplied and withdrawn electricity within the period. This system is favourable for the consumers and easy to understand, but its widespread application, nevertheless, can create problems. The above mentioned loss of network use revenues can accumulate substantially with the application of annual net metering, especially if net purchase from the grid is close to zero as a result of PV sizing, while for the most part PV operators are using the grid for storage. This is why Denmark, the Netherlands and Belgium, and even some of the pioneering states in the US were forced to restructure their net metering schemes. Moreover, the value of electricity can differ between the times of supplying and withdrawing the electricity, potentially generating substantial excess costs for the entities obliged to assume control of the supplied electricity. The Italian „net billing" system copes with this problem by registering the actual value of electricity as opposed to its volume within the period of net metering. The amount saved can be used for future consumption or even transferred to other users.

Thus the Commission considers those systems to be the most appropriate to compensate electricity fed into the grid at market value while also incentivizing own consumption. According to the document, these systems already offer commercial and industrial consumers an alternative worth considering in some countries since larger PV systems - assumed to have been built at a lower unit cost - are capable of achieving a high ratio of own consumption. The direct market participation of a large number of small producers may entail notable transaction costs that could be addressed and reduced through market aggregators. The constant monitoring of the price development for small power plants and their impact on the electricity grid is an important task in order to ensure cost efficiency and avoid excessive support. The application of net metering would be limited by the Commission to the initial period of the adoption of the technology, supplemented by transparent and regular reviews (planned in advance) that avoid retroactive modifications. Furthermore, the Commission is interested in getting small producers accustomed to making adjustments to market conditions by approximating the price they receive in line with the wholesale price of electricity.

In addition to the adverse features listed in the document, the net metering system applied in Hungary does not further the proliferation of demand side response since it promotes own consumption within the net metering period as opposed to immediate use. Moreover, given the availability of network "storage", the operator is not interested in local, on-the-spot energy storage. An additional problem is that net metering - a disguised cost to consumers without PV - provides a support without expiry and without differentiation amongst beneficiaries based on size or customer category. The present incentive mechanism does not consider the level of initial investment support either, resulting in excessive support in some cases. Given these conditions one wonders if replacing net metering with a FIT system is a good choice. As the study prepared by REKK for the Hungarian Energy and Public Utility Regulatory Authority reveals, the current version of net metering was probably introduced too early, since it does

7 On the technological challenges of DSOs see e.g. Dániel Horváth (2013) Decentralised electricity generation from the perspective of the distributor (Decentralizált villamosenergia-termelés az elosztó szemszögéből, in Hungarian), Elektrotechnika, 2013/12, 16-18.

not provide sufficient support due to a rather long payback time for most households and small enterprises. Sector experience suggests that for the last few years investment grants have been much more instrumental in promoting the installation of PV systems than the expected benefit from net metering.[8] The contribution of solar cells to total gross final consumption was about 0.2% in 2014 (in contrast with the 5-6% or higher figures of say Germany, Italy and Greece), indicating that in Hungary we are still only at the beginning of the potential upswing of investments. The results of the calculations carried out by REKK highlight that, considering total financing costs and expected administrative costs, it may be more sensible to apply a modified version of net metering until 2020, which would differentiate between systems of different sizes by delineating appropriate periods of support and accounting for the value of investment grants that were provided. The gradual introduction of a fixed network cost element would also be a reasonable contribution to the costs of network maintenance and development, in line with the rate of decline of technological costs so that investor appetite would not diminish With the gradual reduction of the period of support, eventually the termination of the support could also become feasible. Transforming the current regulation to a net billing system similar to the Italian regime could be a suitable measure to provide incentives for demand side adaptation if needed.

Climate change commitments in preparation for the Paris Climate Conference

One of the most tangible results of the preparations for the Paris Climate Conference to be held at the end of 2015 is the so called INDC[9] list which contains the national GHG reduction targets of specific countries. The list has been gradually expanding since February, starting with the first commitments in the spring (Switzerland, EU, Norway) that has now altogether reached 25 countries alongside the European Union that have committed to national/EU emission reduction targets in order to slow climate change. The list includes, among others, the USA, China, Russia and Australia.

The comparison of commitments is not an easy task since based on the initially accepted methodology[10] the countries can set their targets in different ways. The commitment can take the form of a percentage emission or CO_2 intensity reduction relative to a base year or future reference value (hereafter Business As Usual, BAU scenario), or the achievement of a fixed emission level by the end of a given period. Additionally, the pledge can cover the whole economy or specific sectors, and it may be limited to carbon dioxide or extend to all GHGs. Most targets apply to year 2030, but some of the commitments are valid for 2025 or 2050. The chosen base years also differ, the year of reference is usually 1990 or 2005, but in some cases 2010 or 2013 have been selected.

Most developing countries chose emission reductions relative to the BAU scenario, which often implies an increase in absolute terms but can still represent a substantial contribution to climate change mitigation. The methodology used for setting targets also called attention to the importance of climate change adaptation, therefore a number of countries completed their adaptation strategy as an annex to the INDC.

With respect to four prominent participants, REKK inspected the previous forecasts of their future emissions. Under the scenarios of the 2014 World Energy Outlook of the International Energy Agency (IEA), annual average CO_2 emission rates are published for the 2012-2040 period. These are not directly comparable with the commitments, but we can still easily see that for China and Russia only the most stringent scenario brings about a decline in absolute terms, while the EU achieves real emission reduction even with current measures.

The three scenarios examined by the IEA are:

- Current Policies: the expected annual emission reduction based on measures adopted by mid-2014
- New Policies: in addition to current policies, this scenario also considers those measures that are still only under recommendation, but which the future implementation is probable
- 450: this scenario assumes a combination of measures through which it can be achieved with a probability of 50% that in the long run the global average temperature does not increase by more than 2 °C compared to pre-industrial times.

Based on the studies made jointly by Climate Analytics, PIK, Ecofys and the New Climate Institute,[11]

8 The economic impacts of the penetration of household size small power plants and recommendations to amend the regulation. REKK analysis prepared for MEKH. June 2015. The analysis assumed 1 GW of installed PV capacity for 2020.
9 intended nationally determined contributions
10 http://unfccc.int/resource/docs/2014/cop20/eng/10a01.pdf#page=2
11 http://climateactiontracker.org/assets/publications/briefing_papers/CAT_EmissionsGap_Briefing_Sep2015.pdf
http://climateanalytics.org/files/cat_g7_gap_briefing_june2015.pdf

Table 5 **The 2014 emission reduction scenarios of IEA and the current emission reduction commitments**

	IEA WEO 2014* - CAAGR (%)			INDC
	Current policies	New policies	450	
USA	0.2	-0.7	-3.4	26-28% CO_2 emission reduction by 2025 compared to 2005
China	1.6	0.7	-2.9	Annual CO_2 emission will reach its peak by 2030; 20% of energy production from low carbon sources by 2030; output per unit of GDP to be reduced by 60-65% by 2030 compared to 2005.
EU	-0.5	-1.4	-3.2	40% CO_2 emission reduction by 2030 compared to 1990
Russia	0.6	0.2	-1.6	25-30% CO_2 emission reduction by 2030 compared to 1990

** Only applied to emission from the combustion of fossil fuels*
source: IEA, UNFCCC, http://www.theroadthroughparis.org

the INDCs of the G7 and the EU together anticipate emission reductions[12] by 2025 and 2030 that are equivalent respectively to 20% and 30% of the cuts needed to limit the rise of global temperature to 2 °C. Given that these countries together are responsible for 30% of global emissions, their commitments have a substantial impact on total emissions. The study notes that more ambitious targets are needed to achieve an appropriate level of emission reduction.

While we are not in a position to compile a quantitative comparison, it is safe to declare that the United States, China and the European Union have all committed to moderately ambitious targets. Using the calculations of Climatenexus[13] China's pledge on CO_2 intensity is more or less equivalent to the emission reductions of the New Policies scenario of the IEA. Barack Obama envisaged an obligation for power plants to cut emissions by 32% by 2030,[14] which would indicate a serious dedication by the US within climate policy. Based on the regulation currently in force the emissions of the United States would rise for the next few years, but the full implementation of the Climate Action Plan announced by Obama would result in a 10% emission reduction by 2025 compared to the 1990 level, which is much closer to the 14-17% of the INDC. The present EU regulation would lead to a 23-35% reduction compared to 1990 emissions, requiring additional measures in order to reach the targeted 40% ratio. The commitments of Russia, on the other hand, cannot be viewed as „fair" from the perspective of burden sharing (according to the above studies).

Based on the calculation of the studies the above commitments result in 53-57 and 55-59 $GtCO_2$ emissions for 2025 and 2030, respectively, but the targeted level requires another 12-15 and 17-21 $GtCO_2$ of reduction. Countries with significant contribution to global emissions that have not yet made a commitment include India, Brazil, Saudi-Arabia, South Africa, Turkey and Ukraine. All in all, looking at the combined impact of all of the pledges that have been made by the end of the summer, we are still far away from the targeted emission reduction necessary to limit the rise in average temperatures to 2 °C.

The reform of the EU emission trading system

The proposal to amend the Directive (EC 2003/87) on the EU Emission Trading Scheme (ETS)[15] is also part of the July energy package of the European Commission. The proposal was preceded by the climate and energy policy agreement for the period until 2030, adopted by the Council of Europe in October 2014. The proposal is part of the regulatory efforts to reform allowance trading, the key milestones of which include the launch of backloading (shifting allowances to future ETS periods) and the creation of the Market Stability Reserve. Both instruments aim to make the carbon price of emission trading more predictable, while moving it to an equilibrium price that is higher than today.

The new proposal, published in July 2015, aims to meet a number of climate policy expectations. First, with the proposal the Commission wishes to establish the main elements of the legal framework necessary to achieve a 40% GHG reduction by 2030. The proposal was scheduled for this summer by design, since the Commission can use it to demonstrate a positive, more dedicated European commitment in support of a global climate policy agreement at the Paris summit at the end of the year. Second, the present emission allowance trading system is to be transformed by the proposal so that it would result in a more predictable, more efficient carbon price range during the fourth trading period of 2021-2030, preferably running higher than today. A third inten-

12 Based on the burden distribution proposals that envisage the „fair" contribution of these countries
13 http://www.theroadthroughparis.org/resources/china-announces-climate-offer-ahead-paris-talks
14 New York Times through energiainfo
15 COM 2015/337

tion of the proposal is a more transparent and more efficient system for the free allocation of allowances to industrial facilities. Lastly, the fourth priority of the Commission has been the promotion of a more robust development of technological innovation.

The current, brief review recaps the recommendations for each of the previously mentioned four themes, detailing the new and the continuing parts of the regulation, as well as the specific provisions applicable to member states with lower average income, important from the perspective of Hungary.

The main instrument for the 40% reduction of GHG emissions is an increased rate with which the annual supply of allowances is narrowed. While the number of issued allowances is reduced by 1.74% per year until 2020, the rate of reduction will increase to 2.2% from 2021. This will ensure that by 2030 the ETS sectors provide 43% of the pledged GHG emission reduction (while the figure for non-ETS sectors is 37%). Another important rule is that at least 57% of the allowances are to be allocated through auctions, thus the proposal retained the current ratio for auctioning. The generated revenue can be used by governments quite flexibly: they can finance the more widespread production of renewable energy and contribute to social measures facilitating low carbon-dioxide emissions or international commitments.

Another important element of the scheme is that 2% of the auction revenues are channelled into a so called Modernisation Fund, to be distributed among the 10 new Eastern European member states for allocation to a corresponding number of additional allowances to domestic companies. 7.2% of this supplement is available for Hungary, and only Poland (43.4%), the Czech Republic (15.6%) and Romania (12%) enjoy a more advantageous position on the list of supported new member states.

The second "pillar" targets the development of a more predictable carbon price pathway, and several of the proposed measures belong here. During the fourth ETS period a reserve for new entrants would be created to be supplied from several sources. 250 million allowance units would be transferred to this fund from the unused Market Stability Reserve (MSR), and an additional 145 million units of allowances that have not yet been allocated during the third period would also be moved here. The reserve for new entrants would not only be used by new capacities, but would also be available for capacity extension. As a result of these transfers and the accelerated reduction of the number of emission allowances, according to the impact assessment of the proposal, an average carbon price of 25 Euro/tCO_2 could be secured for the fourth period (as opposed to the present price of 7-8 euros).

The third area of the proposal is the more transparent regulation of the amount of allowances that can be distributed to industrial sectors at no charge. According to the proposal, free allocation should be narrowed to those industrial sectors for which the risk of moving production outside of Europe (carbon leakage) is the highest. The recent regulation applied a correction factor to reduce the demand for excessive free allocation of allowances, the number of allowances to be handed to companies. Since this system was not predictable enough for the participants, the proposal also includes the modification of this method. At present 177 industrial sectors are eligible for 100% free allocation, since their risk of relocation was assumed to be high (based on their high energy use and exposure to intense export competition). The proposed regulation would limit the group of beneficiaries to 50 sectors, while the rest of the sectors would be eligible to receive free allowances equivalent to only 30% of their emissions. The sector specific (emission) reference values that are based on the number of allowances that can be allocated to a given sector have so far been calculated based on 2007-2008 data. These reference values would be re-examined every 5 years during the fourth compliance period, making it easier to track the market trends of the sectors. A pre-defined portion of allowances is also set aside for new entrants, to be used by market participants for the creation of new capacities or the expansion of production.

The fourth area defined within the proposal for the amendment of the Directive is the creation of the Innovation Fund. The fund would start in the fourth period with 400 million emission allowances, to be supplemented with an additional 50 million units transferred from the Market Stability Reserve of the third period. Therefore the fund would amass a value of some EUR 10 billion during the fourth period if the expected carbon price of 25 euros proves to be correct. In addition to carbon capture and storage, the fund may provide support for innovation related to renewable energy as well as development projects within energy intensive industries. The results of the ongoing NER 300 support program have been instrumental in the launch of the fund, to be continued with an expanded spectrum of developments and with more secure financing.

Finally, the proposal did not touch upon a wide range of issues falling under national competence. Member states continue to determine whether they compensate sectors facing high electricity costs, just as they can decide on the use of revenue from auctioning allowances, as the proposal is quite soft on these uses. The member states can also make their own decision with respect to granting exemptions to their SME facilities from the ETS obligations, as long as they commit to emission reductions on a scale comparable to the ETS. The favourable position of lower income member states is mostly retained, as they can use up to 10% of the revenue from allowance sales to boost their economic growth or to develop their energy infrastructure. Moreover, free allowances can continue to be provided to electricity sector suppliers if these companies commit themselves to the modernisation of the sector.

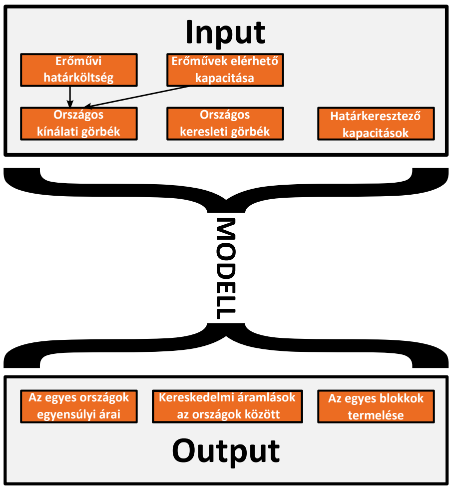
Altogether, the proposal can be viewed as a compromise that accurately reflects the status of the Commission: in order to ensure the proposal would be accepted, special provisions were granted to several member states. With respect to lowering the number of allowances, the previously disclosed percentage reduction was accepted by the Commission, while in case of free allocation more pronounced measures were proposed. The price for the substantial sum of money to be compiled through the Innovation Fund is the essentially unimpaired preservation of member state entitlement, and the untouched privileges left to new member states.

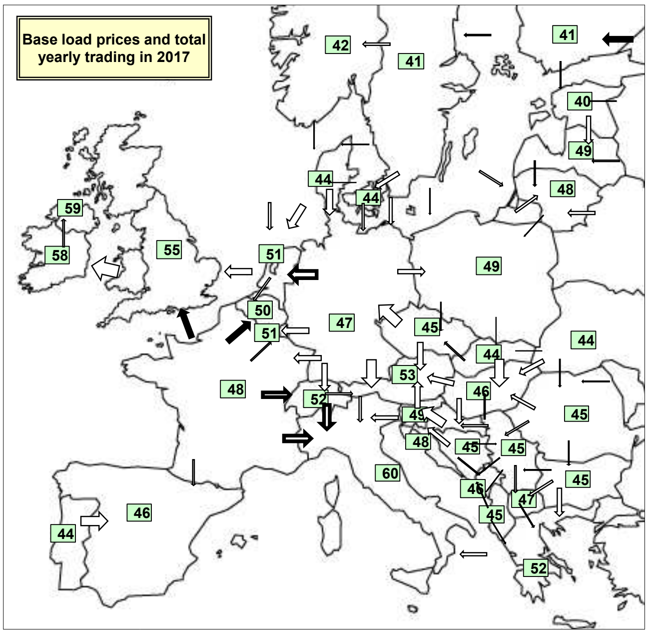
New REKK website

After 10 years, the REKK website is displayed in a new design. Content of the rekk.eu website is still availabe at rekk.hu.

EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

EEMM is the electricity market model of REKK developed since 2006 modelling 35 countries





ASSUMPTIONS

- Perfect competitive market
- The model calculates the marginal cost of nearly 5000 power plant units and the unique merit order for each country
- 12 unique technologies
- Includes future power plant developments
- Takes 85 interconnectors into account
- Models 90 reference hours for each year. By appropriate weighting of the reference hours, the model calculates the price of standard products (base and peak)

USAGE

- Provides competitive price signal for the modelled region
- Facilitates the better understanding of the connection between prices and fundaments. We can analyse the effect of fuels prices, interconnector shortages, etc. on price
- Gives price forecast up to 2030: utilizing a database of planned decommissionings and commissionings
- Allows analysing the effects of public policy interventions
- Trade constraints
- Assessment of interconnector capacity building

RESULTS

- Base and peakload power prices in the modelled countries
- Fuels mix
- Power plant generation on unit level
- Import and export flows
- Cross-border capacity prices

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Evaluating the TYNDP of ENTSO-E
- Assessing the effects of the German nuclear decommissioning
- Analysing the connection between Balcans and Hungarian power price
- Forecasting prices for Easterns and Southeast-European countries
- National Energy Strategy 2030
- Assessment of CHP investment
- Forecasting power plant gas demand
- Forecasting power sector CO2 emmissions

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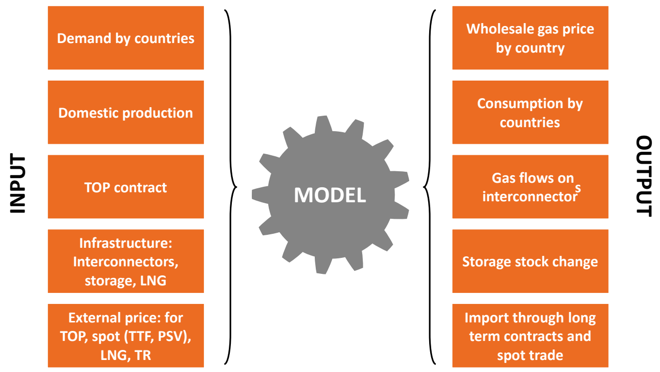
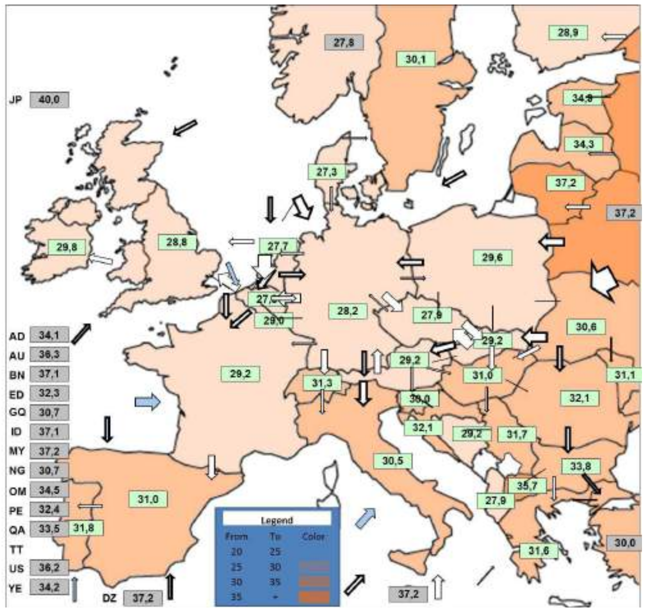
EUROPEAN GAS MARKET MODEL (EGMM)

EGMM is the natural gas market model of REKK developed since 2010 modelling 35 countries





ASSUMPTIONS

- Perfect competitive market
- Modelling period of one year (12 months)
- LTC and spot trade in the modelled countries, pipeline and LNG suppliers
- Physical constraints are interconnection capacities
- Trade constraints: TOP obligation
- Model includes domestic proiduction and storages
- Model calculates with transmission nd storage fees

USAGE

- Provides benchmark prices for the region
- Facilitates the better understanding of the connection between prices and fundaments. Eg. LTC market changes or storage changes.
- Price forecasts
- Allows analysing the effects of public policy interventions
- Analysing trade constraints
- Assessing effects of interconnector capacity expansion
- Security of supply scenarion analysis

RESULTS

- Gas flows and congestion on interconnectors
- Equilibrium prices for all countries
- Source composition
- Storage levels, LTC flows and spot trade
- Welfare indices

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Effects of the Ukrainian gas crisis
- Welfare effects of infrastructure investments (TAP)
- Regional security of supply scenarios and N-1 assessments
- National Energy Strategy 2030
- Regional storage market demand forecast

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