REKK FOUNDATION

HUNGARIAN ENERGY MARKET REPORT

Q4 2017

The REKK Foundation was formally established in March 2016 but its credentials, activities and purpose are centered on REKK's extensive experience from over 10 years of educational and regional forum activities.The mission of REKK Foundation is to create a professional European-wide public forum engaging government officials, industry players, regulators, consumers, journalists and other interested individuals to discuss energy policy issues at the Hungarian, regional, European and international level. Our goal is for the REKK Foundation to be the preeminent energy 'think-tank' of Central and South Eastern Europe.

In the first semester of 2017, the REKK Foundation organized several forums on the „Clean Energy for All Europeans" regulatory package. The first event of this series was the Winter Package Workshop in February, where the experts of REKK and the invited speakers summarized their understanding of the more than 400 pages regulatory proposal and the expected effects on the regional energy markets. On 30th May, REKK Foundation and the European Commission hold a regional energy policy forum on the electricity market integration, where presenters represented several top foreign institutions (ENTSO-E, Florence School of Economics, RAP, Energy Community). During the second semester of 2017, the REKK Foundation aimed to discuss future oriented topics at its forums: in October, the Jacques Delors Institute has presented its new study on Energy Transition in Budapest, in November the effects of PV development on Hungarian wholesale prices and the US sanctions have been discussed, and in December the new REKK Energy Futures have been launched.

In 2018, we will keep working on disseminating the latest energy policy research results, by inviting prominent speakers from abroad. The workplan for the first year consist of the following topics: The public funding behind successful energy innovation projects, The Future of Energy Storage, The latest results from the actual gas market modelling research projects and The Challenges and opportunities of EU-UA gas market integration.

For further details on REKK forums, please visit www.rekk.org!

Dear Reader,

We begin this issue with an overview of the most important energy market developments in the third quarter of 2017. This is followed by three articles delving further into the following instructive energy topics: trends in European wholesale electricity markets since 2015; a review the economics affecting district heating power plants in Budapest; and an analysis and outlook for the European gas storage sector.

In our first article, we review the central developments in European wholesale electricity markets since 2015, including the changes in electricity consumption, the composition of the installed power plant capacities and the fuel structure of electricity generation. We also investigate the dynamics of futures and spot market electricity prices, including the ratio of peak and off-peak prices, the frequency of price spikes and the experience related to the European renewable energy tenders, with subsidies in particular.

Our second paper approaches the topic of gas storage and the tension between the financial viability of the European natural gas storage sector and the security of supply value of these facilities. Following the publication of the European Commission's strategic document on the storage of natural gas, REKK dedicated a separate study on the security of supply role of the European natural gas infrastructure as well as the impact of the regulatory interventions intended to ensure the availability of storage facilities (storage obligations and strategic reserves). This article summarizes the most important conclusions of this study.

In our last article we put forth and assess the key 2016 economic data of power plants with a substantial role in Budapest district heating (Budapest Power Plant, Alpiq Csepel, MVM North-Buda Heating Plant), highlighting the different factors accounting for business performance, especially the impact of taxation on financial results. In addition to a detailed breakdown in the profitability of the respective power plants, we also expand on ways the EU and domestic regulatory requirements will materially impact future market opportunities of these power plants.

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Energy market developments

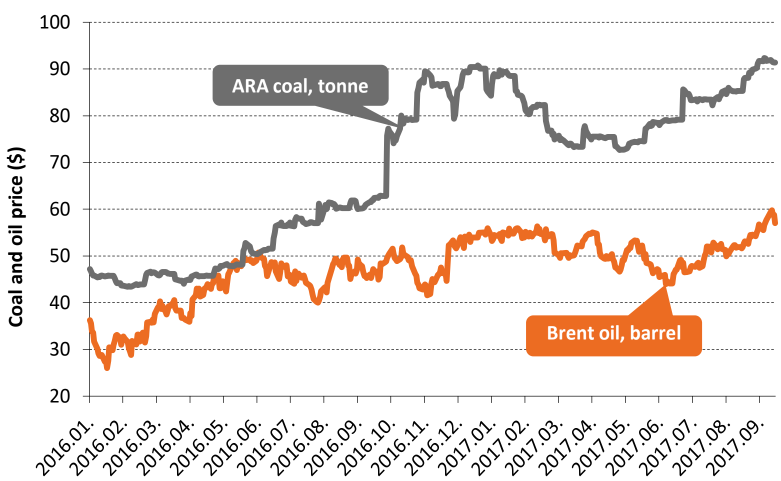
Q3 of 2017 witnessed a break in oil market stagnation that began early in 2017, with Brent prices rising 30% over the period to nearly 60 USD/barrel. Meanwhile, European natural gas market developments were muted with peaks in Asian LNG spot markets in late summer /early autumn not have any influence. Following low European gas prices at the beginning of the summer, there was a moderate uptick by the end the quarter with TTF spot prices closing at 17-18 EUR/MWh in September. European electricity markets were led by continuously growing international coal and EUA prices as well as concerns about the availability of French nuclear power plants. These factors resulted in rising futures both on European and Hungarian markets, with annual baseload trading at 46 EUR/MWh by the end of the quarter. The placid summer for the Hungarian natural gas sector was marked only by peaking Ukrainian exports and abnormally high injection levels.

International price developments

The November 2016 OPEC agreement cutting production by 1.2 million barrel per day combined with growing demand hit markets in Q3 of 2017, lifting Brent prices from 45 USD/barrel at the end of June to 59 USD/barrel by the end of September. OPEC announced in May 2017 an agreement to lower production levels through March 2018, suggesting that prices will not sink below 56 USD/barrel either in 2018 as some analysts predicted.

The rapid price hike on international coal markets that began earnestly in June continued in Q3, with ARA prices growing 15% over the period, exceeding 90 USD/t by the end of September to match prices at the end of 2016. The price growth was primarily induced by coal mining capacity cuts in China and a strong increase in demand. China's five-year plan for the period between 2016 and 2020 signals the closure of 800 million tonnes of outdated coal capacity. This is intended to cut excess coal mining capacities, contribute to the sector's consolidation, and reduce particulate air pollution caused by coal-fired power plants. However, production cuts coincided with unfavourable weather conditions, first dry spells that depleted hydro reservoir stocks, then heavy torrential rains and floods in July leading to further declines in hydro production. In this case, electricity demand propped up by steady economic growth and heatwaves required increased coal-fired power plant production leading to a need for Chinese coal imports thus adding upward pressure to international coal prices.

Figure 1 Prices of month-ahead EEX, ARA coal and Brent crude oil spot prices from January 2016 to June 2017



Source: CME, EIA

The dramatic price decline on international natural gas markets in the first half of the year ended in Q3. Owing to the mild weather and low demand in the USA, Henry Hub prices slid by 5% in Q3, while at the same time Japanese spot LNG prices catapulted by the end of the quarter with the JKM (Japan Korea Marker) up more than 50% from the summer at the end of September. The rise in Asian LNG spot prices was triggered by three factors: coal-to-gas switching in China's energy sector, rapid growth in demand, and delays in the maintenance works of Australian LNG infrastructure. Since China's gas consumption has risen to double Japan's in the last decade, its impact on spot LNG prices continues to grow. Although Chinese LNG imports still lag far behind those of Japan, spot LNG prices will soon become as dependent on changes of the Chinese demand as coal prices.

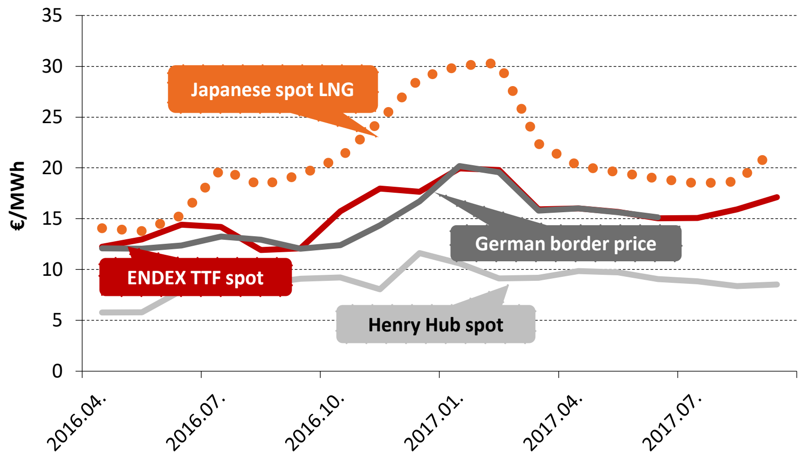
European natural gas prices rose more moderately than in Asia during Q3, reaching 15 EUR/MWh at the end of June and 17-18 EUR/MWh by the end of September. In July, NBP prices were relatively low owing to strong LNG deliveries to the UK, high Norwegian production and low demand. A rise in exports to the Continent, which accompanied with increasing production in Groningen, also put a lid on TTF prices. This depressed market environment began to tighten from August, triggered by production outages in Norway, drying up British LNG transports, and maintenance works first on Yamal and then on the Nord Stream pipeline in September, pushing up gas prices on the Continent.

Electricity futures market turned bullish in the summer after a bearish Q2. Increasing coal and EUA prices resulted in a rise in German year-ahead base prices by 13% in Q3, with a nearly 20-25% year-on-year increase in month-ahead, quarter-ahead and year-ahead base prices.

Day-ahead markets were led by temperature, renewable production and level of rainfall. Even with mild weather at the beginning of July, low renewable production and a delay in the maintenance of French nuclear reactors kept German day-ahead prices high, hovering near 36-37 EUR/MWh. However, later in the month growing renewable production and improved nuclear availability reduced spot prices to 30 EUR/MWh. Day-ahead prices remained soft until the second half of August, and then rose again to 36-37 EUR/MWh. In the first half of September, the market was pared again with prices accounting for 30 EUR/MWh, while fears over French nuclear capacity availability pushed day-ahead prices beyond 40 EUR/MWh, breaking a record by the end of the quarter.

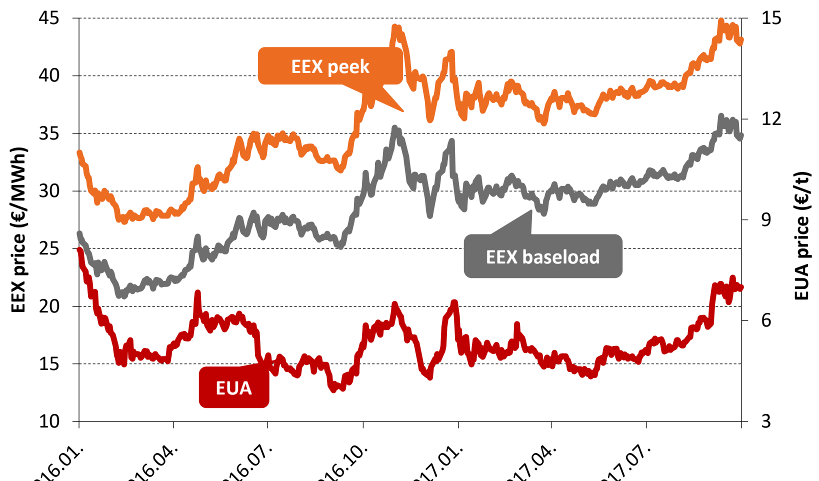
News on the inspection of French nuclear reactors continued to be monitored closely and drove the market, leading to growing prices both on futures and day-ahead markets. The most impactful news was the report of ASN (l'Autorité de sûreté nucléaire) on 16 August which revealed the existence of several irregularities in certain manufacturing files of Creusot Forge plant. Market players started to worry about possible delays in the restart of the given reactors scheduled for October and November, which led to a prompt 5 EUR/MWh jump in French futures (Q4-17 and Q1-18). With winter heating season approaching, fears resumed in autumn when EDF changed the scheduled restart date of several reactors.

Figure 2 Prices on select international gas markets from April 2016 to September 2017



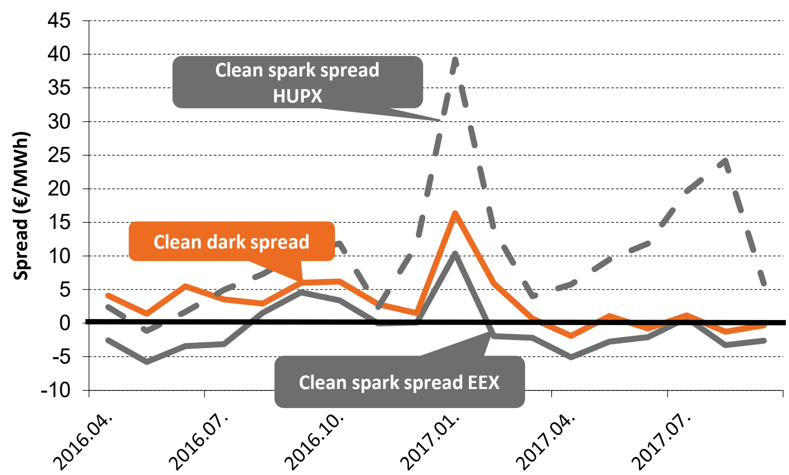
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 Prices of EEX year-ahead futures and CO_2 allowances (EUA) with December delivery from January 2016 to September 2017



Source: EEX, ICE

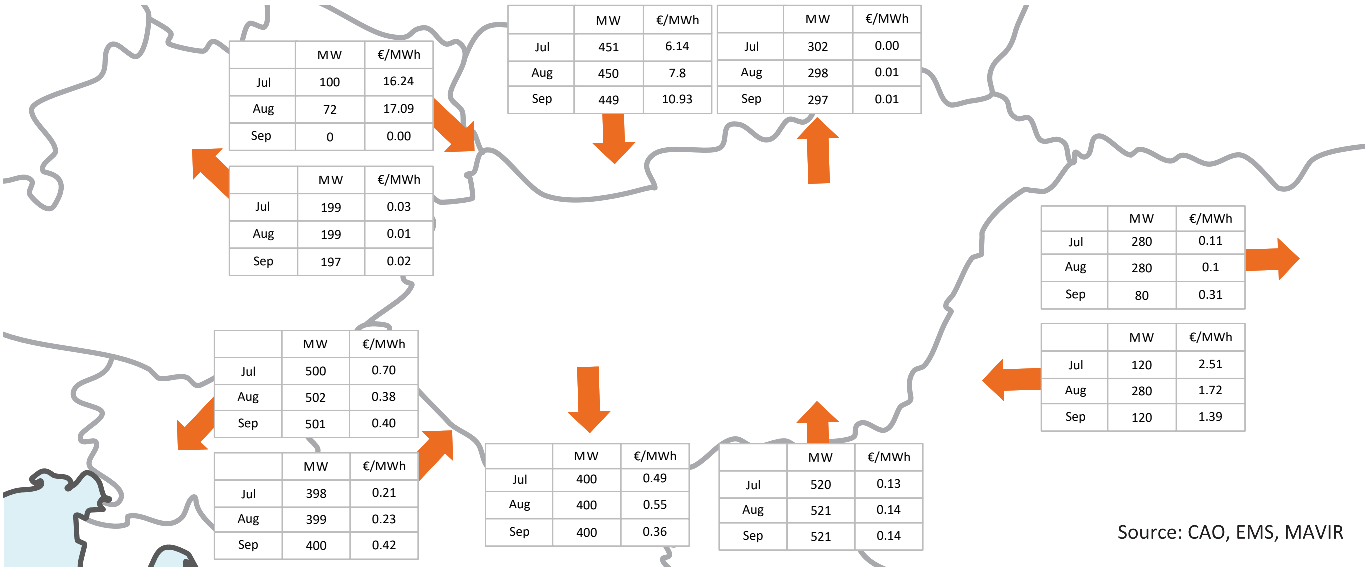
Figure 4 Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from January 2016 to September 2017



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

Note: Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, where the cost of production is added up 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. Calculations are based on spot baseload power prices on the German EEX exchange, Dutch TTF spot prices and ARA coal prices. The Figure shows the monthly averages ofthese two indicators calculated with day-head market prices, assuming 50% energy efficiency in the case of gas-fired power plants and 38% in the case of coal-fired ones.

Figure 5 Results of monthly cross-border capacity auctions in Hungary, Q3 2017



	MW	€/MWh
Jul	100	16.24
Aug	72	17.09
Sep	0	0.00

	MW	€/MWh
Jul	199	0.03
Aug	199	0.01
Sep	197	0.02

	MW	€/MWh
Jul	451	6.14
Aug	450	7.8
Sep	449	10.93

	MW	€/MWh
Jul	302	0.00
Aug	298	0.01
Sep	297	0.01

	MW	€/MWh
Jul	280	0.11
Aug	280	0.1
Sep	80	0.31

	MW	€/MWh
Jul	120	2.51
Aug	280	1.72
Sep	120	1.39

	MW	€/MWh
Jul	500	0.70
Aug	502	0.38
Sep	501	0.40

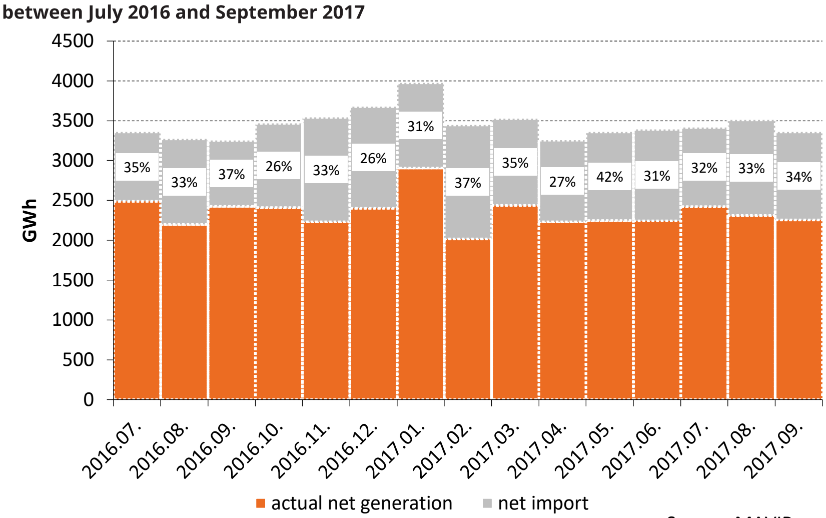
	MW	€/MWh
Jul	398	0.21
Aug	399	0.23
Sep	400	0.42

	MW	€/MWh
Jul	400	0.49
Aug	400	0.55
Sep	400	0.36

	MW	€/MWh
Jul	520	0.13
Aug	521	0.14
Sep	521	0.14

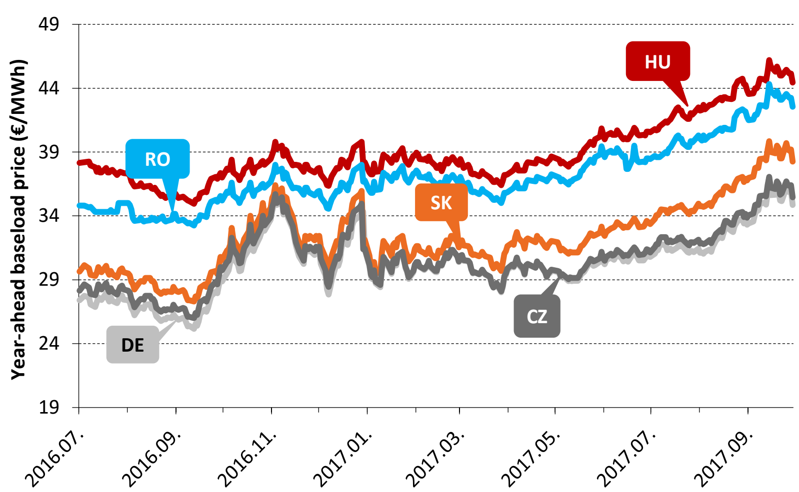
Source: CAO, EMS, MAVIR

Figure 6 Hungary's net electricity production and monthly net electricity imports between July 2016 and September 2017



Source: MAVIR

Figure 7 Year-ahead baseload futures prices between July 2016 and September 2017



Source: EEX, PXE

In the second half of September, French spot prices were consistently above 40 EUR/MWh, closing as high as 75 EUR/MWh in November, more than 5 EUR/MWh above UK.

European electricity prices were also strongly affected by rising EUA prices. In the first half of 2017, the production of the French and German nuclear power plants significantly lagged year-to-year with hydro production 40 TWh due to the low rainfall level. The shortage was covered by fossil-based production, primarily natural gas-fired power plants, leading to unanticipated overdemand for allowances. This demand was further promulgated by expectations for restrictions on available future EUAs with agreement between European Commission and the Parliament on terms for the market stability reserve that will accelerate the withdrawal of surplus emission allowances from the market in coming years. Together this led to a 40% rise in allowance prices within the quarter.

The gradual convergence between the German clean spark spread and clean dark spread during the first half of 2017 ended in Q3. The profitability of the two types of power plants equalized in July, while the clean dark spread exceeded clean spark spread by 2 EUR/MWh by the end of the quarter. Calculated on the basis of futures instead of spot prices, the profitability of gas-fired power plants is continuously improving: clean spark spread having started the year at below minus 8 EUR/MWh at the beginning of the year recovered to -0.45 EUR/MWh by the end of the quarter. The relative improvement in the clean spark spread was due mostly to the rise in coal and EUA prices.

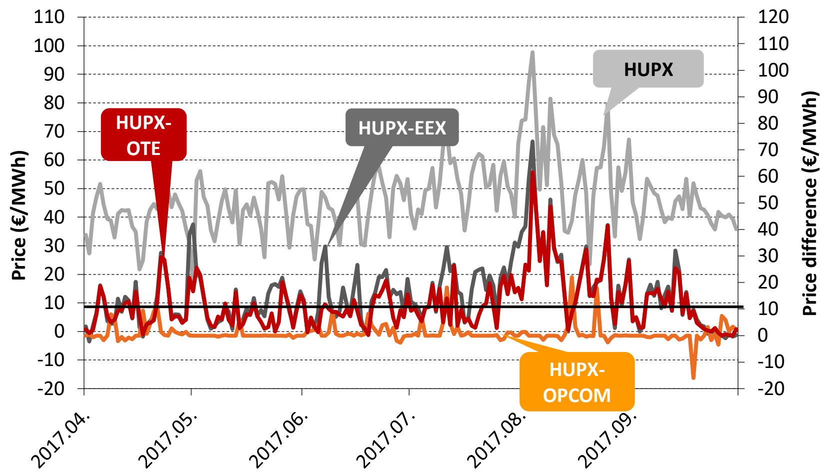
Overview of domestic power market

Austrian and Slovakian import capacity prices continued to rise in the summer. While average monthly Slovakian import capacity prices averaged 4 EUR/MWh in Q2, it doubled in Q3 to more than 10 EUR/MWh. The volume allocated to market players remained even with 450 MW auctioned in Q3 of 2017. Alternatively, Austrian TSOs did not offer any monthly capacities in September. Partly because less cross-border capacity was available, Austrian tariffs exceeded 17EUR/MWh in August. Auction prices on the monthly capacity auctions at the Romanian-Hungarian border sometimes moved above than 1 EUR/MWh but never exceeded 3 EUR/MWh. Little changed with respect to Hungary's southern borders, and in the absence of congestion tariffs remained low.

Domestic power consumption grew by 4% from the previous quarter due to higher year-on-year consumption at the end of July and beginning of August owing to the exceptionally long-running heat waves. At the same time domestic production was down 1.5% year-on-year leading to an 18% year-on-year rise in imports, and elevating the share of net imports to 32%.

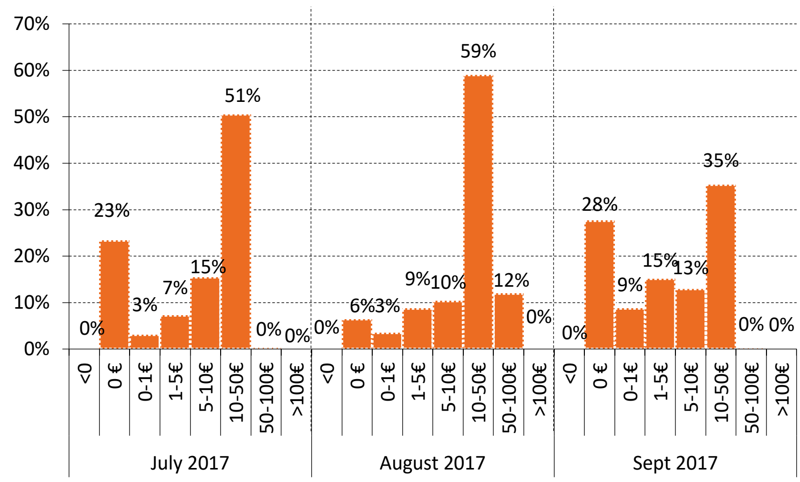
Both HUPX and other European year-ahead baseload futures continued to rise from May 2017 with a 16-20% growth in year-ahead baseload futures on the region's futures markets from rising natural gas and coal prices. By the end of September, the German-Hungarian spread was up to 10 EUR/MWh. In addition, HUPX futures exceeded OPCOM futures by 2 EUR/MWh by the end of Q3 (Figure 7).

Figure 8 Comparison of day-ahead baselaod prices on the EEX, OPCOM, OTE and HUPX exchanges between April and September 2017



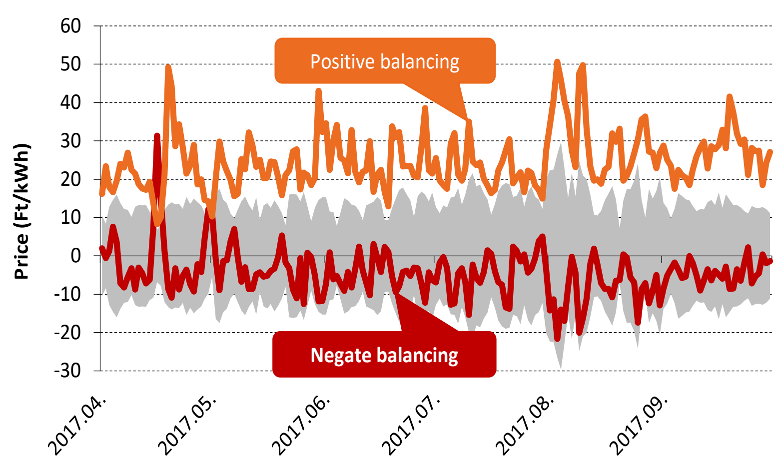
Source: EEX, OPCOM, OTE, HUPX

Figure 9 Frequency of various levels of price difference between the Hungarian and the Czech exchanges between July and September 2017



Source: REKK calculation based on OTE data

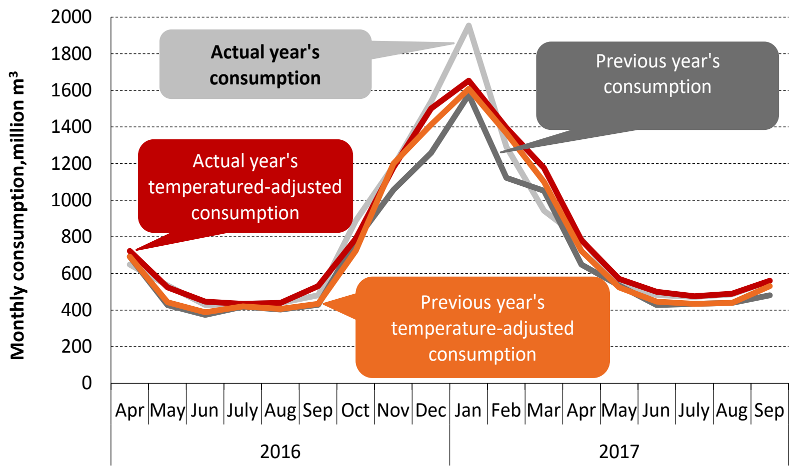
Figure 10 Daily average of balancing prices and spot HUPX prices, Q2-Q3 2017



Source: MAVIR, HUPX

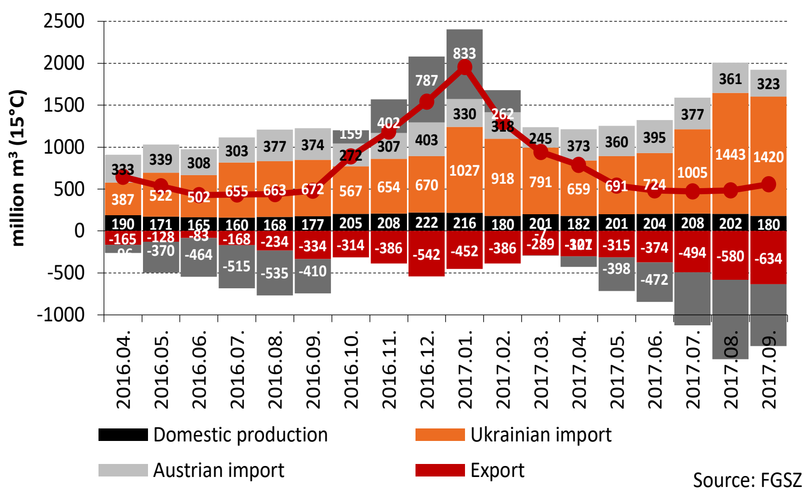
Note: The upper edge ofthe grey range in the figure is determined by the next day price ofHUPX, while the lower edge is the opposite ofthe same price. According to the Trading Rules ofMAVIR the rice of positive balancing power is limited to the next day price on HUPX, while the negative balancing power is constrained by the opposite ofthe next day price

Figure 11 Raw and temperature-adjusted monthly gas consumption between April 2016 and September 2017 compared with the previous year



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

Figure 12 Source structure of Hungarian gas market by month between April 2016 and September 2017



Source: FGSZ

Q3 saw two exceptional spikes in HUPX day-ahead prices. At the very end of July and beginning of August, day-ahead prices climbed to 100 EUR/MWh, while hourly prices exceeded 150 EUR/MWh in certain periods. Although summer consumption records were not broken, countries to the south of Hungary were seeking to import because of the drought across the Balkans. At the same time, there was a small decline in Hungary's import capacities from Austria and one block of Paks Nuclear Power Plant was not available due to scheduled maintenance. These facts led to day-ahead price spikes amounting to nearly 100 EUR/MWh, while German day-ahead prices could be observed near 30 EUR/MWh. There was another smaller peak in HUPX day-ahead prices a few days after 20 August reaching just under 80 EUR/MWh prices. However, the Hungarian premium remained very high compared to the German and Czech day-ahead prices averaging 18.4EUR/MWh, and 14.7 EUR/MWh, respectively on a quarterly basis.

The Hungarian-Romanian relationship was much tighter with an average margin less than 1 EUR/MWh.

In Q3, HUPX decoupled from Czech market prices, particularly in August, when day-ahead prices were the same only in 5% of the hours. Otherwise, the difference between the prices of the two markets varied between 10 and 50 EUR/MWh in nearly 60% of the hours (Figure 10). In 12% of the hours it was even higher, reaching 50-100 EUR/MWh. However, September brought closer alignment below 1 EUR/MWh in 37% of the hours and without any differences exceeding 50 EUR/MWh.

The wholesale price is affected by the costs incurred from the deviation of energy prices from 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 sequence for using the capacities is established according to the energy tariffs offered on the day-ahead regulated market. The system charges for balancing developed by MAVIR provide incentives for market participants to manage anticipated deficits and surpluses through exchange based transactions. For this purpose, the price of upward balancing cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing than the price at the exchange. In Q3, the average price of positive balancing exceeded 26 HUF/kWh was below the 2017 average price by 0.9 HUF/kWh. There were a few days in the quarter when the average positive balancing energy prices exceeded 50 HUF/kWh (Figure 11).

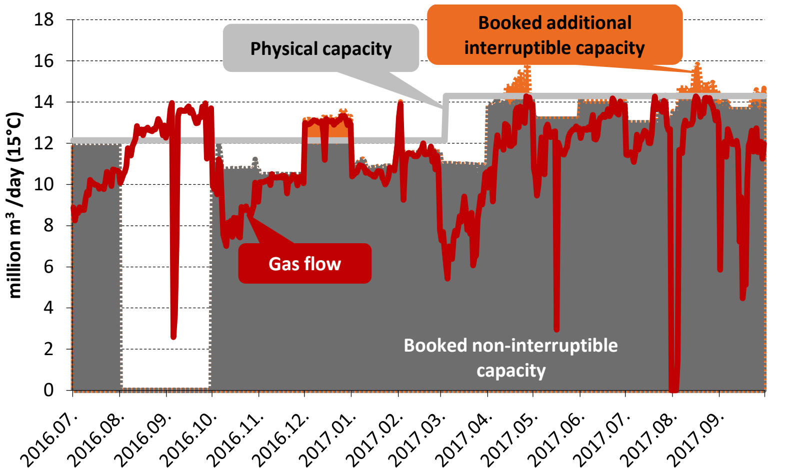
Overview of domestic gas market

Q3 saw a continuation of growth in consumption from the beginning of the year, 11% between July and September 2017 year-on-year, driven by the Q3 surge in economic growth which reached 4.1%. In the first three quarters of 2017, natural gas consumption rose by 11% (by 800 mcm), however, halve of this growth is attributable to the colder than average winter season.

However, the 164 mcm of summer consumption growth is dwarfed by the sky-rocketing Ukrainian exports and domestic injections. Q3's exports to Ukraine jumped to 1.7 bcm, 1 bcm more than the year before, while the volume of natural gas injected in Hungarian storage amounted to 2.3 bcm, 60% above average summer injections.

Increasing exports and intensive injection did not result in any changes in Austrian imports. In Q3, nearly the same natural gas volume was imported from Austria year-on-year. The interconnection capacity utilization of the Mosonmagyaróvár entry point was close to 81% compared to 94% the previous year, suggesting that the market could not make use of the 18% physical capacity extension completed in March 2017.

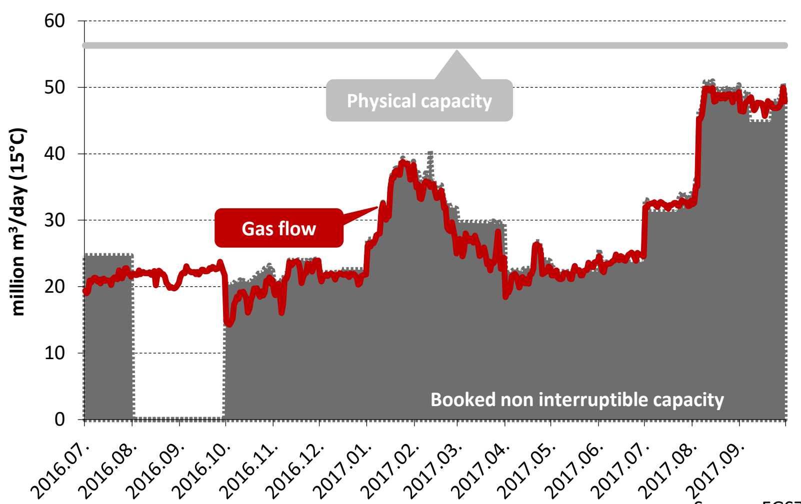
Figure 13 Transmission at the Mosonmagyaróvár (Austrian border) entry point between July 2016 and September 2017 together with booked interruptible and non-interruptible capacities



Source: FGSZ

Note: Data on contracted capacities in August-September 2016 are not available on FGSZ website

Figure 14 Transmission at the Beregdaróc (Ukrainian border) entry point between July 2016 and September 2017, together with booked interruptible and non-interruptible capacities



Source: FGSZ

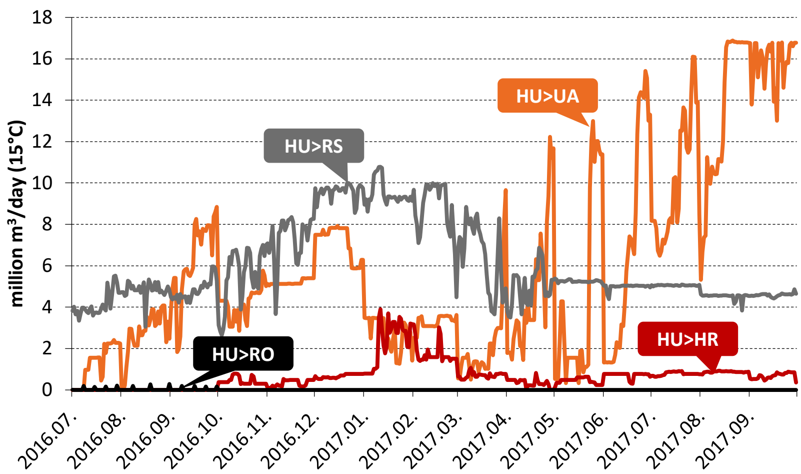
Note: Data on contracted capacities in August-September 2016 are not available on FGSZ website

The majority of the excess demand accounting for nearly 2 bcm was met by Ukrainian imports. The interconnection utilization of Beregdaróc rose sharply to 80-90% at the beginning of August. A daily rate of 50 mcm was transported from Ukraine in August and September, a significant part of which (average 13 mcm per day) was shipped back to Ukraine.

The August peak in Ukrainian exports pushed quarterly Hungarian gas exports to a record-breaking 1.7 bcm. In Q3, shipments to Ukraine accounted for 70% of the total Hungarian natural gas exports, while Serbian exports remained at normal levels, with 434 mcm accounting for 25%. Croatian exports remained inconsequential, 71 mcm, while there were no transports to Romania.

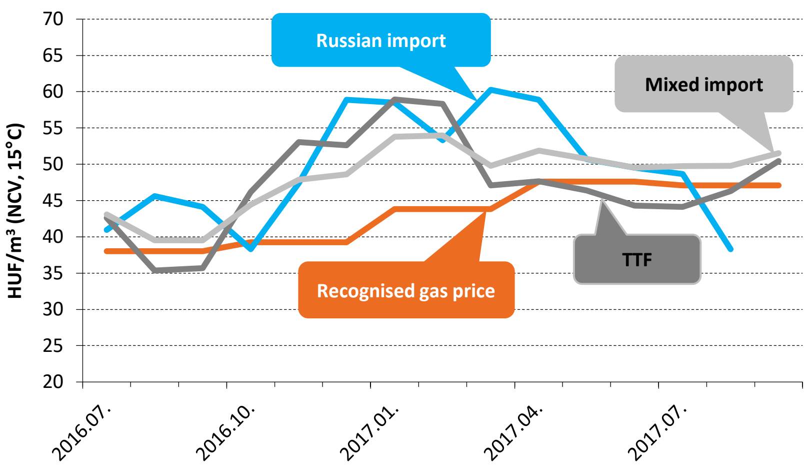
As alluded to above, the exceptionally high Ukrainian exports and injections in domestic storages were caused by from excess transport not from Austrian but Ukraine. As Figure 16 depicts, Russian natural gas import prices plummeted in August (by 17%) below TTF prices, making Russian sources much more attractive.

Figure 15 Hungary's natural gas exports to Ukraine, Croatia, Romania and Serbia from July 2016 to September 2017



Source: FGSZ

Figure 16 Recognised natural gas selling price of universal service providers and elements of the gas price formula between July 2016 and September 2017



Source: REKK calculations based on EIA, Gaspool and Eurostat data

Overview of the European Wholesale Electricity Sector

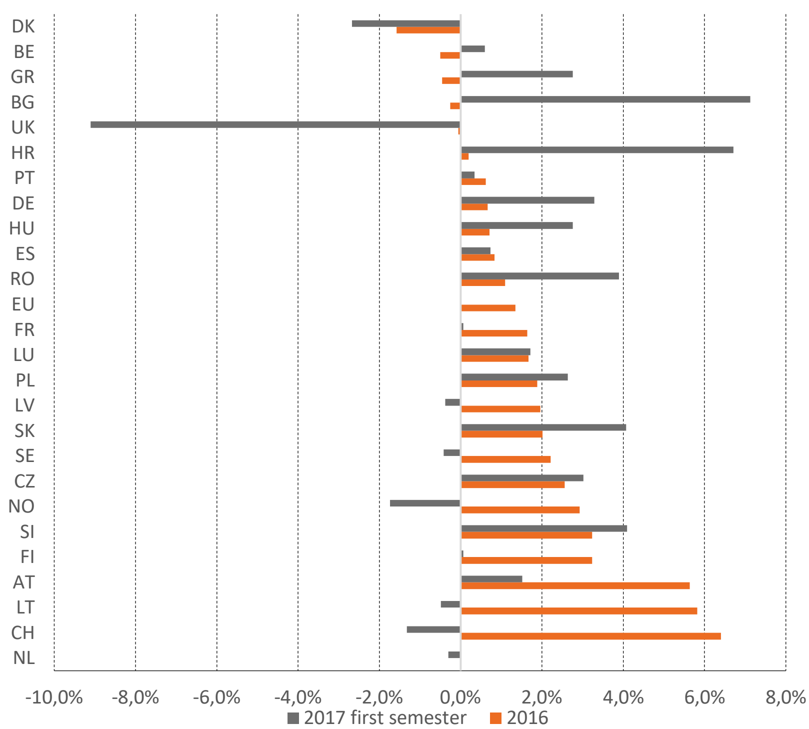
In this article, we highlight the main trends and developments in the European wholesale electricity market since 2015, looking at variations in electricity consumption and the fuel mix, the latter driven by relative fuel prices, and economics of renewable electricity policy and subsidies, leading to the following key conclusions:

- The growth rate of consumption remains moderate. In 2016 electricity consumption in Europe increased by 1.3% year-on-year, and consumption in the first half of 2017 did not significantly differ from the first half of 2016. For the seven years since 2010 consumption has increased by only 1%, although underwritten by substantial annual volatility.
- Capacity investments continue to be dominated by subsidized renewable projects. Of the 24.5 GW of new capacity installed in Europe in 2016, 86% was renewable, with wind power accounting for 51% (12.5 GW) and solar PV 27.7% (6.7 GW).
- Gas has reemerged following several difficult years of decline for the industry, with gas-based production growing by about 50% over the past year compared with 2015. At the same time lignite-based electricity production fell by 10%. Growth in wind and solar power production was offset by the 10% decline of hydroelectric power generation.
- The decline in prices across European electricity market exchanges over the period finally reversed in October 2016, and have risen up to now. In Hungary, wholesale prices were regularly in the neighborhood of 50 EUR/MWh, rising beyond 100 EUR/MWh at times
- The required support for renewable energy sources has declined precipitously, with offshore wind parks now approaching parity with fossil fuel production. Overall, tenders are becoming cost competitive on a market basis, with the premium for PV narrowing to 10-20 EUR/MWh and even lower for German and Spanish wind.

Trends in electricity consumption

Electricity consumption of EU countries has exhibited strong volatility in the last few years. According to aggregate figures, EU consumption increased by 1.3% between 2015 and 2016. Consumption in the first half of 2016 was roughly the same as the first half of 2017, even though in January 2017 Europe-wide temperatures were considerably below the long-term average.

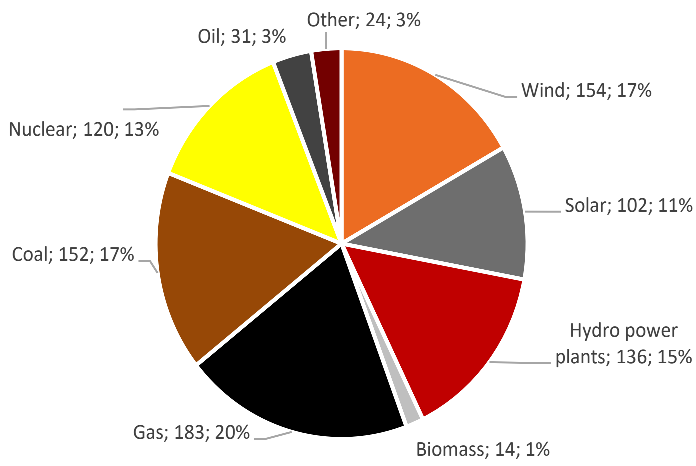
Figure 1 Changes in electricity consumption in the first six months of 2016 and 2017 in EU countries, %



Source: ENTSO-E Transparency Platform

Note:The EU average includes the 22 EU countries for which data of appropriate quality was available

Figure 2 The breakdown of Europe's power plant capacities per technology in 2016, GW



Source: EWEA (2017)

The proportion of subsidized renewable energy projects of all new capacity additions has been growing over the past decade; it was only 20% in 2000 compared to 86% in 2016. In 2017, renewable power plants accounted for 44% of the total installed capacity, comprised most significantly of wind (17%), hydro (15%) and solar (11%). Of the non-renewable resources, only the share of natural gas-based capacities has resisted decline over the past decade with a net capacity increase of nearly 50 GW. The proportion of coal-fired power plants fell to 152 GW in 2016, 17% of the overall capacity portfolio, while nuclear capacity declined slightly in the past decade.

This fits into the broader picture of modest long-term growth in electricity consumption in the EU27 – only 1% since 2010 - with annual fluctuations of up to 1-2%. During 2015/2016 the largest increase in consumption took place in Lithuania, Switzerland and Austria. The 6% rise of the latter two countries may be explained to a large extent by the increased capacity utilization of their pumped storage hydro facilities. Growth in Germany during this period was below the EU average (0.7%), but data for the first half of 2017 already indicates a significant increase in consumption (3.3%). The UK experienced nearly a 10% drop due to warmer temperatures that were 1.7 °C higher than the same period of the previous year. Removing the UK, European consumption would have increased by 1.3% in the first half of the year. In Hungary, similarly to most Central and Eastern European countries, there is a rise in consumption on bar with and sometimes above that of Germany.

Change in installed generating capacities

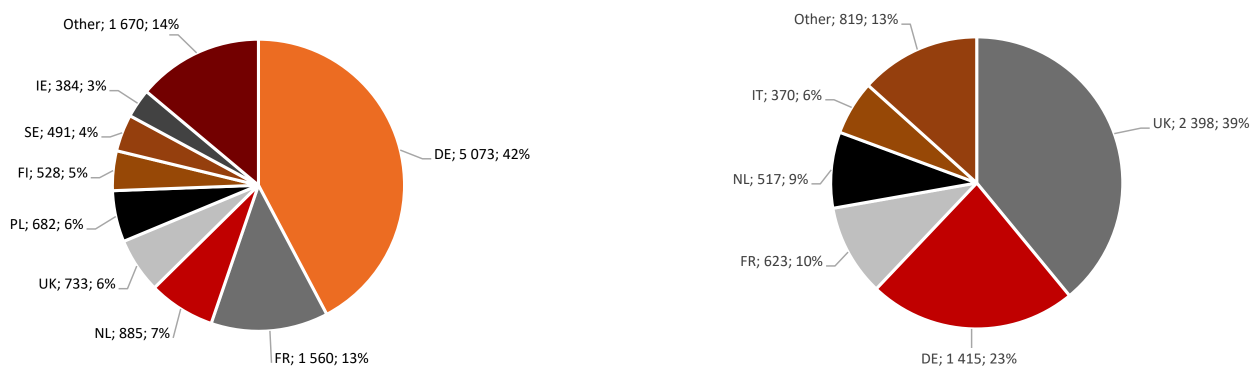
Based on data from the European Wind Energy Association (EWEA), 24.5 GW of new capacities were installed in 2016, about 6.3 GW less than a year earlier. 86% of new capacities were renewable, with wind adding 12.5 GW (51% of total new capacity) and solar adding 6.7 GW (27.7% of new capacities). The capacity of gas fired power plants grew marginally by 3.3 GW, while only 0.2 GW of new coal-fired power plants were added. In addition, more than 7.5 GW of coal-fired and 2.3 GW of gas-fired capacity was closed, marking an overall decline in fossil fuel based installed capacity in Europe.

Table 1 Wind and solar capacities in European countries in 2016, MW

	Wind	Solar	Total	Share
DE	50 019	41 111	91 130	35.4%
ES	23 075	5 491	28 566	11.1%
IT	9 257	18 983	28 240	11.0%
UK	14 542	11 547	26 089	10.1%
FR	12 065	7 134	19 199	7.5%
SE	6 519	182	6 701	2.6%
NL	4 328	1 911	6 239	2.4%
DK	5 227	860	6 087	2.4%
PL	5 782	182	5 964	2.3%
BE	2 386	3 423	5 809	2.3%
PT	5 316	486	5 802	2.3%
GR	2 374	2 611	4 985	1.9%
RO	3 028	1 351	4 379	1.7%
AT	2 632	1 077	3 709	1.4%
IE	2 830	2	2 832	1.1%
CZ	281	2 083	2 364	0.9%
CH	75	1 681	1 756	0.7%
BG	691	1 064	1 755	0.7%
FI	1 539	15	1 554	0.6%
NO	838	0	838	0.3%
SK	3	591	594	0.2%
HR	422	147	569	0.2%
LT	493	75	568	0.2%
HU	329	238	567	0.2%
EE	310	4	314	0.1%
SI	3	257	260	0.1%
LU	58	142	200	0.1%
LV	63	4	67	0.0%
Total	**154 485**	**102 653**	**257 138**	**100.0%**

Source: EWEA and SolarPowerEurope

Figure 3 European wind and solar installations in 2016, MW and %



Source: EWEA and SolarPowerEurope

As we have seen, the most significant growth comes from solar and wind power plants. If we breakdown individual countries, the dominance of Germany is evident, with 35% of the total weather-dependent capacity, approaching 100 GW at the end of 2016. Spain, Italy and the United Kingdom are next, with about 10-11% a piece. Interestingly, the share of solar plants in the UK is quite substantial today due to a favorable new support scheme that sparked installed solar capacities in a brief 2-3 year period. Sweden also ranks highly with 7.5% of total European intermittent capacities as a result of its 6.5 GW of wind capacities. Despite a rapid rise of solar power plants, Hungary is still placed toward the end of the list.

As far as new European intermittent capacity buildout in 2016, Germany was the clear frontrunner in wind power, accounting for 42%, followed by France (13%), the Netherlands (7%), the United Kingdom (6%), Poland (6%) and Finland (5%). The order of magnitude changes for solar, with almost 40% of the new capacities built in the United Kingdom, a country with a relatively low number of sunny hours, moving ahead of Germany (23%). Significant new PV capacities were also built in France (623 MW), the Netherlands (517 MW) and Italy (370 MW).

The composition of electricity generation in the EU

Over the past two and a half years significant changes have taken place in the composition of European electricity production. Coal-based production fell by 10% to 237 TWh in 2016 from 265 TWh in 2015. In this time lignite and brown coal have stagnated while gas-fired production has increased by nearly 50% owing to favorable and recovering clean spark spreads.

Although nuclear capacities did not change significantly, production fell by almost 7%, mainly as a consequence of extensive French maintenance required by the regulator, knocking off 39.2 TWh of production during the inspected period.

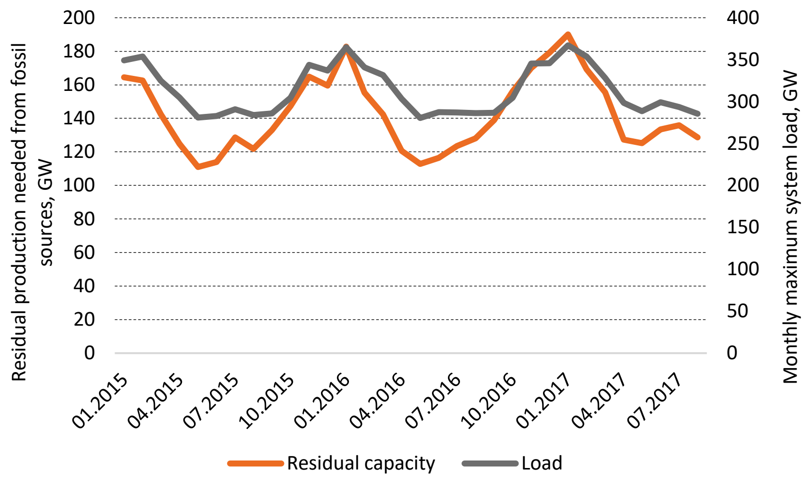
Table 2 Generating mix within the EU* for 2015, 2016 and September 2016 and August 2017 (TWh)

	2015	2016	September 2016 to August 2017	Change, 2016/2015	Change. Sep 2016 to Aug 2017 /2016
Biomass	53.0	55.4	56.8	2.4	1.4
Hard coal	265.4	236.7	239.0	-28.6	2.3
Lignite and brown coal	279.4	270.8	280.9	-8.6	10.1
Natural gas	156.9	193.2	231.4	36.3	38.2
Unspecified fossil fuel	20.1	24.2	27.0	4.1	2.8
Nuklear	680.4	648.8	638.2	-31.6	-10.6
Wind	239.2	236.1	250.4	-3.1	14.2
Solar	67.0	68.2	71.9	1.2	3.8
Hydro	383.6	416.3	368.1	32.7	-48.1
Other renewable	3.9	4.5	4.7	0.6	0.2
Other not specified source	317.4	311.2	290.4	-6.2	-20.8
Total	2466.2	2465.3	2458.8	-0.9	-6.5

Source: ENTSO-E Transparency Platform

Note: Only 18 countries had data of sufficient quality in the database, therefore the table does not include the production of the full EU
For the unspecified fossil category, no information is available in the database whether it is lignite, coal, natural gas or other fossil resources

Figure 4 Monthly maximum residual capacity and monthly maximum system load in the EU, GW



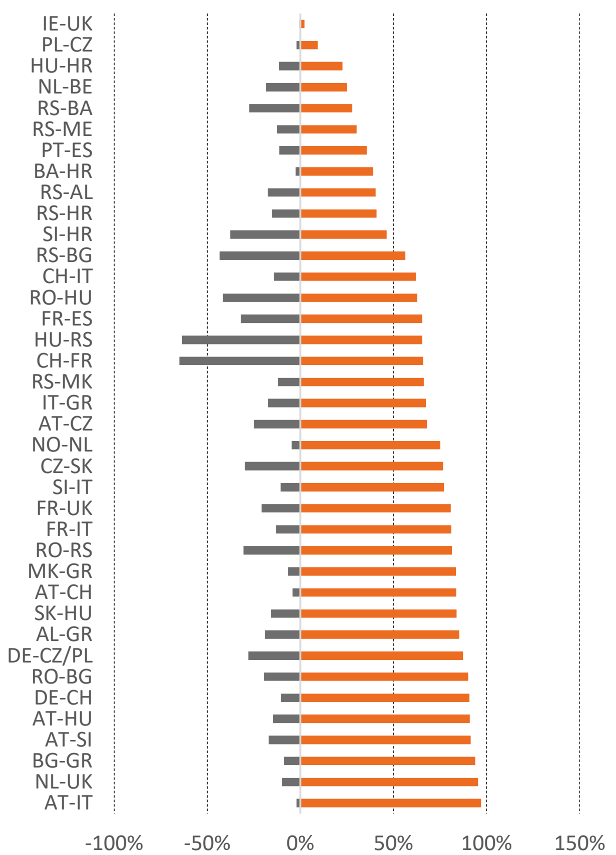
Source: ENTSO-E Transparency Platform

and a projection of residual production needed from fossil sources. This is a critical segment of data because fossil fuels continue to play a key role in the development of wholesale electricity prices. Although the summer system loads have been increasing steadily in recent years, the maximum system load still takes place in the winter with the whole European market taken together, typically 15-20% higher than the summer on average. The discrepancy is further accentuated by greater utilization of solar production in the summer during heat waves that contribute to high consumption and peak load. As a result, the demand for fossil-based generation is about 60% higher for winter peaks than summer peaks. Consequently, electricity prices are typically higher during the winter period when lower efficiency fossil capacities are in greater demand.

While renewable electricity production rose significantly in 2016 year-on-year, based on data from the last 12 months it has regressed to 2015 levels on the coattails of hydroelectric power fluctuation. This skewed the source of output for the period between September 2016 and August 2017, with fossil fuel based production (31.7%) edging out renewables (30.6%) followed by nuclear generation (26.0%).

The hourly data for European countries allows for an assessment of the monthly maximum system loads

Figure 5 Average utilization rates of selected European borders in 2016 (%)



Source: ENTSO-E Transparency Platform

Cross-border capacities

Based on the Market Monitoring Report published by ACER, available cross-border capacity increased by 2.2% between 2015 and 2016, but there are significant regional disparities. The largest growth has taken place in the Baltic region and in the South-West of Europe, thanks to a new 2000 MW interconnector between Spain and France, a 700 MW transmission line on the Lithuanian-Swedish border and a 500 MW line on the Polish-Lithuanian border. Meanwhile capacity at the German-Czech border fell by 600 MW as a result of increasing loop flow.

In 2016 the largest volume of trade was registered on the German-Austrian border, exceeding 40 TWh, which is equivalent to the consumption of Hungary. The North-South "electricity corridor" is clearly outlined by such trade flows, also supported by significant trade on the French-Swiss, French-Italian and Swiss-Italian borders totaling more than 17 TWh.

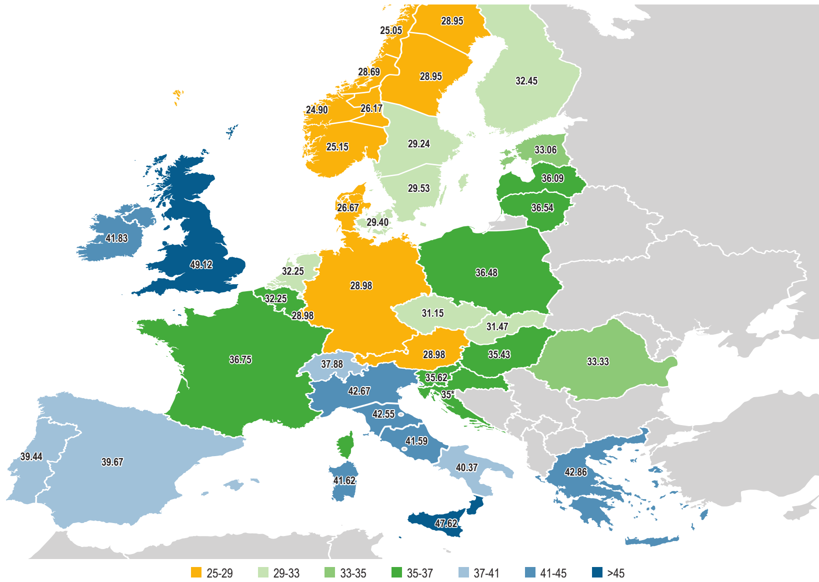
In fact the most heavily traded capacities were at the Austrian-Italian, Austrian-Slovenian, German-Swiss borders and along the Dutch-English subsea line where utilization was 90%. Two European borders maintained utilization rates over 60% in both directions - the Swiss-French and the Hungarian-Serbian - with significant difference between night and day flows.

Changes in exchange prices

In 2016, price spreads more than twofold emerge between European countries. The lowest prices were registered in the Nordic countries, especially Norway, while the highest prices were found in the UK due to the introduction of a CO_2 price threshold of almost 30 EUR/t to achieve the decarbonization targets set by law. The Nordic region continues to record the lowest prices on the strength of hydropower, in the range of 25-29 EUR/MWh, although price rise in the Baltics, towards 36 EUR/MWh in Latvia and Lithuania. With robust wind and solar power capacities, Germany had the second lowest wholesale price level on the continent, averaging 29 EUR/MWh. A dramatic price reduction took place in the Netherlands, which after exhibiting some of the highest prices in the region in recent years, today it has some of the lowest prices in continental Europe. With the decline of nuclear production, French prices are splitting from the German price, with last year's spread exceeding 7 EUR/MWh. With prices above 40 EUR/MWh, Italy and Greece are still the two most expensive countries in continental Europe, although their Mediterranean neighbors Spain and Portugal are quickly catching up. Although wholesale electricity prices in Hungary were almost 7 EUR/MWh higher than in Germany, it is still positioned toward the median European price range.

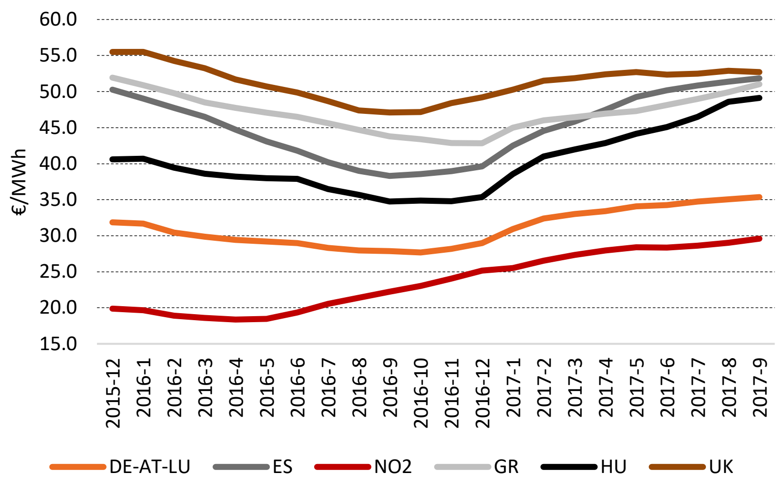
Day ahead baseload electricity product prices have been rather volatile over the last two and a half years. Examining the 12-month moving average of day ahead prices - thus filtering out the seasonality of prices - we can observe interesting trends. In Norway, and the Nordic region in general, prices fell slightly until April 2016 when they began to rise, with an average price of 30 EUR/MWh for the period of September 2016 to August 2017. For all other countries prices fell sharply until the second half of 2016, when price grew significantly (15-50%), and as a result exceeded the average 2015 price everywhere except for the UK. In Hungary, the September 2016 – August 2017 prices increased from 35 to 50 EUR/MWh.

Figure 6 2016 baseload electricity wholesale price in Europe (€/MWh)



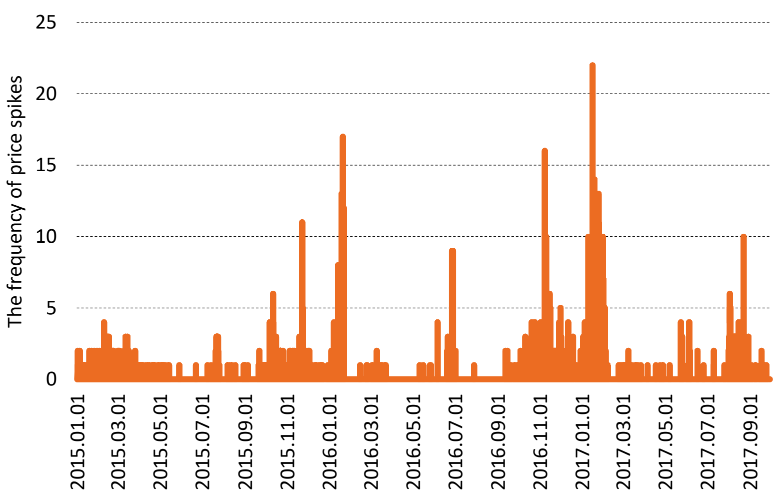
Source: ACER, Market Monitoring Report 2016

Figure 7 The 12-month moving average of day ahead prices in selected European countries (€/MWh)



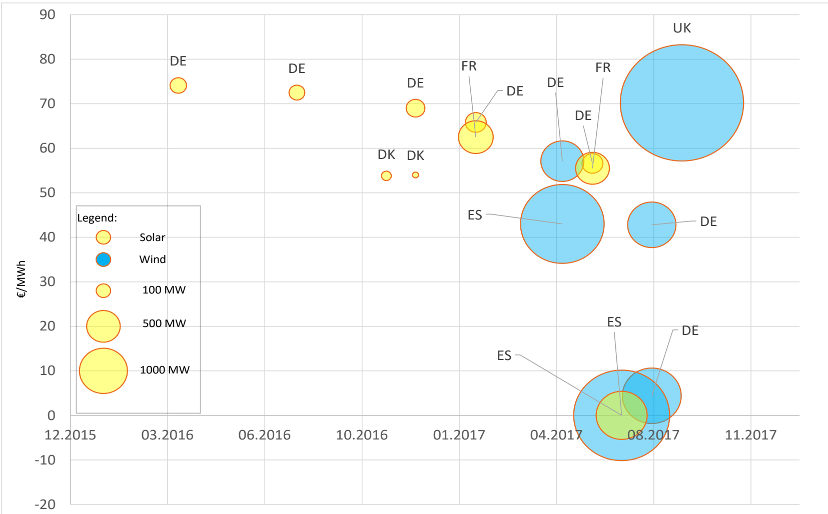
Source: ENTSO-E Transparency Platform

Figure 8 The frequency of price spikes



Source: ENTSO-E Transparency Platform

Figure 9 Price and capacity at the renewable tenders held in five European countries



Source: REKK calculation

Looking at the last two and a half years, the probability that the price would jump above 100 EUR/MWh clearly increased. Moreover, these price spikes tend to occur during the winter period, which follows the logic that less residual electricity is needed in the summer from fossil fuels. Looking at individual countries, after the UK (where there were 410 hours with the price exceeding 100 EUR/MWh) Hungary had the highest number of such spikes (371 cases). The least affected countries are in the Nordic region, Germany, Poland, and interestingly also the two countries of the Iberian Peninsula despite their relatively high baseload price.

To a large extent this was triggered by the exceptionally cold winter period and the extraordinarily warm summer. As a result of the higher price in Hungary, electricity prices started to approach the Greek / Italian / Spanish levels, and the German-Hungarian spread increased to 14 EUR/MWh compared to 6.5 EUR/MWh in 2016. The broad growth in European wholesale prices was largely attributable to the 30% price increase of coal in October 2016 from the decline of Chinese coal mining capacities. Prices continued to hover near 70-80 USD/t, even exceeding 90 USD/t at the end of August 2017. At the same time, the TTF gas price also started to rise in this period, contributing to the increasing electricity prices. The rate of this increase differed between peak and off-peak periods. In case of the 12 month moving average for the period between September 2016 and August 2017 in Germany, peak prices grew by 7.7 EUR/MWh while off-peak prices rose by only 5.6 EUR/MWh.

A similar trend can be observed in futures prices as well. In Germany, year ahead futures baseload product grew from 25 EUR/MWh in the first half of 2016 to 30 EUR/MWh in 2017, and by the end of the summer climbing to 35 EUR/MWh.

In its 2016 Market Monitoring Report, ACER concluded that 2016 was an exceptional year for price spikes: 2009-2010 was the last time a similar frequency was recorded.

Renewable electricity tenders in Europe

In recent years, tenders for renewable price support have become more common in Europe. Below, tender results of five important European markets are depicted in order to identify trends. Although most tenders are held in Germany (eight times in the last two years), the highest volume was allocated in the two Spanish tenders, totaling 8 GW. For the five countries, the amount allocated through auctions over the two years amounted to nearly 20 GW, which accounts for almost the entire newly installed solar and wind capacity in Europe in 2016.

While the price for the German tender carried out in April 2016 was 74.1 EUR/MWh, the PV tender price this June dropped by nearly 20 EUR/MWh to 56.6 EUR/MWh. This latter value cannot be considered as extremely low, with comparable prices met on the Danish and French PV tenders. For onshore wind auctions, two were held in Germany with prices of 57 EUR/MWh and 43 EUR/MWh. In the case of the Spanish tender, guaranteed returns make price determination less straightforward, and the current Spanish wholesale price ensures price support is not required. Finally, two countries also held offshore wind power tenders. In Germany, the winners received a price premium of 4.4 EUR/MWh above the wholesale price, which qualifies as minimal price support, while in England, awarded renewable producers can sell their electricity at the average price of the auction, 70.2 EUR/MWh.

European gas-infrastructure in light of the Commission's new LNG and storage strategy

After the European Commission released its strategic vision for EU LNG and Storage in 2016[1] REKK published a study examining the elasticity of European gas-infrastructure and the effects of storage related regulatory measures (storage obligations and strategic stocks). It tested the effect of the Strategy's infrastructure priorities[2] on supply security and market integration under scenarios of high and low global LNG supply and gas demand projections. The modelling results justify most of the projects outlined, which together reduce prices in CEE by 0.2-0.3 EUR/MWh, leading to price convergence in Europe.

Since the Strategy was published several of its key assumptions pertaining to the European gas market have gone through remarkable changes. Global LNG trade is growing but at a lower rate than expected. Gas consumption has been in steady decline over the last decade and although stabilizing in the past two years, this has left surplus LNG regasification capacity on the market.

Due to surplus capacity on the gas storage market some storage operators are facing financial troubles, marked by the first closure of a storage site in Ireland in March 2017 and followed later by a decision to close the UK's biggest storage facility[3]. European storage operators continue to struggle with low summer-winter spreads, prompting some to introduce new TTF-based pricing formulas to stimulate filling levels. Assuming that storage cost is in the range of the observed summer-winter spread (~1 EUR/MWh), modelled storage utilization is the highest in UK and in IR, which shows that the price of these storage sites were above this range and the market is not willing to pay these costs.

While questions remain about their commercial viability, some Member States make use of the security of supply value of storages by imposing storage obligations on market players or holding strategic stocks. The need for enhanced cross-border cooperation to remove regulatory barriers that impede more effective storage use remains an important recommendation of the Strategy both in light of helping storage sites stay in business and for broader security of supply considerations.

Utilization of storage facilities

REKK used market simulation tools (EGMM model) to examine how much gas is expected to be injected into the available unused storage infrastructure under normal market conditions. The results show that out of the approximately 1100 TWh working gas capacity available in the EU28, 600 TWh was utilized on a market basis, which was sufficient to handle even the most extreme supply and demand shocks. Long-term booked working gas volumes added about 145 TWh to this total. Increasingly available flexibility sources might have a competitive advantage over some storage facilities, but we see no urgent threat to supply security in this regard.

Next, a supply shock scenario is used to test the resilience of European gas infrastructure. Among flexibility sources, storage facilities are most critical for providing seasonal supply flexibility to the European market and responding to crisis situations. The next figure shows how different sources of supply substitute for the missing volumes during a cut to the supply of the main import routes to Europe in January.

Despite the value for security of supply, modelling does not project an optimistic future for storages. The aggregate volume of gas stored is expected to fall by 7% in the EU28, and by 3% in the entire modelled region, by 2020 despite the current storage obligations in place in many countries.

While modelling forecasts an overall dip in storage utilization rates, notably in Austria, Germany and France, storage sites in Bulgaria, Croatia, Italy, Poland and Ukraine exhibit growing rates over the period.

In the 2020 reference case, storage infrastructure remains under-utilized with cheaper alternative sources of flexibility like pipeline and LNG

Figure 1 Yearly regional prices in case of the modelled scenarios (EUR/MWh)

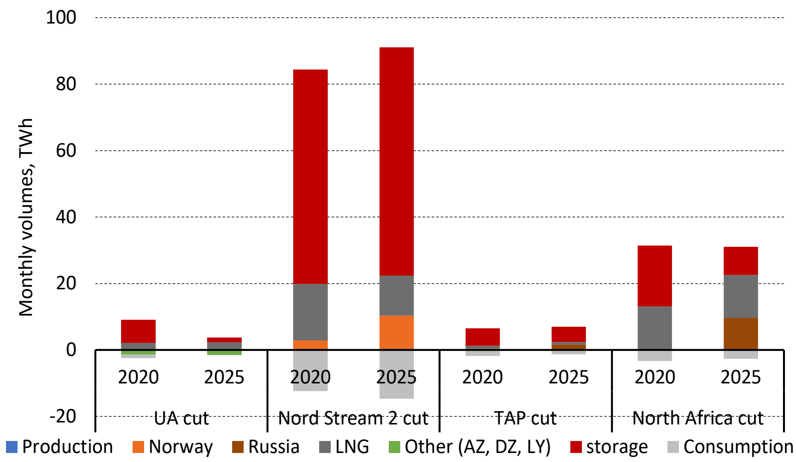
	REFERENCE	LOW LNG& LOW DEMAND	HIGH LNG& LOW DEMAND	LOW LNG& HIGH DEMAND	HIGH LNG& HIGH DEMAND
NWE	17.83	17.95	16.18	18.84	16.61
SEE	18.62	19.36	17.09	21.68	18.78
EU28	18.31	18.45	16.70	20.55	17.39
EnC	22.41	22.43	21.41	23.72	21.81
TR	19.16	24.23	16.54	24.40	16.72

1 For a detailed discussion of this topic read „The Commission's vision for LNG, storage and security: Complete the market" in our 2016/1 issue

2 The study examines the following infrastructure projects supported by the LNG and storage strategy: Croatian LNG terminal, BRUA (Romanian-Hungarian), Balticonnector (Finnish-Estonian), GIPL (Polish-Lithuanian), Latvian-Lithuanian, Estonian-Lithuanian, Spanish-Portuguese, MIDCAT (Spanish-French), IGB(Greek-Serbian), IBS (Bulgarian-Serbian)

3 The decision is attributable to technical reasons too

Figure 2 Comparison of supply cut scenarios



Source: REKK EGMM modelling

increasingly accessible. The value of storages increases significantly with simulated demand or supply shocks; an unforeseen one month demand shock (modelled as a 15% demand increase in February throughout Europe) the benefit of intertemporal arbitrage on stored gas rose from ~25 M EUR to ~96 M EUR in the EU-28. An unforeseen demand surge causes a price spike, making already stored gas volumes more valuable and thereby increasing revenue from sales. Supply shocks have a more moderate price effect, not exceeding 5 EUR/MWh even in the most extreme scenarios tested.

However, storage remains effectual for market players and consumers alike by smoothing the summer and winter spreads. This can be attributed to significant surplus capacities, for one, and also the non-transparent long term bookings with low marginal costs that represent sunk costs to the owners. If less storages were available, summer and winter spreads would be considerably higher and certainly increase the profit of operators still active on the market.

Regulatory interventions - Storage obligations

Storage obligations are in place in several Member States (as depicted on the map below) that increase storage use and ensure a predefined quantity of gas has to be filled into the storages by the beginning of October. Strategic stocks, which cannot be used during normal winter conditions but only in gas crisis situations, are in place in Denmark, Hungary, Italy and Spain.

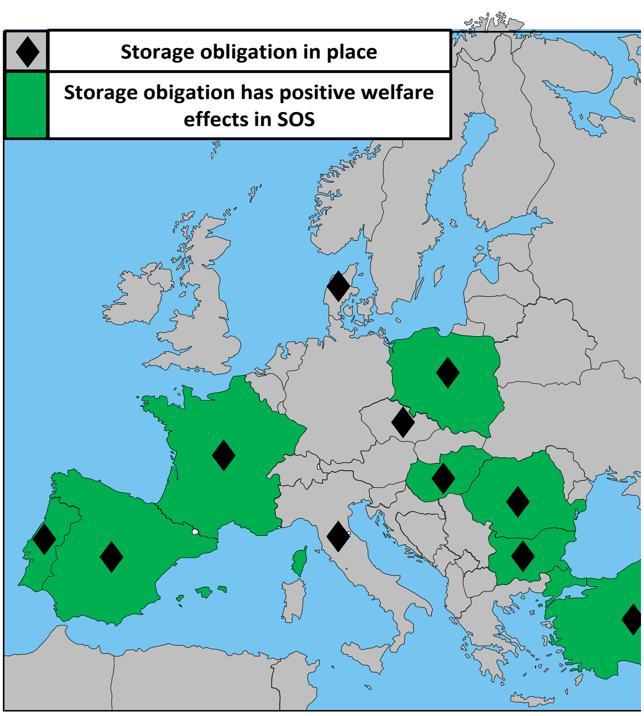
The latter national storage obligations were imposed by Member States because of security of supply concerns but have a distortive effect on the market. Modelling suggests that absent these obligations, the same volume of gas would be stored on a market basis but in different countries. Hungarian and Romanian storages would lose volumes while Austrian and Dutch storages would gain. (see chart below)

Alternative regulatory solution

Modelling results demonstrate the need for many of these obligations (including those in Hungary) under security of supply scenarios, as they play an important role in mitigating demand and supply shocks. At the same time, these storage obligations are in some cases hindering cross border storage use and undermining the business case for those countries without storage obligations.

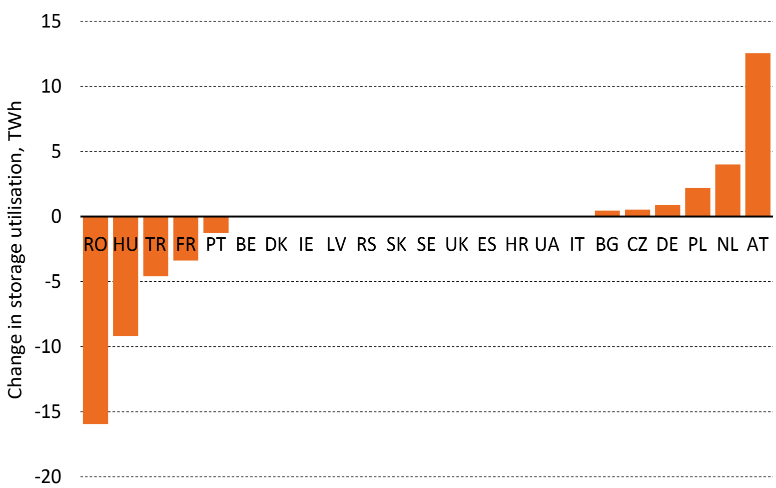
For this reason, REKK puts forward an alternative regulatory solution that would replace EU-wide storage obligations, whereby the suppliers provide financial compensation for at risk, concerned customers to the extent of the damage suffered. This would set the proper incentives for suppliers to optimize commercial storage utilization and also ensure that customer welfare is protected even when customer restrictions are implemented and unavoidable. It will also contribute to the elimination of legal barriers to cross-border gas trading, which is particularly important during gas supply security incidents.

Figure 3 Storage obligations and their effects



It would follow that in each case a supplier cannot physically meet its contractual supply obligations, it pays a firm monetary sum to its customers equaling the damage caused by a supply-cut (calculated as value of lost load - VOLL). This would ensure that although customers can suffer a physical supply cut due to the inability of some suppliers to meet their contracts, the monetary compensation will keep customers' welfare unchanged compared to a no-supply-cut scenario. At the same time suppliers will face the full potential financial risk of non-compliance with their contracts.

Figure 4 Change modelled storage fill level by the end of October, TWh, 2025



Source: REKK EGMM modelling

This might encourage suppliers to optimize their risk management by booking sufficient commercial storage, insurance or other means.

Regional cooperation

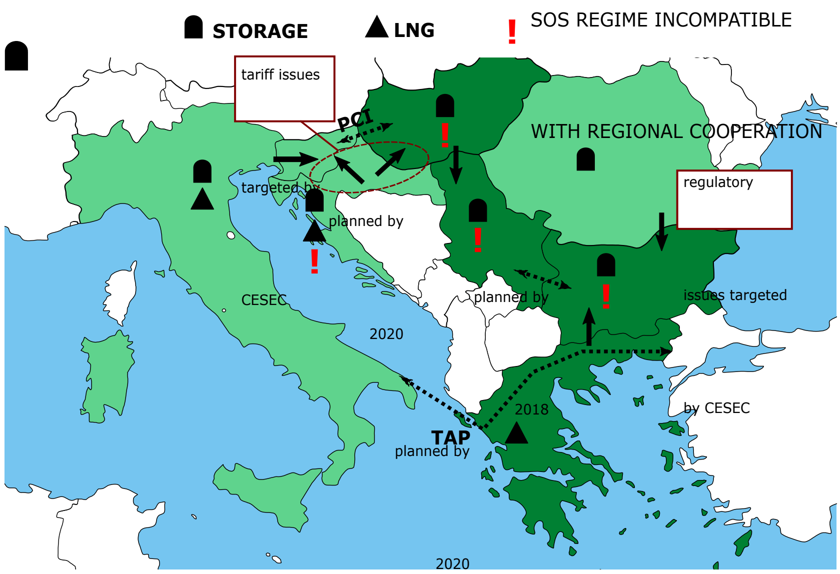
Regional cooperation has the potential to create more welfare gains through the optimization of storage use. First, cross-border cooperation requires the abolishment of some administrative barriers to foster efficiency gains by the market. Second, if some Member States were to value security of supply more than the market, they can establish a regional obligation or strategic stock regime that builds on the efficiency gains of a larger geographic area with more supply and infrastructure.

Based on modelled gas flows and infrastructure use in security of supply scenarios, we see great potential in increased cooperation between Hungary, Serbia, Bulgaria, and Greece to optimize the allocation of additional sources from Hungarian storages and Greek LNG import along this route. This requires the completion of the bi-directional BG-RS interconnector, which has already been decided to build with a target commissioning date of 2018. If the HU-SI interconnector is built and tariff issues are resolved, this cooperation could be extended to Croatia and Slovenia, further enhancing flexibility with the realization of additional sources (Croatian LNG and storages) and supply routes.

Another source of flexibility would come in the form of the removal of regulatory barriers, namely allowing Bulgaria to access Romanian storages. SEE regional cooperation would be completed with Italy's involvement and the harmonization of TAP with Italian storages.

Any cooperation mechanism with the goal of optimizing the use of flexibility tools (e.g. gas storage, LNG-import) requires the free flow of gas across borders in SoS situations. Moreover, traders need to be sure that all volumes they enter into storage will be available in case of an emergency. Storage access regimes that give special rights to governments, transmission or storage system operators for the allocation of storage volumes under such scenarios discourages market-based usage and potentially disrupts cross-border cooperation.

Figure 5 Opportunities and obstacles in regional cooperation in SEE



Economic analysis of combined heat and power plants participating in the district heating service of Budapest

With energy efficiency and climate policy requirements and lingering uncertainty over the future role of gas, a number of questions face the future of gas based combined heat and power plants (CHPs) that currently participate in district heating. In our analysis, we present key business data from the prior fiscal year for the power plants with a notable weight in the district heat supply of Budapest (Budapest Power Station (BERT), Alpiq Csepel, MVM North-Buda Heating Plant), pointing out some of the factors that explain the difference between their business performance, especially the effects of taxation. The investigated power plants are active market participants in both the electricity and the heat markets, therefore data inputs reflect the performance of both business lines. The three BERT and single MVM CHPs operate as heating plants, thus their primary purpose is heat production and power generation is secondary. The production of the Csepel Power Plant, on the other hand, is driven to a much higher extent by the electricity market with a much smaller proportion of heat production. An analysis of the business line reports based on the rules of accounting separation can help provide a more nuanced picture of the recent performance of each power plant, highlighting their similarities and differences, and heat and power market strategies with projected district heating market potential.

Main characteristics of the production structure of Budapest district heating

Budapest district heating is the single biggest district heating system in Hungary, serving some 250,000 residential and industrial customers. The district heat consumption in Budapest was about 10.3 petajoules in 2016. The gas dependence of district heating generation in Budapest (93% in 2016) exceeds the high national average (68%), two-thirds of which is produced from highly efficient cogeneration plants.[1]

In 2016, about 5% of the energy consumed by the Budapest district heating service was provided by the Municipal Waste Management Plant (HUHA) owned by the Fővárosi Közterületfenntartó Zrt (the Capital City Public Space Management Corporation). The remaining heat demand was satisfied mainly by large gas-based power plants (BERT Újpest Power Plant, BERT Kispest Power Plant, BERT Kelenföldi Power Plant, MVM North-Buda Heating Plant, Alpiq Csepel Power Plant) and gas engines and boiler houses. Figure 1 shows the dominant role of gas-based CPHs in the heat supply of Budapest. The five main power plants together account for nearly 80% of the heat demand in Budapest.

Today, gas-based power stations are a given in the heat supply of Budapest but their long term role far from certain. On the one hand, it is unclear if, in the long run, it will be possible to exploit the current benefits of cogeneration in both heat and the electricity markets.

On the other hand, the prospects of heat production are materially influenced by the district heating market strategy of Budapest and the prevailing regulatory environment.

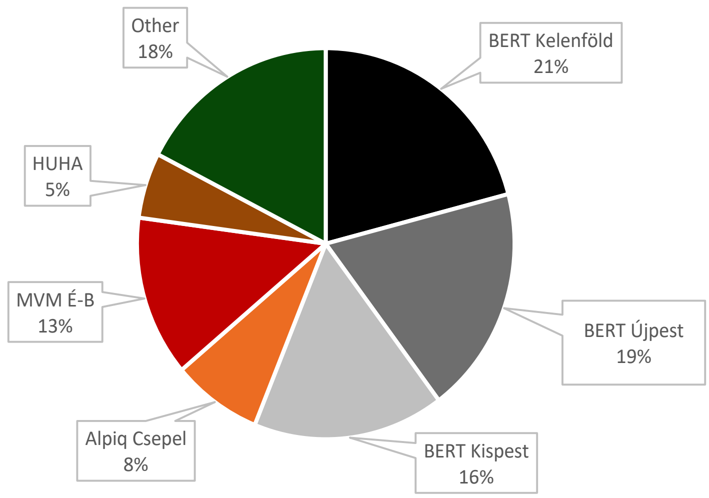
Domestic and EU legislation affecting the future opportunities of cogeneration plants

Of European Union legislation, the Energy Efficiency Directive 2012/27/EU (hereinafter referred to as EED) is of greatest consequence. The preamble of EED states that highly efficient cogeneration and district heating / cooling offer significant primary energy savings potential that is currently underutilized by Member States. The directive explicitly encourages the exploitation of this potential, obliging investors to consider the use of high efficiency cogeneration technology and undergo a cost-benefit analysis prior to the development of power generation facilities with thermal input of 20 MW. Frankly, with respect to support, the directive only states that "... Member States shall take appropriate measures to develop efficient district heating / cooling infrastructure”. The term “efficient district heating / cooling" refers to a district heating or cooling system that operates with at least 50% renewable energy or 50% waste heat or 75% cogenerated heat or 50% of a combination of such energies and heat. Annex II of the Directive provides detailed guidance on the benchmarks expected for cogeneration. Accordingly, energy generation from cogeneration units should achieve at least 10% primary energy savings compared to the reference values of heat production and electricity generation respectively. One wonders if all the inspected Hungarian power plants can meet this criterion.

1 A review of the Budapest district heating servicee: http://www.fotav.hu/media/downloads/2017/02/20/7015.pdf

The current heat production capacity in Budapest is around 2100 MW, while the winter peak demand is estimated at 1100-1200 MW. The Hungarian government and the capital count with gas-fired power plants in the Budapest heat market for the long run. According to the estimated potential of efficient district heating submitted to the European Union in December 2015 under the requirement set by Article 14 (1) of EED[2] , Budapest has potential for 60 MW of biomass, 24 MW of geothermal and 57 MW of municipal solid waste incineration of new heat generation for investment. In addition to the continued operation of HUHA, the rest of the heat demand can be satisfied through high efficiency gas-based cogeneration. In principle, this provides a stable vision for the existing power plants, since the new investments themselves will not be able to meet expected heat demand.

Figure 1 The share of heat producers in Budapest as a proportion of the discharged heat in 2016



Source: FŐTÁV

Two conditions, however, make the picture much more nuanced. First, the profitability of combined power plants also requires appropriate market share opportunity in the electricity market. In this respect, the official domestic energy strategy is not too supportive of gas-based power plants. The "nuclear-coal-green" scenario set out in the 2030 National Energy Strategy assumes that gas based capacities will continue to operate but with declining utilization and a reduced role in system balancing due to new nuclear capacities and the entry of renewables. Heat-coupled electricity production, however, will increasingly require the sale of scheduled products during the heating season.

An even more serious dilemma for Budapest district heating and the power plants operating therein is Decree 7/2006. (V.24.) of TNM on the Determination of the Energy Characteristics of Buildings. The decree requires that new public buildings after 31 December 2018 and residential buildings and other buildings after December 31, 2020, at least 25% of energy needs must be satisfied from renewable energy. District heating is considered to satisfy this requirement only, "if it is provided by district heating or district cooling which, with the exception of the electricity used for the transfer of energy, utilizes solely those energy sources contained in table IV.1 of the regulation [firewood, biomass, energy generated directly or indirectly from biomass, energy of biogas, wood pellet, agripellet] and the use of other energy sources in the district cooling or district heating system is not possible." This constraint all but excludes new building developers from considering district heat as an option to fulfil the requirement for 25% renewable share since within the district heating system heat generation on a renewable and non-renewable basis cannot be physically separated. As long as the text of the TNM decree does not change, this will ensure that district heating in Budapest will gradually be losing its market share.

To sum up, the current EU legal framework and domestic Hungarian policy do not provide clear answers regarding the long term operating environment of combined power plants, thus the owners of current power plants have a much stronger motivation to exploit existing investments than to carry out new ones. In this context, it is necessary to separately review the financial and management data of each power plant and inspect the recent strategies pursued by the three power plant companies: the Swiss Alpiq (owner of the Csepel Power Plant), EPH with roots in the Czech Republic, Luxemburg and Cyprus (owner of the Budapest Power Plant) and MVM (in possession of the North Buda Heating Plant).

A brief description of the inspected power plants

The Budapest Power Plant (BERT) Ltd. provides heat to FŐTÁV based on its gas based combined generation at three production sites. Since 2015 the majority of BERT is owned by Czech investors, 95.62% of the stocks are held by the EP Hungary A.S. corporation.

2The analysis submitted by the Hungarian government to the EU Commission was prepared by Századvég Gazdaságkutató Zrt. in December 2015

The corporation's facilities taking part in the district heat supply of Budapest are the Kelenföld, Kispest and Újpest Power Plants. The Kelenföld Power Plant is a combined cycle power station with a condensing steam turbine, two 5 MW gas turbines and two hot water boilers with 188 MW of power and 377 MW of heat output. The Kispest Power Plant has the following technical specification: a combined cycle power plant with back pressure steam turbine and two hot water boilers with 114 MW of electricity and 341 MW of heat output. The technical features of the Újpest Power Plant are similar to that of the Kispest facility, with 105 MW of electricity and 346 MW heat output.

Alpiq Csepel Kft., owned by the Alpiq Group of Switzerland, helps to meet the thermal needs of Csepel with a condensing steam turbine connected to a three-unit combined cycle power plant and four hot water boilers. Compared to BERT, which operates as a heating plant, the Csepel Power Plant primarily produces electricity and only about 9% of its total revenue comes from the heat business. The installed capacity of the plant is 396 MW of electricity and 317 of MW heat.

In 2006, MVM, in accord with its agreement with FŐTÁV, invested in a power plant to meet the heat demand of North Buda. The three part power plant was built in two phases. During phase 1, a gas turbine of 9.88 MWe and 17 MWth capacity was built, supplemented with a heat utilizing hot water boiler of 30 MWth equipped with auxiliary combustion. This unit has been in operation since the beginning of April 2007. During the first part of phase 2 a unit with the same design features was installed. Finally, during the second part of phase 2, a gas turbine with a power output of 30.2 MWe and 39 MWth was built and a 39 MWth heat utilizing hot water boiler was connected to it.

Business characteristics of the inspected power plants

Based on the activity-based reports prepared as part of the accounting report, the main economic indicators of the five power plant units belonging to the three ownership groups can be compared according to both electricity production and heat production. Figure 2 summarizes the revenue, operating profit and fixed assets of each facility for 2016.

As the figure shows, with two exceptions (Újpest and Kispest electricity generation) the examined producers achieved net positive operating results in 2016 in both the heat and the electricity markets. Strikingly, for Csepel Power Station electricity generation contributed a much larger share of total revenue than BERT or the North Buda Heating Plant of MVM. For Csepel heat production is only an auxiliary activity, and the ratio of heat production is

Figure 2 Revenues, operating results and fixed assets of the business units at the examined power plants in 2016 (million HUF)

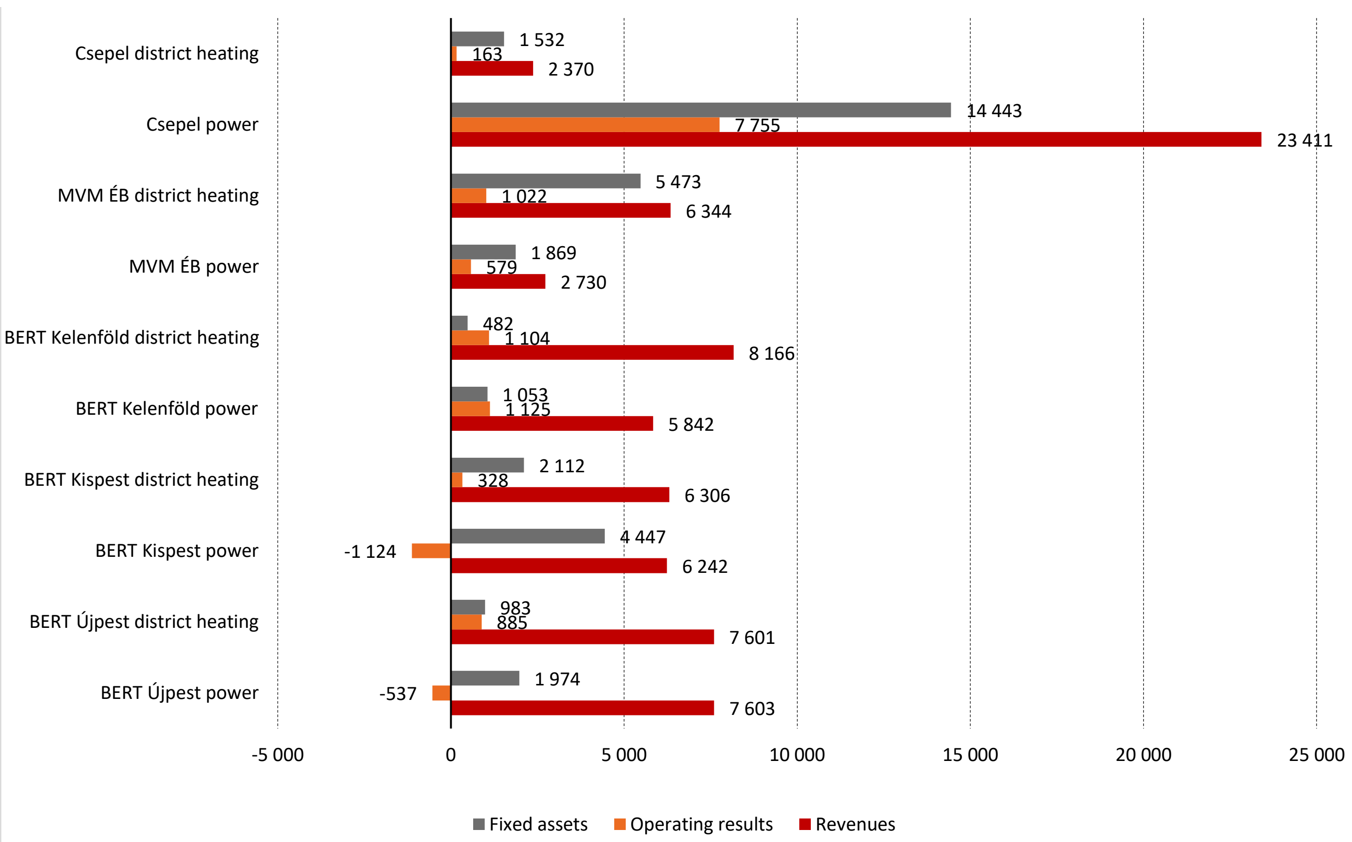


Table 1 The share of electricity generation within total revenues between 2013 and 2016

Share of electricity generation within total revenues	2013	2014	2015	2016
BERT Újpest	48%	47%	48%	50%
BERT Kispest	52%	50%	52%	50%
BERT Kelenföld	37%	35%	38%	42%
MVM ÉB	28%	28%	29%	30%
Csepel	94%	92%	91%	91%

much higher for other power plants, practically even for BERT, while the primary market of MVM's North Buda Heating Plant is the Budapest district heat market with electricity generation filling only a marginal function.

Given the diversity of their primary markets, power plants have faced different mixtures of market exposure in recent years. Not surprisingly as shown in Figure 3, it is difficult to identify pronounced trends in the electricity and heat business for individual producers.

Focusing on the generation of electricity, while the profitability of BERT Ujpest and BERT Kispest facilities continues to slide it improved at the BERT Kelenföld facility. MVM North Buda and Csepel also exhibit a positive trend, with the latter enjoying a truly successful 2015 and 2016. Steadily declining sales revenues were offset by lower fuel costs, thereby substantially improving profitability. This was underpinned by stable sales opportunities through favorably priced medium-term contracts.

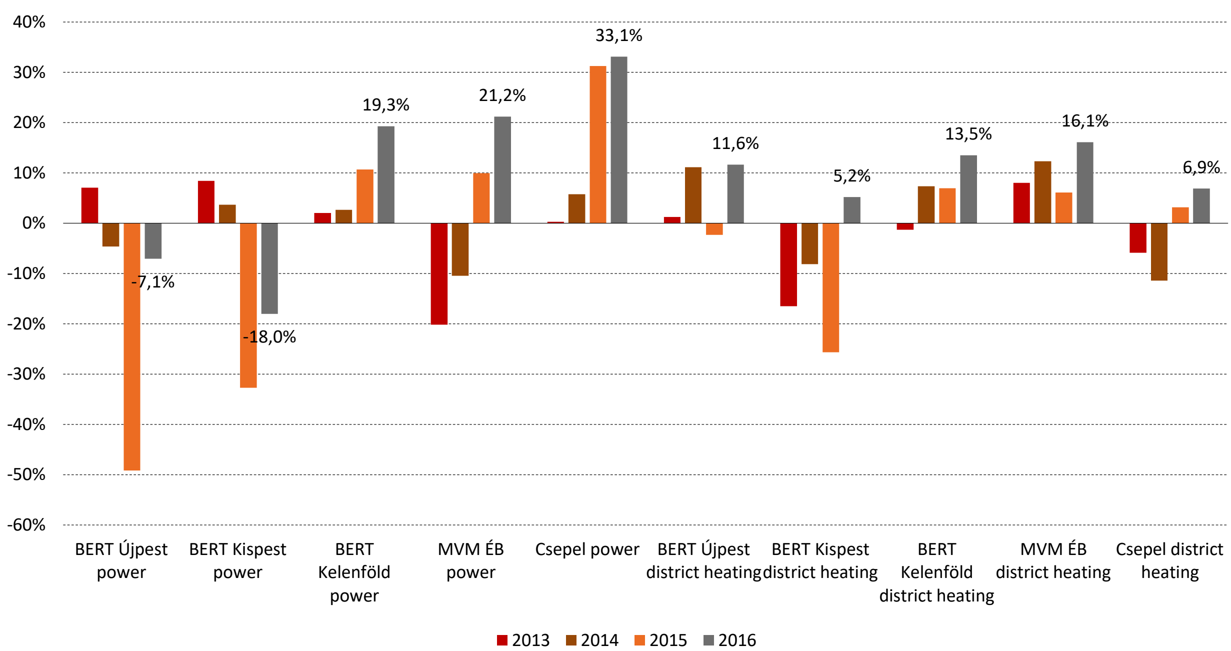
Profitability in the heat market is less volatile and has shown a positive trend over the last four years, with all inspected producers reporting positive operating margins in 2016. The decline of gas costs in recent years has clearly contributed to the improvement of margins in the heat market.

Asset re-evaluation and the impact of taxation on annual results

Annual results alone provide only a partial picture of the fundamental factors that determine the financial performance of each of the producers. They are significantly distorted by one-off items, typically connected to extraordinary depreciation from the devaluation of assets.

For BERT, in 2015 and 2016, the re-evaluation of fixed assets according to expected returns significantly reduced the operating profit. In 2015 and 2016 the company booked a total additional depreciation of HUF 10.1 billion and HUF 4.3 billion respectively, justified by the lower than expected returns of the assets.

Figure 3 The income to revenue ratio of power plant and heat production business units (2013-2016)



According to the 2016 report, the accounted depreciation is significantly different for each site: it was HUF 2.1 billion for the Kispest Power Plant and HUF 2.4 billion for the Újpest Power Plant, with HUF 267 million of depreciation reversed at the Kelenföld Power Plant, improving financial results for the year. Depreciation was calculated with a weighted average cost of capital (WACC) of 9.4%.

The effect of unplanned, one-off depreciation is the reduction of booked profits, but the value of fixed assets is also reduced on the balance sheet with the equity book value declining on the liability side. Such profit adjustments make data comparison problematic for the year in question and balance sheet items informing book value based profitability indicators for many years to come.

The practice of asset devaluation followed by BERT is fully understandable given the direct tax advantages achieved. Table 2 describes the payments of corporate tax and the income tax of energy service providers (widely referred to as the Robin Hood tax) by the three companies for the last three years.

The table succinctly shows that as a result of asset devaluation, BERT has achieved a much more favorable tax rate than MVM North Buda or Alpiq Csepel, neither of which applied additional depreciation. The reason for this is the problematic calculation method of the Robin Hood tax. While the tax base needs to be adjusted in line with the additional depreciation to determine the corporate tax base (increased in case of devaluation), the tax base for the calculation of the Robin Hood tax is equivalent to 31% of the raw figures of the after-tax profit.

By employing this tactic, for the last three years BERT has only paid total taxes of HUF 645 million while the total corporate tax base for the three years total HUF 5.8 billion. At the same time, MVM North Buda faced a tax liability of HUF 874 million even though its total corporate tax base amounted to only HUF 1.3 billion. Similarly to MVM North Buda, Alpiq Csepel also suffered a high tax burden, paying HUF 9.8 billion to the central budget along with a total corporate tax base of HUF 26.7 billion.

Naturally, BERT's practice cannot be continued indefinitely since the devaluation of assets is restricted by minimum capital requirements, but it is clear that due to the anomalies of the rules on calculating the Robin Hood tax, devaluation has ensured a substantial short term financial gain to the investor group that purchased the power plant in 2015. Due to deviations in taxation, the comparison of the raw data from financial statements may lead to flawed conclusions in assessing the real economic state of producers. BERT's corporate tax base showed a significant positive balance for both 2015 and 2016 even though the after-tax result was negative in 2015 and only slightly above zero in 2016. Excluding the impact of asset revaluation, the company enjoyed a relatively stable economic environment during these years, generating adequate income to its shareholders.

Table 2 Tax payment between 2014 and 2016 by the inspected power plants

		Tax payment obligation	Of which: Robin Hood tax	After tax results	Corporate income tax base	Tax rate calculated for the corporate income tax base	Note
BERT	2014	-32 881	0	-481 858	-213 447	0%	Tax rebate (negative tax to be paid)
	2015	497 514	0	-8 229 508	2 907 968	17.1%	
	2016	180 301	-368 036	298 400	3 122 830	5.8%	
MVM North Buda	2014	25 666	25 666	255 347	-211 001	-12.2%	Tax payment despite a negative corporate tax base
	2015	285 922	210 840	246 272	494 164	57.9%	
	2016	562 092	411 476	930 192	1 029 556	54.6%	
Alpiq Csepel	2014	1 352 615	235 361	-159 760	7 485 546	18.1%	
	2015	4 367 312	2 599 378	4 828 801	9 541 754	45.8%	
	2016	4 255 692	2 456 689	3 613 452	9 705 281	43.8%	

The distortions originating from the current calculation of the Robin Hood tax – observed not only for the producers, but also for some of the gas and electricity distribution companies - justify the re-examination of the tax. We believe that introducing a calculation method that is similar to that of the corporate income tax would substantially lower the incentive of companies to try to obtain short term tax advantages by devaluing their assets.

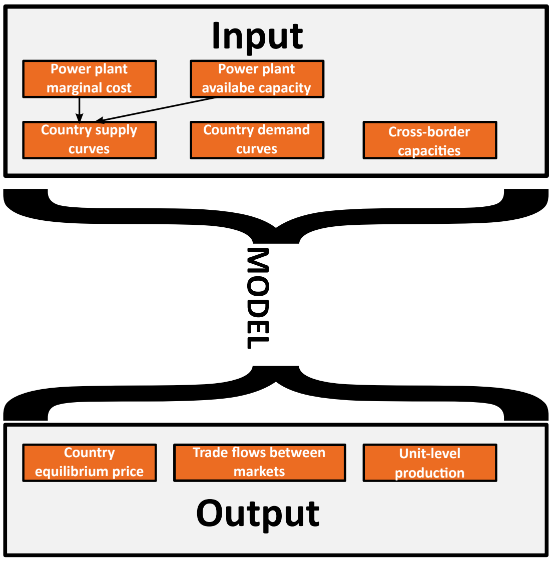
Summary

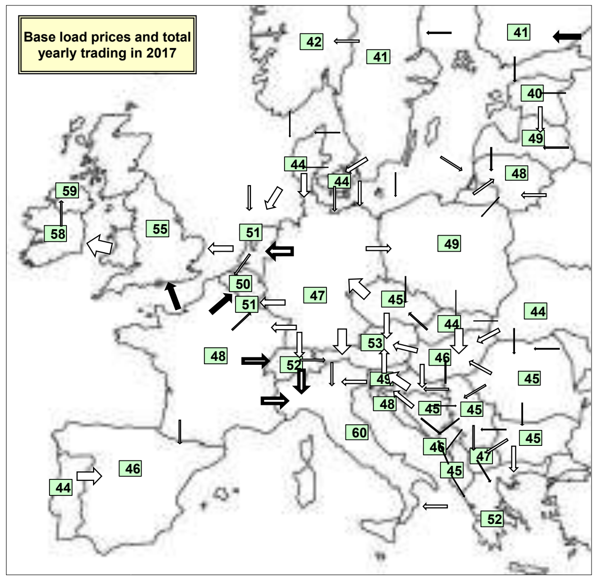
The gas fired power plants participating in the heat supply of Budapest have notably different technical features influencing their past market strategies as well as their future opportunities. The vision of the Csepel Power Plant is shaped by the future share of gas based electricity generation and regulated energy market developments, promising additional revenue and profit for the plant. MVM North Buda operates in a protected environment until 2028 with sales secured by a long-term contract under which profits will be driven by the regulation of producer heat prices.

The three facilities of BERT possess excess heat generating capacity relative to the current district heating demand in Budapest. If the plans of FŐTÁV to connect Budapest heat districts that currently operate on an island materialize, then one of the three BERT power plants will become redundant and may cease to operate in the medium term. It is unlikely that this development would be prevented by increasing demand for heat, therefore the owners of the power plant need to consider whether the expected electricity market developments in Hungary would allow sustained operations by converting one facility into a scheduled or a regulated power plant.

EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

EEMM is the electricity market model of REKK developed since 2006 modelling 36 countries EEMM





ASSUMPTIONS

- Perfect competitive market
- The model calcu lates 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 calcu lates the price of standard products (base and peak)

USAGE

- Provides competitive price signal for the model led 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
- Al lows analysing the effects of public policy interventions
- Trade constraints
- Assessment of interconnector capacity building

RESULTS

- Base and peakload power prices in the model led 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 CO^2 emmissions

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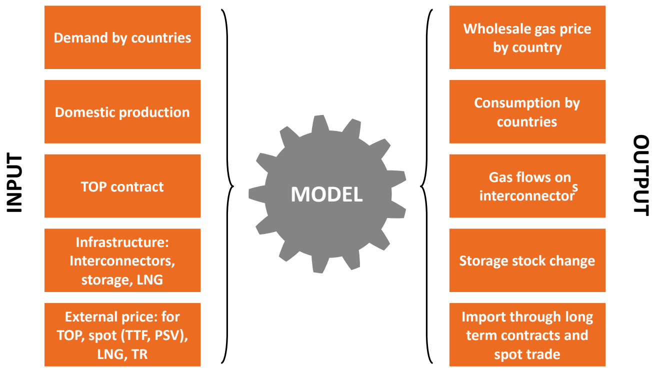
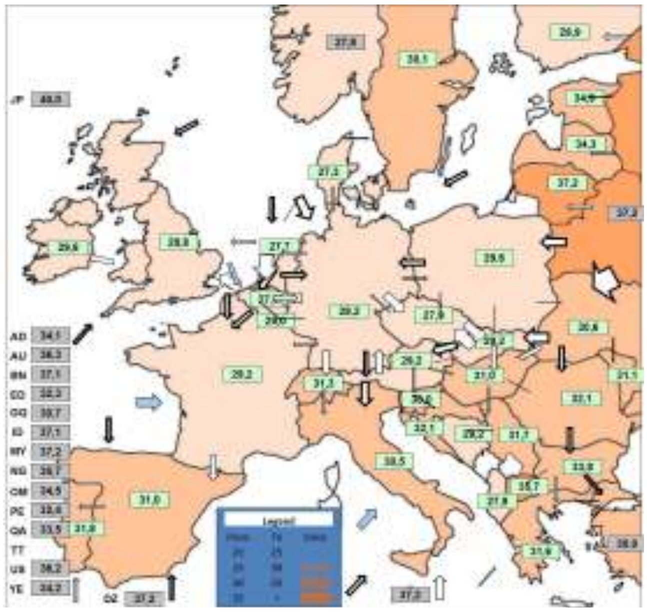
EUROPEAN GAS MARKET MODEL (EGMM)

EGMM is the natural gas market model of REKK developed since 2010 modelling 3 countries





ASSUMPTIONS

- Perfect competitive market
- Model ling period of one year (1 2 months)
- LTC and spot trade in the model led countries, pipeline and LNG suppliers
- Physical constraints are interconnection capacities
- Trade constraints: TOP obligation
- Model includes domestic proiduction and storages
- Model calcu lates 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
- Al lows 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 al l 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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