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de l'Électricité et du Gaz

CREG

Study

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Study on the functioning and price evolution of the Belgian wholesale electricity market – monitoring report 2016

drawn up pursuant to article 23, § 2, second paragraph, 2° and 19°, of the law of 29 April 1999 on the organisation of the electricity market.

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EXECUTIVE SUMMARY

This study relates to the functioning and price evolution of the Belgian wholesale electricity market in 2016. The electricity market is one in which energy is bought and sold before being supplied to end customers, whether private individuals or professionals.

For a better understanding of the evolution of these markets in 2016, a longer period, from 2007 to 2016, and referred to as the "period under review", is often taken into consideration in the study.

An assessment of the Belgian wholesale electricity market in 2016 cannot be made without taking into account all of the 'incidents' which occurred within nuclear installations over the period 2012 to 2015. As such, Belgium has become structurally dependent on its imports. In this context, various measures were taken in 2014 and in 2015, including the creation of a strategic reserve in 2014, whose resources were further strengthened in 2015, and the introduction of an imbalance rate of €4,500/MWh in the event of a structural deficit.

In 2016, the landscape changed, with a strong increase in electricity generation from nuclear sources, and a corresponding strong reduction in electricity imports compared with the previous year.

I. Electricity Grid Load

Electricity consumption in the Elia control area amounted to 77.3 TWh[1] in 2016, which was a leap year, in other words a similar level to that of 2014 and 2015. Over the last three years, **electricity consumption has been at the lowest level during the period under review**. In general, the CREG has observed a downwards trend in electricity consumption for several years, and especially of the peak demand which amounted to 12,734 MW in 2016.

Uncontrollable decentralised generation, including generation of solar panels, is considered as negative consumption by the CREG. **The impact of the generation by solar panels on consumption is significant** but has stagnated over the last three years. In 2016, this generation reached 2.9 TWh, an identical level to that of 2014. On the other hand, wind generation has been covered this year in the chapter on generation.

II. Generation

The **installed capacity** connected to the Elia grid amounted to 14 GW, which represents a small decrease compared to 2015. Nuclear plants and gas fired plants account for more than 70% of the installed capacity in Belgium. In 2016, the last coal unit was shut down.

Electricity generation of units connected to the Elia grid amounted to almost 70 TWh compared to 55 TWh in 2015. This significant increase in 2016 is mainly due to a better availability of nuclear plants.

III. Electricity trading

Yearly averaged **day-ahead wholesale electricity prices** have decreased to their **lowest level** since the liberalisation of the electricity market. At 36.6 €/MWh, electricity wholesale prices have decreased by more than 10 €/MWh in real terms, or **25.7%**, since 2007. Almost 60% of the time, day-ahead wholesale electricity prices have fluctuated between 20 €/MWh and 40 €/MWh with prices higher than

[1] A difference of 0.3TWh with Table 1 is due to consumption in pumping mode, inter-TSO flows and production correction.

80 €/MWh for 3% of the time. Similar reductions in wholesale electricity prices are observed in France, the Netherlands, and Germany. Commodity prices of coal and gas seem to be one of the significant drivers of this trend, while outages of nuclear power plants in Belgium and France during the last quarter of 2016 seem to have limited further reductions in prices.

Although markets are more closely coupled, **full price convergence in the CWE-region was achieved for 35% of the time while full price divergence reached 50%.** Roughly half of the hours with full price divergence are caused by **differences of less than 1 €/MWh** between the Belgian bidding zone and at least one of the other bidding zones in the CWE-region. Ignoring differences of less than 1 €/MWh, the frequency of price convergence becomes 39% while the frequency of price divergence lowers to 28%. The high frequency of divergence is also caused by nuclear outages during the last quarter of 2016.

Trade on the Belpex spot market has decreased following the availability of nuclear power plants in Belgium. This resulted in a higher supply on the Belpex market pushing out more expensive imports from abroad. Therefore, the value of all traded contracts on Belpex decreased, in 2016, to comparable levels with the period 2012 to 2014.

Yearly averaged **intraday wholesale electricity prices** kept their **convergence with the yearly averaged day-ahead wholesale electricity prices** in 2016. On an hourly basis, relatively large price differences between the two values occurs, providing opportunities for flexible units. Most of the trade on the intraday market of Belpex has a cross-border leg, meaning that electricity is exchanged with a **counterparty located in another bidding zone**. The yearly traded volume on the intraday market exceeded 1 TWh for the first time since the observations.

Yearly averaged **long-term wholesale electricity prices continued to decrease** in 2016, indicating that in 2017 the yearly averaged day-ahead wholesale electricity prices are expected to be lower than the values observed in 2016. The reduction in long-term electricity prices is however not observed when looking at monthly averaged prices: the price of all considered long-term wholesale energy products at the end of 2016 was higher than at the beginning of the year. Both occurrences are also observed in the French, Dutch, and German bidding zones.

IV. Interconnections

Efficient use of transmission network capacity is crucial for the integration of the energy markets and the realisation of a European Single Energy Market. Improving and harmonizing the design of congestion management methodologies for market coupling is high on the European agenda. The Capacity Allocation and Congestion Management (CACM) Guidelines, developed at European level, stipulates the design requirements as well as the process towards their effective implementation. The CACM Guideline proposes Flow Based Market Coupling (FBMC) as congestion management method for cross-zonal trade, combined with adequately defined bidding zones.

The Central West European (CWE) region is the first European region to have implemented **FBMC**. In May 2015, FBMC went live for the CWE day-ahead market coupling – replacing the former ATC-method. Intraday market coupling is still based on the ATC-method, although the implementation of FBMC for CWE intraday is anticipated for the end of 2017. Within the CACM Guideline, the focus shifts from CWE towards the CORE level which integrates both Central West and Central East Europe (CWE + CEE). The development and implementation of FBMC at the level of the CORE region is underway, both for the day-ahead and the intraday market, as well as a flow based calculation of the long term transmission rights.

The performance evaluation of the first 1.5 years of CWE day-ahead FBMC operation, presented in this monitoring report, reveals both strengths and weaknesses of the current design and implementation of FBMC. On the one hand, with FBMC, cross-border commercial exchange (including both day-ahead and long-term), has reached volumes of up to 8,829 MW, far above the maximum of 7,023 MW recorded with ATC in 2012. Therefore, since the introduction of FBMC, maximum values for transit flows through Belgium and for physical flows on the Northern and Southern Belgian borders have been recorded. On the other hand, there was a significant amount of congested hours with very low CWE cross-zonal volumes. The 10% percentile with FBMC was 2,311 MW compared to 3,351 MW with ATC. In 2016, the average CWE cross-zonal exchange during congested hours amounted to 3,793 MW. This is the lowest value in 5 years, with averages in 2012 to 2015 being in the range of 4,323 MW and 4,534 MW.

The main reason for the observed reduction of cross-zonal trade during congested hours is due to network constraints. With the current FBMC design, transmission lines inside a bidding zone and which are close to congestion because of domestic trade, can be introduced in the cross-zonal FBMC mechanism. In 55% of the congested hours, cross-zonal trade was limited by internal lines preloaded by physical flows arising from domestic trade - having less than 12% of their thermal line capacity available for cross-zonal trade. The inefficiency of this approach is reflected in the associated shadow prices of more than 153 €/MW. As calculated by CWE TSOs, this has halved the potential social welfare gain which could be realized with FBMC compared to ATC. The impact of these network constraints has been so large, that the LTA-inclusion patch had to be applied almost 70% of the time. LTA-inclusion ensures that volumes exchanged in day-ahead are large enough to remunerate holders of long term transmission rights. In other words, it was the long-term allocated transmission rights which assured that a minimum amount of capacity was made available for the day-ahead market coupling.

For reasons of efficiency, non-discrimination, competitiveness and security of supply, the observed flaws in the CWE FBMC design need to be addressed as soon as possible – and the lessons learned integrated in the design of the FBMC for the day-ahead and intraday market coupling at the CORE region.

V. Balancing

For 2016, minimum control capacities to contract were equivalent to 73 MW for FCR, 140 MW for aFRR and 770 MW for mFRR.

Since the transition to the marginal price to balance tariffs in 2012, the average tariff for positive imbalances is very close to that of the negative imbalances, the difference between the two being the average incentive. For the first time since 2012, these two average tariffs were lower than the average price of Belpex DAM in 2016. Although the volatility of the imbalance tariffs increased considerably in 2015 (more than the price volatility of Belpex DAM), volatility in 2016 decreased for imbalance tariffs and continued to rise for the Belpex DAM price. However, both volatilities, expressed relative to the average, continued to increase in 2016.

Again in 2016, total energy of balancing products activated (excluding IGCC exchanges) decreased by 18% compared to 2015, to 0.64 TWh.

Activated volumes of tertiary reserves contracted and inter-TSO reserves remained negligible. They include demand-side participation, but the CREG believes that a great potential of demand-side participation remains unexploited.

Activations of ICH products are rare, and the volumes interrupted, as well as the number of such events, are rather low. These products will no longer be proposed in 2018.

While the share of automatic control (IGCC & aFRR) decreased slightly in 2015, it continued to increase in 2016, as has been the case since 2012.

INTRODUCTION

In this study, the COMMISSION FOR ELECTRICITY AND GAS REGULATION (CREG) examines the functioning and price evolution of the Belgian wholesale electricity market over the period 1 January to 31 December 2016. The CREG has carried out a similar study every year since 2007.

The aim of these studies is to inform all stakeholders about important aspects of the Belgian electricity market, in particular electricity consumption, generation, electricity trading on electricity exchanges, interconnections with foreign countries, and balancing.

To the extent possible, the historical background of the last 10 years (2007-2016) is provided. 2007 is included in this study since it pre-dates the economic and financial crises of the period studied. As such, the reader will be able to understand the evolution of the wholesale electricity market more easily.

This study includes 5 chapters :

1. the 1st chapter examines electricity consumption ;
2. the 2nd chapter scrutinises electricity generation more specifically ;
3. the 3rd chapter covers electricity trading on markets ;
4. the 4th chapter analyses the interconnections between Belgium and its neighbouring countries;
5. the 5th and final chapter covers balancing.

An *Executive Summary* precedes these five chapters. Several conclusions will also be made at the end of the study. At the end of the document, the reader will find a glossary, the main abbreviations used in the study, a list of the works quoted, and a list of the figures and tables used throughout the study.

The Executive Committee of the CREG approved the present study at its meeting of 28 September 2017.

FUNCTIONING OF THE WHOLESALE ELECTRICITY MARKET

1. PRELIMINARY NOTE

○ *The energy market*

1. The electricity market does not evolve in isolation, and various parameters have an impact on it to varying degrees. Over the period 1 January 2007 until 31 December 2016, the "energy world" evolved considerably. For example, Figure 1 below shows the often considerable changes in the prices of three of the most important types of energy.

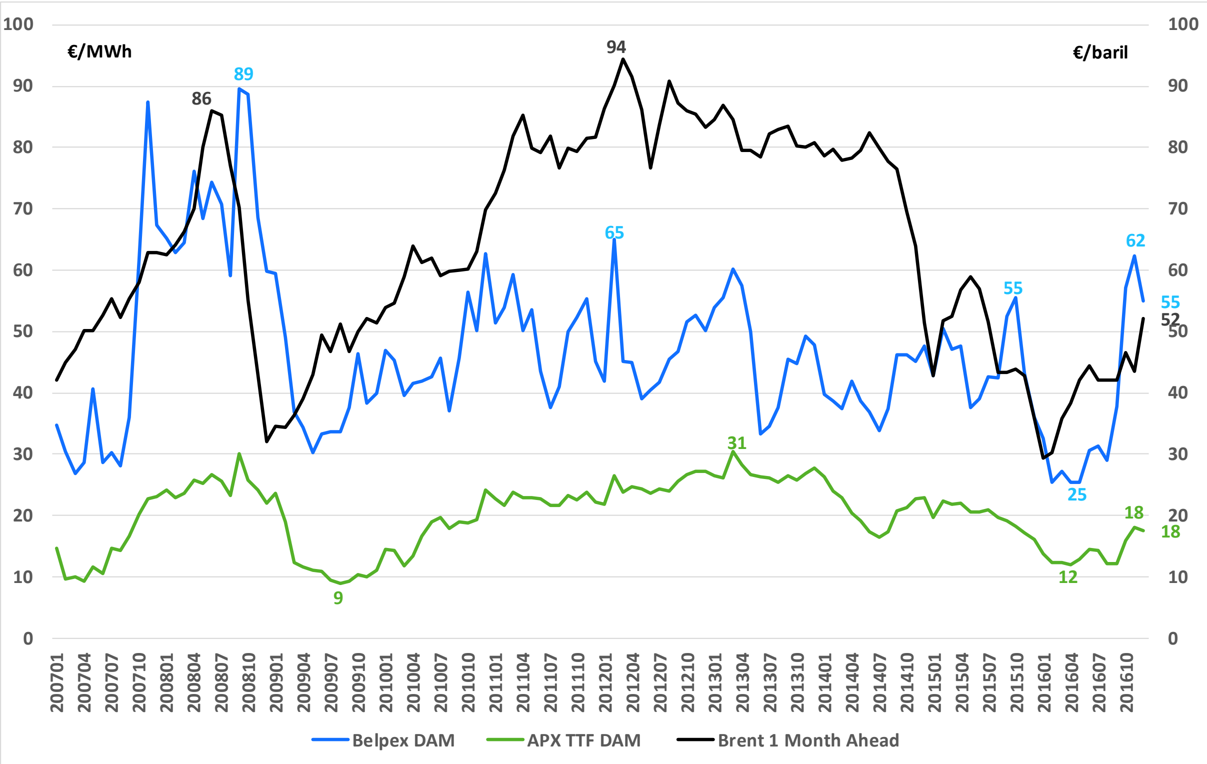

Figure 1: Evolution of the prices of electricity (€/MWh), gas (€/MWh) and petrol (€/barrel) between 2007 and 2016
Sources: Belpex, ICE ENDEX and CREG calculations

○ *The Belgian electricity market*

2. The CREG has received almost all the data[2] included in this study from the transmission system operator (hereinafter referred to as the GRT and/or Elia) and the Belpex exchange; it then processed the data by occasionally incorporating supplementary information, but indicating each time the source of the data and the calculations made, below the tables and figures.

[2] The data communicated are the data which were available at the time the study was published. These data may vary from previous studies, since they are often estimates, and some data may even be the subject of corrections in later years.

[3] The principle pertaining to the extension of the Doel 1 & 2 power stations was approved by the law of 28 June 2015 amending the law of 31 January 2003 on the gradual phasing-out of nuclear energy for industrial electricity generation purposes, in order to guarantee security of supply for energy (Belgian Official Journal of 6 July 2015).

3. The present study relates to the functioning and price evolution of the Belgian wholesale electricity market in 2016. The wholesale market represents the electricity market in which purchases and sales of energy are traded before being supplied to end customers, whether private individuals or companies. Although it is part of the wholesale market, the *Over-The-Counter* (OTC) market was not examined as part of the present study.

Table 1 and Figure 2 below give an overall view of the Belgian electricity market.

- *The energy balance of the electricity market between 2007 and 2016*

4. The energy balance of the Elia network shown in Table 1 provides an overview (GWh) per year over the period 2007 to 2016 :

- of gross physical flows of imports and exports per country ;
- of the load on the Elia network and its losses ;
- of injections into the Elia network in Belgium by connected power stations (including pumped storage stations), and net injections from distribution networks and local generation (>30 kV);
- of the equilibrium balance if 'consumption - net injections' are added to 'exports - imports'.

Statistical differences appear to exist between this energy balance and some of the figures included in the study, since, depending on the subject in question, certain data are aggregated or not at a given moment, such as for example the inclusion or not of pumped storage stations in the data, or network losses. The definition of the 'load on the Elia network' at the bottom of the page in chapter I "Electricity Grid Load" is another example. To the extent possible, the statistical differences shown in the same title will be defined and/or justified.

Import (GWh)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
France	8.332	7.386	1.832	3.167	7.221	7.453	8.777	11.222	9.814	4.795
Luxemburg	2.084	1.629	1.868	1.846	1.532	1.386	702	994	485	1
The Netherlands	5.266	8.119	5.787	7.383	4.515	8.010	7.765	9.575	13.417	9.854
Total	15.681	17.133	9.486	12.395	13.267	16.849	17.243	21.791	23.717	14.650

Export (GWh)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
France	2.322	2.039	6.643	5.409	2.330	2.341	2.435	967	1.437	5.236
Luxemburg	1.631	1.518	910	1.122	1.318	879	786	185	260	310
The Netherlands	5.084	3.005	3.769	5.313	7.004	3.692	4.382	3.037	1.022	2.921
Total	9.037	6.561	11.322	11.844	10.652	6.911	7.603	4.188	2.718	8.467

Net export (+) / import (-) (GWh)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	-6.644	-10.572	1.835	-552	-2.615	-9.937	-9.641	-17.602	-20.999	-6.183

Elia Grid Load - net injections (GWh)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	6.644	10.572	-1.835	552	2.615	9.937	9.641	17.602	20.999	6.183

Net injections (generation)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Injection from Access Holders	74.908	70.480	76.192	76.545	70.747	61.661	62.051	52.110	47.030	61.640
Production locally consumed	6.842	6.640	7.214	9.069	9.647	9.905	8.941	8.189	9.503	10.107
Injection from DSO	77	194	679	697	654	786	850	957	1.073	1.120
Total	81.826	77.315	84.085	86.311	81.047	72.352	71.842	61.256	57.606	72.868

Elia Grid Load	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Direct customers	29.848	29.198	25.740	29.177	28.939	28.596	28.175	28.078	28.466	28.685
Distribution	57.047	57.060	55.109	56.111	53.265	52.248	51.844	49.349	48.763	48.981
Total	86.895	86.258	80.850	85.288	82.203	80.844	80.019	77.426	77.229	77.666
Energy losses	1.575	1.629	1.401	1.575	1.459	1.446	1.464	1.432	1.375	1.385

Table 1: Energy balance of the Elia network between 2007 and 2016 (GWh)
Source : Elia

For the period studied, 2016 was characterised by :

- net imports of 6,183 GWh, a reduction of 70.6% compared with the record year of 2015. This evolution can be explained by a 38.2% reduction of gross imports, and a 211.5% increase in exports;
- the three neighbouring countries (FR, NL and LU), the Netherlands is the only net exporter country to Belgium ;
- net injections of 72.9 TWh ;
- Elia grid load (77.7 TWh) at a similar level to the two previous years, under the weight of low distribution offset by a slight, but regular for three years, increase in electricity consumption by direct customers connected to the Elia network.

5. As was the case in 2014 and 2015, the balance of the Belgian wholesale electricity market in **2016** cannot be drawn up without the backdrop of the Belgian nuclear fleet issue. Although in 2014 and 2015, long and frequent stoppages in nuclear power stations were an essential factor in explaining the disruption to Belgian electricity generation, 2016 is characterised on the other hand by the restarting and extension[3] of many of these power stations.

○ The wholesale electricity market in 2016

6. Figure 2 provides an overview, **for every working day in 2016**, of the evolution of the daily averages (MW and C°) of :

- the load on the Elia network (dark blue line) ;
- generation capacity (blue line) ;
- net physical import flows (red line) ;
- electricity generation from nuclear power stations (yellow line) ;
- the equivalent temperature[4] (dotted green line).

[3] The principle pertaining to the extension of the Doel 1 & 2 power stations was approved by the law of 28 June 2015 amending the law of 31 January 2003 on the gradual phasing-out of nuclear energy for industrial electricity generation purposes, in order to guarantee security of supply for energy (Belgian Official Journal of 6 July 2015).

[4] The equivalent daily temperature is obtained by adding 60% of the average temperature of Day X to 30% of the temperature of Day X-1, and by adding this result to 10% of the temperature of Day X-2 (source : http://www.aardgas.be/professioneel/over-aardgas/nieuws-en-publicaties/graaddagen).

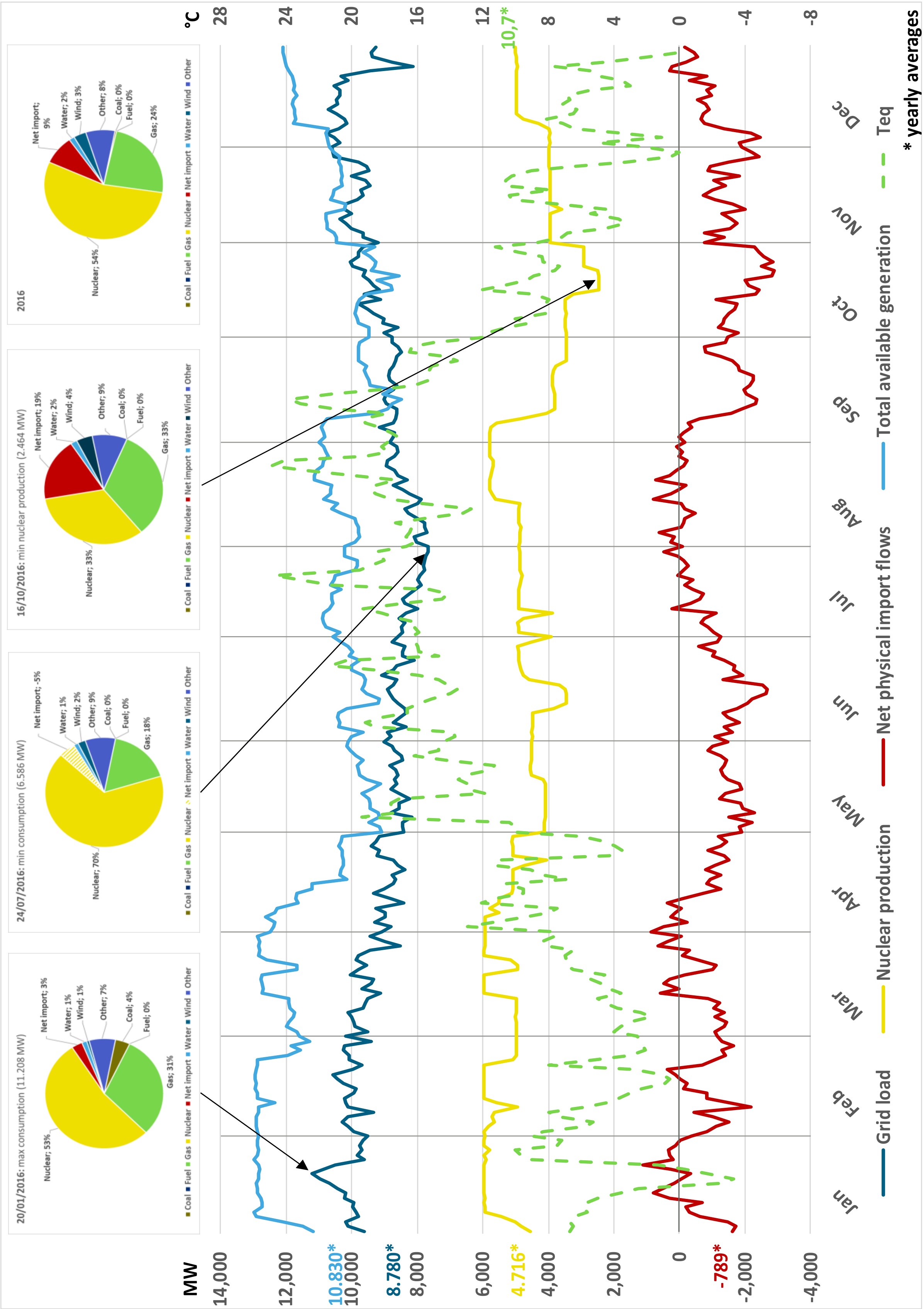

Figure 2: Evolution of the daily average consumption (dark blue), total generation capacity (light blue), nuclear energy generated (yellow), net import volumes (red) and daily equivalent temperature (green) for all working days of 2016
Sources : CREG and Elia

7. 2016 showed some significant evolutions compared to 2015, as reflected in Figure 2 above. This graph shows the interaction between the available domestic generation facilities (light blue), the grid load (dark blue), nuclear generation (yellow), net import flows (red) and the equivalent daily temperature (green) for all working days[5] of 2016.

While Belgian generation units generally suffice to cover domestic demand (i.e. the grid load), some days in September, October and the end of November show that Belgian generation does not entirely cover the grid load. On these days, there is more intensive use of the interconnection facilities with higher import flows.

We note that the grid load is highest in January, on average, as well as in November and December. The highest grid load (11,208 MW) was recorded on 20 January 2016. This was, not coincidentally, the coldest day of the year with an equivalent temperature of -3.3°C. This negative correlation between the grid load and the temperature will be further highlighted later in this study. Fortunately, the full availability of nuclear generation units ensured that domestic power stations were largely sufficient to cover demand – so no high reliability on imported electricity was observed on that day.

When we look at the day with the lowest grid load (i.e. 24 July, with 6,586 MW), we see that the generation mix consists of mostly nuclear generation (70%) and net imports are negative: 5% of the total grid load is exported to neighbouring countries.

On 16 October 2016, we observed the lowest nuclear generation, due to low availability of the reactors: only 33% of Belgian generation was based on nuclear power stations. To put this into perspective, the average nuclear generation over the entire year 2015 also equalled 33%. On 16 October, the reduced availability of nuclear reactors in combination with an average grid load, caused gas-fired power stations to run significantly more (i.e. 33% of total generation as opposed to the yearly average of only 24%) and the control area relied more heavily on import flows (19%; yearly average is 9%).

[5] Week-ends and holidays are omitted as these typically show lower grid usage. Only focusing on working days improves the legibility of the data.

2. ELECTRICITY GRID LOAD

2.1. HISTORICAL BACKGROUND : SIGNIFICANT EVENTS

2008

- eruption of the financial crisis

2012

- February 2012 cold spell in France and Belgium

2.2. SPECIAL TOPIC: IMPACT OF MASS INTRODUCTION OF ELECTRIC VEHICLES

8. In 2014, there were 5.6 million passenger cars in Belgium[6]. In total, they drove 83.9 billion kilometres or on average about 15,000 kilometres per car per year, or on average 41 kilometres per car per day.

9. In 2016, there were 4,368 electric passenger cars in Belgium or less than 0.08% of the total number of passenger cars. Although electric cars are still a rarity, many big car companies seem to be betting on the mass introduction of electric passenger cars[7] in the near future. This will have an impact on the wholesale electricity market. The speed of this mass introduction, and whether it will occur, is difficult to predict.

10. In this special topic, we briefly analyse the impact of such a mass introduction of electric vehicles in Belgium on the electricity consumption and on the supply needs.

2.2.1. Characteristics of the Electric Passenger Car

11. The typical electric passenger car is assumed to have a battery storage capacity of 50 kWh. This is probably an underestimate of the real capacity for future electric passenger cars, since the cost of batteries continues to fall and the cars' autonomy continues to increase. It is safe to assume several cars on the market will have an autonomy above 300 km.

12. With regards to electric consumption, the VAB assumes 0.15 kWh/km[8]. However, other sources indicate that the real individual consumption is higher. So, we assume a substantial higher electric

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[6] Data on passenger cars in Belgium from FOD Economie : http://statbel.fgov.be/nl/statistieken/cijfers/verkeer_vervoer/verkeer/voertuigpark/.

[7] Thierry van Kan, the president of Febiac, the Belgian Federation of Automobile and Motorcycle Industries, said he expects around 20% of car sales in Belgium to be electric cars in 2020, the equivalent of 100,000 vehicles per year. (De Tijd, 20 June 2017, http://www.tijd.be/ondernemen/auto/Voorzitter-autolobby-Tijd-van-de-petrol-is-voorbij/9905794).

[8] https://www.vab.be/nl/nieuws/2016/8/10/kostelektrischrijden.

consumption of 0.20 kWh/km[9]. The average daily electric consumption per car is then 0.20 kWh/km * 41 km = 8.2 kWh.

Typical electric passenger car		
Usable battery storage	50	kWh
Electric consumption	0.20	kWh/km
Distance driven	15,000	km/year

Table 2: Characteristics of a typical electric passenger car
Sources : VAB and CREG

13. With these characteristics, it is easy to calculate the additional electricity consumption and battery storage capacity when the use of electric passenger cars increases sharply. The following table shows this impact for different numbers of electric cars.

number of cars	distance driven	total yearly consumption by electric cars	% of total electricity consumption	total daily consumption	storage capacity	total "free" storage capacity
	billion km	TWh	%	GWh	GWh	GWh
100,000	1.5	0.3	0.4%	0.8	5.0	4.2
250,000	3.8	0.8	0.9%	2.1	12.5	10.4
500,000	7.5	1.5	1.9%	4.1	25.0	20.9
1,000,000	15.0	3.0	3.8%	8.2	50.0	41.8
2,000,000	30.0	6.0	7.5%	16.4	100.0	83.6
5,000,000	75.0	15.0	18.8%	41.1	250.0	208.9

Table 3: Electricity consumption and battery storage capacity depending on the number of electric passenger car
Source : CREG

14. Given the annual electricity consumption of around 80 TWh, it is clear that even with one million cars, the impact on total consumption is small: an increase by 3 TWh or a little less than 4%. Only when several million cars become electric, will there be a significant impact on electricity consumption.

15. On the contrary, the relative impact on the storage capacity within Belgium becomes significant, even with a relatively small number of electric cars. The current storage capacity in Belgium is about 6 GWh[10]. Already 100,000 electric cars with a capacity of 50 kWh each will increase this by 5 GWh, or almost double the existing storage capacity. Of course, part of this capacity will be used for driving purposes. But since the storage capacity of each car is much higher than the average daily need for driving, most of the storage capacity will -on average- not be used for driving and is “free” for use on the electricity market. With a battery storage of 50 kWh and an average daily consumption of less than 10 kWh, the average “free” storage capacity can be more than 80% of total storage capacity.

16. This “free” capacity can be used to deliver services to the grid or to arbitrage on the wholesale market, by buying, storing and selling electricity. This implies that the electric car can also supply power to the grid (the so-called “vehicle-to-grid”).

17. Importantly, also without supplying power to the grid, an electric car can deliver services to the grid or arbitrage on the wholesale market by not charging the battery during the day when prices are

[9] A consumption in the range of 0.15-0.22 kWh/km will not significantly change the conclusions.
[10] Mostly pumped-hydro-storage Coo and PlateTaille.

generally higher and postpone this until night time or weekends when prices are generally lower. The time of charging is crucial.

2.2.2. Electricity Demand vs Supply Capacity

18. Since electric cars can store electricity, their electricity offtake from the grid can be planned. In this section it will be demonstrated that well-timed battery charging could avoid the need for any additional supply capacity, even when there are a million electric cars on Belgian roads.

19. Good timing means that the battery of the electric car is charged when electricity demand is lower than maximal supply capacity. On average, this means that charging does not occur during peak hours in the morning and the evening, giving the current situation. The figure below shows a typical working day during January 2016. It is clear that it is possible to consume or store additional electricity at night, in the afternoon and the late evening.

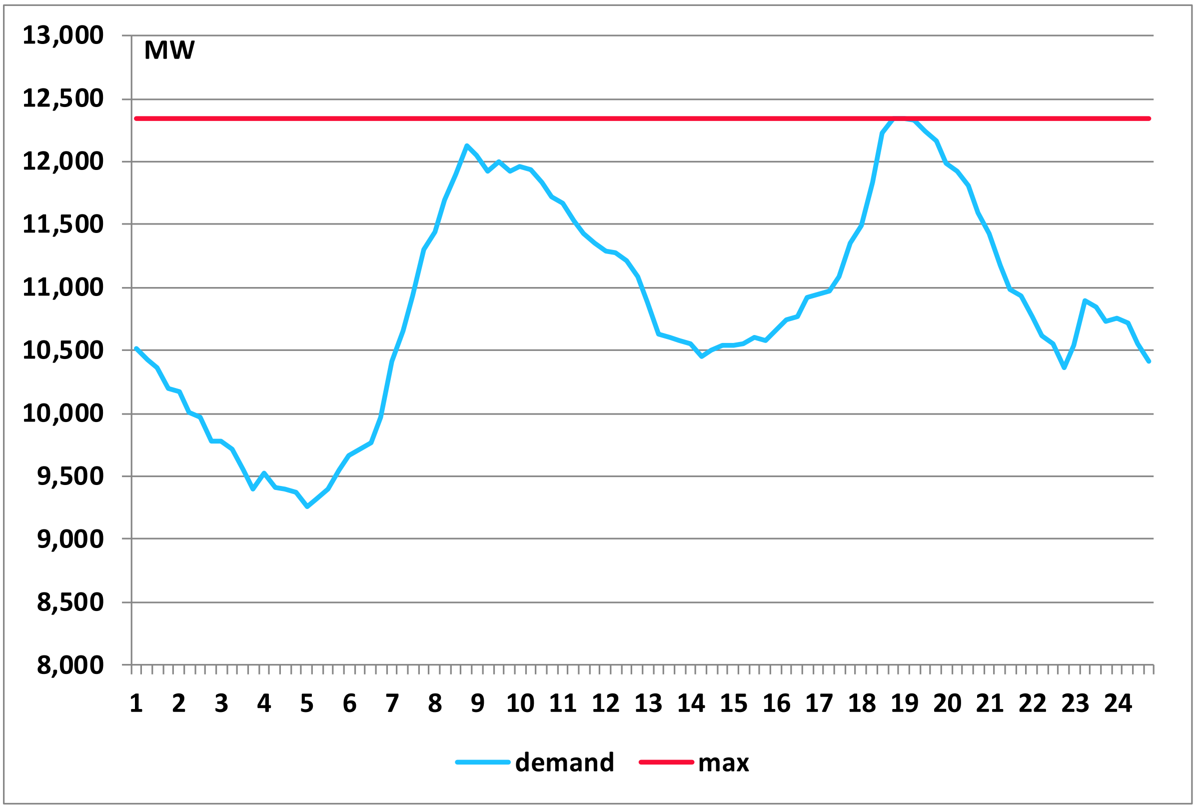

Figure 3: Electricity demand during a typical working day in January 2016
Sources : CREG and Elia

20. In this section, the maximal supply capacity is roughly estimated as the maximum grid demand as measured by Elia during 2016 minus 1,000 MW. Since some supply capacity is energy-limited, like demand response and pumped-storage, we subtract 1,000 MW from the maximum grid demand to determine a rough estimate of the maximal supply capacity which is assumed not to be limited in energy. For 2016, the maximum grid demand was 12,734 MW. The maximal supply capacity is then 12,734 MW – 1,000 MW = 11,734 MW. So it is assumed that in 2016 there was 11,734 MW of supply capacity in Belgium that was not limited by energy. This is generation capacity and import capacity combined.

21. The CREG is aware this is a simplistic approach to calculate the maximal supply capacity, but given the results below, it is a good enough approach in this context.

22. Based on the grid demand (per quarter hour) and the maximal supply capacity (11,734 MW in 2016), it is possible to calculate the additional electricity that could have been supplied on a daily basis in 2016 without surpassing the maximal supply capacity. The figure below gives this result for each day of 2016 :

- the orange line ("night (11.00pm-7.00am)"): the daily additional electricity that can be supplied during night (from 11.00pm to 7.00am), without surpassing the maximal supply capacity ;
- the blue line ("day + night"): the daily additional electricity that can be supplied during the day, without surpassing the maximal supply capacity ;
- three horizontal lines (red, turquoise, green) : the daily average consumption of 1, 2 or 5 million electric cars (8.2, 16.4 and 41.1 GWh respectively).

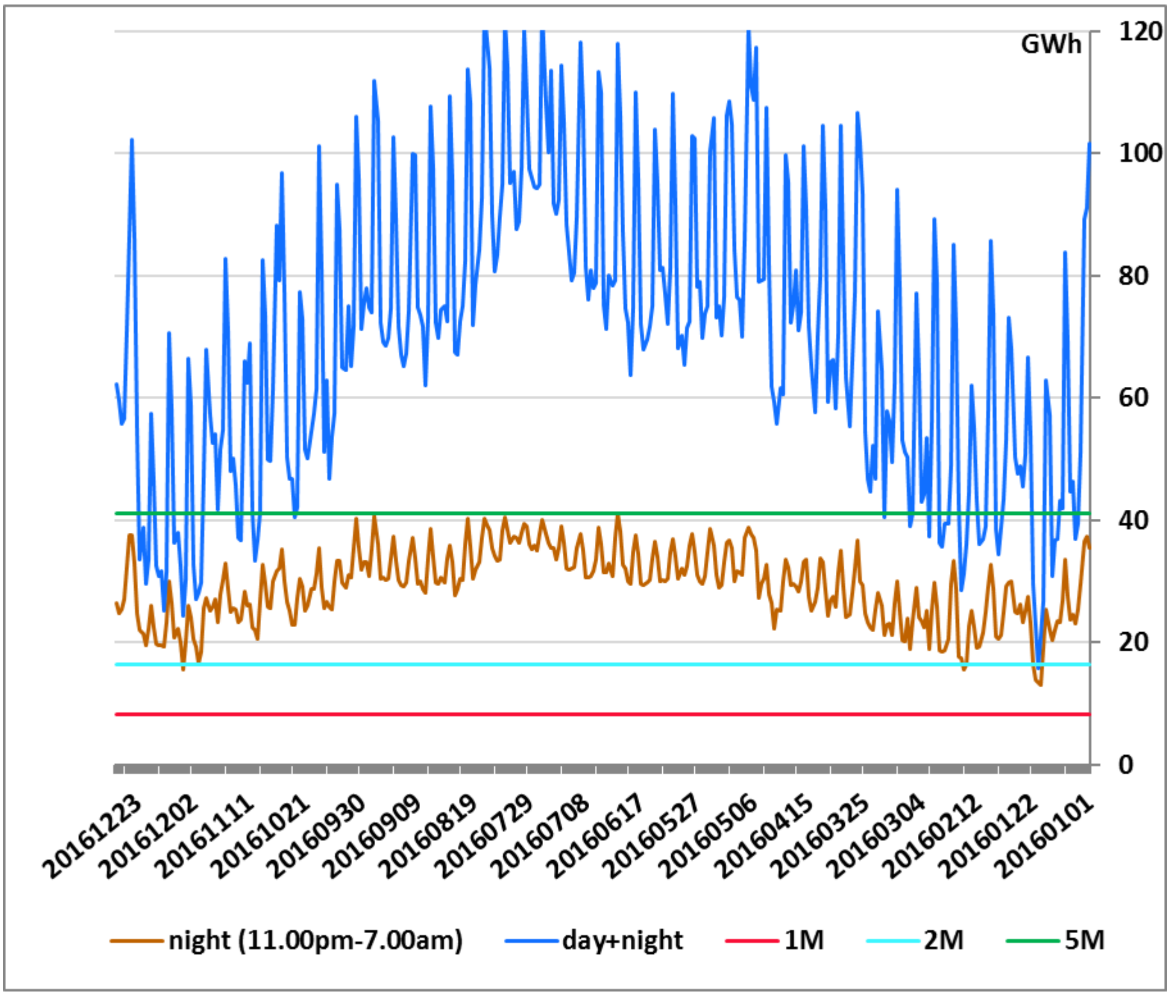

Figure 4: additional electricity that can be supplied during night/day compared to average daily electricity consumption for 1, 2 and 5 million electric passenger cars
Sources : CREG and Elia

23. The figure shows that the red line is below the orange one, which means that the average daily consumption of 1 million electric cars can be generated by available supply capacity during the night. Even the batteries of 2 million electric cars could almost always be charged during the night with existing supply capacity, except for some days during winter[11]. Only when 5 million electric cars are on

[11] Even during these days, it could be possible not to surpass the maximal supply capacity by charging less during some critical nights and using the whole capacity of the 50 kWh car battery for driving purposes.

Belgian roads, it is clear that charging should also be done during the day, which means additional charging infrastructure. During winter, there are several days where existing supply capacity, as defined in this analysis, will not be sufficient to charge all 5 million electric cars. For more than one or two million electric cars, a more sophisticated approach for calculating the maximal supply capacity is needed.

24. Of course, even with smart charging, some electric cars will be charged during traditional peak hours, mostly in the evening. But this additional peak demand could be supplied by other electric cars in a “vehicle-to-grid” modus.

2.2.3. Conclusion

25. Although this simulation uses an average daily consumption of electricity for driving purposes, which simplifies real consumption and driving patterns, the important conclusion of this simulation is that even with one million electric cars, we are far from exceeding the maximal supply capacity during the night.

26. This means that a massive introduction of one – or even two – million electric passenger cars in Belgium will not decrease security of supply, on the condition that electric cars are charged in due time. On the contrary, by consuming more during off-peak hours, the running hours of generation capacity will increase, thereby increasing their profitability and possibly even attracting new investment.

27. On top of that, even at a fairly modest introduction, the electric cars could themselves become a supply source because of the increased storage capacity: only 100,000 electric passenger cars would in theory almost double the existing electricity storage capacity in Belgium.

28. There is one crucial condition for the above conclusions to hold: electric cars should be charged in due time. In this simulation, we looked at demand levels to conclude that the electric car should not be charged during peak hours, but e.g. during the night. Of course, more effective are the price signals on spot markets which will provide the best information regarding when to charge electric cars. As such, for a smooth and efficient mass introduction of electric cars, electricity consumption for charging car batteries needs to be billed per hour or quarter hour. If this is the case, electric cars will not jeopardize security of supply, but they will improve it, along with improving market functioning.

2.3. STATISTICS

2.3.1. Evolution of the Grid Load

At the European level

29. Figure 5 illustrates the hourly electricity demand peak from 2011 to 2016 for Belgium and its bordering countries. In the Netherlands and United Kingdom the demand peaks in 2015 and 2016 end up higher than in 2011. For France, Germany and Belgium, on the other hand, the demand peaks in 2015 and 2016 are lower than in 2011. This bearish trend observed is confirmed, more particularly for Belgium (96% in 2016), within the framework of this study.

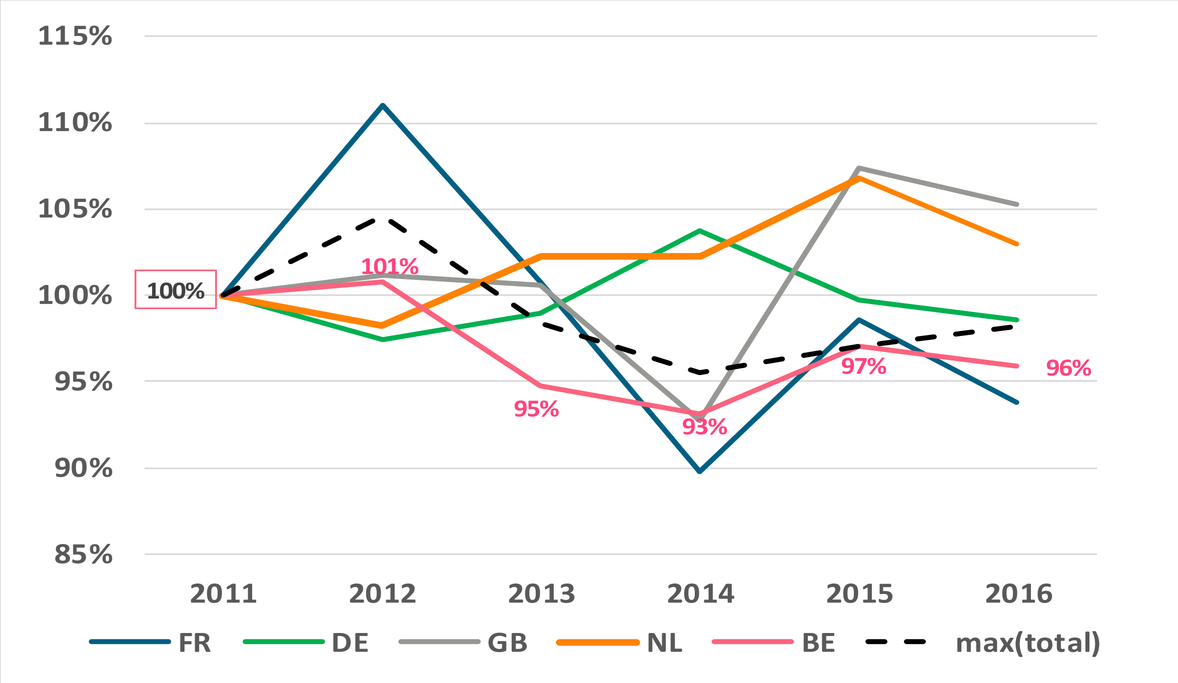

Figure 5 : Evolution of the hourly electricity demand peak (max hour/year) from 2011 to 2016 for Belgium and its bordering countries
Sources : CREG, ENTSOE[12]

At the Belgian level

30. This chapter analyses the evolution of the Elia grid load[13], based on data provided by the TSO. Since this grid load does not take into account a significant part of the distributed generation, it is not equal to the total electricity consumption of Belgium. However, this selected approach gives a good idea of how the electricity market works. Figure 6 give an overview of who consumes electricity coming from the producers and the net imports in 2016.

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[12] Some definitions and parameters of grid load between countries may slightly differ but the general trend per country is valid.

[13] The Elia-grid load is a calculation based on injections of electrical energy into the Elia grid. It incorporates the measured net generation of the (local) power stations that inject power into the grid at a voltage of at least 30 kV and the balance of imports and exports. Generation facilities that are connected at a voltage of less than 30 kV in the distribution networks are only included if a net injection into the Elia grid is being measured. The energy needed to pump water into the storage tanks of the pump-storage power stations connected to the Elia grid is deducted from the total.
Decentralised generation that injects power at a voltage less than 30 kV into the distribution networks is not entirely included in the Elia-grid load. The significance of this last segment has steadily increased during the last years. Therefore Elia decided to complete its publication with a forecast of the total Belgian electrical load.
The Elia-grid comprises networks of at least 30 kV in Belgium plus the Sotel/Twinerg grid in the south of Luxembourg. (Source: http://www.elia.be/en/grid-data/Load-and-Load-Forecasts/Elia-grid-load).

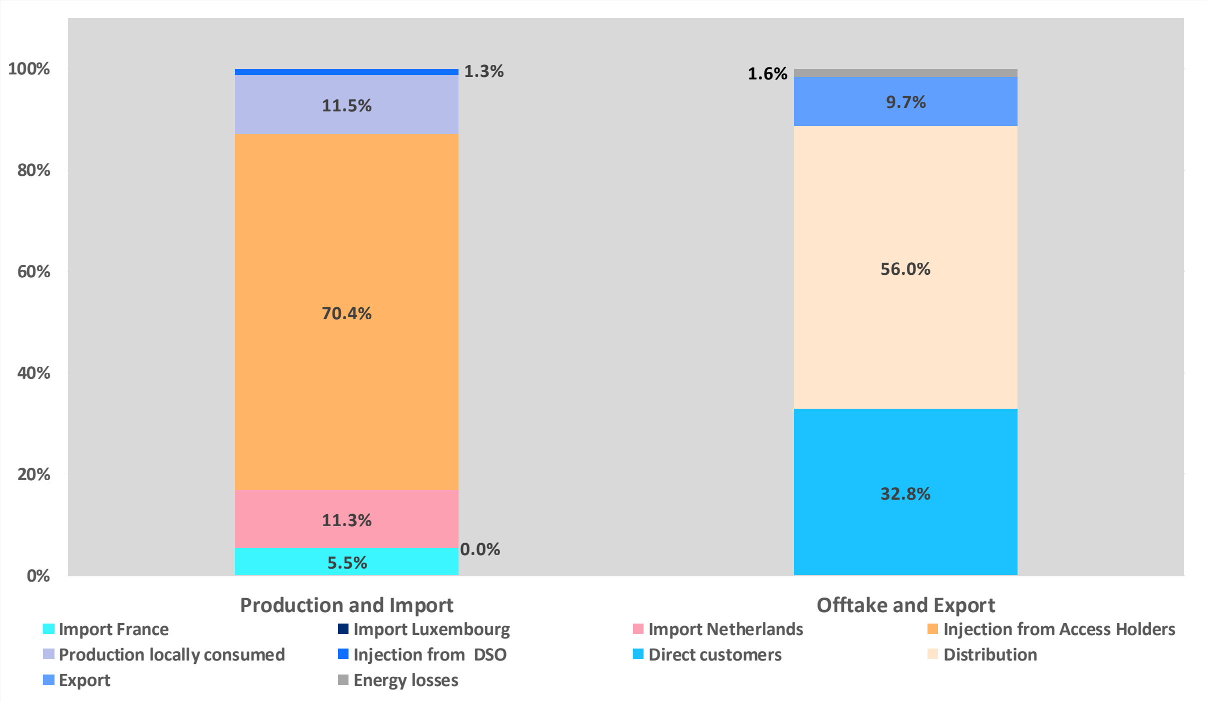


Figure 6 : Who consumes electricity coming from the producers and the net imports in 2016
Sources : Elia, Synergrid and CREG

31. The Elia grid load [14] amounted to 77.3[15] TWh in 2016, at a level similar to that of the previous year, in other words a low level for the period under review. This is illustrated in Figure 7 by the monotonic curves of the Elia grid load. These curves represent the Elia grid load over the last 10 years. For each year the average electricity demand over fifteen minute intervals is classified in decreasing order. On the X-axis, the 8,760[16] hours comprising one year are shown in 15 minute intervals, and on the Y-axis, the electricity demand is shown, expressed in MW.

32. On average, the peak demand over 2007-2016 was slightly lower than 13,500 MW, with 2007 having experienced the highest peak of 14,033 MW. Since 2014, the floor of 13,500 MW has been broken, in other words a higher deviation than 1,300 MW compared to 2007. To meet peak demand, it is necessary to implement significant resources or provide substantial electricity for very discontinuous short periods of time, in other words on average - for the studied period - approximately 1,600 MW (1,710 MW in 2016) during 400 hours (4.6% of the time), of which approximately 1,000 MW during 100 hours or approximately 1,300 MW during 200 hours.

[14] The variations observed between the estimates of consumption of electricity of Synergrid and Elia, are primarily due to the fact that (most of) the generation connected to the distribution grids and the losses of networks of the DSO's are not taken into account in the statement of electricity forwarding only by the Elia network.
[15] A difference of 0.3TWh with Table 1 is due to consumption in pumping mode, inter-TSO flows and production correction.
[16] More 24 hours in 2008, 2012 and 2016 because they are three leap years.

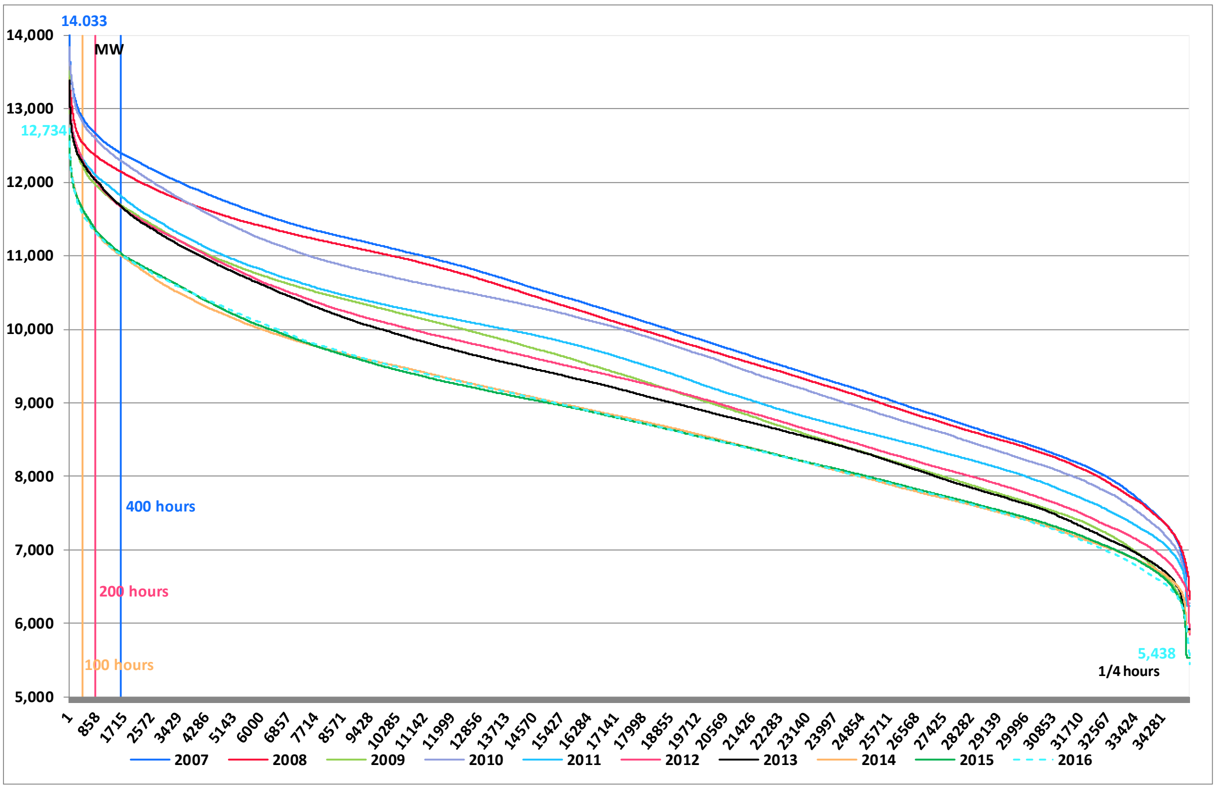


Figure 7: Monotonic curves of the Elia grid load during 2007 to 2016
Sources : Elia, CREG

33. The average electricity demand between 2007 and 2016 was 9,366 MW (8,799 MW in 2016). The baseload can be estimated over the same period, on average, slightly less than 6,000 MW during the 8,760 hours of the year.

34. Figure 8 illustrates, year per year, the evolution of generation, the net imports and the Elia grid load - losses included - according to data presented at Table 1. Table 4 shows the total electricity grid load over the period 2007 to 2016, as well as the maximum and minimum electricity demands during these years. On the whole in 2016, the Elia grid load amounted to 77.3 TWh, a similar level to 2014 and 2015. Bearing in mind that 2016 is a leap year, it is proportionally the lowest level of the last 10 years. To explain this decrease, in addition to the economic situation, technical evolutions regarding a more rational use of energy and the increasing importance of distributed generation, including electricity generated by solar panels and windmills, are important factors in particular.

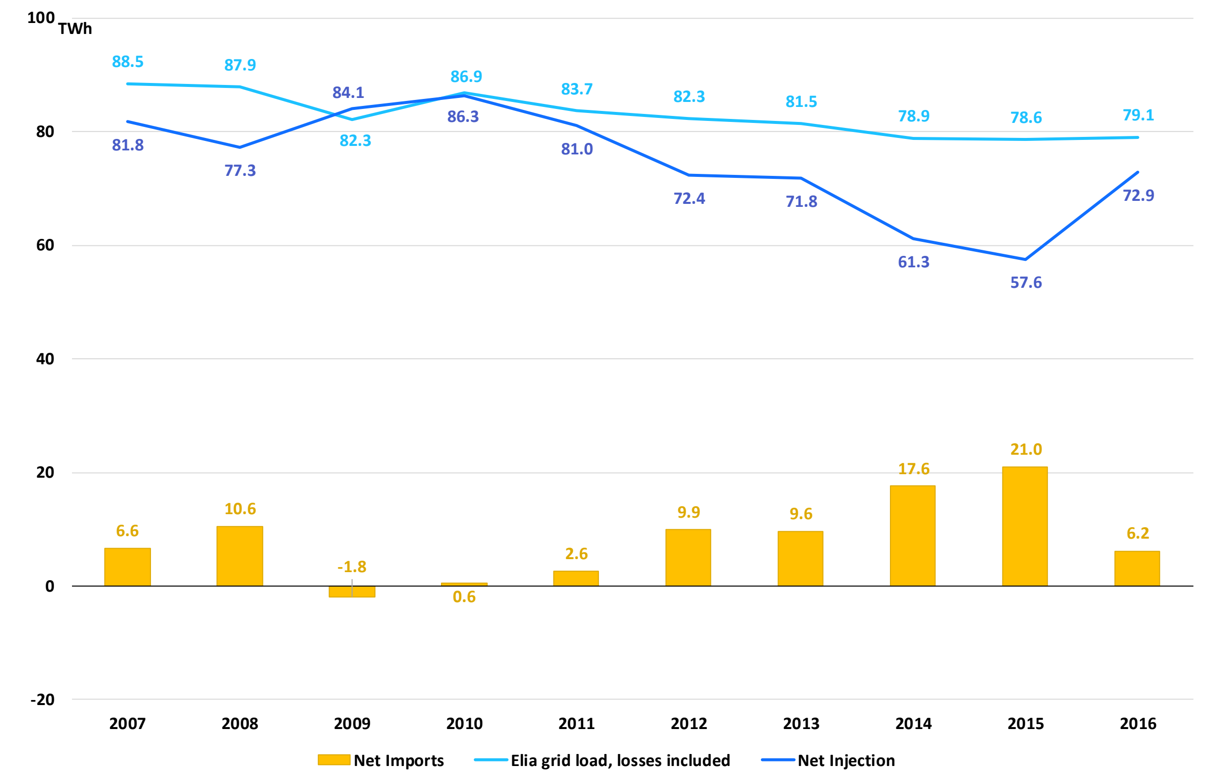


Figure 8 : Evolution of the generation, the imports and the Elia grid load, losses included between 2007 and 2016 (Table 1)
Sources : Elia, CREG

Consumption	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total (TWh)	88.6	87.8	81.6	86.5	83.3	81.7	80.5	77.2	77.2	77.3
Maximum Power Demand (MW)	14,033	13,431	13,513	13,845	13,201	13,369	13,385	12,736	12,634	12,734
Minimum Power Demand(MW)	6,378	6,330	5,895	6,278	6,232	5,845	5,922	5,889	5,529	5,438
Baseload (TWh)	55.9	55.6	51.6	55.0	54.6	51.3	51.9	51.6	48.4	47.8
% Baseload (energy)	63%	63%	63%	64%	66%	63%	64%	67%	63%	62%
% Baseload (power min/max)	45%	47%	44%	45%	47%	44%	44%	46%	44%	43%

Table 4: Elia grid load (TWh) and power demands (MW – 1/4h) between 2007 and 2016
Sources : Elia, CREG

The maximum power demand amounted to 12,734 MW in 2016, a slight rise compared to the previous year which witnessed the lowest level of the studied period. The minimum power demand in 2016 was 5,438 MW, in other words, the lowest level of the period under review. As for the grid baseload, this rose to 47.8 TWh[17], or 61.8% of the total intake, the lowest level of the last 10 years.

35. Figure 9 illustrates the evolution of the annual average and maximum power demand in the Elia control area, as a trend line. The figure shows that the average demand has decreased with by about 1.5 % per year since 2007. More important is the continuous decrease of 1.4% per year on average of the maximum demand between 2007 and 2016. The maximum demand in 2016 was slightly higher than in 2015, the lowest of the 10 years analysed. All in all, the bearish trend continues in spite of the fact that the weather conditions observed in 2016 (2,330 degree-days[18]) worsened compared to those of 2014 (1,828 degree-days) and of 2015 (2,112 degree-days). Compared to the normal degree-days

[17] Minimum Power Demand (5,438 MW) * 8,784 (366 days * 24 hours) / 1,000,000 = 47.8 TWh.
[18] Source: http://www.synergrid.be/index.cfm?PageID=17601&language_code=FRA.

(average over 30 years), 2016 is characterised by a rise of 1.3% whereas the two previous years were respectively 20.6% and 8.2% lower than the average.

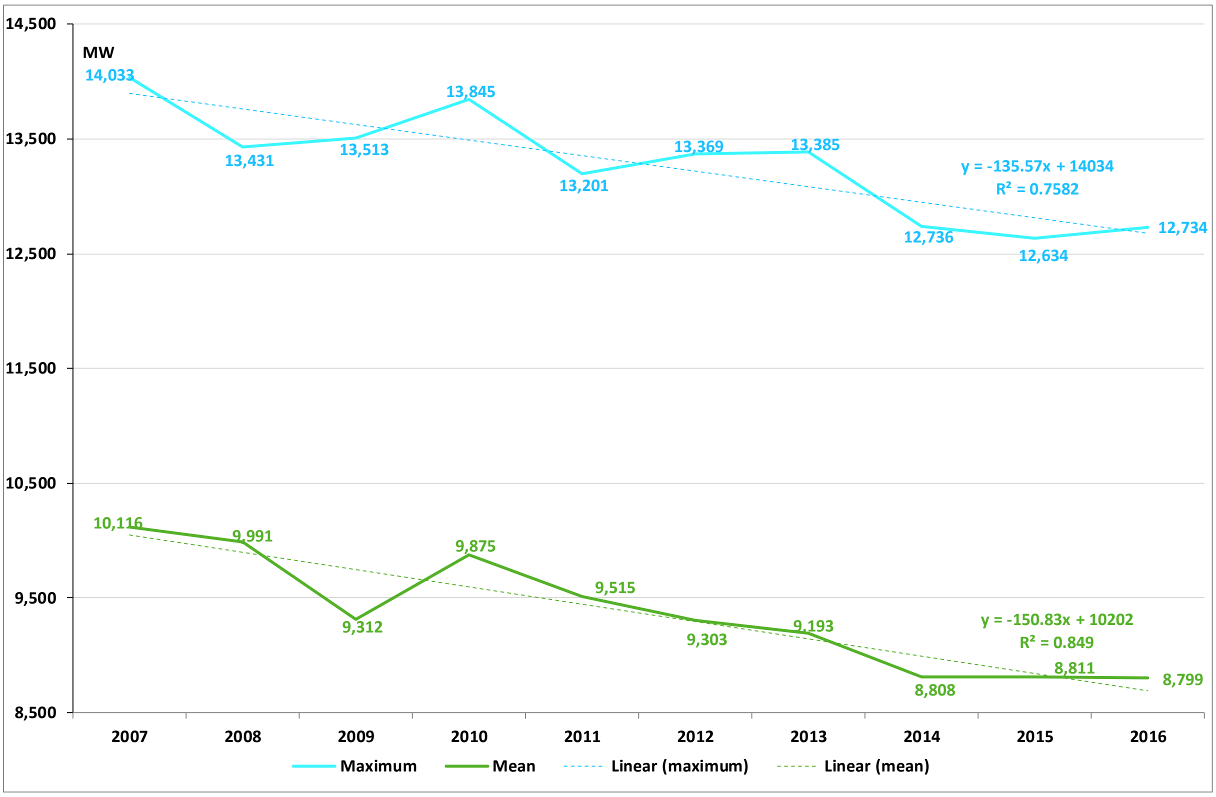


Figure 9 : Evolution of the average and maximum demand (MW) in the Elia control area and their trend curves over the period 2007-2016
Sources : Elia and CREG

36. Figure 10 shows in more detail the evolution of the electricity demand in the Elia control area over the 10 last years. Four levels are shown here:

- the highest level (blue line - “maxCap”);
- 100 hours after the highest level (orange line - “Cap@h100”);
- 200 hours after the highest level (red line - “Cap@h200”);
- 400 hours after the highest level (dark blue line - “Cap@h400”).

Until 2014, all the trends observed were increasingly negative over the years. It appears that the lower the level of the electricity demand, the more the negative trend grew, and the less the variation of this trend was pronounced, the more the predictive index (R^2) increased. The fall of the hour 100 demand level was estimated at 1.2% on average per year. Since 2014, the bearish tendency has marked a stage of consolidation.

The annual difference between the highest level of electricity demand (“maxCap”) and that of hour 100 level (“Cap@h100”) fluctuates between 900 and 1,300 MW. In other words, this means that additional power of only + 1,100 MW is necessary for less than 100 hours to meet the peak demand. For the following 100 hours (“Cap@h200”), slightly more than 200 MW was added. For the 400 hours (“Cap@h400”), or 4.6% of the time, it was necessary to rely on average on 1,600 MW, or 12.0% of the peak demand (13.7% for 2016).

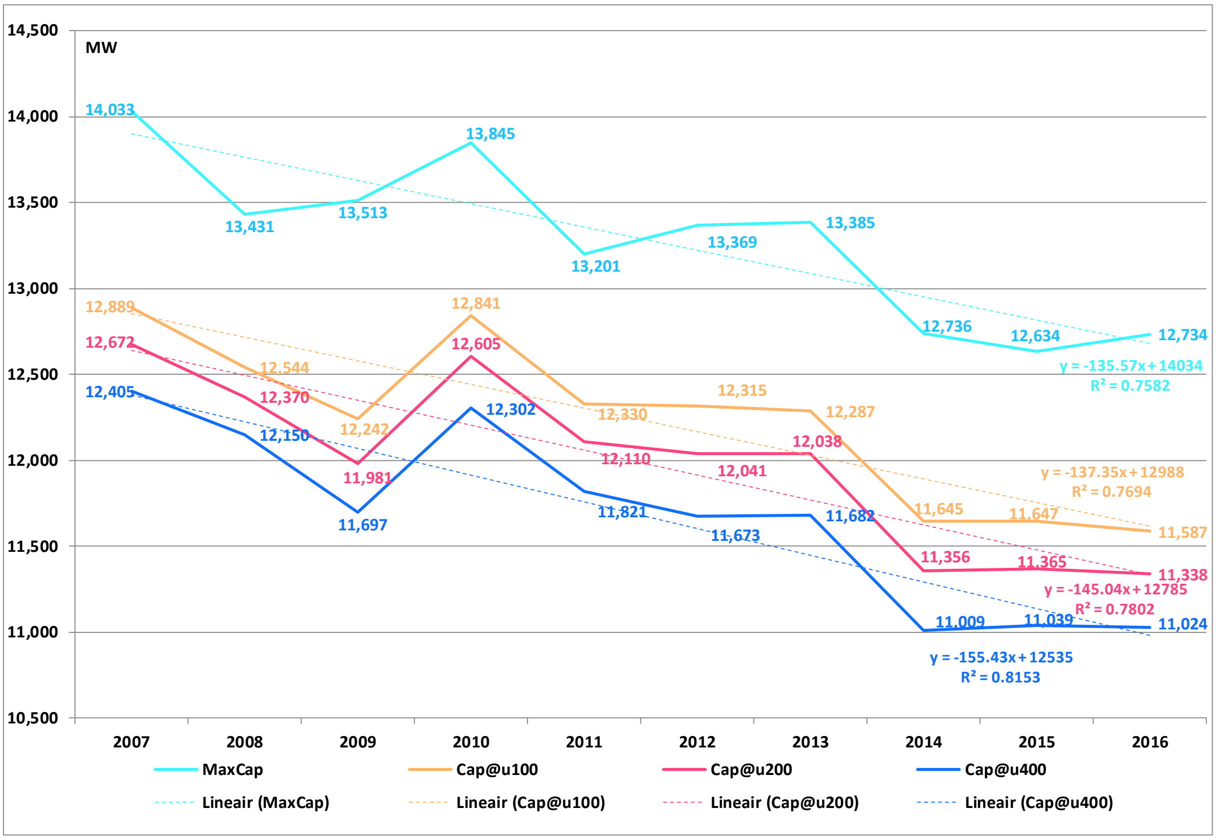


Figure 10 : Evolution of the demand levels classified within the Elia control area (MW) for 2007-2016 (for the higher ¼ hour, hour 100, hour 200 and hour 400), like their trend curve
Sources : Elia and CREG

37. With regards to the Elia control area, the figures indicated above were not adjusted to take the temperature and (most of) the distributed generation into account. For the peak demand, greater price elasticity was observed by the CREG, since major consumers reduce their demand when prices are high. In any case, the CREG wonders to what extent the evolutions observed above are structural or not, or whether they are dependent on the economic situation, meteorological circumstances or other reasons. In other words, will the downward trend of the peak demand and the consumption of electricity continue, for example due to economic growth? In order to be able to answer this question with more certainty, a thorough analysis would be necessary. However, such an analysis is beyond the scope of this monitoring report.

2.3.2. Electricity Demand according to Meteorological Conditions

38. Figure 11 shows the average electricity demand per month. The shape of the curves gives an important indication of the seasonal effects on electricity consumption. During the winter months, the average electricity demand is appreciably higher (up to 2,000 MW) than in the summer months.

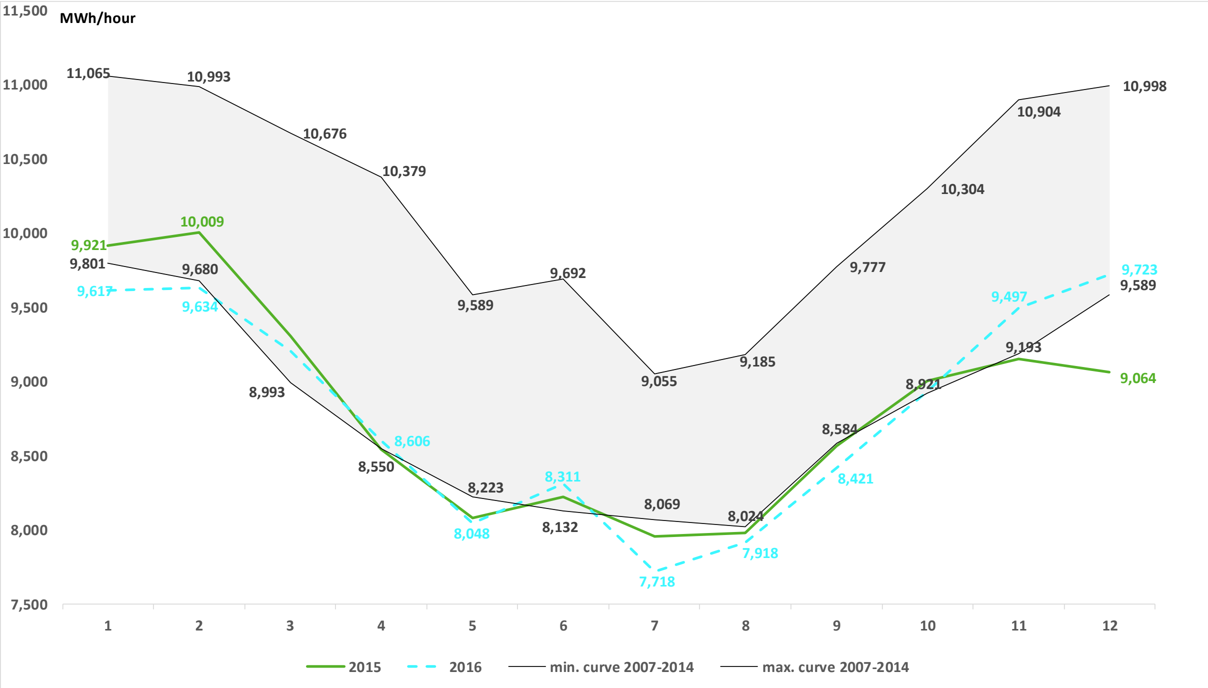


Figure 11 : Average monthly electricity demand in the Elia control area between 2007 and 2016
Sources : Elia and CREG

39. Figure 12 represents for all working days of 2016, the average daily values for the estimated total demand of Belgium and the Elia grid demand (split into the net demand of distribution grids (< 30 kV) and the demand directly connected to the Elia-grid), in relation to the equivalent temperature[19]. In general, all the represented demand levels show a clearly negative relation to the temperature.

40. The explanatory power of the linear regression[20] of the demand in relation to the temperature is quite high (R^2=0.6113). This is mostly due to the explanatory power of the demand of the distribution grids (R^2=0.6420). A decrease of the equivalent temperature by 1°C leads to an increase of the average daily demand of approximately 125 MW. Of this 125 MW increase, a large part (i.e. 105 MW) is due to the behaviour of the demand of the distribution grids. This can be intuitively explained by electric heating used for residential purposes. In contrast, for the same temperature drop, demand by industrial consumers directly connected to the Elia grid (direct demand Elia grid) only increases by 20 MW. Industrial consumers tend to have more stable, predictable demand regardless of meteorological conditions.

41. As we can see on the far right side of the scatter diagram, electricity demand tends to show a positive relation to the equivalent temperature for hotter days. This is related to increased electricity demand for cooling purposes on hot days.

[19] The equivalent daily temperature is calculated as a rolling average of the daily temperatures over the last three days, weighted as follows: 60% of temperature of day D + 30% of temperature of day D-1 + 10% of temperature of day D-2 (source: http://www.synergrid.be/index.cfm?PageID=17601&language_code=NED).

[20] The linear regression is only performed for days during which the equivalent temperature does not exceed 16°C, as the incremental electricity demand for heating purposes can be considered negligible from that point upwards.

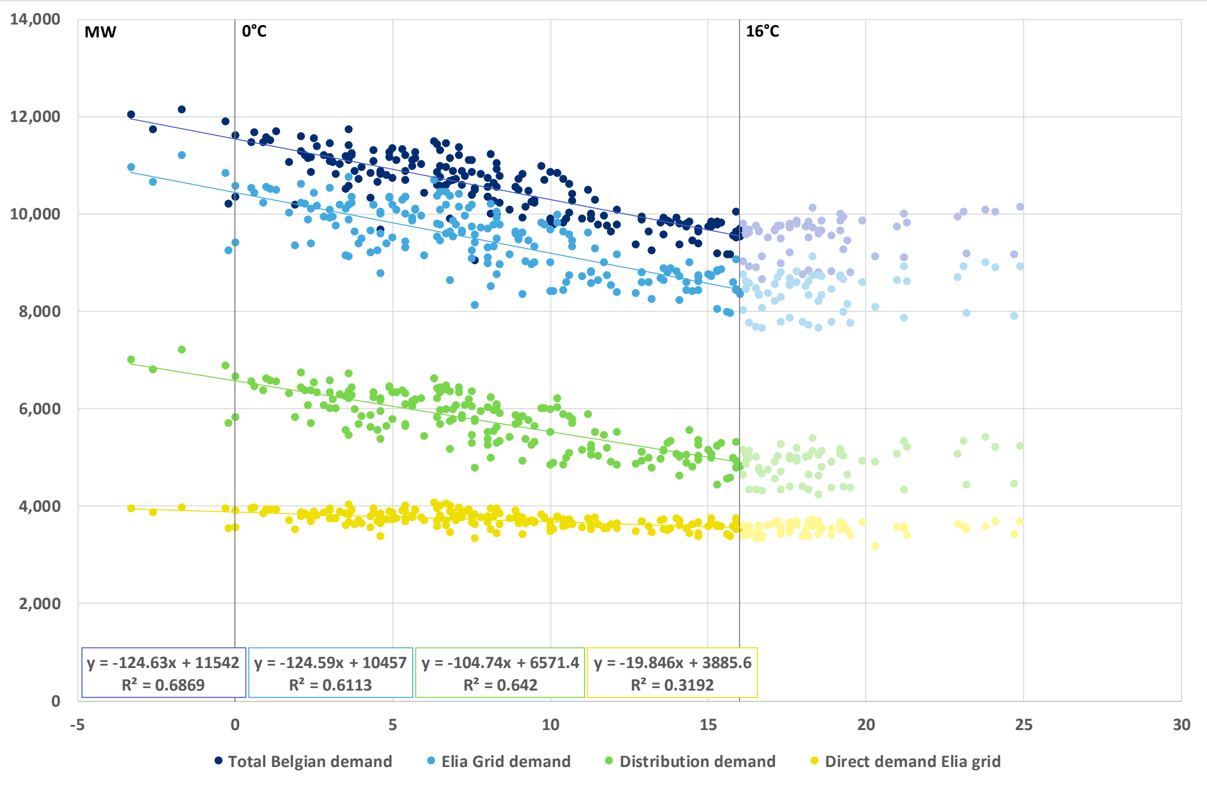


Figure 12: Thermo-sensitivity (in MW/°C) of total Belgian demand and Elia grid demand, split into distribution demand and direct demand on Elia grid, for all working days of 2016

Sources : Elia and CREG

2.3.3. Use Patterns and the Impact of Solar Panels

42. Figure 13 shows the evolution of the average electricity demand per fifteen minutes in the Elia control area for the years 2007 to 2016.

43. The period 2007 to 2014 was aggregated in the greyed zone of the chart by including the minimum and maximum of the averages of the electricity demand per quarter of an hour in the Elia control area. 2015 and 2016, on the other hand, appear distinctly in the chart. 2009, 2012, 2013 and especially 2014 illustrate the gradual and constant reduction in electricity demand. The patterns of 2014 to 2016 – which are rather similar – confirm the gradual flatness of the daytime period and to a lesser extent the night period. The peak just before midday has disappeared since 2013. Generation resulting from solar panels undeniably contributed to the disappearance of this midday peak. On the other hand, the minimum demand of the day in 2014 just before 4.00 am during 'off-peak' at night of 7,496 MW, is confirmed as well in 2015 as in 2016 with a rather similar level (7,546 MW).

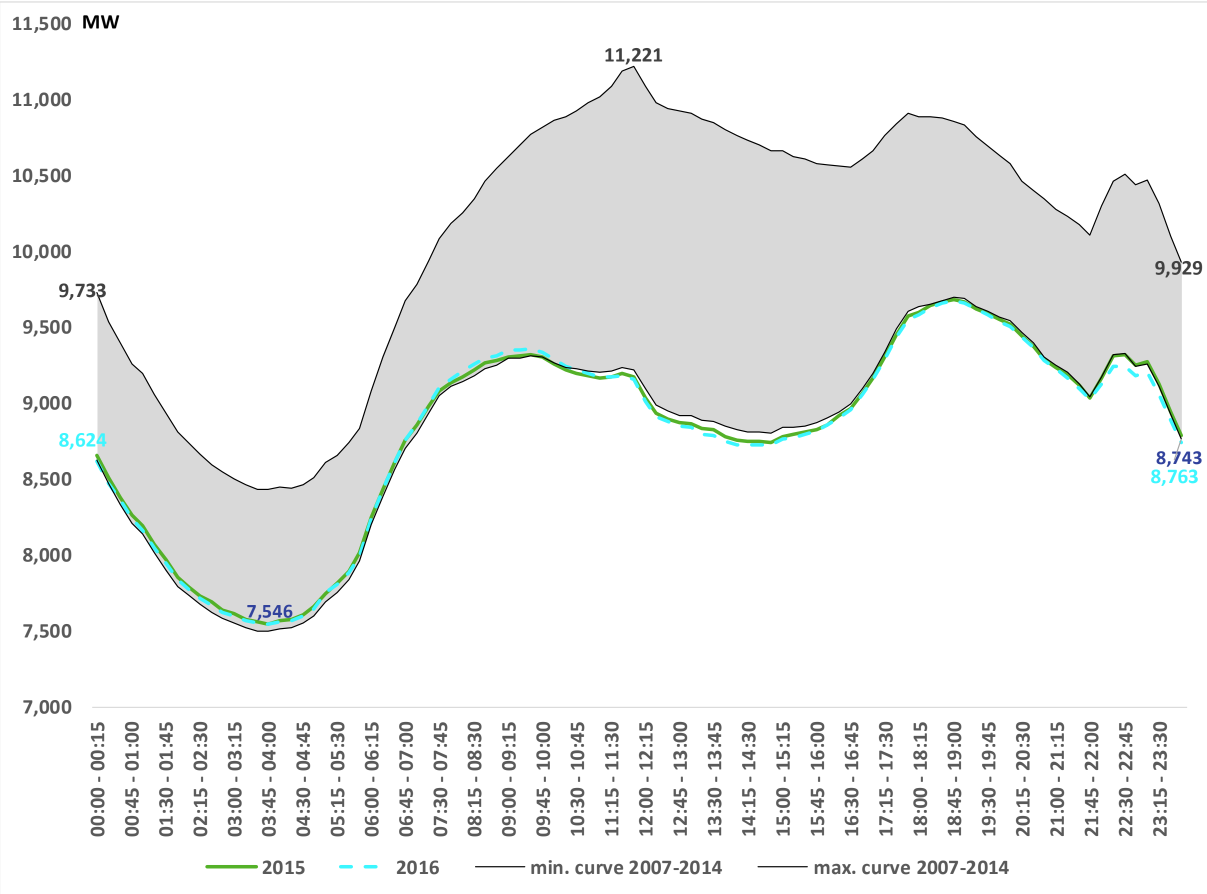


Figure 13 : Average electricity demand per quarter of an hour in the Elia control area over the period 2007 to 2016 (MW)
Sources : Elia and CREG

44. Figure 13 shows not only that the electricity demand in the middle of day dropped until 2015 compared to the previous years, but also that the reduction of the demand is less marked during the off-peak hours. Even when 2016 shows a slight recovery, the trend of the variability of the average electricity demand during the day therefore seems to remain depressed. These observations are confirmed by Figure 14 which shows the variability of the average electricity demand during the day measured using the standard deviation ("AV D-Stdev" - blue line) as well as the standard deviation of the difference in electricity demand between two consecutive days ("StdDev of D-D-1" - red line).

Figure 14 also illustrates on the right-hand axis the standard deviation of the difference between two consecutive quarters of an hour (“Stdev of QtoQ - right axis” - orange line). This last observation also falls, but to a lesser extent until 2012. Starting from 2013, the fall is more pronounced. The result is that the variability of electricity demand decreases not only during one day but also between two consecutive fifteen minute intervals. With regards to variability between two consecutive fifteen minute intervals, the variability in 2016 fell to the lowest level in the 10 years studied.

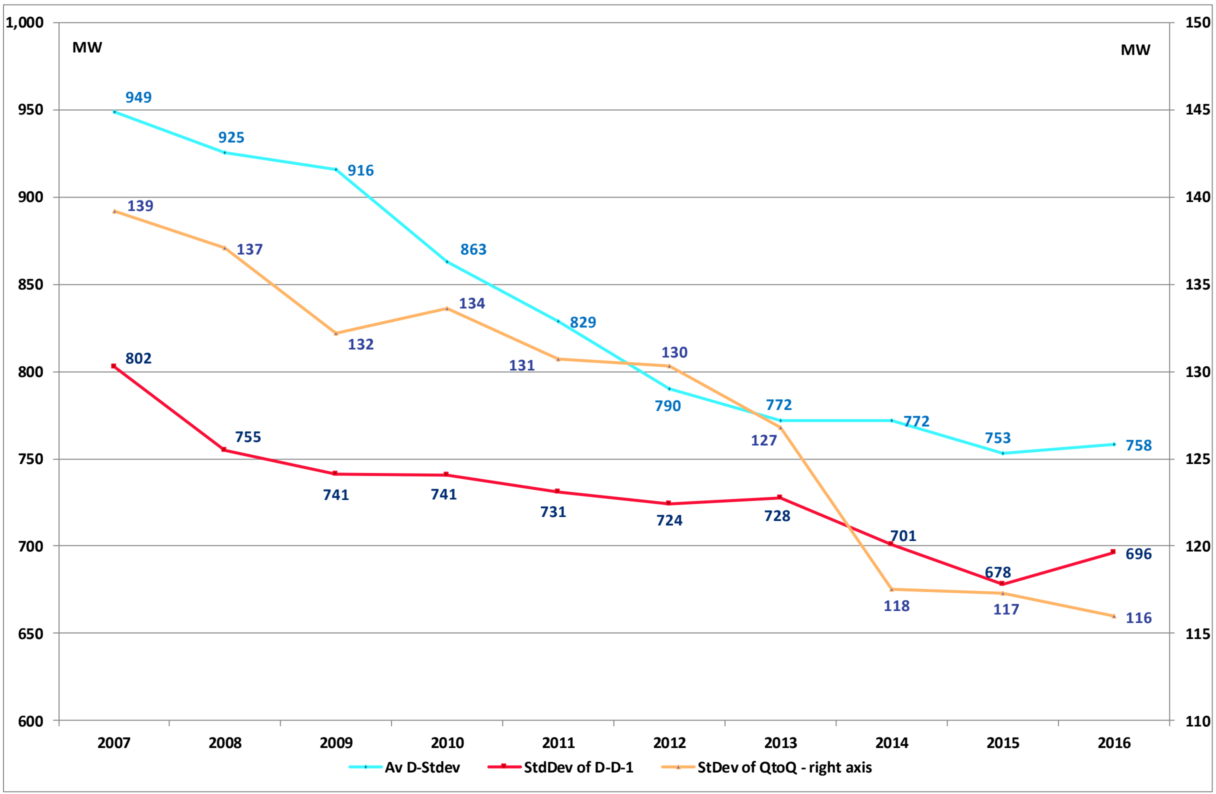


Figure 14 : Annual variability of the average electricity demand during one day (“AV D-Stdev” - blue line), the difference between two consecutive days (“StdDev of D-D-1” - red line) and, on the right-hand axis, the difference between two consecutive fifteen minute intervals (“Stdev of QtoQ” - orange line) (MW). The right and left-hand axes start respectively at 600 MW and 110 MW
Sources : Elia, CREG

45. A fall in variability does not necessarily imply a reduced need for flexibility. Indeed, variability is not the same as predictability. As explained in chapter six on *balancing*, up until 2012, the transmission system operator needed to spend more resources every year in order to maintain the electrical power balance, in spite of the (slight) variability decrease of the electricity demand as indicated above. Since 2013, on the other hand, a decrease in the resources required to maintain the power balance has been observed.

Impact of solar generation

46. The CREG only has TSO data from 2013 onwards. Figure 15 shows the day patterns of the minimum, average and maximum estimate solar generation for Belgium, between 2013 and 2016. When the evolution of the minimum generation is negligible, the average and maximum day patterns increased strongly between 2012 and 2013. Starting from 2014, the maximum of the pattern of the average generation still slightly progresses in 2015 but it decreases in 2016 compared to 2015, indicating a deceleration of the annual installation of new solar panels. For the year 2014, the maximum of the pattern of maximum generation is 2,159 MW and 2,266 MW in 2015 to reach a record 2,373 MW in 2016.

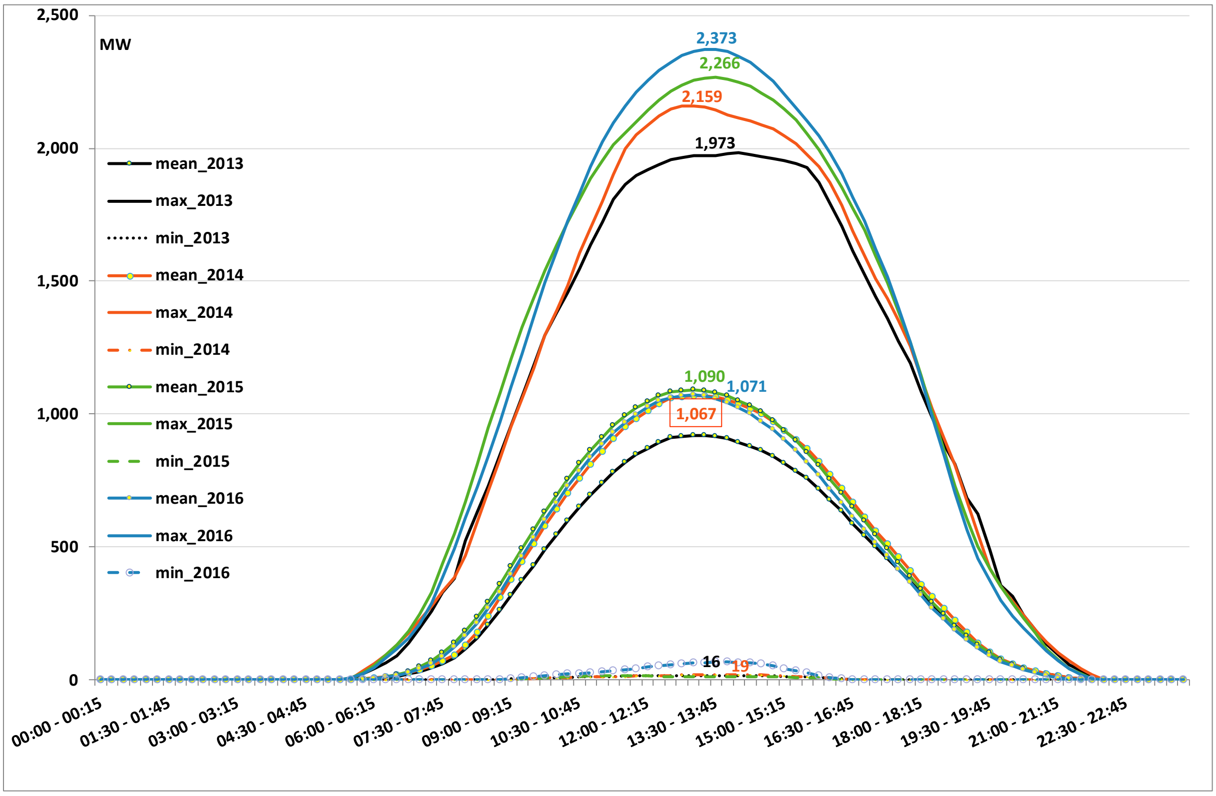


Figure 15: Estimate of maximum, average and minimum quarter-hourly generation (MW) of installed solar panels between 2013 and 2016
Sources: Elia and CREG

47. The total generated solar energy (Table 5) amounts to 2.9 TWh in 2016, a slight fall compared with 2015. The yearly generated solar energy has barely evolved since 2013, a sign of a slowdown in investments in this sector.

(TWh)	Generated Solar Energy
2013	2.6
2014	2.9
2015	3.0
2016	2.9

Table 5: Generated electricity of solar origin 2013-2016
Source: CREG

48. In 2016, the installed capacity of solar panels was 2,953 MW, a slight increase compared to 2015 (2,818 MW as of 1 January 2015). Figure 16 shows the monthly generated solar energy in 2016. Unsurprisingly, most electricity was generated between April and September, with a peak in July.

Taking into account the average number of hours of sunshine at Uccle[21] over a period of 30 years (1981 to 2010), the generated solar energy in 2016 compared to a calculated theoretical maximum

[21] Number of hours of normal climatological sunshine at the Uccle monitoring station 1981-2010 - Source IRM : http://www.meteo.be/meteo/view/fr/360955-Normales+mensuelles.html#ppt_5238269.

generation (installed capacity 2016 x average monthly number of hours of sunshine 1981-2010) does not exceed 74.5% of the theoretical maximum generation. Represented by the yellow/green curve, this ratio highlights the evolution of solar panel efficiency (orientation, maintenance, age, temperature, etc.) during the course of 2016.

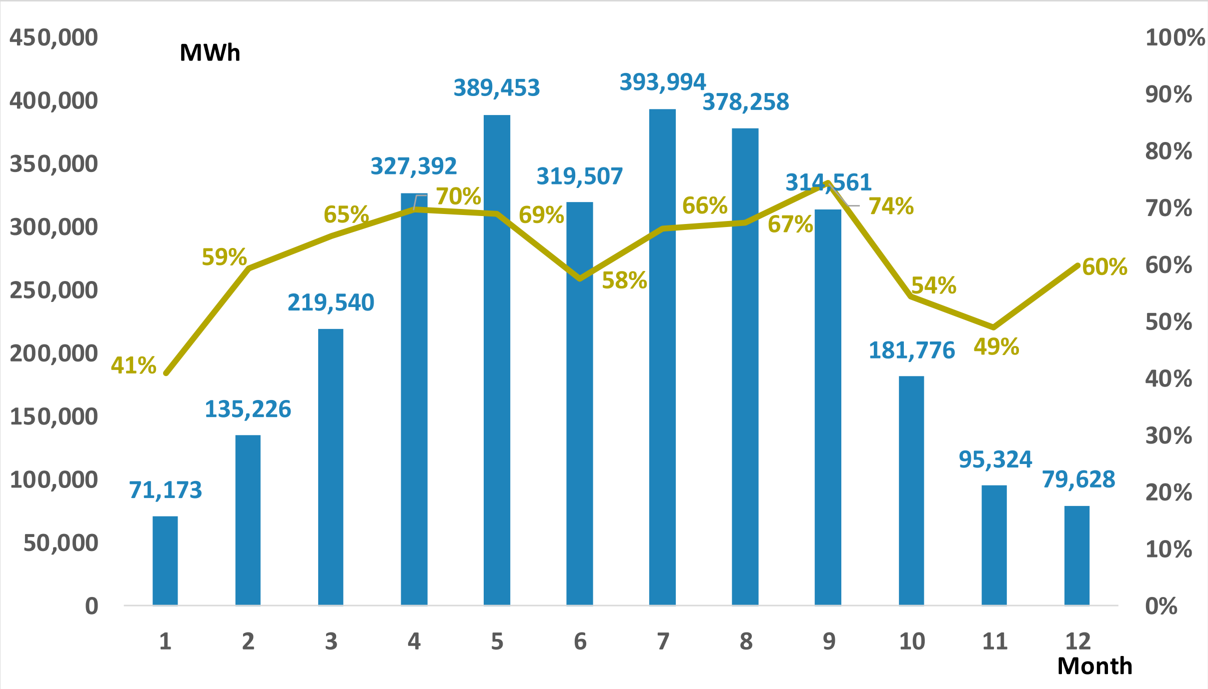


Figure 16: Monthly generated solar energy in 2016 (MWh, left axis) and yellow/green curve representing the efficiency of the monthly generation (%, right axis) (monthly generation in MWh / installed capacity in MW x the average monthly hours of sunshine 1981-2010)
Sources: Elia and CREG

49. Figure 17 shows, based on these same data, the evolution of the maximum, average and minimum monthly generation at hour 13 of the day. The hours with the highest generation are observed between July and May. The estimated maximum generation rose to 1,965 MW in June 2013, 2,157 MW in in May 2014, 2,239 MW in July 2015 and 2,349 MW in May 2016.

50. The fact that the highest average generation in 2016 is less than those of the previous two years prooves that the growth of investments in the solar sector observed between 2011 and 2013, stopped abruptly from 2014 onwards.

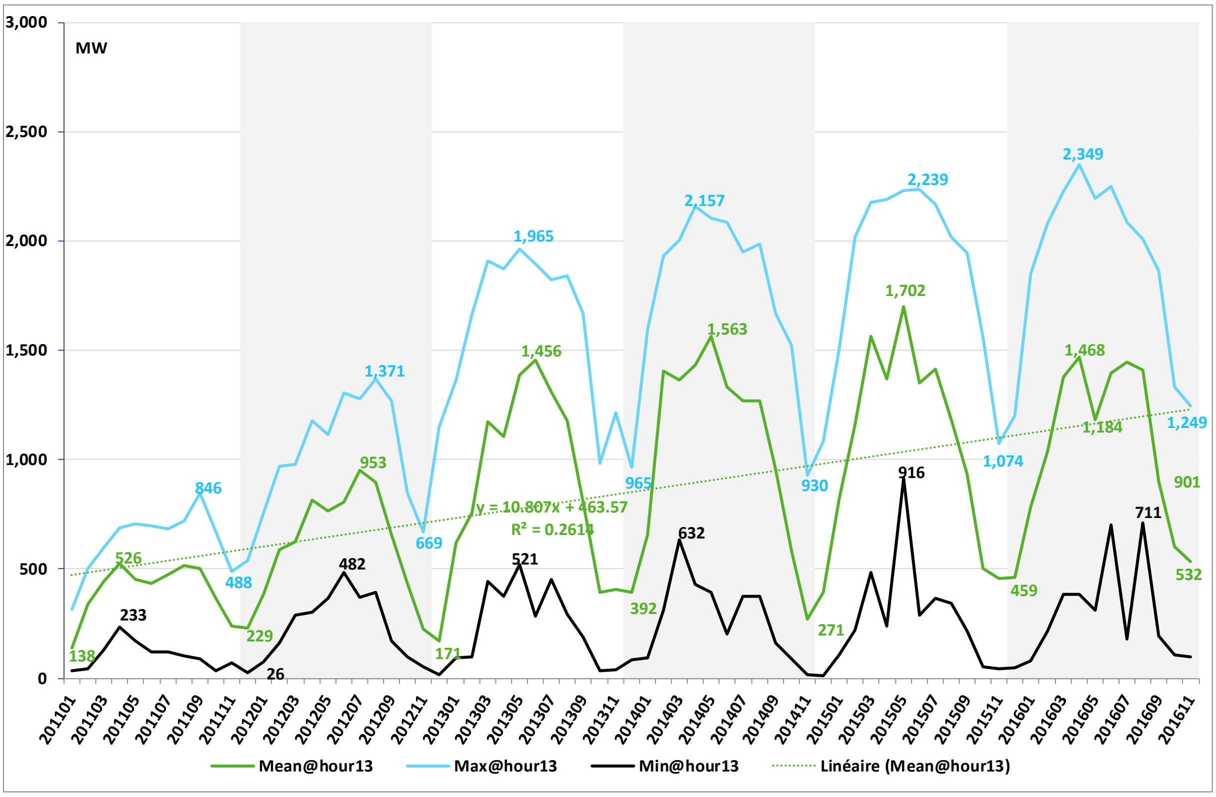


Figure 17: Evolution of the maximum, average and minimum monthly generation at the thirteenth hour of the day
Sources: Elia, CREG

51. The variability of solar generation should be perceptible in the event of higher variability of the demand on the Elia network in the middle of day. Figure 18 shows, per year, a daily pattern of demand variability, measured using the standard deviation of the average demand per fifteen minute intervals.

The period 2007 to 2014 was aggregated in the greyed zone of the figure by combining the minimum and maximum values of the daily patterns of demand variability. 2015 and 2016, on the other hand, appear distinctly in the figure.

Since 2012, the variability of the demand in the middle of the day had increased by 100 to 200 MW compared to the previous years, in other words an increase of 10 to 20%. This trend continued in 2013. However, 2014 to 2016 registered the opposite trend to these previous two years. In addition to these observations, it is clear that the variability in the daytime period has reduced significantly, and as for the night-time period, the last three years have registered a significantly low level of variability compared to all the other years.

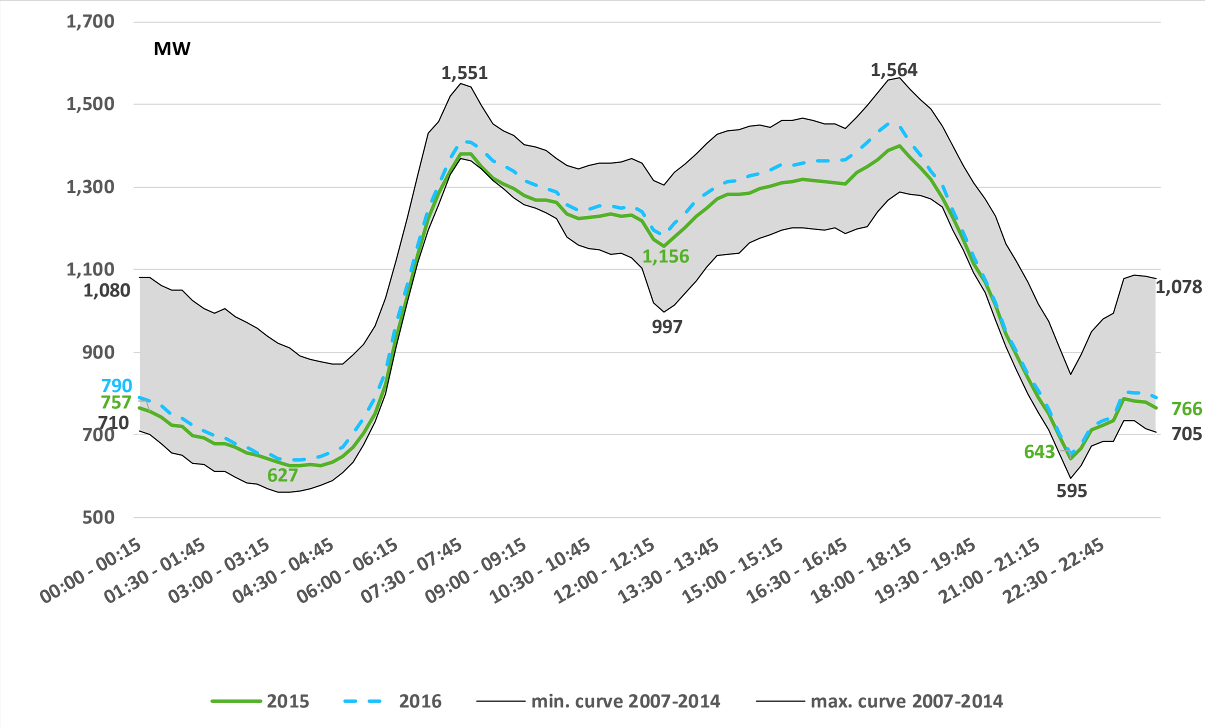


Figure 18: Standard deviation of the average demand per quarter of an hour on the network in the Elia control area (MW) between 2007 and 2016. The y-axis starts at 500 MW.
Sources: Elia and CREG

52. It is advisable to qualify the variability observed in Figure 18. Indeed, the latter reflects the variability of electricity demand per fifteen minute intervals for a whole year. When the standard deviation of the difference between the electricity demand of two consecutive fifteen minute intervals is analysed, it appears that the variability has further decreased since 2014, compared to previous years. This can be ascertained from Figure 19[22]. This chart shows that the variability of the difference between two consecutive fifteen minute intervals decreases the last three years for almost all the daily patterns, compared to the previous years. In 2016, the calculated variability was for 31.3% of the time at the lowest level of the 10 years under review (38.5% in 2015 and 86.5% in 2014)[23].

[22] The years 2007 to 2014 were aggregate in the greyed zone of the figure by taking for each year the minimum and the maximum of the standard deviations of the difference between the electricity demand of two consecutive fifteen minute intervals (MW). The years 2015 and 2016, on the other hand, appear distinctly in the figure.
[23] Cumulated, these last two years account for 55.2% of the time.

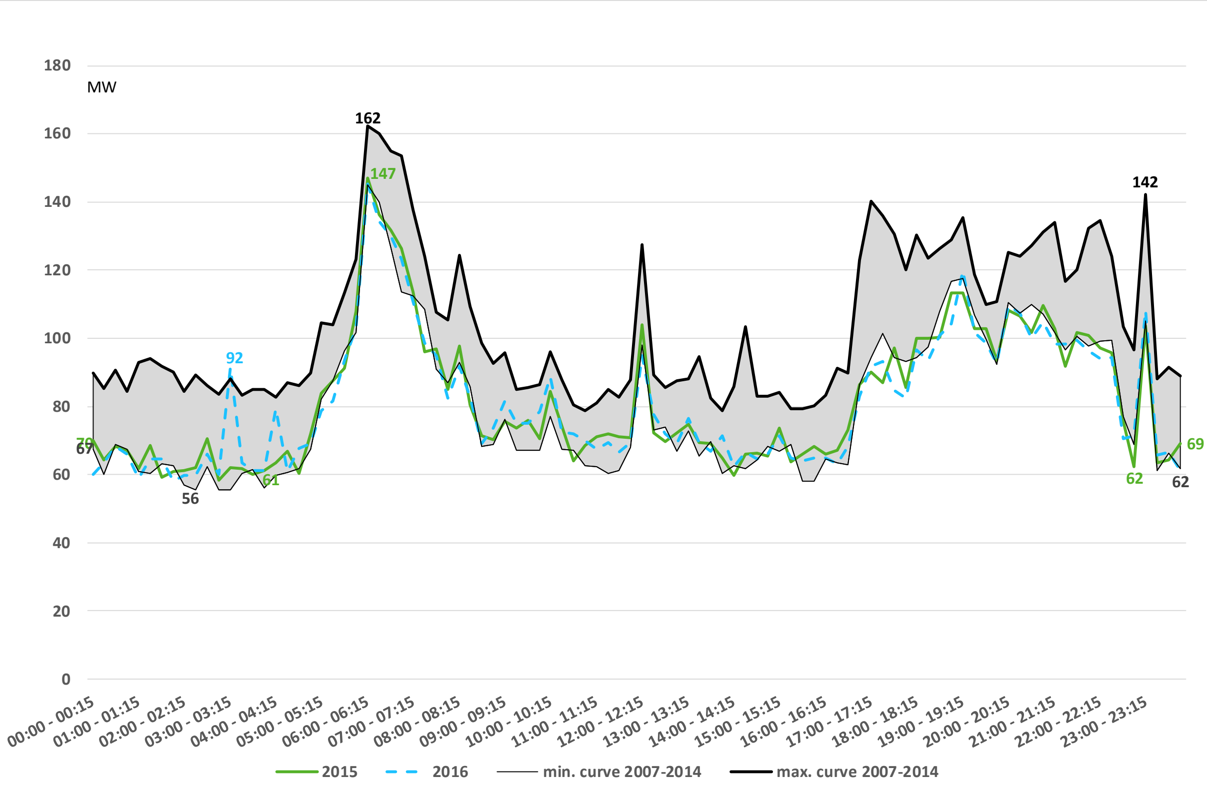


Figure 19 : Standard deviation of the difference in electricity demand between two consecutive fifteen minute intervals (MW)
Sources : Elia and CREG

53. The impact of the installation of new solar panels on generation will probably be slightly larger in 2017, because the figures above constitute an average for the whole year 2016. In 2013, changes to the rules regarding the awarding of regional subsidies appreciably slowed down installations of solar panels in the country, which probably explains the deceleration observed since 2014.

3. GENERATION

3.1. HISTORICAL BACKGROUND AND SIGNIFICANT EVENTS

54. During the last decade, electricity generation in Belgium has been subject to some major changes. Investments in new conventional generation facilities dropped significantly since the financial crisis in 2009 which also coincided with the beginning of a continuous fall in electricity demand. On the other hand, the installed capacity of investments in generation units using renewable energy sources is still increasing. This renewable capacity is characterised by relatively small marginal costs which affect the wholesale market price.

Conventional generation units have suffered from a fall back in revenues due to declining running hours combined with lower market prices. The decline in running hours was mainly caused by lower electricity demand, increased renewable generation which precedes conventional units in the merit order and the low carbon value which led to a coal-before-gas scenario.

The elements described above led to a number of announcements of the temporary closure (mothballing) and definitive decommissioning of older, less profitable units. In addition to the decommissioning of some smaller older units (turbojets, old co-generation), the closure of some CCGTs was also announced.

Since 2012, an increase of unplanned unavailability from nuclear generation facilities has been observed.

The combination of several announcements regarding the mothballing and decommissioning of generation facilities, and this increase in the unavailability of nuclear plants, has led to concern about the security of electricity supply in Belgium. While in our neighbouring countries, a reflection was carried out on the need to introduce a capacity remuneration mechanism, Belgium was confronted with a short-term security of supply issue. In 2014 and 2015 various measures were taken to cope with this issue: postponing the nuclear phase-out and setting up a mechanism of strategic reserves. Since winter 2014-2015 the mechanism of strategic reserves has been operational, although it has not been necessary to make use of this reserve.

Finally in 2016 the last coal fired unit in Belgium (Langerlo – 470 MW) was temporarily shut down in order to convert it to a biomass unit. Discussions on the level of support for biomass fired plants raised uncertainty about the future of this unit.

3.2. STATISTICS

3.2.1. Main characteristics of electricity generation in Belgium

55. At the end of 2016, the installed generation capacity (excluding mothballed capacity and capacity in strategic reserve) connected to the Elia grid amounted to 14 GW. Total electricity generated in 2016 by units connected to the Elia grid amounted to 69.7 TWh. Figure 20 shows the distribution of the installed capacity at the end of 2016 and the electricity generated in 2016 per fuel source.

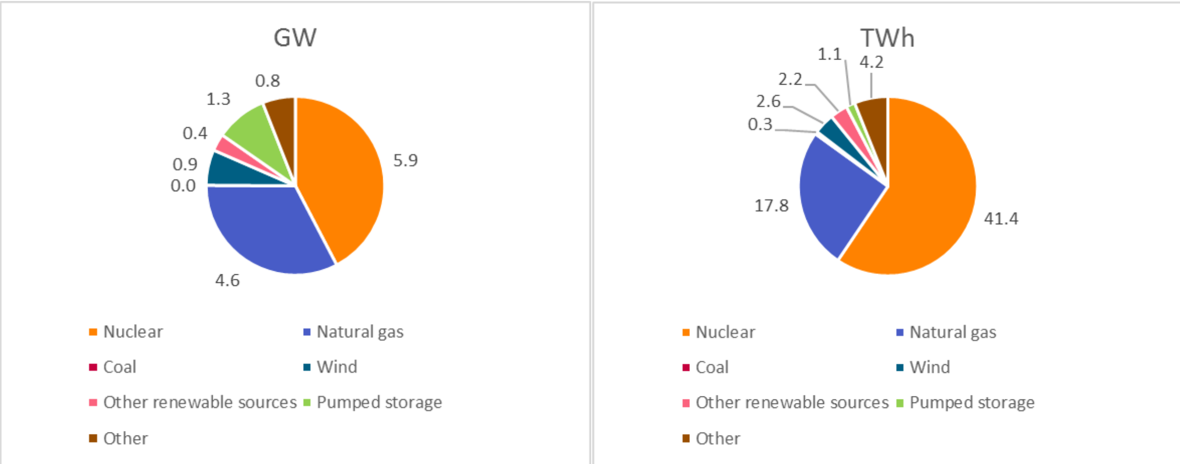


Figure 20 : Installed capacity and electricity generation in 2016 by fuel source.
Sources : Elia, CREG

56. An estimate of the evolution of the installed capacity per fuel type connected to the Elia grid is shown in Table 6, considering the situation at the end of December. The share of the 7 nuclear power plants is quite stable and represents 42% of the total installed capacity in Belgium. The share of capacity using natural gas (open and closed cycle gas turbines) is decreasing slightly. In 2016, the last coal power plant (470 MW in Langerlo) was closed and a conversion to a biomass plant is under discussion. The generation capacity shown is the capacity in the market: it does not include the installed generation capacity which is temporarily decommissioned and which might be contracted in the strategic reserve.

Type of fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Nuclear	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9		37%	36%	36%	37%	37%	36%	38%	40%	41%	42%
Natural gas	5.7	6.0	6.0	6.2	6.3	6.6	6.0	5.1	4.6	4.6		36%	38%	37%	38%	39%	40%	38%	34%	32%	33%
Coal	1.6	1.4	1.4	0.9	0.8	0.7	0.5	0.5	0.5	0.0		10%	9%	9%	6%	5%	4%	3%	3%	3%	0%
Wind	0.0	0.1	0.1	0.3	0.3	0.5	0.7	0.9	0.9	0.9		0%	0%	1%	2%	2%	3%	5%	6%	6%	6%
Other renewable sources	0.2	0.2	0.2	0.4	0.6	0.4	0.4	0.4	0.4	0.4		1%	1%	1%	3%	3%	3%	3%	3%	3%	3%
Pumped storage	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3		9%	9%	8%	9%	8%	8%	8%	9%	9%	9%
Other	1.2	1.1	1.4	1.0	1.0	0.9	0.8	0.9	0.9	0.8		8%	7%	9%	6%	6%	6%	5%	6%	6%	6%
Total	15.9	16.0	16.3	16.2	16.2	16.4	15.7	15.0	14.5	14.0		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 6: Evolution of generation capacity by fuel type (GW)
Source: Elia, CREG

57. An estimate of the evolution of the generated electricity per fuel type connected to the Elia grid for the last decade is shown in Table 7. The level of electricity generation in Belgium in 2016 is close to the level in 2013. The low values in the years 2014 and 2015 were mainly caused by the unavailability of some nuclear power plants. The issue of unavailability of nuclear plants will be discussed in more detail below.

Type of fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Nuclear	45.8	43.4	45.0	45.7	45.9	38.5	40.6	32.1	24.8	41.4		56%	56%	53%	53%	57%	54%	57%	54%	45%	59%
Natural gas	24.5	22.8	29.2	29.8	23.9	21.7	18.0	16.6	18.4	17.8		30%	30%	34%	34%	30%	30%	25%	28%	33%	25%
Coal	7.6	6.9	6.4	5.2	4.5	5.0	3.0	2.2	2.1	0.3		9%	9%	7%	6%	6%	7%	4%	4%	4%	0%
Wind	0.0	0.0	0.2	0.3	0.9	1.1	1.8	2.5	2.9	2.6		0%	0%	0%	0%	1%	2%	3%	4%	5%	4%
Other renewable sources	0.7	0.9	0.7	0.8	0.6	0.8	1.9	1.3	2.0	2.2		1%	1%	1%	1%	1%	1%	3%	2%	4%	3%
Pumped storage	1.3	1.3	1.4	1.4	1.2	1.3	1.3	1.2	1.1	1.1		2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Other	2.6	2.1	2.7	3.5	3.4	3.5	4.1	4.1	4.4	4.2		3%	3%	3%	4%	4%	5%	6%	7%	8%	6%
Total	82.6	77.4	85.5	86.6	80.4	71.8	70.7	59.9	55.7	69.7		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 7: Evolution of electricity generated per fuel type (TWh)
Source: Elia, CREG

58. Table 8 shows the evolution of the market shares of generation capacity connected to the Elia grid for different Access Responsible Parties (ARP) in the last decade. The table is based on end-of-year data.

The Herfindahl-Hirschman Index (HHI), which is an indication of market concentration, remains between 4000 and 5000. A market is considered to be highly concentrated when HHI-values are above 2000. There is still a long way to go to achieve a competitive market for generation in Belgium.

ARP	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electrabel	13.5	13.7	12.2	11.8	11.4	11.0	10.3	10.2	10.2	10.2		85%	86%	75%	73%	70%	67%	65%	68%	71%	73%
EDF-Luminus	2.0	1.9	2.2	2.4	2.4	2.3	2.2	1.8	1.7	1.9		12%	12%	13%	15%	15%	14%	14%	12%	12%	14%
E.ON	0.0	0.0	1.4	1.5	1.5	1.5	1.5	1.1	0.6	0.0		0%	0%	9%	9%	9%	9%	9%	7%	4%	0%
T-Power	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4		0%	0%	0%	0%	3%	3%	3%	3%	3%	3%
Enel	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.0		0%	0%	0%	0%	0%	2%	3%	3%	3%	0%
Other	0.4	0.4	0.5	0.6	0.5	0.8	0.9	1.1	1.2	1.5		2%	2%	3%	3%	3%	5%	6%	7%	8%	11%
Total	15.9	16.0	16.3	16.2	16.2	16.4	15.7	15.0	14.5	14.0		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
											HHI	7410	7470	5770	5540	5170	4720	4460	4760	5160	5510

Table 8: Evolution of generation capacity by ARP (GW)
Source: Elia, CREG

59. The energy generated by units connected to the Elia grid by ARP is shown in Table 9. The share of Electrabel for generation increased from 65% in 2015 to 78% in 2016. This evolution is mainly due to the increase of nuclear generation in 2016.

ARP	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electrabel	71.2	65.8	69.8	62.6	58.9	50.7	49.9	40.7	37.0	54.1		86%	85%	82%	72%	73%	71%	71%	68%	66%	78%
EDF-Luminus	9.3	9.4	10.6	12.2	9.3	8.5	8.6	7.6	7.2	7.2		11%	12%	12%	14%	12%	12%	12%	13%	13%	10%
E.ON	0.0	0.0	2.5	8.8	8.5	7.8	6.9	6.3	4.3	0.4		0%	0%	3%	10%	11%	11%	10%	11%	8%	1%
T-Power	0.0	0.0	0.0	0.0	1.0	0.5	0.4	1.4	2.2	2.6		0%	0%	0%	0%	1%	1%	1%	2%	4%	4%
Enel	0.0	0.0	0.0	0.0	0.1	1.3	1.4	0.7	1.2	0.4		0%	0%	0%	0%	0%	2%	2%	1%	2%	1%
Other	2.1	2.2	2.6	3.0	2.7	3.1	3.5	3.2	3.9	5.1		3%	3%	3%	3%	3%	4%	5%	5%	7%	7%
Total	82.6	77.4	85.5	86.6	80.4	71.8	70.7	59.9	55.7	69.7		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
											HHI	7500	7300	6750	5440	5550	5190	5230	4900	4670	6160

Table 9: Evolution of generated electricity by ARP (TWh)
Source: Elia, CREG

3.2.2. Nuclear generation

60. As previously mentioned, nuclear generation represents a major part of electricity generation in Belgium. Nuclear plants are geographically situated at two locations: Doel and Tihange. Table 10 provides an overview of the capacity and the ownership of the 7 nuclear plants.

Nuclear Plants		Doel 1	Doel 2	Doel 3	Doel 4	Tihange 1	Tihange 2	Tihange 3	Total	
Installed capacity		433 MW	433 MW	1006 MW	1038 MW	962 MW	1008 MW	1046 MW	5926 MW	100.0%
Ownership	Electrabel	100.0%	100.0%	89.8%	89.8%	50.0%	89.8%	89.8%	5027 MW	84.8%
	EDF			10.2%	10.2%	50.0%	10.2%	10.2%	899 MW	15.2%

Table 10: Ownership of nuclear plants
Source: Elia, CREG

Although ownership is shared between Electrabel and EDF-Luminus for some nuclear units, Electrabel manages the daily operation and is the only Access Responsible Party for all units. Up until the end of December 2015 E.ON had drawing rights on a part of the Electrabel share.

Electricity generation by nuclear plants has been extremely volatile in recent years due to unplanned unavailability of some nuclear units. Figure 21 shows the monthly nominations for all nuclear power plants in Belgium. Nuclear generation in 2016 was much higher than in 2014 and 2015. During the first months of 2016 nuclear generation reached maximum historic levels of generation (period 2007 – 2013 is used as reference). In the last quarter of 2016 nuclear generation was still above minimum historic levels.

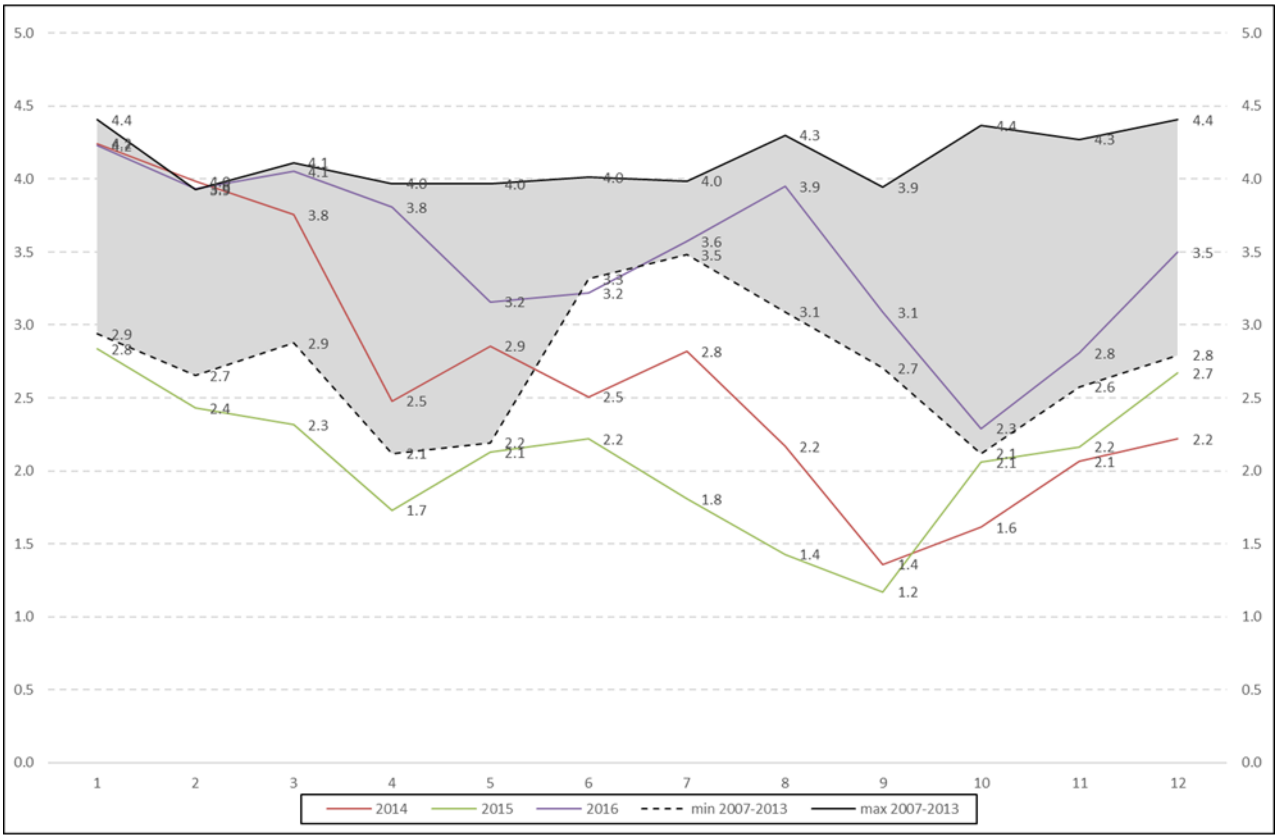


Figure 21 : Monthly nominations for generation by nuclear power plants per year
Sources : Elia, CREG

61. The next figure shows for each year of the last decade the number of days of unavailability for each nuclear plant. The high unavailability of Doel 1, Doel 3 and Tihange 2 in 2014 and 2015 can be observed. On 7 September 2016, Tihange 1 was shut down because one building had been damaged during civil construction works. It remained unavailable until May 2017.

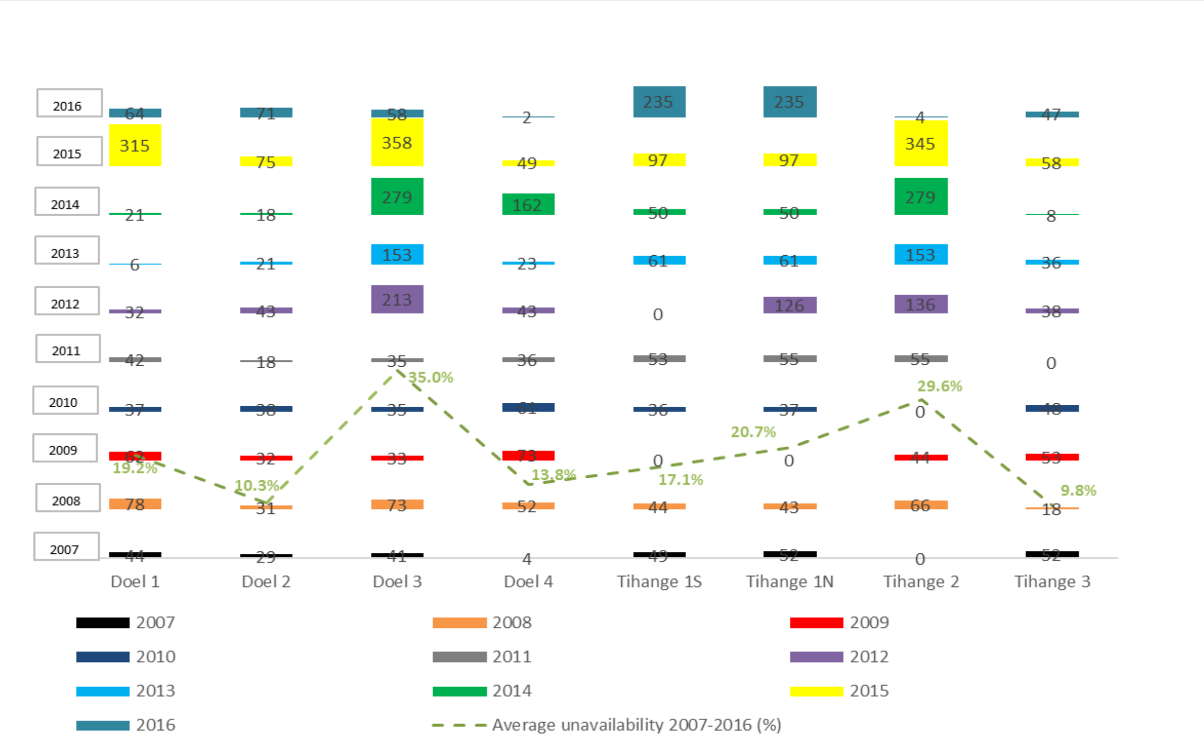


Figure 22 : Number of days of unavailability of the 7 nuclear plants per year
Sources : Elia, CREG

3.2.3. Gas fired plants

62. Gas fired electricity generation in Belgium represents 25% of electricity generation in Belgium, behind nuclear generation (see also Table 7). Table 11 shows the ownership of the most important CCGTs in Belgium which are still operating in the market[24].

Major CCGT's (± 400 MW) in Elia-zone		
Owner	**Unit**	**MW**
Electrabel	AMERCOEUR 1	420
Electrabel	DROGENBOS	460
Electrabel	HERDERSBRUG	460
Electrabel	SAINT-GHISLAIN	350
Electrabel 50% / BASF 50%	ZANDVLIET POWER	395
EdF/SPE	RINGVAART	357
T-Power	T-POWER	422
Enel	Marcinelle Energie	405
Totaal		3269

Table 11: Overview of major CCGTs in Belgium
Source: CREG

[24] The 465 MW CCGT unit of Seraing operated by EDF-Luminus has been contracted in the strategic reserve between 1/11/2014 and 31/10/2017 and is not considered to be operational in the market.

63. As demonstrated in Figure 23, electricity generation by CCGTs had been decreasing since 2010. At the end of 2014 this trend was reversed and a further increase in generation by CCGT was observed in 2016. The blue line represents the average minimum volume to be nominated in order to supply the secondary reserves (R2) of 140 MW.

In the 10 previous years, the number of CCGTs available in the market varied from 8 in 2007 to 11 in February 2012. From 2014 onwards the number of CCGTs operational in the market decreased from 11 to 8 in 2015. The periods with different numbers of operational CCGTs are indicated by different shades of grey in Figure 23.

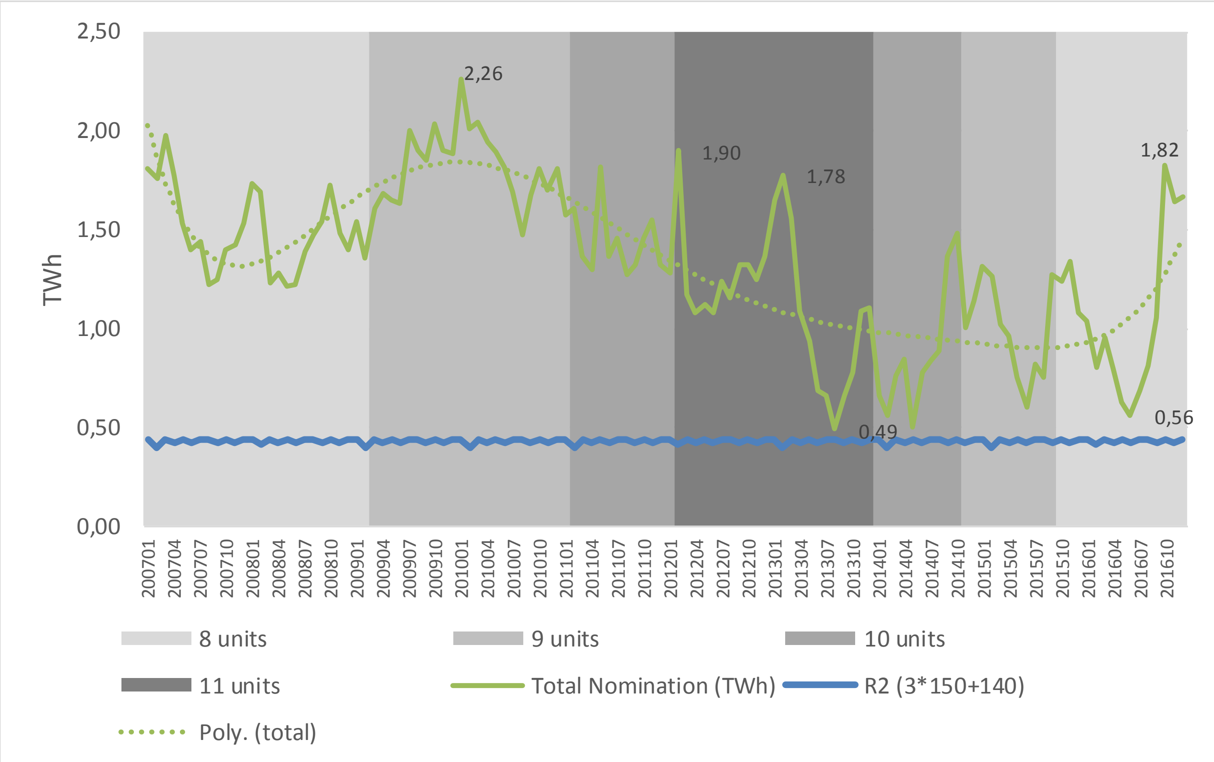


Figure 23 : Total nominee energy in day-ahead of the Elia regulation zone CCGTs, per month, as well as an indication of the minimum average volume to be nominated for secondary reserves (blue line)
Sources : Elia, CREG

The high generation levels of CCGT at the end of 2016 can be attributed to the unavailability of several French nuclear power units and to the unavailability of Tihange 1.

Table 12 gives for each year the total nomination for generation by CCGTs, the evolution of the generation in percentage, the average load factor for all CCGTs, the evolution of the load factor and the minimum and maximum load factor (which corresponds to the CCGT having relatively generated the least and most electricity). The decreasing trend of generation by CCGTs was reversed in 2015 and in 2016 there is still a slight increase. It should be noted that there is a big gap between the most profitable CCGT (which might be assumed to have the highest load factor) and the least efficient CCGT (with the minimum load factor). For obvious reasons, the load factors are impacted by unavailability of the unit.

(TWh)	Total electricity generation	Evolution (%)	Average load factor	Evolution (%)	minimum load factor	maximum load factor
2007	18.5		64%		46%	90%
2008	17.4	-6.1%	60%	-7.1%	34%	81%
2009	21.0	21.0%	63%	5.1%	31%	88%
2010	22.1	5.2%	67%	6.0%	44%	88%
2011	17.4	-21.4%	43%	-35.4%	4%	77%
2012	15.3	-12.3%	37%	-13.3%	6%	80%
2013	12.5	-18.3%	30%	-18.7%	3%	62%
2014	10.8	-13.3%	29%	-3.5%	2%	68%
2015	12.4	15.0%	37%	26.6%	5%	64%
2016	12.5	0.2%	42%	12.1%	1%	71%
2007-2016	16.0	-32.7%	47%	-35.5%		

Table 12: Overview of major CCGTs in Belgium
Source: Elia, CREG

4. ELECTRICITY TRADING

4.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

4.1.1. Founding of the Belgian power exchange

2005 The Belgian power exchange Belpex was founded in July 2005 following the liberalisation of the European electricity market and the transposition into national law on 29 April 1999. The Royal Decree of October 20, 2005 established the rules concerning the creation, access and operation of the market for the exchange of energy blocks.

2006 On 11 January 2006 Belpex was designated as market operator responsible for organizing the Belgian short term electricity market. Belpex was first operational on 21 November 2006. The Belgian Transmission System Operator (TSO) Elia held stake of 70%, the Dutch (APX) and the French (Powernext/EPEX Spot) power exchanges each held an stake of 10% as well as the Dutch TSO TenneT. The French TSO RTE also subsequently participated by taking over a stake of 10% from Elia.

4.1.2. Organisation of the Belgian day-ahead market by Belpex

2006 Since its inception, the day-ahead market Belpex DAM was coupled with APX and Powernext. The trilateral market coupling (TLC) algorithm imposed a floor price of 0.01 €/MWh and a ceiling price of 3,000 €/MWh.

2010 On 9 November 2010, the market coupling was expanded to Germany and Luxembourg, thereby creating the Central West-European (CWE) price coupled region and revising the floor price of the algorithm to -3,000 €/MWh while maintaining the ceiling price at its level. The CWE-region was also coupled by volumes with the Scandinavian power market consisting of Norway, Sweden, Denmark, Finland, and Estonia.

2011 On 1 April 2011 the BritNed-cable linked the Dutch power market with the power market in Great-Britain, thereby coupling the CWE-region with the United Kingdom (CWE+UK).

2014 The coupling of the CWE-region with the Scandinavian power market was revised from volume coupling to price coupling on 4 February 2014 to create the North Western European (NWE) market coupling. Besides the countries already mentioned above Austria, Poland, Lithuania, and Latvia were also included in the NWE-region. The NWE-region was the first region that used the algorithm *Euphemia*, developed as part of the Price Coupling of Regions (PCR) project, to optimize the social welfare in day-ahead by determining the commercial flows between bidding zones and by fixing market prices in each bidding zone. The floor price was revised to -500 €/MWh while the ceiling price was maintained at 3,000 €/MWh.

On 13 May 2014 the South Western European (SWE) region consisting of Spain and Portugal was coupled with the NWE-region to form the Multi-Regional market coupling (MRC). Later that year on 19 November 2014 Romania, the Czech Republic, Slovakia, and Hungary were coupled with each other (4M market coupling). During these developments, the CWE-region prepared to substitute the coupling method by means of Available Transfer Capacities (ATCs) with the flow-based market coupling method. While the former optimizes social welfare in the coupled region by exchanging electricity between adjacent bidding zones as long as the ATC permits, the latter at once calculates and allocates electricity exchanges between all bidding zones in the coupled region based on the order books of all coupled bidding zones and the technical limitations of the underlying electricity grid.

2015 The flow-based market coupling method was applied on 20 May2015 (delivery 21 May).

4.1.3. Organisation of the Belgian intraday market by Belpex

2008 Belpex started organizing the continuous intraday market on 13 March 2008. The new Belpex CIM segment allowed market participants to act on the market until 5 minutes before delivery time to adjust their commercial position to changes in expected supply or demand in day-ahead.

2010 On 13 December 2010, the German TSOs Amprion and EnBW together with the French TSO RTE organized the implicit allocation of cross-border intraday capacity between the French and German bidding zone.

2011 The implicit intraday market coupling on the Belgian-Dutch border followed on 17 February 2011. On 14 March 2011 the implicit intraday market coupling was expanded to include Denmark, Norway, Sweden, Finland, Estonia and Germany.

2012 On 16 October 2012 the Austrian intraday market was created and immediately coupled with the French and German intraday markets.

Since 2012 it had been envisaged to create a pan-European intraday electricity market platform in the NWE-region. The cross-border intraday market project (XBID) is still under way.

2013 In the meantime, the Swiss intraday market was coupled by an explicit mechanism on 26 June 2013.

2014 Until 30 November, 2014, SPE (now: EDF-Luminus) provided liquidity on the intraday market by offering 25 MW of electricity during 80% of the trading window at a price within a certain pre-determined price interval. No other company has engaged in market making activities since.

4.1.4. Integration of the activities operated by Belpex in EPEX SPOT

2015 On 17 April 2015 Belpex, APX and EPEX SPOT announced the planned integration of their services with the aim of reducing barriers in power trading in the CWE region including the United Kingdom. Market participants should therefore benefit from harmonized trading systems, one single set of rules and one admission process for the entire region, thereby reducing trading costs and lowering barriers to entry for new participants. Moreover, they should gain access to a wider range of products and benefit from best-of-both standards and reliable customer support. Overall, the integration would lead to more effective governance and further facilitate the creation of a single European power market fully in line with the objectives of the European electricity regulatory framework. EPEX SPOT would then encompass Belgium, the Netherlands, France, Germany, Austria, Luxembourg and Switzerland. On 1 October 2015, APX and Belpex integrated their staff into the governance structure of EPEX SPOT. The operational integration occurred in multiple steps.

2016 On 31 December 2016, Belpex changed its corporate name to EPEX SPOT Belgium. The trading platform was migrated from Eurolight – as used by Belpex for day-ahead and intraday[25] trade – to the M7 platform (intraday trade) on October 4 2016 and the EPEX Trading System (day-ahead trade, ETS)

[25] Until September 8 20156 the Elbas trading system was used.

on 24 January 2017. The migration of the intraday trading platform resulted in the Belgian intraday market being coupled with those of Germany, France, Austria, and Switzerland on October 5.

Before Belpex was fully integrated operationally, EPEX SPOT requested a modification of the market rules of Belpex. On 7 January 2016[26], 19 July 2016[27] and 22 September 2016[28] the CREG gave opinions on the requested modifications of the Belpex market rules. In these opinions, the CREG recommended any obligations or restrictions applicable to the market participant to be included in the market rules in accordance with the Royal Decree of 20 October 20 2005. The CREG specified in its opinions the impact of the ECC Clearing Conditions on the ability for a small market participant to access the market which led to the design and launch of the ECC Direct Clearing Participant model (DCPM) for participants in Belgium and the Netherlands on 1 September 2016, later expanded to France, Germany and the British Isles. In its opinions, the CREG also drew attention to the possible unintended consequences of imposing transaction limits, by third parties, on market participants. The CREG also recommended including objective criteria to assess a Manifest Error. The Minister of Energy approved the proposed modifications.

4.1.5. Legal framework impacting Belgian power exchanges

2015 On 14 August 2015 Regulation (EU) No. 2015/1222 of 24 July, 2015 establishing a guideline on capacity allocation and congestion management (CACM) entered into force requiring the Minister of Energy to nominate one or more Electricity Market Operators (NEMO) in Belgium before 14 December 2015.

On 7 October 2015 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT) came into force.

4.1.6. Other relevant developments

2016 On 14 January2016 the CREG gave two opinions, one for the nomination of Belpex[29] as NEMO and one of the nomination of Nord Pool[30] as NEMO, following requests by the Minister of Energy received on 7 December 2015. Both power exchanges have been successfully nominated as NEMO.

In 2016, on 5 days, including 4 in November, a second auction was triggered, the majority due to high prices in hour 17 and/or 19. Second auctions are triggered if the market clearing price in a bidding zone exceeds 500 €/MWh. The impacted markets were Belgium and the United Kingdom. On 7 days, the risk of partial decoupling existed. Besides the 4 days in November, 2 days in September and 1 in May were impacted. On 10 days the market coupling results were delayed, suggesting that it took the market clearing algorithm more than 10 minutes to calculate a feasible market clearing price, of which 7 are related to the causes described above. On 19 October2016, version 9.5 of Euphemia was released.

[26] http://www.creg.be/nl/publicaties/advies-a160107-cdc-1502 (available in Dutch and French).
[27] http://www.creg.be/nl/publicaties/advies-a160719-cdc-1549 (available in Dutch and French).
[28] http://www.creg.be/nl/publicaties/advies-a160922-cdc-1567 (available in Dutch and French).
[29] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1501 (available in Dutch and French).
[30] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1503 (available in Dutch and French).

4.2. SPECIAL TOPIC

64. **Market resilience** is an indicator of how sensitive the day-ahead wholesale electricity price is if an additional volume of baseload electricity has been supplied or demanded. The more liquid the market, the higher the market resilience or the higher the price robustness. In 2016, yearly averaged price resilience was rather low: only 2007, 2008 and 2015 were characterized by a lower price resilience (Figure 24). Monthly averaged price resilience illustrates that the price robustness was lowest during the months September and October because many plants are under maintenance during that period, in preparation for the winter period starting in November (Figure 25). However, during the other months of the year, price robustness is very high, showing very little price impact in the event that 500 MWh/h was additionally offered or bid. Note that a volume of must-buy demand impacts the market price more than the equivalent volume of must-run supply.

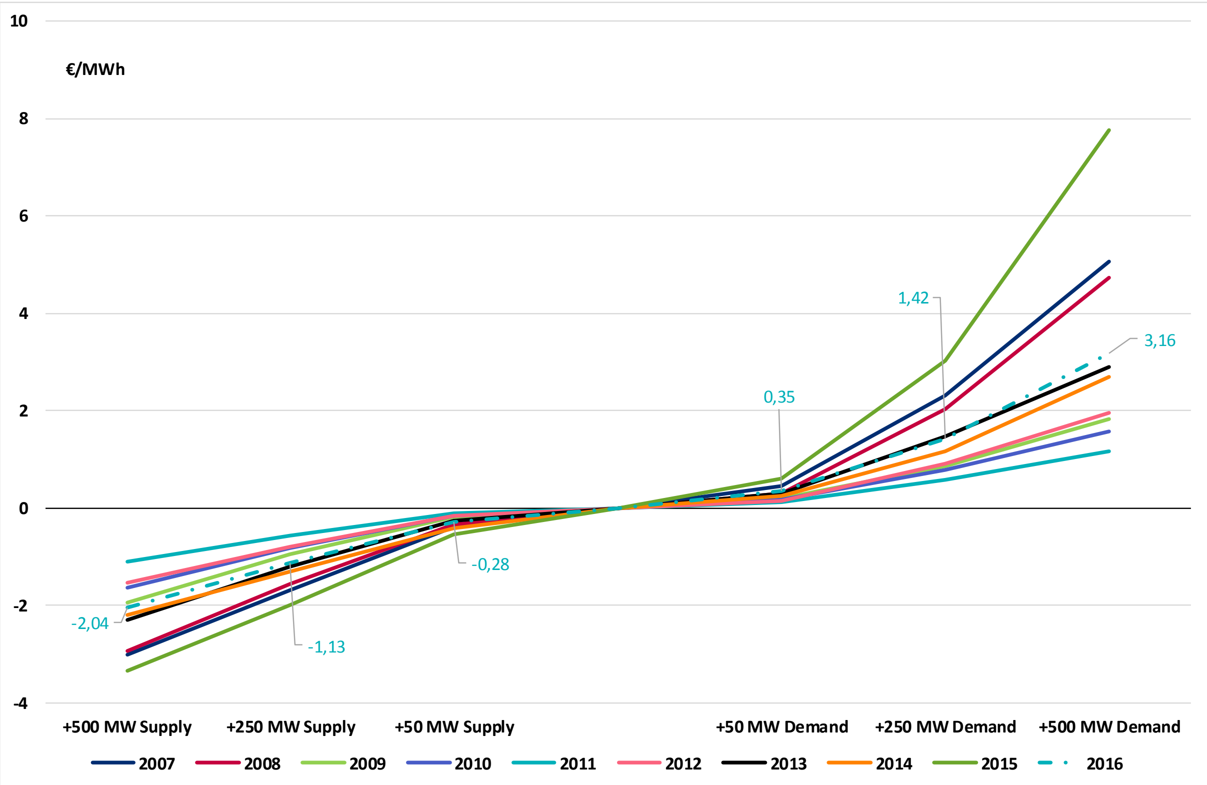


Figure 24 : The yearly averaged resilience of the day-ahead wholesale electricity price for delivery in the Belgian bidding zone. Additional demand shows a much lower impact on prices than observed in 2015, but still higher than any other year except for the exceptional years 2007 and 2008. Additional supply in contrast shows a generally lower impact, but the impact is still comparable with years characterised by frequent nuclear outages (2013, 2014).
Sources : CREG based on data from EPEX SPOT Belgium

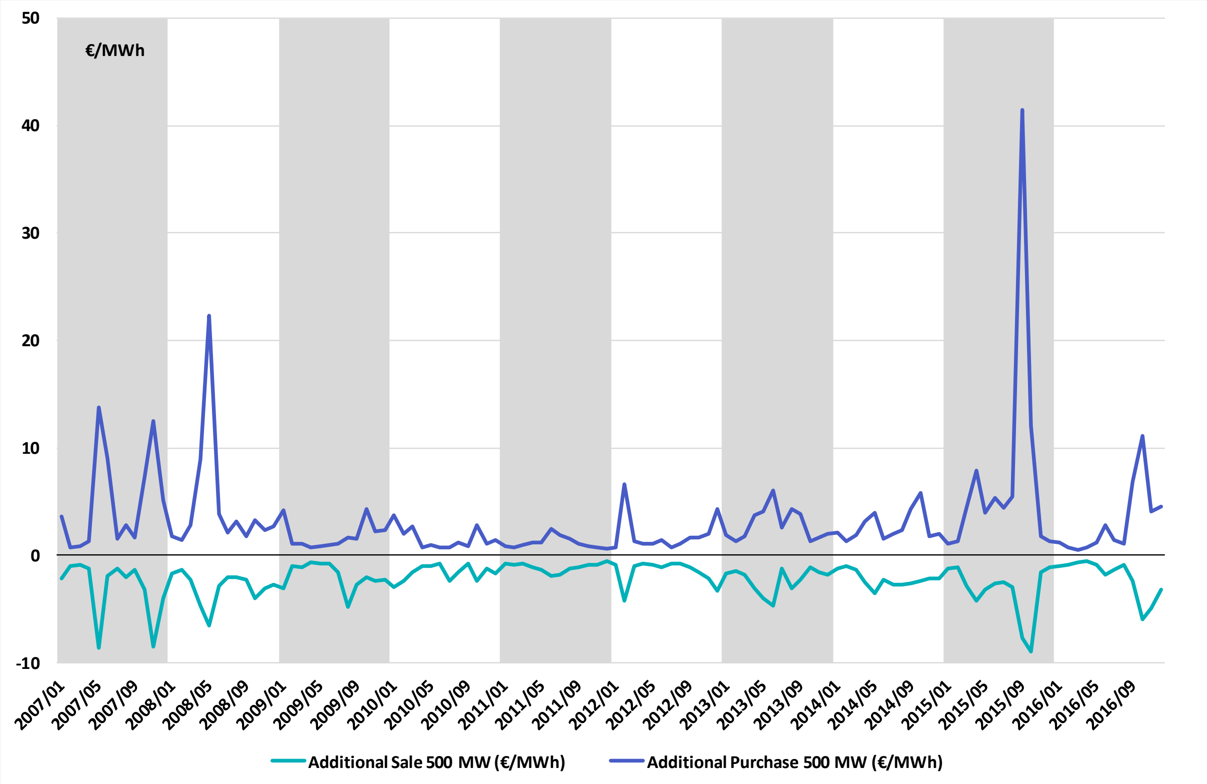


Figure 25 : The monthly averaged resilience of the day-ahead wholesale electricity price for delivery in the Belgian bidding zone in the event that 500 MWh/h is additionally sold or bought, is in 2016 high from September until the end of the year. A local peak is observed in June 2016. Resilience during the remainder of the year is of an order of magnitude not seen since 2013.
Sources : CREG based on data from EPEX SPOT Belgium

65. Intuitively, increasing the volume offered will lead to lower prices while increasing the volume bid will decrease prices. This is not always the case as can be derived from the histograms of price differences when selling additional volume (Figure 26) and when buying additional volume (Figure 27). The former should intuitively result in only negative differences while only positive differences should occur in the latter case. Even though the distributions are skewed in the expected direction, the more so the higher the additional volume, counterintuitive price differences can be observed, albeit at small absolute values.

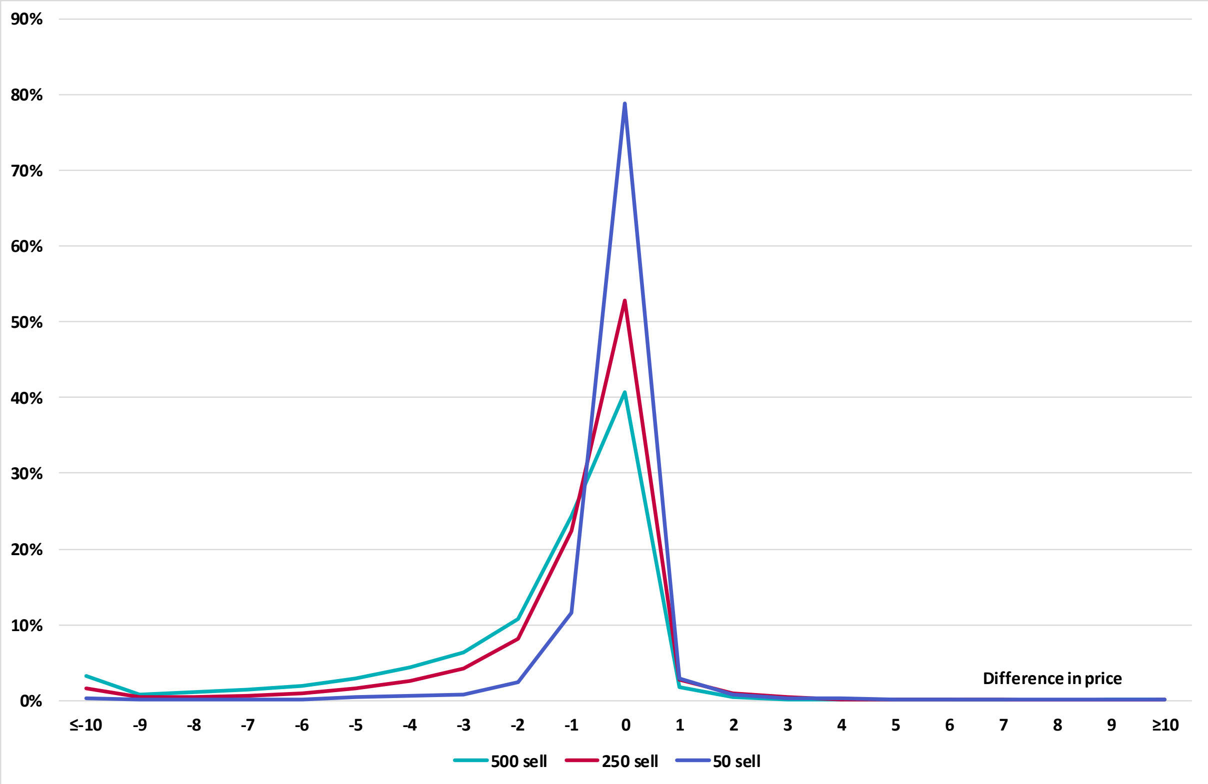


Figure 26 : The distribution of absolute changes in prices in 2016 when selling an additional volume is negatively skewed: supplying additional volumes logically results in lower prices. Skewness increases with increasing volumes of supply. Positive changes in prices occur as well, mostly limited to less than 1.5 €/MWh.
Sources : CREG based on data EPEX SPOT Belgium

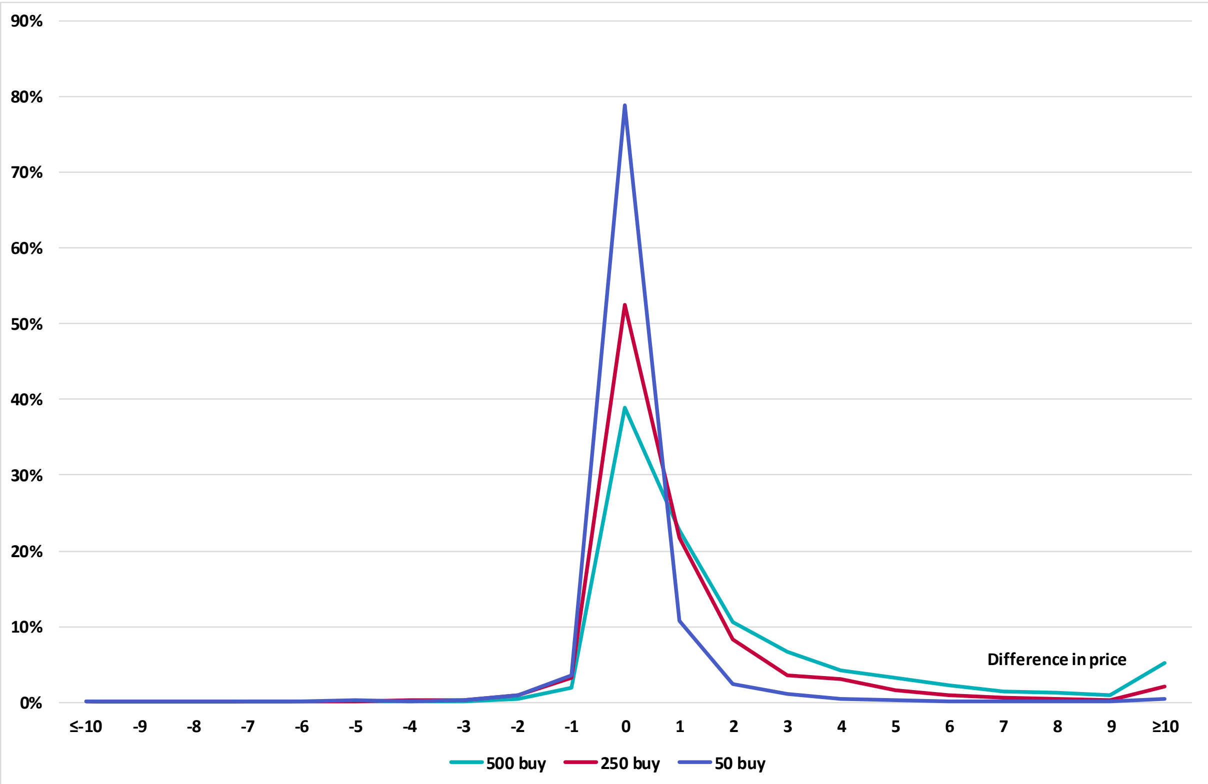


Figure 27 : The distribution of absolute changes in price in 2016 when buying an additional volume is positively skewed: demanding additional volumes logically results in higher prices. Skewness increases with increasing volumes of demand. Negative price changes occur as well, mostly limited to less than -1.5 €/MWh.
Sources : CREG based on data EPEX SPOT Belgium

66. The presence of profile block orders and smart orders are the cause for this observation. The volume represented by these orders needs to be entirely accepted by the market clearing mechanism before the order can be executed. The presence of these orders leads to a discontinuous social welfare function that is maximized to find the optimal market results. This discontinuous optimization function is the reason why hours exist with a counterintuitive price resilience, at which buying an additional volume of 50 MWh/h leads to lower prices and selling 50 MWh/h more volume leads to higher prices (Figure 28). Profile block orders have been available for market participants since 2007. Smart orders were introduced in 2014 which helps explain the jump in the number of hours with counterintuitive results. A reduction in occurrence can be seen since then, but in 2016, a significant number of hours are characterized by counterintuitive price resilience.

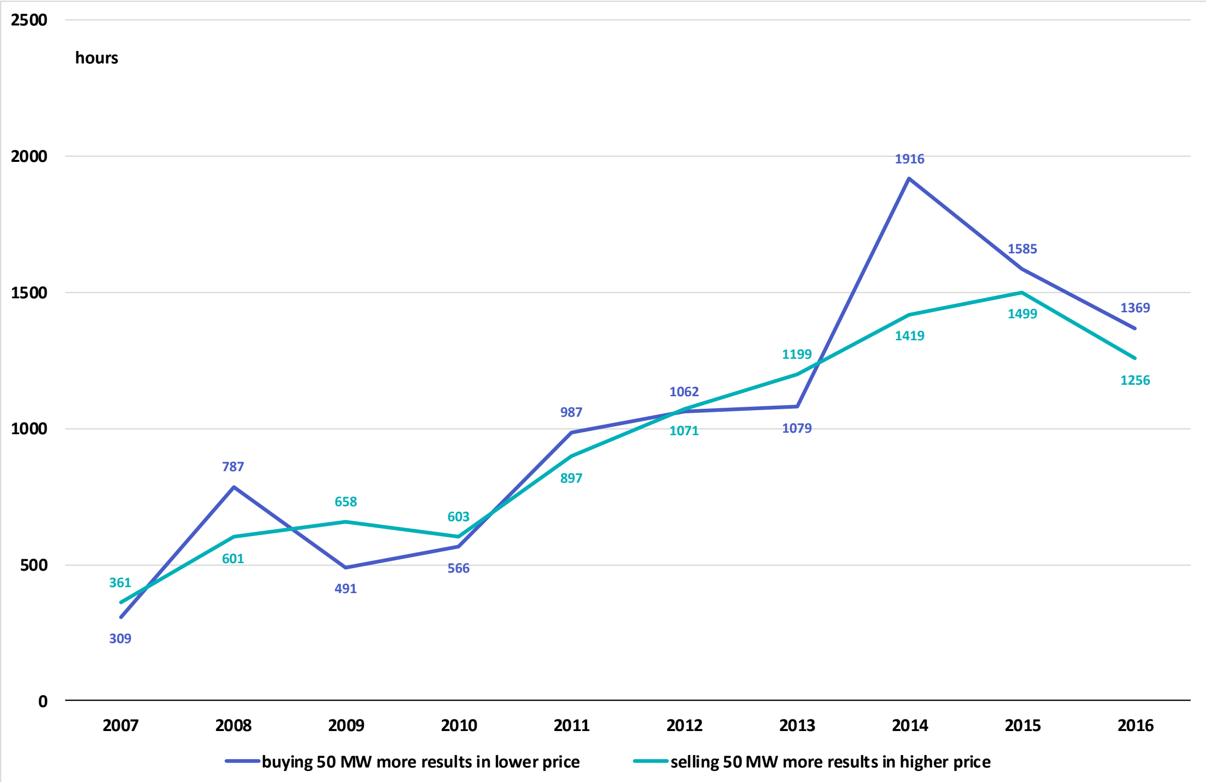


Figure 28 : The number of hours at which a counterintuitive price resilience is observed has steadily increased since the introduction of (profile) block orders in 2007 and its subsequently more widespread use. In February 2014, smart orders (linked and exclusive orders) were made available to market participants, resulting in a sudden increase of the number of hours with counterintuitive prices. The decreasing trend after 2014 might be the result of efficiency improvements when calculating the optimal market results.
Sources : CREG based on data EPEX SPOT Belgium

67. Counterintuitive price resilience when selling additional volume could occur in 2016 during the whole day but more likely – around 30% of the time – in the late afternoon and evening (Figure 29). In the morning, until hour 10, mainly volumes of 50 MWh/h cause counterintuitive prices while after hour 14 selling volumes up to 250 MWh/h might still result in higher prices. When considering the buy side, similar observations can be made except for the fact that the likelihood of having counterintuitive price resilience lies around 30% of the time from hour 7 to midnight (Figure 30).

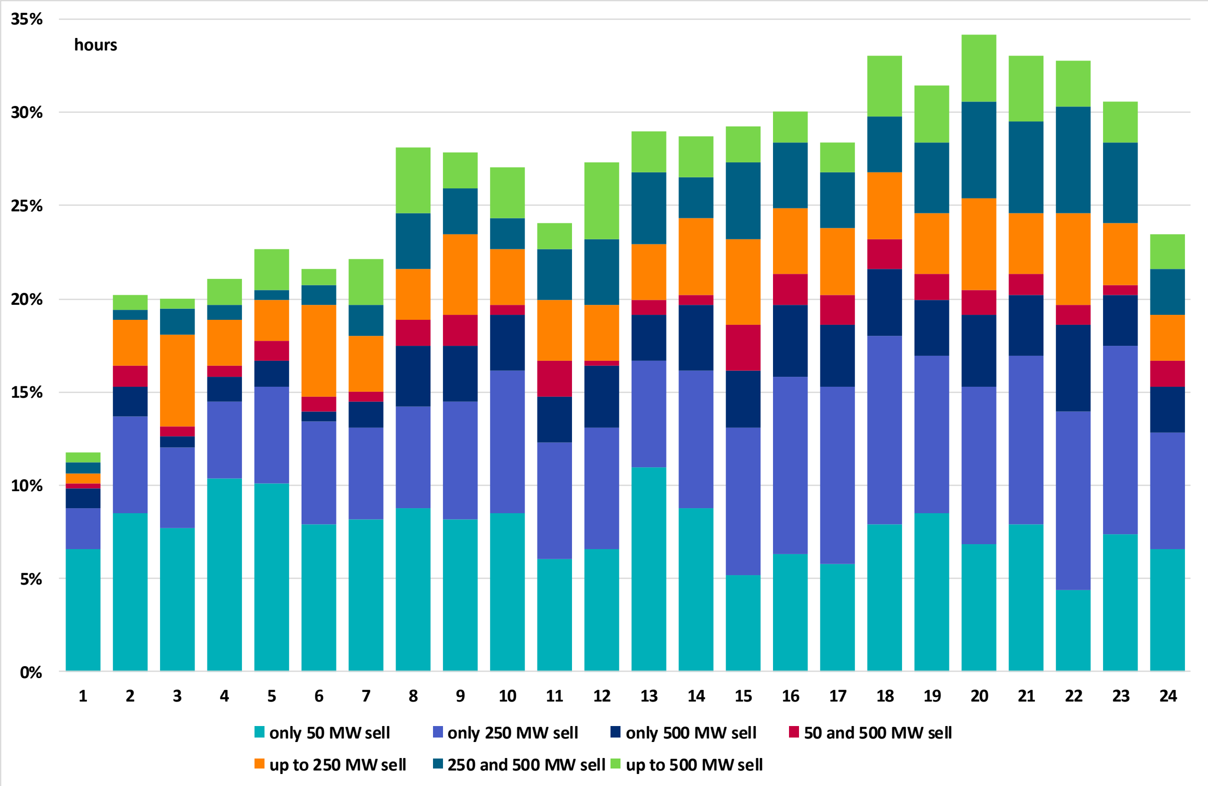


Figure 29 : The number of hours, in 2016, with counterintuitive resilience when selling an additional volume are highest around the late evening (hours 19 to 23).
Sources : CREG based on data EPEX SPOT Belgium

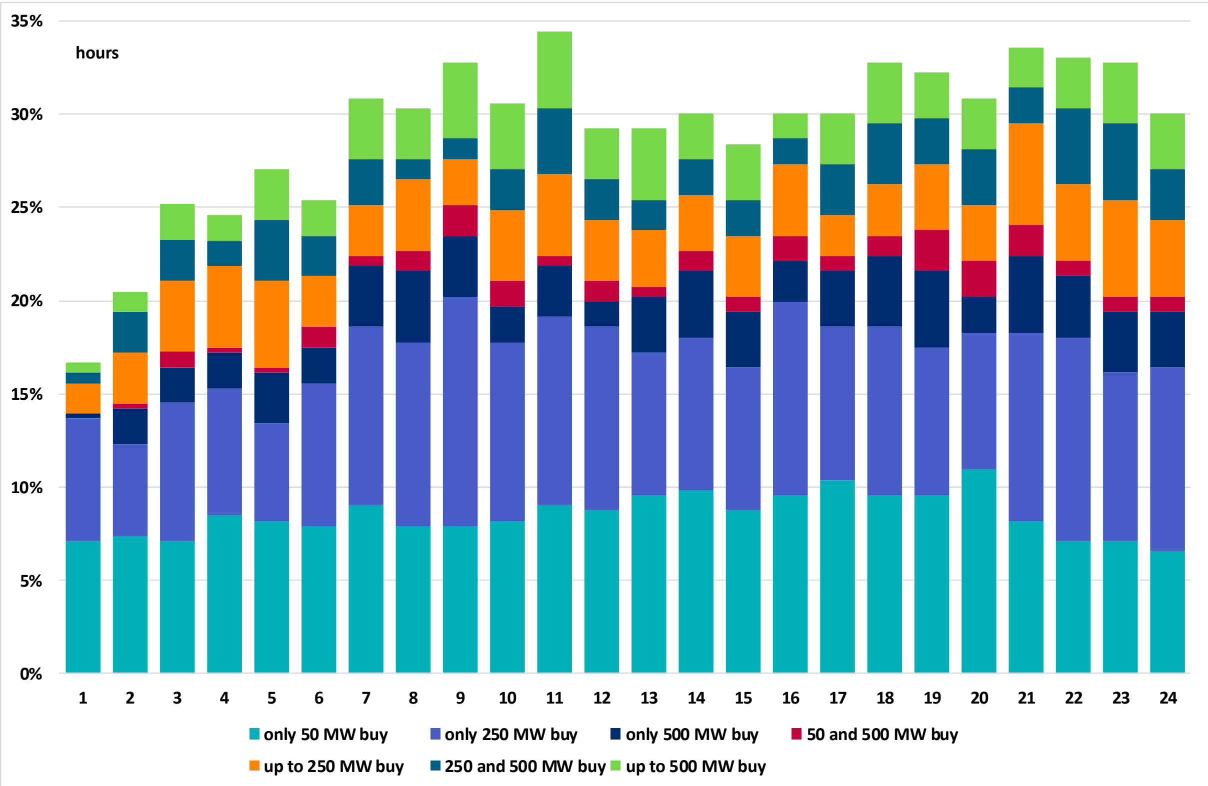


Figure 30 : The number of hours, in 2016, with counterintuitive resilience when buying additional volume are more equally distributed during the day than those when selling additional volume, except for the few hours at the very beginning of the day.
Sources : CREG based on data EPEX SPOT Belgium

68. As has been seen before, the absolute value of the counterintuitive price difference is very small, or even insignificant, when adding supply. When adding 50 MWh/h of demand, small counterintuitive price differences of 1 €/MWh to 2 €/MWh seem to occur relatively often. Analysis shows that, although counterintuitive prices occur during the whole year, the months with highest occurrence are June, November, and December 2016.

69. Low market resilience either indicates a need for (hourly) flexibility or a period of scarcity. Firstly, even small volumes of additional demand (or supply) can greatly impact the market clearing price. Secondly, large volumes of additional demand seem to result in price differences that are above those observed when small volumes of demand have been added only during 12 hours: during hour 9 and from hour 16 to hour 19 on 13 September, from hour 9 to hour 15 on 25 October. Considering the low price resilience covers a period of consecutive hours, one could argue that there was scarcity. The maximum market clearing price with additional volume of 500 MWh/h would nonetheless have been 999,99 €/MWh, indicating that the markets in the CWE-region could have accommodated the additional volume without significant issues.

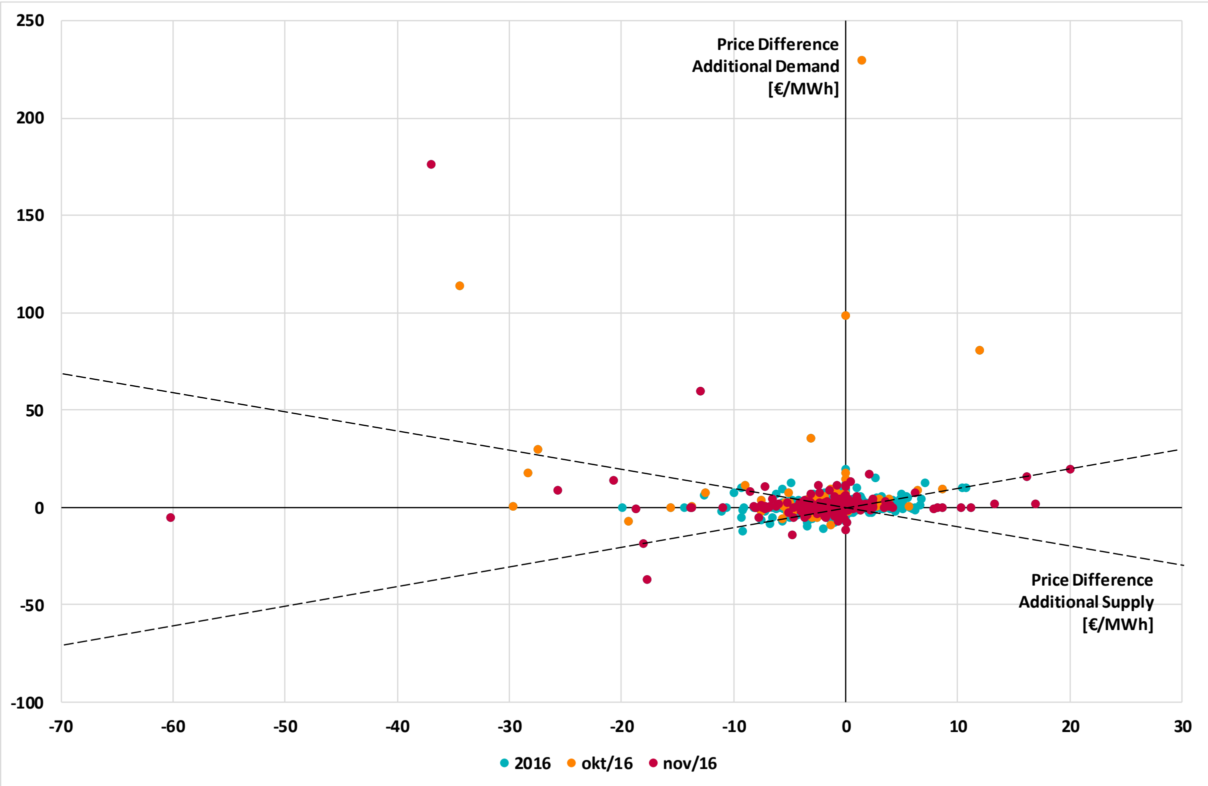


Figure 31 : Hourly price differences when additionally supplying 50 MWh/h and additionally demanding 50 MWh/h plotted against each other reveals that more frequently an equal volume of additional supply impacts the price more than additional demand however when additional demand has a higher impact, the impact is more significant compared with those of additional supply.
Sources : CREG based on EPEX SPOT Belgium

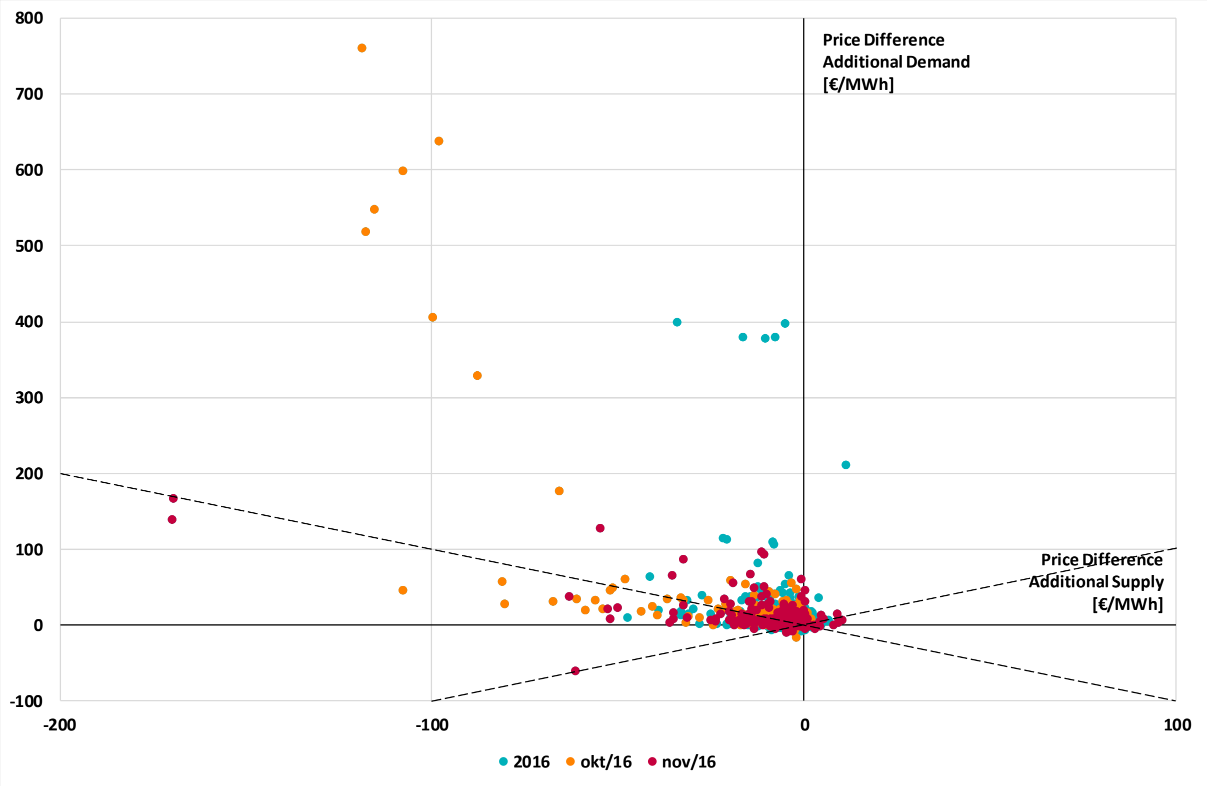


Figure 32 : Hourly price differences when additionally supplying 500 MWh/h and additionally demanding 500 MWh/h plotted against each other reveals that more frequently an equal volume of additional supply impacts the price more than additional demand however when additional demand has a higher impact, the impact is more significant compared with those of additional supply.
Sources : CREG based on EPEX SPOT Belgium

70. Baseload power prices during days in November, but also some days in October and December 2016 are subject to low levels of robustness, indicating that market participants benefit by accurately offering must-run demand in the day-ahead market (Figure 33). Counterintuitive price changes seem to propagate to counterintuitive baseload prices even though the number of instances as well as the impact on baseload prices is limited compared with that of intuitive price changes.

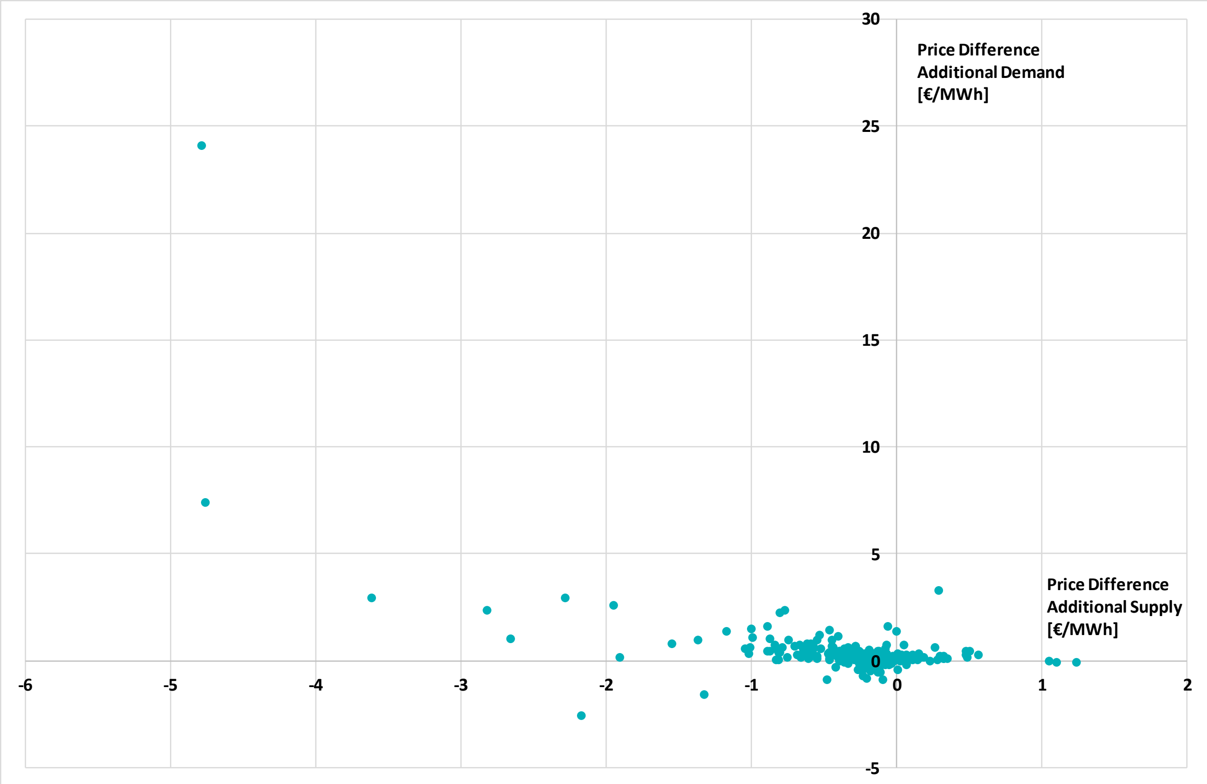


Figure 33 – Baseload price differences when additionally supplying 50 MWh/h and additionally demanding 50 MWh/h plotted against each other reveals that during some days baseload prices in the last quarter of 2016 could be significantly impacted by small volumes of additional demand and supply. Note that counterintuitive baseload price changes exist as well but are less significant compared with price changes caused by significant price changes.
Sources : CREG based on EPEX SPOT Belgium

4.3. STATISTICS

4.3.1. Day-ahead wholesale electricity market for delivery in Belgium

71. The yearly averaged day-ahead wholesale electricity price in Belgium reached its lowest level since 2007 at 36.6 €/MWh (Figure 34). After adjustment for inflation yearly averaged day-ahead electricity prices have become 25.7% cheaper since the liberalisation of the electricity market (Table 13). In 2016 during 70% of all hours, day-ahead wholesale electricity prices in the Belgian bidding zone were lower than 40 €/MWh (Table 14). Compared with all 6 years prior to 2016 the highest frequency of elevated day-ahead wholesale electricity prices is observed in 2016: 1.2% of the day-ahead prices in 2016 were higher than 100 €/MWh. The daily averaged day-ahead wholesale electricity price in Belgium, which is often used as an index for the determination of prices of supply contracts, reached a level higher than €100/MWh on 5 days in 2016, all of them occurring in the fourth quarter.

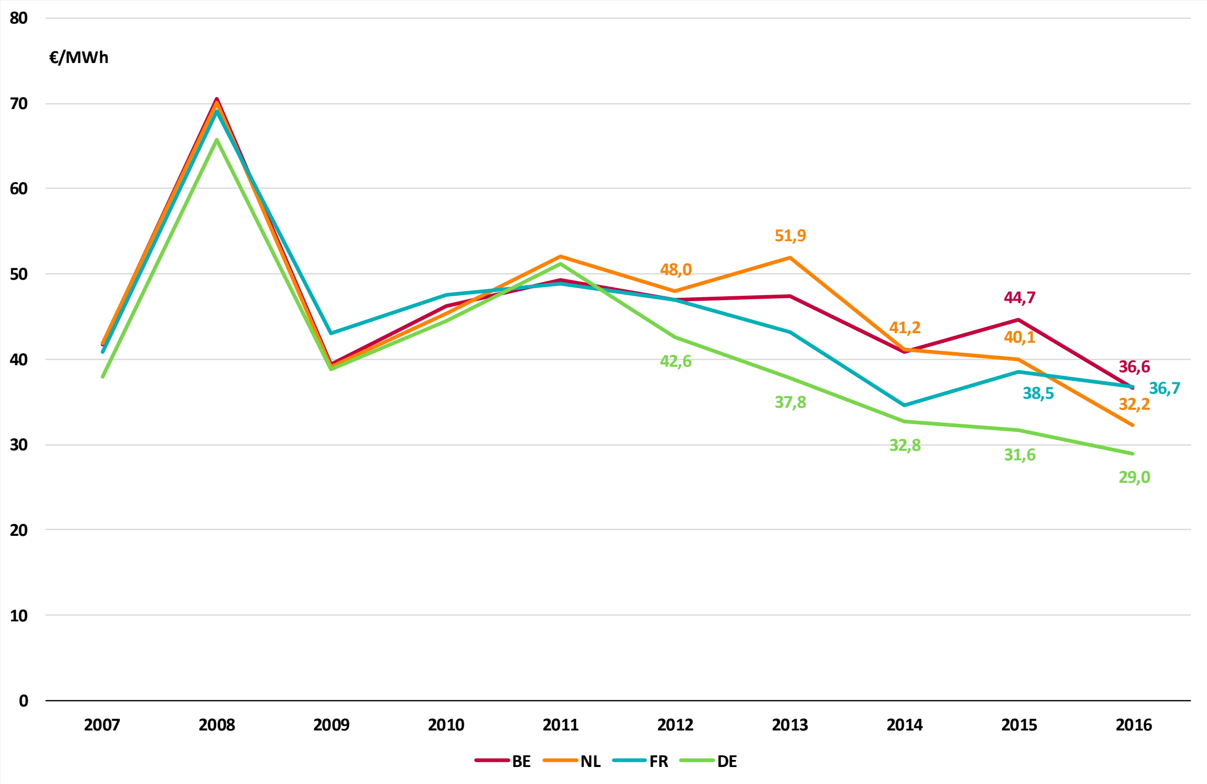


Figure 34 : Yearly average hourly day-ahead wholesale electricity prices, per bidding zone in the CWE region, continued to decrease in 2016. The Belgian bidding zone together with the French zone have the highest averaged prices.
Sources: CREG based on data received from EPEX SPOT Belgium, EPEX SPOT

Year	BE nominal	BE real (ref. jan 2007)	BE real (ref. dec 2016)
2007	41,72	41,28	49,44
2008	70,64	67,20	80,48
2009	39,40	37,26	44,62
2010	46,28	43,04	51,55
2011	49,41	44,63	53,45
2012	47,07	41,39	49,57
2013	47,50	41,28	49,44
2014	40,79	35,30	42,28
2015	44,74	38,31	45,88
2016	36,58	30,66	36,72

Table 13 : Yearly averaged monthly baseload day-ahead wholesale electricity market prices in the Belgian bidding zone, in nominal terms, illustrate a price decrease of 5,14 €/MWh. In real terms, the price of the commodity electricity has decreased by 10,62 €/MWh, more than double the nominal price decrease.
Sources : CREG based on data received from EPEX SPOT Belgium, FPS Economy, SMEs, Self-employed and Energy

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
€-500/MWh - €0/MWh	0,0%	0,0%	0,0%	0,0%	0,0%	0,1%	0,2%	0,0%	0,0%	0,0%
€0/MWh - €20/MWh	17,3%	4,1%	10,9%	5,3%	9,3%	4,2%	9,6%	5,1%	3,3%	11,3%
€20/MWh - €40/MWh	48,1%	8,7%	47,4%	27,8%	11,8%	28,5%	22,1%	43,8%	35,9%	59,6%
€40/MWh - €60/MWh	20,0%	24,2%	30,8%	50,1%	53,4%	50,3%	44,5%	45,6%	50,6%	19,5%
€60/MWh - €80/MWh	6,8%	30,9%	8,2%	14,8%	24,8%	14,5%	20,7%	5,2%	8,7%	6,6%
€80/MWh - €100/MWh	3,8%	18,8%	2,2%	1,4%	0,5%	1,5%	2,3%	0,2%	0,7%	1,6%
€100/MWh - €250/MWh	3,6%	13,2%	0,5%	0,6%	0,2%	0,8%	0,5%	0,1%	0,5%	1,2%
€250/MWh - €500/MWh	0,3%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,2%	0,0%
€500/MWh - €1000/MWh	0,1%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%
€1000/MWh - €3000/MWh	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%

Table 14 : Histogram of day-ahead wholesale electricity prices in the Belgian bidding zone illustrate a higher frequency of prices higher than 80 €/MWh. Almost 60% of the time, hourly prices are situated between 20 €/MWh and 40 €/MWh, a significant shift compared with the histograms observed since 2010.
Sources : CREG based on data provided by EPEX SPOT Belgium

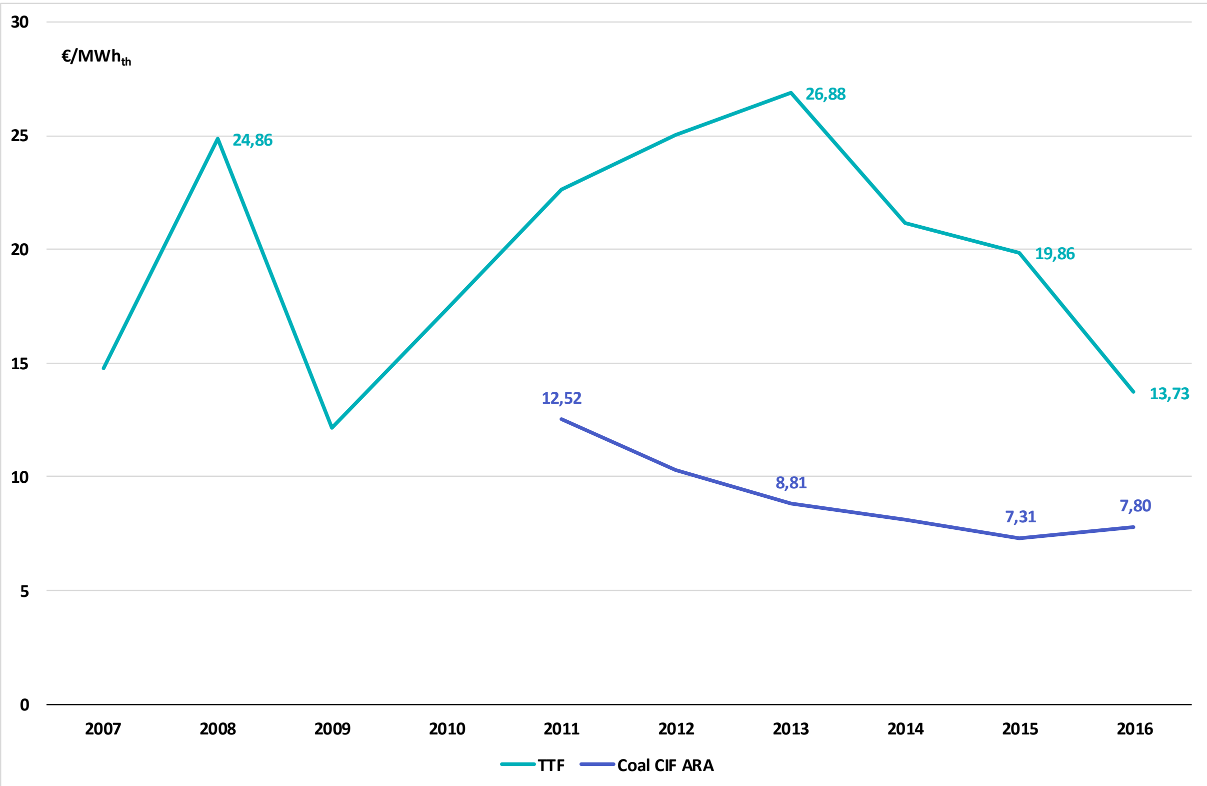


Figure 35 : Yearly averaged day-ahead wholesale coal (CIF ARA) and gas (TTF) prices show a decrease in commodity prices used for the generation of electricity by plants at the higher end of the merit order curve in Germany and the Netherlands respectively. Gas prices have decrease by almost 50% since 2013, corresponding with the 38% reduction of Dutch wholesale electricity prices since 2013. Since 2013, coal prices have decreased by 11% and German wholesale electricity prices by 23%. Often only attributed to the integration of renewable energy sources, the decrease of wholesale electricity prices might be more significantly impacted by developments of commodity prices.
Sources: CREG based on TTF and CIF ARA

72. Yearly averaged wholesale electricity prices in all neighboring countries were also lower in 2016 compared with 2015 but the reduction of the yearly averaged wholesale electricity price in Belgium was most important in the CWE region (Figure 34). The reduction of wholesale electricity prices in Belgium and in the CWE region is explained by the integration of renewable energy sources and more importantly the reduction of wholesale coal and gas prices which serve as an important input to determine the short term marginal cost of a gas or coal power plant and hence the price level at which its generated electricity should be offered to the Belgian day-ahead market. Wholesale gas prices are nearing the minimum price level observed since 2009 while wholesale coal prices only increased slightly in 2016 after having fallen every single year since 2011 (Figure 35).

73. The convergence, observed in 2015, of the yearly averaged day-ahead wholesale electricity price between Belgium and France on the one hand and the Netherlands and Germany nonetheless continued in 2016 (Figure 34). The price spread of yearly averaged day-ahead wholesale electricity prices in the CWE region lowered to 7.8 €/MWh in 2016 from 13.1 €/MWh in 2015, the lowest level since 2013 but still more than double the minimum price spread observed since 2007. Prices have diverged primarily by events during the last 4 months of 2016 (Figure 36). Among others these events can be traced back to nuclear outages in Belgium from September onward and a lower than usual output of EDF's nuclear fleet in France following the detection of anomalies in the Flamanville Pressurized Water Reactor (PWR) vessel in May and the subsequent series of investigations affecting a total of 18 of the 58 PWRs installed in France. Hence the higher frequency of elevated prices in Belgium seems to result from the energy-only market providing price signals reflecting scarcity conditions in the CWE region (Table 14). As such, in 2016, the energy-only market in Belgium did not only provide opportunities for active flexible consumption or generation units reacting on within-day price signals but also those reacting on inter-day price signals (Figure 37, Figure 38).

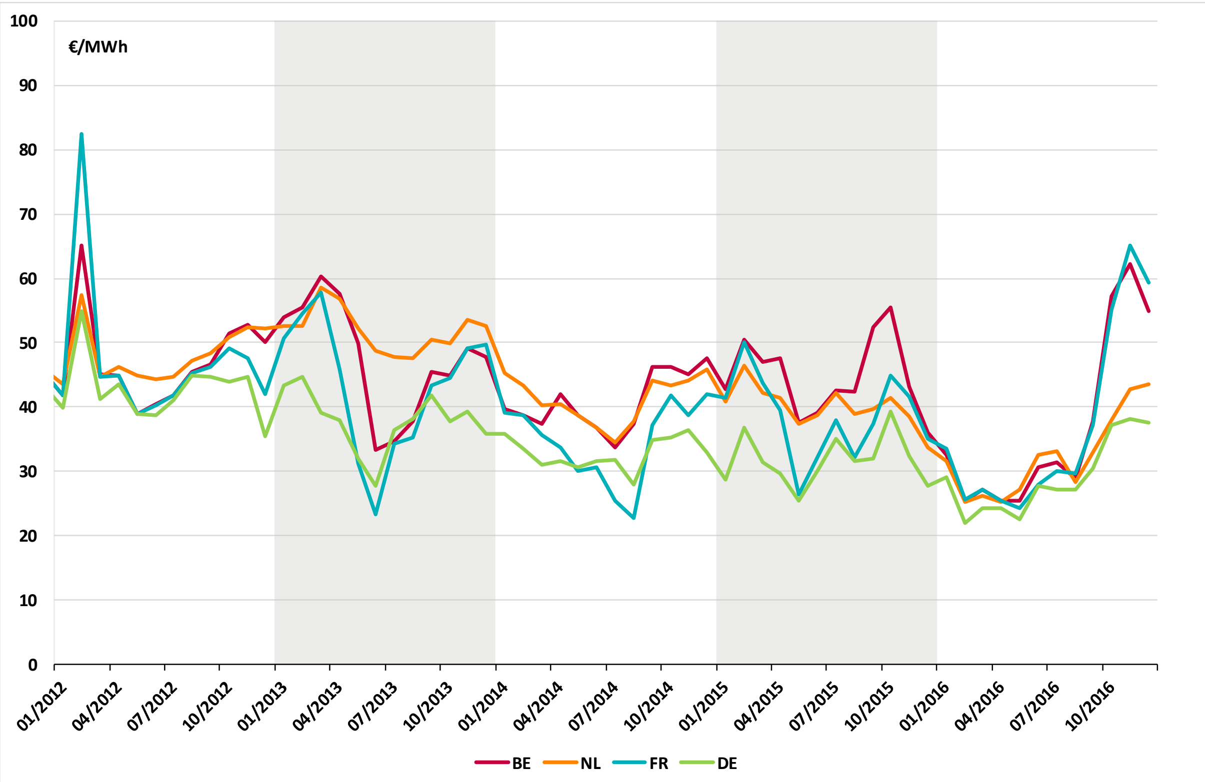


Figure 36 : Monthly averaged day-ahead wholesale electricity prices per bidding zone in the CWE region illustrate that extremely high prices have emerged from September until December 2016. The year 2016 also marks the first year since 2012 where prices in the German bidding zone were higher at the end of the year than at the beginning. Unavailability of nuclear power plants in Belgium and France explain the price increase at the end of the year.
Sources: CREG based on data received from EPEX SPOT Belgium, EPEX SPOT

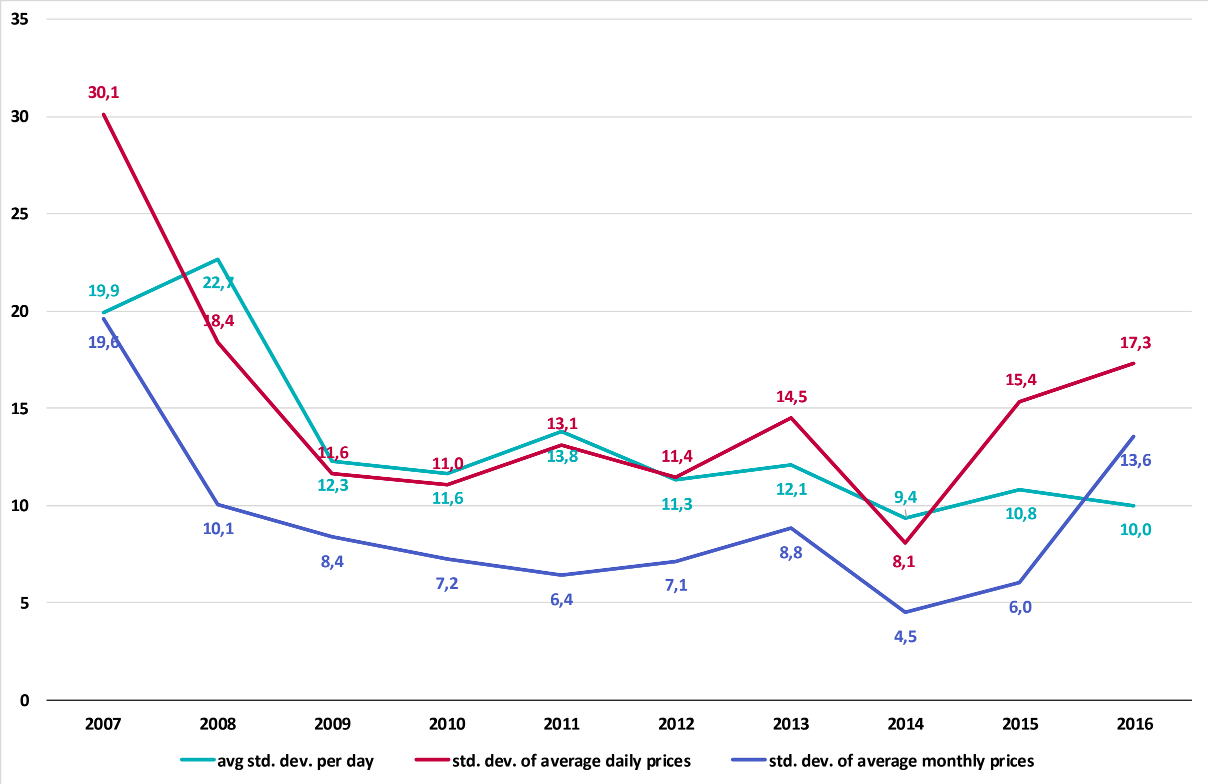


Figure 37 : Volatility of the day-ahead wholesale electricity price in the Belgian bidding zone illustrates that hourly price peaks have not occurred more often than usual (turquoise). Elevated prices during multiple hours or days have occurred more often. Sources: CREG based on data received from EPEX SPOT Belgium

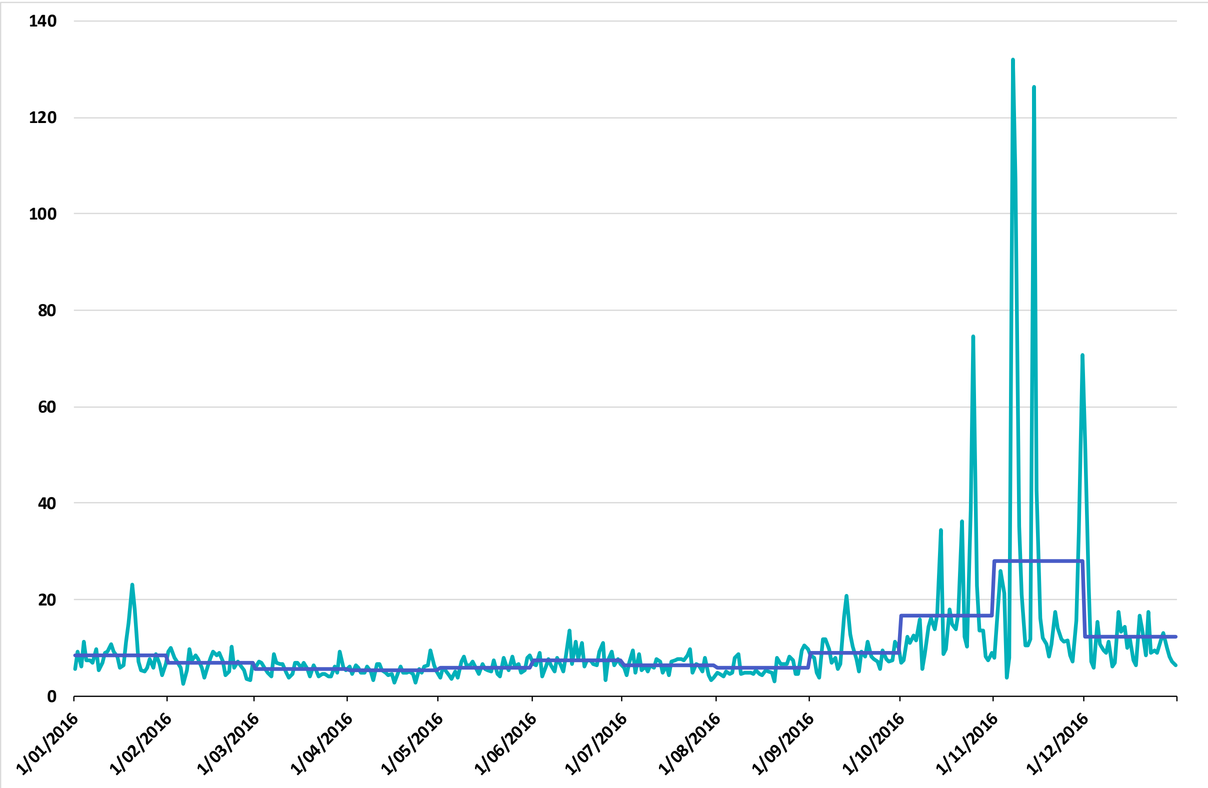


Figure 38 : Price volatility during the day of day-ahead wholesale electricity prices in the Belgian bidding zone averaged over daily and monthly periods indicate that flexible units mainly had arbitrage opportunities during October and November 2016. Sources : CREG based on data provided by EPEX SPOT Belgium

74. The frequency of hourly prices between Belgium and all 3 other bidding zones in the CWE region differing less than 0.01 €/MWh, denoted further as full convergence, has improved from 18.9% in 2015 to 34.5% in 2016, the highest level recorded since 2013 (Figure 39). Full price convergence between Belgium and any of the 3 other bidding zones in the CWE region on the other hand further deteriorated resulting in an increase of hours with full price divergence in the CWE region from 42.1% in 2015 to 50.1% in 2016, the highest level observed since 2007. Around half of the hours with full price divergence were caused by price differences of less than 1 €/MWh as illustrated by calculating price convergence using a threshold price difference of 1 €/MWh. In most cases the Belgian bidding zone is approximately price convergent with France. Analysis of monthly price convergence in 2016 confirms that low price convergences occur during the last 3 to 4 months of 2016 (Figure 41, Figure 42). During the first 8 months of 2016 the day-ahead wholesale electricity price in the Belgian bidding zone is more than 80% of the time approximately equal to the wholesale electricity price in any of the other 3 bidding zones of the CWE region.

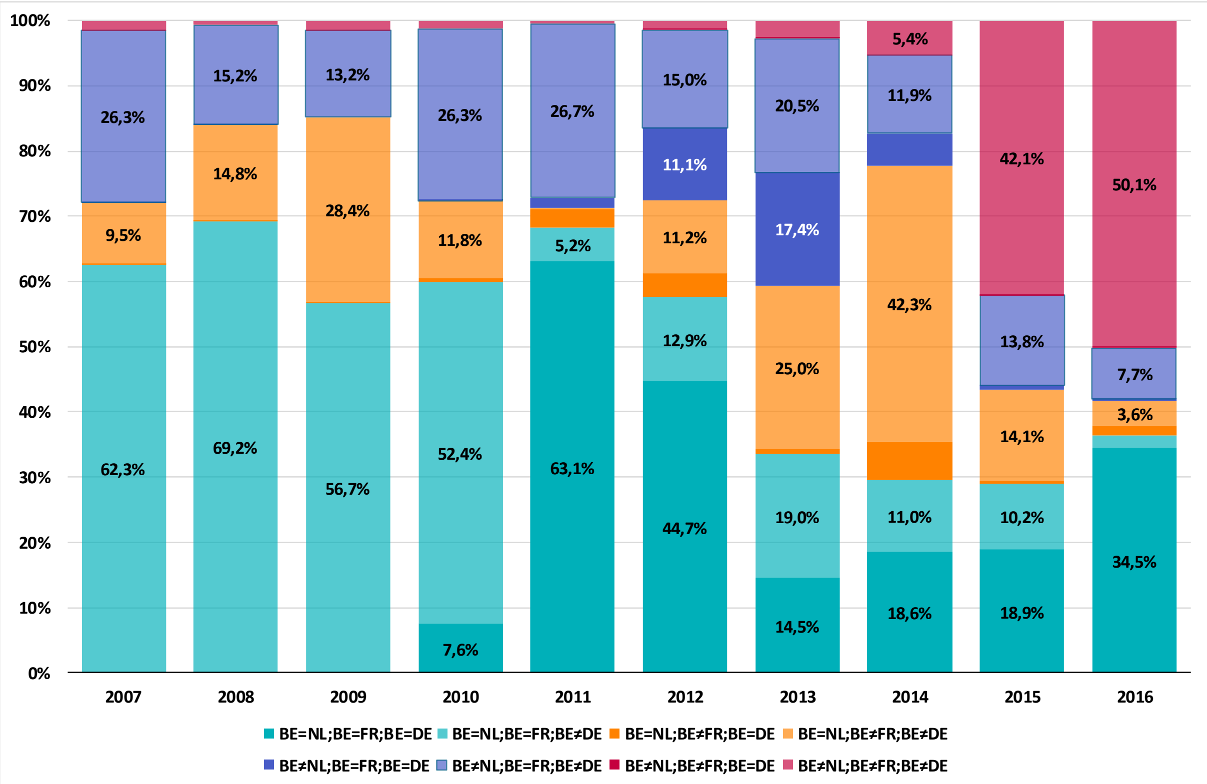


Figure 39 : Full price convergence (price spread < 0.01 €/MWh) between the Belgian bidding zone and the other bidding zones in the CWE region shows the highest occurrence of full price convergence since 2013. Full price divergence exceeded 50% for the first time since the observations. Price convergence between the Belgian bidding zone and on the one hand only the French bidding zone, and on the other hand only the Dutch bidding zone have reached their lowest frequency since the observations.
Sources : CREG based on data provided by EPEX SPOT Belgium, EPEX SPOT

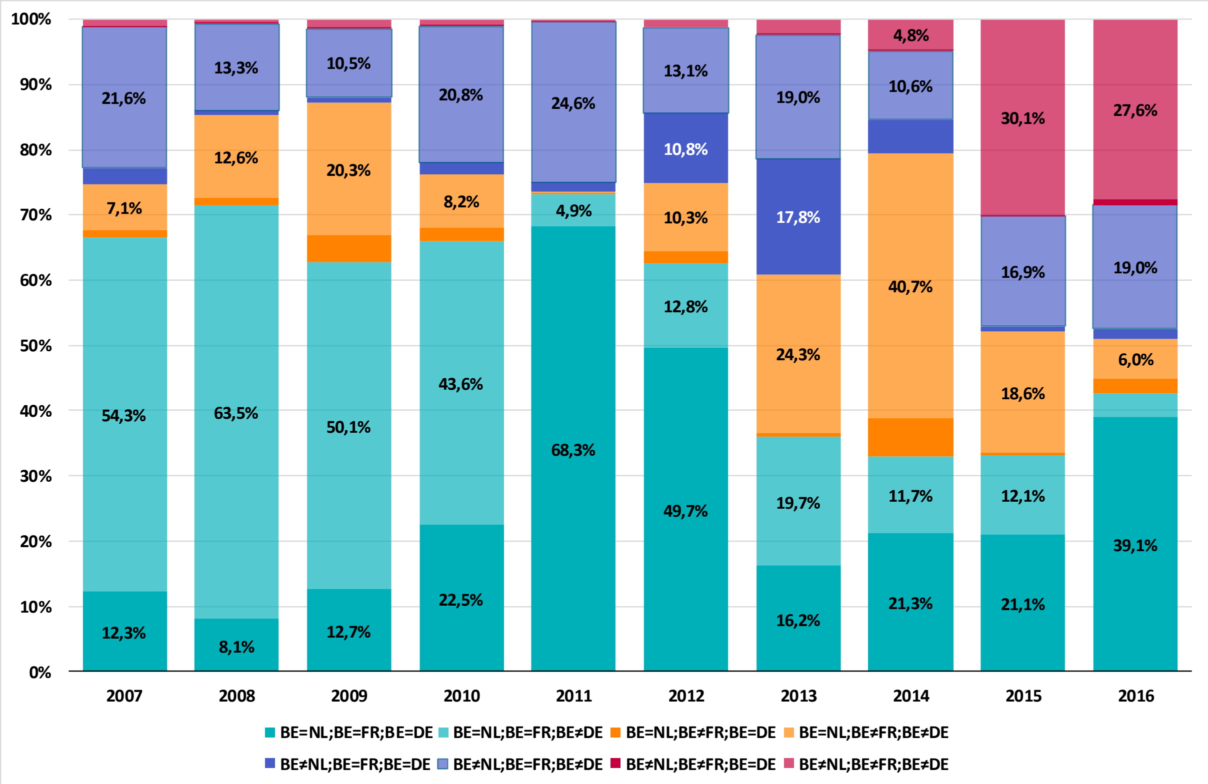


Figure 40 : Approximate price convergence (price spread < 1 €/MWh) between the Belgian bidding zone and the other bidding zones in the CWE region shows that frequently a price difference of less than 1 €/MWh exists between the Belgian and French bidding zone.
Sources: CREG based on data provided by EPEX SPOT Belgium, EPEX SPOT

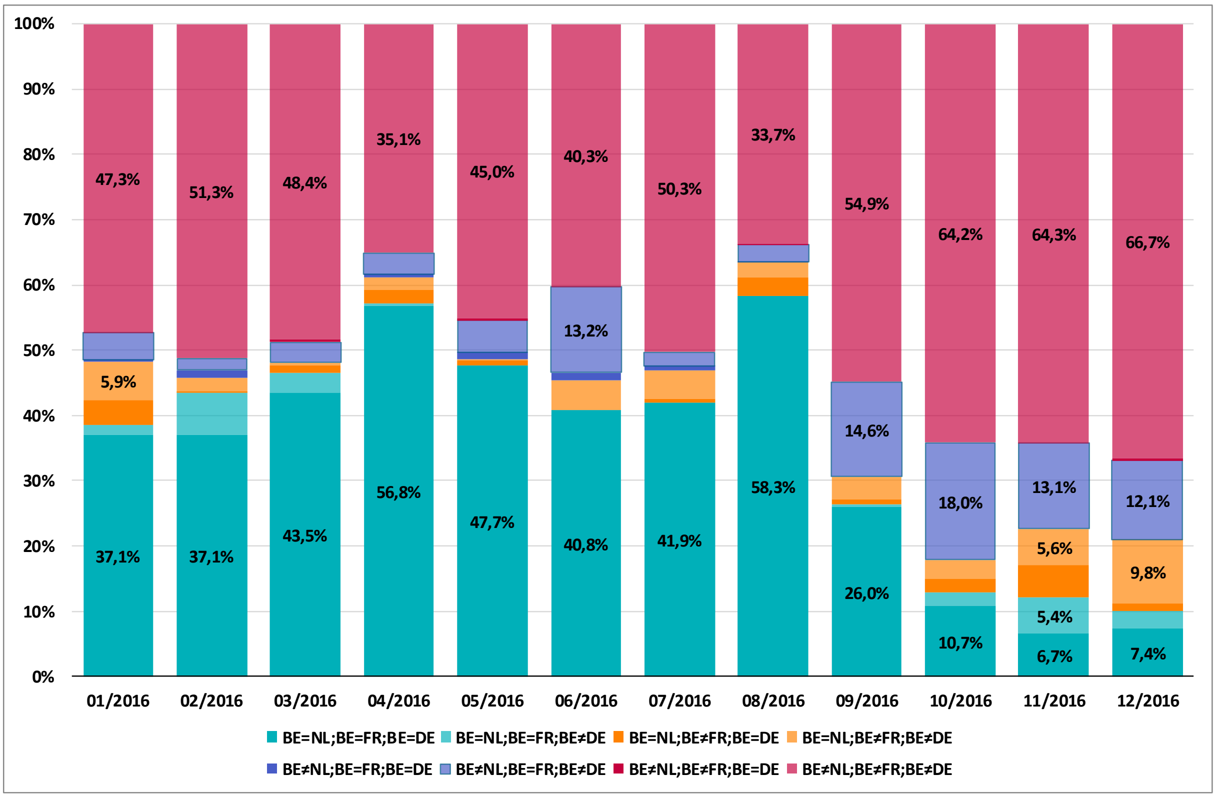


Figure 41 : Full price convergence (price spread < 0.01 €/MWh) between the Belgian bidding zone and the other bidding zones in the CWE region in 2016 shows that the last quarter of 2016 saw frequent price divergence.
Sources: CREG based on data provided by EPEX SPOT Belgium, EPEX SPOT

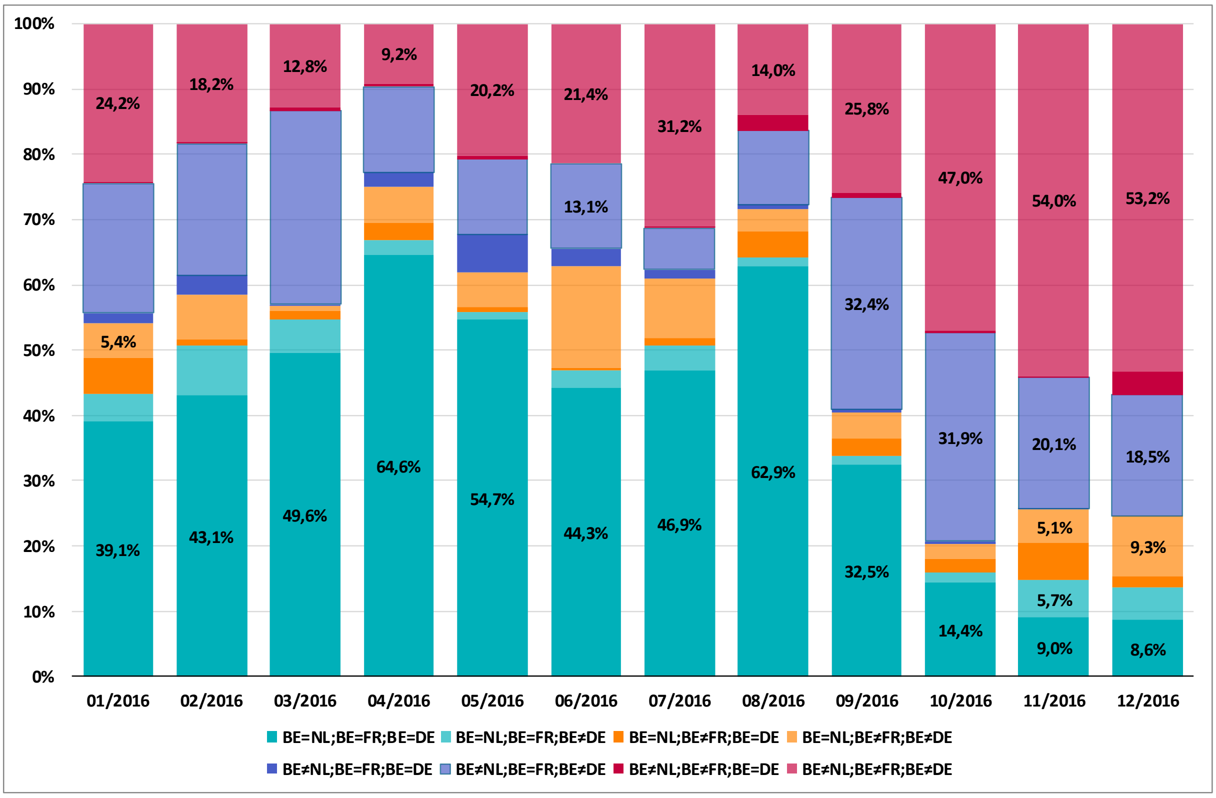


Figure 42 : Approximate price convergence (price spread < 1 €/MWh) between the Belgian bidding zone and the other bidding zones in the CWE region in 2016 shows that frequently a price difference of less than 1 €/MWh exists between the Belgian and French bidding zone.
Sources : CREG based on data provided by EPEX SPOT Belgium, EPEX SPOT

75. Increased nuclear electricity generation during 2016 resulted in a strong reduction of imported volumes on the day-ahead market for the delivery of electricity in the Belgian bidding zone from 14.0 TWh in 2015 to 7.6 TWh in 2016 (Table 15). Volumes exported increased to 1.2 TWh, the highest value since 2012. Trade volumes are at a similar level as 2014. The reduction in yearly averaged day-ahead wholesale electricity price hence primarily drives the reduction of the value of all contracts settled from 1.08 billion to 786 million euros in 2016, its lowest level since 2012 (Figure 43).

Year	Buy	Sell	Trade	Import	Export	Net Import	Trading / Load ELIA	Value of contracts [Meuro]
2007	6,8	4,8	7,6	2,7	0,8	2,0	8,6%	365,9
2008	10,4	4,3	11,1	6,8	0,7	6,1	12,6%	802,2
2009	6,0	9,1	10,1	1,0	4,1	-3,1	12,4%	388,5
2010	9,6	8,9	11,8	2,9	2,3	0,7	13,7%	560,8
2011	10,3	9,2	12,4	3,1	2,1	1,1	14,8%	618,7
2012	15,8	8,9	16,5	7,6	0,6	6,9	20,1%	804,3
2013	16,1	11,2	17,1	5,9	1,0	4,9	21,3%	859,4
2014	19,6	9,5	19,8	10,3	0,2	10,1	25,6%	830,2
2015	23,6	9,6	23,7	14,0	0,0	14,0	30,7%	1080,4
2016	18,3	11,9	19,6	7,6	1,2	6,4	25,3%	785,6
2007-2016	136,6	87,5	149,6	62,0	12,9	49,1	18,5%	7095,9

Table 15 : Total volumes of day-ahead wholesale energy products sold, bought, traded, imported and exported (all expressed in TWh), including the churning rate and the total value of contracts settled.
Sources : CREG based on data provided by EPEX SPOT Belgium, EPEX SPOT

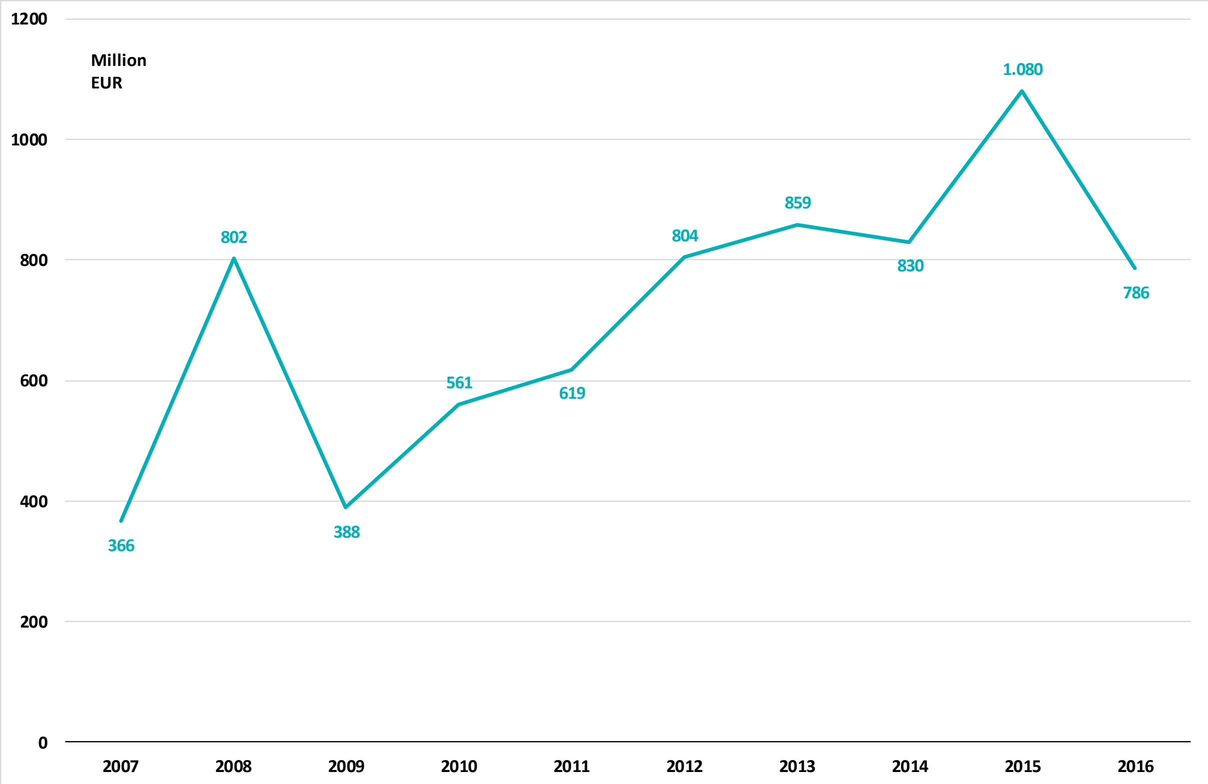


Figure 43 : Total value of all contracts settled on the day-ahead wholesale electricity market for delivery in Belgium have declined since last year, to a level equivalent to that observed in 2008 and the period ranging from 2012 to 2014.
Sources : CREG based on data provided by EPEX SPOT Belgium

76. As already mentioned the availability of the Belgian nuclear power plants significantly impact trade of wholesale energy products on the Belgian day-ahead wholesale electricity market (Figure 44). During the first half of January 2016, apart from some periods of unavailability of Tihange 1 and Doel 1 in March and May, the Belgian nuclear fleet generated electricity at full capacity, resulting in a sudden reduction of demand and imports on the day-ahead market with respect to December 2015. The next few months were characterized by a substitution of sold volumes with competing imports from abroad to satisfy gradually lower demand at competitive prices. The drop of sold volumes in April and May coincided with a drop in available generation capacity of almost 3 GW. Competition and a gradually recovering available generation capacity during the summer resulted in the substitution of imports by supply in Belgium. In September, Tihange 1 (962 MW), Tihange 3 (1045.8 MW) and Doel 1 (433 MW) became unavailable followed by Doel 3 (1006 MW) in October. The loss of almost 3.500 MW of baseload supply resulted in a sharp increase in demand to its highest level observed since 2007, which was fully covered by imports. The restart of Doel 1, Tihange 3, and Doel 3 from October onward again lowered demand and increased supply on the day-ahead market, resulting in gradually lower imports until the end of the year.

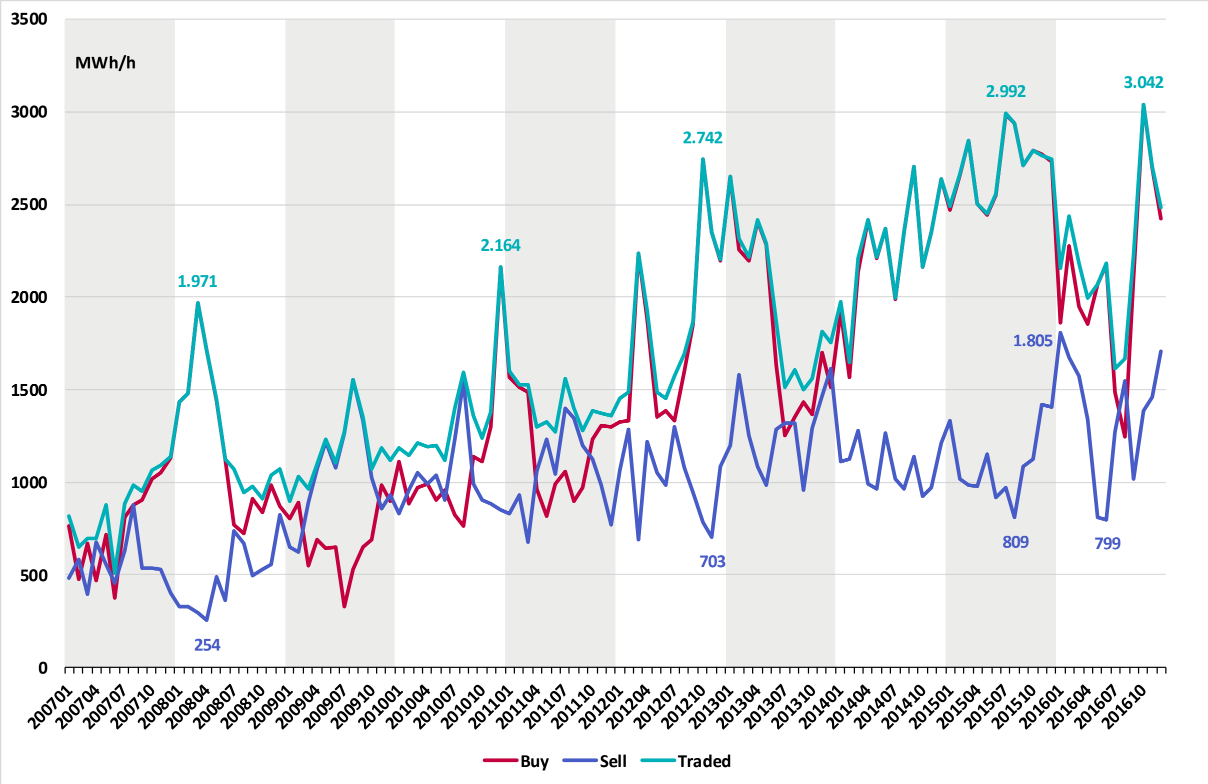


Figure 44 : Average hourly volumes of day-ahead wholesale energy products sold, bought, and traded declined steadily from December 2015 until August 2016. Since September 2016 the volume traded and bought increased significantly to record levels observed since 2007 and at a higher rate than the volume sold over the same period.
Sources : CREG based on data provided by EPEX SPOT Belgium

4.3.2. Intraday wholesale electricity market for delivery in Belgium

77. The yearly averaged intraday wholesale electricity price in Belgium in 2016 is 13% lower than in 2015, thereby attaining its lowest value since 2008 at 37,97 €/MWh (Table 16). The evolution of the yearly averaged intraday wholesale electricity price closely follows the evolution of the yearly averaged day-ahead wholesale electricity price in Belgium.

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Belpex CIM Price [EUR/MWh]	84,46	41,78	49,88	55,59	51,66	52,40	42,55	43,85	37,97
Belpex DAM Price [EUR/MWh]	87,80	41,57	49,12	54,16	51,08	52,58	41,62	44,41	37,20
Belpex CIM Volume [GWh]	61	167	254	364	513	651	786	749	1089
Import [GWh]	-	-	-	-	-	-	302	239	552
Export [GWh]	-	-	-	-	-	-	395	357	402

Table 16 : Yearly total volumes of intraday wholesale electricity products illustrate that cross-border energy exchanges represent a significant part of all trade. Yearly averaged prices of intraday and day-ahead wholesale electricity products illustrate that they have been convergent, on average, during the whole period observed.
Source: CREG based on data provided by EPEX SPOT Belgium [31]

[31] Values of traded volumes might differ from those published in the reports of previous years due to detected discrepencies in values transmitted to the CREG by Belpex.

78. The variation as measured as the yearly averaged absolute difference between the day-ahead and intraday wholesale electricity prices shows an oscillating pattern but a slightly declining trend since 2011 (Figure 45). This indicates that opportunities to arbitrage[32] on in the intraday wholesale electricity market have increasingly better utilized by flexible generation and/or consumption units over the past 5 years. The steady increase in intraday market liquidity – an increase of 2.5 times since 2011 if proxied by the number of hours an intraday wholesale electricity price can be calculated – is one of the reasons for this observation (Figure 46). The equal number of hours when the intraday wholesale electricity price is higher respectively lower than the day-ahead wholesale electricity price indicates both opportunities of arbitrage are equally exercised by market participants.

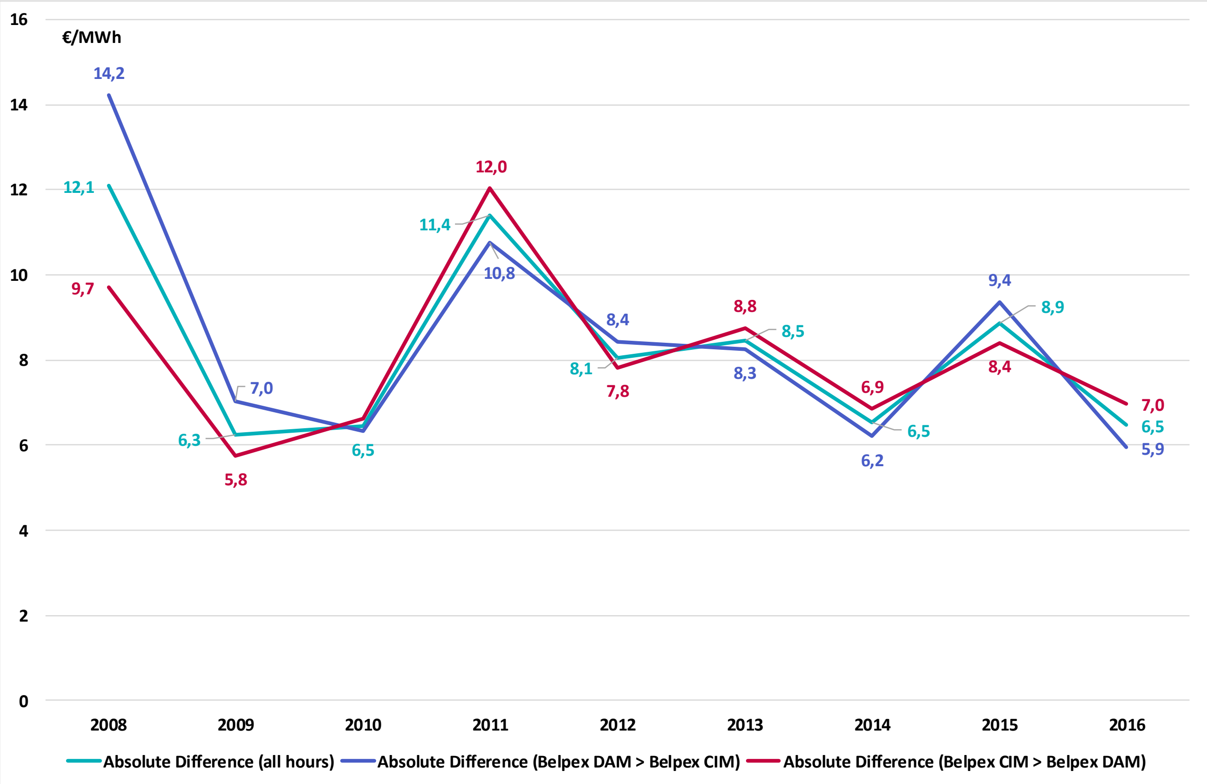


Figure 45 : Yearly averaged prices of intraday and day-ahead wholesale electricity products, including the absolute error between both, illustrates that large differences may occur. Positive and negative differences are roughly equal.
Source: CREG based on data provided by EPEX SPOT Belgium

[32] If the intraday wholesale electricity price is lower than the day-ahead wholesale electricity price, additional profits can be generated by buying electricity by either reducing the output of generation units (with higher short-run marginal costs than the intraday wholesale electricity price) or increasing the input of a consumption unit (with a willingness to consume at a price higher than the intraday wholesale electricity price). In case the intraday wholesale electricity price is higher than the day-ahead wholesale electricity price, profit is generated by either increasing the output of generation units or decreasing the input of a consumption unit.

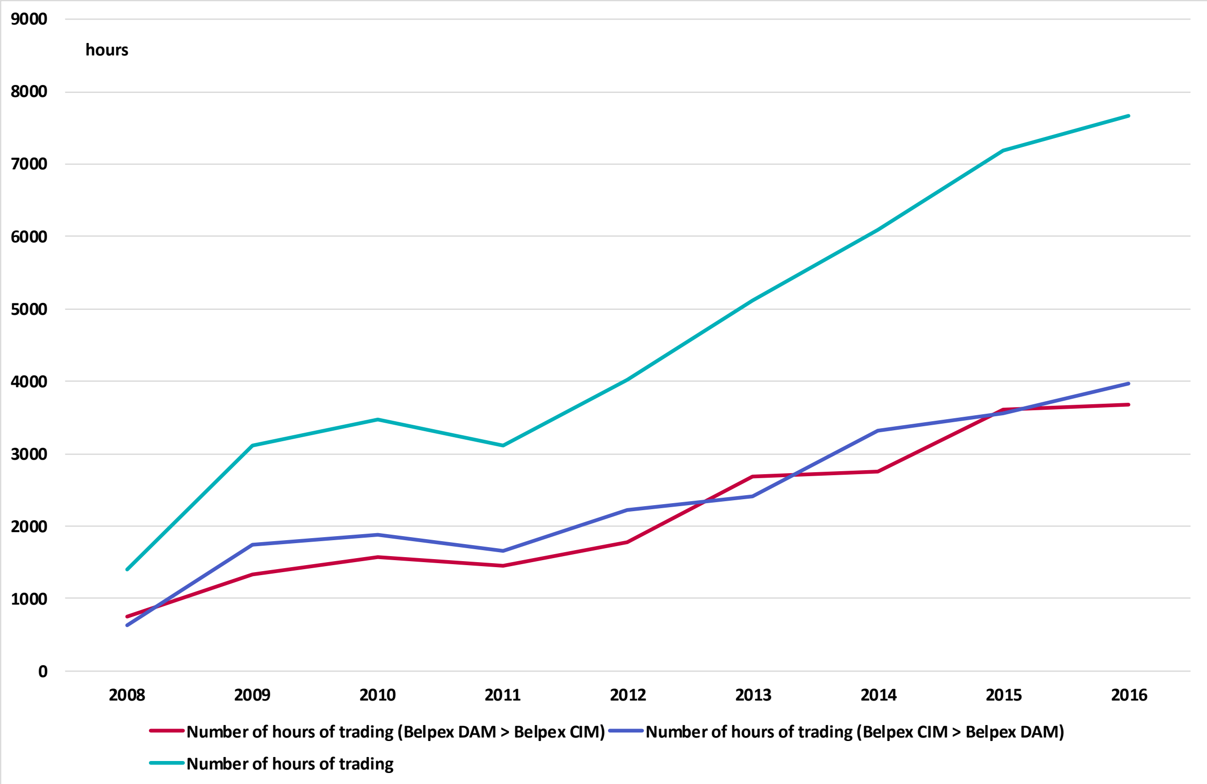


Figure 46 : The number of hours during which an intraday wholesale electricity price could be calculated based on actual trade data has steadily increased over time.
Source : CREG based on data provided by EPEX SPOT Belgium

79. The increase in market liquidity also manifests itself in terms of traded volumes: traded volumes have increased by a factor of 2.8 since 2011 to 1.03 TWh in 2016 (Table 16). The traded and imported volumes are correlated with more than 99%, indicating that imports are driving the increase in traded volumes. Imports increased with more than 100% year-on-year from 2015 to 2016.

4.3.3. Long-term wholesale electricity markets for delivery in Belgium

80. In 2016, the yearly averaged price of all long-term wholesale electricity products in Belgium for delivery during the front period reached its lowest value since 2007 (Figure 47). All yearly averaged long-term wholesale electricity prices follow a similar trend over the years even though relatively large differences between them might exist: for example, the yearly averaged year-ahead wholesale electricity price for delivery in Belgium in 2016 was traded at a discount of 3.5 €/MWh compared with the three other products available. Since the products that are compared cover different delivery periods, the discount could be interpreted as the best estimate of the state of the Belgian electricity system given the publicly available information at the time. The discount of 3.5 €/MWh illustrates that the market expects the baseload price next year to be lower on average compared with the baseload prices covered by the other products.

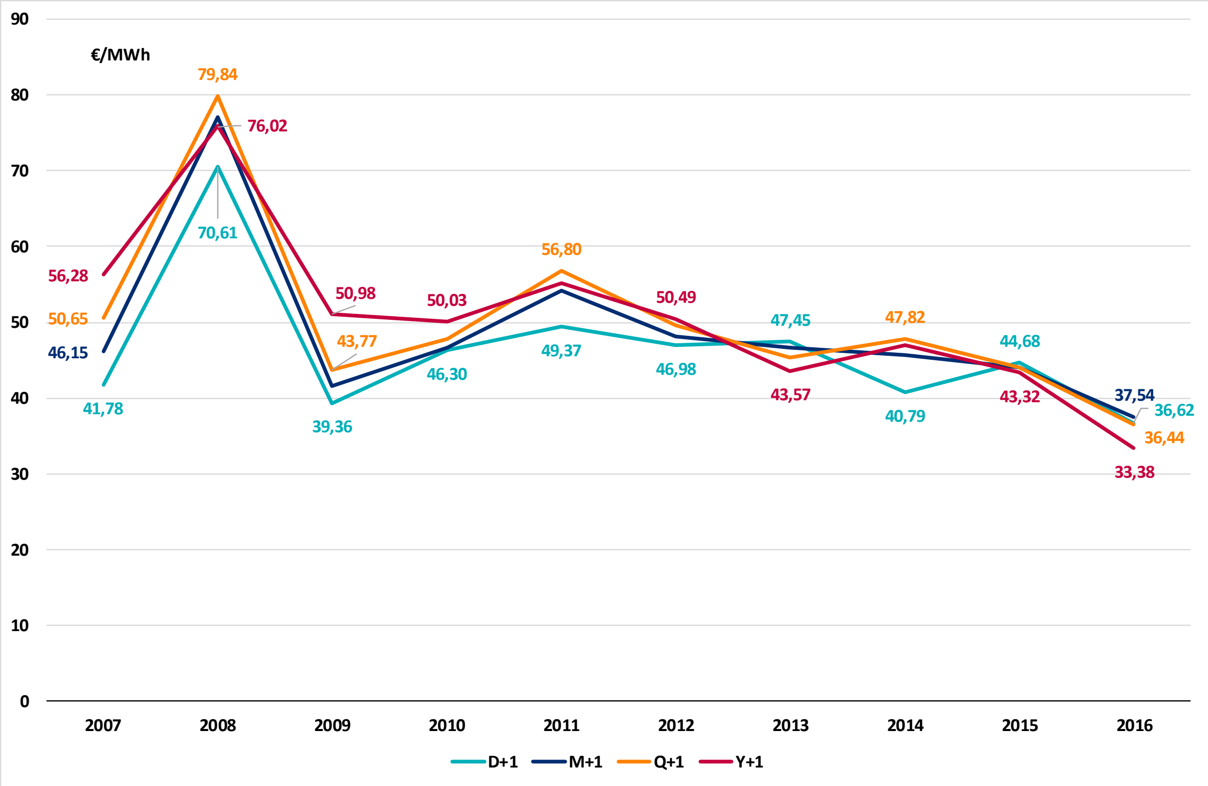


Figure 47 : Yearly averaged prices for long-term wholesale electricity products traded for delivery in Belgium, per year of trade, decreased in 2016. Note that the price of year-ahead wholesale electricity products traded in 2016 serves as a best prediction of the day-ahead wholesale electricity price in 2017. Since its value is lower than the day-ahead wholesale electricity price in 2016, the market is expecting wholesale electricity prices to decrease further in 2017.
Sources : CREG based on data provided by ICE Endex

81. The monthly averaged price of all long-term wholesale electricity products in Belgium per month of trade indicates that year-ahead wholesale energy prices are least volatile on a month-per-month basis (Figure 48). Outages of nuclear power plants and tight market situations during the winter season have increased volatility more for the remaining long-term wholesale energy products. Both reasons result in a significantly higher price than the year-ahead wholesale energy product.

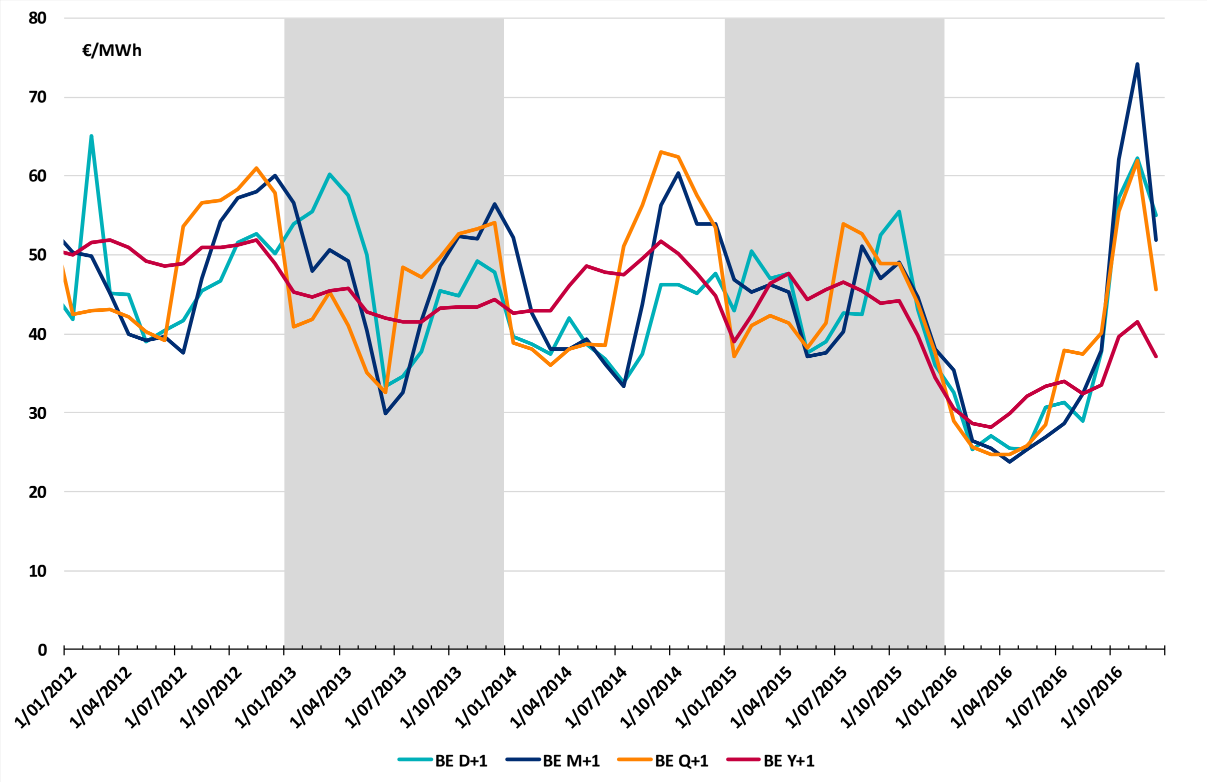


Figure 48 : Monthly averaged prices for long-term wholesale electricity products traded for delivery in Belgium, per month of trade, shows that the price of all considered products were visually correlated in 2016. The year-ahead wholesale electricity price nevertheless started to increase prior to the price increases observed with other wholesale electricity products.
Sources : CREG based on data provided by ICE Endex

82. Interestingly, the price of the month-ahead product lags the quarter-ahead product. This can be interpreted by market participants hedging their position through the quarter-ahead product in anticipation of the winter season. Also interesting is that the lag disappears when prices go down after the winter season at the end of 2014 and 2015. In 2016 the lag also disappears when prices increase from September onward.

83. This observation might indicate an increasing focus towards short term trading and can be understood as follows. As market participants that have used quarter-ahead contracts to hedge themselves during the winter season saw themselves locking in a higher price than the day-ahead wholesale market price for delivery in the fourth quarter of 2014 and 2015, they could have anticipated being exposed to a similar situation in 2016 (Figure 49). In 2016, anticipating this opportunity cost, market participants could have preferred to hedge a lower volume through quarter-ahead products. Because of nuclear outages and a higher volume of still unhedged volumes, demand outpaced supply leading to high prices for month-ahead and day-ahead wholesale energy products.

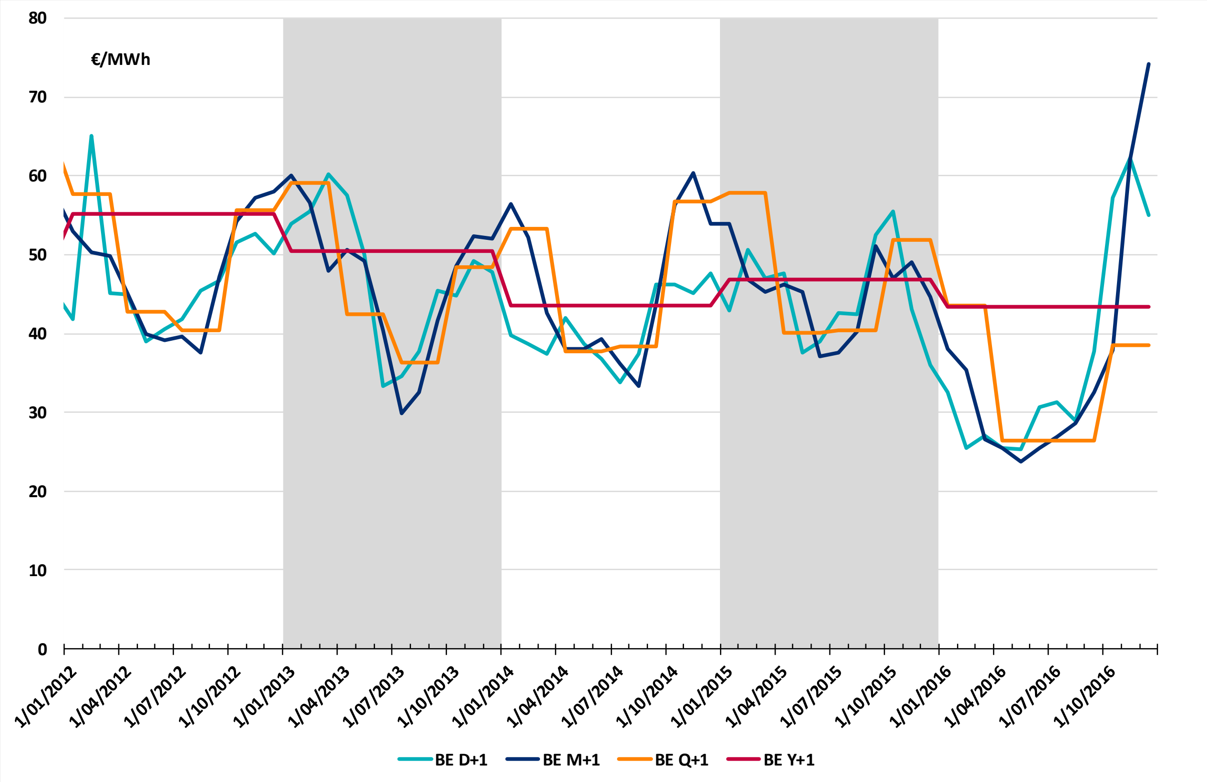


Figure 49 : Monthly averaged prices for long-term wholesale electricity products traded for delivery in Belgium, per month of delivery, illustrate a coincidence in the last quarter of 2016, of low price levels of quarter-ahead wholesale energy products and high price levels of day-ahead and month-ahead wholesale energy products.
Source : CREG based on data provided by ICE Endex

84. The increase in wholesale electricity prices during the last 4 months of 2016 resulted in Clean Spark Spreads (CSS) of Combined Cycle Gas Turbines (CCGTs) to rise into positive territory (Figure 50). The CSS for the delivery of baseload electricity in the first quarter of 2017 increased significantly to above 25 €/MWh, even for CCGTs with a low efficiency of 47%. The impact is also visible in the CSS for the delivery of baseload electricity in 2017. Note that the CSS for the delivery of baseload electricity in the first quarter of 2017 is positive most of the time during its trading window.

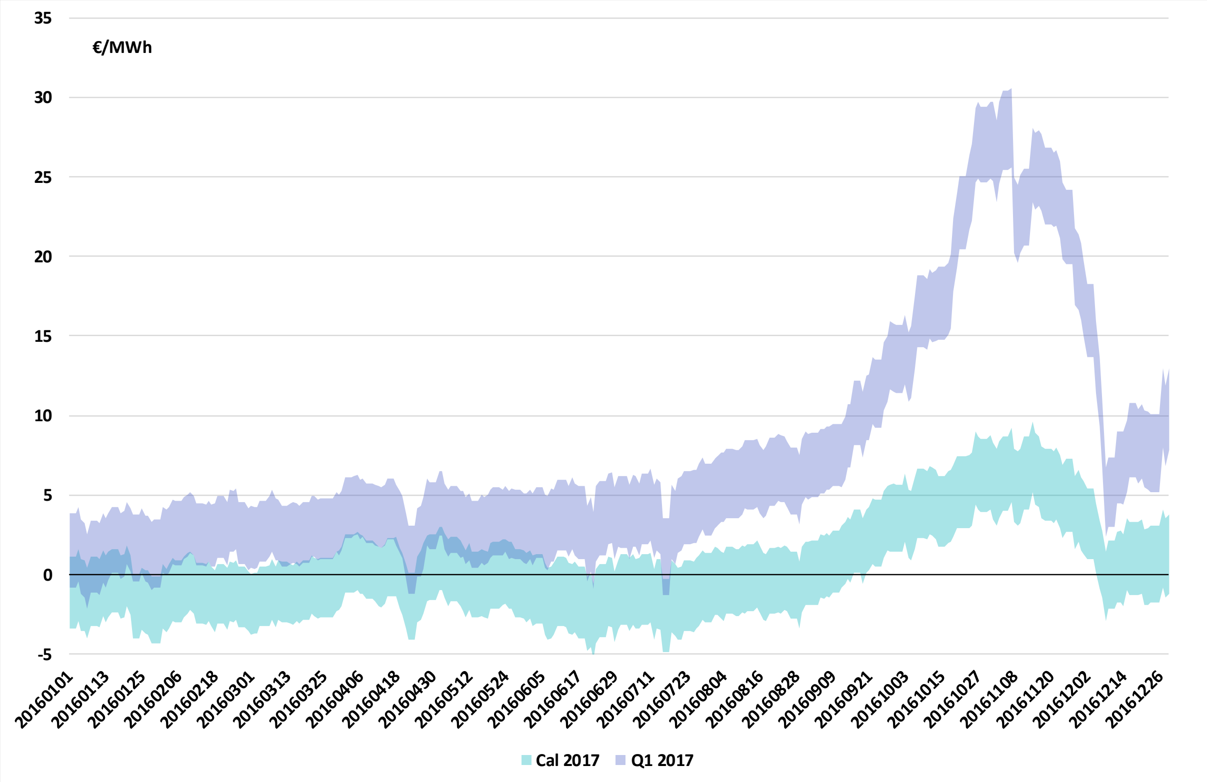


Figure 50 : Clean Spark Spread of a CCGT with an efficiency between 47% and 53%, for delivery of baseload electricity in the Belgian bidding zone using Calendar wholesale energy products for delivery in 2017, and Quarterly products for delivery in the first quarter of 2017, are positive from September to November. During 2016, Clean Spark Spreads for delivery in Belgium in the first quarter of 2017 were positive.
Sources: CREG based on data provided by ICE Endex, TTF

85. In the CWE region, for the first time since 2013, year-ahead wholesale energy prices closed the year at a higher price than at the beginning of the year (Figure 51). Wholesale energy prices for delivery in Belgium, the Netherlands and France are all at a similar price level. Wholesale energy prices for delivery in Germany are traded at a discount of around 6,80 €/MWh compared with those for delivery in any other bidding zone of the CWE region.

86. Averaging the year-ahead wholesale electricity prices over the year of trade shows that German wholesale baseload futures traded in 2016 at a discount of 20% compared with those in Belgium. The discount has nevertheless decreased significantly compared with the 29% figure in 2015. Year-ahead baseload products traded at similar levels in France as in Belgium.

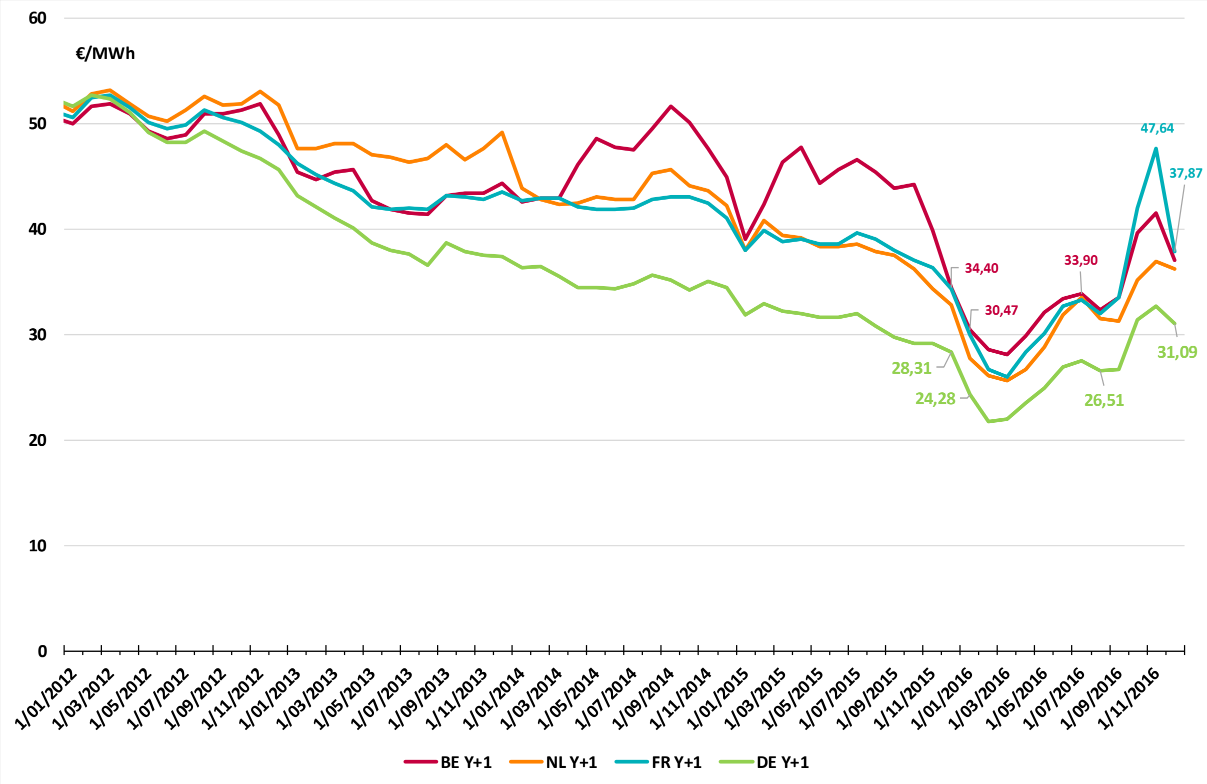


Figure 51 : Monthly averaged year-ahead wholesale energy prices traded for delivery in each bidding zone in the CWE-region, per month of trade illustrate that prices have started to increase in all bidding zones since the beginning of 2016, before the issues concerning nuclear power plants in France were made public in May. At the end of December 2016, monthly averaged year-ahead wholesale electricity prices in the French, Belgian and Dutch bidding zones converged.
Sources: CREG based on data provided by ICE Endex, EEX

	[€/MWh]				[%]		
	BE	**NL**	**FR**	**DE**	**Δ NL - BE**	**Δ FR - BE**	**Δ DE - BE**
2007	56.28	60.29	54.36	55.87	7.12	-3.41	-0.73
2008	76.02	76.31	74.07	70.23	0.38	-2.56	-7.61
2009	50.98	50.31	51.79	49.22	-1.33	1.58	-3.45
2010	50.03	49.54	52.43	49.94	-0.99	4.79	-0.18
2011	55.18	56.01	56.00	56.05	1.51	1.49	1.59
2012	50.49	51.88	50.57	49.27	2.76	0.15	-2.41
2013	43.57	47.48	43.30	39.06	8.97	-0.62	-10.35
2014	46.90	43.45	42.41	35.08	-7.36	-9.56	-25.21
2015	43.32	37.59	38.13	30.94	-13.23	-11.98	-28.58
2016	33.38	30.97	33.37	26.61	-7.24	-0.03	-20.28
2007-2016	**50.62**	**50.38**	**49.64**	**46.23**	**-0.46**	**-1.92**	**-8.67**

Table 17: Yearly averaged year-ahead wholesale energy prices traded for delivery in each bidding zone in the CWE-region, per year of trade, and the relative difference between those prices in Belgium with the other bidding zones in the CWE region, illustrate in 2016 a closing price gap between forwards with delivery in Belgium and the other bidding zones in the CWE-region. It also illustrates that prices in Germany are 20% lower than those in Belgium.
Sources: CREG based on data provided by ICE Endex, EEX

5. INTERCONNECTIONS

5.1. HISTORICAL BACKGROUND : SIGNIFICANT EVENTS

2001 ETSO (the predecessor of ENTSO-E, *i.e.* the member organization of all European transmission system operators) publishes its guidelines regarding methodologies for the calculation of available transmission capacities (ATC) for cross-border interconnections. In 2016, these methodologies are still being applied by some Transmission System Operators, among which Elia, for the calculation of available interconnection capacities.

2005 The Belgian, Dutch, French, Luxembourg and German governments found the Pentalateral Energy Forum (PLEF). This Forum is established to, inter alia, optimize and harmonize the methodologies applied for the calculation and allocation of cross-border interconnection capacities between the different countries involved. The PLEF consists of representatives of Ministries, National Regulatory Authorities, Transmission System Operators, Power Exchanges and the Market Parties Platform.

2007 CWE regulators publish, in **February**, their action plan to strengthen the integration of their power markets. This action plan anticipates the development and implementation of a *flow-based* market coupling for the CWE bidding zones. In **June**, all Ministers of the CWE countries sign, jointly with the representatives of TSOs, power exchanges, regulators and market participants, a Memorandum of Understanding to develop and implement the flow-based market coupling for the day-ahead timeframe.

2008 In **June**, CWE TSOs and power exchanges, through the Joint Steering Committee, unilaterally announce the implementation of an ATC-based approach to couple the markets in the CWE region.

2010 Elia develops and submits a proposal for a new general model for the calculation of the total transfer capacity and the transmission reliability margin. In addition, Elia submits a proposal for the calculation of day-ahead transmission capacity to CREG, for approval. In **October**, CREG decides not to approve the proposal from Elia, due to the fact that it considers the proposal non-compliant with European legislation related to the non-discrimination of domestic and cross-zonal exchanges. In light of other benefits of increased market coupling in the CWE region, CREG decides nonetheless to authorize the implementation of the proposed methodology.

2011 Elia develops and submits a proposal for the calculation for yearly and monthly transmission capacities as well as the transmission reliability margin. CREG again decides not to approve, based on the same argumentation as above, but takes note of the implementation by Elia of the proposed methodology. Elia appeals CREG's decision but, in **2012**, the Court of Appeal rules Elia's arguments for the appeal to be unfounded.

2013 The CWE Flow-Based Market Coupling project starts the first "external parallel run", in order to compare every week the simulated flow-based market results with the ATC calculations. In **August**, the CWE FBMC Project develop the first FBMC "approval package", containing a description of the flow-based market coupling methodology. This document forms the basis for the first submission of a proposal by Elia for a day-ahead flow-based market coupling methodology.

2014 The CWE FBMC Project starts running daily "internal parallel runs", starting from **February**. In **May**, the CWE FBMC Project submits a second approval package[33]. CWE regulators consider the package to be incomplete and continue the development and discussions with the CWE FBMC Project partners. In **June**, CWE regulators organize a public consultation on the FBMC. In **August**, the CWE FBMC Project submits a third, adapted version of the approval package[34]. Between now and **March 2015**, the partners continue modifying and adding to the approval package, in cooperation with CWE regulators. Over the following months, project partners address issues related to the functioning of FBMC in times of scarcity and flow factor competition.

2015 In **February**, Elia submits for approval the methodology for day-ahead flow-based market coupling of the CWE markets, to CREG. In **March,** they publish their views on FBMC in a position paper[35]. In **April**, CREG decides the proposal to be not non-compliant with Regulation 714/2009, specifically the articles related to non-discrimination of internal versus external exchanges[36]. However, in light of the expected benefits of ongoing market coupling implementation - in particular the social welfare gain compared to ATC expected by the results of the parallel runs - CREG decides to approve the proposal conditionally on the implementation of a number of improvement proposals, by CREG and other CWE regulators. In **May**, the CWE FBMC Project operates the first successful business day of day-ahead flow-based market coupling. In **August,** the Regulation (EU) 2015/1222 ("CACM Guidelines") enters into force, providing a legal framework for regulators, TSOs and power exchanges ("NEMOs") to develop common methodologies for all aspects related to single day-ahead and intraday market coupling of European bidding zones. For long-term (yearly and monthly) market coupling, CREG approves, in **October**, the early implementation of the Harmonized Auction Rules and, for the Belgium-Netherlands and Belgium-France borders, the introduction of "Financial Transmission Rights – options". This replaces the earlier approach where "Physical Transmission Rights with Use-it-or-sell-it" were used.

STATUS 2016

In 2016, regional (voluntary) cooperation shifted towards a more closely integrated, European approach for coupling markets. With the entry into force of Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (the "CACM Guideline") on 14 August 2015, the single day-ahead and intraday coupling officially became the pillars of the *"Target Model"* for the design of European electricity Markets. Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (the "FCA Guideline") does the same for forward market coupling.

With the introduction of the CACM Guideline in 2015 and the FCA Guideline in 2016, the market coupling of the Belgian bidding zone and other bidding zones can be discussed on a geographical basis (i.e. regional versus European) or on a temporal basis (i.e. long-term markets versus short-term markets).

On 17 November 2016, ACER issued its Decision 06-2016 on Capacity Calculation Regions[37]. With this decision, taken after all regulatory authorities failed to agree on the all TSOs proposal pursuant to art.

[33] http://www.elia.be/~/media/files/Elia/Projects/CWE-Flow_Based/CWE_FBMC_approval-document_06-2014.pdf.
[34] http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D.
[35] http://www.creg.info/pdf/Opinions/2015/b1410/CWE_NRA_Position_Paper.pdf.
[36] http://www.creg.be/nl/publicaties/beslissing-b150423-cdc-1410.
[37] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf.

9(6)(b) of the CACM Guideline, ACER confirmed that the future regional aspects of both the CACM as well as the FCA Guidelines should be the CORE CCR[38], rather than two separate CWE and CEE regions.

The most important consequence of ACER's Decision 06-2016 concerns the regional scope of capacity calculation methodologies and related proposals. Starting from the moment of this decision, TSOs and NEMOs of the CORE CCR need to start developing a flow-based market coupling methodology for the day-ahead and intraday timeframes, to be submitted for approval in Q3 2017.

On a European level, TSOs and NEMOs need to co-operate to deliver methodologies for, inter alia, a Common Grid Model, Congestion Income Distribution Methodology, a day-ahead and intraday price coupling algorithm, etc. The development and approval of these methodologies are the trigger for a new level of co-operation between and among energy regulators, TSOs and NEMOs in Europe and will form the basis for similar projects in the long-term (yearly and monthly) market coupling.

[38] The Core Capacity Calculation Region consists of the borders between France, Belgium, the Netherlands, Germany, Luxemburg, Austria, Czeckia, Slovakia, Hungary, Poland and Romania. https://www.entsoe.eu/major-projects/network-code-implementation/cacm/core-ccr/Pages/default.aspx.

5.2. SPECIAL TOPICS

5.2.1. Physical interconnection capacity and its commercial use

Figure 52 : Map of the Belgian transmission network.
Source : Elia

Cross-border	kV	Substation 1	Substation 2	Pmax (MVA)	PST (MVA)	DLR-1h	DLR-60h
BE-FR	380	Achêne	Lonny	1,316		x	x
	380	Avelgem	Mastaing	1,528		x	x
	380	Avelgem	Avelin	1,316		x	x
	220	Aubange	Moulaine	442		x	x
	220	Aubange	Moulaine	442		x	x
	220	Monceau	Chooz	405			
Total BE - FR				**5,449**			
Total BE - FR N-1 (*)				3,921			
BE-NL	380	Van Eyck	Maasbracht	1,420	1,400	x	-
	380	Van Eyck	Maasbracht	1,350	1,400	x	x
	380	Zandvliet	Borssele	1,645	1,400	x	-
	380	Zandvliet	Geertruidenberg	1,645	1,400	x	-
Total BE - NL				**6,060**			
Total BE - NL with PST				5,550			
Total BE - NL N-1 (*)				4,150			

Table 18 : Overview of the interconnection lines at the Belgian-French (BE-FR) and Belgian-Dutch (BE-NL) border and the resulting nominal interconnection capacity in the N and N-1 condition, taking into account the capacity of the Phase Shift Transformers (PST) on the Belgian-Dutch interconnectors. Dynamic Line Rating (DLR) is used to predict the thermal line capacity hour-ahead (DLR-1h) and two-days ahead (DLR-60h). (*) This is a simplified approach of the N-1 calculation which does not take into account flow redistribution.
Sources : Elia and CREG

87. Belgium is physically interconnected with France and the Netherlands. In total, the installed interconnection capacity is 5449 MVA on the Southern border and 6060 MVA on the Northern border (Table 18).

88. The actual physically available capacity is lower because of the **N-1 condition** to be respected in all operational conditions. The N-1 condition considers the case of the outage of the most impacting network element. At the French border, the N-1 available physical interconnection capacity is 3291 MW, with the N-1 condition being the outage of the line Avelin - Avelgem. At the Dutch border, the physical capacity is additionally reduced because of the 1400 MW Phase Shift Transformers (PST) on each interconnection line. Without any outage (N-criterion), the physical interconnection capacity with the Netherlands is therefore 5550 MW. The N-1 available interconnection capacity is 4,150 MW, considering the outage of Zandvliet-Borsele or Zandvliet-Geertruidenberg in combination of an outage of one of the PST on these lines. Note that this is a rough estimation since it does not consider flow distribution. Evaluation of the physical utilization of the interconnection capacity is always performed with the physically available capacity in the N-1 condition as a reference.

89. The actual physical capacity of a line or 'thermal line capacity' differs from its nominal capacity. The **thermal line capacity** increases at lower ambient air temperatures and higher wind speeds since these conditions help to cool down the lines and thus increase its maximal current. Dynamic Line Rating (DLR) technology aims to predict this thermal capacity through statistical analysis of the historical data combined with weather forecasts. This way, DLR is less conservative then the static seasonal limits. DLR can serve multiple purposes. The first one is to assess the grid security in real time through DLR equipment with a one-hour-ahead weather forecast. The second purpose is to estimate the commercial capacity for the day-ahead market, using 60-hours-ahead weather forecasts. Elia has been using DLR on internal lines since 2009 and on cross-border lines since 2014. Currently, Elia uses DLR for real-time security assessment on 19 lines and for D+2 capacity forecast on 8 of the 10 interconnection lines.

90. Physical flows arising from commercial exchanges follow the physical path of least resistance according to Kirchoff's laws. These flow patterns depend on the grid topology as a whole and on the generation and demand pattern. Active power flow elements such as **Phase Shift Transformers** (PST)

are used to influence the flow patterns. The PSTs at the Northern border optimize the utilization of the grid by changing the distribution of the flows over the Dutch-Belgian interconnection lines. For instance, an overloading of the interconnectors Zandvliet-Borssele and Zandvliet-Geertruidenberg can be mitigated by redirecting the flows towards the interconnectors Maasbracht-Van Eyck.

91. The use of the Belgian interconnection capacity with France and the Netherlands for cross-border trade is now organized at the Central-West European (CWE) regional level. The **CWE-region** is the collection of borders between the following bidding zones: France, Belgium, the Netherlands and Germany/Luxembourg/Austria. Commercial exchanges between each pair of the involved bidding zones influence the physical flows over the entire network and thus the amount of capacity available for other commercial exchanges. Coordination of the use of the network for cross-border exchanges is therefore required.

92. Commercial exchanges on these borders are organized for the following time frames: year-ahead, month-ahead, day-ahead and intraday.

- **Year-ahead**, the Net Transfer Capacity (NTC) method is used to determine the long-term commercial cross-border capacity on each individual border and direction. This capacity is calculated at each individual border. It is based on a common grid model for 12 reference days. A fraction of this NTC-value is brought to the market and allocated through the yearly auctions. They can be auctioned in terms of physical transmission rights (PTR) and financial transmission rights (FRT). Only on the Belgian borders FTRs are applied.
- **Month-ahead**, the same procedure is repeated as for the year-ahead. With a common grid model, an updated NTC value is calculated. The allocation to the market is done through the monthly auctions.
- **Day-ahead**, the Flow Based Market Coupling (FBMC) is used. An optimization algorithm collects the inputs provided by TSOs and market participants. TSOs provide information on the status of the grid and the network element constraints to be respected, while market participants provide their demand and production bids through the power exchange platforms. With these inputs, the market coupling algorithm optimizes the set of all CWE cross-border exchanges simultaneously. In theory, this should result in larger gross welfare through a better utilization of the available cross-zonal transmission capacity.
- **Intraday**, the NTC method is used again to determine the remaining capacity for cross-border exchange at each individual border, using updated grid status and market information.
- **Real-time,** the remaining cross-border capacity can be used for balancing (IGCC).

The calculation methods for each of these time frames is documented and published by Elia[39].

5.2.2. Flow based market coupling in the CWE region

Motivation

93. Since May 2015, Flow Based Market Coupling (FBMC) has replaced the ATC-method to manage the use of interconnection capacity for day-ahead market coupling in the Central West-European (CWE) region. FBMC is chosen because it is potentially more efficient than ATC. The implementation of FBMC on other European borders is under development (e.g. in CORE) or being investigated.

[39] http://www.elia.be/nl/producten-en-diensten/cross-border-mechanismen/transmissiecapaciteit-op-de-grenzen/berekeningsmethode#anchor5.

94. The establishment of a single European Energy market is based upon market coupling. The efficient use of the cross-border capacity is a key element in reaching this objective. Commercial use of interconnection capacity comprises two key elements: capacity calculation and capacity allocation. Capacity calculation defines how much capacity is available for commercial exchange; and is considered as a core task of transmission system operators. Capacity allocation defines how this capacity is allocated to the market participants and is considered to be determined by the market in a competitive and non-discriminatory way.

95. Capacity calculation and capacity allocation are done in two consecutive steps. With the ATC-method, TSOs calculate the amount of capacity available for import and export on each individual border. This can be done bilaterally, i.e. by the two TSOs sharing the border, or at a regional level, i.e. by all TSOs of the so-called Capacity Calculation Region (CCR). Next, the actually nominated capacities for import and export resulting from the explicit market auctions. This method is still used in the CWE region in intraday market coupling and on all non-CWE European borders.

96. The ATC-method entails significant conservatism. The main reason is that at the stage of determining the available commercial capacity on a specific border, the set of commercial exchanges on the other borders is not known yet. This matters for capacity calculation. Commercial exchanges give rise to physical flows which make use of the entire network, following the path of least resistance (Kirchhoff's laws). These physical flows can increase the capacity for commercial exchange in one direction, and decrease it in another direction. Therefore, one cannot simply say that the physical capacity of an interconnection line between two adjacent markets is the capacity available for commercial exchange. One needs to take into account the physical impact on the network of all commercial exchanges taking place at the same time. For grid security reasons, the commercial capacity given to the market by TSOs with ATC equals the smallest capacity resulting from all possible sets of exchanges.

97. With FBMC, by contrast, the set of commercial exchanges between the different bidding zones are defined (and optimized) simultaneously, taking into account the impact of the commercial exchanges on the total social welfare on the one hand, and on the physical use of the network on the other. Compared to ATC, Flow Based Market Coupling reduces the uncertainty related to the commercial exchanges *between* zones and makes it possible to create synergies through combinations of exchanges. This way, a less conservative and a more effective usage of the existing transmission network capacity can be achieved.

98. The use of FBMC for optimizing cross-zonal trade removes the uncertainty on the physical flows related to commercial exchanges on the CWE cross-zonal borders. The uncertainty on the physical flows related to commercial exchanges *within* the zones, i.e. domestic flows and loop flows, however, is still present. This uncertainty is inherent to the choice for a zonal market design in the European target model. With a nodal market design, by contrast, there are no 'internal exchanges': all commercial exchanges between any pair of nodes is made explicit, and thus also the physical impact on the network. This way, the set of *all* commercial exchanges can be optimized simultaneously and *all* network constraints can be taken into account. The zonal market design can approach the effectiveness of the nodal one by having smaller and appropriately defined bidding zones. Such an adequate zonal configuration is a prerequisite for achieving the multiple (and sometimes considered conflicting) objectives of an efficient, market-based, non-discriminating and secure grid management.

Mathematical description of the optimization problem

99. FBMC optimizes the use of cross-border capacity such that the total CWE social welfare resulting from the day-ahead market coupling, is maximized. Mathematically, this is formulated as an

optimization problem, with the goal of maximizing social welfare being translated into an objective function; and the requirement for safe grid operation being translated in a set of network constraints. The market provides the hourly supply and demand bidding curves for evaluating the objective function, while the TSOs provide the hourly set of network constraints. Outputs of the optimization are:

- the Net Exchange Position of each bidding zone,
- the day-ahead market clearing price in each bidding zone,
- the shadow cost of the active network constraint(s) (see §104)

100. The optimization algorithm searches for the optimal set of Net Exchange Positions NEP*, i.e. the set of NEP that maximizes the social welfare for the given adequacy and network constraints. The mathematical description is the following (with variables described further below):

Objective:

max (Social Welfare(NEP)) [Eq. 1]

Subject to the adequacy constraint:

Sum(NEP)=0 [Eq.2]

And subject to the set of network constraints

*Sum(PTDF*NEP)<=RAM* for all CBCOs in the CBCO-set [Eq.3]

Social welfare [Eq.1] is defined as the sum of CWE consumer surplus (CS), CWE producer surplus(PS) and total Congestion Rents (CR), all of which are function of the set of NEP:

max (Social Welfare(NEP)) = max(CS(NEP)+PS(NEP)+CR(NEP)) [Eq.4]

The adequacy constraint [Eq.2] assures that at any time, the sum of imported and exported volumes is equal.

The network constraints [Eq.3] assure that cross-zonal commercial exchanges do not cause thermal overloading on any of the transmission lines included in the CBCO-set. The line loading resulting from a set of NEP is calculated by means of Power Transfer Distribution Factors (PTDF). The Remaining Available Margin (RAM) is the line capacity left after deducting the reference flows and the safety margins (see further). A CBCO is a network element or 'critical branch' (CB) under a certain N or N-1 condition or 'critical outage' (CO).

TSOs can also set an explicit limit to their zonal net exchange position. These "external constraints" are written in the format of [Eq.3] by setting the RAM value equal to the import or export limitation and the relevant PTDF-factor for that zone equal to 1 (or -1); and all others PTDF-factors to zero.

101. The constraints [Eq.2 – Eq.3] define the so-called "flow based domain". This domain defines all feasible solutions, i.e. the sets of NEP which respect the constraints. The optimization algorithm searches the set of NEP which maximizes the objective function inside this flow based domain.

102. Currently, the CWE-region consists of 4 bidding zones. Because of the adequacy constraint [Eq.2], there are therefore 3 independent NEP to be optimized and as such the flow based domain is a three-dimensional space.

103. Figure 53 and Figure 54 illustrate the idea of FBMC. They show a two-dimensional slice of a (hypothetical) flow-based domain and the altitude lines of the objective function. In the 'uncongested

case', the market clears within the flow-based domain (Figure 53). In the 'congested case', the solution hits at least one of the network constraints (Figure 54). Since the social welfare could have been higher without that constraint, there is an opportunity cost or 'shadow cost' associated with the active constraint.

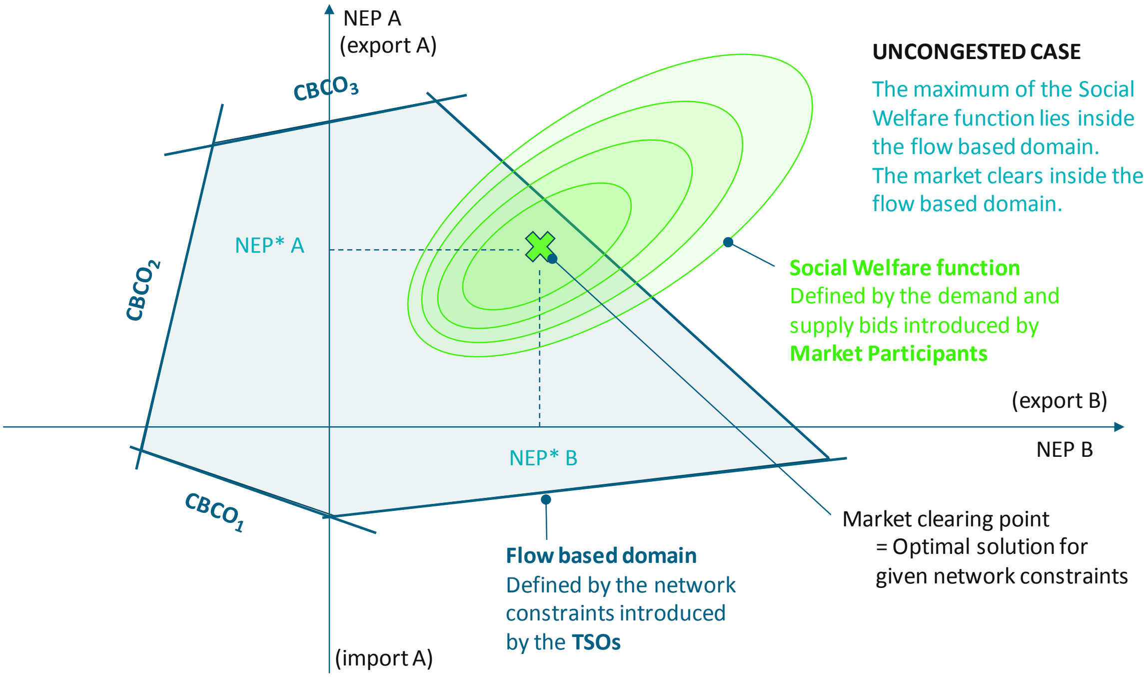


Figure 53 : Illustration of Flow Based Market Coupling in the uncongested case. The combination of Net Exchange Positions (NEP) which maximizes the Social Welfare objective function, lies inside the Flow based domain. Full price convergence between the different price zones is reached.
Source : CREG

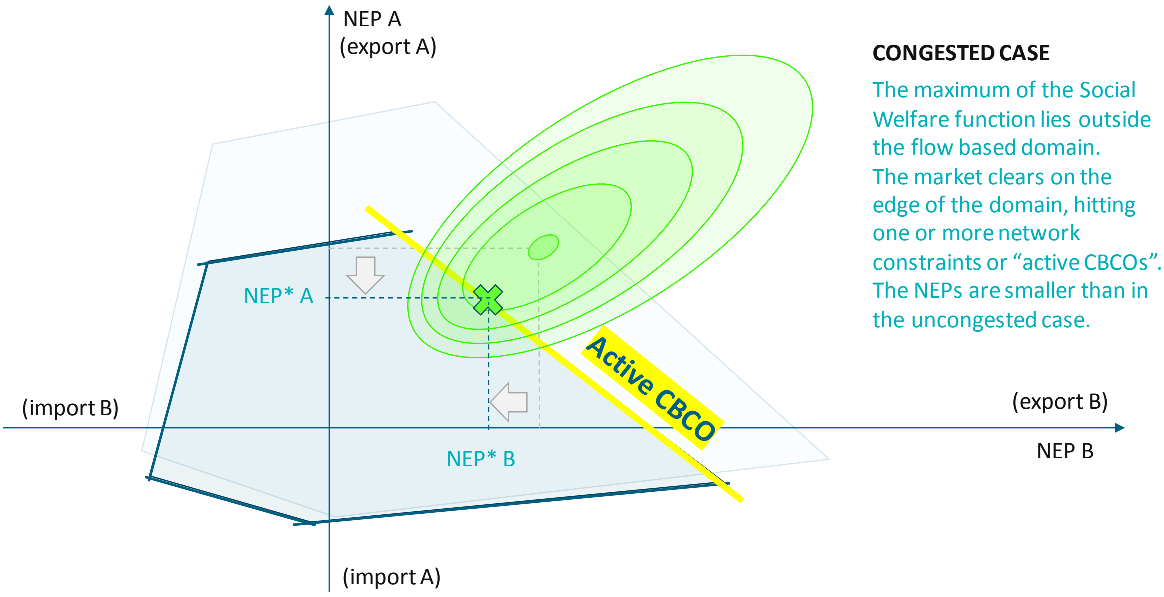


Figure 54 : Illustration of Flow Based Market Coupling in the congested case. The combination of Net Exchange Positions which maximizes the objective function of Social Welfare, lies outside the Flow Based domain. The optimization searches for the solution within the Flow Based domain which is closest to this maximum, hitting one (or more) network constraints. This (these) are the active critical branches – critical outages (CBCOs) for that hour. There is no full price convergence. The shadow price (€/MW) associated with the active CBCO, reflects the marginal loss of welfare resulting from the limitation of the cross-border exchange
Source : CREG

104. The shadow cost (expressed in €/MW) associated to an active constraint is defined by the slope of the objective function at the market clearing point, i.e. the marginal increase of social welfare (expressed in €) for a marginal increase in capacity on that constraint (expressed in MW). In the uncongested case, the slope of the objective function at the market clearing point is zero. There is no active constraint and therefore no shadow cost.

105. The size and shape of the flow-based domain depends on the introduced network constraints. In general, the more capacity available on the introduced CBCOs, the larger the size of the flow based domain. In the limit of a copper plate grid, the flow-based domain is infinite and the market can always clear at the set of NEP which maximizes social welfare. In the limit with no available capacity, the flow-based domain is empty and no cross-border trade is possible. The reality lies somewhere in between. First, the physically available interconnection capacity is not infinite and limited by its thermal line capacity. Second, not all physical capacity is available for cross-border trade because of 3 main reasons. The first reason is the N-1 criterion which requires that the capacity given to the market always considers the possible outage of one of the network elements (see also paragraph 88). The second reason is a consequence of the choice of a zonal market design. A zonal market design implies that the market coupling starts from a base case with domestic trade inside the zone satisfying the zonal demand. This domestic trade entails physical flows *inside* the zone ('domestic flows') and *outside* the zone ('loop flows'). The resultant flows from all domestic trades in all zones, are the so-called 'reference flows'. Since they are present in the base case before market coupling, reference flows get priority access to the grid and "preload" the lines. The third reason is also linked to the zonal market design: domestic trade inside a zone is (currently) associated with limited information on where and how much will be produced and/or consumed. A part of the line capacity is reserved to cope with this locational uncertainty.

106. The methodology for the selection and characterisation of network constraints is described by TSOs in the FBMC Approval Package. The result is a set of linear equations for each hour of the day which define the flow-based domain for that hour, with each CBCO being characterized by its Remaining Available Margin (RAM, in MW) and the set of Power Transfer Distribution Factors (PTDF, in MW/MW) (see Eq.3). Below, we discuss the RAM, the PTDF and the selection of the CBCO-set.

107. The RAM in [Eq. 3] is the capacity available for day-ahead cross-border exchange, calculated as:

$$RAM = Fmax - Fref' - FRM - FAV \qquad [Eq.5]$$

With

$$Fref' = Fref_0 + Fref\_LTN \qquad [Eq.6]$$

i.e. the capacity available on a CBCO after the zero-balanced reference flows ($Fref_0$, in MW) and the flow reliability margin (FRM, in MW) are deduced from the thermal line capacity (Fmax, in MW). Flows resulting from nominations of long term transmission rights of type PTR (Fref_LTN, in MW) are also taken into account. The Flow Adjustment Value (FAV, in MW) is a value TSOs can introduce to increase or lower the RAM based on a specific TSO action.

108. The set of PTDFs in [Eq.3] are the zone-to-hub PTDFs which estimate the change in line loading on a CBCO as a response to a change in Net Exchange Position of a zone. Since there are 4 zones in the CWE region at the moment, each CBCO has 4 zone-to-hub PTDFs, reflecting the line loading as a result of a change in NEP of each of the zones.

$$PTDF = [\ PTDF\_z1\text{-}h,\ PTDF\_z2\text{-}h,\ PTDF\_z3\text{-}h,\ PTDF\_z4\text{-}h] \qquad [Eq.7]$$

The grid topology and the expected market outcome determine the zone-to-hub PTDFs :

PTDF = GSK_z-n * PTDF_n-h [Eq.8]

The nodal PTDF matrix (PTDF_n-h) represents the CWE grid topology; and captures all information on nodes and network elements to perform a DC load flow calculation. The Generation Shift Keys matrix (GSK_z-n) contains the GSKs (in MW/MW) of all zones; and defines the estimated change in generation (in MW) in each node of the network in response to a change in zonal NEP (in MW).

109. At the moment, all CBCOs with at a maximum zone-to-zone PTDF of at least 5%, can be introduced as a network constraint in the CBCO-set (Eq.3.). The zone-to-zone PTDF is calculated as:

Max PTDF_z-z = Max (PTDF_zi-h) – Min (PTDF_zi-h) with i = 1:Z (Z = number of zones)

This 5% threshold indicates that there is at least of one pair of zones where a 1000 MW exchange results in a 50 MW change in line loading.

110. Before the market coupling, TSOs check whether the flow-based volume is large enough to cover the all possible exchanges related to the long term allocated (LTA) transmission rights. To this end, TSOs construct the LTA-domain, based on the long term allocated capacities in the yearly and monthly auctions. If a corner of the LTA-domain falls outside of the initial flow-based domain, the latter is increased. This is shown in Figure 55.

The RAM on the constraining CBCO(s) is increased by applying a negative FAV (see Eq.[5]) or they are replaced by virtual CBCO(s) such that all corners of the LTA-domain fall are included in the flow based domain. This 'LTA-inclusion' assures that the day-ahead exchanges can cover all long term allocated capacities. It assures financial adequacy, since in that case the congestion rents resulting from the day-ahead market coupling are sufficient to remunerate all holders of long-term capacity rights. If the market clears in a part of the flow-based domain which was virtually increased by LTA-inclusion, this event is referred to as LTA-violation.

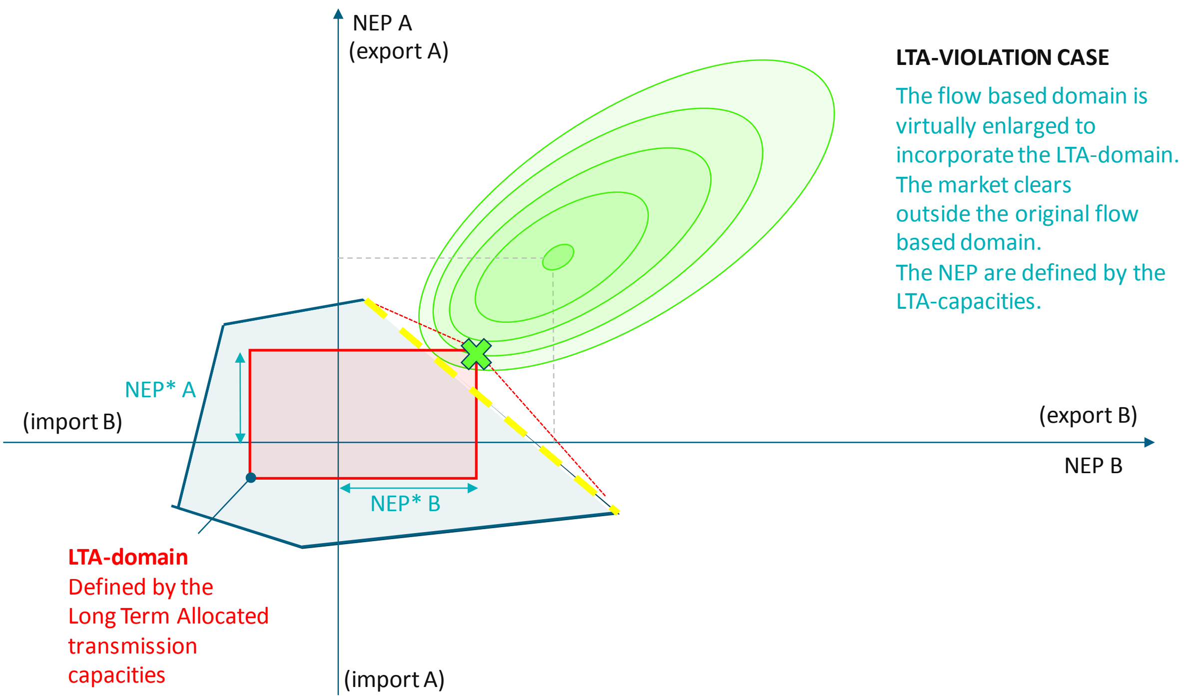


Figure 55 : LTA-inclusion assures financial adequacy for remunerating long-term capacity holders by increasing the flow based domain in the event that the flow-based domain is not large enough to cover all allocated long-term capacities (LTA-domain). Source : CREG

111. The current CBCO-selection rule (§109) does not distinguish between interconnection lines (cross-border lines) or internal lines (inside the zone) and does not define any RAM requirements. This is under discussion amongst CWE NRAs and CWE TSOs as it gives TSO the possibility to include highly preloaded internal lines (with low RAM) into the FBMC. The monitoring results of FBMC indicate that this threat has materialized: highly preloaded internal lines have seriously reduced the flow based domain, calling for many hours of LTA-inclusion and limiting cross-border exchange in a majority of congested hours (see Section 5.3).

5.2.3. Performance evaluation FBMC at CWE level (May 2015 – December 2016)

112. The first 1.5 years of FBMC illustrate both the significant potential of the method as well as deficiencies in its current implementation. Of course, all performance analysis should be done within the market context. Especially with FBMC, where capacity calculation and allocation are implicitly defined through the optimization algorithm, it is hard to distinguish between the impact of system operation– reflected in the CBCO data set provided by the TSOs –and the impact of the market situation - reflected in the bidding curves of market participants. Nevertheless, comparison of performance indicators before and after introduction of FBMC show interesting results.

113. The potential of the FB method is revealed through the recorded maximums of CWE cross-border exchange volumes and the number of hours of full price convergence between all CWE zones. In addition, the average CWE cross-border volumes during the first months after the introduction of FBMC, showed record highs. CWE cross-border exchange is defined as the total of exported (or imported) volumes or the sum of the exporting (or importing) net positions.

- The percentage of hours of full price convergence increased from 16% - 21% in the previous three years to 39,1% in 2016. Full price convergence is defined as the maximal price spread of less than 1 €/MWh.
- Maximum exchanged CWE cross-border exchange increased (Figure 59). Maximums of more than 8800 MW were recorded in the October, November and December of 2016. With ATC, the maximum recorded volume was 7023 MW in July 2012.
- Also maximum exchanged volumes during congested hours increased (Figure 60). Whereas maximum CWE-volumes typically ranged from 6200 to 7000 MW before FBMC, they ranged from 7000 MW to almost 9000 MW following the introduction of FBMC.
- Monthly averaged CWE-volumes peaked with 5643 MW in June 2015 and with 5378 MW in August 2015. With ATC, the maximum monthly average was 4834 MW, recorded in March 2013.

114. However, other performance indicators clearly deteriorated after the introduction of FBMC. The first months of FB the cross-zonal exchanges seemed promising, with volumes being significantly higher than with ATC (Figure 56, Figure 58). From September 2015 onwards, however, the exchanged volumes dropped significantly. This reduction persisted until the end of the monitoring period, i.e. December 2016. The exchanged volumes are on average 1000 MW lower with FBMC than with ATC.

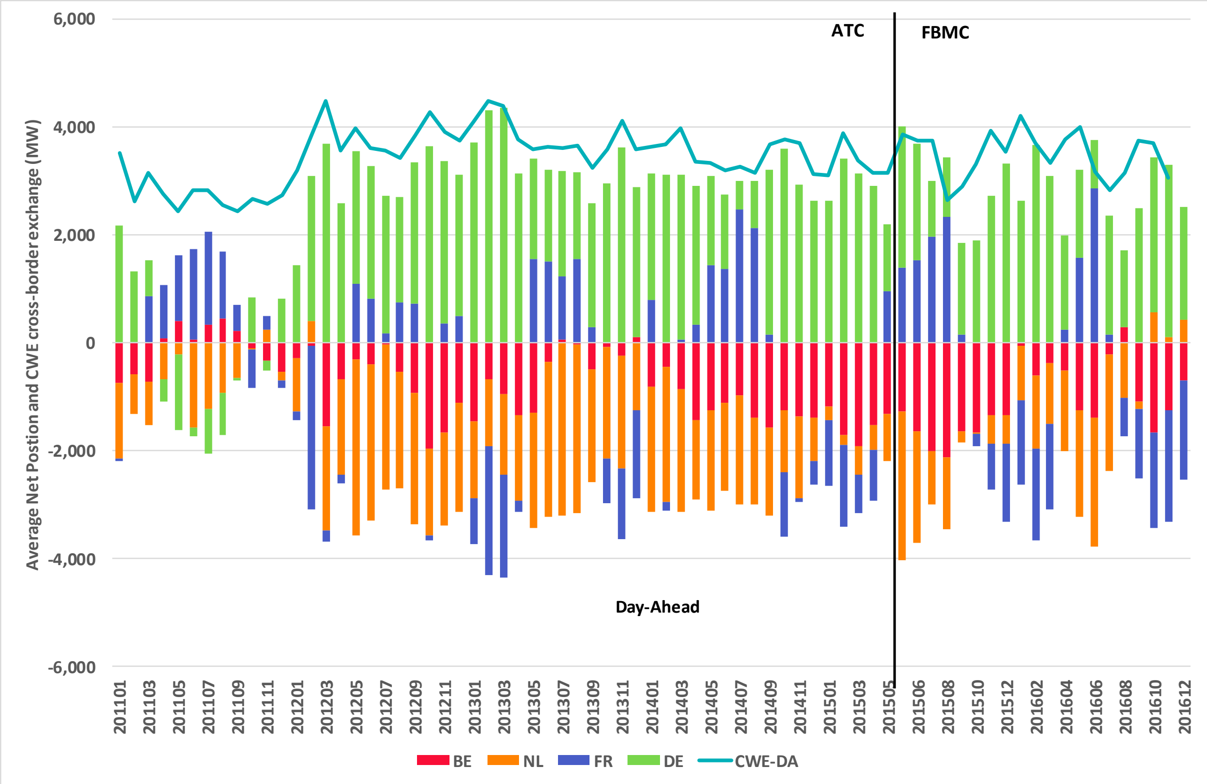


Figure 56 : Monthly averaged Net Positions and CWE cross-zonal exchanges in day-ahead before and after introduction of FBMC on 21/05/2015.
Sources : CWE TSOs, CREG

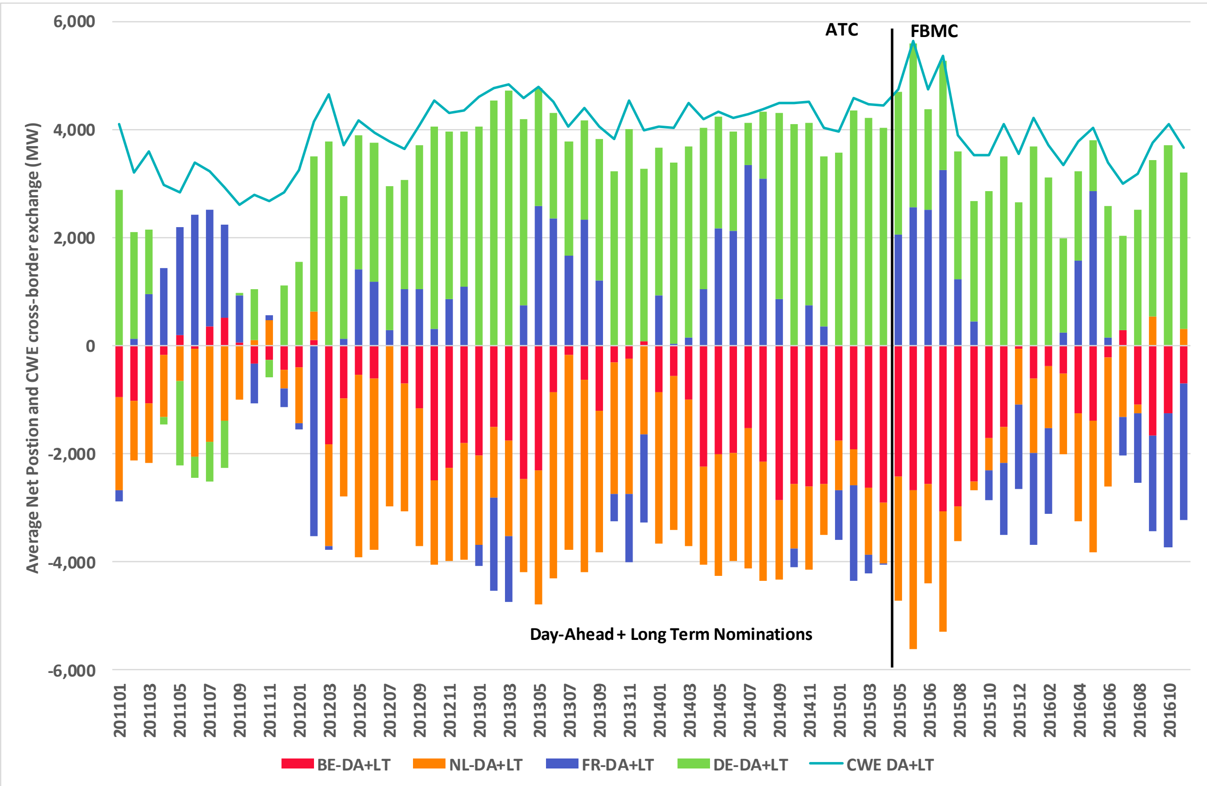
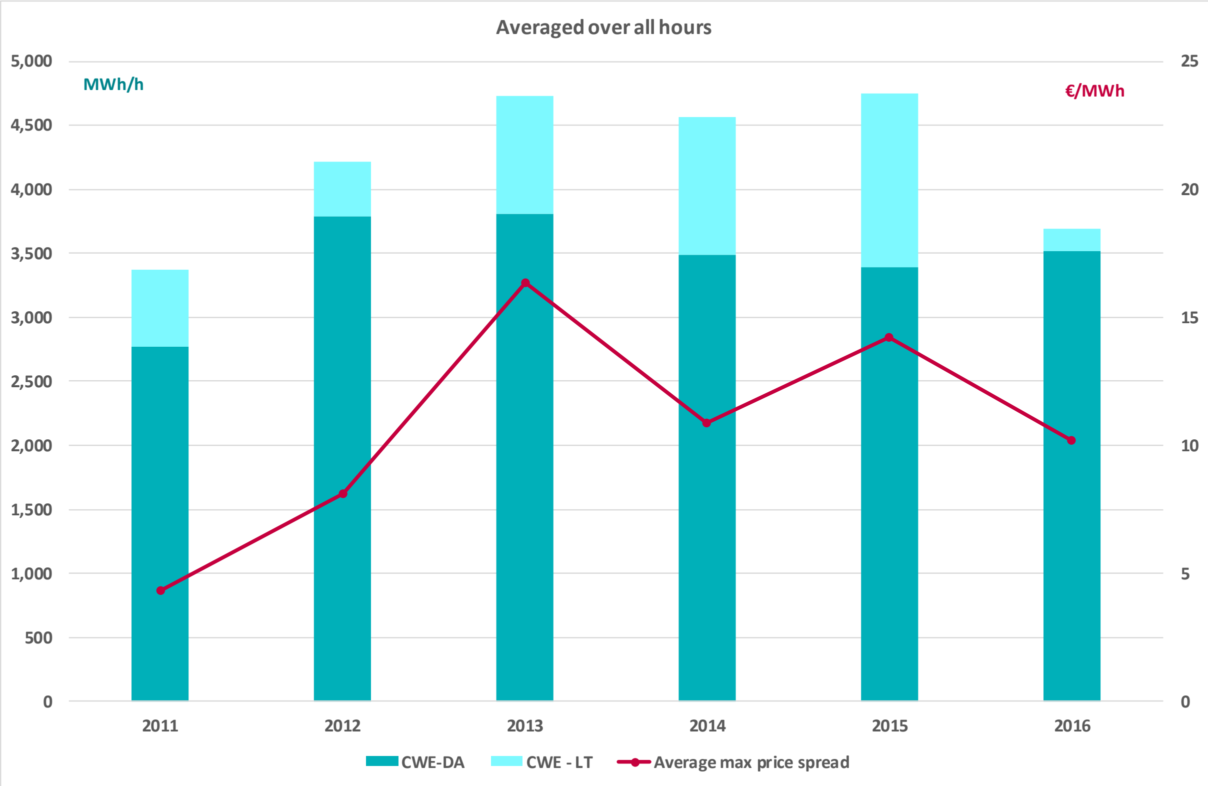


Figure 57 : Monthly averaged Net Positions and CWE cross-zonal exchanges in day-ahead + long term before and after introduction of FBMC on 21/05/2015.
Sources : CWE TSOs, CREG

115. Day-ahead cross-zonal volumes remained roughly the same (Figure 56) while the share of long-term volumes decreased substantially (Figure 58). Yearly averaged CWE cross-border exchange in day-ahead remained at the same level as previous years, i.e. 3500 MW, and have not made up for the reduction in long term capacities. In 2016, total CWE cross-border trade was 3700 MW on average during congested hours, a decrease of 900 MW compared to 2014.

116. Two reasons explain the reduction of long term nominated volumes. The first reason is the decrease in long term capacity allocated to the market. The volumes on the German-Dutch border have halved (from 832 MW to 400 MW) in both directions. A second reason is that since 2016, the long term rights on the Belgian borders are offered as financial transmission rights (FTRs) which do not have to be nominated. The volumes for import or export are included in the day-ahead volumes. This is in contrast with the physical transmission rights (PTRs) which still are nominated and appear in different figures. Note that FTRs and PTRs are equal in terms of physical firmness of import and export capacities.



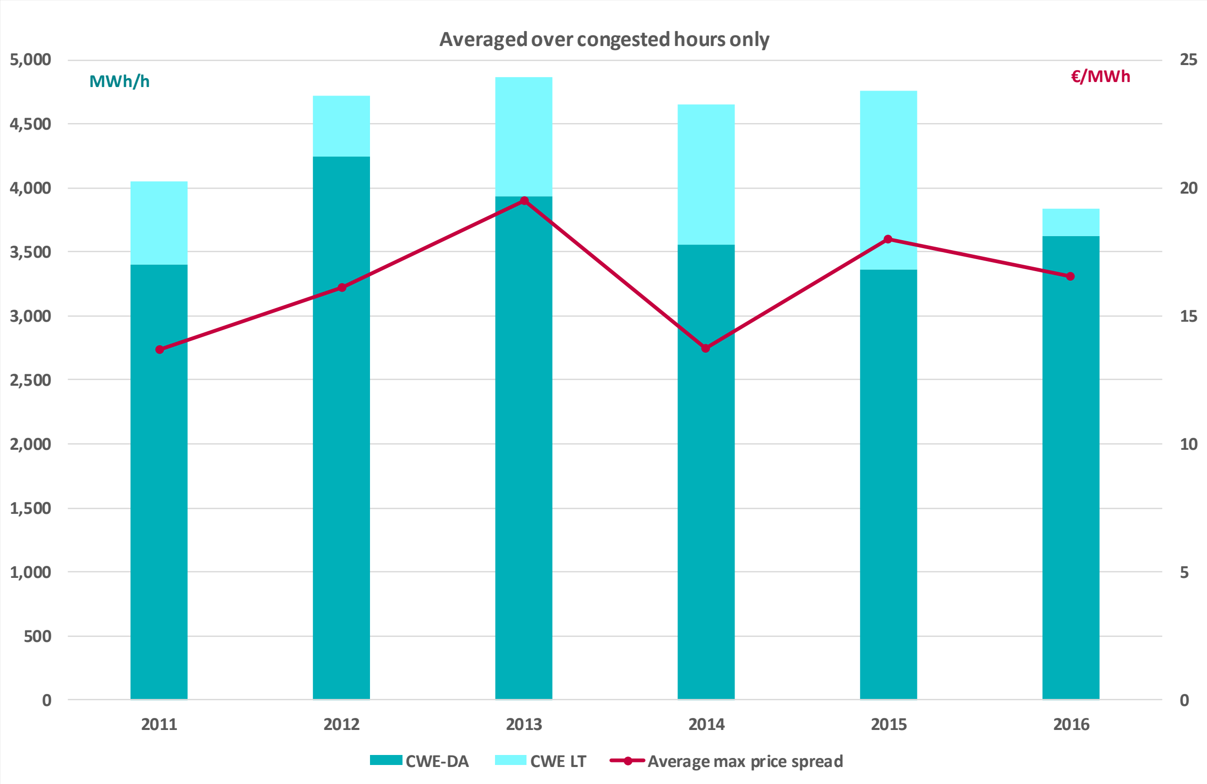


Figure 58 : 6-year evolution of CWE cross-zonal exchange on the long term (LT) and day-ahead (DA) market against the average maximum price spread within the CWE region, evaluated for all hours (top) and for all congested hours (bottom).
Sources : CWE TSOs, CREG

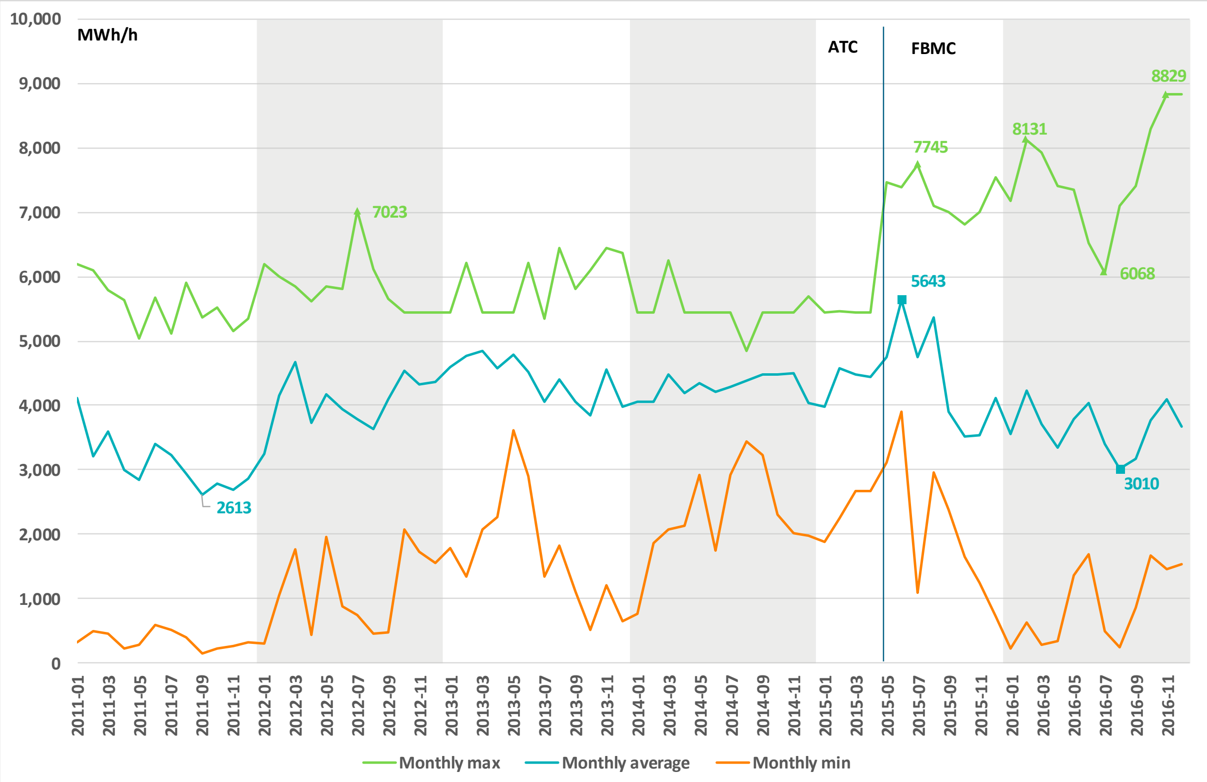


Figure 59 : Maximum, average and minimum monthly values of CWE cross-border volume (day-ahead + long term) for 2011 – 2016. The vertical line indicates the start of FBMC for day-ahead market coupling.
Sources : CWE TSOs, CREG

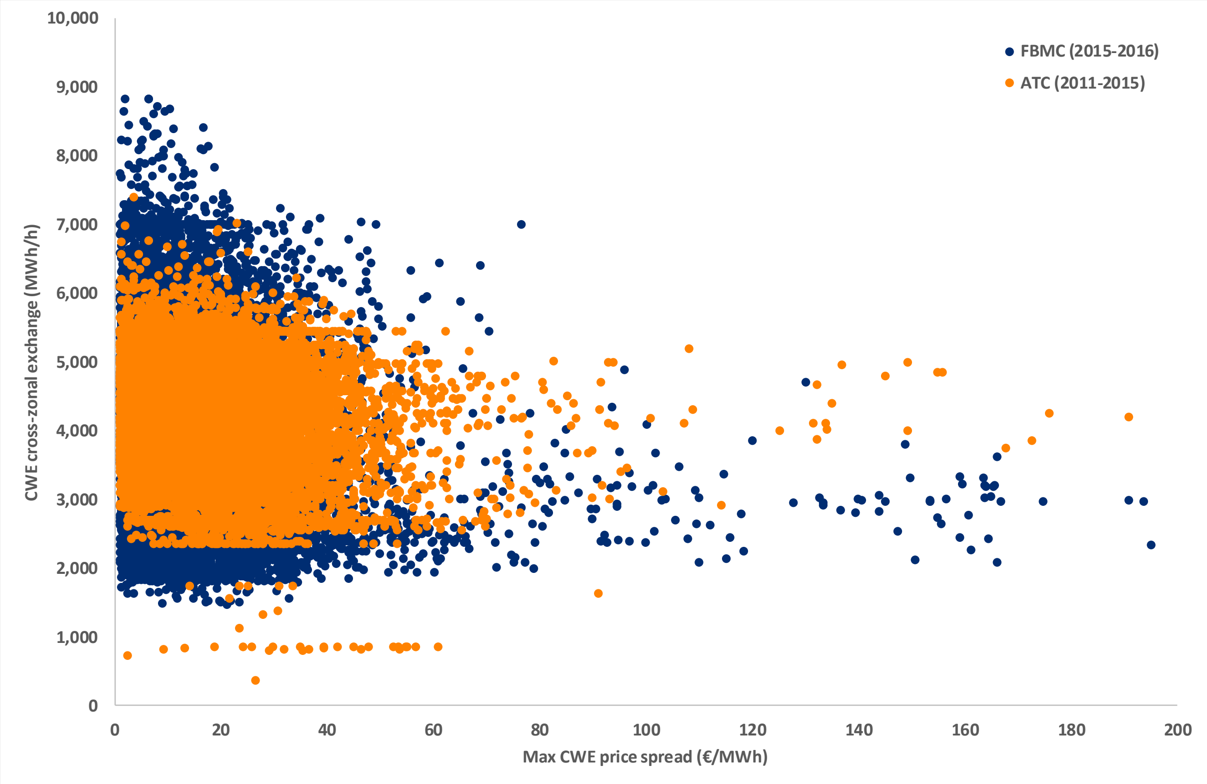


Figure 60 : Hourly values of CWE cross-zonal exchange (DA + LT) in function of the maximum price spread before and after introduction of FBMC. Hours with price spreads higher than 200 €/MWh are not shown.
Sources : CWE TSOs, CREG

117. The findings of the first 1,5 years of FBMC operation are summarized in Figure 60. FBMC can outperform ATC, leading to higher cross-zonal exchanges and smaller price spreads. In 13% of the hours covered by the monitoring period, the volumes exchanged with FBMC were above 5449 MW, being the 90% percentile value with ATC. FBMC – as implemented now in CWE - can also perform worse. In 24% of the hours, the volumes exchanged with FBMC were below 3351 MW, being the 10% percentile value with ATC. The graph indicates that at hours with high price spreads, the volumes exchanged with FBMC are in the range of 1000 MW lower than with ATC. The hours with price spreads above 200€/MWh are not displayed. For the given monitoring period, the occurrence of hours with high price spreads has significantly increased. Price spreads reflect the opportunity cost of the limited available interconnection capacity. In the next paragraph we look at the characteristics and impact of network constraints on the cross-zonal exchanges.

Overview of congested hours

118. About 35% of the hours, the market cleared inside the flow based domain, yielding full price convergence. The average day-ahead market clearing price in these hours was 31 €/MWh (Table 19) with an average cross-border volume, including both day-ahead and long-term commercial exchanges, of 3748 MW (Table 20). On average, full price convergence was reached when both Germany and France were exporting and Belgium and the Netherlands were importing.

119. The other 65% of hours, the market cleared at the border of the flow based domain, hitting one or more network constraints, giving rise to different zonal prices. For the given period, the average maximal price spread within the CWE zones was 17€/MWh, and the average cross-border volume 4079MW. On congested hours, Belgian and French markets were impacted most severely, with average prices rising up to 44€/MWh and 40€/MWh respectively. Only on the German market, wholesale prices on congested hours are lower than on uncongested ones (Table 19).

120. Averaged over all uncongested hours, Germany and France are exporting and Belgium and the Netherlands are importing. Averaged over all congested hours, Germany is exporting and France, Belgium and the Netherlands are importing (Table 20).

CWE FBMC	Occurrence	Average Price Spread	Average BE-DAM	Average NL-DAM	Average FR-DAM	Average DE-DAM
	(hours)	(€/MWh)	(€/MWh)	(€/MWh)	(€/MWh)	(€/MWh)
No congestion	4,902	0	31	31	31	31
Congestion	9,283	17	44	37	40	30
Total	**14,185**	**11**	**39**	**35**	**37**	**30**

Table 19 : Average day-ahead market clearing prices in the 4 CWE bidding zones for hours without and with congestion.
Sources : CWE TSOs, CREG

CWE FBMC	Occurrence	Average CWE XB Vol	Average NEP BE	Average NEP NL	Average NEP FR	Average NEP DE
	(hours)	(MW)	(MW)	(MW)	(MW)	(MW)
No congestion	4,902	3,748	-1,179	-1,400	648	1,931
Congestion	9,283	4,079	-1,473	-1,056	-327	2,855
Total	**14,185**	**3,964**	**-1,371**	**-1,175**	**10**	**2,536**

Table 20 : Average Net Position (day-ahead + long term) in the 4 CWE bidding zones for hours without and with congestion.
Sources : CWE TSOs, CREG

Congestion per market direction

121. The question arises whether the occurrence of congestion is linked with a certain market situation. Table 21 gives a summary of the occurrence and impact of congestion for the given monitoring period per market direction.

- The two most likely market outcomes were (1) France and Germany exporting to the Netherlands and Belgium (#1: 4033 hours) and (2) Germany being the only exporting country (#2: 3888 hours). When only Germany is exporting, the frequency of congested hours (75%) is larger than when both France and Germany are exporting (59%).
- The market outcome suffering most from congestion, is the one where both Germany and the Netherlands are exporting to France and Belgium (#3: 2083h), with congestion in 80% of hours.
- The case where Belgium is the only importing country (#6: 573h), also highly suffers from congestion (74% of hours).
- Disregarding the situation where all zones are exporting to Germany, the case with least congestion is when France and Belgium export to the Netherlands and Germany (21% of hours).

In general, one could say that cross-zonal commercial exchanges inducing physical flows from south to north through Belgium and the Netherlands suffer less from congestion than commercial exchanges inducing flows in the other direction. This suggests that south-north oriented flows are predominant in the preloading of the transmission lines following the base case.

Market outcome	Occurrence	Congestion	Congestion	Average shadow price	CWE XB Vol (DA+LT)@ no congestion	CWE XB vol (DA+LT) @ congestion	Difference CWE XB Vol (DA+LT)
	(hours)	(hours)	(% hours)	(€/MW)	(MW)	(MW)	(MW)
Bi-Ni-Fe-De	4,033	2,392	59%	67	4,106	4,084	-22
Bi-Ni-Fi-De	3,888	2,908	75%	102	4,093	4,540	447
Bi-Ne-Fi-De	2,083	1,671	80%	125	4,107	3,677	-430
Be-Ni-Fi-De	1,321	887	67%	90	3,524	4,214	690
Bi-Ni-Fe-Di	981	469	48%	48	3,758	5,005	1,247
Bi-Ne-Fe-De	573	425	74%	194	2,948	2,828	-120
Bi-Ne-Fe-Di	344	83	24%	116	2,900	3,162	262
Be-Ni-Fe-De	292	104	36%	28	2,493	3,632	1,139
Be-Ne-Fi-De	277	195	70%	96	2,759	2,167	-592
Be-Ni-Fe-Di	160	34	21%	19	2,628	3,557	929
Bi-Ne-Fi-Di	126	93	74%	181	1,514	4,604	3,090
Be-Ne-Fi-Di	68	20	29%	76	1,704	1,972	268
Be-Ne-Fe-Di	29	1	3%	35	2,029	4,048	2,019
Be-Ni-Fi-Di	9	0	0%	-	1,156	-	-
Total	**14,184**	**9,282**	**65%**	**96**	**3,964**	**4,079**	**-114**

Table 21 : Frequency and impact of congestion for the different market outcomes in terms of social welfare loss (shadow price) and CWE commercial cross-border exchanges (CWE XB Vol) in day-ahead and long term (DA + LT).
"B","N","F" and "D" represent respectively Belgium, the Netherlands, France and Germany. The index "i" denotes a net import position and the index "e" denotes a net export position. In total, there are 14 market outcomes possible for 4 zones, considering that the combination of all zones importing or all zones exporting is not possible (adequacy). For each market direction, the occurrence of congestion is shown, together with the average shadow price of congestion (€/MW) and average CWE cross-border commercial exchange at hours without and with congestion – and the difference between both (MW).
Sources : CWE TSOs, CREG

122. The shadow price, averaged over the congested hours per market direction, shows a large variation in the welfare impact of congestion. The welfare impact is the largest for the situation when Belgium is the only importing zone (average shadow price of 194 €/MW), followed by the situations when the Netherlands is the only exporting zone (average shadow price of 181 €/MW) and when both Belgium and France are importing (average shadow cost of 125 €/MW).

123. The change in volume between congested and non-congested hours also depends on the market direction, though no clear pattern is observed (Table 21, last column). In most market directions the average volume exchanged during congested hours is larger than on non-congested hours, indicating that the congestion is triggered by higher trading volumes. In other market directions, however, it is the inverse, indicating that network constraints reduce 'normal trading volumes'.

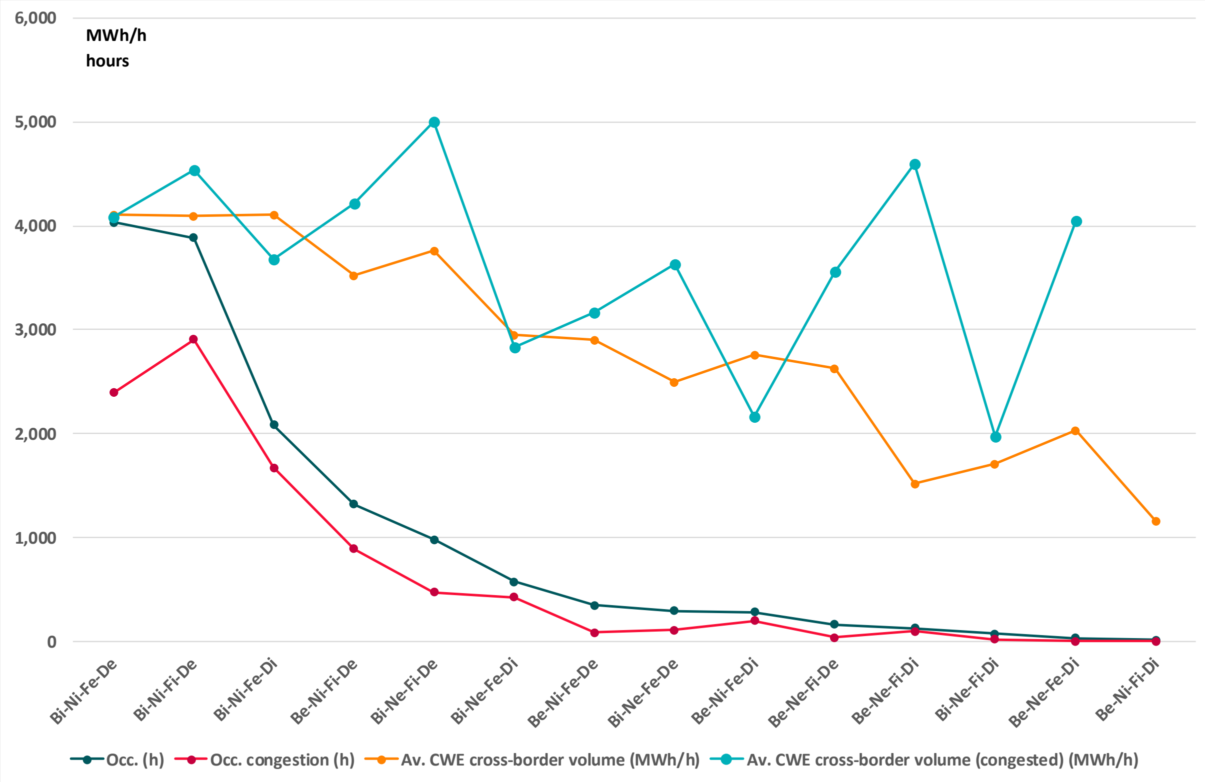


Figure 61 : Occurrence of the combination of Day-Ahead CWE Net Exchange Positions (B: Belgium, N:Netherlands, F:France, D:Germany/Austria/Lux and i:import, e:export) with number of congested hours and average CWE cross-border volumes (all hours and congested hours only). More likely market directions typically have higher average CWE-cross-border volume. All directions, except for the one where France and Germany are exporting to Belgium and the Netherlands (Bi-Ni-Fe-De) suffer highly from congestion.
Sources : CWE TSOs, CREG

Congestion per type of CBCO: cross-border CBCO, internal CBCO and external constraints

124. With FBMC, one can exactly pinpoint which CBCOs have been active – at least for the hours with Flow Based Plain (FBP). For the hours where the flow based intuitiveness patch (FBI) was applied, the CBCOs which triggered the intuitiveness patch can only be partially retrieved. In total, in 13% of the congested hours, i.e. 1312 hours, the location of the congestion could not be identified. In almost 30% of these hours, multiple CBCOs are active at the same time because the market clears at a corner of the flow based domain.

125. Network constraints inside a bidding zone have limited cross-border trade more often and more severely than constraints on interconnectors (Table 22). The occurrence of active constraints on internal CBCOs (5,793 h) higher than that of cross-border CBCOs (5,005 h). The associated shadow price, averaged over the entire monitoring period, was 152€/MW compared to 61€/MW for cross-border CBCOs. The average day-ahead cross-border exchange (before last column) is also lower: 2,629 MW when internal CBCOs were limiting compared to 4,468 MW in the case of cross-border CBCOs.

126. Network constraints inside a bidding zone have been limiting the FBMC outcome when their RAM was very low. With limited RAM left, CBCOs can limit cross-border exchange even if they have a low PTDF. In 26% of the cases, the active critical branch had less than 10% RAM (Figure 62).

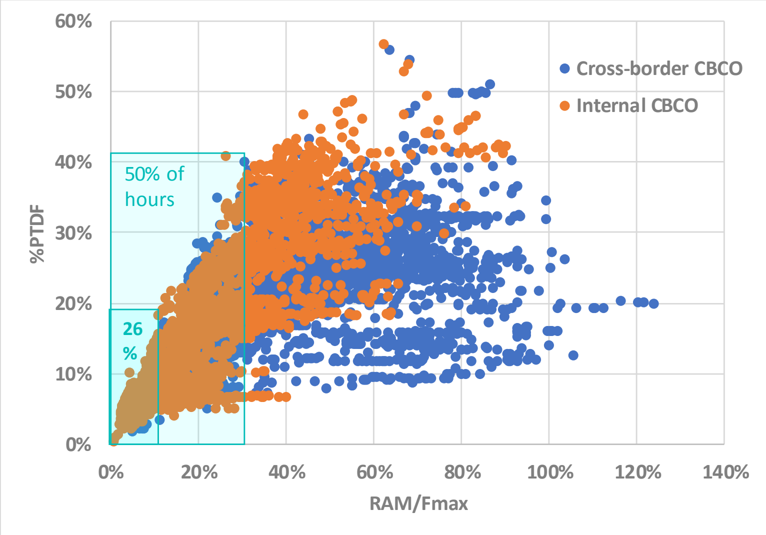


Figure 62 : In 50% of hours, the Flow Based market outcome was limited by CBCOs with a RAM of less than 30% of Fmax. In 26% of hours, the RAM was less than 10% of Fmax.

Sources : CWE TSOs, CREG

127. External constraints limited cross-border trade in 923 hours, i.e. 10% of the identified congested hours. Since external constraints are triggered at higher exchanged volumes, the associated shadow cost tends to be lower. On average, external constraints limit CWE cross-zonal exchange in day-ahead to 5,834 MW.

Type of Active CBCO	Total (FBP + FBI)	FBI	LTA	Av. PTDF	Av. RAM	Av. RAM/ Fmax	Av. Shadow price	Av. Price spread	Av. CWE XB Vol (DA)	Av. CWE XB vol (DA+LT)
	(hours)	(%h)	(%h)	(%)	(MW)	(%)	(€/MW)	(€/MW)	(MW)	(MW)
Cross-border CBCO	5,005	9%	39%	24%	603	44%	61	17	4,093	4,468
Internal CBCO	5,793	26%	71%	13%	255	16%	152	20	2,629	3,425
External Constraint	923	5%	0%	100%	4,931	92%	7	11	5,834	6,131
Total	**11,721**	**17%**	**52%**	**24%**	**772**	**34%**	**96**	**18**	**3,506**	**4,083**

Table 22 : Overview of active CBCOs grouped by type for the period (21/05/2015 – 31/12/2016: 14185 hours). Note that in 30% of the congested hours, there was more than one active constraint.
Sources : CWE TSOs, CREG

128. In about 17% of the congested hours, the Flow Based Intuitive patch (FBI) had to be applied to avoid a non-intuitive market solution where a price zone with a higher market clearing price exports to a price zone with a lower market clearing price (Table 22, 2nd column). In the majority of cases, the CBCO having triggered congestion was an internal CBCO. In 26% of the cases an internal CBCO was active with Flow Based Plain (FBP), the intuitiveness patch had to be applied. Note that once the intuitiveness patch is applied, the active CBCO (FBP) no longer appears as an active CBCO (FBI).

129. In 39% of the cases there was LTA-violation on a cross-border CBCOs, and up to 71% on internal CBCOs (Table 22, 3rd column). To put these figures in perspective, in the parallel runs before the go-live of FBMC, the occurrence of LTA-violations was of the order of 5% of the time – a fraction of what has been observed until now. LTA-violation indicates that the FB domain is very small in the market direction. LTA-inclusion increases the FB domain such that the long term allocated capacities are covered by the day-ahead FB domain in order to insure that the income from congestion revenues collected in the day-ahead are sufficient to remunerate all holders of long term capacity rights. Note that all RAM-values presented in the figures and tables take into account the RAM-increase due to

LTA-inclusion. Without LTA-inclusion, RAM values would have been even be lower. The increase of RAM through LTA-inclusion is on average 171 MW on cross-border lines and 183 MW on internal lines.

130. Table 23 presents the results for hours with LTA-violation. These are congested hours where the active CBCOs was a virtual CBCO: a CBCO where the RAM or the PTDF is changed by application of the LTA-inclusion patch (see §110). LTA-violation occurred in 6054 hours, or 52% of congested hours! The cross-border volume during these hours, 2516 MW, is smaller than on other congested hours. Note the large share of internal CBCOs in LTA-violations (4393 hours). LTA-violations are triggered by congestion on CBCOs with relatively low RAM-values (298 MW, see Table 23, compared to 773 MW on average, see (Table 22).

Type of Active CBCO	Total (FBP + FBI)	FBI	LTA	Av. PTDF	Av. RAM	Av. RAM/ Fmax	Av. Shadow price	Av. Price spread	Av. CWE XB Vol (DA)	Av. CWE XB vol (DA+LT)
	(hours)	(%h)	(%h)	(%)	(MW)	(%)	(€/MW)	(€/MW)	(MW)	(MW)
Cross-border CBCO	1,960	13%	100%	22%	454	35%	79	21	3,120	3,590
Internal CBCO	4,095	28%	100%	13%	223	14%	162	22	2,226	3,033
Total	**6,055**	**23%**	**100%**	**16%**	**298**	**21%**	**132**	**21**	**2,515**	**3,213**

Table 23 : Occurrence and characteristics of active CBCOs on which LTA-inclusion was applied, evaluated over the monitoring period (21/05/2015-31/12/2016).
Sources : CWE TSOs, CREG

131. Most market directions suffer more from congestion on internal CBCOs, e.g. Belgium and France importing from the Netherlands and Germany (Figure 61, 3rd bar), but a few market directions, e.g. Belgium and the Netherlands importing from France and Germany, suffer more from congestion on cross-border CBCOs (Figure 61, 2nd bar). The latter are the market directions which are in general less affected by congestions (compare the height of the bar with the line indicating the number of hours per market direction in Figure 61).

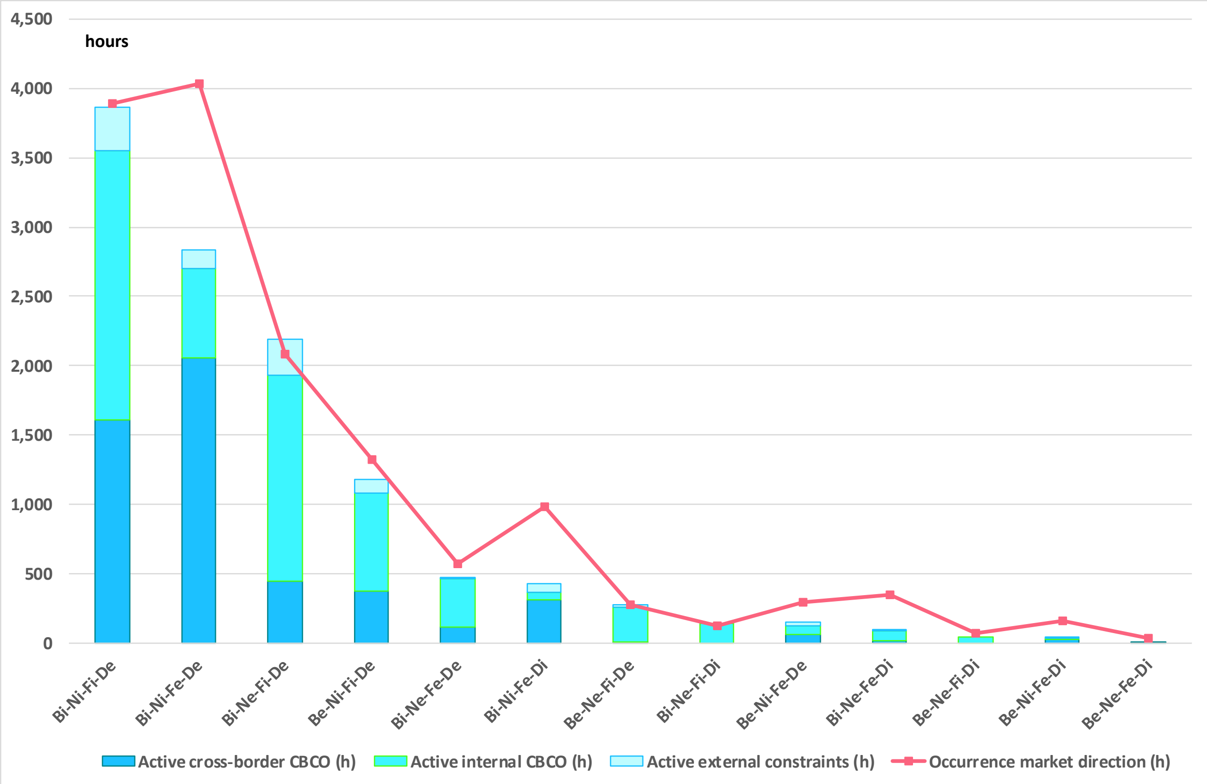


Figure 63 : Number of hours the market cleared in a certain direction (line) and a breakdown of the total number of active CBCOs (bars) in cross-border CBCOs, internals CBCOs and external constraints. The market direction is defined by the combination of Net Positions of Belgium (B), France (F), the Netherlands (N) and Germany/Austria/Luxembourg (D) with import (i) and export (e). The total number of hours the market cleared in a certain direction, is indicated by the line (#hours). Sources : CWE TSOs, CREG

Location of active cross-border CBCOs

132. Most congestion on CWE cross-border lines occurred on the border between Germany and the Netherlands. The two most constraining cross-border CBCOs were the interconnectors Diele-Meeden (XDI-ME) between Tennet DE and Tennet NL, and Sierdorf-Maasbracht (XSI-MB), between Amprion and Tennet NL (Figure 64). These are followed by the PSTs in Gronau (PST-DGRON), on the interconnector between Tennet DE and Tennet NL, and the interconnector Rommerskirchen – Maasbracht (XRO-MB) between Amprion and Tennet NL.

133. The most constraining Belgian cross-border elements were the interconnector Auban-Maubonge (XAU_M) and – to a lesser extent - the PSTs in Zandvliet (PST-BZANDV), the interconnector Van Eyck – Maasbracht (XVY – MB) and the interconnector Avelin – Avelin (XAV-AV) (Figure 64). For an overview of Belgian cross-border lines, see Section 5.2.1.

134. Figure 64 shows also the value of Fmax, FRM, Fref’, FAV and the resulting RAM– averaged over the entire monitoring period and considering only the active hours. Note the positive FAV on the three interconnectors between Amprion and Tennet NL. Amprion applied an FAV of 300 MW on these three lines from 29 May 2015 onwards - a few days after the go-live of FBMC, after having observed high flows in real-time. From September 2016 onwards, Amprion reduced the FAV values by 50 MW per month – having completely removed them from January 2017 onwards. Note also the relatively high share of Fref’ on the interconnectors, on average 965 MW or 41% of Fmax, and which solely result from loop flows. In winter, the direction of the loop flows crossing the Belgian network, is mainly north-south. The preloading of the network in this direction limits the import capacity of Belgium (and France) from the Netherlands and/or Germany.

Figure 64 : Average characteristics and occurrence of active cross-border critical branches, ranked by the number of active hours. The height of the bar corresponds to the average thermal line capacity (Fmax). The margin available for day-ahead cross-zonal trade (RAM) results from this total line capacity after deduction of the preloading (Fref') and the flow reliability margin (FRM). One some cross-border lines, the RAM was further reduced or increased by a positive or negative Flow Adjustment Variable (FAV). The markers indicate the number of congested hours ('count').
Sources : CWE TSOs, CREG

Location of active internal CBCOs

135. Figure 65 and Figure 66 illustrate one of the main problems of the implementation of the CWE FBMC: Internal CBCOs, mainly from the Amprion region, were close to pre-congestion when active, with little capacity left for cross-border exchange (RAM). Together, internal lines in the Amprion zone have limited cross-border trade in 35% of all congested hours. Their impact on the flow based domain was so large, despite their low PTDF, because their RAM-value was structurally low (around or below 10% of Fmax - when active).

136. Some of these CBCOs (circled in Figure 66) were added by Amprion a few weeks after the go-live of FBMC, as a response to high flows observed in real time. These lines were not present in the CBCO-set of the parallel runs, which run over 2 years before the go-live of FBMC to assess the welfare gain of FBMC compared to the former ATC- method, and which served as an input for the decision to move versus FBMC. With the introduction of these additional CBCOs, only half of the welfare gains forecasted in the parallel runs were realized, according to simulations run by CWE TSOs and the power exchange markets.

137. The impact on social welfare of these CBCOs - reflected in the high shadow prices – illustrates the inaptitude of using cross-zonal FBMC as a congestion management tool to solve structural congestion problems inside a zone. The recorded low volumes of cross-border exchange along with high price spreads, has pushed CREG and other CWE NRAs to re-iterate the urge for an improved CBCO-

selection method. This revision is needed to reduce the number of pre-congested cases, LTA-violations… and so forth which resulted in the observed reduction of cross-border trade.

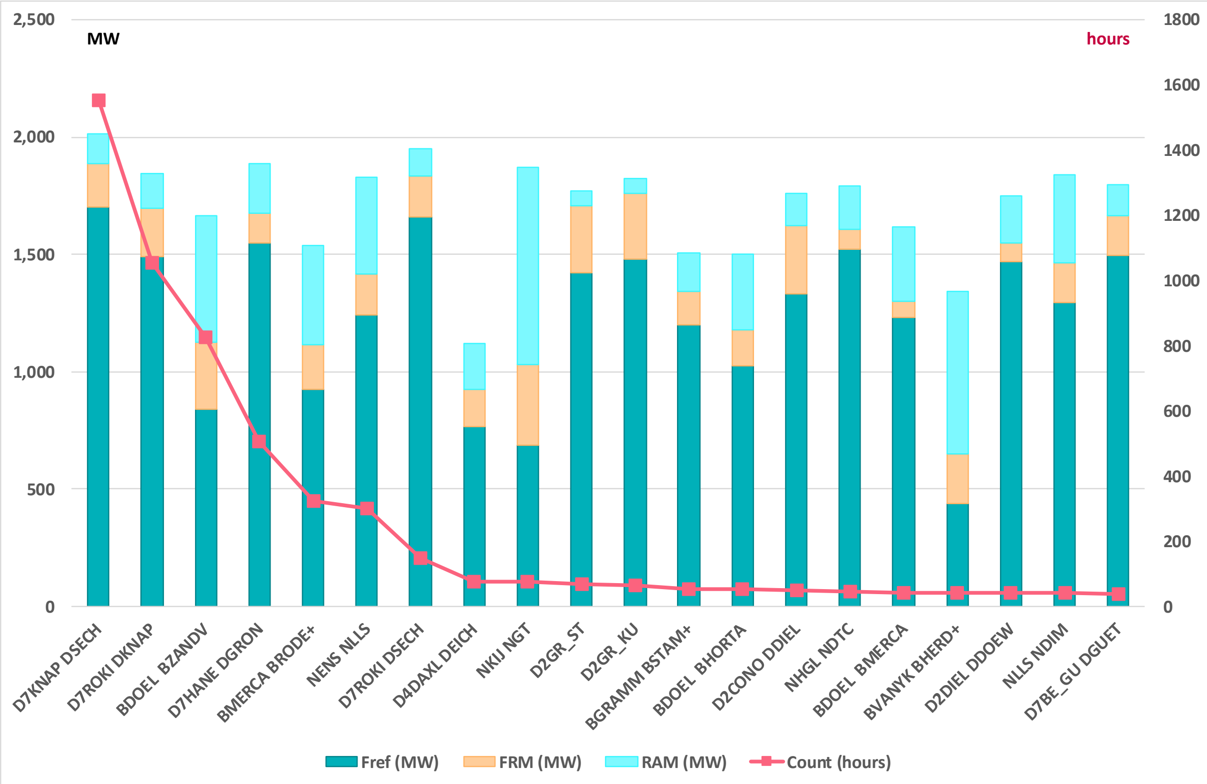


Figure 65 : Average characteristics and occurrence of the Top 20 internal critical branches, ranked by the number of active hours. The height of the bar corresponds to the average line capacity, i.e. the thermal line capacity (Fmax) including the virtual capacity increase by LTA-inclusion. The margin available for day-ahead cross-zonal trade (RAM) results from this total line capacity after deduction of the preloading (Fref') and the flow reliability margin (FRM). The first letter of the Critical Branch name indicates its zonal location (D : Germany/Austria/Luxembourg, B: Belgium, N : the Netherlands, F : France). The markers indicate the number of congested hours ('count').
Sources : CWE TSOs, CREG

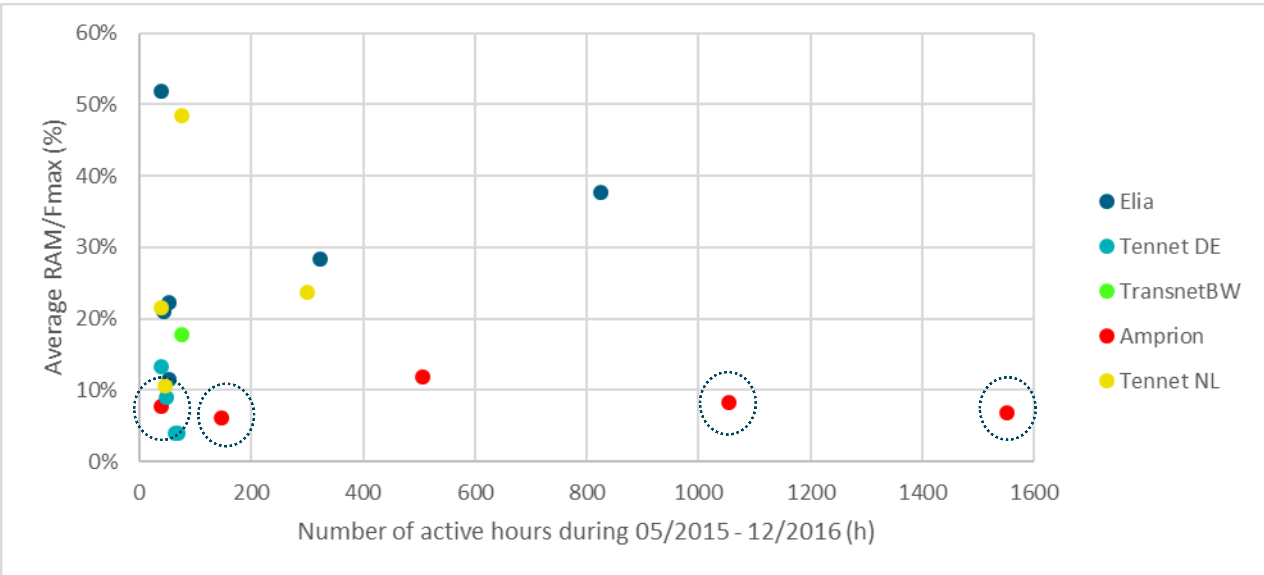


Figure 66 : The same information as in the figure above, presented differently. We observe that all 5 active internal CBCOs of Amprion (red dots) included in the Top 20 list, have an average RAM below or slightly above 10%. Based on the NRA monitoring data, those circled were added after the go-live of FBMC.
Sources : CWE TSOs, CREG

Location of active export constraints

138. All TSOs applied import and/or export constraints. German export constraints and French import constraints were the most active external constraints (Figure 67). Export constraints were applied by RTE until august 2016 and are still applied by Germany.

139. Belgian import constraints were active in 91 hours. The average value of the import constraint during these hours was 3,440 MW (far below the 4,500 MW import limit which is the standard value for Belgium). The Belgian import constraint was primarily triggered during summer 2015, when the import limit was reduced to 3,250 MW or 4,000 MW between 28 August and 19 October 2015 because of infrastructure works on the Belgian transmission grid[40].

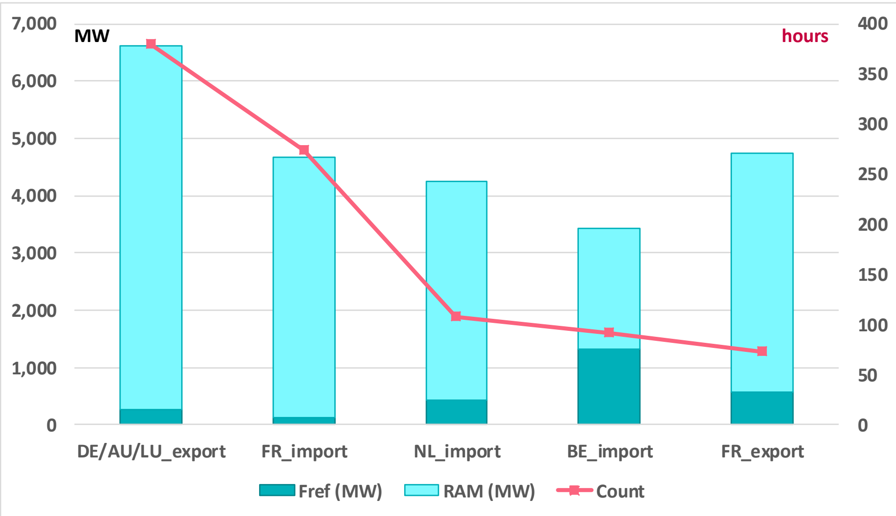


Figure 67 : Average value and occurrence of the external constraint when active (21/05/2015-31/12/2016). The value introduced for the day-ahead market coupling takes into account the nominated long-term rights (here denoted by Fref). The markers indicate the number of hours the constraint was active ('count').
Sources : CWE TSOs, CREG

5.3. STATISTICS

140. This section focuses on the commercial cross-zonal exchanges for Belgium and the physical use of the interconnection capacity at the Belgian borders with France and the Netherlands. Depending on the availability of data, the analysis covers the period 2007 – 2016 or the period 2011 – 2016. The results are discussed in their CWE- regional context, where appropriate.

Statistics on the commercial cross-border exchanges include :

- The yearly and monthly auctions of long term capacity rights ;
- The day-ahead exchanges ;
- The intraday exchanges.

Statistics on the physical use of the Belgian interconnection capacity includes :

[40] See Elia website http://www.elia.be/en/about-elia/newsroom/news/2015/25-08-2015-Reduction-of-Belgian-maximum-import, accessed page on September 8 2017

- Physical flows on the interconnectors arising from cross-zonal exchanges (‘competitive flows’). These flows are linked to import or export and to transit flows ;
- Physical flows on the interconnectors arising from exchanges inside a zone (‘non-competitive flows’). These flows are linked to domestic trade inside Belgium (‘domestic flows’) and flows linked to domestic trade in another zone (‘loop flows’).

5.3.1. Long-term transmission capacity auctions

141. Long term capacities are still being calculated and allocated on the both borders and on both directions individually. The capacities are calculated with the NTC-method. The capacities are allocated as ‘long term transmission rights’ to market participants in yearly and monthly auctions.

142. Since 1 January 2016, it is no longer possible for market participants to nominate long term rights at the Belgian borders. The capacity rights are issued as Financial Transmission Rights (FTRs) instead of Physical Transmission Rights (PTRs). The latter are still in use on all other CWE-borders. As previously stated, FTRs grant the same guarantee as PTRs that physical import or export volumes are available (in FBMC, this is guaranteed through the LTA-inclusion), and the same financial hedging. Compared to PTRs, FTRs give more degrees of freedom to the market coupling optimization algorithm and therefore enable solutions with higher social welfare.

Yearly auctions

143. The volume of available yearly long term capacities has remained almost stable over the last 10 years (Table 24). The long term import capacity on the Southern border is more than triple that at the Northern border. The long term export capacity, by contrast, is smaller at the Southern border than at the Northern one. In 2016 the long term export capacity to France was exceptionally lower than the years before, due to planned network maintenance.

	FR=>BE			BE=>FR			NL=>BE			BE=>NL			Total
Year	Cap	Price	Revenu	Cap	Price	Revenu	Cap	Price	Revenu	Cap	Price	Revenu	Revenu
	(MW)	(€/MWh)	M€	(MW)	(€/MWh)	M€	(MW)	(€/MWh)	M€	(MW)	(€/MWh)	M€	M€
2007	1299	2.06	23.4	400	0.25	0.9	467	0.11	0.5	467	3.45	14.1	38.9
2008	1300	0.90	10.3	400	0.56	2.0	468	1.57	6.5	468	2.04	8.4	27.1
2009	1300	0.88	10.0	400	0.81	2.8	468	3.07	12.6	468	1.34	5.5	30.9
2010	1297	0.16	1.8	400	3.46	12.1	467	2.02	8.2	467	0.80	3.3	25.5
2011	1449	0.06	0.8	400	0.69	2.4	467	1.10	4.5	465	0.59	2.4	10.1
2012	1447	0.10	1.3	400	0.52	1.8	467	0.85	3.5	466	2.20	9.0	15.6
2013	1449	1.07	13.6	400	0.72	2.5	468	1.95	8.0	471	3.04	12.6	36.7
2014	1450	1.21	15.4	400	1.16	4.1	468	1.24	5.1	468	4.41	18.1	42.6
2015	1450	2.86	36.3	399	0.39	1.4	467	5.44	22.3	468	1.25	5.1	65.1
2016	1449	0.96	12.2	200	1.25	2.2	468	3.22	13.2	468	1.39	5.7	33.4

Table 24 : Annual long term import and export capacities (MW), transmission rights (€/MW) and resulting revenues (€) at the border with France and the Netherlands.
Sources : Elia, CREG

144. The price that market participants are willing to pay for the yearly long-term capacities, varies. The price reflects the expected annual average day-ahead price spread on that border. For 2016, prices were the highest for NL=>BE (3,22 €/MW) and the lowest for FR=>BE (0,96 €/MW). Market participants correctly anticipated Belgian prices to be higher than in the Netherlands and similar to those in France. Total income from the yearly auctions amounted to 33.4 M€. This is significantly less than in 2015 when the yearly auctions climbed to 65€/MW. 2015 was exceptional in the sense that the long-term outage of 3 Belgian nuclear reactors forced Belgian to rely more on imports - prompting market participants to hedge against high price spreads on both borders.

Monthly auctions

145. In contrast to the annual long term capacities, the volume of monthly long term capacities varies substantially. The monthly import capacities in 2016 were substantially higher than the previous years – and this on both borders (Figure 68) while the export capacities remained similar to the previous years (Figure 69). Since 2014, the import and export capacities had shown a seasonal trend. The import capacity from France is higher in winter than in summer, while for imports from the Netherlands, it is the other way around. This suggests that the monthly capacity calculations start from a base case with a larger share of loop flows from north to south in winter than in summer. Consequently, the monthly auctioned export capacities to France is higher in winter, and to the Netherlands it is higher in summer.

146. During the first 6 months, the prices of all monthly long term capacities remained low. From October to December, however, prices climbed for both imports from the Netherlands and exports towards France. Market players reacted to the stressed winter situation in France which caused France to become more reliant on imports. With both France and Belgium importing, market participants anticipated high price spreads for November of 18 €/MWh between Belgium and the Netherlands and of 5€/MWh between France and Belgium. For December, market participants had overestimated price spreads. The auction price for imports at the northern border for December 2016 climbed to 24€/MWh while the realized monthly price spread dropped to 11€/MWh after having hit a 10-year-record high of 22€/MWh in November 2016. The auction price for exports at the southern border in December overestimated the realized price spread of 5€/MWh by 5€/MWh. Disregarding the last 3 months of 2016, the prices at the monthly auctions are relatively good estimates of the actual price spreads.

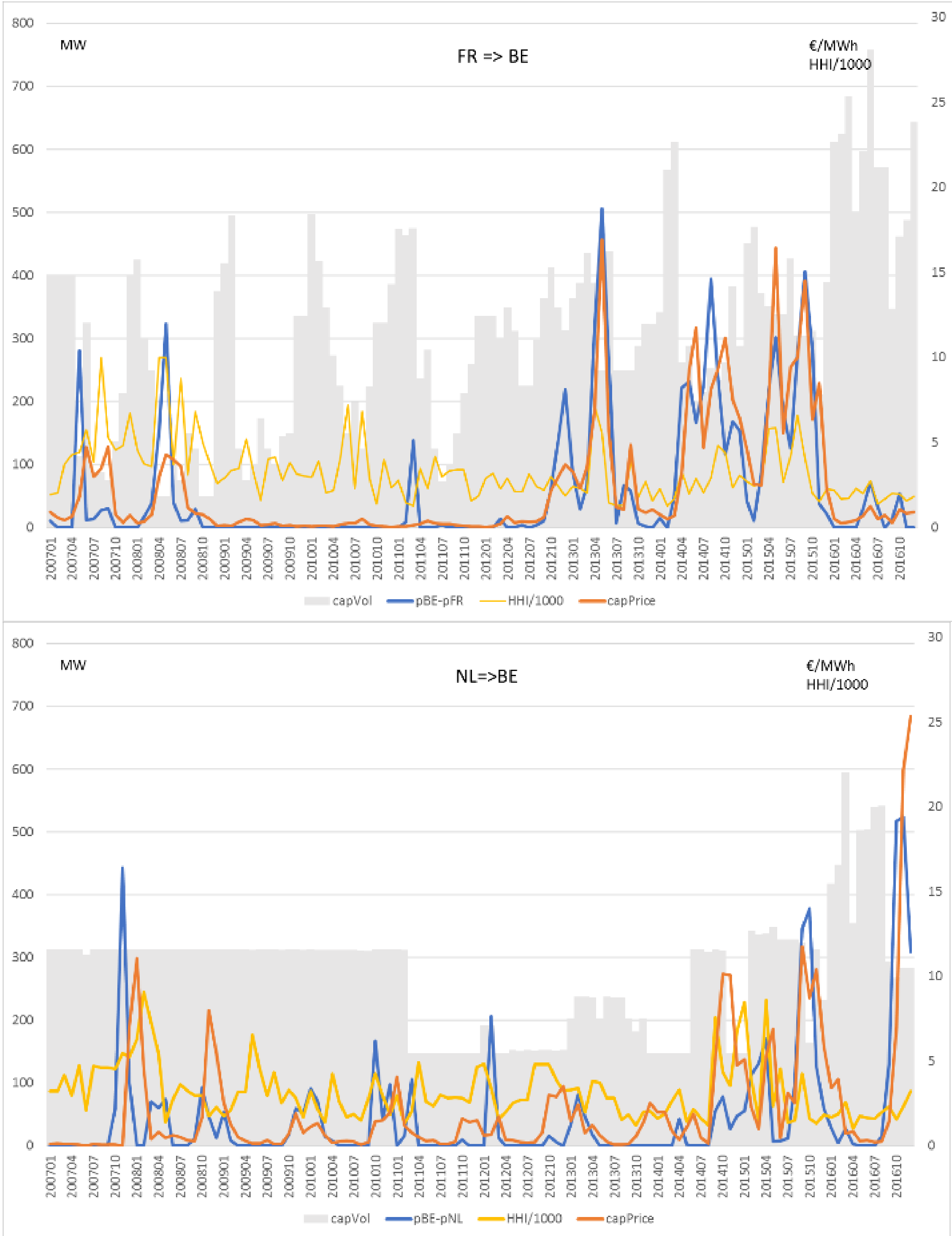
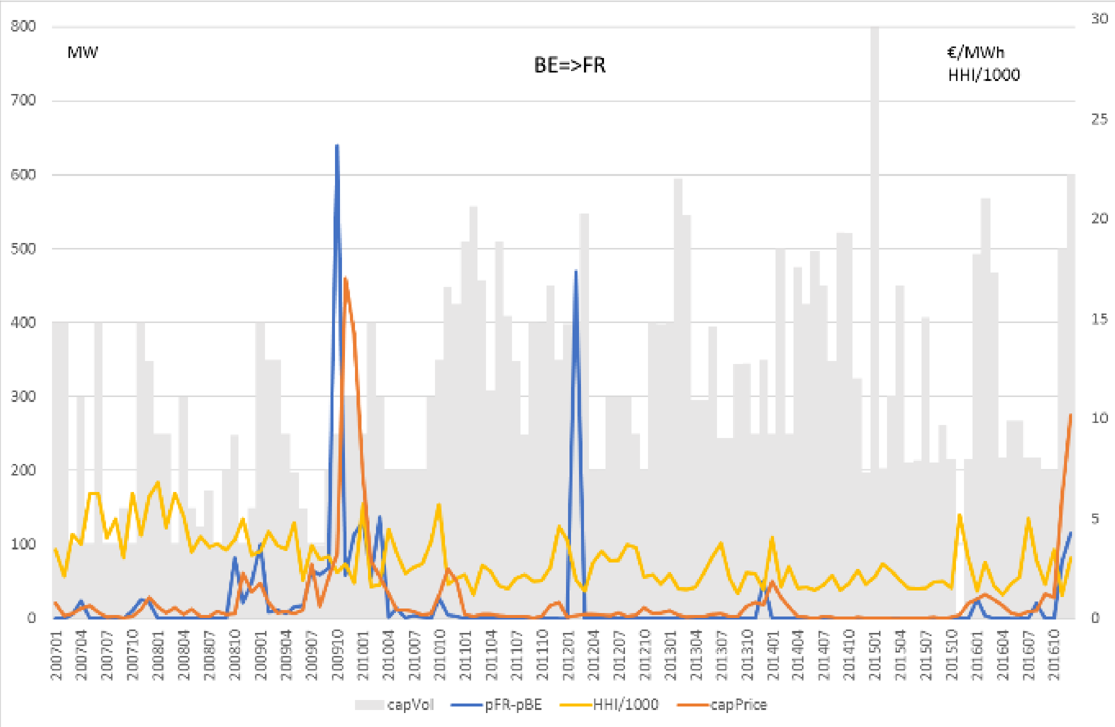


Figure 68 : Monthly long term IMPORT capacity auctions at the French border (top) and at the Dutch border (bottom). The gray bars indicate the auctioned volumes (MW), the blue line the monthly averaged price spread at each border in the given direction, the orange line the price of the transmission right. The better the auction prices are correlated with the actually realized price spread, the better the market was able to anticipate the market situation. The yellow line shows the HHI-index which is a measure of the market competitiveness as a function of the number of market players participating in the auction. Sources: Elia, CREG



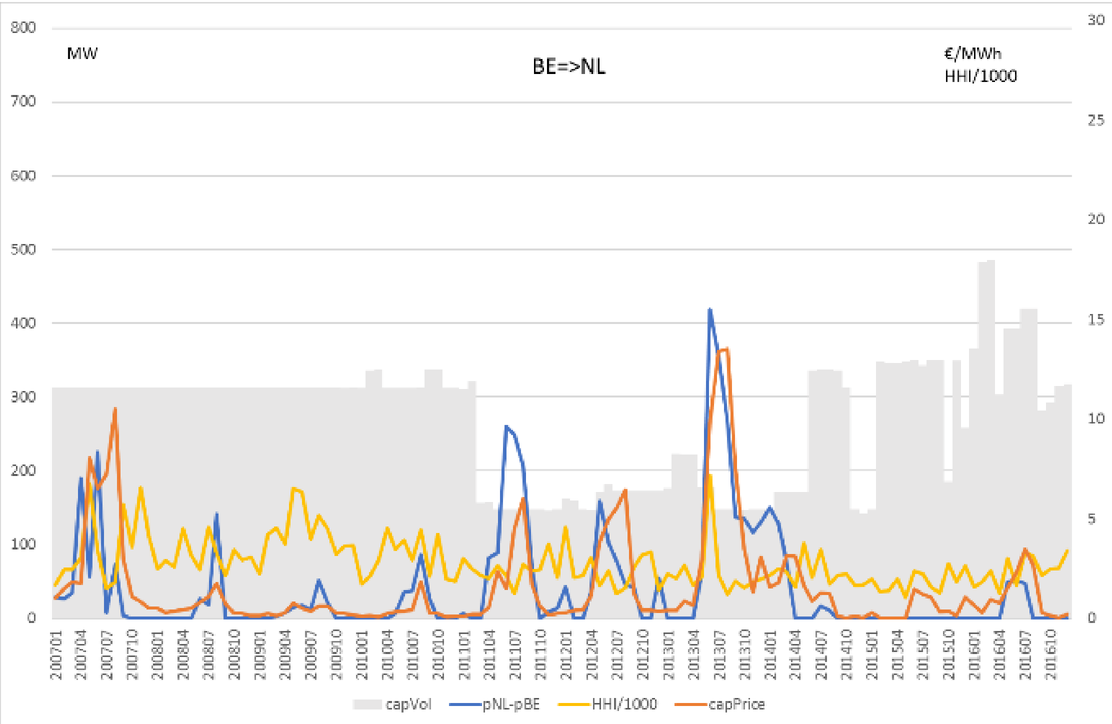


Figure 69 : Monthly long term EXPORT capacity auctions at the French border (top) and at the Dutch border (bottom). The grey bars indicate the auctioned volumes (MW), the blue line the monthly averaged price spread at each border in the given direction, the orange line the price of the transmission right. The better the auction prices are correlated with the actually realized price spread, the better the market was able to anticipate the market situation. The yellow line shows the HHI-index which is a measure of market competitiveness as a function of the number of market players participating in the auction.
Sources: Elia, CREG

5.3.2. Day-ahead cross-border exchange

147. The yearly total net sum of exchanged volumes is shown in Table 25. In 2016, the trend of increasing net import position of Belgium, observed since 2009 (see Table 10 in the next section), was reverted. In 2015 Belgium imported a record volume of 14.11 TWh. In 2016, this figure dropped to 6.4 TWh – a value which is even below the import level of 2012. Despite the lower net import position, Belgium remained a net importer during all months with the exception of August (+296 MW on average) (Figure 16). Imports were highest in July (-1655 MW on average).

148. In 2016, Germany was the only net exporting country. The exported volume amounted to 20.43 TWh which is the same value as the previous 2 years and less than in 2012 – 2013. The reduction in imports by Belgium was compensated by an increase in imports of 5.4 TWh by France and of 2.06 TWh by the Netherlands.

149. The monthly averaged, minimum and maximum day-ahead net position for Belgium alone in 2016 and the past 5 years are shown in Figure 70 and Figure 71. The figures indicate that the recorded minimum and maximum net positions have not significantly altered compared to previous years.

Year	BE	FR	NL	DE/AU/LUX	Tot CWE
	(TWh)	(TWh)	(TWh)	(TWh)	(TWh)
2011	-0.99	5.5	-5.89	1.39	6.88
2012	-6.93	0.69	-16.97	23.21	23.9
2013	-4.89	-2.08	-17.99	24.96	24.96
2014	-10.1	5.11	-15.16	20.15	25.26
2015	-14.11	0.24	-6.34	20.22	20.45
2016	**-6.4**	**-5.64**	**-8.4**	**20.43**	**20.43**
Average	-7.24	0.64	-11.79	18.39	19.03

Table 25 : Annual net import (-) or export (+) volume on the CWE-day ahead market. From 2011 to 2015, the net import position of Belgium increased steadily. In 2016, however, the net import position was only 6.4 TWh – similar to the value of 2012. The main difference with 2015 was that France became a net importer. Note that the total volume of cross-border exchange in 2015 and 2016 was lower than in the previous 3 years.
Sources: Elia, CREG

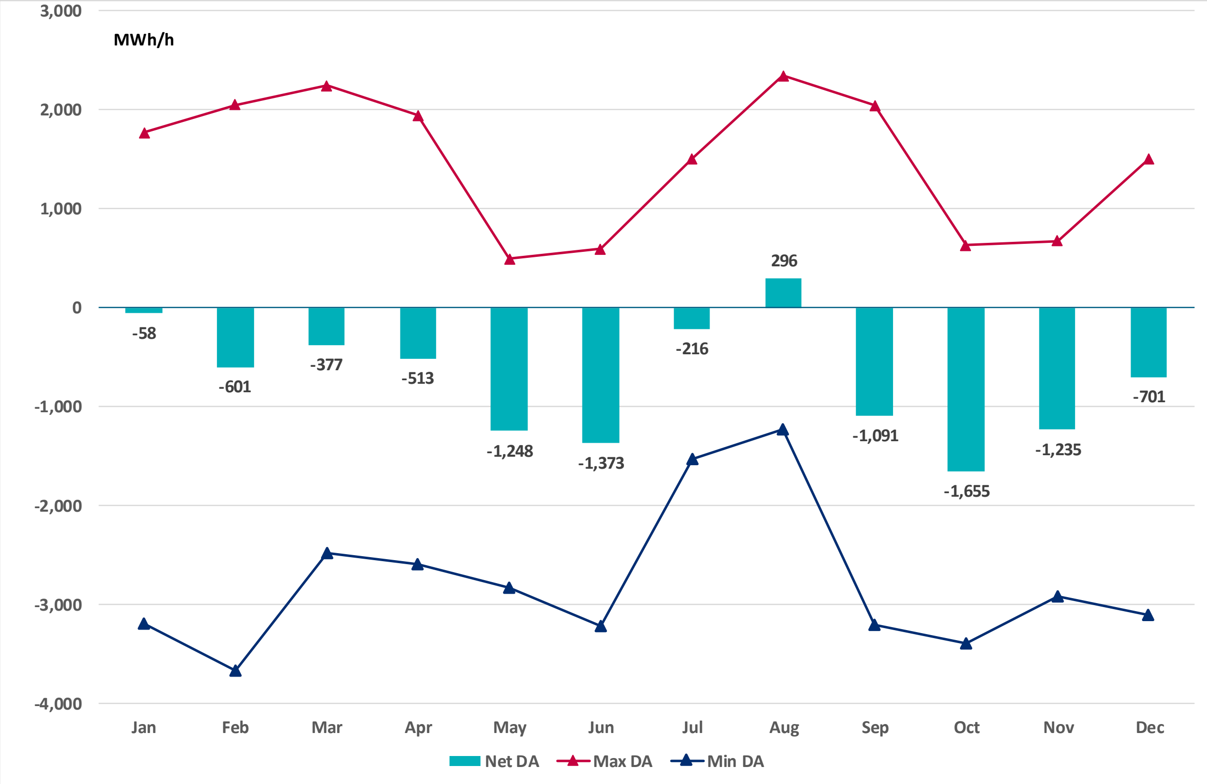


Figure 70 : Monthly averaged Belgian day-ahead Net Position (bar), maximum export Net Position (line, +) and maximum import Net Position (line, -) in 2016.
Sources: Elia, CREG

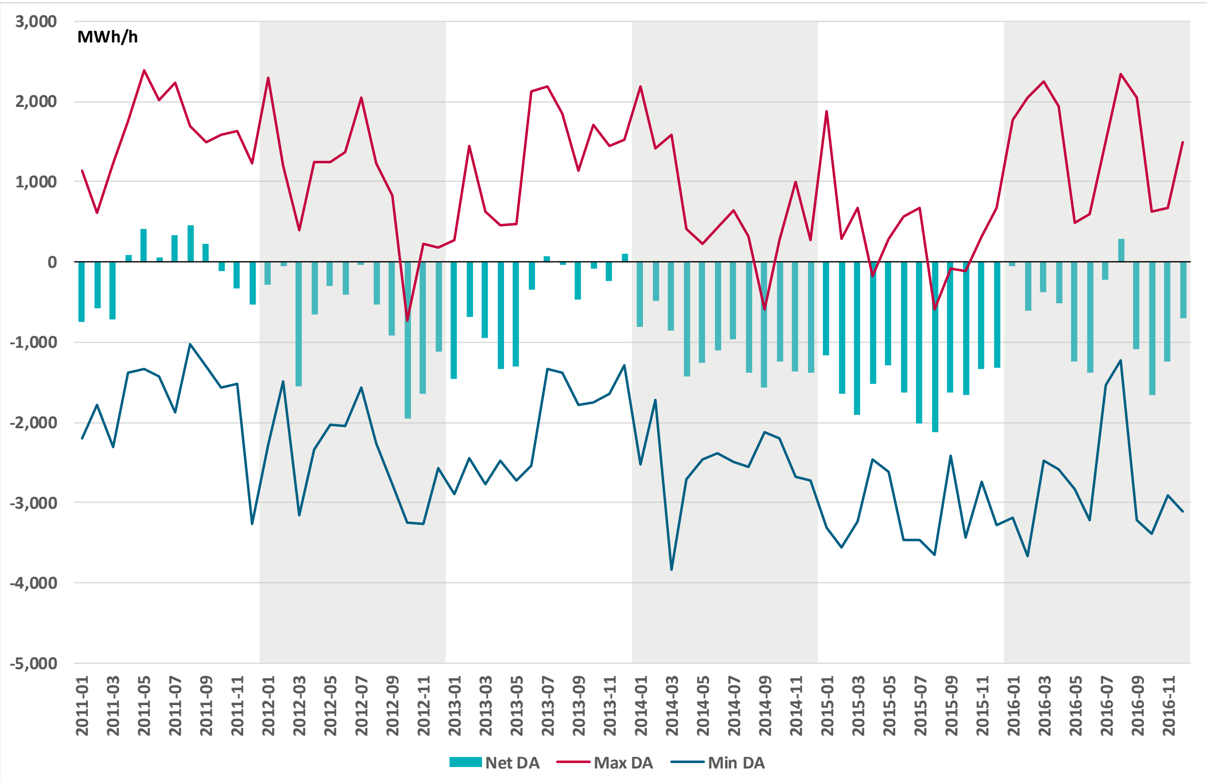


Figure 71 : Monthly averaged Belgian day-ahead Net Position (bar), maximum export Net Position (line, +) and maximum import Net Position (line, -) from 2011 to 2016.
Sources: Elia, CREG

5.3.3. Intraday cross-border exchange

150. We observe the following long-year trends in the intraday cross-border exchange (Table 9):

- The absolute contribution of intraday cross-border exchange on the Belgian net exchange position, expressed in MW, has been steadily rising since 2007. In 2007, the contribution was marginal: on average only 10 MW for export ('Exp-ID') and 8 MW for import ('Imp-ID'). In 2016 this was respectively 114 MW and 136 MW.
- Also the relative share increased. In 2007, intraday cross-border exchange represented only 1% of the export and 0% of the import volume. In 2016 this was respectively 19% of the export and 10% of the import.
- In 2016, the intraday exchanges were lower than the previous 3 years. Because of the lower total import and export volumes in the day-ahead market (which comprises the long term capacity rights) the relative share did not decrease.

Year	Mean Exp-ID	Mean Imp-ID	Mean Net-ID	% Export	% Import
	(MW)	(MW)	(MW)	(MW)	(MW)
2007	10	8	2	1%	0%
2008	41	25	16	8%	1%
2009	47	44	3	4%	5%
2010	56	62	-6	6%	7%
2011	81	110	-29	9%	9%
2012	95	129	-34	12%	7%
2013	139	154	-15	14%	7%
2014	122	139	-17	22%	6%
2015	137	156	-19	45%	6%
2016	114	136	-22	19%	10%

Table 26 : The annual average Intraday Net Positions for all hours (Net-ID), for all hours with an export intraday net position (Exp-ID) and an import intraday net position (Imp-ID) are listed in the first 3 columns. The relative contribution of the intraday cross-zonal exchange in the total export and import volumes is listed in the last 2 columns.
Sources: Elia, CREG

151. Intraday cross-border exchange seems to be used for adjusting volumes rather than for sourcing:

- On an annual basis, the net contribution of the intraday market ('Net-ID'), i.e. the sum of the imported and exported volumes in intraday- is close to zero or marginal: in 2016, only -22 MW (Table 26).
- Also on a monthly basis, the monthly volumes of intraday nominations for import and export are also close to the same, with import slightly outweighing export (Figure 72). As a consequence, the net contribution of the intraday market ('Net-ID') on the monthly net position is rather small : in 2016, it reached a maximum of close to -200 MW in June. Note that in the summer of 2015 and in the summer of 2013, higher monthly averages were recorded (Figure 73).
- On an hourly basis, volumes of intraday nominations vary between typically +1000 MW and -1500 MW, with a record peak of + 1969 MW of exports in January 2016 and a record peak of – 1838 MW in January 2015. The volumes do not show a clear seasonal pattern. The range in which the volumes vary, has remained stable over the last 6 years (Figure 73, Figure 75).

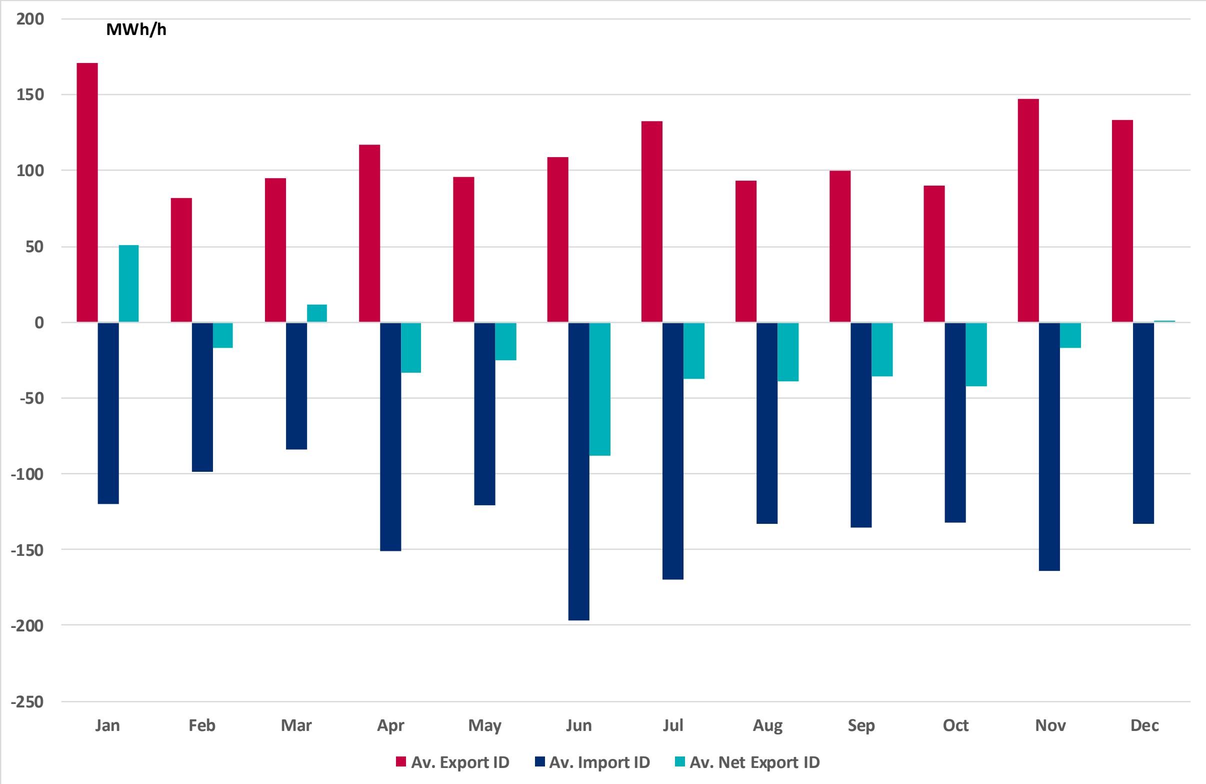


Figure 72 : Monthly averaged values of intraday export nominations (Exp-ID), import nominations (Imp-ID) and resulting intraday net position (Net-ID) for 2016.
Sources: Elia, CREG

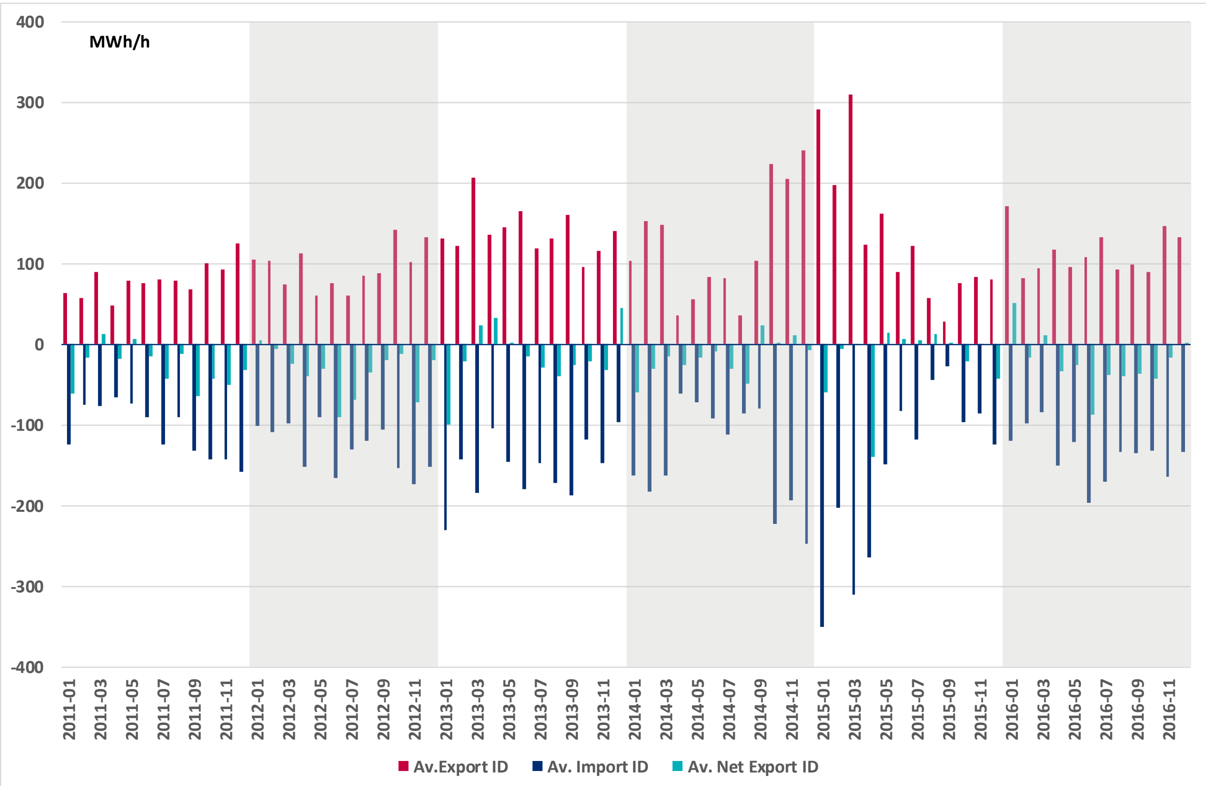


Figure 73 : 10 year evolution of monthly average export and import nominations on the intraday market and resulting intraday net export position.
Sources: Elia, CREG

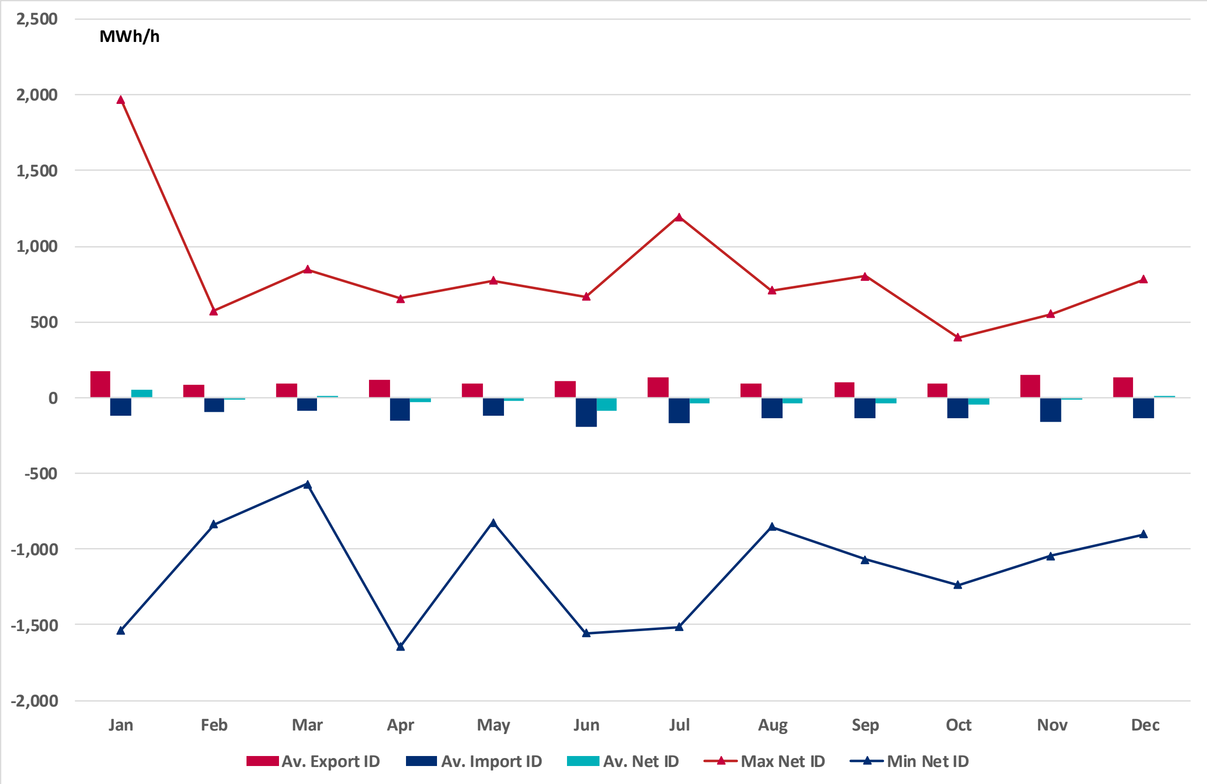


Figure 74 : Maximum intraday net export position (Max of Net-ID) and maximum intraday net import position (Min of Net-ID) for 2016. The averaged values shown in Figure 72 are added for comparison. In January, a 10-year record height intraday net position of +1969 MW was reached (see also Figure 75).
Sources: Elia, CREG

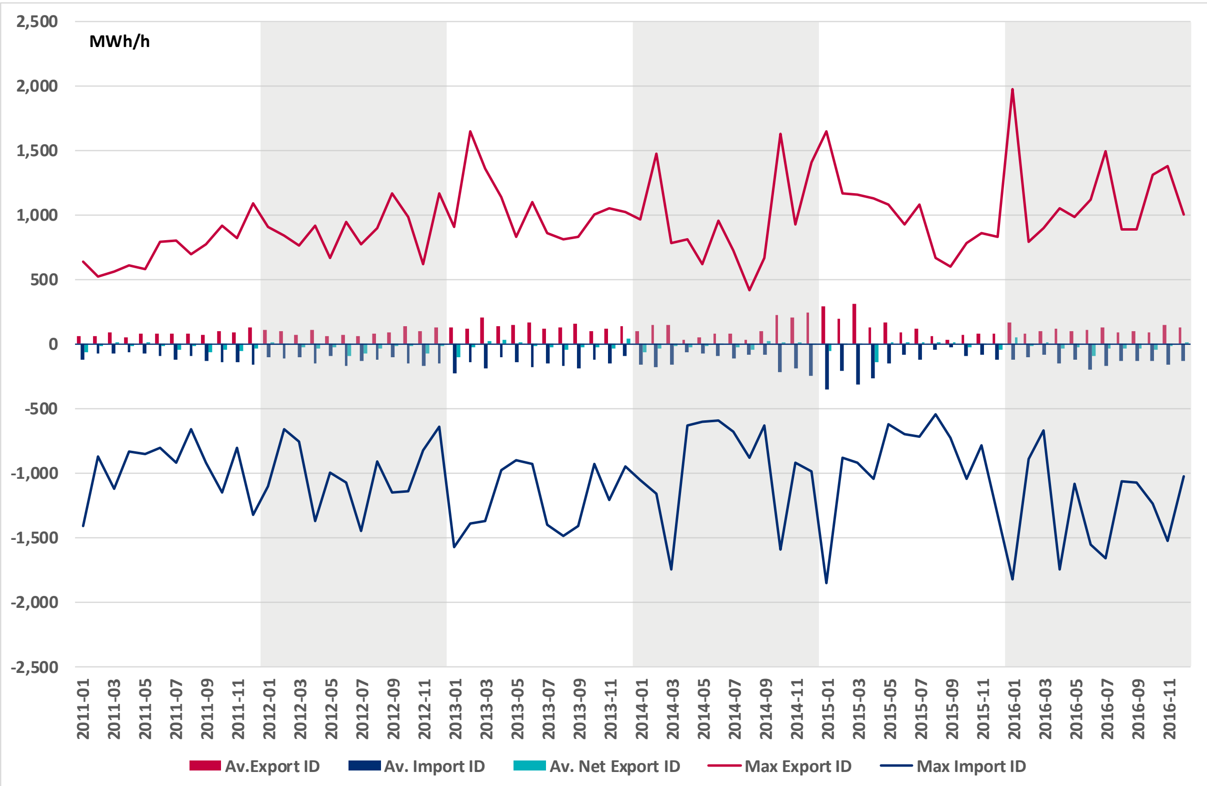


Figure 75 : 10 year evolution of monthly average export nominations (Exp-ID) and import nominations (Imp-ID) and resulting intraday net position (Net-ID).
Sources: Elia, CREG

5.3.4. Overview of commercial cross-border exchanges

152. Figure 76 and Table 27 summarize the contribution of the long term, day ahead and intraday markets in the Belgian import and export volume over the last 10 years. The figures confirm the main findings discussed above: reduced imports in 2016 compared to previous years, the disappearance of long-term nominations since the introduction of FTRs for the long term transmission rights in January 2016, and the modest though increasing share of intraday cross-border trading in the net position. Note that these figures only show the importance of the different markets in terms of average volumes (MWh/h), not in terms of power (MW).

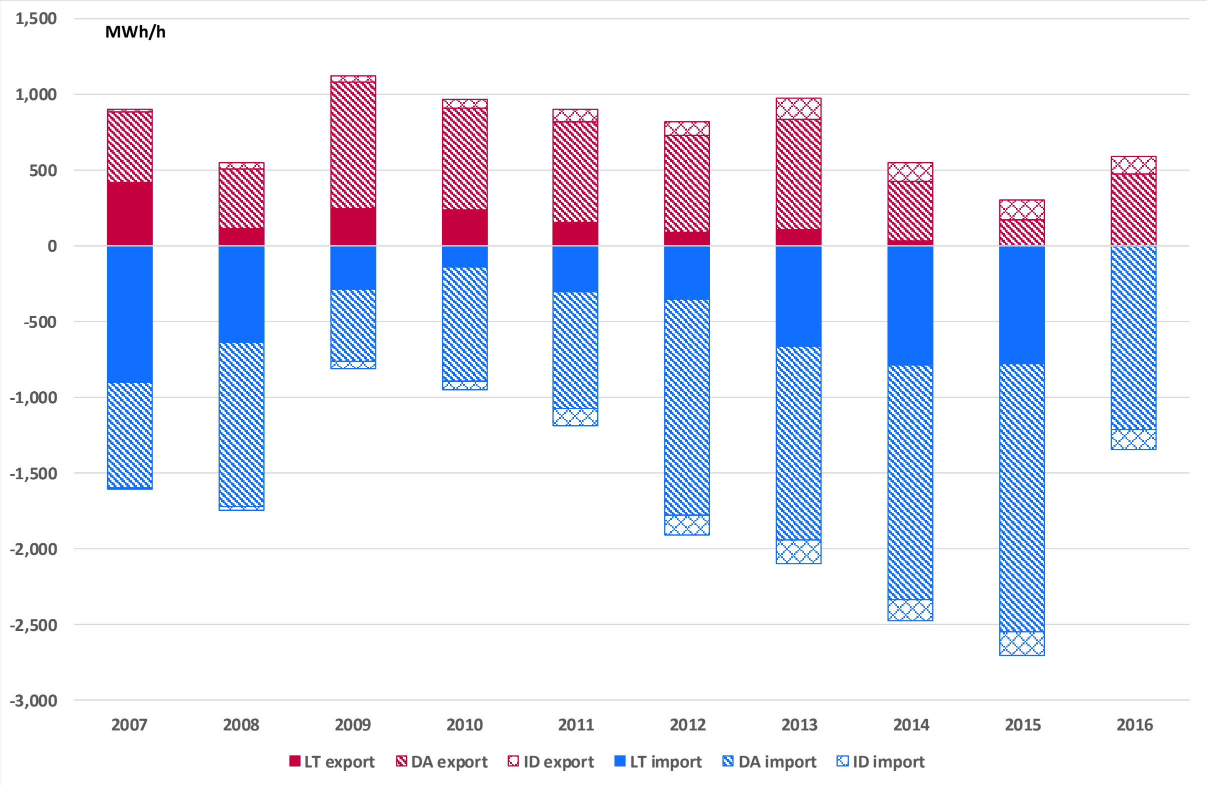


Figure 76 : Imported and exported volumes on the long term (LT), day-ahead (DA) and intraday (ID) markets.
Sources: Elia, CREG

	LT+DA+ID (Volume, TWh)			LT + DA + ID (Average, MW)			Share in Export			Share in Import		
Year	**Export**	**Import**	**Net**	**Export**	**Import**	**Net**	**%LT**	**%DA**	**%ID**	**%LT**	**%DA**	**%ID**
2007	7.88	14.09	-6.22	899	1,609	-709	46%	53%	1%	56%	43%	0%
2008	4.8	15.3	-10.5	546	1,742	-1,196	22%	71%	8%	36%	62%	1%
2009	9.88	7.08	2.8	1,128	808	319	22%	74%	4%	36%	59%	5%
2010	8.5	8.35	0.15	970	953	17	24%	70%	6%	14%	79%	7%
2011	7.91	10.38	-2.47	903	1,185	-282	17%	74%	9%	25%	66%	9%
2012	7.2	16.72	-9.52	820	1,904	-1,084	11%	77%	12%	19%	75%	7%
2013	8.54	18.39	-9.85	975	2,099	-1,124	11%	74%	14%	32%	61%	7%
2014	4.8	21.68	-16.88	548	2,475	-1,926	6%	72%	22%	32%	63%	6%
2015	2.68	23.69	-21.01	306	2,705	-2,398	0%	55%	45%	29%	65%	6%
2016	5.16	11.79	-6.63	588	1,342	-754	0%	81%	19%	0%	90%	10%

Table 27 : Share of the long term (LT), day-ahead (DA) and intraday (ID) markets in the Belgian electricity export and import.
Sources: Elia, CREG

5.3.5. Congestion rents

153. With the ATC method, the calculation of the congestion rents was straightforward, based on the hourly nominated capacities and price difference on each border. With FBMC, the calculation is more complex since the output of FBMC are the zonal net positions, not the nominations on individual borders. Therefore, FBMC requires a post-processing step to determine the congestion rents.

154. In 2016, the congestion rents generated at the Belgian borders were lower than previous years (Figure 77). The congestion rents at the northern border increased because of higher price spreads with the Netherlands, though this increase this was outweighed by the sharp decrease of congestion rents at the southern border linked to the lower price spreads with France.

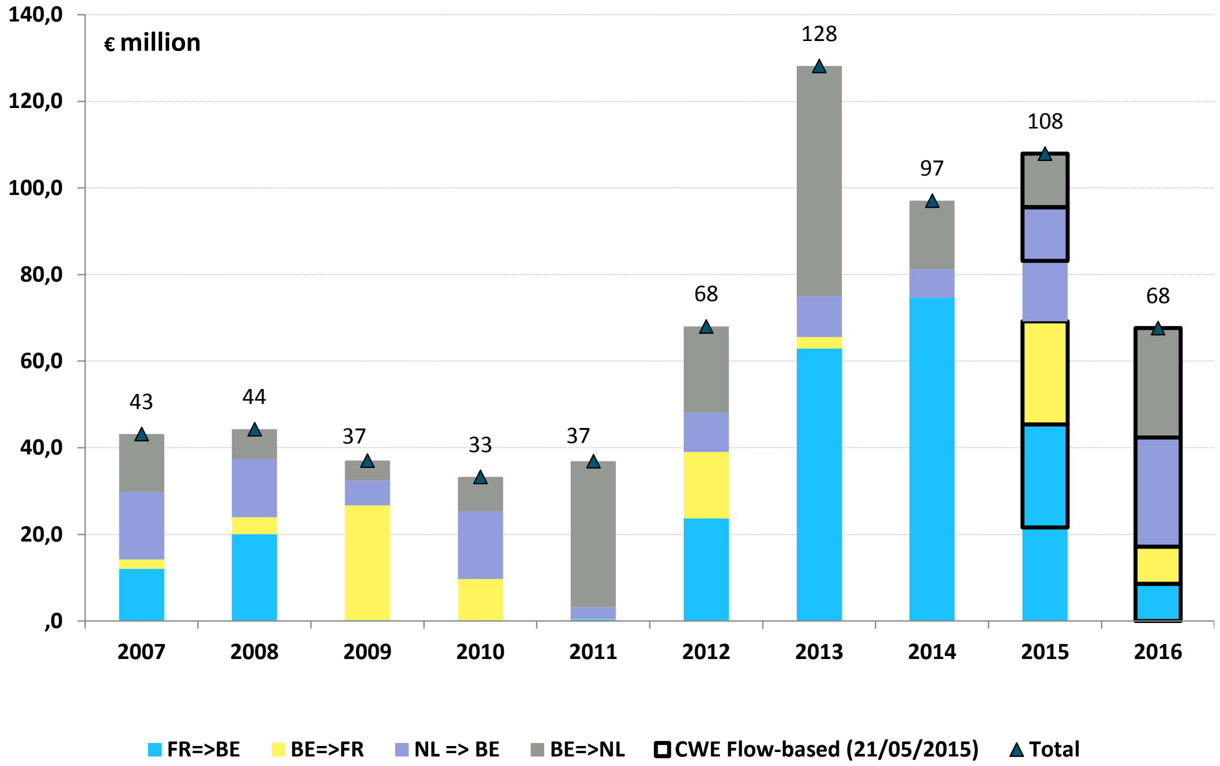


Figure 77 : Congestion rents per border and per direction. For the data with FBMC, the values correspond to the total congestion income generated on the Belgian borders prior to resales. The values do not show how the income is distributed amongst long term transmission rights holders on the one hand and the TSOs of the concerned bidding zones on the other. Source: Elia, CREG

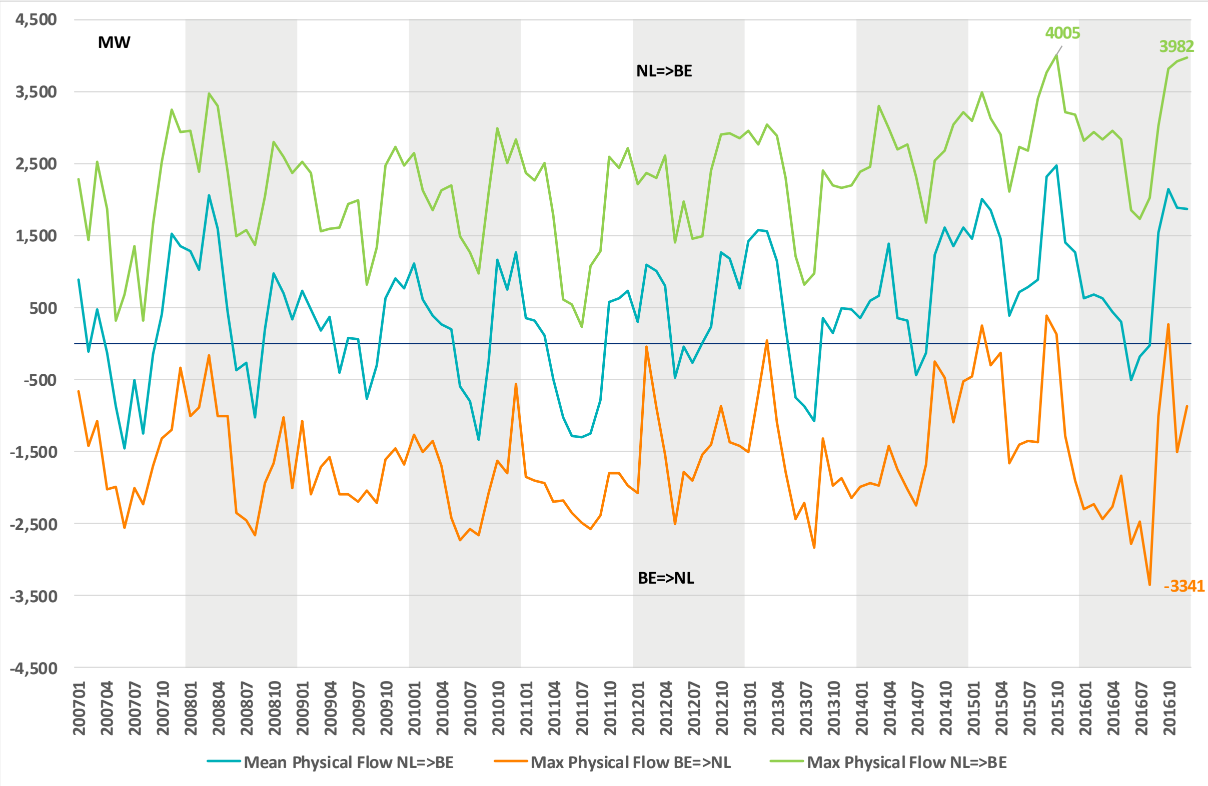
5.3.6. Physical flows

155. Since the go-live of FBMC, physical flows on the cross-border lines reached higher maximum values then previous years (Figure 78). In 2016, the following maxima were reached:

- On the Northern border, a maximum of 3982 MW (NL=>BE) was recorded on 04-12-2016 at 23h and a maximum of 3341 MW (BE=>NL) on 15-08-2016 at 07h.
- On the Southern border, a maximum of 3218 MW (BE=>FR) was recorded on 22-01-2016 at 19h and of maximum of 3962 MW (FR=>BE) on 12-06-2016 at 16h.

High physical flows arise from high volumes of cross-border exchange (Belgian import, Belgian export and Transit Flows through Belgium) and/or high loop flows. The maximum flow of 3858 MW on the

Northern border on 4 December 2016, for instance, corresponded to an hour where Belgium and France were together importing 8640 MW (DA+LT), which is close to the maximum value of 8829 MW of CWE volume exchanged later that month (18-12-2016). The transit flows through Belgium also reached maximums in 2016, as shown in the next Section.



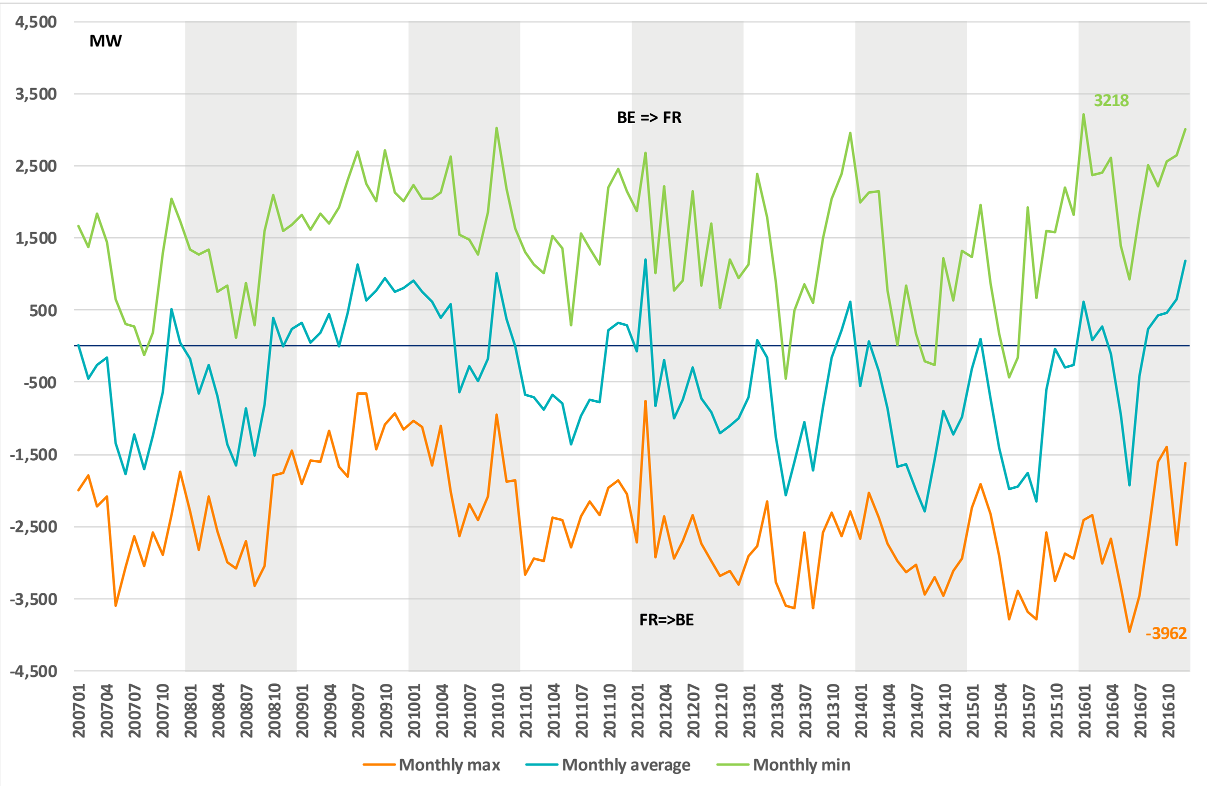


Figure 78: Physical flows on the Northern border (top) and the Southern border (bottom). Positive values indicate physical flows in the North-to-South direction. In 2016, recorded values have been recorded on both borders and in both directions. Sources: Elia, CREG

5.3.7. Transit flows

156. Transit flows are physical flows crossing the Belgian control area, resulting from commercial exchanges between two other bidding zones. With the ATC-method, bilateral commercial exchanges are translated into capacity nominations on individual borders. For some commercial exchanges, this results in a transit flow crossing Belgium from North to South (Transit North=>South). For other commercial exchanges the resulting transit flow crosses Belgium from South to North (Transit South=>North). The net transit flow, shown in Figure 79, is the resultant of all transit flows. Positive flows indicate a resultant flow in the North-South direction.

In 2016, transit flows reached record values in both the North-South and South-North directions:

- On 1 May 2016 at 17h, the transit flow from South to North reached a maximum of 4245 MW. At that hour, France was the only exporting country. The CWE Net Positions (DA+LT) at that hour were: BE -1322 MW, NL -4249 MW, FR +5751 MW and DE/AT/LU 181 MW. The measured physical flows on the Southern border were 2381 MW in the direction FR=>BE and 1121 MW on the Northern border in the direction BE=>NL.
- On 17 December 2016 at 05h, the transit flow from North to South reached a maximum of 2302 MW. At that hour, total CWE cross-border exchanged volume (DA+LT) was very high, 7045 MW, with all exports going to France. The Belgian, Dutch and DE/AT/LU Net Positions were respectively 200 MW, 3164 MW and 3680 MW. The physical flows reached 2922 MW (BE=>FR) on the Southern border and 2709 MW (NL=>BE) on the Northern border.

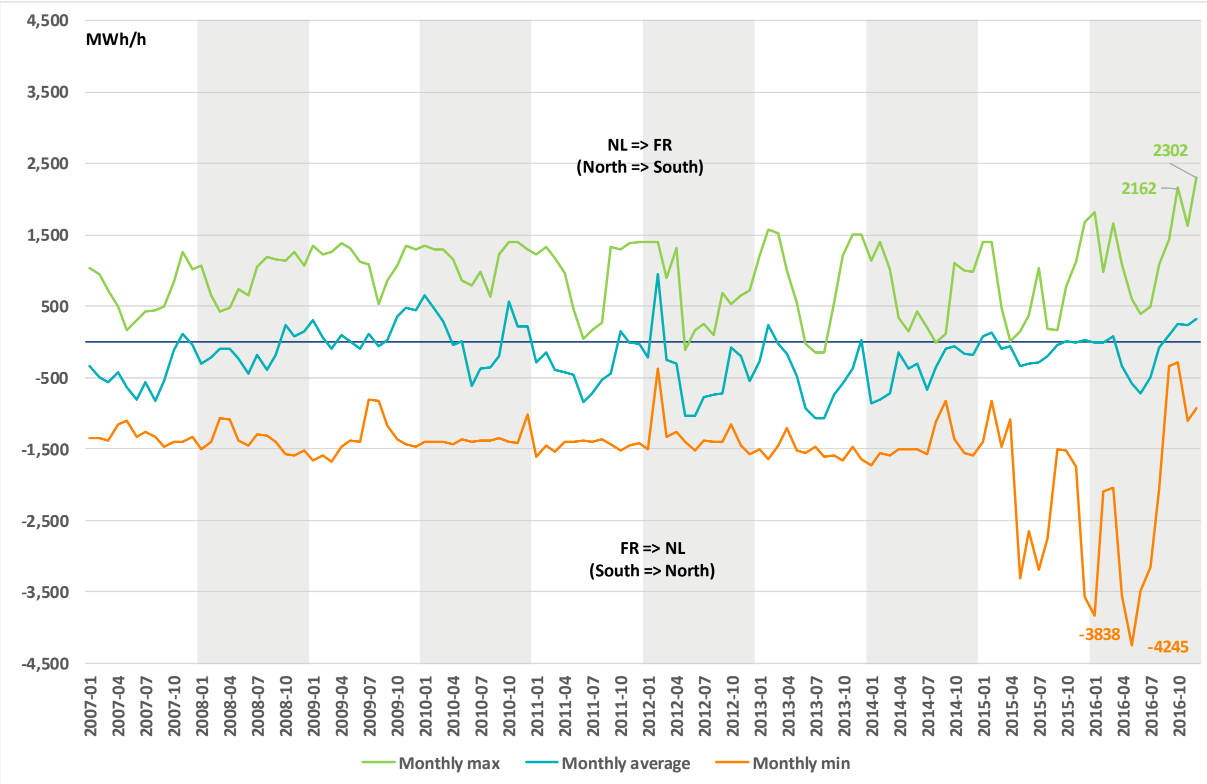


Figure 79: Monthly average, maximum and minimum net transit flows through Belgium. In 2016, record values were recorded in both directions, with the highest values reached in the direction South-to-North. In 2016, transit flows were mainly South-North oriented in summer, when France was exporting, and mainly North-South oriented in winter, when France was importing.
Sources: Elia, CREG

Mean Transit via Belgium (MW)				
Year	Transit NL=>FR (North – South)	Transit FR=>NL (South-North)	Transit Net NL=>FR (Net North – South)	pFR-pNL (€/MWh)
2007	137	-569	-432	-1
2008	144	-281	-136	-1
2009	327	-187	140	4
2010	307	-239	68	2
2011	109	-454	-345	-3
2012	120	-538	-418	-1
2013	140	-597	-457	-9
2014	25	-418	-393	-7
2015	56	-146	-89	-2
2016	**136**	**-236**	**-100**	**5**
Mean	150	-366	-216	-1

Table 28 : Mean transit flows via Belgium from 2007 to 2016. Transit flows in 2016 were higher than in 2015 in both the North-South and the South-North direction. Note that since 2015, with FBMC, transit flows are calculated from the combination of zonal Net Exchange Positions, whereas in ATC these were calculated from the individual zone-to-zone commercial exchanges. With FBMC, individual zone-to-zone commercial exchanges cannot be uniquely defined.
Sources : Elia and CREG

Net Position in day-ahead + long term (MW)				
2016	**BE**	**NL**	**FR**	**DE/AU/Lux**
Jan	-58	-1,024	-1,571	2,653
Feb	-601	-1,378	-1,708	3,687
Mar	-377	-1,138	-1,600	3,116
Apr	-513	-1,488	245	1,756
May	-1,248	-1,995	1,577	1,666
Jun	-1,373	-2,438	2,874	937
Jul	-216	-2,379	157	2,438
Aug	296	-1,306	-724	1,734
Sep	-1,091	-156	-1,284	2,531
Oct	-1,655	553	-1,777	2,879
Nov	-1,235	21	-2,487	3,700
Dec	-701	324	-2,521	2,897

Table 29 : Monthly average Net Positions of the 4 CWE bidding zones in 2016 resulting from the CWE day-ahead and long-term commercial exchanges. In 2016, except for August, Belgium was net importing in all months. In December, net import volumes were lower, despite higher export volumes from the Netherlands – because of a reduced export position of the German bidding zone and an increased import position of the French bidding zone.
Sources : Elia and CREG

157. Table 28 shows the annual mean transit flows in both directions and the resulting net transit flow, arising from all CWE cross-zonal exchanges (long-term, day-ahead and intraday). Note that with FBMC, one obtains the Net Transit flows resulting from the set of zonal Net Positions. The decomposition of this Net Transit flow into Transit NL=>FR and Transit FR=>NL is not uniquely defined and is therefore somewhat arbitrary.

158. Since 2011, the transit flows through Belgium are predominantly South to North (Table 28). This was also the case for 2016, despite France having been net importing during 8 of the 12 months (see Table 29).

5.3.8. Loop flows

159. Since 1 January 2017, the loop flows through the Belgian zone are published on a daily basis on the Elia website[41]. The calculation methodology adopted by Elia is based on data from the FBMC process. The loop flows are calculated based on the D2CF files of the base case. The calculation method is published on the Elia website.

160. Loop flows correspond to physical flows observed on a network element resulting from domestic exchanges inside another bidding zone. They correspond to externalities for economists. As discussed before, all commercial exchanges give rise to physical flows. Not all are considered to be "externalities". Physical flows arising from commercial exchanges *between bidding zones* (long term, day-ahead, intraday) are not. They are considered as competitive flows since the commercial exchanges go in competition for the use of the network transmission capacity. Physical flows arising from commercial exchanges *inside another zone*, by contrast, get a priority access to the grid and are present in the base case. This priority access is not only market distorting, it also creates inefficiencies at the grid management level. The loop flows originating from exchanges inside other bidding zones create uncertainty for which system operators take safety margins. In turn, these safety margins reduce the capacity available for commercial exchange. It is therefore important to closely monitor the level of loop flows.

161. Figure 80 shows the loop flows through Belgium calculated by Elia since the start of FBMC (May 2015 to December 2016). Most of the hours, the resultant of all loop flows generated in the CWE zones through Belgium, flows in the North-South direction. For the given monitoring period, the value of loop flows through Belgium is Gaussian distributed with a mean of +873 MW (North=>South) and a standard deviation of 514 MW. Recorded maximums are +2459 MW (North=>South) and -1010 MW (South=>North).

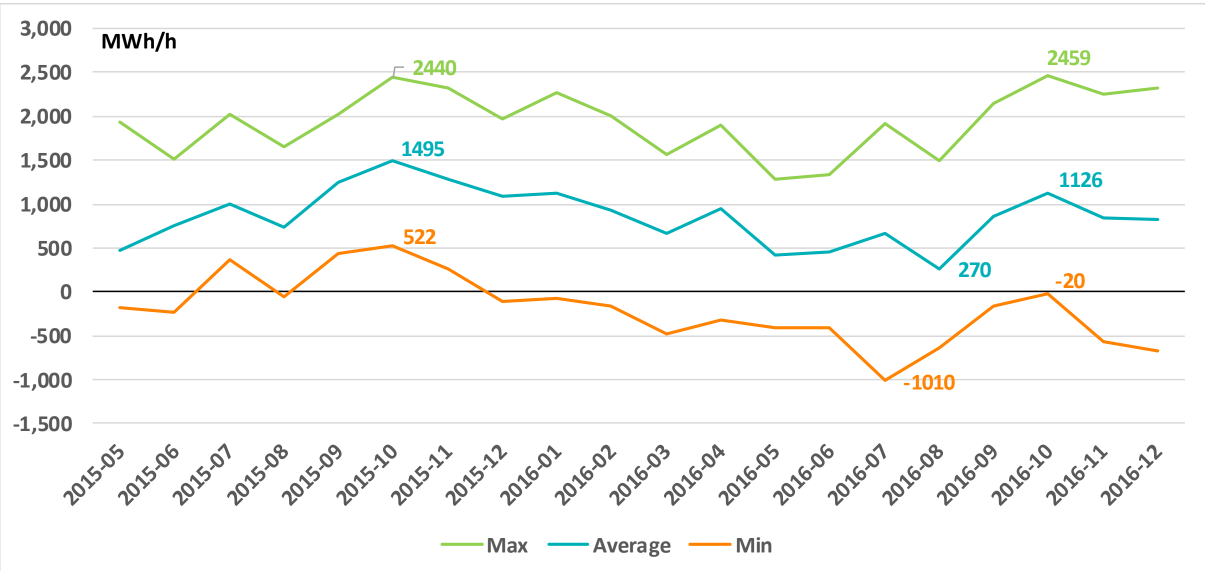


Figure 80 : Maximum, minimum and monthly averaged loop flows through Belgium, forecasted in D-2. Positive values indicate loop flows in the direction North-to- South.
Sources : Elia and CREG

[41] See Elia website, Data download, Category "Interconnection" on http://www.elia.be/en/grid-data/data-download.

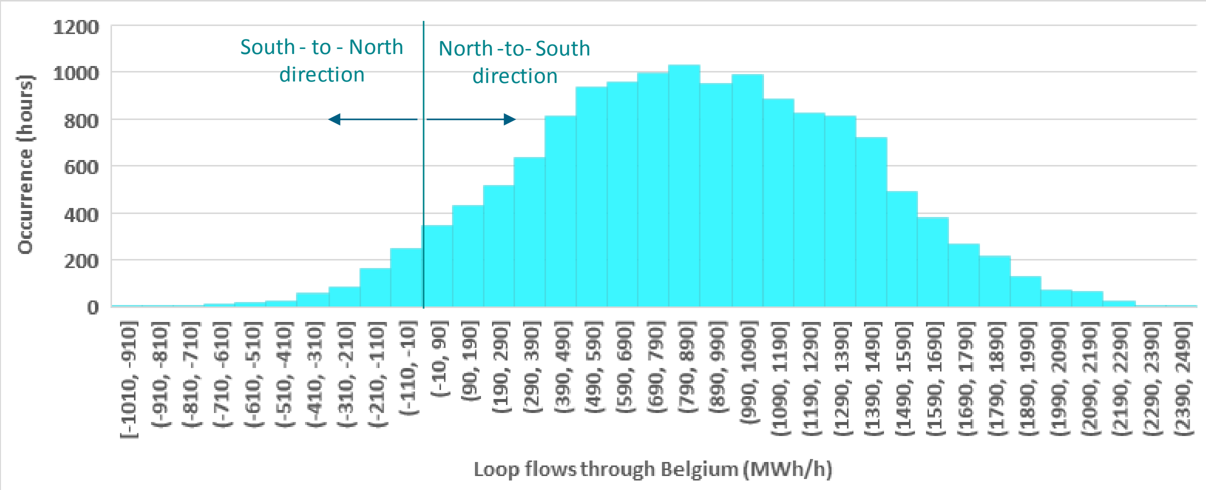


Figure 81 : Histogram of the loop flows through Belgium (05/2015 – 12/2016) shows a Gaussian-like distribution with an average of +873 MW and a standard deviation of 514 MW. Positive values indicate loop flows in the direction North-to- South. Sources : Elia and CREG

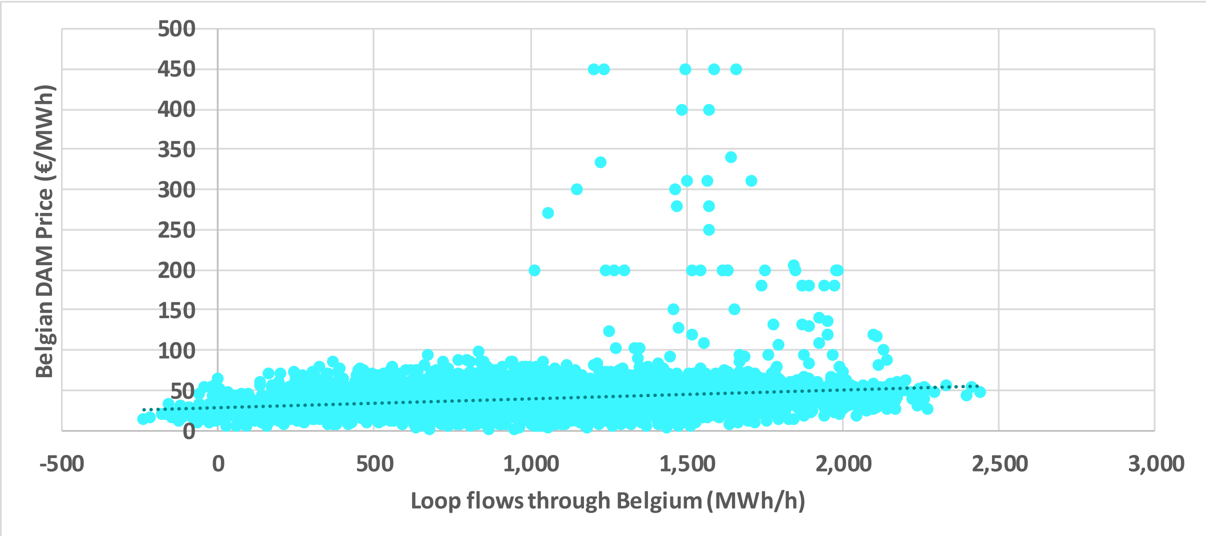


Figure 82 : Belgian day-ahead prices versus D-2 loop flows for all hours in the monitoring period July 2015 to December 2016. Positive loop flows indicate physical flows crossing the Belgian network from North to South. Price spikes above 100 €/MWh have only been observed when the D-2 loop flows through Belgium were above 1000 MWh/h.
Sources : Elia and CREG

162. Since the go-live of FBMC, price spikes on the Belgian day-ahead market have only occurred in hours with high loop flows, i.e. 1000 MW and more (Figure 82). This finding is remarkable and is in line with the results of the CREG Study on “the price spikes observed on the Belgian day-ahead spot exchange Belpex on 22 September and 16 October 2015”[42]. This study concluded that loop-flows through Belgium were the at the origin of these price spikes. Indeed, even if the Belgian physical imports were coming from France, it was the North border of Belgium which was overloaded in the North-South direction due to loop-flows in the same direction. These results were confirmed by Elia.

[42] CREG Study CDC-1520: http://www.creg.info/pdf/Studies/F1520EN.pdf.

6. BALANCING

6.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

163. This section presents some significant events of the balancing design evolution in Belgium for the period 2012-2016, while the next sections show the evolution of some key indicators related to balancing energy markets for the same period.

- **2012**
  - Introduction of single marginal price for imbalance tariffs.
  - End of June: introduction of a virtual resource with 0 MW capacity activated at a price equal to €-100/MWh in periods where all resources for downward activation are activated and additional decremental activations are needed.
  - October: start of the participation of ELIA control block to IGCC.
- **2014**
  - Introduction of asymmetrical products for R1, opening the R1 market to demand response.
  - Introduction of monthly auctions for a part of the R1 and R2 volumes to be contracted.
  - Introduction of R3 DP product.
  - Introduction of a special tariff for the hours where strategic reserve is activated: €3,000/MWh in case of shortage of injection bids to reach the clearing of the DAM and €4,500/MWh in case of structural shortage and technical trigger in intraday and real time.
- **2015**
  - Extension of monthly R1 and R2 auctions to the whole volume to be contracted.
- **2016**
  - Introduction of monthly auctions for a part of the R3 volumes to be contracted, excluding R3 ICH product.
  - August: Full opening of all R1 products: any supplier is allowed to participate in all primary control services, irrespective of the connection point of the resource involved.
  - August: introduction of weekly auctions for the whole volume of R1 and R2 to be contracted; access of Elia (purchase) and the market participants (sale) to the Regional (AT-BE-DE-NL) Auctions Platform for R1 for the R1 standard product (symmetrical R1 200 mHz).

6.2. SPECIAL TOPIC: SHORT TERM AUCTIONS RESULTS

164. The current section shows and analyses the average monthly auction price for the reservation of FCR, aFRR and mFRR capacity in short term auctions.

6.2.1. FCR and aFRR

165. In 2016, short-term auctions were organized by ELIA for the procurement of the whole volume of FCR and aFRR. From January up to July, auctions were organized monthly and from August onwards,

they were organized weekly. During the latter period, a part of the FCR was bought on the FCR Regional Platform. Belgian market participants introduced 8 bids for the weekly auctions of weeks 31 to 52 on that Platform, of which 1 bid was selected by the Platform.

166. Figure 83 shows the evolution of the monthly average auction price for each of these services in 2016.

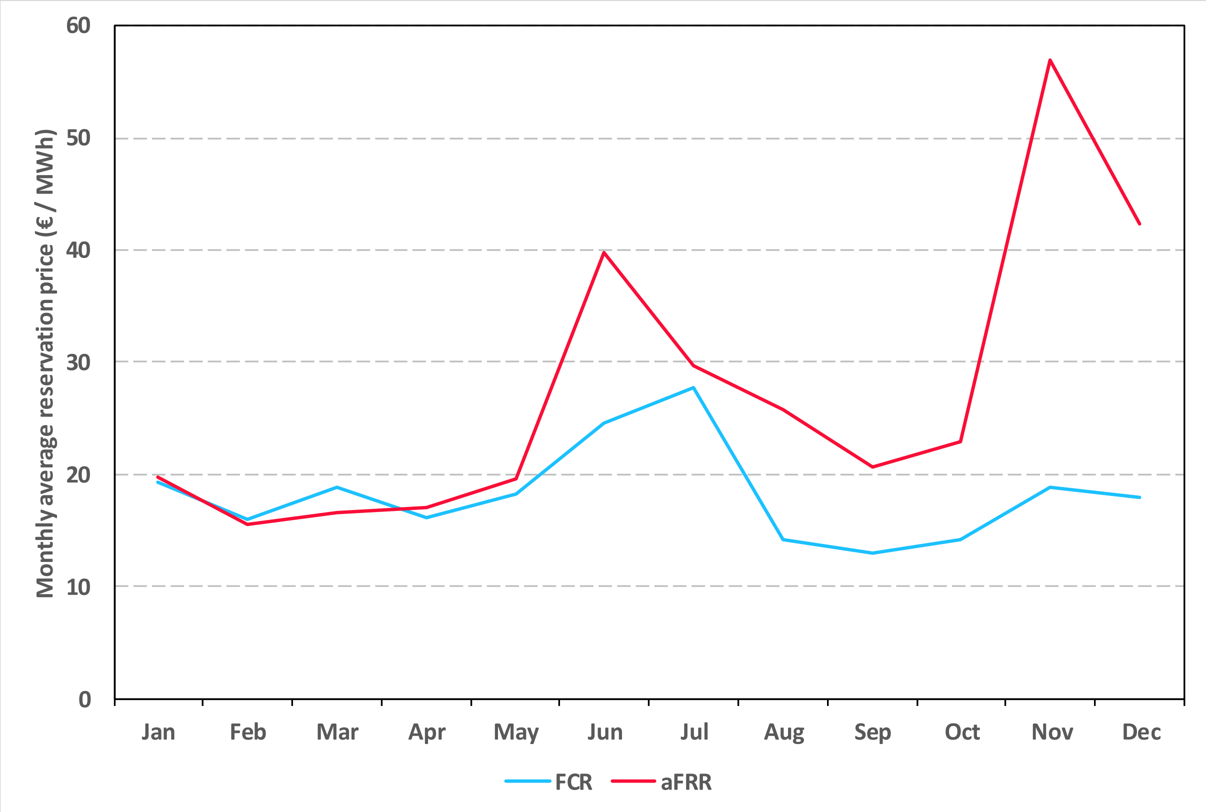


Figure 83: Monthly FCR and aFRR average reservation price in 2016
Sources: Elia and CREG

All products combined, the HHI index equated to 1,853 for FCR products and to 4,857 for aFRR products, showing a more liquid and competitive market for FCR than for aFRR.

The total expenses for FCR and aFRR reservation by ELIA was equal to €45.3m, which is 56% of the budget (€80.5m).

167. Figure 84 shows the evolution of the monthly average auction price for FCR and aFRR in 2015 and 2016, as well as the value of the clean spark spread (CSS) the day before the auction. From August 2016 onwards, the auctions were organized weekly and the monthly values are computed as an average of the weekly values weighted by the number of days of the week in the month in question.

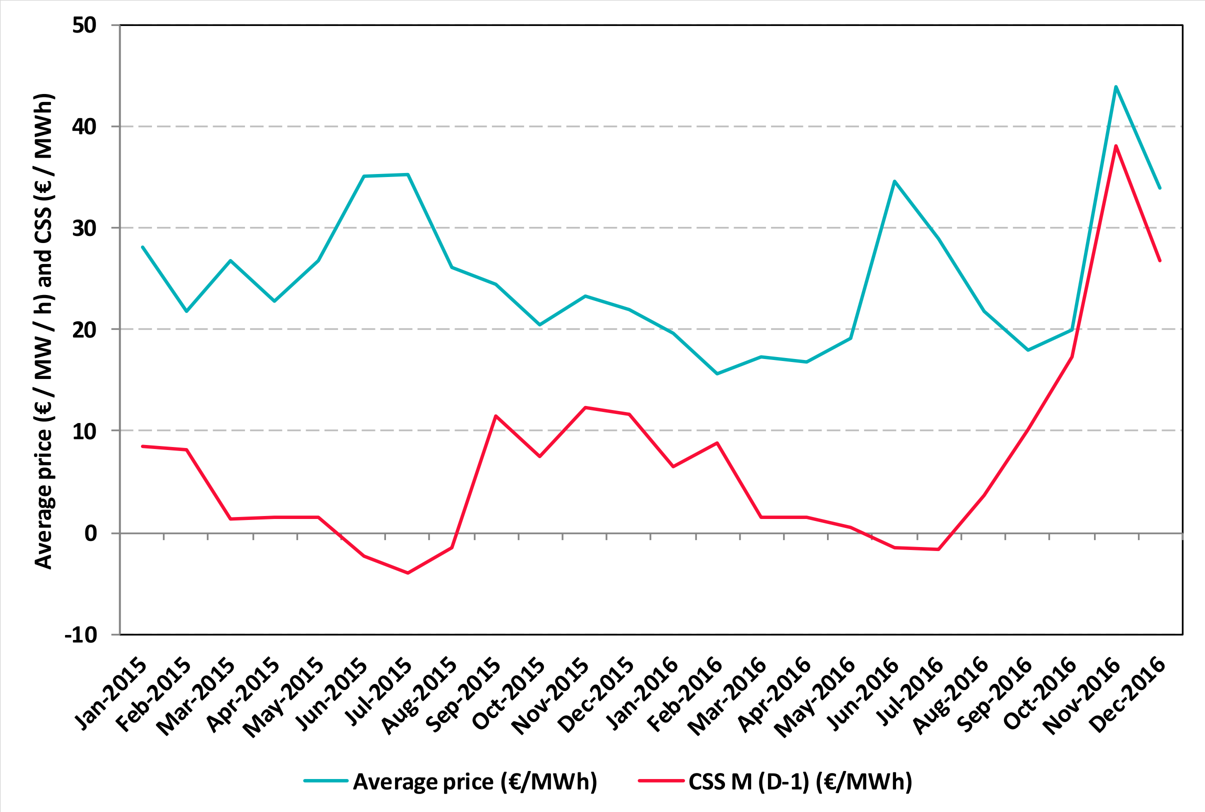


Figure 84: Monthly value of the average price of FCR and aFRR, as well as of the clean spark spread the day before the auction in 2015 and 2016
Sources: Elia and CREG

For June and July 2015, as well as for June 2016, the average price of FCR and aFRR shows a peak (partially) due to the negative value of the CSS. Another peak appears in November and December 2016, due to the high value of the CSS, and consequently a large value of the opportunity cost. The average price for FCR and aFRR, resulting from the yearly auctions of 2013 for the year 2014, was between €40 and 50/MW/h.

168. Figure 85 shows the weekly evolution of the price of the FCR bought on the regional platform. The red curve shows the price used by ELIA in the local auction to simulate the FCR bought on the platform (last price known from the platform at the date of the local auction) and the blue curve shows the actual price from the platform.

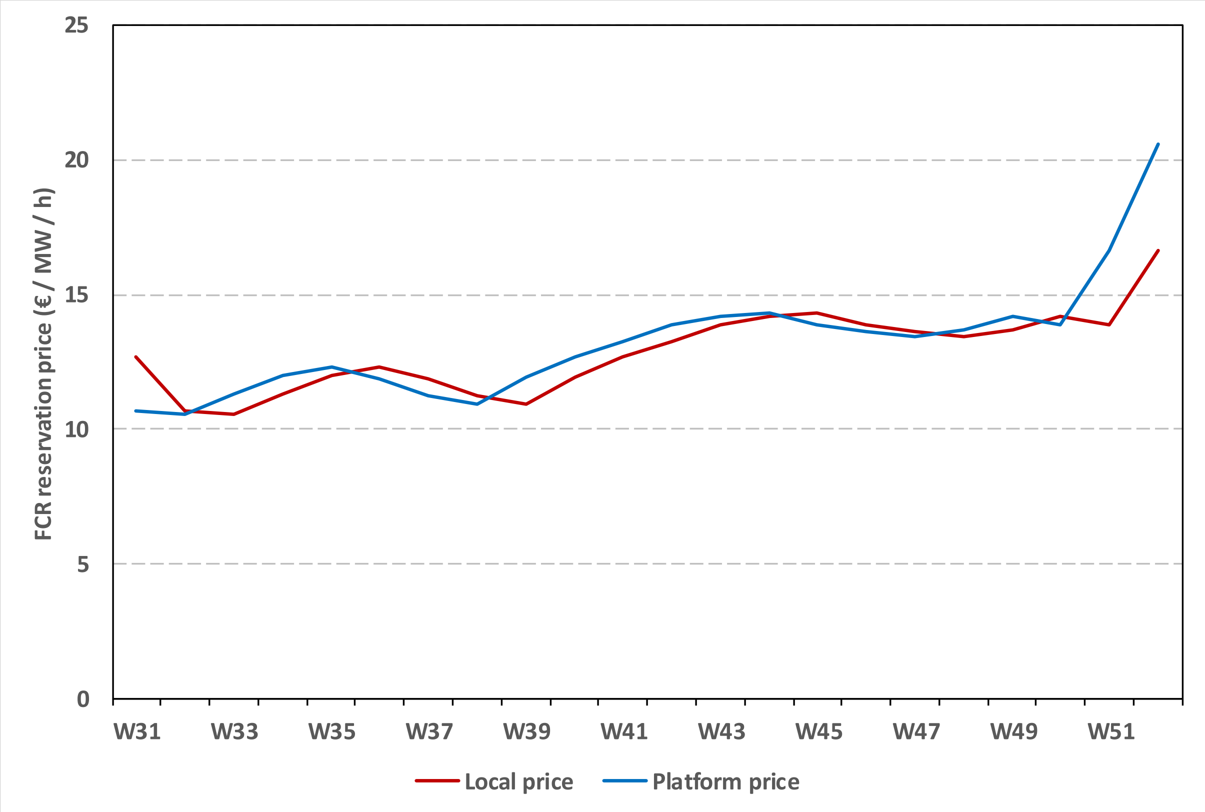


Figure 85: Prices for volumes of FCR bought on the platform
Sources: Elia and CREG

The largest differences between both prices happen for the first week of the Belgian participation (week 31 of 2016) and for the last two weeks of the year (weeks 51 and 52). As the local price for the virtual bid from the Regional Platform is equal to the price of the previous auction on this Platform, the increase of the difference between both prices at the end of the year indicates an increase of the price volatility on the Regional Platform during the last weeks of the year.

6.2.2. mFRR: R3 production and R3 DP

169. In 2016, monthly auctions were organized by ELIA for the procurement of 70 MW of mFRR, allocated among R3 production and R3 DP products. The proportion of each product is determined by the auction algorithm to minimize the whole procurement cost.

170. Figure 86 shows the evolution of the average monthly auction price for mFRR (R3 production and R3 DP) reservation in 2016: the blue curve shows the average price of monthly auctions (70 MW of R3 production and R3 DP), the horizontal orange line shows the yearly average of those prices, and the horizontal green line shows the average price of yearly auctions (512 MW R3 production and R3 DP).

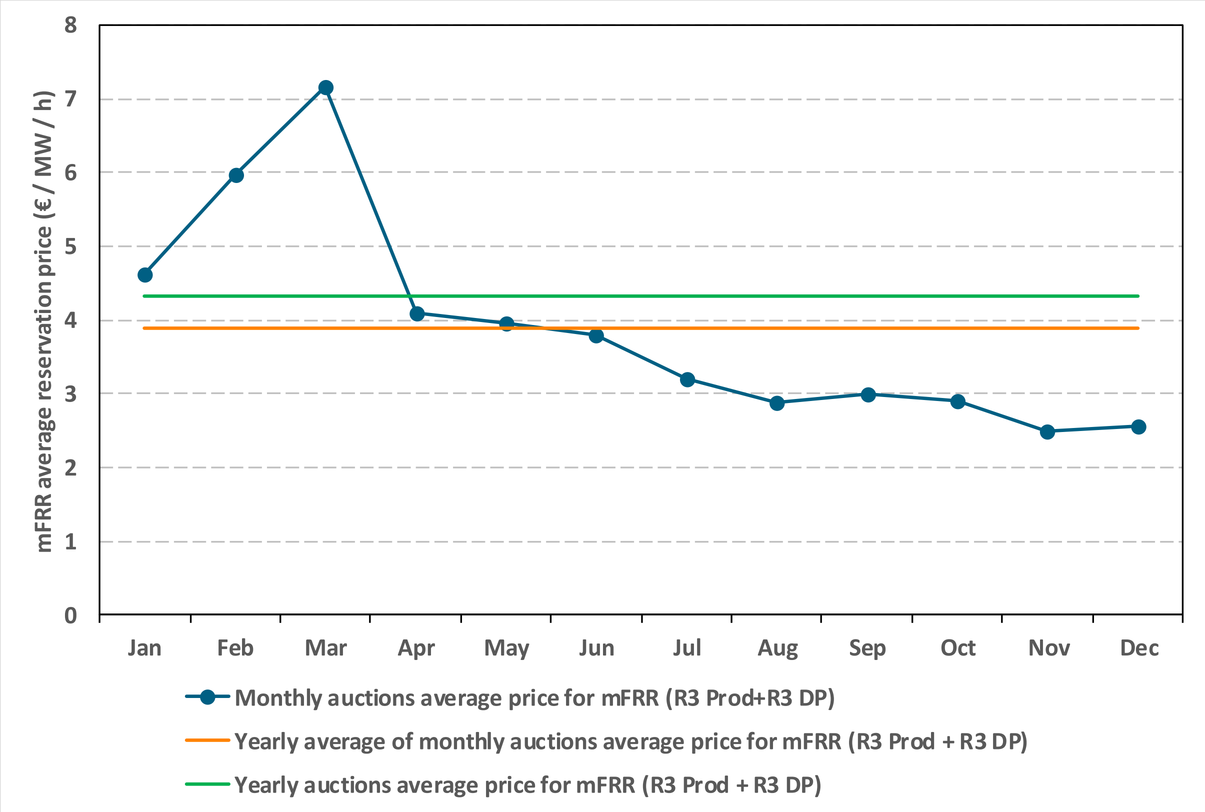


Figure 86: Average mFRR reservation prices for 2016
Sources: Elia and CREG

After a large increase up to March, the average monthly auctions price decreased from April onwards. The average price of the yearly auctions for R3 production and R3 DP in 2016 was equivalent to €4.33/MW/h, and the average price of the monthly auctions for R3 production and R3 DP to €3.88/MW/h.

All products combined, the HHI index was equivalent to 3,343 for the auctions, showing a more liquid and competitive market for mFRR than for aFRR, but less liquid and competitive than for FCR.

The total expenses for mFRR reservation by ELIA during short term auctions was equal to €2.4m, which is 71% of the budget (€3.4m for short term).

171. Figure 87 shows the monthly evolution of the share of volumes of R3 production and R3 DP for the monthly auctions. The blue series shows the volume of R3 production and the orange one the volume of R3 DP. For the first three months, almost the whole volume was allocated to R3 production. From April onwards, the share between R3 production and R3 DP changed from month to month, showing a large volatility in the allocation, and for the months of July, August and November, the whole volume was allocated to R3 DP.

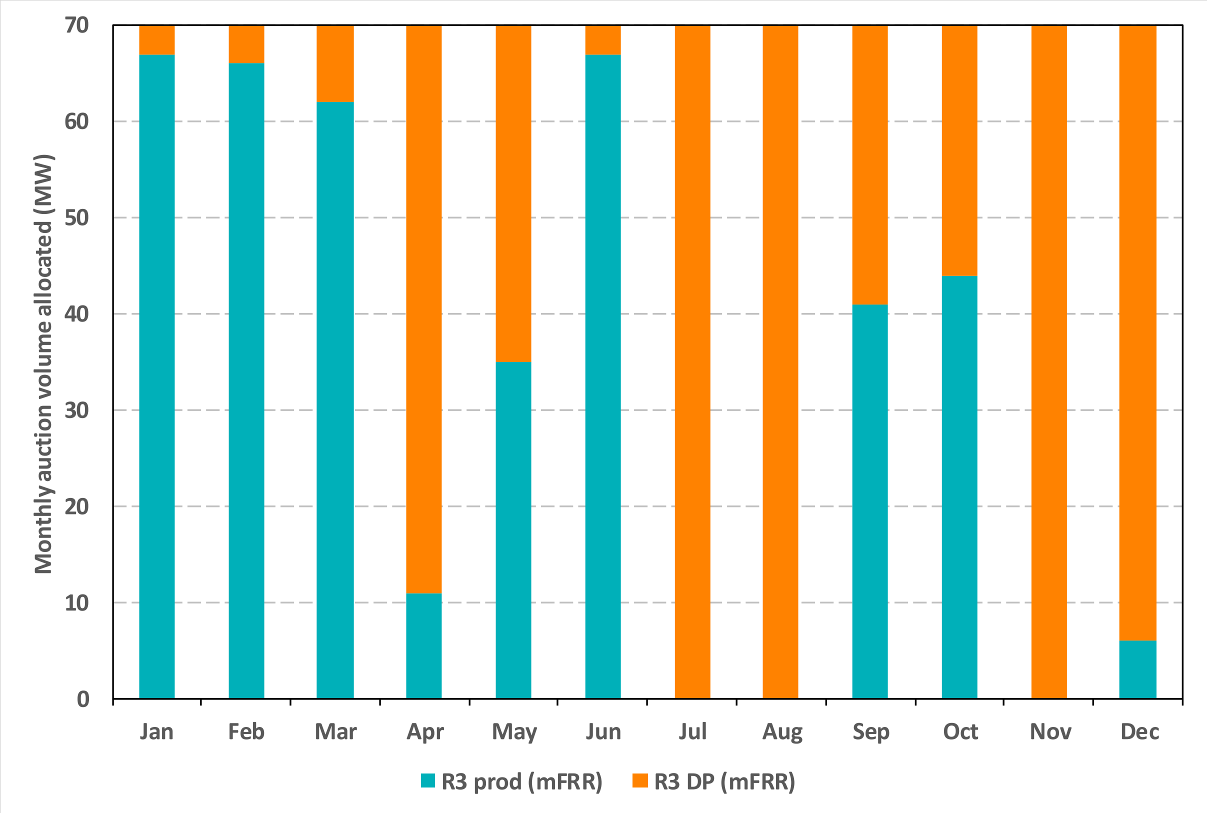


Figure 87: Monthly auction volumes allocated to mFRR products in 2016
Sources: Elia and CREG

6.3. STATISTICS

172. The first section presents the (minimum) volumes that ELIA must buy in the market for 2016, while the next sections show the evolution of some key indicators related to balancing energy markets for the period 2012-2016.

6.3.1. Volumes to buy per type of reserve for 2016

173. The federal grid code requires Elia to propose for the approval of CREG both a methodology to be used to evaluate the volumes of primary, secondary and tertiary control reserves that contribute to guarantee the security, the reliability and the efficiency of the grid in the control zone, and the results of the evaluation.

By its decision (B)150717-CDC-1423 of 17 July 2015, CREG approved the proposal of Elia for the year 2016. The evaluated volumes are given in table 15 below.

Primary and secondary control powers were bought during monthly auctions on a local (Elia) platform from January to June (delivery periods). From August, a maximum of 47 MW of primary control powers could also be acquired by Elia during weekly auctions on a regional platform shared by Austrian, Belgian, Dutch and German control zones. As such, the remaining primary control powers and the whole secondary control powers were also bought from August 2016 during weekly auctions on the local platform.

Type of reserve	Volume (MW)	Delivery period
Primary control power - FCR	73	Month (from January to July) Week (from August onwards)
Automatically activated secondary control power – aFRR	140	Month (from January to July) Week (from August onwards)
Manually activated tertiary control power – mFRR	770	Contract dependent
R3 production + R3 DP	Min 400	Whole year
R3 production	Min 300	Whole year
R3 production + R3 DP	Min 70	Month
R3 ICH	Max 300	Whole year

Table 30: Types of reserves to be bought by Elia for 2016
Sources: Elia and CREG

6.3.2. Balancing tariff and Day Ahead Market price

174. Figure 88 below shows the evolution of the annual average values of the balancing tariffs (in red for the short positions of the ARP and in green for its long positions), as well as (in blue) of the Day-Ahead Market prices, for the period 2012-2016.

A new balancing tariff was launched in 2012, which implemented a single marginal price approach.

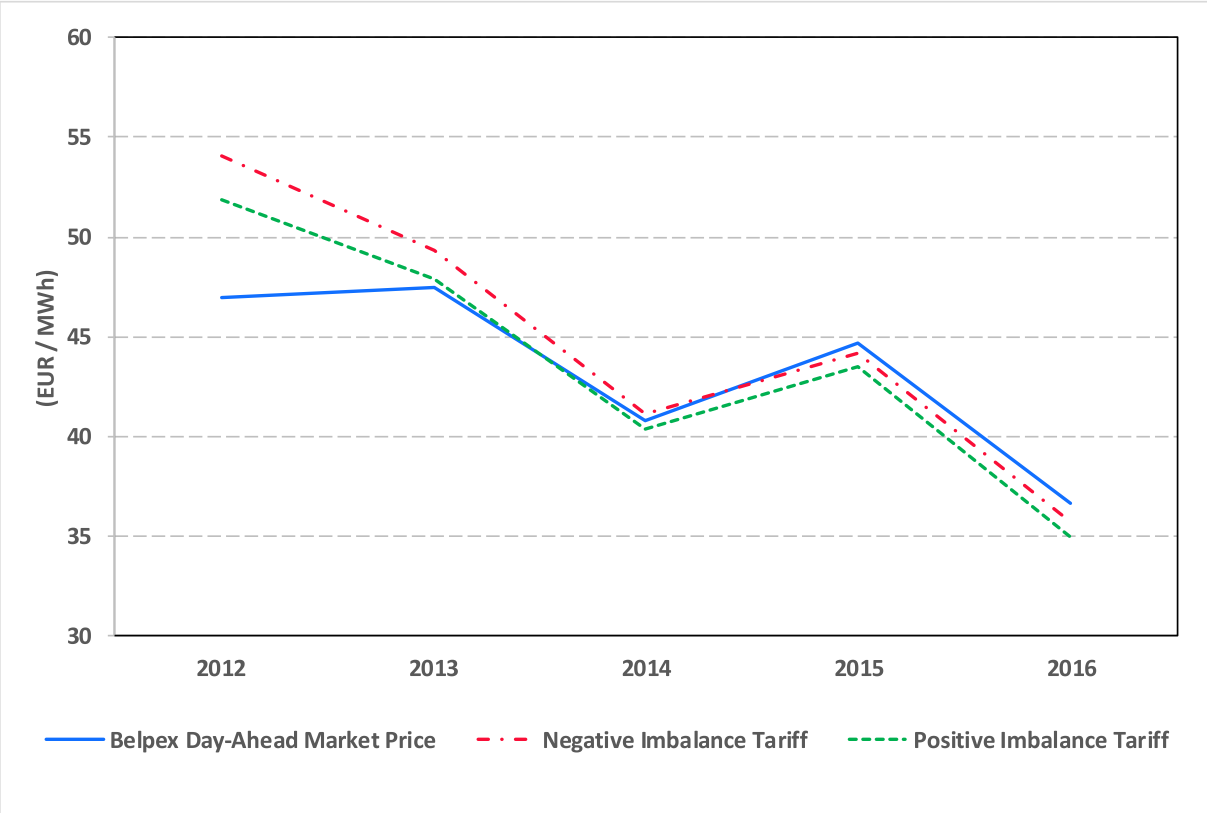


Figure 88: Average balancing tariffs and day-ahead prices
Sources: Elia and CREG

Figure 88 shows, excluding 2015, a decrease of the imbalance tariff, both for long ARP positions and for short ones. Both tariffs are close to each other.

The imbalance tariff follows the trend of the DAM prices.

In 2012, the first year of the single marginal price as imbalance tariff, the imbalance tariffs are about 10% above the DAM price. For the subsequent years, they are closer, with an alternation of years where DAM price is below imbalance tariffs (2012-2013), a year (2014) where DAM price is between the imbalance tariffs and years (2015-2016) where DAM price is above imbalance tariffs.

The difference between the red and green curves shows an average of the α-parameter (α1 and α2) of the imbalance tariff (incentive for the ARP to either be balanced or "help" the system to be balanced).

The figure shows how far the average DAM price is from the real-time price, which is a kind of price for the option of solving the portfolio residual imbalance in day ahead. Before 2014, it was cheaper to solve it in day-ahead. From 2015 onwards, it was cheaper to wait for real time to solve it, for the ARP for whom the assumption of random imbalance volumes is relevant.

From 2015, the figure can be interpreted as a lower value of the flexibility (balancing) with respect to the commodity (DAM). Nevertheless, the flexibility has an intrinsic value because it allows to catch market opportunities, but this intrinsic value cannot be deduced from the figure.

6.3.3. Volatility of balancing tariff and Day-Ahead Market price

175. Figure 89 below shows the evolution of the annual standard deviations of the balancing tariffs (in red for the short positions and in green for the long positions), as well as (in blue) of the Day-Ahead Market prices, for the period from 2012 up to 2016.

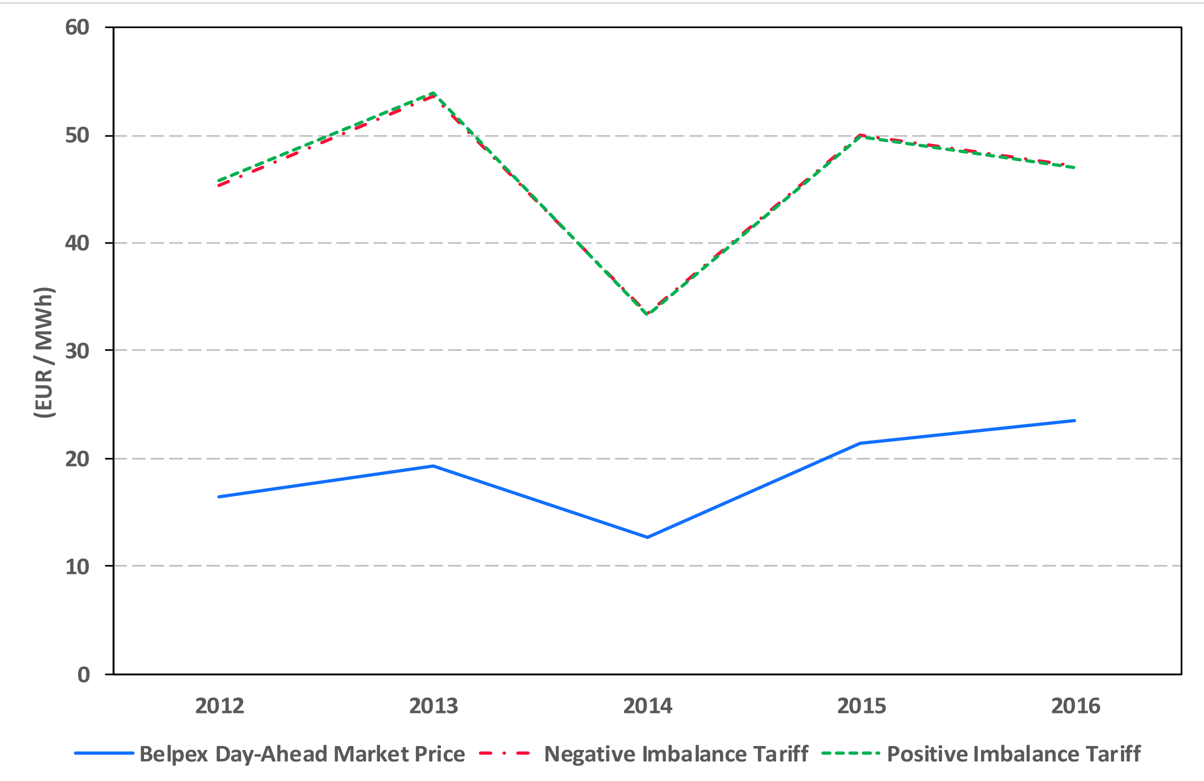


Figure 89: Standard deviation of balancing tariffs and Day Ahead Market price
Sources: Elia and CREG

The figure shows that standard deviation of negative imbalance tariff and positive imbalance tariff are almost the same. This is obvious, given that both tariffs differ only by the value of the incentive α, which is relatively small and often equal to zero.

Comparing the standard deviations of balancing tariff and DAM price shows that their evolutions could be considered as linked from 2012 to 2015, while differing in 2016 when the standard deviation of balancing tariff decreases while the one of DAM price increases with respect to 2015.

The values of the standard deviations of the DAM and the imbalances market tariffs are a picture of these indicators. It is interesting to note that the volatility of balancing tariffs decreases in 2016 while that of the DAM increases.

176. Figure 90 below shows the evolution of the annual coefficient of variation[43] of the balancing tariffs (in red for the short positions and in green for the long positions), as well as (in blue) of the Day-Ahead Market prices, for the period 2012-2016.

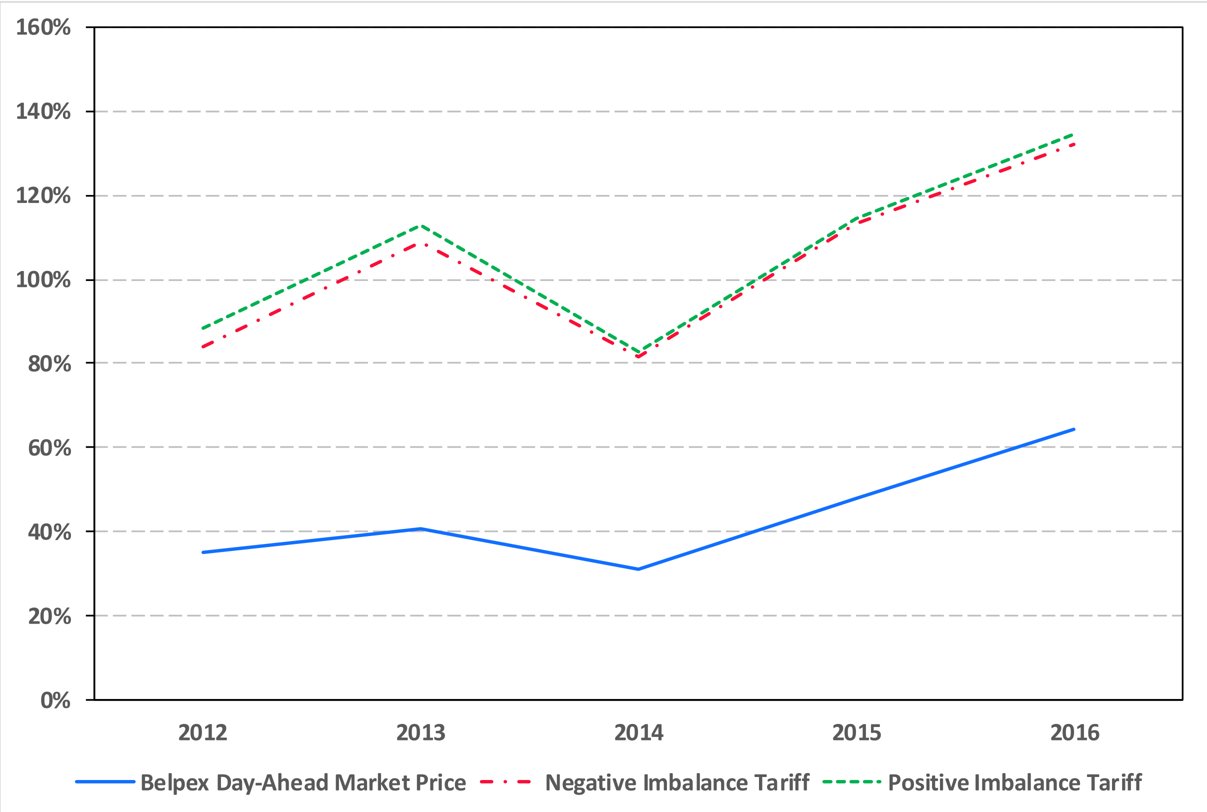


Figure 90: Coefficient of variation of balancing tariffs and Day Ahead Market prices
Sources: Elia and CREG

It is interesting to note that for both 2015 and 2016, the relative value of the volatility increases, showing a trend of an increase of the risk. The next question could be: “will that trend be mitigated in the coming years?”

[43] The coefficient of variation equals the standard deviation divided by the average. It is a picture of the relative value of volatility, as it is scaled with respect to the average value.

6.3.4. Balancing volumes activated

177. As both the balancing market design and the international context evolve from year to year, it is interesting to check the evolution of the balancing energy activated by product type. Figure 91 below shows the evolution of the energy activated annually upward and downwards (when it exists) for each balancing product type. Most relevant product types include R2 (aFRR, in red), "free" R3 bids (in blue) and IGCC (in orange).

Additionally, this figure also shows the total balancing energy activated annually for both upwards and downwards activations, the total energy activated (black line) and the sum of the total energy activated and the energy exchanged through IGCC (blue line).

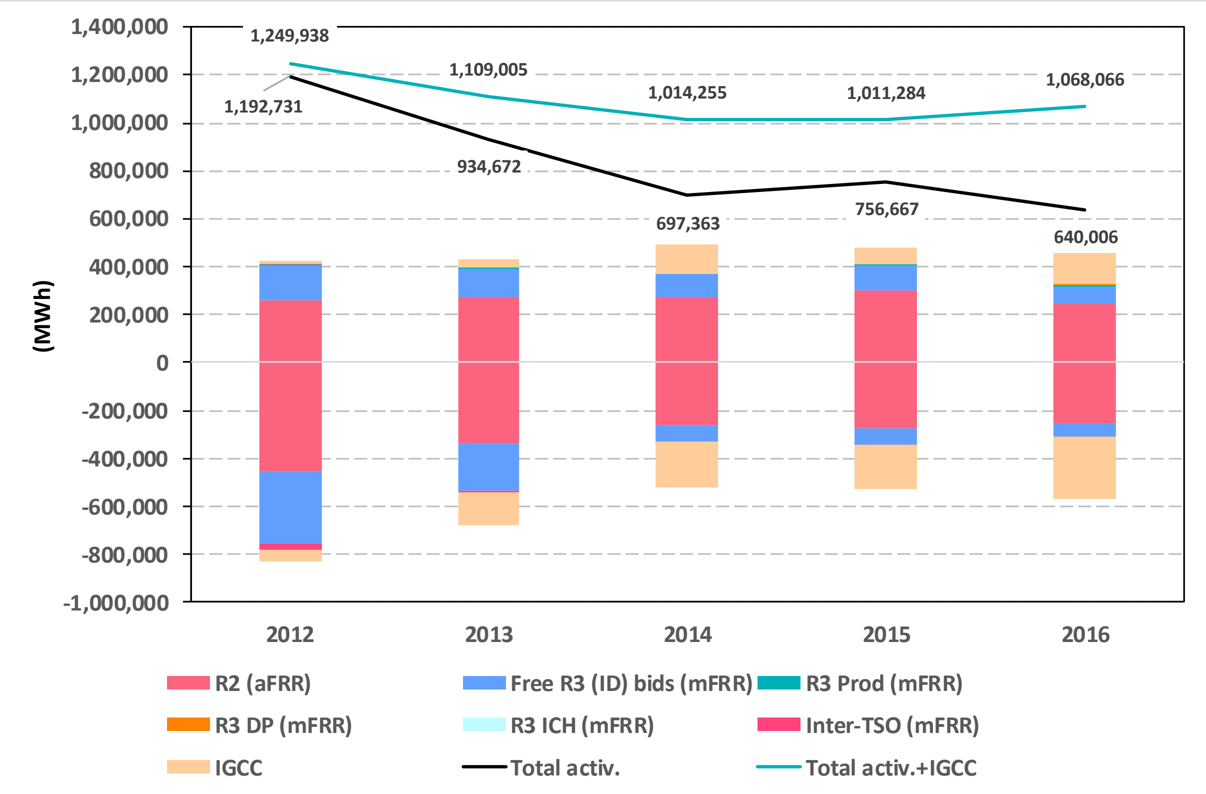


Figure 91: Balancing energy activated by product type
Sources: Elia and CREG

Overall, the figure above shows a decrease of the total activated energy including IGCC until 2015, while that total energy increases again in 2016. On the other side, total activated energy excluding IGCC decreases from 2012 to 2014, increases in 2015 and decreases again in 2016, reaching a lower level than that of 2014.

Regarding the product types, the figure shows the same evolution of both the R2 energy and the free bids energy activated: a decrease between 2012 and 2014, an increase in 2015 and again a decrease in 2016. The evolution of IGCC energy activated is reversed: an increase between 2012 and 2014, a decrease in 2015 and an increase again in 2016, as also illustrated by the difference between the blue and black lines.

Because of the increase in the installed capacity of the intermittent generation, an increase of the system imbalance and therefore of the activated energy could have been expected. The decrease of the black curve in the figure above (total activations, therefore excluding energy exchanged through

IGCC) is due to several factors such as the existence of IGCC, the improvements of the IGCC algorithm, the evolution of the behaviour of the market participants and the evolution of market prices.

6.3.5. Shares of balancing activations

178. Figure 92 below shows the evolution of shares of the energy activated annually, aggregating upward and downward activations when relevant, for each balancing product type. Most relevant product types include IGCC (in orange), R2 (aFRR, in red) and "free" R3 bids (mFRR, in blue). Compared to Figure 91, the order of the series was modified, pushing the IGCC series closer to the X-axis.

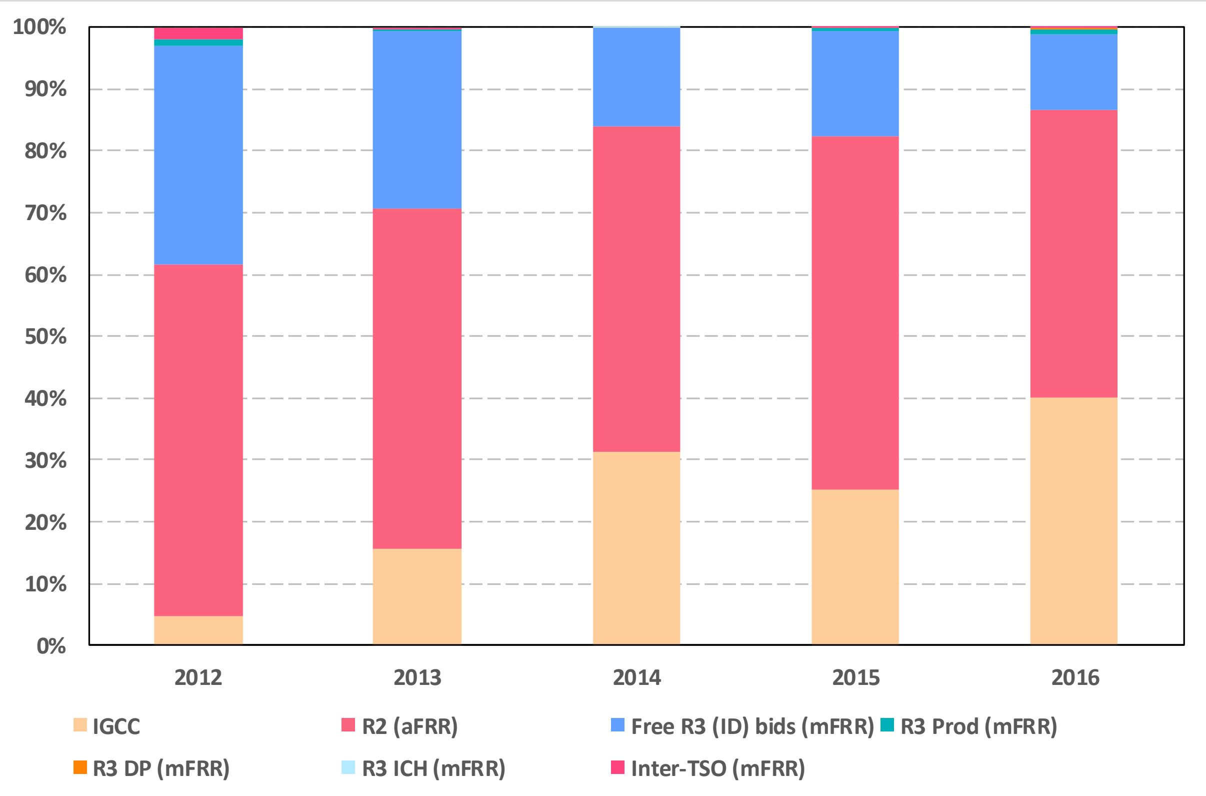


Figure 92: Shares of balancing energy activated by product type
Sources: Elia and CREG

Several observations can be done on that figure:

- Free R3 bids, R2 and IGCC shares cover most of the activation needs of balancing energy. In 2016, they total 98.9%.
- Excluding 2015, the sum of the shares of IGCC and R2 increases every year, reaching 87% in 2016.
- The part of IGCC exchanges in the total of R2 activations and IGCC exchanges increases, rising to 47 % in 2016.

Imbalance netting (IGCC) and secondary control (R2) are closely linked in nature. As they are calculated before activating R2, IGCC exchanges avoid R2 activations and frees R2 capacity for additional activations. As such, IGCC and R2 can be considered as very similar in nature, even if IGCC is not a true activation, but through imbalance netting, a way to avoid physical activations. Both complement each other and their total is relevant to show the increasing importance of the automatic control of imbalance compensation. This also indicated that applying imbalance netting with a positive financial outcome could reduce the need for additional balancing capacity to be contracted beforehand. Elia should assess that in the future stochastic evaluations of contractual reserve capacity needs.

7. CONCLUSIONS

179. For the third year in a row, the Elia Grid Load, a proxy for the Belgian electricity consumption in 2016 was around 77 TWh. This **stabilization of the Belgian electricity offtake** comes after a continuous decline since 2007. At the same time, the estimated solar electricity generation stabilized at about 3 TWh in 2016.

180. In a special topic on electricity consumption, the impact of a massive introduction of electric passenger cars is briefly analysed. **One million electric passenger cars in Belgium will only increase electricity consumption by 4 percent**. This additional consumption will not decrease security of supply, on the condition that electric cars are charged in due time. On top of that, even at a modest introduction, electric cars could themselves become a supply source during peak hours because of the increased storage capacity: **with 100,000 electric passenger cars the existing electricity storage capacity in Belgium would in theory almost double**.

181. Compared to 2015, **electricity generation by Belgian power plants increased sharply** from 55.7 TWh to 69.7 TWh. This is largely due to the return of two nuclear power plants at the end of 2015. However, more nuclear electricity production had no negative impact on gas-fired electricity production. Combined-cycle gas turbines (CCGTs) produced the same amount of electricity in 2016 (12.5 TWh) compared to 2015 (12.4 TWh), but **the load factor of CCGTs in the market increased to 42%** because fewer CCGTs were available. The variability of nuclear production has had no significant impact on gas-fired production; the nuclear production increase leads to decreasing imports.

182. Until the end of September price convergence in Central-West Europe (CWE) was relatively high in 2016. During the last months of 2016, a decrease in nuclear capacity in France and Belgium and limited interconnection capacity in CWE have led to higher prices in Belgium and France, with several hourly price spikes above 500 €/MWh. This **lack of interconnection capacity for cross-border trade is also clearly visible on the forward markets**, where Belgian consumers faced an average year ahead price of 33.4 €/MWh in 2016, compared to 26.6 €/MWh for German consumers. An efficient and fair use of interconnection capacity in CWE is very important to have fair and competitive prices for Belgian consumers.

183. In an elaborate special topic on interconnection capacity, the CREG analyses and explains the functioning of flow-based market coupling. It shows that this market coupling has severe flaws that lead to discriminatory and non-efficient market outcomes. Several internal transmission lines in Germany are frequently and rapidly congested and hence are preventing a fair an efficient internal market in CWE. Most of these internal lines were added to the market coupling algorithm after the go-live of flow-based market coupling in May 2015. **Structurally congested internal transmission lines, mostly situated in Germany, lead to an underperforming and unfair Internal Electricity Market in CWE.**

184. Since 2013, after the introduction of a single price mechanism, the average imbalance tariff (the "real-time electricity price"), is very close to the average day ahead price. This was also the case for 2016. Hence, **the average day ahead price can be seen as a more or less unbiased predictor of the average real-time price**.

185. In 2016, the use of reserves for balancing the Elia grid was 640 GWh (down and up regulation combined), the lowest in more than five years. Activation of about 400 GWh of reserves could be avoided with IGCC, a mechanism through which the imbalance of one country can be netted with other countries participating in the mechanism. Hence, **the IGCC mechanism highlights, also for balancing and reserves, the importance for Belgium to co-operate on a European level in the interest of Belgian consumers**.

For the Commission of Electricity and Gas Regulation:

Andreas TIREZ	Marie-Pierre FAUCONNIER
Director	President of the Executive Committee

8. ANNEXES

8.1. GLOSSARY

3rd energy package : this title groups together

- two directives pertaining to gas and electricity markets ;
- two regulations concerning the access conditions to natural gas networks, and the access conditions to networks for cross-border electricity exchanges;
- the regulation establishing ACER.

Belpex CIM : Belpex Continuous Intra-day Market Segment, a market segment of the Belpex Spot Market where instruments are traded by the continuous matching of purchase orders and delivery orders, without an opening auction, and for which the nomination of contracts is carried out in accordance with the rules of Intra-day Internal Energy Transfer, in the ARP Contract.

Belpex DAM : Belpex Day-Ahead Market Segment', a market segment of the Belpex Spot Market where instruments for which the delivery period relates to a precise hour of the day in accordance with the Exchange Day, are traded via auction following an order accumulation phase, and for which the nomination of the contracts is carried out in accordance with the rules of Day-Ahead Internal Energy Transfer, in the ARP Contract.

Belpex Spot Market : a completely electronic market for the anonymous trading of electricity blocks, organised and managed by Belpex in accordance with the Royal Decree, and regulated by the Market Regulations. The Belpex Spot Market is made up of the Belpex DAM and Belpex CIM market segments.

Consumed capacity, at a given access point and in one quarter of an hour, is equal to the difference, to the extent that it is positive, between the capacity consumed by the loads connected to this access point, and the capacity injected by the local generation associated with this access point. If this difference is negative, the consumed capacity is zero (source: Elia).

Consumed energy, at one access point and for a given period, is equal to the total consumed capacity at this access point over the period of time considered (source: Elia).
E.g. : the consumed energy for a given load amounts to 100 MW for a quarter of an hour, to which a local generation is linked, injecting 40 MW during the same quarter of an hour, is equal to: 15 MWh = max (0, 100 MW – 40 MW) * 15 minutes.

Elia control area is the electric area for which Elia must maintain overall equilibrium between the supply and demand of electricity Elia has various means at its disposal to achieve this, including the secondary and tertiary reserves, as well as reserve agreements concluded with neighbouring system operators. The Elia control area covers Belgium and part of the Grand Duchy of Luxembourg (Sotel network).

The **Elia-grid load** is a calculation based on injections of electrical energy into the Elia grid. It incorporates the measured net generation of the (local) power stations that inject power into the grid at a voltage of at least 30 kV and the balance of imports and exports. Generation facilities that are connected at a voltage of less than 30 kV in the distribution networks are only included if a net injection into the Elia grid is being measured. The energy needed to pump water into the storage tanks of the pump-storage power stations connected to the Elia grid is deducted from the total. Decentralised generation that injects power at a voltage less than 30 kV into the distribution networks is not entirely included in the Elia-grid load. The significance of this last segment has steadily increased during the last years. Therefore Elia decided to complete its publication with a forecast of the total Belgian electrical load. The Elia-grid comprises networks of at least 30 kV in Belgium plus the Sotel/Twinerg grid in the south of Luxembourg. The **total load** incorporates all electrical loads on the Elia grid and in underlying distribution networks (and also includes electrical losses). It is estimated based on a combination of measurements and upscaled values of injections of power plants, including generation in the distribution networks, to which imports are added. Subsequently, exports and power used for energy storage are deducted, leading to an estimation of the actual total load in the Elia-grid and all underlying networks. (source: Elia).

Energy consumption at a given point of access is the energy consumed by the loads connected at this point of access (source: Elia). **Market coupling by prices**. In a system of coupling by price, each market participating in market coupling provides different data to a coordinated calculation system: the transmission capacity available at each border for each direction and for each period; the supply and demand curves for each period; the multi-hour orders "in blocks" submitted by the market participants. Based on this information, the exchanges determine the price and net position for each period, using a calculating algorithm, for each market participating in the market coupling. Since the introduction of market coupling by price, the prices between markets only vary if there is not enough available interconnection capacity between two markets.

If there is a constraint at a given border, this means that the transmission capacity at the border is saturated, which results in congestion rent.

ENTSO-E, the *European Network of Transmission System Operators*, which represents 42 GRTs in 35 countries.

EPEX SPOT is an exchange which manages spot markets for electricity in France, Germany, Austria and Switzerland.

Equivalent temperature is obtained by adding 60% of the average temperature of Day X to 30% of the temperature of Day X-1, and by adding this result to 10% of the temperature of Day X-2 (source : http://www.aardgas.be/professioneel/over-aardgas/nieuws-en-publicaties/graaddagen).

The **Grid Control Cooperation** (hereinafter referred to as "**GCC**") is a collaboration between German GRTs. It aims to optimise the supply and activation of automatic secondary regulation. It is based on the observation that the regulation of different German control areas often act in opposite directions. It aims at balancing between these control areas the use of reserves acting in opposite directions, with the conditions that the resulting capacity flows do not hinder access to the network, and do not jeopardise the security of the network.

The GCC is made up of four modules:

- Module 1: reduction of the use of reserves in opposite directions;
- Module 2: reciprocal support in the event of a lack of secondary reserves;
- Module 3: technical coordination in the area of pre-qualification of a unit;
- Module 4: merit order lists for German control areas.

The decision was taken to leave open the possibility for other control areas to participate in module 1, which is known under the name of **IGCC**. Belgium started to participate in the IGCC in October 2012.

Heating value: there are two types, namely

• the Higher Heating Value (**HHV**) is the thermal energy released by the combustion of 1 kilogram of fuel. This energy includes sensible heat, but also latent heat from water evaporation, which is generally generated by combustion. This energy can be completely recovered if the water vapour released is condensed, in other words if all the evaporated water ultimately ends up in liquid form.

• the Lower Heating Value (**LHV**) is the thermal energy released by the combustion of 1 kilogram of fuel in the form of sensible heat, excluding energy from evaporation (latent heat) of the water present at the end of the reaction.

The difference between the two heating values is significant. The change of state (between vapour at 100°C and water at 100°C) absorbs or releases a significant amount of heat.
To increase the temperature of 1 litre of water by 1°C, 4.18 kJ is required. This is the specific heat value of water (4.18 kJ/kg/°C). Evaporation energy is the energy required to evaporate a substance at its evaporation temperature. The evaporation energy of water is approximately 540 calories per gram, or 2250 J/g (this energy depends on temperature and pressure). This means that to heat 1 litre of water from 0°C to 100°C (418 kJ), 5 times less energy is required compared to evaporating 1 litre of water at 100°C (2250 kJ).

IGCC "International Grid Control Cooperation".

Injected capacity, at a given access point and in one quarter of an hour, is equal to the difference, to the extent that it is positive, between the capacity injected by the associated generation at this access point, and the capacity consumed by the load(s) associated with this access point. If this difference is negative, the injected capacity is zero (source: Elia).

Injected energy, at one access point and for a given period, is equal to the total injected capacity at this access point over the period of time considered (source: Elia).
E.g. : the injected energy for a given load amounts to 40 MW for a quarter of an hour, to which a generation is linked, injecting 100 MW during the same quarter of an hour, is equal to: 15 MWh = max (0, 100 MW – 40 MW) * 15 minutes.

Instantaneous System Imbalance (SI) is calculated by taking the difference between the *Area Control Error* (ACE) and the Net Regulation Volume (NRV). The System Imbalance (SI) is obtained by neutralising the activated auxiliary services (NRV) – implemented by Elia to manage the equilibrium of the area – of the ACE.

Level of use of a generation unit is the energy actually generated, divided by the energy which the power station would have to generate as long as it generated at its maximum capacity every hour of the year.

Loop flows is the difference in the physical flows measured at the interconnections, and the expected flows based on total nominations for these interconnections.

Market coupling by volumes This coupling has been achieved between the CWE region (BE, DE, FR, NL, LU) and the Nordic region (NO, SE, DK, FI, ES). In this case, the available transmission capacities at each border for each direction and each period, as well as the net export curves of each country for each period, make it possible, using a calculation algorithm from the company EMCC to define the flows on the interconnections between areas coupled by price. This information is then taken into account by the exchanges to calculate the prices in the different markets.

Market resilience indicates price sensitivity following an increase in supply or demand in the market.

Month-ahead is the Endex Power BE *Month* which represents the mathematical average expressed in €/MWh of the fixed reference prices at the "*end of day*" of the *month ahead* contracts (contracts for the physical supply of electricity on the Belgian high-voltage network for the month ahead), as published on the website http://www.iceendex.com/.

Net Regulation Volume (**NRV**) is calculated using the difference for each moment between the sum of the volumes of all upward regulations and the sum of the volumes of all downward regulations, including the exchanges via the International *Grid Control Cooperation* requested by Elia to maintain the balance of the control area. A positive value indicates a net upward regulation signal.

Nomination : a range of forecast data linked to an access point on the network. These data make it possible to define the characteristics of Day X and, in particular, the quantity of active capacity per quarter of an hour to be injected or consumed. These nominations are supplied by the ARP to Elia. Most nominations are shown as Day X-1 for the operation of the network on Day X. (source: Elia).

Paradoxically rejected block orders (**PRB**) are non-convex offers which, based on the prices obtained from the market, should have been accepted but which were rejected anyway.

Quarter-ahead is the Endex Power BE Month which represents the mathematical average expressed in €/MWh of the fixed reference prices at the "end of day" of the quarter ahead contracts (contracts for the physical supply of electricity on the Belgian high-voltage network for the quarter ahead), as published on the website http://www.iceendex.com/**.**

Secondary reserve (R2) is a reserve which is activated automatically and continually, both upwards and downwards. It intervenes rapidly (from 30 seconds to 15 minutes) and remains active for the time required. This reserve regulates the current imbalances and is intended to continually re-establish the equilibrium within the control area of Elia, and to continually manage the frequency variations.

Spread: is the difference between the market price of electricity and its variable short-term cost, estimated on the basis of market prices for fuels, in other words an approximation of the very short-term gross margin;

- if CO_2 becomes an additional component of the variable cost, it is referred to as a clean spread;
- if the determination of the spread is calculated to generate with:
  - a coal-fired power station, it is referred to as a dark spread and,
  - a gas-fired power station, it is referred to as a spark spread.

Tertiary reserve (R3) is a capacity reserve which certain producers or industrial actors make available to Elia. It makes it possible to confront a significant or systemic imbalance in the control zone, offset significant frequency variations, and resolve significant congestion problems. This reserve is mobilised manually.

Use-It-Or-Sell-It (UIOSI) is the principle of transferring non-utilised capacity in the daily market**.**

Year-ahead is the Endex *Power BE Calendar* which represents the mathematical average expressed in €/MWh of the fixed reference prices at the "*end of day*" of the *calendar* contracts (contracts for the physical supply of electricity on the Belgian high-voltage network for the calendar year ahead), as published on the website http://www.iceendex.com/.

8.2. LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
AFCN	*Agence fédérale de Contrôle nucléaire* (Federal Agency for Nuclear Control)
ACER	Agency for the Cooperation of Energy Regulators, operational since 3 March, 2011
aFRR	Automatic Frequency Restoration Reserve
APX	Amsterdam Power Exchange
APX-ENDEX	currently the ICE - ENDEX Intercontinental Exchange
ARP	Access Responsible Party, which has concluded an ARP contract with the GRT Elia
AT	Austria
ATC	Available Transfer Capacity, a congestion management and capacity allocation method for cross-zonal exchange where cross-zonal transmission capacities are explicitly defined per border and per direction.
BE	Belgium
CACM	Capacity Allocation and Congestion Management
CASC	Capacity Allocating Service Company, namely an allocating platform for the auction of cross-border electricity transmission capacities for the CWE and CSE regions, the north of Switzerland and part of Scandinavia (jao.eu)
CCGT	Combined Cycle Gas Turbine
CCR	Capacity Calculation Region
CEE	Central East Europe, including Austria, Czeckia, Slovakia, Hungary, Poland and Romania
CEER	Council of European Energy Regulators, created in 2000
CIM	Continuous Intra-day Market
CB	Critical Branch, network element either within or between bidding zones taken into account in the capacity calculation process, limiting the amount of power that can be exchanged
CBCO	Critical Branch Critical Outage, network element in the N-1 state either within or between bidding zones taken into account in the capacity calculation process, limiting the amount of power that can be exchanged
CO	Critical Outage, contingency taken into account in the capacity calculation process for compliance with the operational security limits.
CORE	The combination of Central West European (CWE) borders and Central East European (CEE) borders
CSE	Central South Europe region, including Germany, Austria, France, Greece, Italy and Slovenia
CSS	Clean Spark Spread
CWE	Central West Europe including Germany, Belgium, France, Luxembourg and the Netherlands, established on 9 November, 2010
D2CF	Two Day Ahead Congestion Forecast, TSOs’ forecast of network loading in D-2 (best grid estimate in D-2)

DACF Day Ahead Congestion Forecast, TSOs' forecast of network loading after day-ahead market coupling (best grid estimate in D-1)

DAM Day-Ahead market

DE Germany

DLR Dynamic Line Rating, technology and methodology to integrate weather forecasts (temperature, wind…) in the assessment of a transmission line thermal limit as opposed to the use of static seasonal values.

EEX European Energy Exchange

ENTSO European Network of Transmission System Operators for Electricity (ENTSO-E) – and Gas (ENTSO-G)

ERGEG European Regulators' Group for Electricity and Gas

EUPHEMIA "Pan-European Hybrid Electricity market integration algorithm", selected for the PCR initiative

FAV Flow Adjustment Variable, parameter in the Flow Based Market Coupling which can be introduced by a TSO to increase or decrease the RAM on a specific critical network element (see also: FBMC, RAM, CBCO).

FBI Flow Based Intuitive, patch in the flow based market coupling which prevents imports from a higher price bidding zone (or export towards a lower price bidding zone).

FBMC Flow Based Market Coupling, a congestion management and capacity allocation method for cross-zonal exchange where the market clearing point equals the set of net positions which maximizes the Social Welfare objective within the feasible domain defined by the network constraints (see: CBCOs).

FBP Flow Based Plain, original result of the Flow Based Market Coupling without or prior to any patches

FCR Frequency Containment Reserve

FR France

Fref Reference flows, physical flows observed in the D2CF basecase

$Fref_0$ Zero-balanced Reference flows, physical flows observed in the zero-balanced basecase, i.e. the case which starts from the D2CF base case and where all Net Positions are brought back to zero (no cross-zonal exchange).

Fref' Zero-balanced Reference flows including the physical flows induced by long term nominations. These physical flows get priority access to the grid. They are taken into account in determining the capacity available for the market (see also: RAM, CBCO, FBMC).

FTR Financial Transmission Right, type of long term transmission right entitling its holder to receive a financial remuneration based on the Day Ahead Market results between two Bidding Zones during a specified period of time in a specific direction (see also : PTR).

GME Gestore Mercati Energetici, operator in the Spanish market for electricity and gas

GRT *gestionnaire du réseau de transport* (Transmission System Operator : TSO)

GSK Generation Shift Key, a method of translating a change of zonal net position into estimated specific injection increases or decreases in the common grid model.

HHI Herfindahl-Hirschman Index: measure of the concentration of the market

ICH interruptible customers

ID-bids incremental/decremental bids

IRM	*Institut royal météorologique* (Royal Meteorological Institute)
IGCC	International Grid Control Cooperation for imbalance netting
ITVC	Interim Tight Volume Coupling
JAO	Joint Allocation Office
LU	Luxembourg
LTA	Long Term Allocation of transmission capacity
M€	million euros
MCR	Multi-Regional Coupling
mFRR	Manual Frequency Restoration Reserve
NEMO	Nominated Electricity Market Operator
NEP	Net (Exchange) Position, the netted sum of electricity exports and imports for each market time unit for a bidding zone
NL	Netherlands
NRV	Net Regulation Volume is calculated using the difference for each moment between the sum of the volumes of all upward regulations and the sum of the volumes of all downward regulations, including the exchanges via the International Grid Control Cooperation requested by Elia to maintain the balance of the control area. A positive value indicates a net upward regulation signal.
NTC	Net Transfer Capacity = TTC (Total Transfer Capacity) – TRM (Transmission Reliability Margin).
NWE	North West Europe**:** including Germany/Austria, the Benelux, Denmark, Estonia, Finland, France, Great Britain, Latvia, Lithuania, Norway, Poland and Sweden.
OMIE	OMI-Polo Español S.A. operator in the Spanish market for electricity and gas
OTC	Over-the-counter or off-exchange
OTE	Operator in the Czech market for electricity and gas
PCI (HHV)	Higher Heating Value (see also glossary)
PCR	Price Coupling of Regions, an initiative of 7 European exchanges to develop a single algorithm to calculate a single coupling price in Europe, and to improve the efficiency of allocations of cross-border interconnection capacities on a day-ahead basis.
PCS (LHV)	Lower Heating Value (see also glossary)
PLEF	The Pentalateral Energy Forum, framework for regional cooperation in Central Western Europe (BENELUX-DE-FR-AT-CH) towards improved electricity market integration and security of supply. The initiative aims to give political backing to a process of regional integration towards a European energy market. This cooperation is formalized trough the PLEF MOU signed in 2007.
PST	Phase-Shifting Transformer, a transformer for controlling the power flow through specific lines, without changing voltage level
PTDF (nodal)	Nodal Power Transfer Distribution Factor, (set of) parameter of a critical network element representing the physical flow induced by a change in nodal net position(s) – depends on grid topology.

PTDF (zonal)	Zonal Power Transfer Distribution Factor, (set of) parameters of a network element representing the physical flow induced by a change in zonal net position(s) – depends on grid topology and on GSK.
PTR	Physical Transmission Rights, type of long term transmission right entitling its holder to physically transfer a certain volume of electricity in a certain period of time between two Bidding Zones in a specific direction (see also : FTR)
PV	Photovoltaic panels
PWR	Pressurized Water Reactor
R1	Primary Reserve or Primary Control Power; name of FCR in the Electricity Balancing Guidelines
R2	Secondary Reserve or Secondary Control Power**;** named aFRR in the Electricity Balancing Guidelines
R3	Tertiary Reserve or Tertiary Control Power; named mFRR in the Electricity Balancing Guidelines
R3 DP	R3 on dynamic profiles (offtakes and decentralized generation)
R3 ICH	R3 on interruptible offtakes
RAM	Remaining Available Margin, capacity (in MW) of a Critical Branch Critical Outage (see: CBCO) which is given to the market
REMIT	Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency
RR	Replacement Reserve; not used by ELIA
SER - EnR	Sources of renewable energy
SWE	South West Europe
TGV	*Turbine Gaz-Vapeur* (Combined Cycle Gas Turbine)
TLC	Trilateral Market Coupling of the Belgian (Belpex), French (Powernext) and Dutch (APX) electricity markets, established on 21 November 2006 with the GRTs TenneT, Elia and RTE.
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TRM	Transmission Reliability Margin
UIOSI	Use-It-Or-Sell-It
XBID	**Cross-border Intraday**

Units

EUR	euro
GW	gigawatt, equal to 1 billion watts
kV	kilovolt
MEUR	million euro
mHz	millihertz, unit of frequency
MW	megawatt, equal to 1 million watts
MWh	megawatt hour, equal to 3.6 billion megajoules
TW	terawatt, equal to one thousand billion watts
W	Watt, unit of measurement for capacity derived from the international system of units, which measures the rate of electric conversion

8.3. LIST OF FIGURES

8.4. LIST OF TABLES