Commission de Régulation
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 2017

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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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 2017. 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 11 years (2007-2017) 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 examines electricity generation in particular;
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.

Several conclusions are 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 7 June 2018.

FUNCTIONING OF THE WHOLESALE ELECTRICITY MARKET

1. ELECTRICITY GRID LOAD

1.1. HISTORICAL BACKGROUND : SIGNIFICANT EVENTS

2008

- eruption of the financial crisis

2012

- February 2012 cold spell in France and Belgium

1.2. SPECIAL TOPIC: IMPACT OF WIND ON 'RUNNING HOURS' OF PEAK CAPACITY

1. In discussions on security of electricity supply, it is important to know the electricity demand during peak hours and how this will evolve in the future. It could be argued that intermittent renewable capacity such as wind turbines and solar panels have little impact on the need for peak capacity to guarantee security of supply, because it cannot be ensured that this renewable energy will be produced during peak periods. This means that back-up capacity is necessary.

2. However, wind and solar capacity do have an important impact on the running hours[1] of the required peak capacity to guarantee security of supply. In this special topic, the impact of wind capacity in Belgium on the running hours of peak capacity is analysed. In this analysis, the peak capacity is divided into two categories, namely 'super peak capacity' which is the last 1000 MW of capacity that is needed to supply the electricity peak demand and 'peak capacity' which is the next 1000 MW of capacity that is needed. The analysis compares the residual Elia Grid load with and without wind energy and the running hours of the (super) peak capacity.

3. The figure below shows the residual Elia Grid load during the 5000 15-minute intervals of 2017 that this load was the highest, without taking wind energy into account. If there is no wind capacity installed, the super peak capacity must supply 68 GWh. This means that each MW of the super peak capacity would have been needed to be activated during 68 hours on average in 2017. The next 1000 MW of peak capacity would have been needed to supply 607 GWh or an average of 607 running hours.

[1] 'Running hours' in the context of this analysis are the minimum hours that a megawatt of capacity needs to be activated to guarantee the required level of security of supply. In this analysis the legal requirement of maximum 3 hours of loss of load is taken into account.

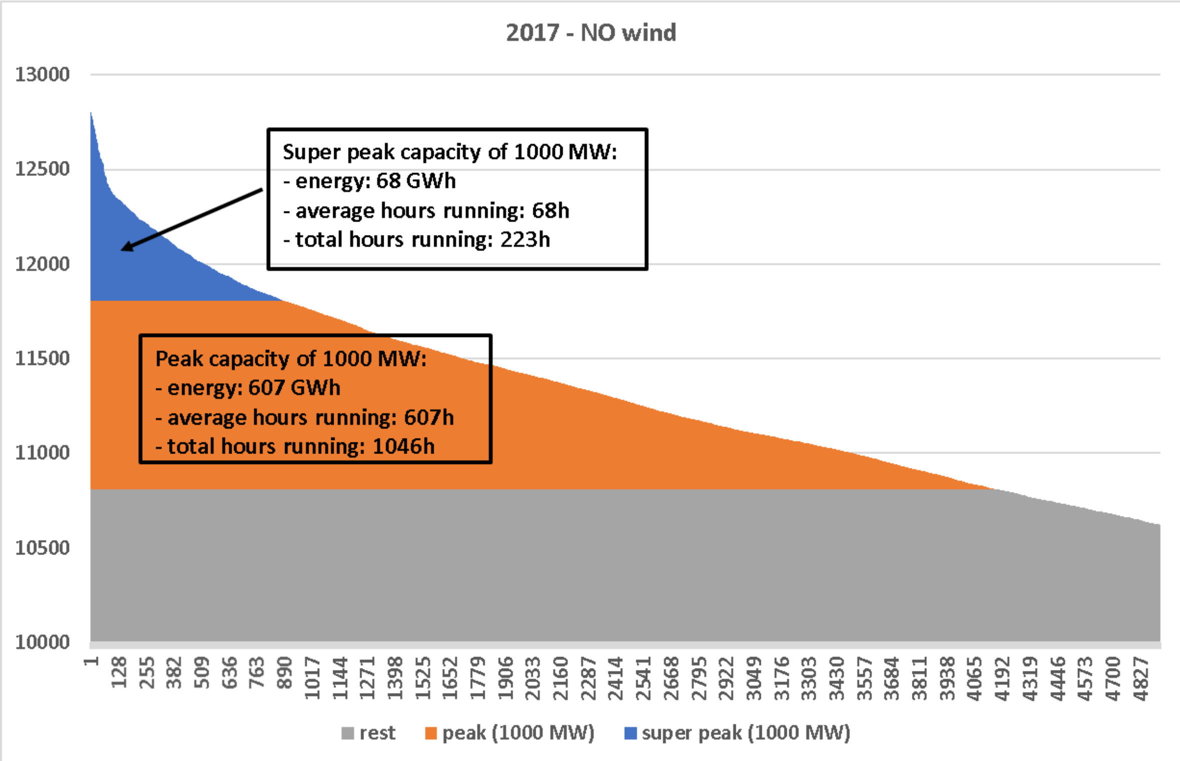

Figure 1: Elia Grid load duration curve for the first 15-minute intervals of 2017 without taking into account produced wind energy.
Sources: CREG, Elia

4. The figure below shows the residual Elia Grid load during the 5000 15-minute intervals of 2017 when this residual load is the highest, with taking wind energy into account as produced in 2017. With wind, the running hours of (super) peak capacity decrease dramatically. Now, the same super peak capacity needs to supply only 24 GWh during an average of 24 running hours. This is almost three times less compared to the above situation if it is assumed there is no wind capacity. The next 1000 MW of peak capacity needs to supply 267 GWh or an average of 267 running hours. This is more than two times less compared to the situation without wind. The supplied energy by super peak capacity and peak capacity with wind is respectively 0.03% and 0.34% of total Elia grid load in 2017.

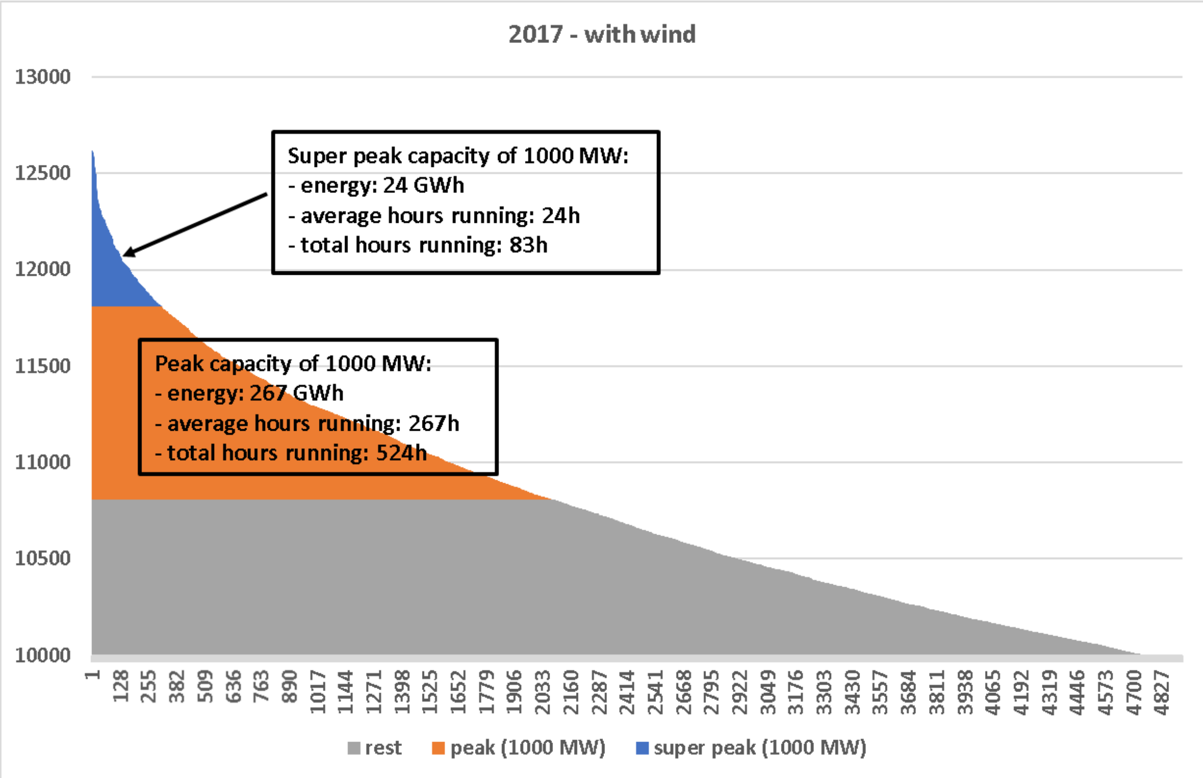

Figure 2 : Residual Elia Grid load duration curve for the first 5000 15-minute intervals of 2017, taking into account the produced wind energy in 2017.
Sources: CREG, Elia

5. We can also simulate what the impact is if we had even more wind capacity in 2017. The figure below gives the same data as the figure above, but with three times the wind energy as was produced in 2017. By tripling wind capacity, the running hours of (super) peak capacity continue to decrease dramatically: the same super peak capacity needs to supply only 8 GWh during an average of 8 running hours. That is almost three times less compared to the situation with the real wind capacity. The next 1000 MW of peak capacity needs to supply 126 GWh or an average of 126 running hours. This is more than two times less compared to the situation with the real wind capacity. The supplied energy by super peak capacity and peak capacity with tripling wind capacity would have been respectively 0.01% and 0.16% of total Elia grid load in 2017. These results show that increasing wind capacity keeps lowering the running hours of peak capacity.

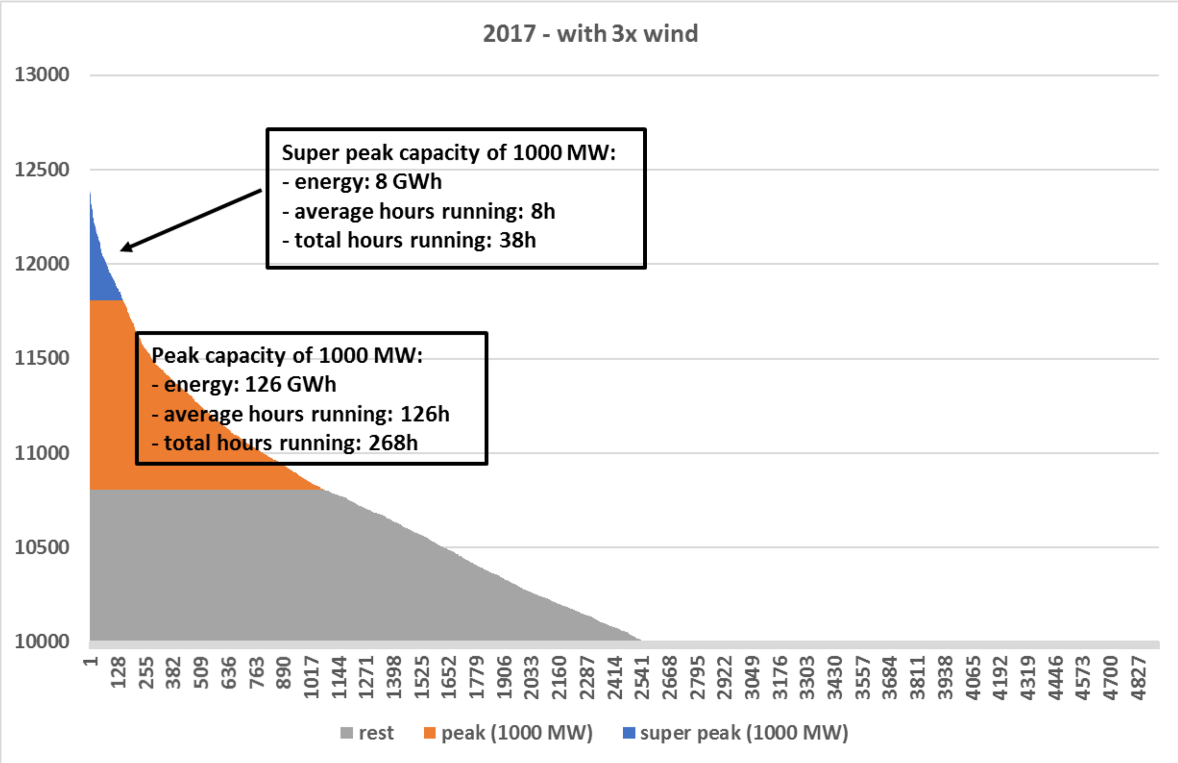

Figure 3 : Simulation of the residual Elia Grid load duration curve for the first 5000 15-minute intervals of 2017, taking into account 3 times the produced wind energy in 2017.
Sources: CREG, Elia

6. From these results, it is clear that the impact of wind on 'running hours' of (super) peak capacity is very high. The sharp decrease of running hours, by a factor of two to three, means that conventional peaking units, like open-cycle gas turbines, could become less cost-effective for providing the last 1000-2000 MW and perhaps more of peak capacity. However, there are other types of capacity for which lower running hours can make their entry into the market more likely: capacity with low capital expenditure but high activation costs, such as emergency generators and demand response, could become more cost-effective due to the increased wind capacity leading to lower running hours. Indeed, it can be expected that demand response is more likely to be activated during 8 or 24 hours per year than during 68 hours. Likewise, it can be expected that emergency generators are more likely to be activated 126 or 267 hours per year instead of 607 hours.

7. In the context of assessing the running hours of (super) peak capacity, it is important to highlight the difference between the average running hours of *each MW* of a certain type of capacity (like 'super peak' and 'peak' capacity) and the total running hours for *the whole block* of 1000 MW of that type of capacity. The latter is the number of hours that at least one MW of the whole block is required. For 2017, the total running hours of super peak capacity (namely, the number of hours that at least one MW of super peak capacity is required) taking into account the produced wind energy amounts to 83 hours. However, the average running hours for each MW of super peak capacity is only 24 hours, or more than three times less. For peak capacity, the total running hours is 524 compared to the average running hours of each MW of only 267 hours.

8. The importance of the difference between total and average running hours of super peak capacity can be illustrated by the so-called 'Dunkelflaute' in January 2017, during which generation of wind and solar electricity was very low for several consecutive days. The figure below shows the Elia Grid load with and without wind during 16 to 19 January and 23 to 26 January 2017 (8 days in total). It is clear that wind did not provide much electricity during this period. During all hours that the Elia grid load with wind was above the horizontal red line, the super peak capacity needed to be activated. This

was necessary for 55 hours, providing almost 20 GWh during these 8 days. However, the average activation time of each MW of the super peak capacity was less than 20 hours on average, much less than the 55 hours of total running hours.

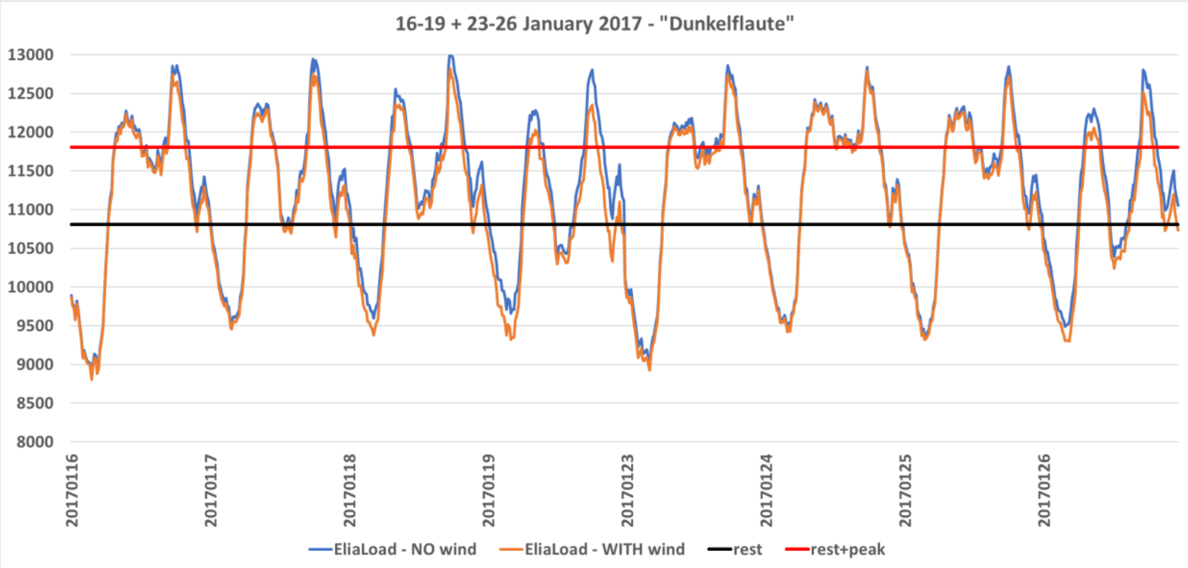

Figure 4 : Elia Grid load with and without wind during 16 to 19 January and 23 to 26 January 2017
Sources: CREG, Elia

9. The table below provides some additional statistics on the 'Dunkelflaute' of January 2017. The maximal daily running hours of the super peak capacity was 11.5 hours, but even during this day, each MW of the super peak capacity was only needed for less than 4 hours on average.

1000 MW of super peak capacity use - 8 days Jan 2017			
	total	**av/day**	**max/day**
Energy (MWh)	19,580	2,447	3,815
Total running hours	54.75	6.8	11.5
Average running hours	19.6	2.4	3.8

Table 1: Elia grid load (TWh) and power demands (MW) between 2007 and 2017
Sources: CREG

10. In the above analysis, it is suggested that the (super) peak capacity could be supplied by demand response and emergency generators. Of course, this ignores other alternatives, such as thermal capacity, import capacity and storage (including pumped-storage and batteries). To have a better view on the running hours in the future and taking into account the other means of capacity (but without the 4800 MW of OCGTs and CCGTs currently installed in Belgium), Elia made a very useful calculation assuming the Energy Pact scenario for 2025, after the complete nuclear phase-out. In this scenario, the wind and solar capacity that was expected for 2030 would already be installed in 2025.

11. The results of this calculation are shown in the table below. The table gives the total running hours per tranche of 1000 MW that will be needed in 2025 to guarantee security of supply (with the key assumption that Belgium imports 6500 MW during all hours of the year, if generation is available abroad). First, as expected, an increase of wind and solar capacity only slightly lowers the total need for capacity (from 5900 MW to 5700 MW). However, the total running hours of the last 700 MW and 1000 MW of capacity are very low. For an average year, these are respectively 5 and 10 hours per year. For an extreme year (P95 or once every 20 years), this increases to respectively 30 and 40 hours. It is important to remark that the running hours calculated are total running hours. The average running

hours of each MW will be even lower than the total running hours, especially for the peak and super peak capacity. The maximal energy that is needed from the 700MW and 1000MW tranche for guaranteeing security of supply is 3.5 GWh and 10 GWh, respectively, for an average year (representing 0.004% and 0.013% of total demand). For an extreme year, once every 20 years, this increases to 21 GWh and 40 GWh (representing 0.026% and 0.05% of total demand).

12. Elia also calculated the total running hours in case of unexpected events, such as reduced availability of power plants in neighbouring countries (without conversion to gas or biomass). In this case, the results from Elia show an additional requirement of 2000 MW. Nevertheless, the total running hours of these two tranches of 1000 MW are also very low: 5 hours for an average year and 30 hours for an extreme year (once every 20 years). Also here, it is important to remark that the running hours calculated are total running hours. The average running hours of each MW will be even lower than the total running hours.

	Energy Pact scenario		
	capacity	**running hours average - P95**	
	1000 MW	5 - 30 h	in case of unexpected events
	1000 MW	5 - 30 h	
5700 MW	700 MW	5 - 30 h	
	1000 MW	10 - 40 h	
	1000 MW	60 - 100 h	
	1000 MW	300 - 600 h	
	1000 MW	700 - 1100 h	
	1000 MW	1200 - 1700 h	

probability of need
<50%
>50%
100%

Table 2: Total running hours of each 700MW/1000MW tranche of capacity with the Energy Pact scenario in 2025 as calculated by Elia. The total running hours are calculated so that security of supply is guaranteed.
Sources: Elia, CREG

1.3. STATISTICS

1.3.1. Evolution of the Grid Load

At the European level

13. Figure 5 illustrates the total electricity demand as published by EntsoE from 2011 to 2017 for Belgium and its bordering countries France, the Netherlands, Germany and the United Kingdom. Total electricity demand for this region amounts to 1477 TWh in 2017; this is more or less constant in the observed period, with 1459 TWh the lowest and 1495 TWh the highest total demand. Belgium represents 6% of this total demand. If the UK is excluded, the Belgian share rises to 7.5%.

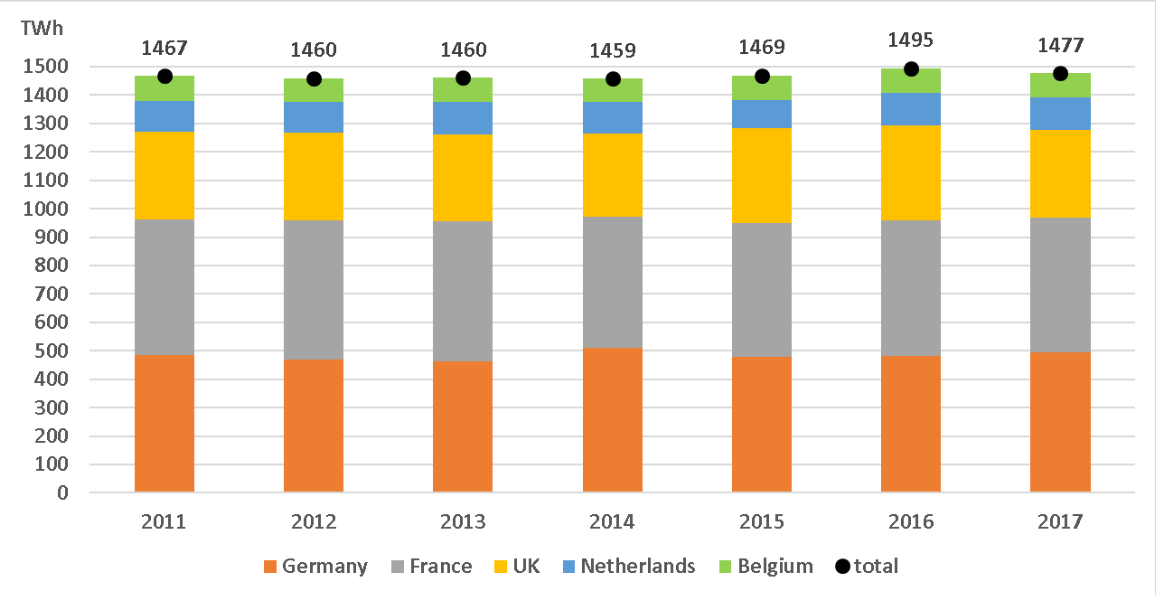

Figure 5: Evolution of the total electricity demand as published by EntsoE (TWh) from 2011 to 2017 for Belgium and its bordering countries
Sources: CREG, ENTSOE[2]

At the Belgian level

14. This section analyses the evolution of the Elia grid load[3], 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

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

[3] 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 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 in recent years. As such, Elia decided to complete its publication with a forecast of the total Belgian electricity 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).

equal to the total electricity consumption of Belgium. However, this selected approach gives a good idea of how the wholesale electricity market is evolving.

15. The Elia grid load [4] amounted to 77.4[5] TWh in 2017, at a level similar to that of the three previous years. Figure 6 shows the total Elia grid load over the last 11 years. Compared to 2007, the Elia grid load decreased by 12 TWh, or about -10%. The figure also shows the baseload part of the Elia grid load. This decreased from 56 TWh to 49.4 TWh, also a decrease of about -10%. As such, the baseload part of the total grid load was more or less constant throughout the last 11 years, varying around 64%. This is noteworthy, as it would be expected that intermittent renewables would not only decrease the grid load, but also the baseload part of this load. The most obvious explanation for the constant baseload share is the increase of demand response to lower the peak.

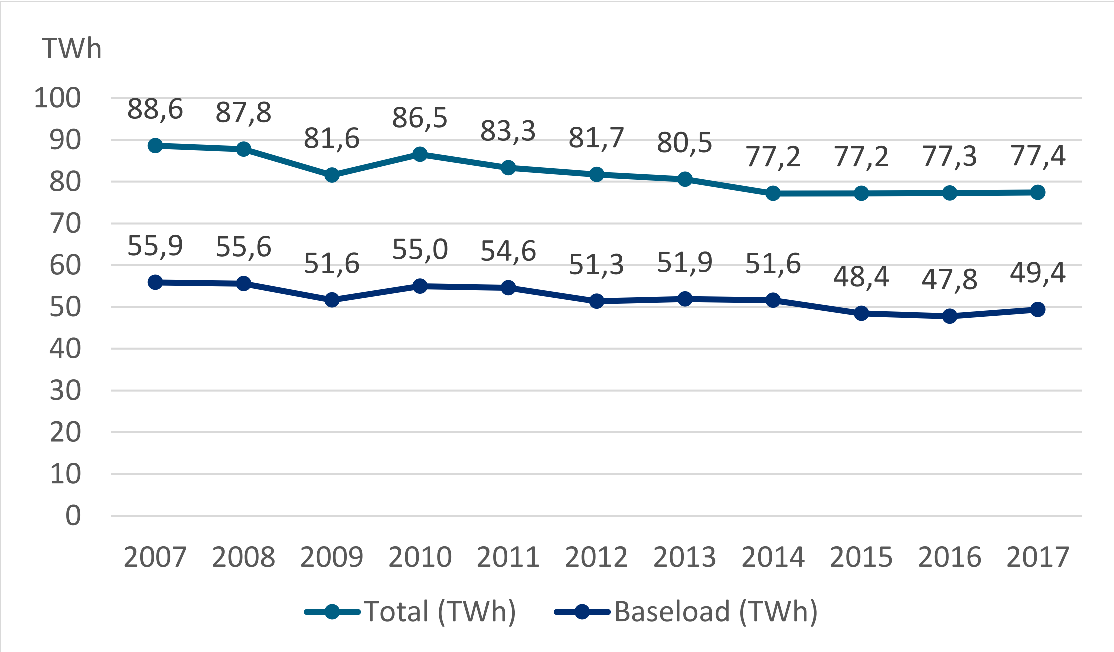

Figure 6: Total Elia Grid load and Baseload Elia Grid load during 2007 to 2017
Sources: Elia, CREG

16. The table below gives the detailed data on the total Elia grid load and its baseload part in 2007-2017. It also shows the average, maximum and minimum load per year for this period. The average power demand in 2017 was 8,837 MW. The baseload power demand was 5,638 MW. The maximum power demand amounted to 12,867 MW in 2017, slightly higher than the three years before, but still significantly lower than in 2007-2013.

[4] 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.
[5] A difference of 0.1TWh with CREG Note 1719 is due to validation of measured data.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total (TWh)	88.6	87.8	81.6	86.5	83.3	81.7	80.5	77.2	77.2	77.3	77.4
Maximum Load (MW)	14,033	13,431	13,513	13,845	13,201	13,369	13,385	12,736	12,634	12,734	12,867
Average Load (MW)	10,116	9,991	9,312	9,875	9,515	9,303	9,193	8,808	8,811	8,799	8,837
Minimum Load (MW)	6,378	6,330	5,895	6,278	6,232	5,845	5,922	5,889	5,529	5,438	5,638
Baseload (TWh)	55.9	55.6	51.6	55.0	54.6	51.3	51.9	51.6	48.4	47.8	49.4
% baseload	63.0%	63.4%	63.3%	63.6%	65.5%	62.8%	64.4%	66.9%	62.7%	61.8%	63.8%

Table 3: Elia grid load (TWh) and power demands (MW) between 2007 and 2017
Sources: Elia, CREG

17. Figure 7 shows in more detail the evolution of the electricity peak demand in the Elia control area over the 11 last years. Four levels are shown here:

- the highest level (“maxCap”);
- 100 hours after the highest level (“Cap Hour 100”);
- 200 hours after the highest level (“Cap Hour 200”);
- 400 hours after the highest level (“Cap Hour 400”).

Until 2014, all the trends observed were negative over the years. Since 2014, this 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 Hour 100”) 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 Hour 200”), slightly more than 200 MW was added. For the 400 hours (“Cap Hour 400”), or 4.6% of the time, it was necessary to rely on average on 1,600 MW, or 12.0% of the peak demand.

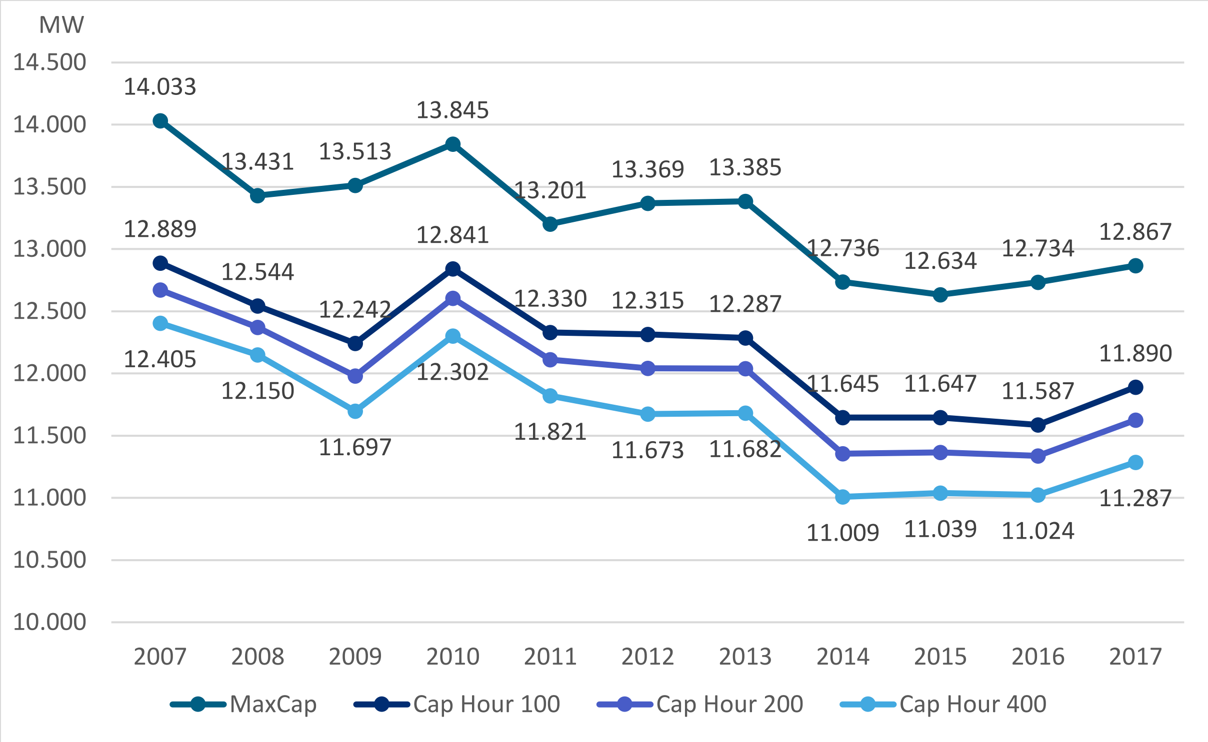

Figure 7: Evolution of the demand levels classified within the Elia control area (MW) for 2007-2017 (for the higher ¼ hour, hour 100, hour 200 and hour 400), like their trend curve
Sources: Elia and CREG

1.3.2. Electricity Demand according to Meteorological Conditions

18. Figure 8 shows the average Elia grid load per month. The shape of the curves shows the seasonal effects on the Elia grid load. During the winter months, the average Elia grid load is significantly higher (up to 2,500 MW higher) than in the summer months.

19. In February to October 2017, the average monthly Elia grid load was at the same low level as the years before. However, for January, November and December, the average was markedly higher than the few years before.

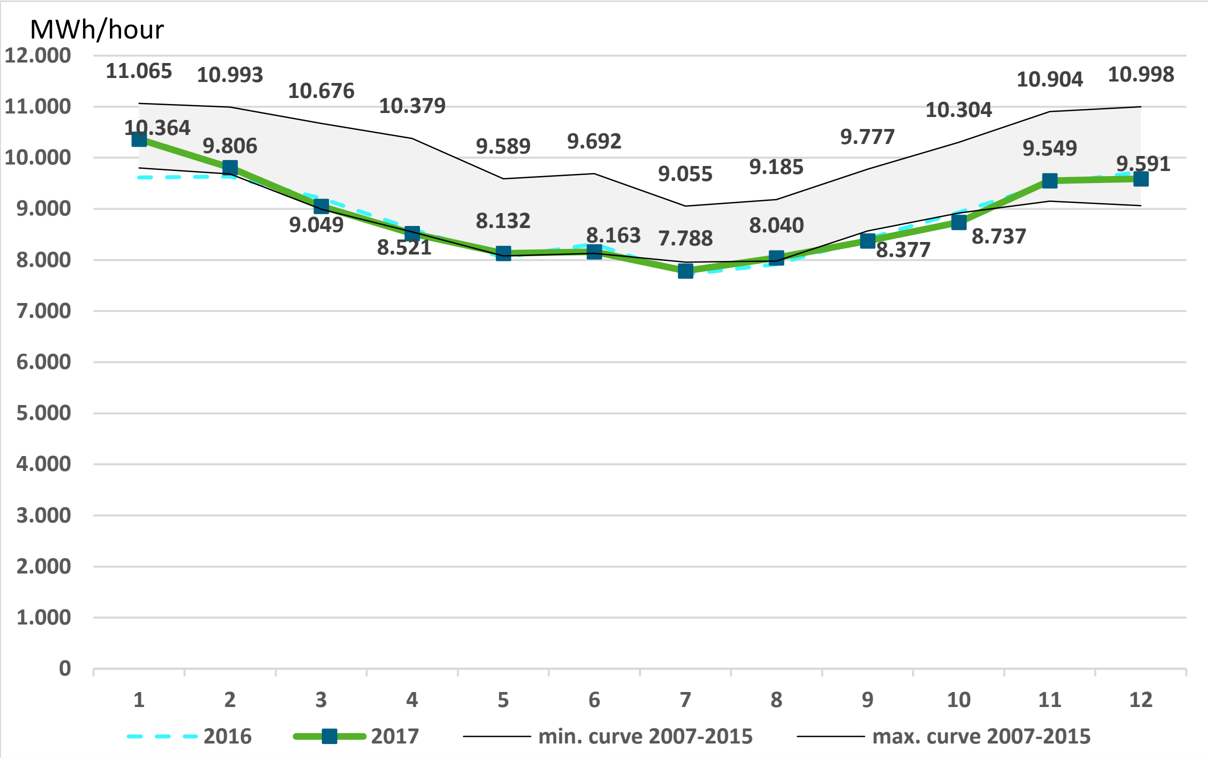

Figure 8: Average monthly Elia grid load between 2007 and 2017
Sources: Elia and CREG

1.3.3. Load Patterns and the Impact of Solar Panels

20. Figure 9 shows the evolution of the daily pattern of the average Elia grid load for the years 2007 to 2017. The period 2007 to 2015 was aggregated in the greyed zone of the chart by including the minimum and maximum of the averages of the Elia grid load per 15-minute interval. 2016 and 2017, on the other hand, appear distinctly in the chart. The peak just before midday has disappeared due to generation from solar panels. During the night and morning, the average Elia grid load increased slightly compared to 2016 and the minimum of the years before. During the day and the evening, the average Elia grid loads is at its minimum for the whole observed period.

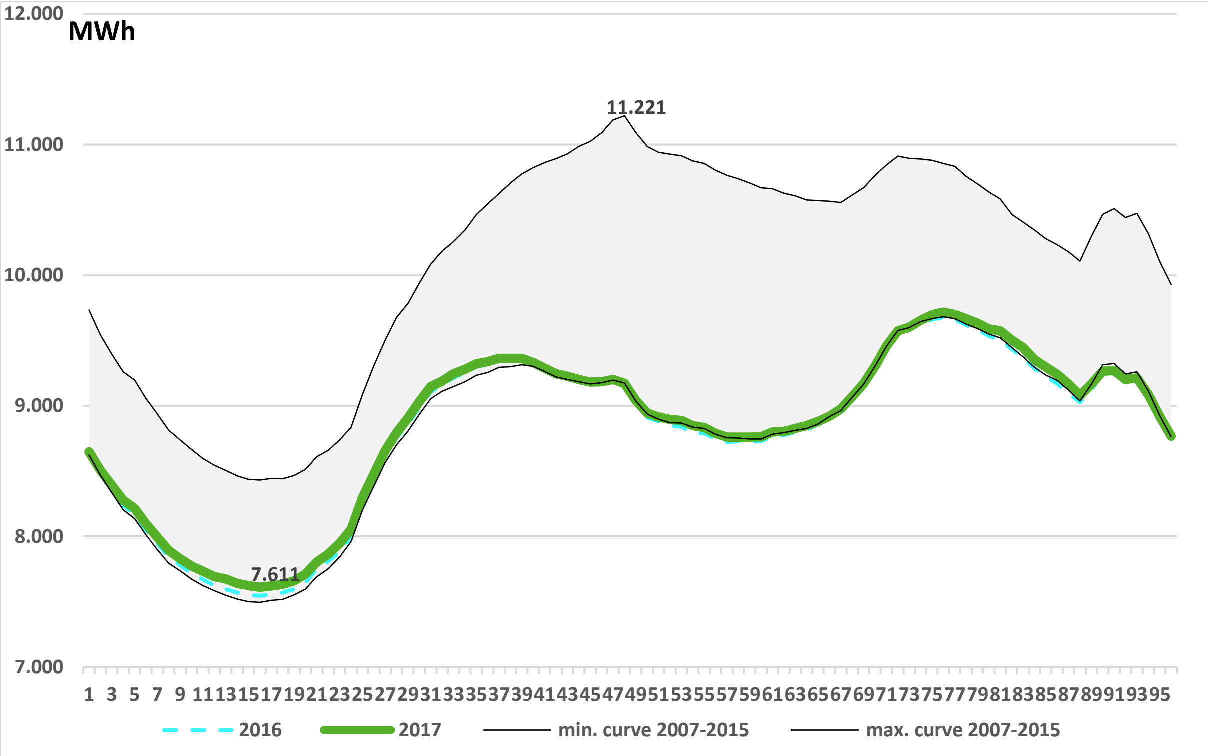

Figure 9: Average Elia grid load per 15-minute interval over the period 2007 to 2017 (MW)
Sources: Elia and CREG

21. These observations are confirmed by Figure 10 which shows the variability of the average Elia grid load during the day measured using the standard deviation (“AV D-StdDev” - blue line) as well as the standard deviation of the difference in Elia grid load between two consecutive days (“StdDev of D-D-1” - red line). Figure 10 also illustrates on the right-hand axis the standard deviation of the difference between two consecutive 15-minute intervals (“Stdev of QtoQ - right axis” - green line). Only this last observation increases slightly in 2017.

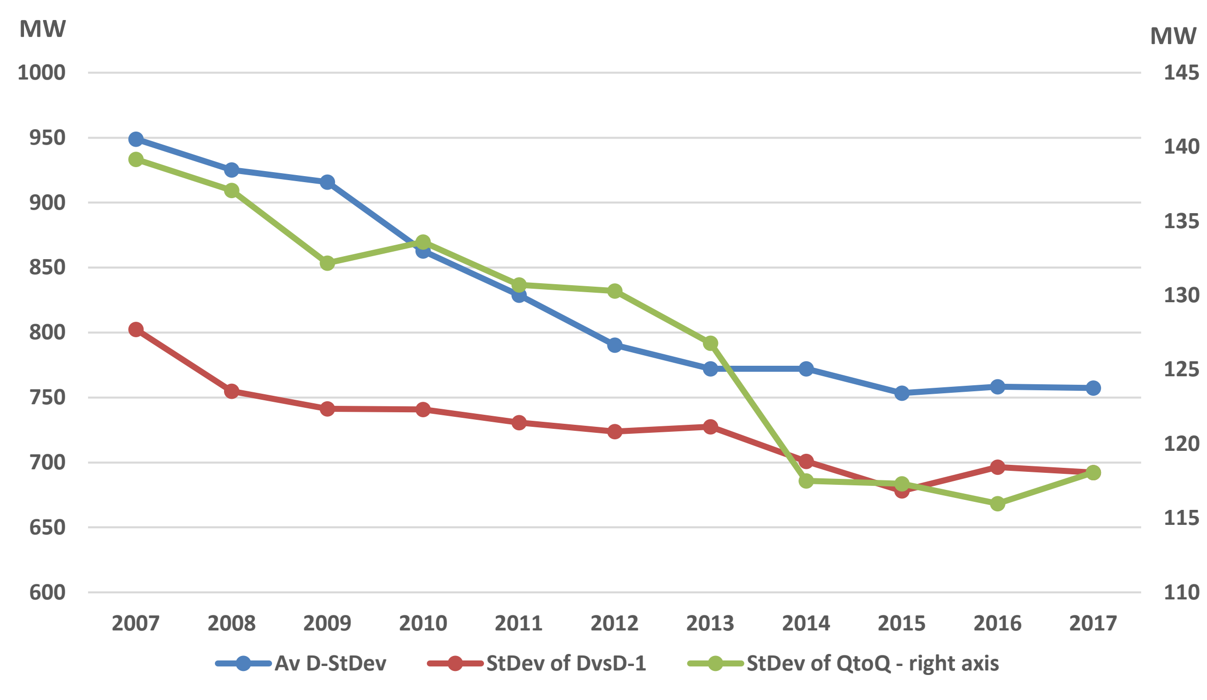

Figure 10: Annual variability of the average electricity demand during one day ("AV D-Stdev" - blue line), the difference between two consecutive days ("StdDev of D-D-1" - red line) and, on the right-hand axis, the difference between two consecutive 15 minute intervals ("Stdev of QtoQ" - orange line) (MW). The right and left-hand axes start respectively at 600 MW and 110 MW
Sources: Elia, CREG

22. The constant lower levels of variability compared to 2013 and previous years is an indication that the need for flexibility has decreased. This is confirmed in Chapter six on *balancing.* Since 2013, a decrease in the resources required to maintain the power balance has been observed.

Impact of solar generation

23. The CREG only has TSO data from 2013 onwards as regards solar electricity generation. Figure 11 shows the yearly pattern of the monthly average solar generation for Belgium for 2017 compared to the 4 preceding years (2013-2016). During winter months, average solar generation varies between 50 and 100 MW, whereas during summer months this is above 350 MW or 4 to 8 times more. The average monthly solar generation in 2017 is very similar to the average solar generation in 2013-2016.

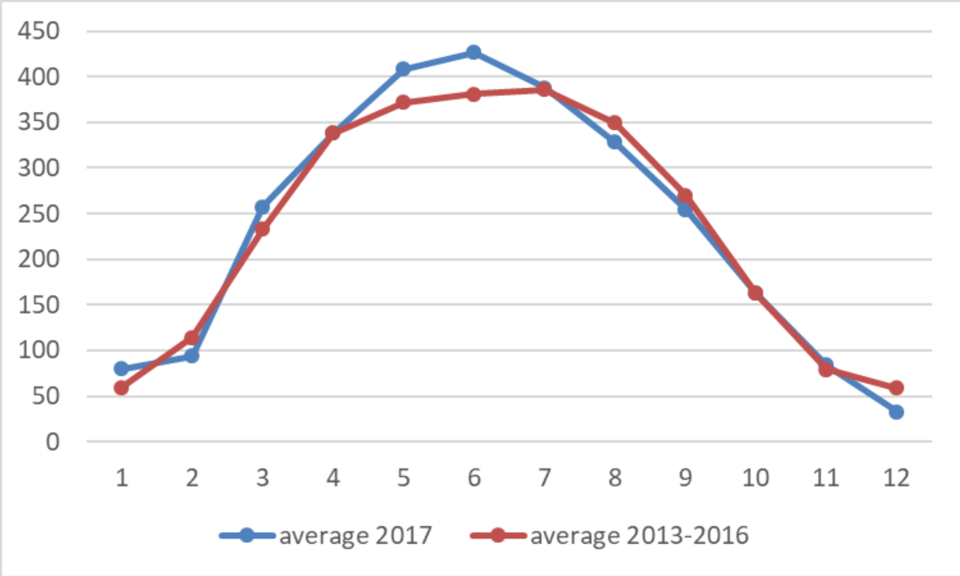

Figure 11: Monthly average solar electricity generation (MW) of installed solar panels for 2017 compared to 2013-2017
Sources: Elia and CREG

24. The total generated solar energy (Table 4) amounts to 2.9 TWh in 2017, the same level as the recent preceding years. The yearly generated solar energy has barely evolved since 2014, reflecting a slowdown in investments in this sector.

(TWh)	**Generated Solar Electricity**
2013	2.4
2014	2.8
2015	3.0
2016	2.9
2017	2.9

Table 4: Generated electricity of solar origin 2013-2017
Source: CREG

25. Figure 12 shows the evolution of the maximum, average and minimum monthly generation at hour 13 of the day. The hours with the highest generation are observed in May and June. The estimated maximum generation rose to 1965 MW in June 2013, 2157 MW in in May 2014, 2239 MW in July 2015, 2349 MW in May 2016 and 2277 MW in May 2017. The fact that the highest average generation in 2017 is less than in 2016 shows that the growth of investments in the solar sector has stalled.

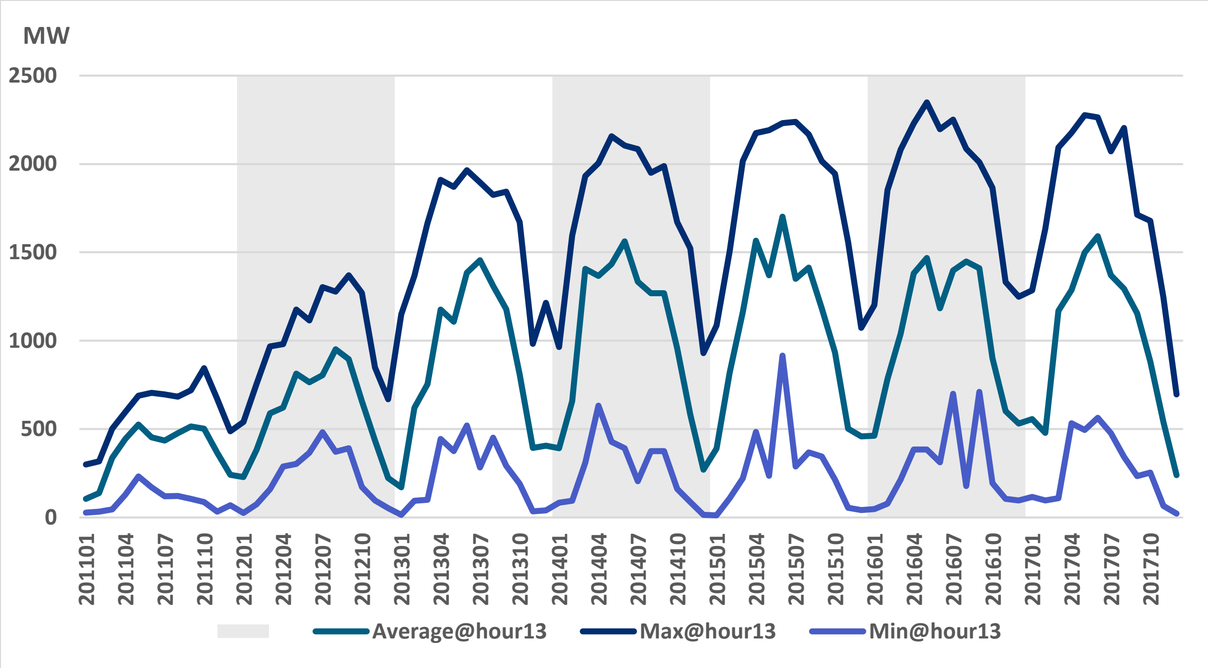

Figure 12: Evolution of the maximum, average and minimum monthly generation at the thirteenth hour of the day
Sources: Elia, CREG

26. From the figure above it is clear that solar electricity generation varies considerably. This variability could be noticeable in the event of higher variability of the Elia grid load in the middle of day. Figure 13 shows, per year, a daily pattern of demand variability, measured using the standard deviation of the average demand per 15-minute intervals.

The period 2007 to 2015 was aggregated in the greyed zone of the figure by combining the minimum and maximum values of the daily patterns of demand variability. 2016 and 2017, 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 100-200 MW compared to the previous years, namely an increase of 10 to 20%. This trend continued in 2013. However, 2014 to 2016 registered the opposite trend to these previous two years. For 2017, however, the variability in the daytime period has increased significantly.

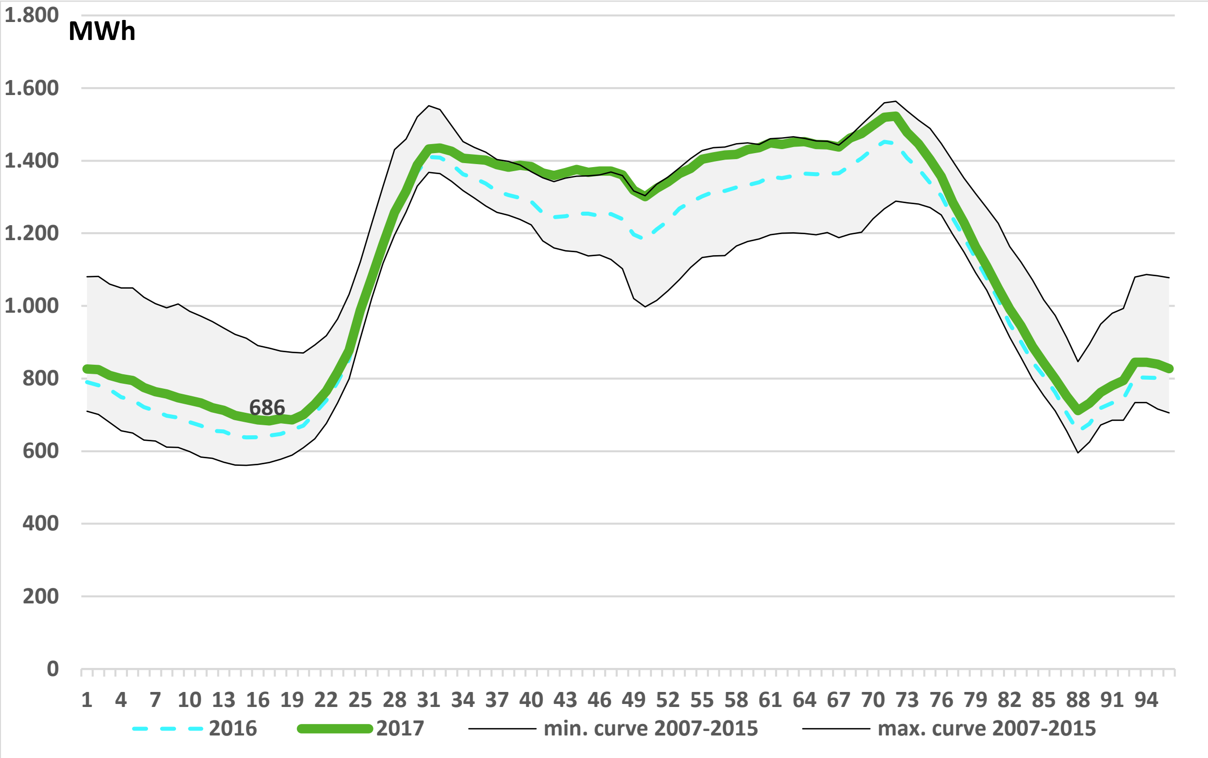

Figure 13: Standard deviation of the average demand per 15 minute interval on the network in the Elia control area (MW) between 2007 and 2017. The y-axis starts at 500 MW.
Sources: Elia and CREG

2. GENERATION

2.1. HISTORICAL BACKGROUND AND SIGNIFICANT EVENTS

27. During the last decade, electricity generation in Belgium has been subject to several major changes. Investments in new conventional generation facilities dropped significantly following the financial crisis in 2009, which also coincided with the start 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 drop 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. Whereas a reflection was carried out in neighbouring countries 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 2017, the profitability of CCGT plants was further increasing and several notifications of decommissioning of power plants have been further postponed until 2019-2021. The decommissioning of power plants is covered in the next chapter.

2.2. SPECIAL TOPIC: DECOMMISSIONING OF GENERATION UNITS

28. Forecasting the decommissioning of generation units has always been an important issue when evaluating the adequacy of the electricity system and specifically evaluating the need for additional generation units in order to guarantee the security of supply.

29. In 2012, a first attempt to create a framework for the decommissioning of generation units was made by inserting Article 4*bis* in the Electricity Act.

30. In 2014, the modification of the Electricity Act, whose primary objective was to set up a mechanism of strategic reserve, modified this article 4*bis,* by aligning the timings for decommissioning with the process of determining and tendering the volume of strategic reserve.

31. The more strict regulation for decommissioning appears to have influenced the behaviour of generators, firstly by notifying of any decommissioning and increasing the need for strategic reserve in the process, and secondly by making use of the legal timeframes to withdraw earlier notifications.

32. This chapter aims to summarize and visualize the information on decommissioning of units that the CREG received for the last 5 years. The notifications for decommissioning encompass a multitude of information: volume of capacity reduction, temporary versus definitive decommissioning, conditional versus unconditional decommissioning, partial versus total decommissioning, change of decommissioning date or recall of an earlier notification, capacity reduction of gas turbines when converting a CCGT to an OCGT peak unit and other qualitative information. Obviously, all these possible aspects of the notifications cannot be summarized in a single table or graph. The analysis below is intended to give a simplified overview rather than an exhaustive analysis of the recent history of decommissioning of generation units.

33. The next table gives an overview of the number of notifications for each year in the period 2013 – 2017, as well as the number of units and the number of sites concerned for these notifications.

Several terms must first be defined to ensure good understanding of the table.

A notification is defined as a notice of a capacity reduction or a temporary or definitive decommissioning of a single unit. Some decommissionings are related to full generation plants (for example a CCGT, while other decommissionings only refer to, for example, a steam turbine. A common approach is necessary if all the announced decommissionings are put together. A letter of confirmation of decommissioning, without changing any aspects of the decommissioning, is not considered as a notification.

A unit is defined as a part of a plant which can be coupled to an electric generator. The units considered are gas turbines, steam turbines in CCGT, steam turbines in conventional thermal units and turbojets. A CCGT power plant composed of 2 gas turbines and a steam turbine has 3 units. A decommissioning for such a CCGT will be accounted for 3 notifications.

A site is defined as a geographical location were units are installed.

In the table the number of notifications is mostly higher than the number of units. This means that within a single year, multiple notifications are made for the same unit. When looking at the data for individual years there does not appear to be a problem, as the gap between the number of notifications and the number of units concerned is quite small, except for 2016: indeed in 2016, for half of the number of units in question, a second notification followed in the same year. When looking at the whole period 2013-2017, it can be observed that 116 notifications were received for only 44 units. On average, multiple notifications are received for decommissioning units.

Period	# Notifications	#units	#sites
2013	27	26	19
2014	27	23	11
2015	25	24	13
2016	27	19	10
2017	10	10	5
period 2013-2017	**116**	**44**	**27**

Table 5: overview of number of notifications for decommissioning

34. The CREG is aware that changes in economic conditions lead to revisions of decisions made for decommissioning. On the other hand, given that a notification for decommissioning can easily be

cancelled and constitute, as such, a free option to participate in the strategic reserve, it may be the case that generators notify of a decommissioning to guarantee a basic revenue for the power plant in the strategic reserve. When market conditions enable generators to generate sufficient revenues in the market then the notification is rescinded. A modification of the Electricity Act with some changes to article 4bis is currently being examined.

35. The next graph shows a quantitative summary of the content of the notifications since 1 January 2014. The graph shows the realised or expected volume of decommissioning on different time horizons (for the years 2014 until 2021). For each of these years, the volume of decommissioning is presented based on the notifications received until a certain date (1 January of the years 2015 until 2018 and 1 May 2018).

The stable decommissionings in 2014 are due to the fact that these are historical decommissionings. The notifications received before 1/1/2015 projected a net volume of 1858 MW decommissioning for the year 2015, from which only 874 MW was effectively realised. For most of the other 1000 MW, the decommissioning was postponed and 2016. Some forecasted decommissionings were cancelled.

The notifications received before 1/1/2016 projected a net volume of 1366 MW decommissioning for the year 2016, from which only 585 MW were effectively decommissioned. Most of the remaining forecasted decommissioning were postponed.

The notifications received before 1/1/2017 projected a net volume of 589 MW decommissioning for the year 2017, from which only 52 MW were effectively decommissioned.

The notifications received before 1/1/2018 did not project any additional decommissioning in the year 2018. Based on the notifications received until 1 May 2018, 485 MW of decommissioned units will return to the market.

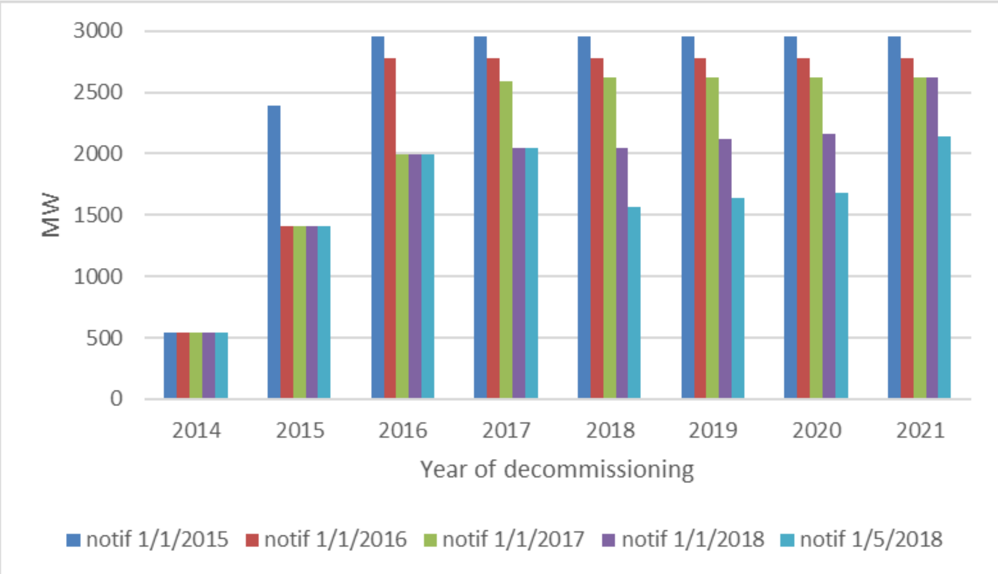

Figure 14: Evolution of projection of decommissioned capacity at different moments in time

36. These observations show that notifications for decommissioning tend to overestimate the decommissioning of units for the following year. Based on the current available notifications, current decommissioning for 2018 appears to be almost 1400 MW lower than projected at the start of 2015 and almost 1100 MW lower than projected at the start of 2017.

2.3. STATISTICS

2.3.1. Main characteristics of electricity generation in Belgium

37. At the end of 2016, the installed generation capacity (excluding mothballed capacity and capacity in strategic reserve) connected to the Elia grid amounted to 14.1 GW. Total electricity generated in 2017 by units connected to the Elia grid amounted to 70.2 TWh. Figure 15 shows the distribution of the installed capacity at the end of 2017 and the electricity generated in 2017 per fuel source.

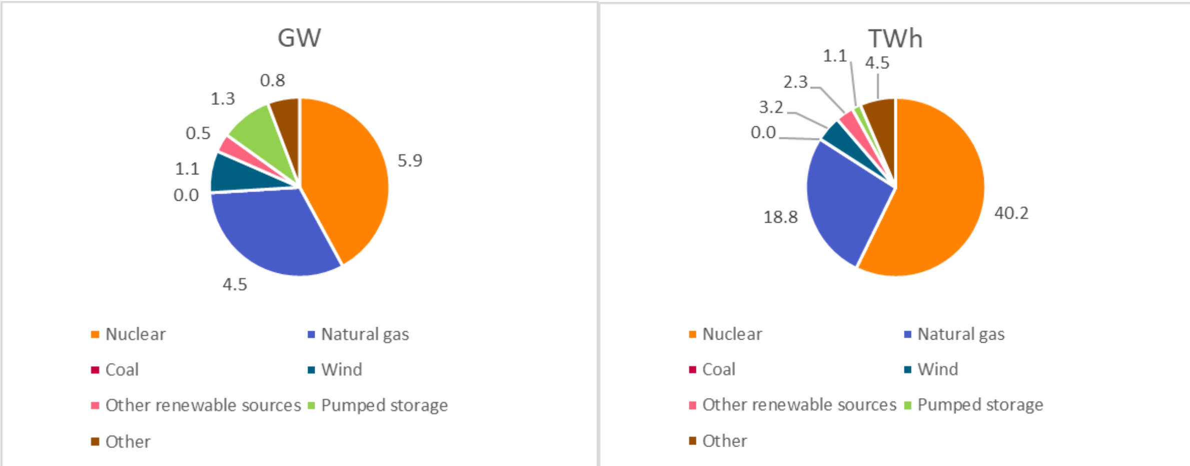

Figure 15: Installed capacity and electricity generation in 2017 by fuel source.
Sources: Elia, CREG

38. 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. 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.

Table : Evolution Installed Generation Capacity per fuel type (GW)

Type of fuel	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Nuclear	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Natural gas	6.0	6.0	6.2	6.3	6.6	6.0	5.1	4.6	4.6	4.5
Coal	1.4	1.4	0.9	0.8	0.7	0.5	0.5	0.5	0.0	0.0
Wind	0.1	0.1	0.3	0.3	0.5	0.7	0.9	0.9	0.9	1.1
Other renewable sources	0.2	0.2	0.4	0.6	0.4	0.4	0.4	0.4	0.4	0.5
Pumped storage	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Other	1.1	1.4	1.0	1.0	0.9	0.8	0.9	0.9	0.8	0.8
Total	16.0	16.3	16.2	16.2	16.4	15.7	15.0	14.5	14.0	14.1

Table : Evolution Installed Generation Capacity per fuel type (%)

Type of fuel	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Nuclear	36%	36%	37%	37%	36%	38%	40%	41%	42%	42%
Natural gas	38%	37%	38%	39%	40%	38%	34%	32%	33%	32%
Coal	9%	9%	6%	5%	4%	3%	3%	3%	0%	0%
Wind	0%	1%	2%	2%	3%	5%	6%	6%	6%	8%
Other renewable sources	1%	1%	3%	3%	3%	3%	3%	3%	3%	3%
Pumped storage	9%	8%	9%	8%	8%	8%	9%	9%	9%	9%
Other	7%	9%	6%	6%	6%	5%	6%	6%	6%	6%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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

39. 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 2017 is close to the level in 2013. The low values in the years 2014 and 2015 were mainly caused by the unavailability of certain nuclear power plants. The issue of unavailability of nuclear plants will be discussed in more detail below.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Nuclear	43.4	45.0	45.7	45.9	38.5	40.6	32.1	24.8	41.4	40.2
Natural Gas	23.4	29.4	30.2	24.1	21.9	18.1	16.8	18.5	18.0	18.8
Coal	6.4	6.3	4.9	3.7	3.3	3.0	2.2	2.2	0.4	0.0
Wind	0.0	0.2	0.4	1.0	1.1	1.8	2.5	2.9	2.7	3.2
Other Renewable	0.9	0.7	0.8	1.4	2.4	1.9	1.3	2.0	2.2	2.3
Puimped Storage	1.3	1.4	1.4	1.2	1.3	1.3	1.2	1.1	1.1	1.1
Other Renewable	2.0	2.6	3.3	3.2	3.3	3.9	3.9	4.2	4.1	4.5
Total	**77.4**	**85.5**	**86.6**	**80.5**	**71.9**	**70.7**	**59.9**	**55.8**	**69.9**	**70.2**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Nuclear	56%	53%	53%	57%	54%	57%	54%	44%	59%	57%
Natural Gas	30%	34%	35%	30%	31%	26%	28%	33%	26%	27%
Coal	8%	7%	6%	5%	5%	4%	4%	4%	1%	0%
Wind	0%	0%	0%	1%	2%	3%	4%	5%	4%	5%
Other Renewable	1%	1%	1%	2%	3%	3%	2%	4%	3%	3%
Puimped Storage	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Other Renewable	3%	3%	4%	4%	5%	5%	6%	7%	6%	6%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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

40. 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 6000. 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	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electrabel	13.7	12.2	11.8	11.4	11.0	10.3	10.2	10.2	10.2	10.1
EDF-Luminus	1.9	2.2	2.4	2.4	2.3	2.2	1.8	1.7	1.9	2.0
E.ON	0.0	1.4	1.5	1.5	1.5	1.5	1.1	0.6	0.0	0.0
Other (<3%)	0.4	0.5	0.6	1.0	1.6	1.7	1.9	2.0	1.9	1.9
Total	16.0	16.3	16.2	16.2	16.4	15.7	15.0	14.5	14.0	14.1

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electrabel	86%	75%	73%	70%	67%	65%	68%	71%	73%	72%
EDF-Luminus	12%	13%	15%	15%	14%	14%	12%	12%	14%	14%
E.ON	0%	9%	9%	9%	9%	9%	7%	4%	0%	0%
Other (<3%)	2%	3%	3%	6%	10%	11%	13%	14%	14%	14%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HHI	7470	5850	5620	5260	4810	4550	4860	5160	5510	5410

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

41. The energy generated by units connected to the Elia grid by ARP is shown in Table 9. The share of the different ARPs remain in 2017 at similar levels to 2016.

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electrabel	65.8	70.3	62.7	58.9	50.7	49.9	40.7	37.2	55.0	54.4
EDF Luminus	9.4	12.2	12.2	9.3	8.5	8.6	7.6	6.6	6.5	7.8
E.ON	0.0	0.5	8.8	8.5	7.8	6.9	6.3	4.6	0.9	0.0
T-Power	0.0	0.0	0.0	1.0	0.5	0.4	1.4	2.2	2.6	2.5
Andere (<3%)	2.2	2.6	3.0	2.8	4.4	4.9	4.0	5.1	4.9	5.5
Totaal	**77.4**	**85.5**	**86.6**	**80.5**	**71.9**	**70.7**	**59.9**	**55.8**	**69.9**	**70.2**

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electrabel	85%	82%	72%	73%	71%	71%	68%	67%	79%	77%
EDF Luminus	12%	14%	14%	12%	12%	12%	13%	12%	9%	11%
E.ON	0%	1%	10%	11%	11%	10%	11%	8%	1%	0%
T-Power	0%	0%	0%	1%	1%	1%	2%	4%	4%	4%
Andere (<3%)	3%	3%	3%	4%	6%	7%	7%	9%	7%	8%
Totaal	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HHI	**7299**	**6868**	**5439**	**5599**	**5242**	**5223**	**4893**	**4679**	**6303**	**6152**

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

2.3.2. Nuclear generation

42. As previously mentioned, nuclear generation represents a major share of electricity generation in Belgium. Nuclear plants are 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 16 shows the monthly nominations for all nuclear power plants in Belgium. Nuclear generation in the first part of 2017 was lower than in 2016; from June 2017 until the end of 2017, nuclear production was higher than in 2016. On a year-to-year basis, the nuclear generation was 1.4 TWh lower than in 2017. During the summer months (July and August) nuclear generation reached maximum historic levels of generation (period 2007 – 2014 is used as reference).

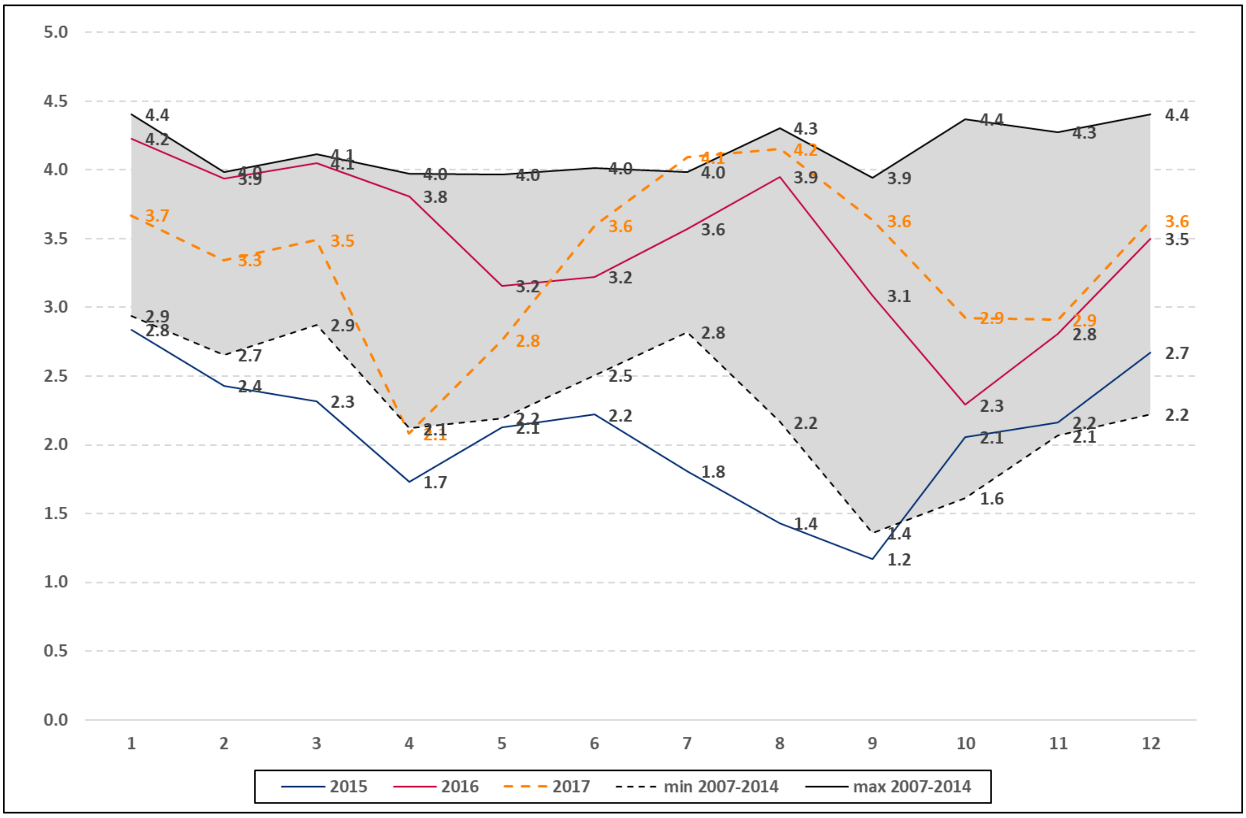

Figure 16: Monthly nominations for generation by nuclear power plants per year
Sources: Elia, CREG

43. 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.

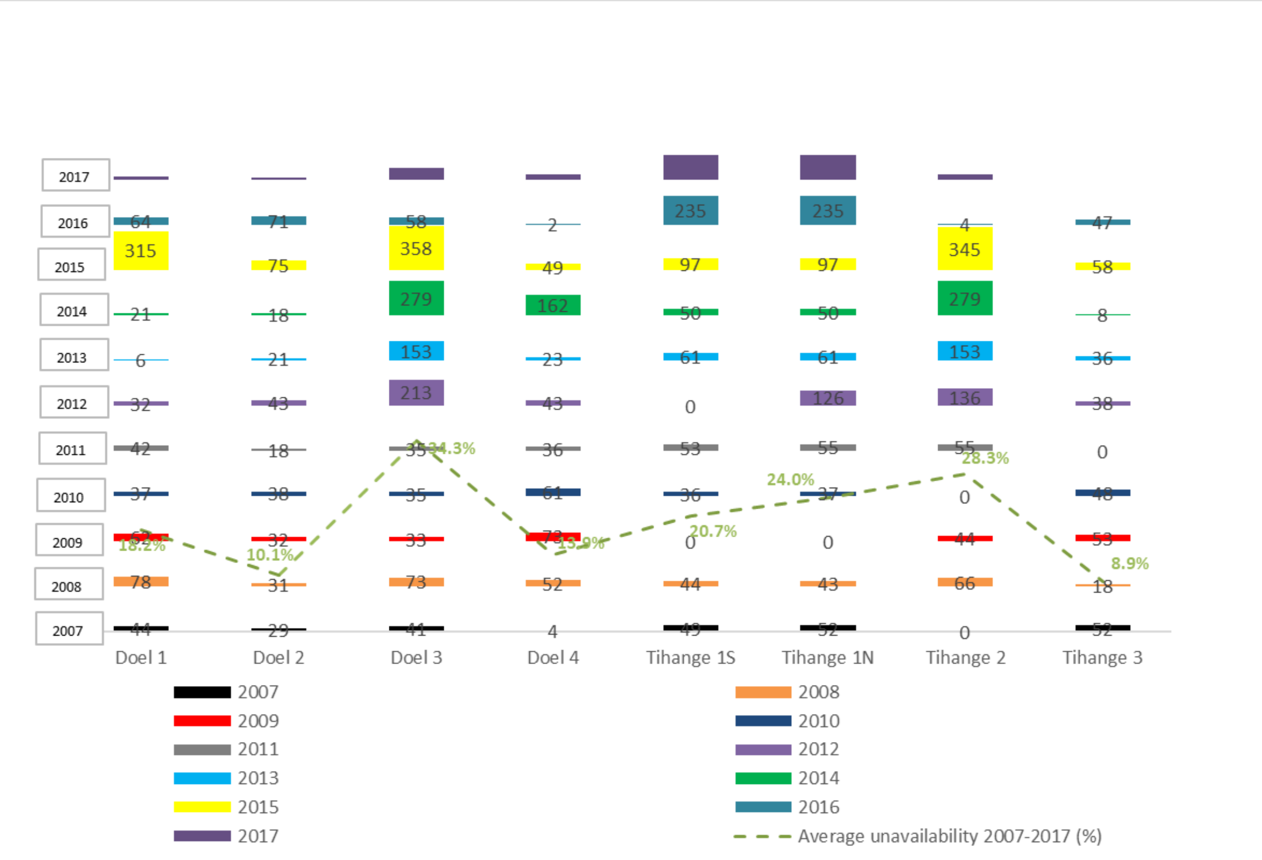

Figure 17: Number of days of unavailability of the 7 nuclear plants per year
Sources: Elia, CREG

2.3.3. Gas fired plants

44. Gas fired electricity generation represents 27% 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 active in the market[6].

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 Luminus	RINGVAART	365
T-Power	T-POWER	422
Direct Energy	Marcinelle Energie	405
Totaal		3277

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

[6] The 465 MW CCGT unit of Seraing operated by EDF-Luminus was contracted in the strategic reserve between 1/11/2014 and 31/10/2017 and is not considered active in the market.

45. As demonstrated in Figure 18, 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 previous 11 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 18.

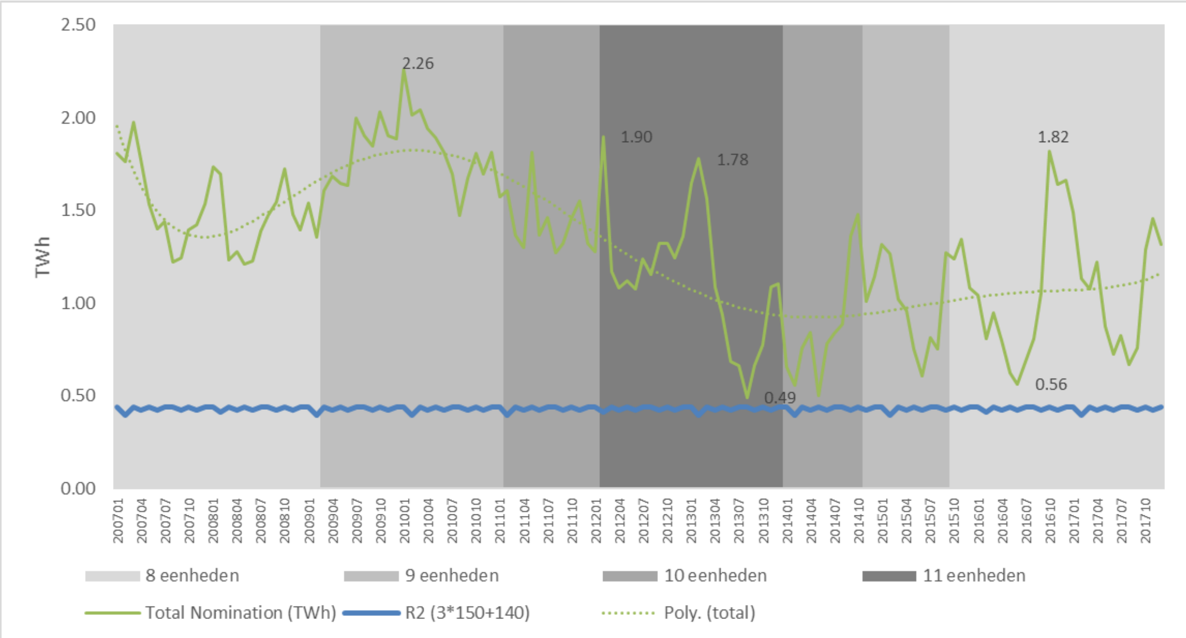

Figure 18: Total nominated energy in day-ahead of the Elia regulation zone CCGTs, per month, as well as an indication of the minimum average volume to be nominated for secondary reserves (blue line)
Sources: Elia, CREG

The high generation levels of CCGT at the end of 2016 and beginning of 2017 can be attributed to the unavailability of several French nuclear power units, and the unavailability of Tihange 1.

Table 12 gives 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) for each year. The decreasing trend of generation by CCGTs was reversed in 2015 and since 2016 there is still a slight increase. It should be noted that there is a significant 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%	41%	11.9%	1%	70%
2017	12.8	2.9%	45%	8.8%	0%	69%
2007-2016	16.0	-32.7%	47%	-35.6%		

Table 12: Overview of electricity generated by major CCGTs in Belgium and their load factors
Source: Elia, CREG

46. An evaluation of the historic operational profit of a CCGT plant of 400 MW by performing a standard asset-backed trading strategy confirms that market conditions have improved since 2014 (Figure 19). The trading strategy is only performed by using Calendar baseload products and daily products covering the peak and off-peak period for delivery of baseload power in Belgium. Even though the level of operational profit before 2013 is significantly higher than the operational profit to be expected for an average CCGT plant in Belgium in recent years, it still attains a positive value.

Calendar products seem to be barely relevant to attain a positive operational profit. In fact, most CCGT plants do not generate electricity throughout the year but rather during the winter period when renewable energy generation levels are typically low. As such, averaged yearly baseload prices are not the best indicator to assess the operational profit of a CCGT plant.

Analysing historic operational profit does not provide insight into future operational profits, as it does not assess future market risks, nor does it include information on the net profit or the bottom line of the profitability of the CCGT plant (after taxes, interest, depreciation and amortisation).

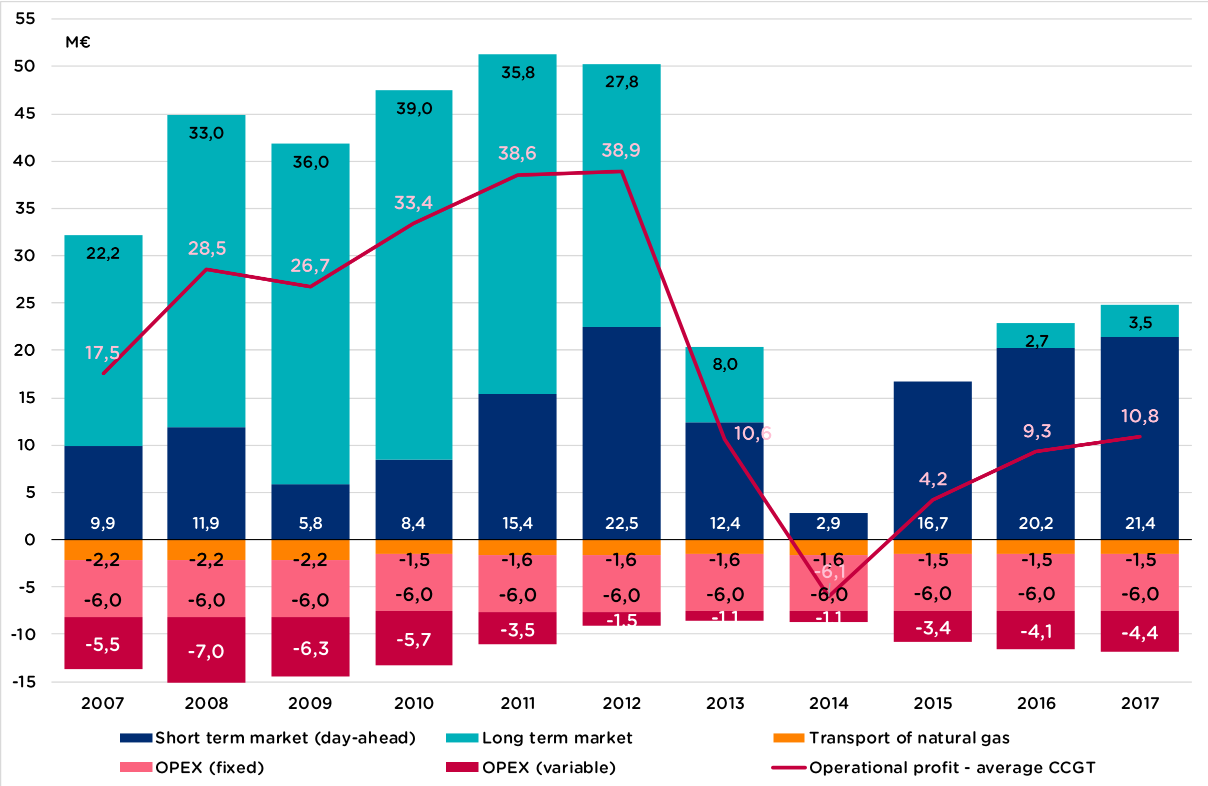

Figure 19: Operational profit of an average CCGT plant of 400 MW located in Belgium (red line) by following a static standard asset-backed trading strategy, 2007-2017
Source: CREG

3. ELECTRICITY TRADING

3.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

3.1.1. 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 20 October 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 organising the Belgian short term electricity market. Belpex became operational on 21 November 2006. The Belgian Transmission System Operator (TSO) Elia held a stake of 70%, the Dutch (APX) and the French (Powernext/EPEX Spot) power exchanges each held a stake of 10%, as did the Dutch TSO TenneT. The French TSO RTE also subsequently participated by taking over a stake of 10% from Elia.

3.1.2. 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 existing 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 the United Kingdom, thereby coupling the CWE-region with the latter country (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. In addition to the countries already mentioned above, Austria, Poland, Lithuania, and Latvia were also included in the NWE region. The NWE region was the first region to use the algorithm *Euphemia*, developed as part of the Price Coupling of Regions (PCR) project, to optimise 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 optimises social welfare in the coupled region by exchanging electricity between adjacent bidding zones to the extent allowed by the ATC, the latter simultaneously 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 May 2015 (delivery 21 May).

3.1.3. Organisation of the Belgian intraday market by Belpex

2008 Belpex started organising 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, organised the implicit allocation of cross-border intraday capacity between the French and German bidding zones.

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 ongoing.

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.

3.1.4. 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[7] trade – to the M7 platform (intraday trade) on 4 October 2016 and the EPEX Trading System (day-ahead trade, ETS)

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[7] 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 5 October.

Before Belpex was fully integrated operationally, EPEX SPOT requested a modification of the market rules of Belpex. On 7 January 2016[8], 19 July 2016[9] and 22 September 2016[10] the CREG gave its opinion on the requested modifications of the Belpex market rules. In these opinions, the CREG recommended that any obligations or restrictions applicable to the market participant be included in the market rules in accordance with the Royal Decree of 20 October 2005. In its opinions, the CREG highlighted 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 United Kingdom. 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.

2017 After completing tests in January, on 24 January, the migration of the Belgian and Dutch day-ahead markets from Euphemia to the Emission Trading System was completed. At the same time, EPEX SPOT substituted the free, daily communication of market results to market participants regarding the Belgian market to a paid service via its SFTP server[11].

3.1.5. 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 Nominated 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.

2016 In relation to CACM, on 14 January 2016, the CREG gave two opinions, one for the nomination of Belpex[12] as NEMO and one of the nomination of Nord Pool[13] as NEMO, following requests by the Minister of Energy received on 7 December 2015. Both power exchanges have been successfully nominated as NEMO.

In relation to REMIT, the CREG received 3 formal notifications. In total, 7 cases were analysed during the year and 1 was closed or transferred to another authority.

2017 In relation to CACM, on 29 June 2017, the CREG published its decision on the application of EPEX SPOT Belgium and Nord Pool SA and all designated electricity market operators for the revised plan concerning the joint performance of MCO functions.

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[8] http://www.creg.be/nl/publicaties/advies-a160107-cdc-1502 (available in Dutch and French).
[9] http://www.creg.be/nl/publicaties/advies-a160719-cdc-1549 (available in Dutch and French).
[10] http://www.creg.be/nl/publicaties/advies-a160922-cdc-1567 (available in Dutch and French).
[11] Market prices can still be freely consulted on the Transparency Platform of ENTSO-E, under the tab 'Transmission': https://transparency.entsoe.eu/
[12] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1501 (available in Dutch and French).
[13] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1503 (available in Dutch and French).

In relation to market monitoring activities, on 24 May and on 17 July, following enquiries from market participants, the CREG published two reviews explaining the day-ahead market results on 6 April, 10 April 10, and 1 May.

In relation to REMIT, the CREG received 7 formal notifications. In total, 13 cases were open for analysis during the year and 6 were closed or transferred to another authority.

3.1.6. Organisation of the Belgian day-ahead and intraday markets by EPEX SPOT Belgium

2016 On 14 January 2016, the CREG gave two opinions, one for the nomination of Belpex[14] as NEMO and one for the nomination of Nord Pool[15] as NEMO, following requests by the Minister of Energy received on 7 December 2015. Both power exchanges were 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, there was a risk of partial decoupling. 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 October 2016, version 9.5 of Euphemia was released.

2017 From 11 January onwards, the upper threshold to trigger a second auction was raised from €500/MWh (£500/MWh in the UK) to €1,500/MWh (£1,500/MWh in the UK). The lower threshold remains at -€150/MWh (-£150/MWh). No second auctions were triggered in 2017 and on 1 day the publication of market results was delayed, suggesting that it took the market clearing algorithm more than 10 minutes to calculate a feasible market clearing price.

Intraday trading was restricted on several occasions. On 9 January from 2:20 to 3:11, on 10 January from 15:55 to 19:00, and on 24 January from 15:55 to 19:00 (advanced to 18:05) cross-border trading with the Netherlands was restricted. On 30 January from 19:40 until 31 January at 00:15 all local intraday trade was suspended.

On 14 November 2017, version 6.0 of the M7 trading system was deployed between 16:30 and 23:25.

Finally, on 17 July, Nord Pool spot was appointed market operator for the exchange of energy blocks by Ministerial Decree, after having filed a request on 16 May.

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[14] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1501 (available in Dutch and French).
[15] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1503 (available in Dutch and French).

3.2. SPECIAL TOPIC

47. During the past two years, trading on the Belgian intraday market has increased significantly, from 737 GWh in 2015 to 1991 GWh in 2017 (+250%, Figure 20). The increase in trading volumes signals increased liquidity on the Belgian market, and might even indicate that the formerly illiquid intraday market might have become sufficiently liquid for market participants to reliably find a counterparty for their trading needs. The special topic of this chapter analyses whether the increased liquidity resulted in an increase in competition on the Belgian intraday market.

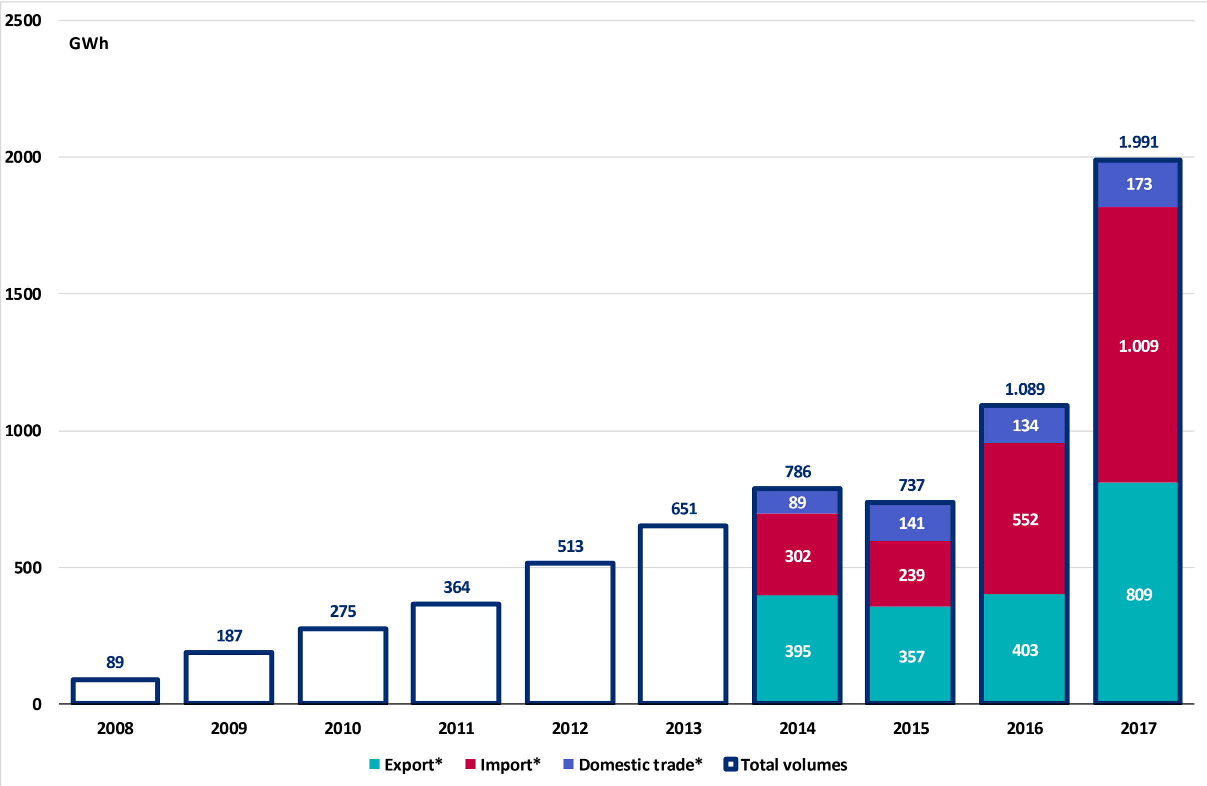

Figure 20 – Volumes traded on the Belgian intraday market, including segmentation in import, export and domestic trade within Belgian since 2014.
Source: CREG based on data provided by EPEX SPOT Belgium

48. Roughly 90% of the trades have a cross-border leg. During the past two years, roughly 60% of cross-border trades were intended to import energy to Belgium. The increase in trade on the Belgian intraday market since 2016 is due to the change from explicit to implicit intraday capacity allocation on the Belgian-French and Belgian-Dutch borders starting from October 2016. Implicit intraday capacity allocation has been made possible following the enlarged international scope of orderbooks visible by the Belgian orderbook, from only France and the Netherlands before May 2015 to also Germany, Austria and Switzerland, following the development of activities by EPEX SPOT on the Belgian market.

49. The net trade volumes, i.e. excluding trading that transits commercial flows in and out of Belgium during a delivery hour, are 715 GWh in 2016 and 1,158 GWh in 2017. These account for 75% and 64% of the gross cross-border traded volumes respectively. Of the 1,158 GWh traded in 2017, 479 GWh was exported for 3,386 hours and 679 GWh was imported for 3,126 hours. In 2016 the exports were 282 GWh for 2,866 hours, while the imports were 432 GWh for 3,661 hours. These numbers suggest that the Belgian intraday market is exposed to competition from abroad. The proportion of hours exporting versus importing, however, deviates significantly with the proportion observed on the day-ahead market (see Table 15) and in the direction of a 50%-50% import-export split, suggesting that

market participants currently use the intraday market more for portfolio optimisation purposes given their day-ahead schedules than for additional sourcing or arbitrage between the different bidding zones. This observation emphasizes the need for fair and objective day-ahead cross-zonal capacity allocation.

50. In 2017, cross-border trade is low in January, November and December (Figure 21). During these months, much of electricity volumes were interchanged with France. From March until September trade increases with Germany and to a lesser extent with the Netherlands, possibly because of fewer loop flows and lower demand.

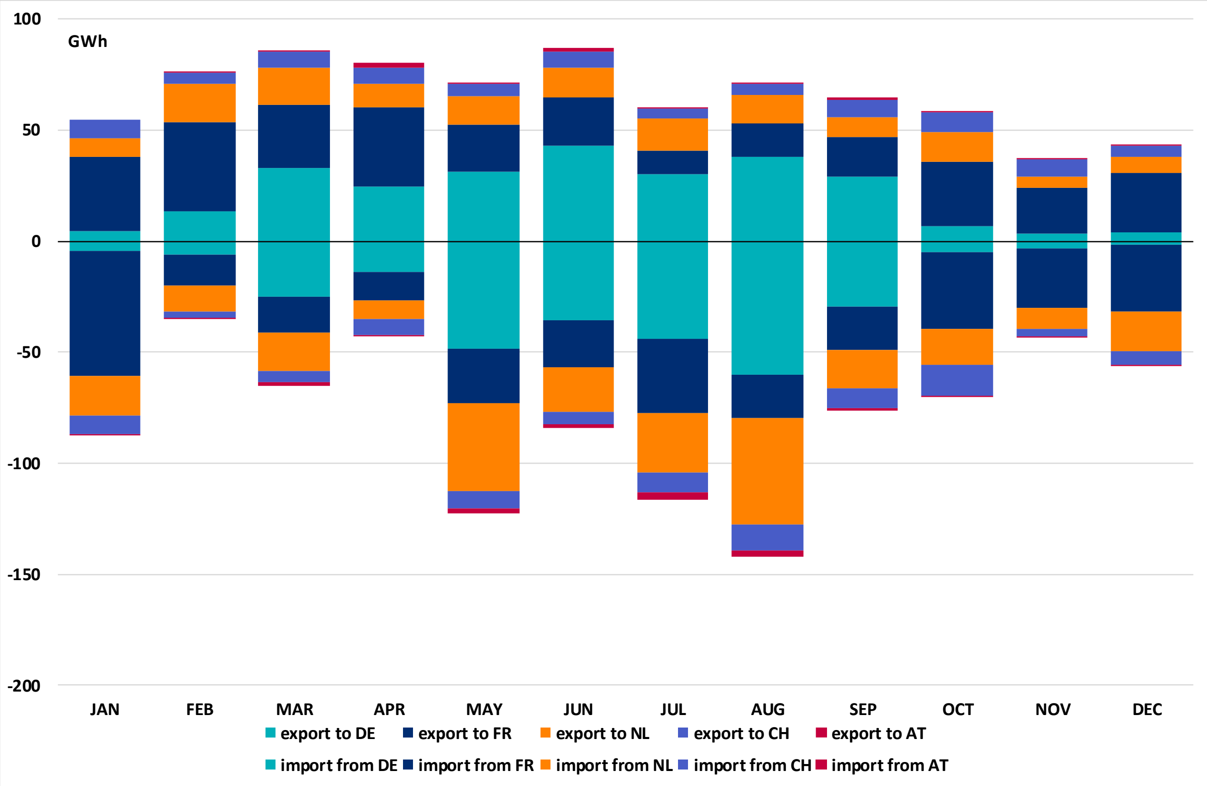

Figure 21 – Segmentation of the traded volumes on the Belgian intraday power exchange in terms of destination (for exports) or origin (for imports), per month in 2017. Traded volumes within Belgium are not represented in the graph.

51. Liquidity is not uniformly available throughout the whole intraday trading window, but is concentrated for import and export around 4 hours before delivery time (Figure 22). Trade between market participants located in Belgium is concentrated around 3 hours before delivery time, suggesting a wait-and-see attitude on the part of Belgian market participants on the yields of cross-border trade.

Generally, internal trades in Belgium occur until 2 hours before delivery time while cross-border trades happen until 3 hours before delivery time (Figure 23). Currently[16], the end of cross-border capacity is one hour before the start of the delivery period, explaining the low cross-border volumes one hour before delivery time. The fact that, also two hours before delivery time, cross-border trade is low indicates that the intraday market is not used to trade away updates of renewable energy forecasts after 3 to 4 hours before delivery time.

[16] See the information brochure concerning cross-border allocations: http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/C-Cross-border%20allocations/C3_E_WEB.pdf

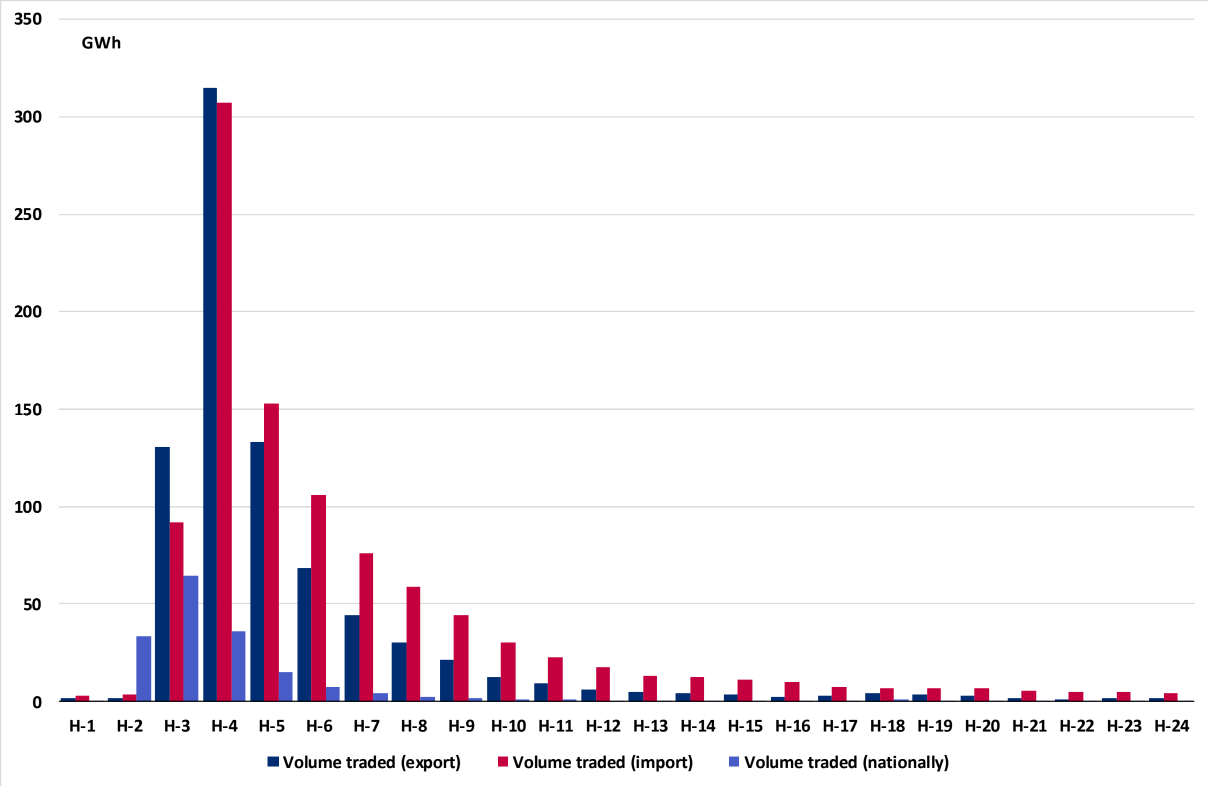

Figure 22 – Volume traded per segment in terms of lead time to delivery for 2017
Source: CREG based on data provided by EPEX SPOT Belgium

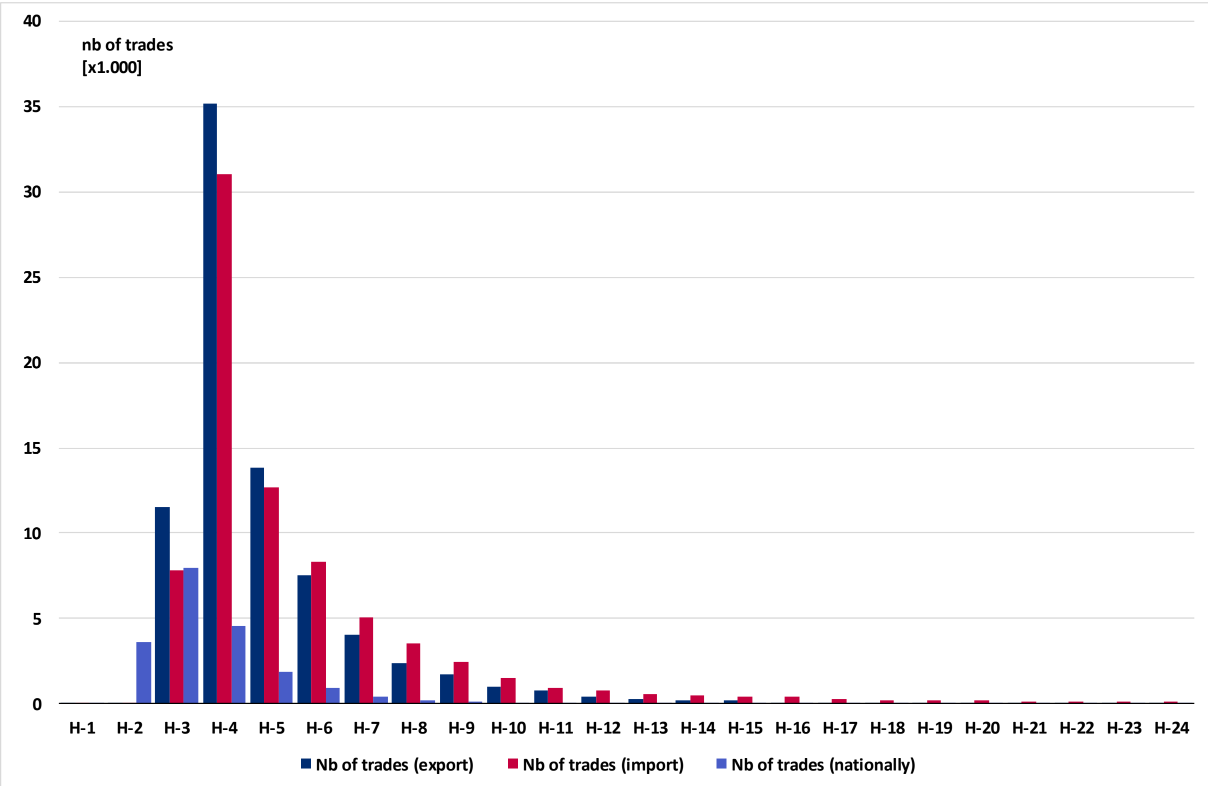

Figure 23 – Number of trades per segment in terms of lead time to delivery for 2017
Source: CREG based on data provided by EPEX SPOT Belgium

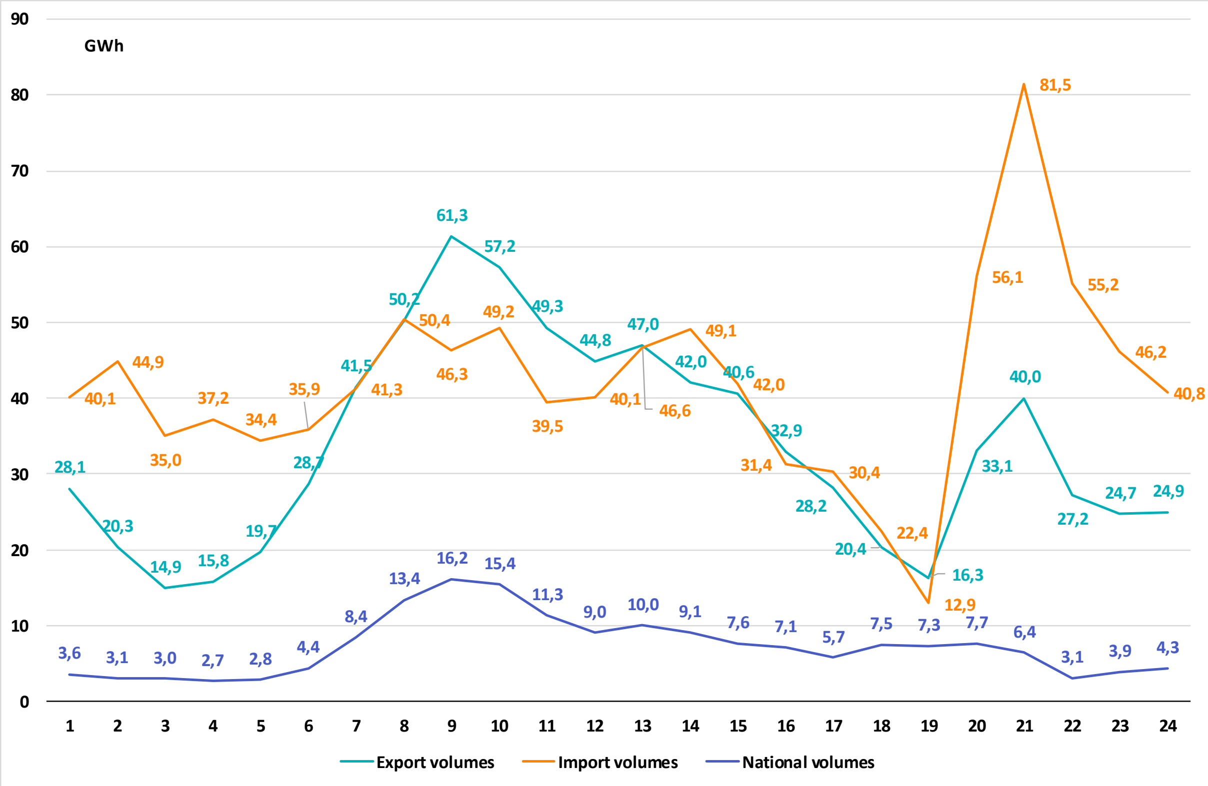

Figure 24 – Volume traded per segment in terms of transaction time during the day to delivery for 2017
Source: CREG based on data provided by EPEX SPOT Belgium

52. Export, and especially import transactions, are mainly concluded from the moment available cross-border transmission capacity is allocated to the borders, at 21:00 (hour 21 in Figure 24)[17]. Cross-border trade occurs at every hour of the trading day. The import and export curve are closely aligned (except for right after available transfer capacity is made available at 21:00), indicating that market participants primarily aim to be balanced according to their day-ahead schedule.

53. Internal intraday trade in Belgium occurs around the morning peak. At the same time export volumes traded are increasing. Intraday trade drops steeply during the hours before cross-border capacity is made available, signalling that cross-border intraday capacity holds a value for market participants that is sufficiently significant to delay trades. This observation is in contrast with the zero-cost pricing at which the available cross-border capacity is made available to market participants on a first-come-first-served basis.

54. A clear inverse correlation between traded volumes in the intraday market and low price spreads with the day-ahead price, which is assumed to serve as a reference on which market participants bid in their intraday bids and offers (Figure 25). Hours when the intraday price is higher compared with the day-ahead price are generally characterised by a wider range of price spreads at similar volume levels.

On average, the price spread is also higher if the intraday price is higher than the intraday price, except when volumes of around 400 MWh to 500 MWh have been traded (Figure 26). At lower traded volumes, the data signals that price spreads might be higher because of low levels of competition. Increasing volumes lead to lower price spreads in case the intraday price is lower than the day-ahead

[17] Cross-border capacity is allocated at 21:00 between Belgium and France, and at 21:05 between Belgium and the Netherlands. Instruments for intraday trade are available as from 14:00 the trading day prior to delivery until 5 minutes before delivery.

prices. If intraday prices are higher however, the price spread increases again from 500 MWh onward, possibly signalling a higher valuation of the volume.

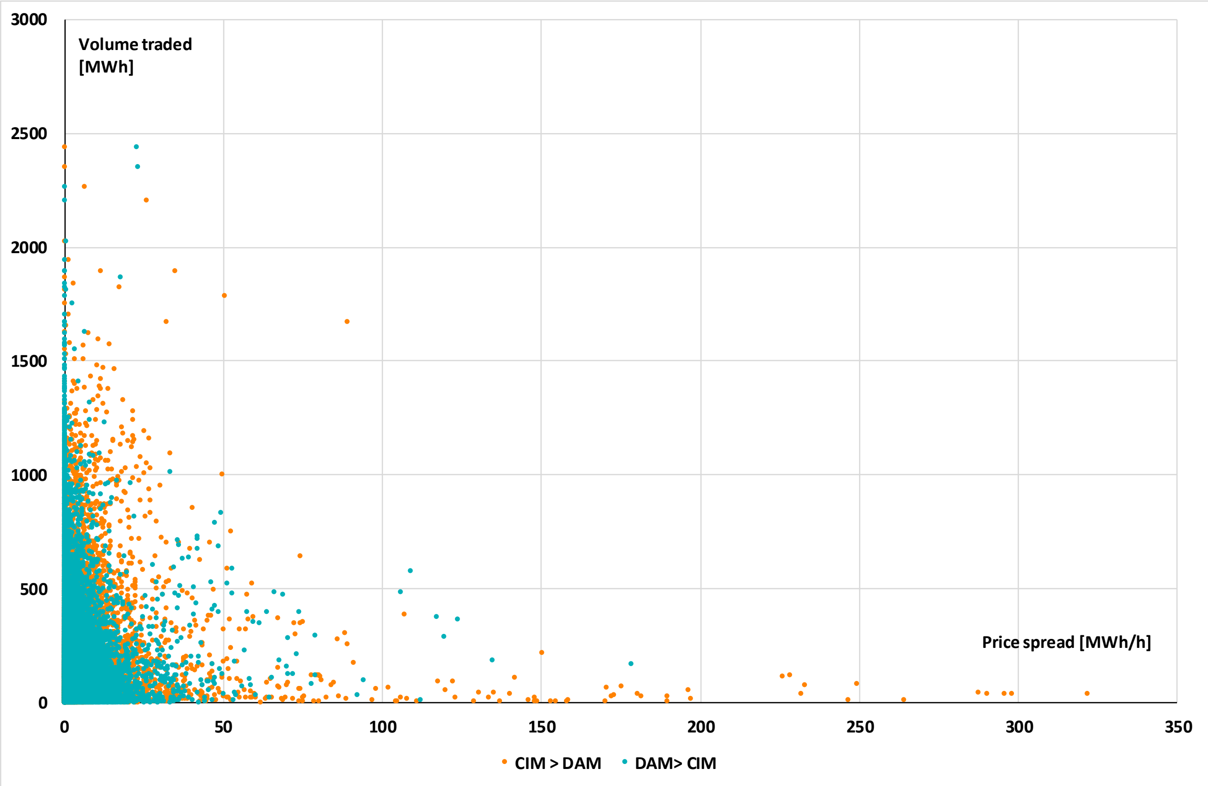

Figure 25 – Traded volume according to the price spread between the intraday and the day-ahead price of each hour in 2017, and segmented based on the sign of the price spread.

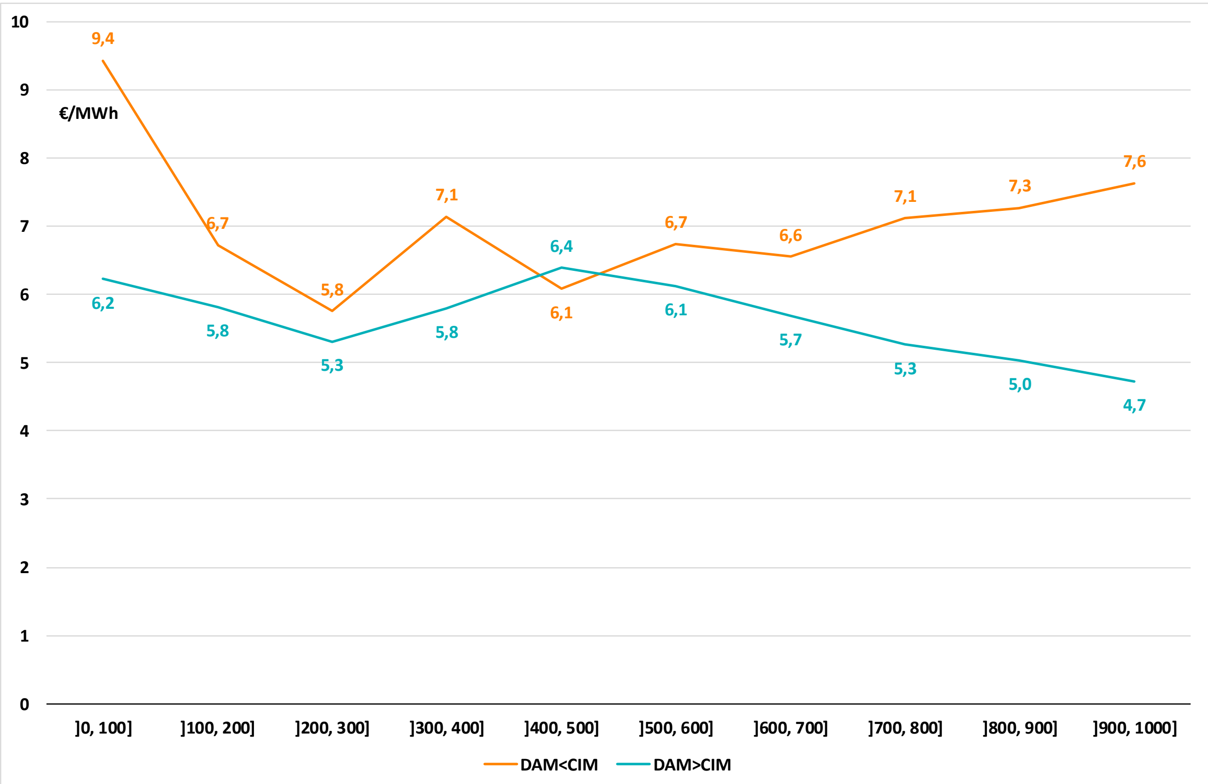

Figure 26 – Average (absolute) price spread between the intraday and day-ahead price, per interval of 100 MWh hourly trade volume

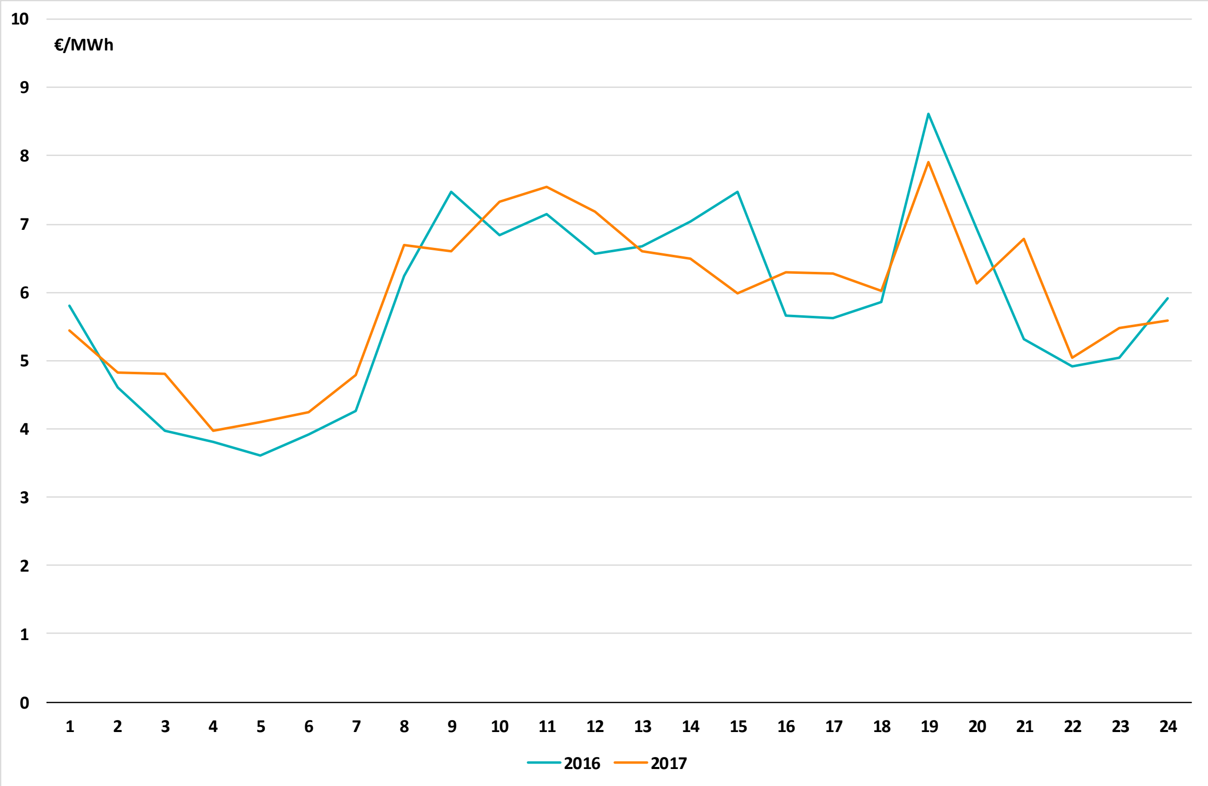

Figure 27 – Average (absolute) price spread between the intraday and day-ahead price if the intraday price is lower than the day-ahead price, for each hour of the day, for the years 2016 and 2017

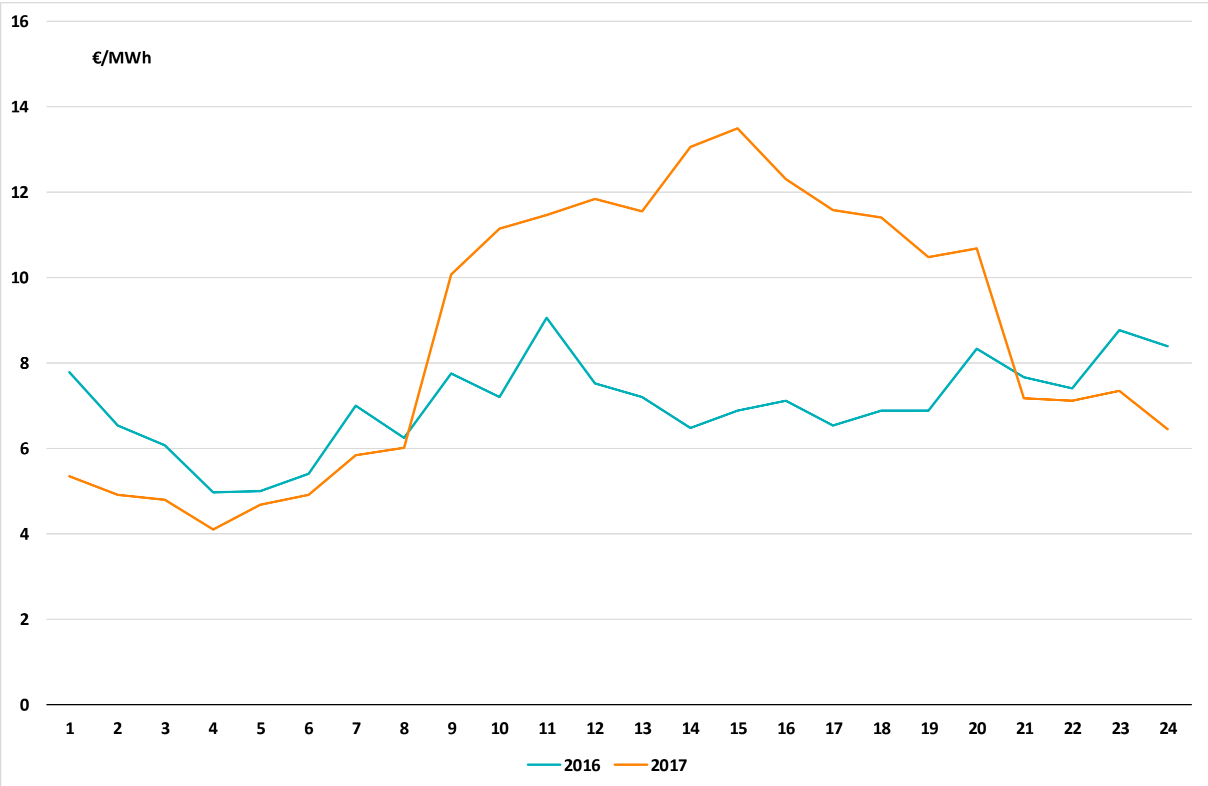

Figure 28 – Average (absolute) price spread between the intraday and day-ahead price if the intraday price is higher than the day-ahead price, for each hour of the day, for the years 2016 and 2017.

55. The daily profile of the price spread between the day-ahead and intraday market in 2017 has not changed significantly from the one in 2016 if the intraday price is lower than the day-ahead price (Figure 27). During the peak period, and especially at hour 19, a higher price spread is observed. The profile significantly changed during the peak period if the intraday price is higher than the day-ahead price (Figure 28).

3.3. STATISTICS

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

56. The yearly averaged day-ahead wholesale electricity price in Belgium increased back to a level not seen since 2015 (€44.6/MWh) (Figure 29). The 21% year-on-year price increase is observed in all bidding zones in the CWE region and signals that, on average in 2017, the region relied on more expensive supply to meet demand.

57. The monthly averaged day-ahead price in Belgium shows that prices are high during periods of high demand (e.g. winter time) and when generation units are scheduled to be in maintenance (e.g. April and October) (Figure 30, turquoise). It also shows that prices are low during the summer period. Both periods show a year-on-year increase in prices, suggesting a structural shift of the supply-demand equilibrium throughout the year.

The shift was driven by the low nuclear power plant availability in France in 2017 as French day-ahead prices closely correspond to the Belgian ones (Figure 30, purple). A lower amount of baseload capacity increases prices during summer time when the marginal cost of baseload power plants set the price. It also increases prices during winter time because peak units are more frequently called upon to meet demand. However, average monthly prices that exceed the expected marginal cost of Belgian peak power plants running on natural gas, as was the case in winter 2017[18], suggest there were situations of scarcity.

[18] The monthly average of the ZTP day-ahead price during winter 2017 equalled approximately €20/MWh_t (leading to an expectation of a marginal cost of around €40/MWh_e). See figure 17 of CREG Note 1719, [available online in Dutch or French, http://www.creg.be/nl/publicaties/nota-z1719].

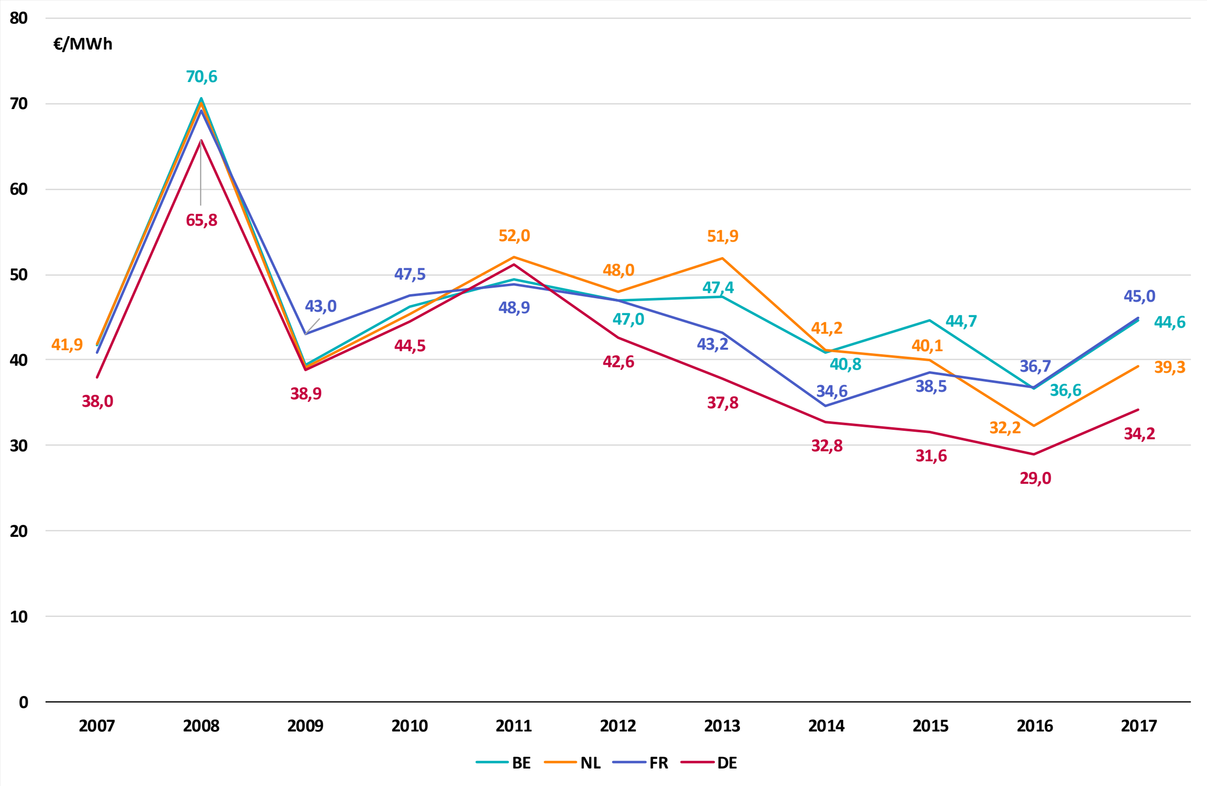

Figure 29: Yearly average hourly day-ahead wholesale electricity prices, per bidding zone in the CWE region, increased in 2017. The Belgian bidding zone together with the French zone have the highest averaged prices.
Sources: CREG based on data received from EPEX SPOT Belgium, EPEX SPOT

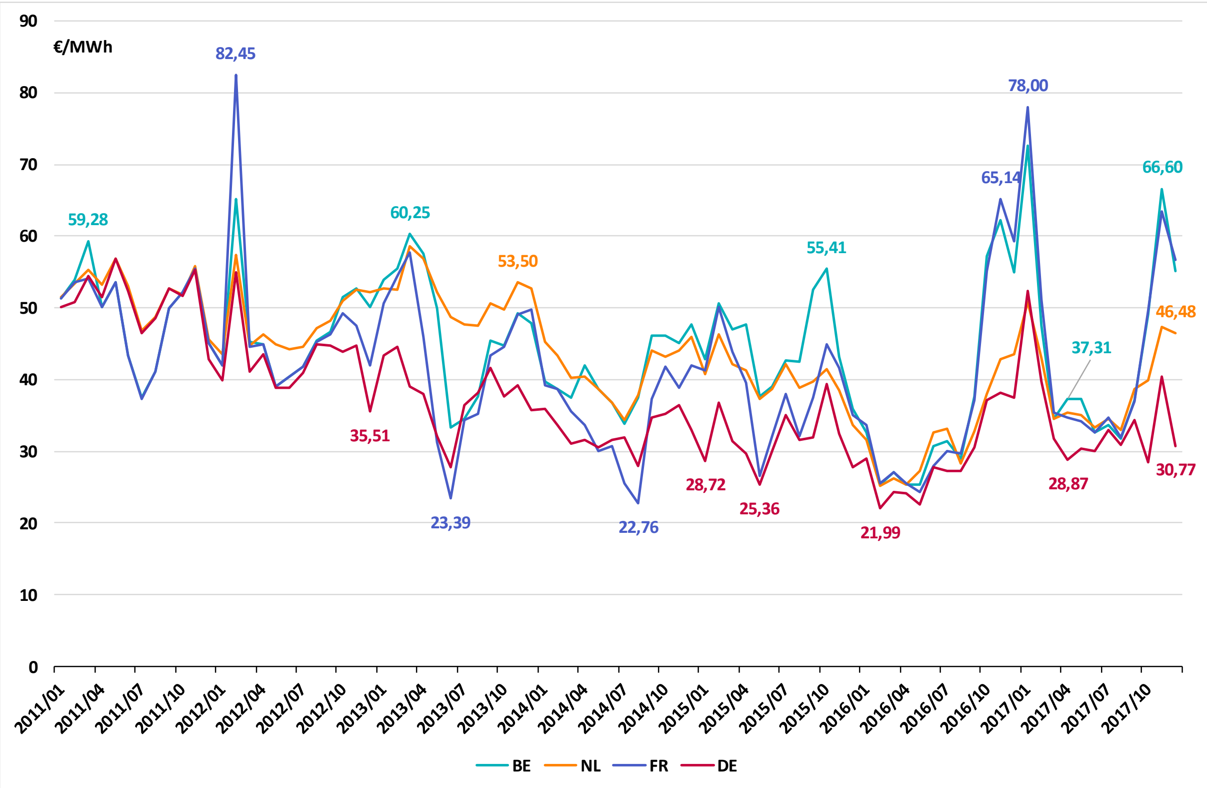

Figure 30 – Monthly average hourly day-ahead wholesale electricity prices, per bidding zone in the CWE region, increased in 2017. The Belgian bidding zone together with the French zone have the highest averaged prices.
Source: CREG based on data received from EPEX SPOT Belgium

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
<0	0	0	0	0	0	7	15	2	0	2	6
[0 - 20[	1493	354	940	457	815	370	830	444	285	989	309
[20 - 40[	4190	757	4117	2421	1033	2495	1912	3779	3111	5222	4256
[40 - 60[	1770	2105	2731	4391	4666	4405	3873	4032	4438	1724	2744
[60 - 80[	605	2711	730	1314	2178	1291	1871	477	796	590	913
[80 - 100[	339	1675	199	123	48	140	215	19	65	140	296
[100 - 200[	305	1164	43	52	19	73	44	6	29	98	229
[200 - 300[	25	13	0	2	0	3	0	1	22	14	5
[300 - 500[	15	2	0	0	0	0	0	0	14	2	2
[500 - 1000[	14	3	0	0	0	0	0	0	0	3	0
[1000 - 3000[	4	0	0	0	1	0	0	0	0	0	0

Table 13 – Histogram of the Belgian day-ahead wholesale electricity prices, per year.
Source: CREG based on data provided by EPEX SPOT Belgium

58. Defining hours during which the Belgian day-ahead price exceeds €80/MWh as hours with scarcity, in 2017 over 6% of the time (532 hours) scarcity was observed, double the number of hours of the previous year and quadruple the number of hours the year before (Table 13). As such, the energy-only market remunerated the most expensive generation asset above its marginal cost in 2017, allowing it to receive a premium and therefore mitigate the cash shortfall.

A large share of hours (49%) lie between €20 EUR/MWh and €60 EUR/MWh in 2017. This share did not change significantly with respect to 2016, pointing to sufficient baseload generation capacity in the CWE region, even in the absence of available nuclear power plants in France.

A negative price was observed for 6 hours in 2017. Negative prices are typically imported from Germany when large volumes of renewable energy are injected into its grid. In 2017, German day-ahead prices were negative for 146 hours on 24 days. The large difference in the number of negative hours between Belgium and Germany suggests that the commercial interconnection capacity made available by TSOs for day-ahead trade is insufficient to effectively integrate the four markets in the CWE region when infeed from renewable energy is high.

59. French available nuclear power plant capacity is expected to increase. Consequently, it is premature to assume that the price observations in 2017 are part of a trend that will persist in subsequent years. However, the low available commercial interconnection capacity for day-ahead trade in the CWE region already persists for several years (Table 14). In 2017 the four bidding zones in the CWE region were only price convergent for 34% of the time. Even though this share has increased gradually since 2013 and significantly since 2016, full price divergence in the CWE region has also increased, to 49%, from less than 3% in 2012. The observations therefore suggest that the introduction of the flow-based market coupling in May 2015 discourages partial market integration in the CWE region if full market integration cannot be achieved. Additional analyses in Chapter 4 support the observation that the suboptimal application of the flow-based market coupling method by TSOs in the CWE region exacerbates this problem.

	BE = FR				BE ≠ FR			
	BE = NL		BE ≠ NL		BE = NL		BE ≠ NL	
	BE = DE	BE ≠ DE	BE = DE	BE ≠ DE	BE = DE	BE ≠ DE	BE = DE	BE ≠ DE
2007	0,29%	62,26%	0,11%	26,27%	0,06%	9,45%	0,00%	1,56%
2008	0,11%	69,13%	0,06%	15,21%	0,02%	14,74%	0,00%	0,73%
2009	0,11%	56,69%	0,01%	13,22%	0,06%	28,32%	0,00%	1,59%
2010	8,08%	52,35%	0,07%	26,26%	0,21%	11,79%	0,01%	1,23%
2011	65,82%	5,16%	1,52%	26,69%	0,10%	0,25%	0,00%	0,46%
2012	46,61%	12,85%	11,01%	14,97%	1,90%	11,24%	0,00%	1,42%
2013	14,76%	19,01%	17,28%	20,50%	0,68%	25,05%	0,01%	2,71%
2014	18,66%	10,99%	4,97%	11,89%	5,83%	42,29%	0,00%	5,35%
2015	18,95%	10,16%	0,67%	13,78%	0,27%	14,28%	0,06%	41,83%
2016	34,53%	1,80%	0,42%	7,90%	1,66%	3,72%	0,13%	49,84%
2017	34,19%	3,61%	0,71%	6,31%	1,39%	5,00%	0,14%	48,65%
JAN	5,65%	0,81%	0,00%	14,52%	2,28%	4,44%	0,40%	71,91%
FEB	22,47%	0,30%	0,15%	4,17%	1,34%	9,82%	0,30%	61,46%
MAR	44,41%	2,96%	0,81%	2,83%	3,36%	4,71%	0,94%	39,97%
APR	29,17%	2,36%	0,14%	8,89%	0,00%	8,06%	0,00%	51,39%
MAY	49,46%	0,13%	0,40%	3,36%	0,00%	2,28%	0,00%	44,35%
JUN	56,11%	0,42%	1,53%	3,75%	2,22%	3,33%	0,00%	32,64%
JUL	60,75%	0,81%	0,13%	1,34%	2,96%	5,65%	0,00%	28,36%
AUG	65,59%	1,48%	2,82%	1,34%	2,55%	0,54%	0,00%	25,67%
SEP	53,89%	4,44%	2,50%	2,78%	0,00%	2,50%	0,00%	33,89%
OCT	8,86%	8,72%	0,00%	13,83%	0,27%	5,91%	0,00%	62,42%
NOV	7,64%	6,53%	0,00%	10,97%	0,14%	6,67%	0,00%	68,06%
DEC	5,51%	13,98%	0,00%	7,80%	1,48%	6,59%	0,00%	64,65%

Table 14 – Full hourly price convergence (≤ €0.01/MWh) between Belgian day-ahead prices and the day-ahead prices in the other bidding zones in the CWE region, per year and for each month of 2017
Sources: CREG based on data provided by EPEX SPOT Belgium

60. Contrary to the monthly average price convergence between day-ahead prices in France and in Belgium (Figure 30), hourly price convergence is achieved for only 45% of the time between the two bidding zones in 2017, of which in 75% of the cases full price convergence with all bidding zones in the CWE region was attained (Table 14). During the months when monthly average day-ahead prices in France and Belgium clearly diverge from those in the Netherlands and Germany, price convergence between only Belgium and France increased from an average of 3.6% to 7.8% or even 14.5%. During the same months full price divergence in the CWE region also increased.

This observation highlights the price fluctuations to which smaller bidding zones are subject following increased competition of larger bidding zones, for imports. When the French bidding zone competes for imports from Germany, in addition to the Belgian bidding zone, the import needs of the French bidding zone drive up the price of these imports. In order for the Belgian bidding zone to secure imports to meet its supply-demand balance, a similar price must be paid. The less frequent a bidding zone relies on imports from Germany to satisfy its demand, as is the case for the Dutch bidding zone, the lower the price influence following competition for imports. The reliance on imports is either structural, for example due to the low cost-competitiveness of the existing generation mix in a given bidding zone, or acute, for example following a temporary unavailability of cost-competitive generation units.

61. The reduction of baseload generation capacity in France and Belgium did not significantly affect price volatility in 2017 compared with the situation in 2016 (Figure 31). Each statistic shows a slight increase however. Inter-day and inter-month volatility reach a new high not seen since 2010. This observation combined with the increase in frequency of elevated day-ahead prices (see Table 13), suggests that the market environment to economically valorise flexible generation or demand units has improved.

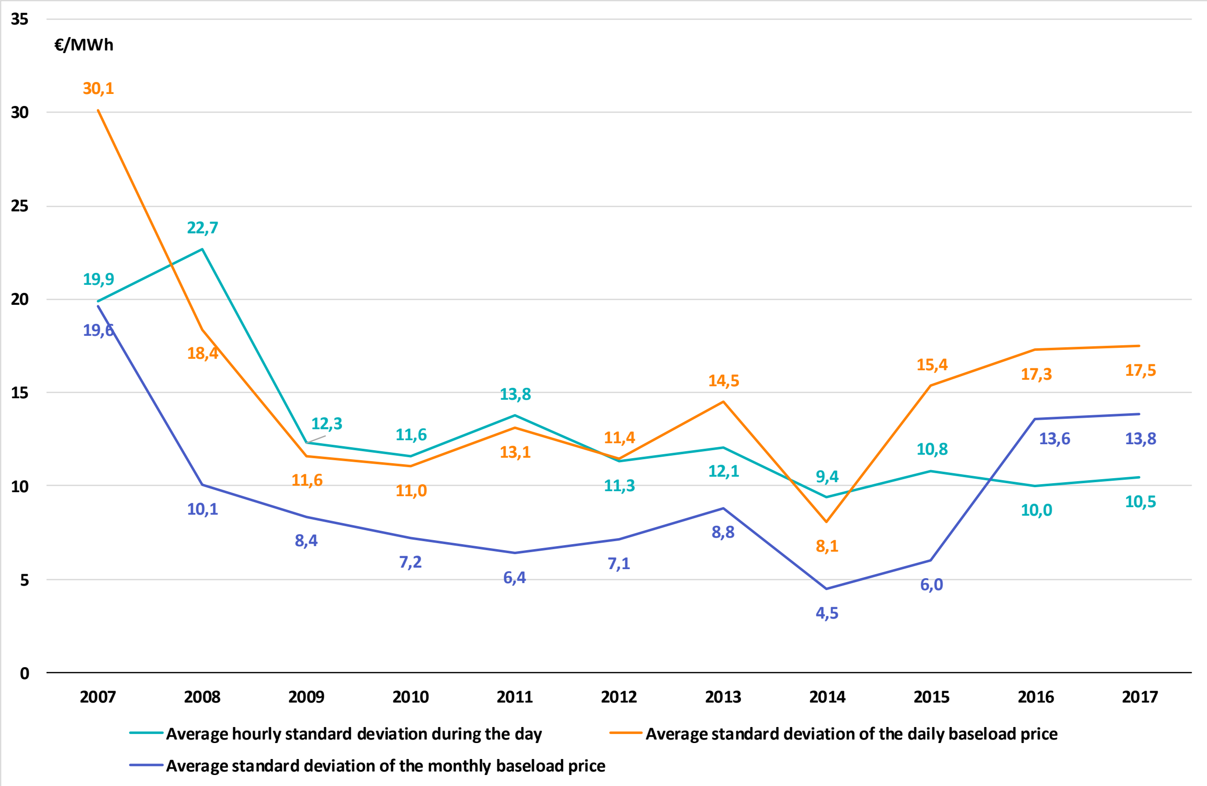

Figure 31 – Volatility of the Belgian day-ahead price, described by three statistics
Source: CREG based on data provided by EPEX SPOT Belgium

62. Trade on the Belgian day-ahead market fell by 1.7 TWh in 2017 compared with 2016 (Table 15). This reduction in trade is due to the reduction of buy and sell volumes introduced by market participants on the Belgian power exchange. Imports and exports remained stable at respectively 7.7 TWh and 1.3 TWh. Day-ahead trade on the power exchange accounted for 23% of the Elia load. Despite the decrease in volume traded, the total value of contracts traded on the Belgian power exchange increased due to the increase of day-ahead prices (Figure 32). The value of traded contracts is aligned with the observed historic values (except for 2015).

Buy volumes were high in the first 5 months and last quarter of the year, with a peak in April. Sell volumes remained relatively flat throughout the year with an uptick in July (Figure 33). This observation points to a large volume of supply being hedged in forward markets or traded on markets other than the day-ahead power exchange (e.g. OTC markets) and demand being sourced more flexibly on day-ahead power exchanges.

The role of the day-ahead power exchange in fairly and objectively creating transparent price signals is important. Day-ahead prices formed on power exchanges determine commercial cross-border exchanges and are used as references for the majority of bilateral contracts. Consequently, the CREG expects market participants to trade, in day-ahead and by efficiently using all products, all available generation and demand capacity at a price that is cost-reflective (i.e. marginal costs). Scarcity on the day-ahead market should be the result of the fair and competitive interplay of demand and supply, not an artificially created opportunity by not offering available generation and demand capacity.

	Buy	Sell	Trade	Import	Export	Net Import	Trading / Load ELIA
2007	6,8	4,8	7,6	2,7	0,8	2,0	8,6
2008	10,4	4,3	11,1	6,8	0,7	6,1	12,6
2009	6,0	9,1	10,1	1,0	4,1	-3,1	12,4
2010	9,6	8,9	11,8	2,9	2,3	0,7	13,7
2011	10,3	9,2	12,4	3,1	2,1	1,1	14,8
2012	15,8	8,9	16,5	7,6	0,6	6,9	20,1
2013	16,1	11,2	17,1	5,9	1,0	4,9	21,3
2014	19,6	9,5	19,8	10,3	0,2	10,1	25,6
2015	23,6	9,6	23,7	14,0	0,0	14,0	30,7
2016	18,3	11,9	19,6	7,6	1,2	6,4	25,3
2017	16,6	10,1	17,9	7,7	1,3	6,4	23,1
2007-2017	*153,1*	*97,6*	*167,5*	*69,7*	*14,2*	*55,5*	*18,9*

Table 15 – Traded volumes and commercial cross-border exchanges on the Belgian day-ahead power exchange, including the share of traded volume in terms of the Elia load
Source: CREG based on data provided by EPEX SPOT Belgium

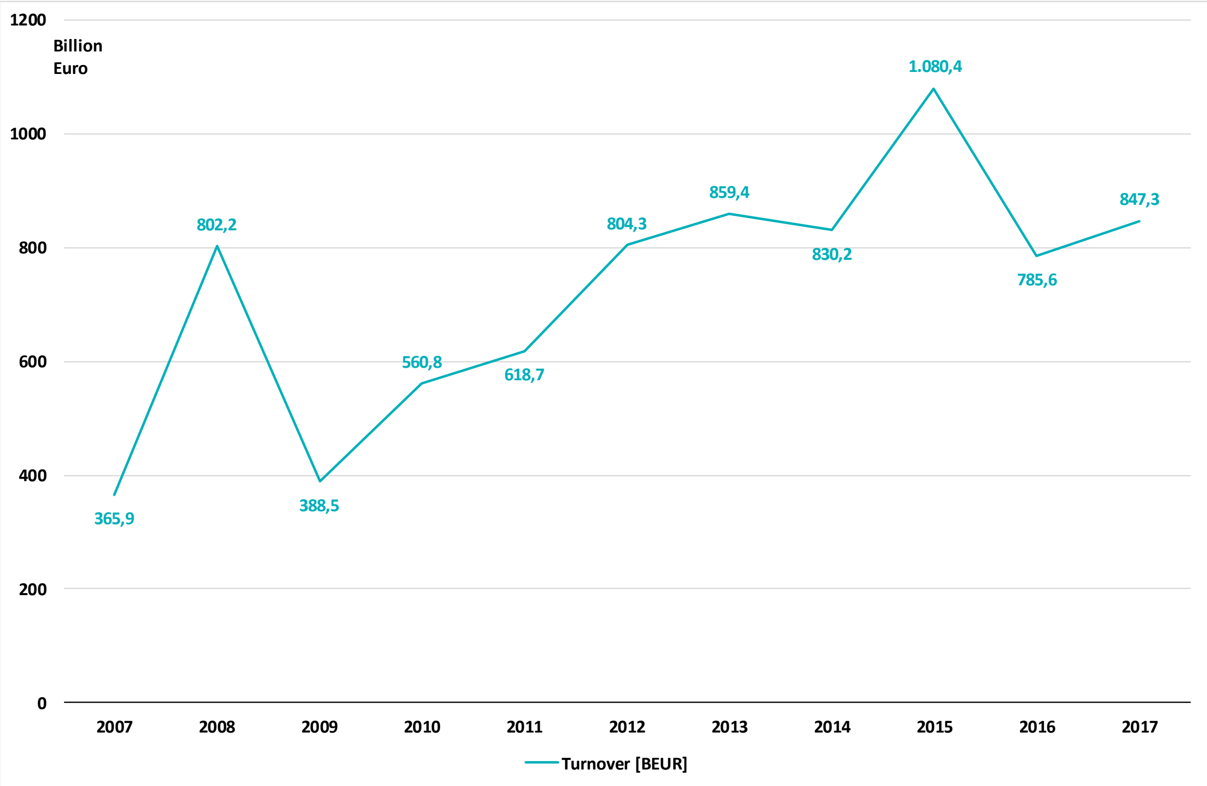

Figure 32 – Value of the contracts traded on EPEX SPOT Belgium
Source: CREG based on data provided by EPEX SPOT Belgium

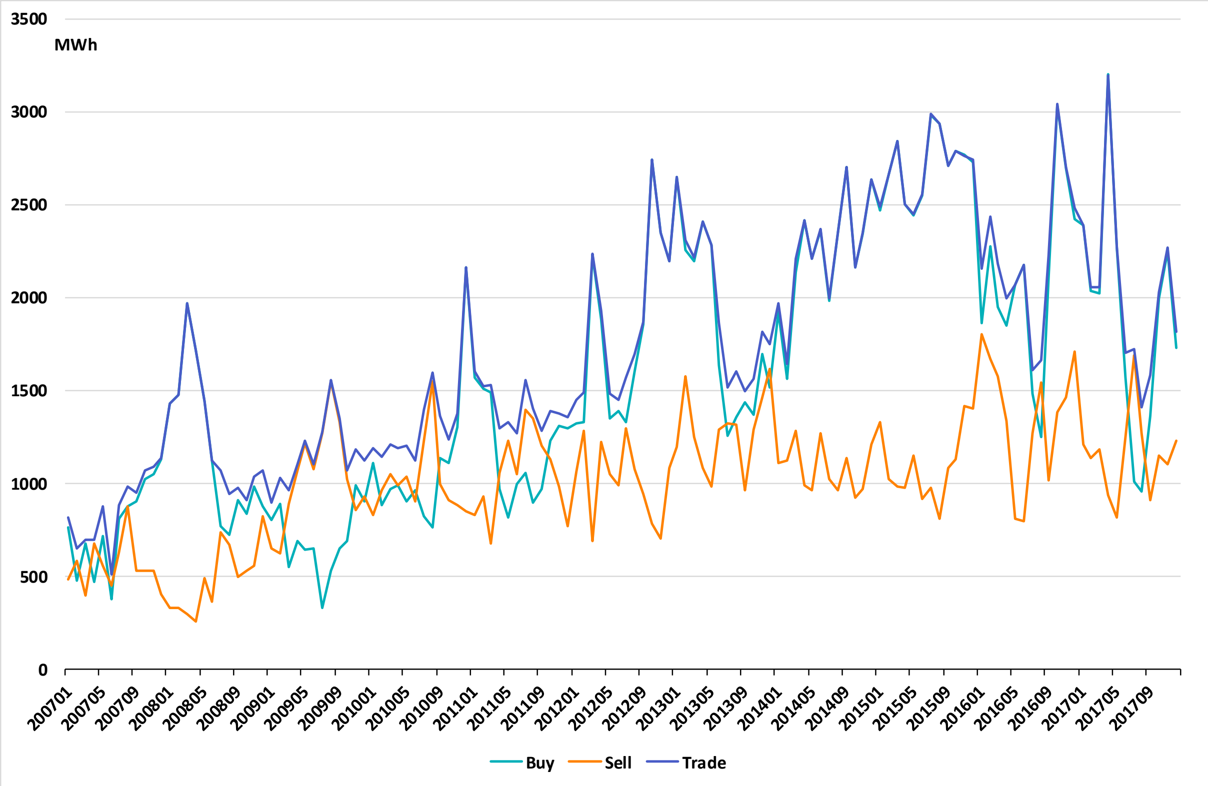

Figure 33 – Average traded, sold and bought volumes on the Belgian power exchange between 2007 and 2017.
Source: CREG based on data provided by EPEX SPOT Belgium

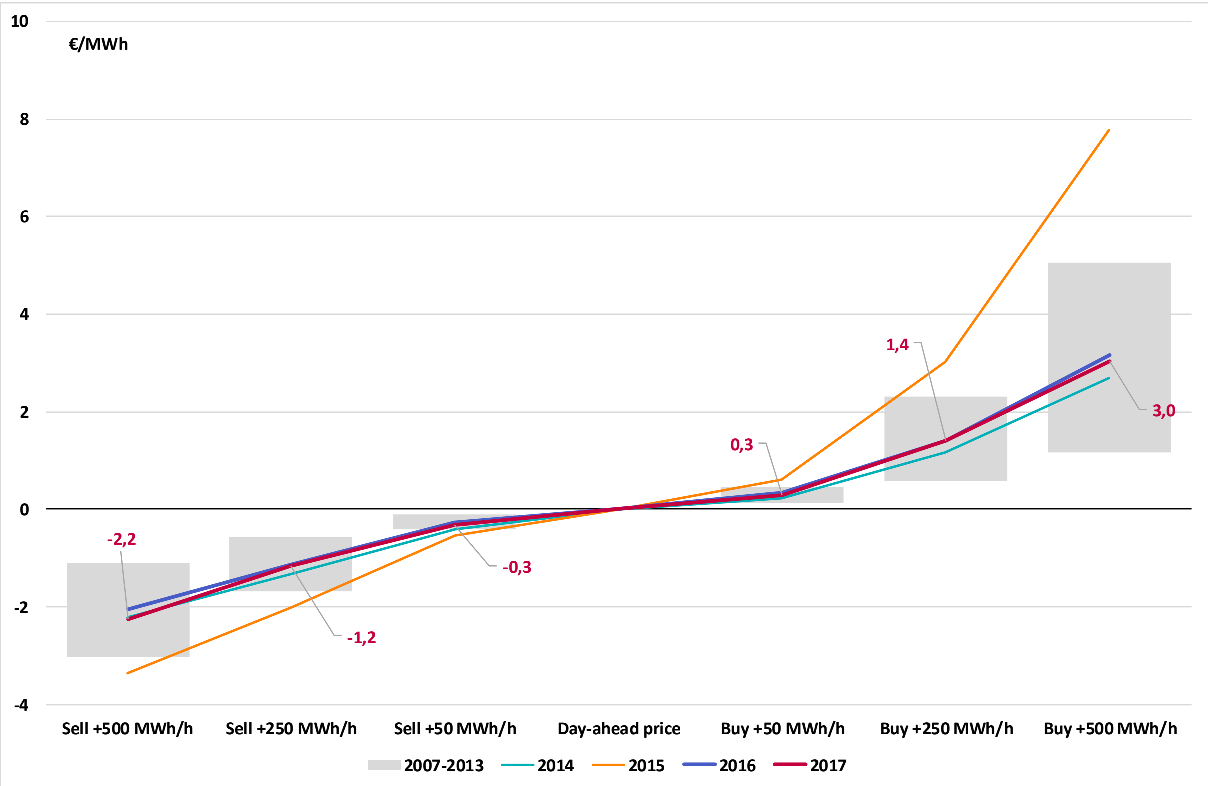

Figure 34 – Average change of the Belgian day-ahead price in terms of additional supply or additional demand, 2007-2017
Source: CREG based on data provided by EPEX SPOT Belgium

63. Average day-ahead price robustness in 2017 has not changed with respect to 2016 (Figure 34). As was the case last year, the last quarter of the year showed the highest day-ahead price sensitivity (Figure 35).

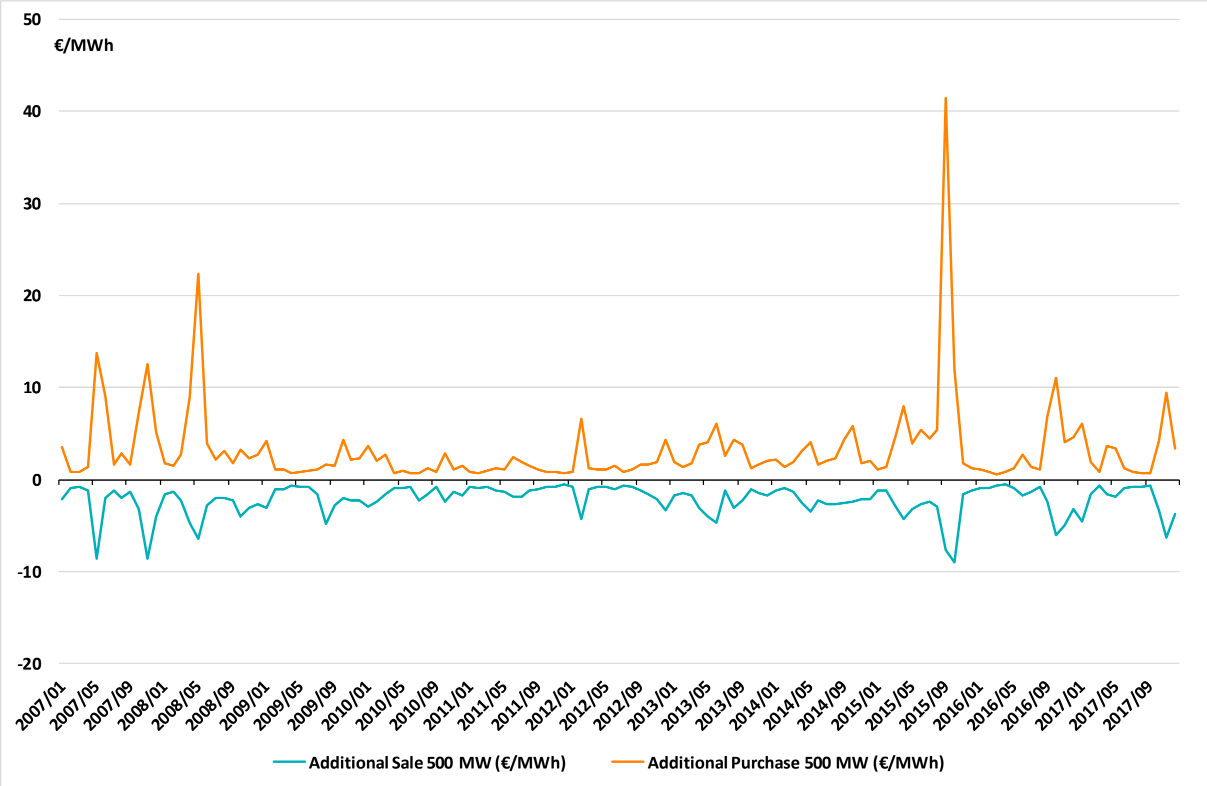

Figure 35 – Average absolute sensitivity of the Belgian day-ahead price in terms of 500 MWh/h additional supply or 500 MWh/h additional demand
Source: CREG based on data provided by EPEX SPOT Belgium

3.3.2. Intraday wholesale electricity market for delivery in Belgium

64. In 2017 the traded volume on the intraday power exchange increased significantly compared with the volume traded in 2016 (Table 16). Volumes have increased 250% since EPEX SPOT Belgium started its activities in 2015. The yearly traded volume on the intraday market equals 5.6% of the yearly traded volume on the day-ahead market (see Table 15).

In 8,489 hours, a volume was traded compared with 7,743 hours in 2016. The average volume traded during these hours increased from 140 MWh/h in 2016 to 235 MWh/h in 2017 suggesting the intraday market becomes sufficiently liquid for market participants to find a counterparty for their trades. Whether this entails adequate levels of competition on the Belgian market is further analysed in the special topic of this Chapter.

65. Intraday prices were on average €1.15/MWh higher than day-ahead prices (Table 16). Except for the year 2015, the spread in 2017 is the lowest of the observed period, pointing to a continuously decreasing opportunity cost for exercising the option to trade baseload power on the intraday market instead of the day-ahead market. Correlation between day-ahead and intraday prices decreased however, from 89% in 2016 to 78% in 2017, indicating a reduced statistical relationship.

The hourly spread between the day-ahead and intraday prices is lower than €5/MWh for 60% of the time (Figure 40). It can be as low as - €178.11/MWh and as high as €321.6/MWh. The tail of the histogram of the price spread is longer on the positive side, but the skew is very small.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Intraday Market Price (EUR/MWh)	84,46	41,78	49,88	55,59	51,66	52,40	42,55	43,96	37,93	45,73
Day-ahead Market Price (EUR/MWh)	70,61	39,36	46,30	49,37	46,98	47,45	40,79	44,68	36,62	44,58
Intraday Volume (GWh)	89	187	275	364	513	651	786	737	1089	1991
Import [GWh]	-	-	-	-	-	-	302	239	552	1009
Export [GWh]	-	-	-	-	-	-	395	357	403	809

Table 16 – Intraday prices and volumes for delivery of electricity in Belgium, 2008-2017. Export and import volumes are provided since 2014.
Source: CREG based on data provided by EPEX SPOT Belgium

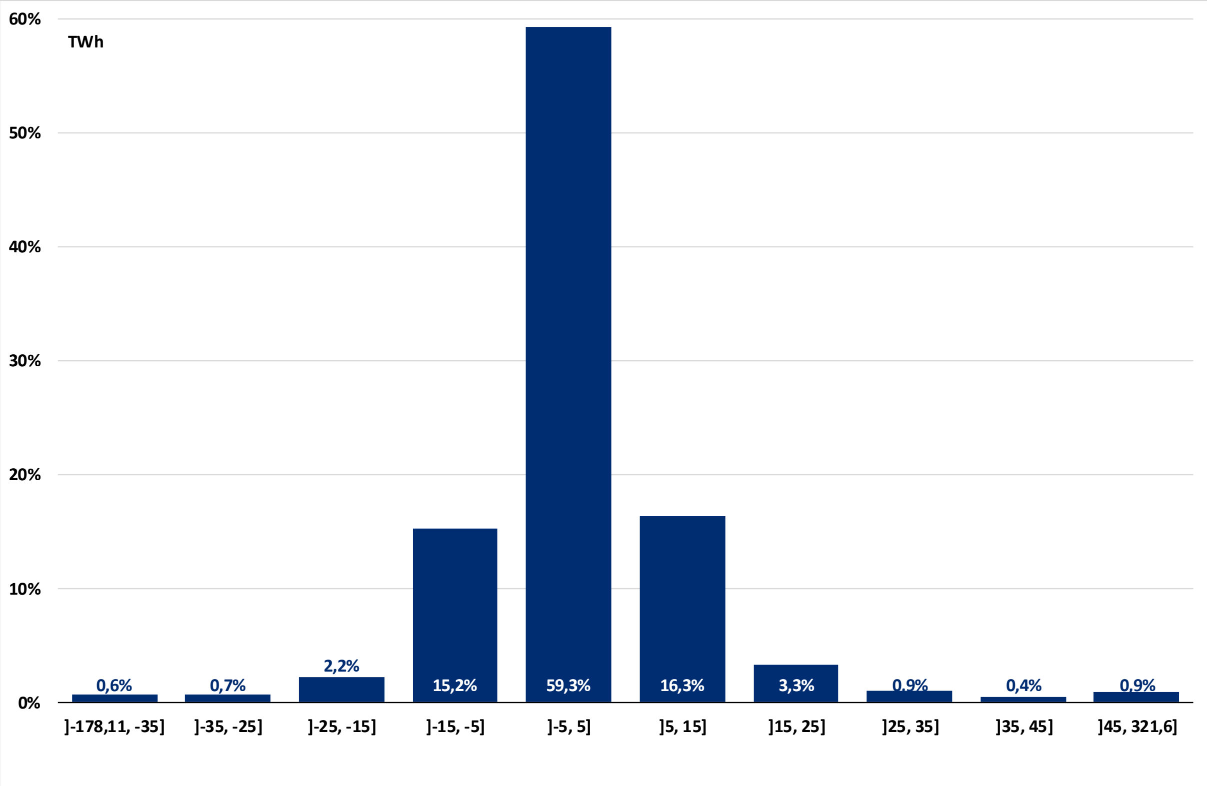

Figure 36 – Histogram of hourly differences between the day-ahead and intraday prices.
Source: CREG based on data provided by EPEX SPOT Belgium

3.3.3. Long-term wholesale electricity market for delivery in Belgium

66. The yearly averaged year-ahead wholesale electricity price in Belgium increased to €37.3/MWh in 2017 (Figure 37). Year-over-year price increases ranging from 15% to 22% are observed in all bidding zones in the CWE region and signals that, on average, market participants expect the average day-ahead price in 2018 to be higher than in 2017 in the CWE region. Year-ahead prices gradually increased since May 2017 and show a similar profile in each bidding zone. As such, market participants confidently expect price spreads to remain in the CWE region during 2018 (Figure 38).

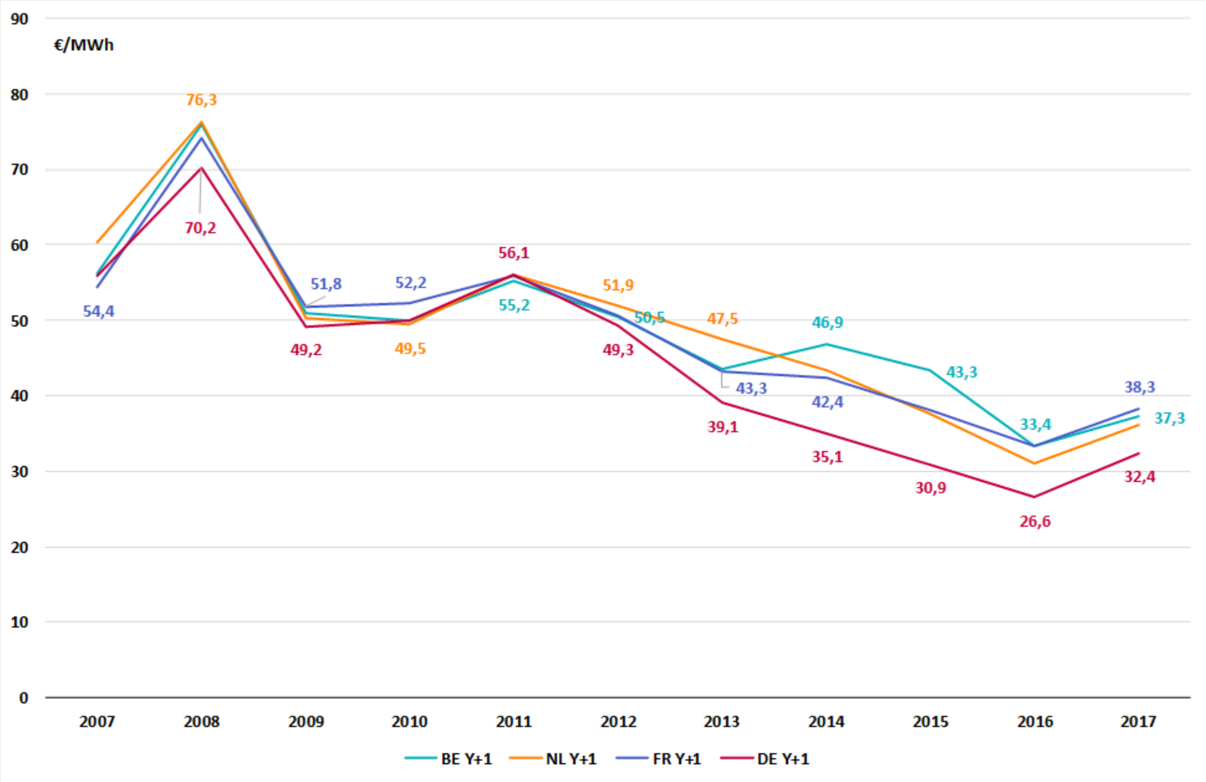

Figure 37 – Yearly averaged year-ahead wholesale electricity prices in the CWE region
Source: CREG based on data provided by ICE Endex and EEX

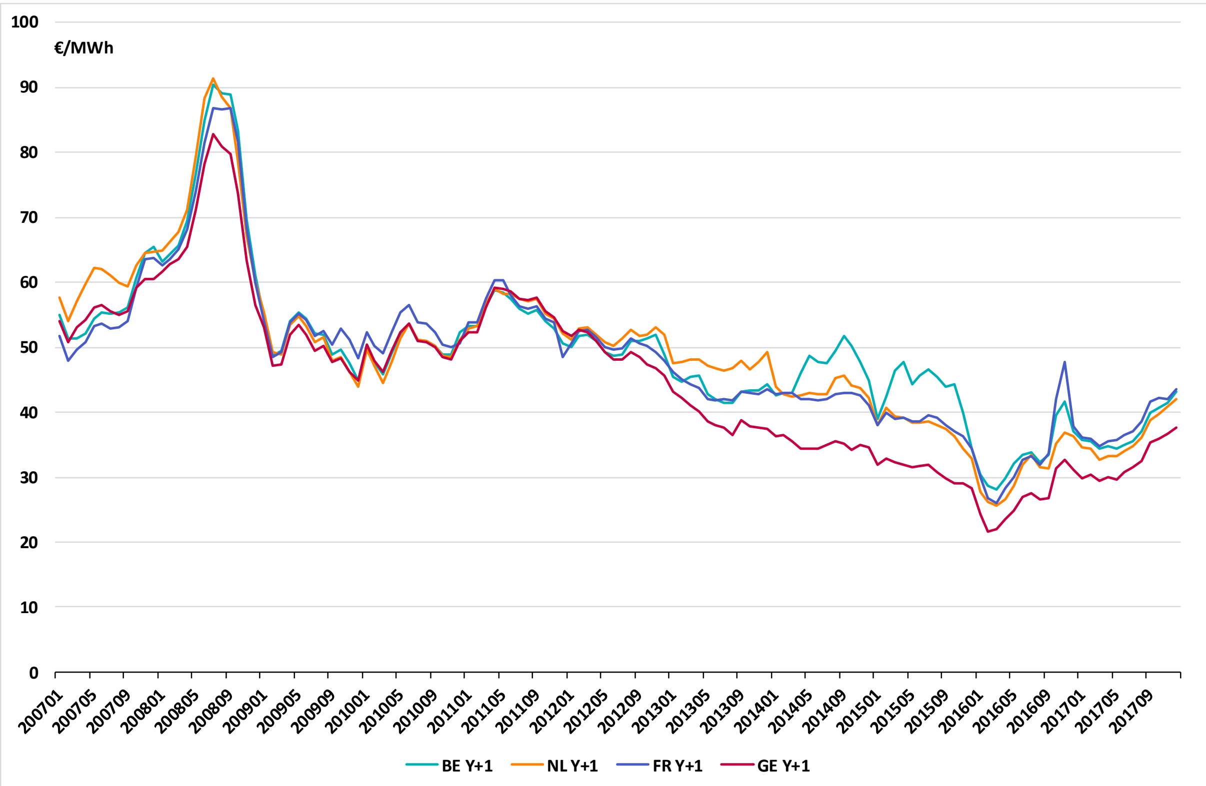

Figure 38 - Monthly averaged year-ahead wholesale electricity prices in the CWE region
Source: CREG based on data provided by ICE Endex and EEX

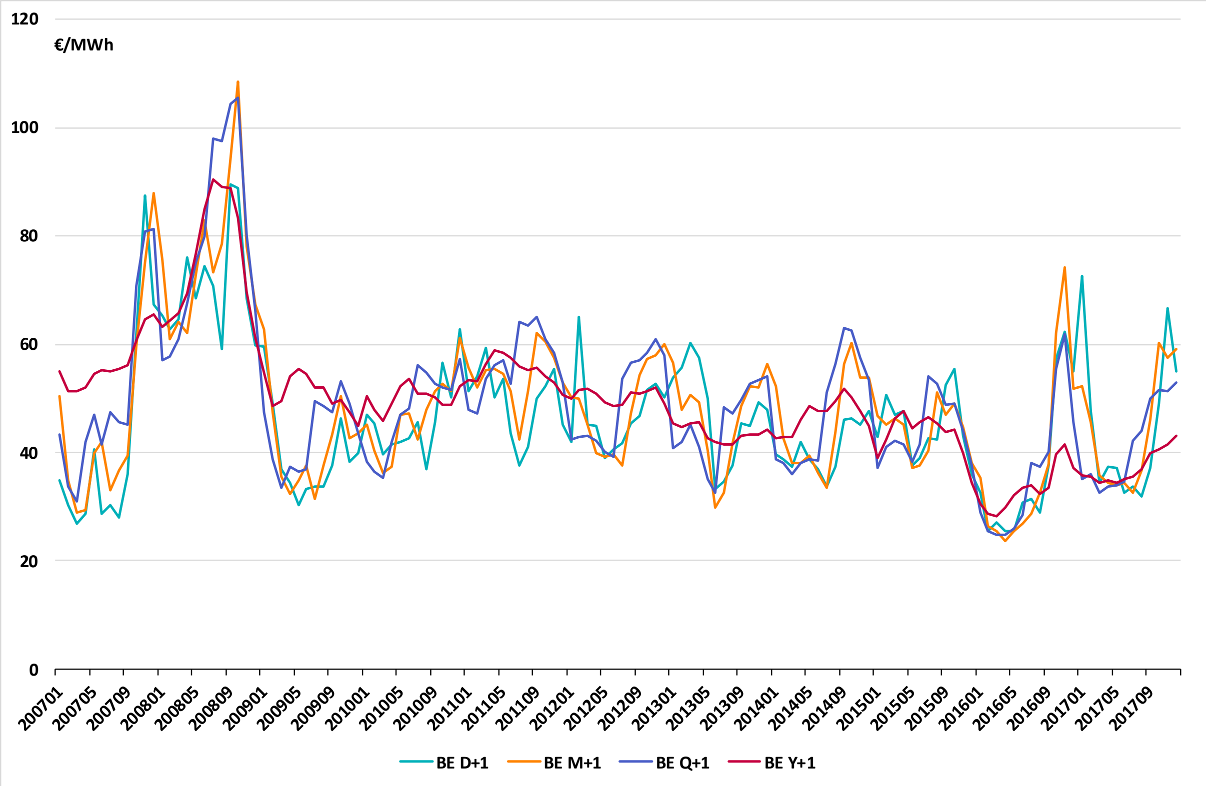

Figure 39 – Monthly average prices for four types of contracts for delivery in the Belgian bidding zone, in terms of month of trade
Sources: CREG based on data provided by EEX and ICE Endex

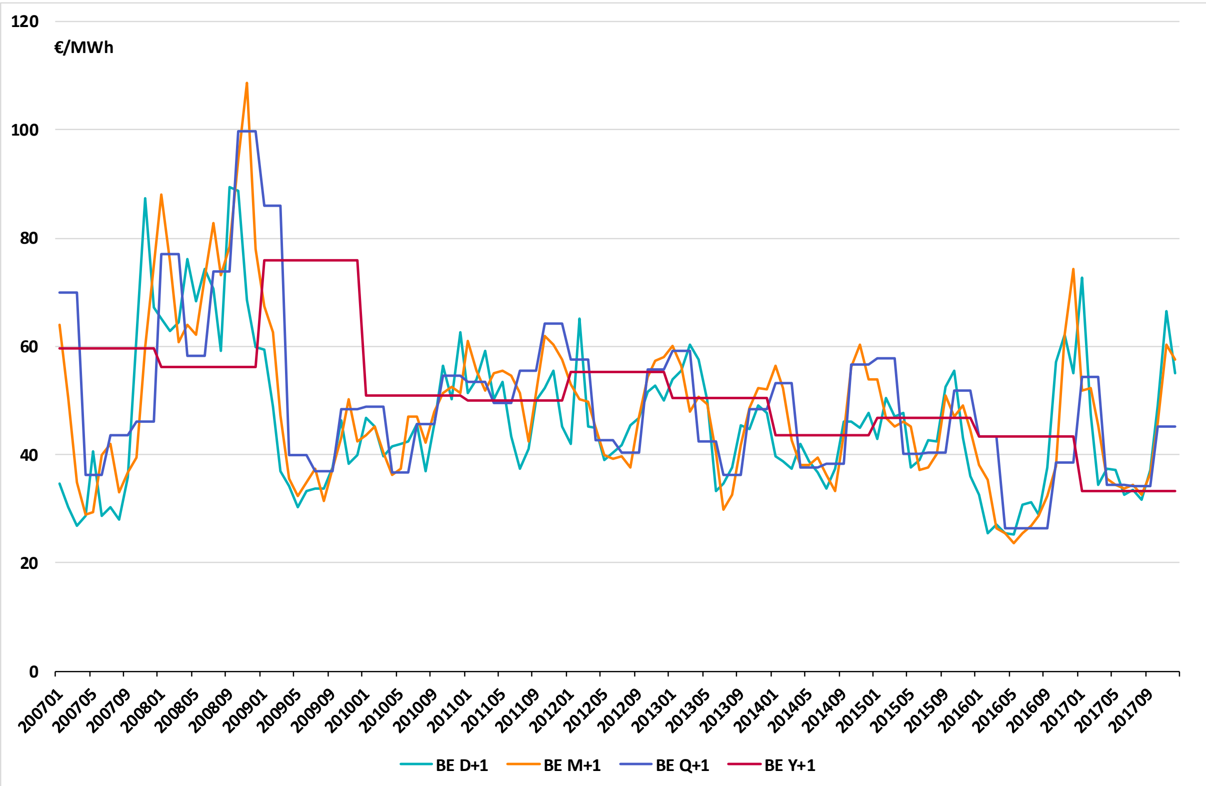

Figure 40 –Average prices for four types of contracts for delivery in the Belgian bidding zone, in terms of delivery period
Sources: CREG based on data provided by EEX and ICE Endex

2007-2017

	BE M+1	BE Q+1	BE Y+1
BE D+1	88.72%	73.58%	61.49%
BE M+1		86.72%	70.86%
BE Q+1			81.92%

2017

	BE M+1	BE Q+1	BE Y+1
BE D+1	69.46%	27.98%	39.97%
BE M+1		70.30%	82.22%
BE Q+1			94.34%

Table 17– Correlation between different types of contracts for delivery in the Belgian bidding zone, for 2007-2017 (left) and for 2017 (right)
Source: CREG based on data provided by EEX and ICE Endex

67. Prices of day-ahead and month-ahead contracts are correlated for 70% in 2017, a reduction compared with the historical average (Figure 39, Table 17). Quarter-ahead prices are not correlated with day-ahead prices in 2017 pointing to a complete reversal compared with the historically good correlation of around 73%. Correlation with the month-ahead prices also dropped, but is still high, at around 70%. Year-ahead prices are well correlated with quarter-ahead prices (94%) and month-ahead prices (82%).

In contrast to previous years, year-ahead contracts were the least expensive to source a baseload supply in 2017 (Figure 40). Day-ahead and month-ahead contracts were the most expensive on the other hand. Sourcing using year-ahead contracts resulted in a discount of €11.2/MWh compared with sourcing using the day-ahead market (Table 18). Historically however, contracts traded with a longer lead time before delivery on average trade at a premium with respect to shorter term contracts.

	D+1	M+1	Q+1	Y+1	Δ (D+1, M+1)	Δ (D+1, Q+1)	Δ (D+1, Y+1)
2007	41,78	44,61	48,95	59,57	2,83	7,17	17,79
2008	70,62	78,48	77,67	56,28	7,86	7,06	-14,33
2009	39,36	43,41	52,91	76,02	4,05	13,55	36,66
2010	46,30	45,25	46,59	50,98	-1,05	0,29	4,68
2011	49,37	54,92	55,75	50,03	5,55	6,38	0,66
2012	46,98	47,76	49,30	55,18	0,79	2,33	8,20
2013	47,45	46,62	46,70	50,49	-0,84	-0,75	3,04
2014	40,79	45,91	46,67	43,57	5,12	5,88	2,78
2015	44,68	45,33	47,67	46,90	0,65	2,99	2,22
2016	36,61	36,42	33,75	43,32	-0,19	-2,86	6,71
2017	44,58	43,39	42,07	33,38	-1,19	-2,51	-11,20

Table 18 – Average prices for four types of contracts for delivery in Belgium, per year of delivery, 2007-2017
Source: CREG based on data provided by EEX and ICE Endex

4. INTERCONNECTIONS

4.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

2001 ETSO (the predecessor of ENTSO-E, *i.e.* the member organisation 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, including 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, inter alia, to optimise and harmonise the methodologies applied for the calculation and allocation of cross-border interconnection capacities between the various countries involved. The PLEF consists of representatives of Ministries, National Regulatory Authorities, Transmission System Operators, Power Exchanges and the Market Parties Platform.

2007 In **February**, CWE regulators publish 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 jointly sign a Memorandum of Understanding, together with the representatives of TSOs, power exchanges, regulators and market participants, 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 the CREG, for approval. In **October**, the CREG decides not to approve the proposal from Elia, as 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, the CREG decides nonetheless to authorise 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. The 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 the 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 the simulated flow-based market results with the ATC calculations every week. In **August**, the CWE FBMC Project develops 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[19]. CWE regulators consider the package to be incomplete and continue the development and discussions with the CWE FBMC Project partners. In **June**, CWE regulators organise a public consultation on the FBMC. In **August**, the CWE FBMC Project submits a third, adapted version of the approval package[20]. Between this date 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 the methodology for day-ahead flow-based market coupling of the CWE markets to the CREG for approval. In **March,** they publish their views on FBMC in a position paper[21]. In **April**, the CREG rules that the proposal is non-compliant with Regulation 714/2009, specifically the articles related to non-discrimination of internal versus external exchanges[22]. 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 – the CREG decides to approve the proposal conditionally on the implementation of a number of improvement proposals by the 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,** Regulation (EU) 2015/1222 ("CACM Guideline") 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, the 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.

2016 Regional (voluntary) cooperation shifts towards a more closely integrated, European approach for coupling markets. With the introduction of the CACM Guideline in 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 [23]. With this decision, taken after all regulatory authorities failed to agree on the proposal by all TSOs pursuant to art. 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[24], 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

[19] http://www.elia.be/~/media/files/Elia/Projects/CWE-Flow_Based/CWE_FBMC_approval-document_06-2014.pdf.

[20] http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D.

[21] http://www.creg.info/pdf/Opinions/2015/b1410/CWE_NRA_Position_Paper.pdf.

[22] http://www.creg.be/nl/publicaties/beslissing-b150423-cdc-1410.

[23] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf .

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

MHNEMOs 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. In **November**, ACER published its Recommendation 02/2016 on the Common Capacity Calculation and Redispatching and Countertrading cost sharing methodologies[25], recalling the objectives of CACM Regulation to establish a well-functioning internal electricity market through the effective implementation of efficient, transparent and non-discriminatory common methodologies. Results of the first 1.5 years of CWE FBMC are well below expectations. In 2016, CWE cross-zonal exchanges are 3,700 MW on average during congested hours, a decrease of 900 MW compared to the average of 4,600 MW obtained with ATC in 2014. Internal lines in the Amprion region appear to be the most constraining elements in the CWE FBMC. In **December**, in the face of regional pressure, Amprion applies winter ratings on these lines, increasing the capacity by 20% compared to summer values.

Status update 2017

In **January** 2017, CWE TSOs increase regional cooperation efforts to face the challenges of the January 2017 cold spell[26]. This includes week-ahead adequacy studies and increased coordination of the phase shift transformers in D-2.

At CWE level, the persistent underperforming results of the day-ahead market coupling with CWE FBMC triggers actions from the NRA side. In **March** 2017, CREG proposes a revised CBCO-selection method to address the problem of discrimination of domestic versus cross-zonal trade being at the basis of the low cross-zonal available capacity in the CWE FBMC. In **December** 2017, the CREG publishes Study 1687 on the impact of TSO discretionary actions on the functioning and design of the CWE FBMC[27]. In **December** 2017, CWE regulators agree upon a set of short-term and medium-term solutions to remediate the situation of low cross-zonal capacities in the CWE region. This agreement lies at the basis of the 20% minimum RAM threshold applied on 26 April 2017 as a short-term solution, and the CNEC-selection study to be submitted by CWE TSOs on 1 May 2017 towards a medium-term solution.

In **June** 2017, CWE TSOs submit a common proposal for the capacity calculation for the intraday timeframe with planned go-live date in October 2018. In **September**, CWE NRAs compose a common position paper with requests for clarifications and improvements of the proposed methodology[28]. In **November** CWE TSOs communicate delays for the start of the external parallel runs and the go-live of the new methodology.

At Core level, following the entry into force of the CACM Guideline and ACER's Decision 06-2016 to establish the Core capacity calculation regions, TSOs of the Core CCR started to develop the methodologies for regional capacity calculation and congestion management. In **September** 2017, the Core TSOs developed and submitted a proposal for the coordinated capacity calculation methodology, for the approval of all Core regulatory authorities. The aim of this methodology is to develop and establish flow-based capacity calculation methodologies for the day-ahead and intraday timeframes.

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[25] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf

[26] https://docstore.entsoe.eu/Documents/News/170530_Managing_Critical_Grid_Situations-Success_and_Challenges.pdf

[27] http://www.creg.be/nl/publicaties/studie-f1687

[28] See annex of CREG Decision 1732 of 22 February 2018 on the methodology for calculating cross-zonal capacities in the intraday time frame: http://www.creg.be/nl/publicaties/beslissing-b1732

4.2. SPECIAL TOPICS: THERMAL LINE RATINGS IN THE CWE DAY-AHEAD CAPACITY CALCULATION

68. For day-ahead capacity calculation, TSOs have to define the thermal line capacity (Fmax) in D-2. This thermal line capacity or “line rating” defines the maximum power on a line. It depends on weather conditions and increases with colder temperatures and higher wind speeds. In the CWE capacity calculation region, the methodology for defining Fmax is not harmonised. The definition of the Fmax-value is a discretionary TSO action.

69. The approaches used by the different CWE TSOs vary significantly. Within a same TSO region, approaches per individual line also vary substantially. Figure 41 to Figure 46 show the average Fmax-value used in the day-ahead capacity calculation by CWE TSOs from 2016 to 2017. For each TSO, only the lines which have been frequently constraining the CWE market coupling, are shown.

70. Most CWE TSOs use seasonal limits, although there are still TSOs who apply a static limit throughout the year on all (or part) of their lines. The Fmax-values on lines within the Tennet NL region remain constant throughout the year. Given that some of those lines have often been limiting the CWE day-ahead market coupling, e.g. the interconnection line Diele-Meeden (XDI_ME), it is clear that the use of static limits has a high opportunity cost (see also next section, Table 31). The monthly average opportunity cost or ‘shadow price’ of a network constraint in the CWE day-ahead market coupling is shown in Figure 49. It is especially high during the winter when the use of seasonal limits or dynamic line ratings could offer more capacity to the market.

71. The range of Fmax-values of some lines in the RTE zone is noticeably high (17% to 40%). RTE does not only consider seasonal or dynamic line ratings, but also monitors different outage scenarios where they apply temporary limits.

72. The observed variety in Fmax-approaches (Figure 41 to Figure 46 and Table 19) in terms of temporal resolution (constant, winter/summer, winter/mid-season/summer, DLR), switching dates and relative capacity increases (temperature sensitivity), shows there is still ample room for improvement on this specific point. For instance, if a 20% Fmax increase can be achieved on an internal line (e.g. D7ROKI DSECH, Amprion), one may wonder why the Fmax increase on the adjacent cross-border line is limited to 2% (e.g. XSI_MB, DE-NL). Also, there is no consistency in the application of Fmax on Phase Shift Transformers. While the Fmax of the PSTs at the Belgian-Dutch border (PST ZANDV and PST VANYK) vary, the PST at the German-Dutch border (PST GRON) has a constant Fmax. Given the high occurrence of active constraints on PSTs (see Table 19), this point deserves further consideration.

TSO	Critical line	Count	Thermal line capacity (MW)								
			2015			2016			2017		
		2017 (h)	Min	Max	Delta	Min	Max	Delta	Min	Max	Delta
BE	PST ZANDV	1658	-	-	-	1508	1614	7%	1415	1614	14%
	BMERCA BRODE+	742	1246	1551	24%	1385	1551	12%	1385	1627	17%
	BHORTA BAVLGM	183	1246	1468	18%	1468	1551	6%	1385	1551	12%
	BDOEL BZANDV	110	1246	1566	26%	1399	1566	12%	1385	1627	17%
	PST VANYK	48	1246	1551	24%	1385	1614	17%	1415	1614	14%
	XZA_BS	45	1731	1731	0%	1731	1945	12%	1731	1945	12%
	XZA_BS	45	1558	1731	11%	1731	1945	12%	1731	1945	12%
	XVY_MB	42	1515	1696	12%	1515	1696	12%	1515	1696	12%
	XVY_MB	42	1246	1551	24%	1385	1566	13%	1385	1627	17%
	BACHEN XAC_LO	34	1246	1566	26%	1385	1627	17%	1385	1627	17%
	BDOEL BHORTA	33	1246	1468	18%	1385	1551	12%	1551	1551	0%
	BZANDV BDOEL	24	1246	1468	18%	1385	1550	12%	1385	1627	17%
	XAU_M.	19	406	506	25%	452	506	12%	452	532	18%
	XAV_AV	16	1447	1819	26%	1624	1819	12%	1790	1790	0%
	BAVLGM XAV_AV	11	1447	1819	26%	1624	1819	12%	1608	1891	18%
	BDOEL BMERCA	3	1246	1551	24%	1385	1551	12%	1385	1551	12%
	XZA_GT	2	1558	1731	11%	1731	1945	12%	1731	1945	12%
	BGRAMM BSTAM+	1	1385	1551	12%	1385	1551	12%	1385	1605	16%
	BRODE+ BMERCA	1	1385	1468	6%	1551	1551	0%	1454	1633	12%
D2	XDI_ME	1135	1053	1053	0%	1053	1053	0%	1053	1053	0%
	D2DOEW DDO_HA	113	1379	1379	0%	1379	1441	4%	1441	1441	0%
	D2YNLA DNL_ME	107	1379	1379	0%	1379	1441	4%	1441	1441	0%
	D2DIEL DDOEW	16	1535	1535	0%	1535	1535	0%	1535	1535	0%
	D2DIEL DYRHE	15	1381	1381	0%	1381	1535	11%	1535	1535	0%
	D2GKRO DGK_DE	7	1697	1697	0%	1697	1884	11%	1884	1884	0%
	D2CONO DDIEL R	6	1535	1535	0%	1535	1535	0%	1535	1535	0%
	D2GR DGR_HO	3	2078	2078	0%	2078	2078	0%	2078	2078	0%
	D2GKRO DGK_UR	2	1663	1663	0%	1663	1884	13%	1884	1884	0%
D4	D4DE_VO	76	1787	1787	0%	1787	1787	0%	1787	1787	0%
	D4PU_HO	19	1777	1777	0%	1777	1777	0%	1777	1777	0%
	XLA_KU	9	1607	1607	0%	1330	1330	0%	1330	1663	25%
	D4DA_WE	1	1787	1787	0%	1787	1787	0%	1884	1884	0%
D7	D7HANE DGRON	1197	1787	1787	0%	1787	1787	0%	1787	2182	22%
	PST GRON	505	1500	1500	0%	1500	1500	0%	1500	1500	0%
	D7NL_ME	378	1379	1379	0%	1379	1379	0%	1441	1441	0%
	D7DO_HA	368	1379	1379	0%	1379	1379	0%	1441	1441	0%
	D7KNAP DSECH	351	1857	1857	0%	1857	2182	18%	1857	2182	18%
	D7ROKI DSECH	298	1787	1787	0%	1787	2145	20%	1787	2182	22%
	XSI_MB	287	1801	1839	2%	1801	1839	2%	1801	1839	2%
	D7BE_GU	234	1697	1697	0%	1697	1697	0%	1884	1884	0%
	D7ROKI DKNAP	90	1787	1787	0%	1787	2145	20%	1787	2182	22%
	XEN_VI	53	1884	1884	0%	1884	1884	0%	1884	1884	0%
	D7ENSD DUCHT	12	1884	1884	0%	1884	1884	0%	1884	2182	16%
	XRO_MB	12	1787	1787	0%	1787	1787	0%	1787	1787	0%
	D7NSTE DOSBU	10	1777	1777	0%	1777	1777	0%	1777	1781	0%
	D7GRON DKUSE	7	1777	1781	0%	1777	1777	0%	1777	2182	23%
	D7UCHT DMITB	3	1787	1787	0%	1787	1787	0%	1787	2182	22%
	D7MITB DYBUE	2	1777	1777	0%	1777	1777	0%	1777	2134	20%
	D7OPLA DROKI	2	1787	1787	0%	1787	1787	0%	1787	2134	19%
	D7OBZI DDAHL	1	1787	1787	0%	1787	1787	0%	1787	1787	0%
FR	XAV_AV	16	1609	2161	34%	1609	2161	34%	1641	2295	40%
	FAVELI FGAVRE	5	1551	1817	17%	1551	1817	17%	1551	1817	17%
	XAC_LO	1	1386	1552	12%	1386	1552	12%	1454	1763	21%
NL	NENS NLLS	893	1732	1732	0%	1732	1732	0%	1732	1732	0%
	XSI_MB	287	1801	2009	12%	1801	2009	12%	1801	2009	12%
	NLLS NDIM	155	1732	1732	0%	1732	1732	0%	1732	1732	0%
	NHGL NDTC	67	1732	1732	0%	1732	1732	0%	1732	1732	0%
	NKIJ NGT	64	1732	1732	0%	1732	1732	0%	1732	2078	20%
	XZA_BS	45	1732	2061	19%	1732	2061	19%	1732	2061	19%
	XZA_GT	2	1732	2009	16%	1732	2009	16%	1732	2009	16%
	NMEE XDI	2	1053	1053	0%	1053	1053	0%	1053	1053	0%
	NGT NKIJ	1	1732	1732	0%	1732	1732	0%	1732	2078	20%

Table 19: Minimum and maximum thermal line capacity of the critical network elements having limited the CWE cross-zonal exchange in 2017, together with the annual maximum spread for 2015, 2016 and 2017. The critical branches are ordered per TSO: Elia (BE), Tennet Germany (D2), TransnetBW (D4), Amprion (D7), RTE (FR) and Tennet NL (NL).

73. Increases in the Fmax-value of several critical network elements included in the CWE FB capacity calculation might be a factor explaining the partial recovery of CWE cross-border exchanged volumes from September - December 2017, compared to the historically low values recorded in September – December 2016 (Figure 47). Since December 2016, CWE TSOs have increased the Fmax-value on several network elements, thereby raising the Fmax for winter 2016-2017 compared to the winter 2015-2016 (Figure 41 to Figure 46). These are, inter alia:

- Cross-border line XZA_BE (BE-NL, Elia): 1731 MW → 1945 MW (winter limit, °Dec 2016)
- Internal line D2DOEW DDO_HA (Tennet DE): 1379 MW → 1441 MW (permanent, °Nov 2016)
- Internal line D4DA_WE (Transnet BW): 1787 MW→ 1884 MW (permanent, °Jan 2017)
- Internal line D7KNAP DSECH (Amprion): 1857 MW → 2182 MW (winter limit, °Dec 2016)
- Internal line D7ROKI DSECH (Amprion): 1787 MW → 2145 MW (winter limit, °Dec 2016)
- Internal line D7DO_HA (Amprion): 1379 MW → 1441 MW (permanent, °Jan 2017)
- Internal line D7HANE DGRON (Amprion): 1787 MW → 2002 MW (°Sep 2018) → 2182 MW (°Dec 2018)
- Internal line NKIJ NGT (Tennet NL): 1732 MW → 2078 MW (permanent, °Mar 2018)

In 2016, the internal lines D7KNAP DSECH and D7ROKI DSECH had been the most constraining elements in the CWE DA FBMC. Thanks to the application of winter limits on these internal lines, the number of hours these lines have been limiting in 2017 reduced significantly.

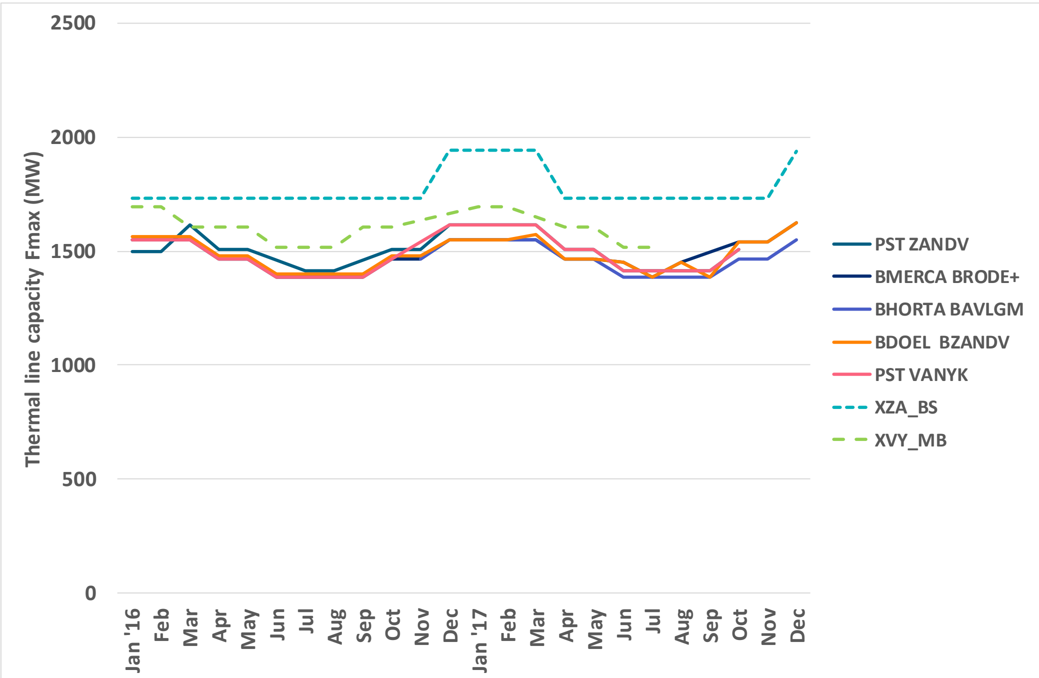


Figure 41: Monthly average Fmax values for the most frequently active CBCOs of Elia, the Belgian TSO, from 2016 to 2017.

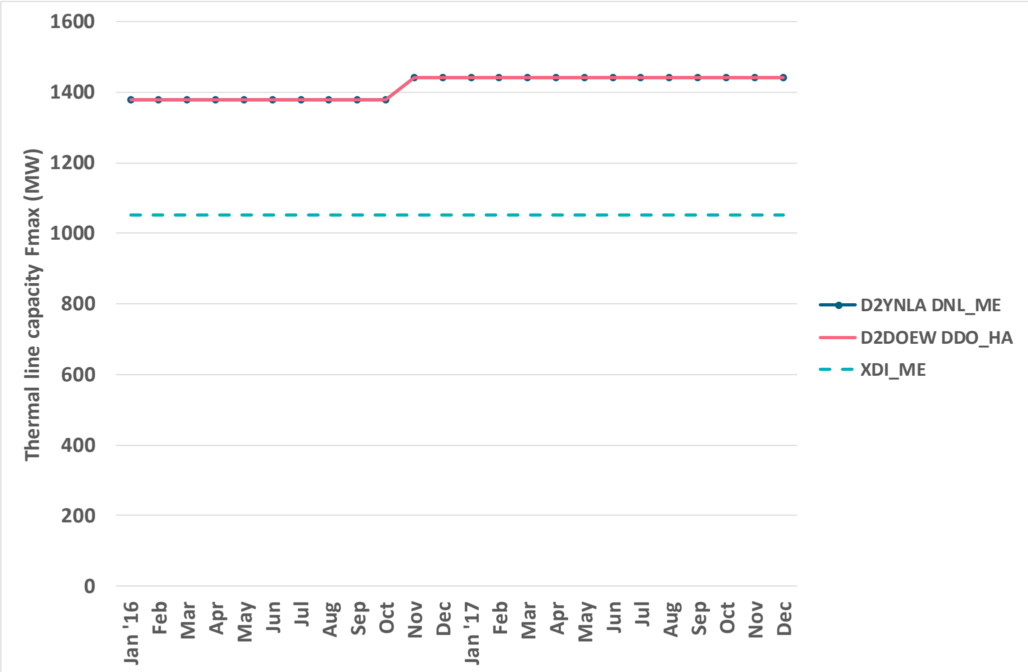


Figure 42: Monthly average Fmax values for the most frequently active CBCOs of Tennet DE, a German TSO, from 2016 to 2017.

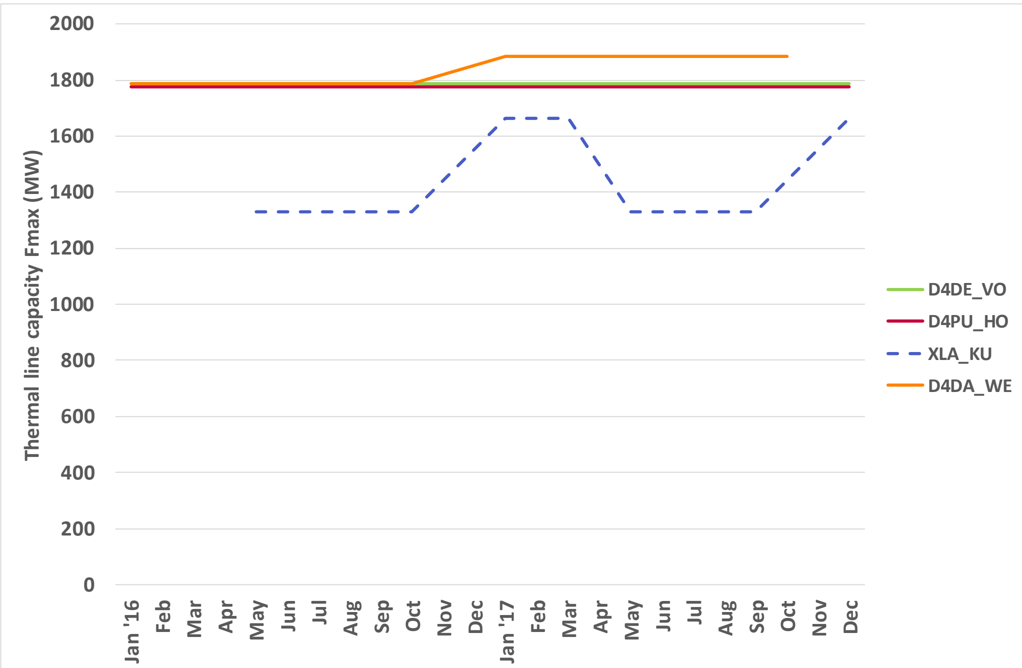


Figure 43: Monthly average Fmax values for the most frequently active CBCOs of TransnetBW, a German TSO, from 2016 to 2017.

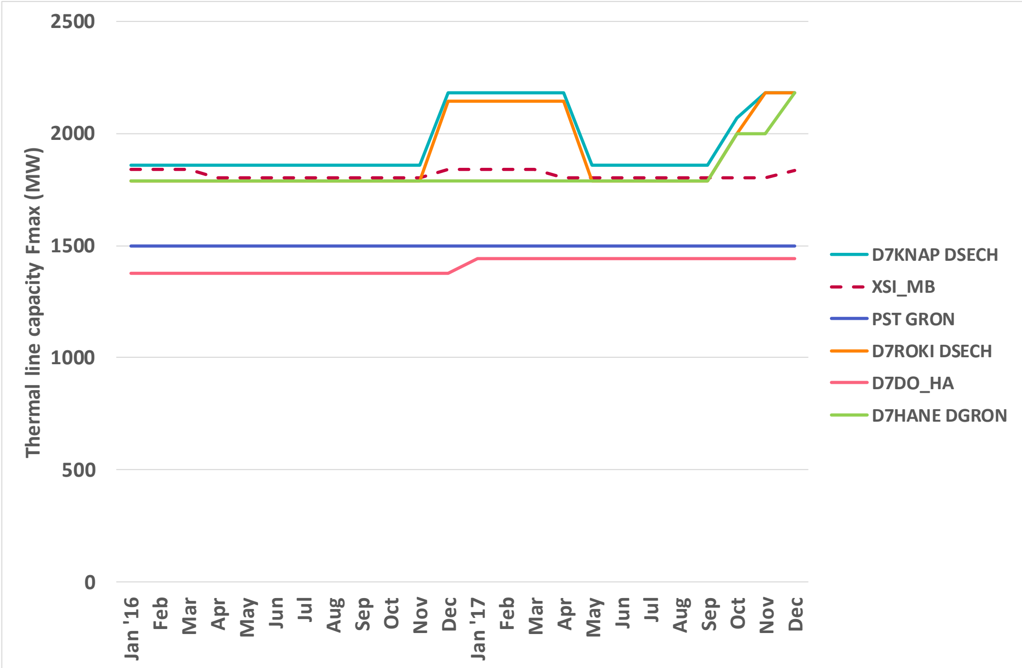


Figure 44: Monthly average Fmax values for the most frequently active CBCOs of Amprion, a German TSO, from 2016 to 2017.

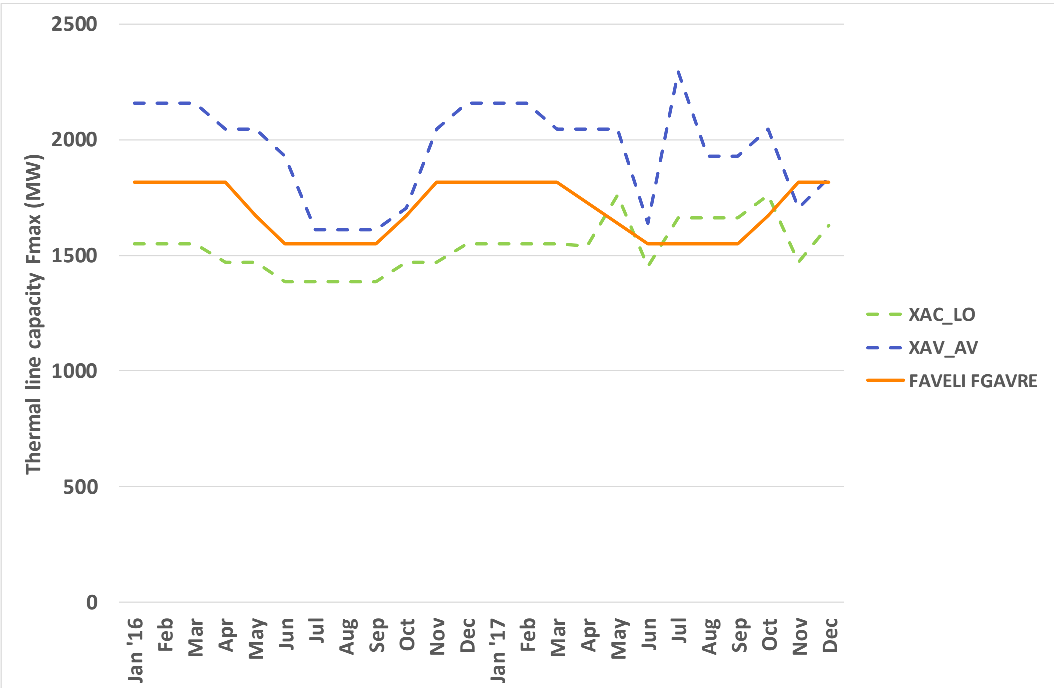


Figure 45: Monthly average Fmax values for the most frequently active CBCOs of RTE, the French TSO, from 2016 to 2017.

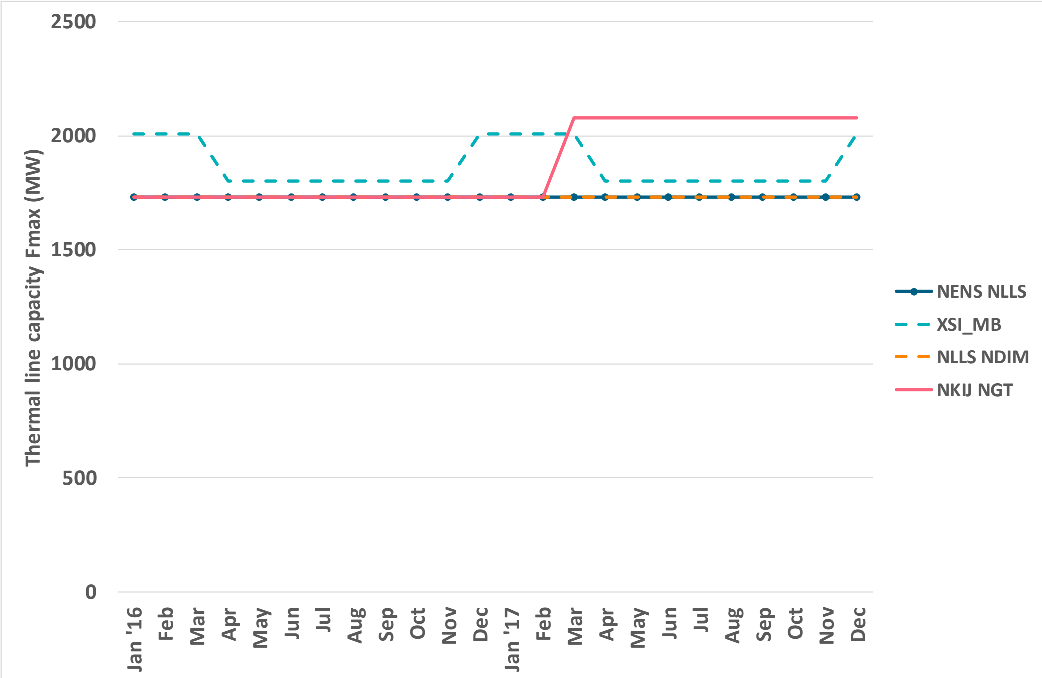


Figure 46: Monthly average Fmax values for the most frequently active CBCOs of Tennet NL, the Dutch TSO, from 2016 to 2017.

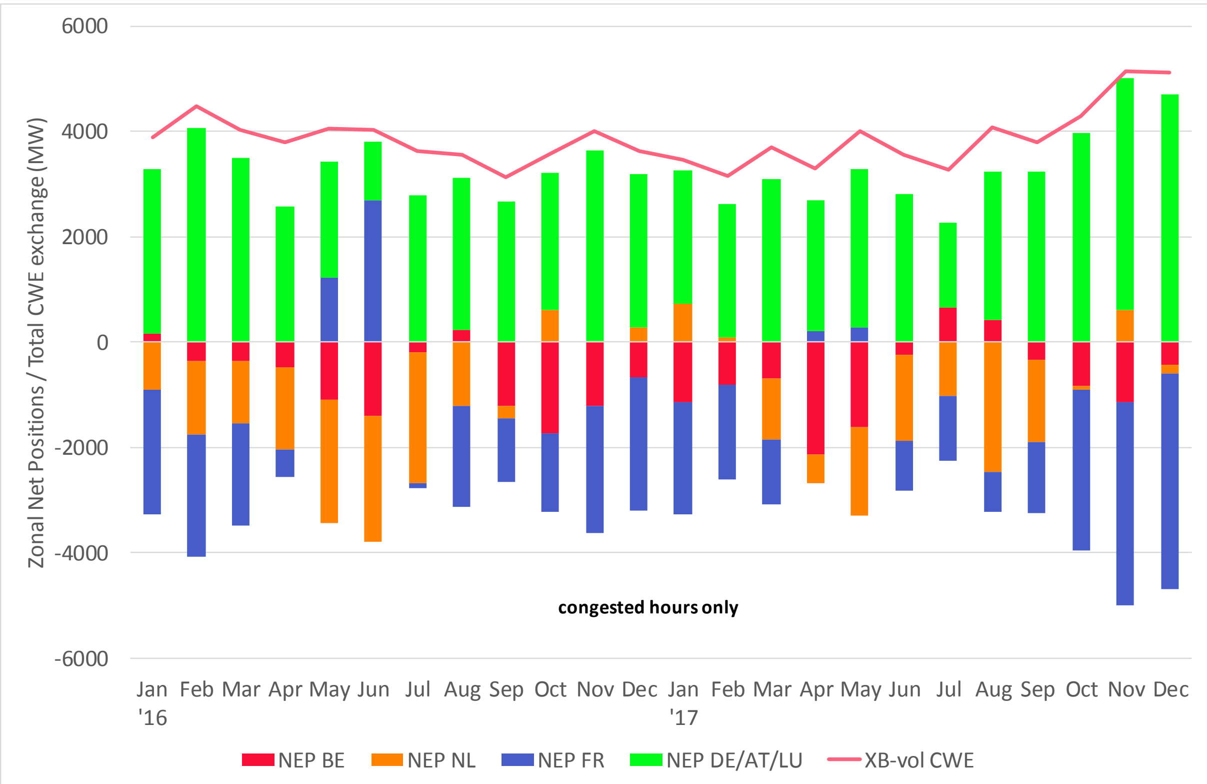


Figure 47: Monthly average of the net exchange positions of the four CWE bidding zones and of the CWE cross-zonal exchange, from 2016 to 2017.

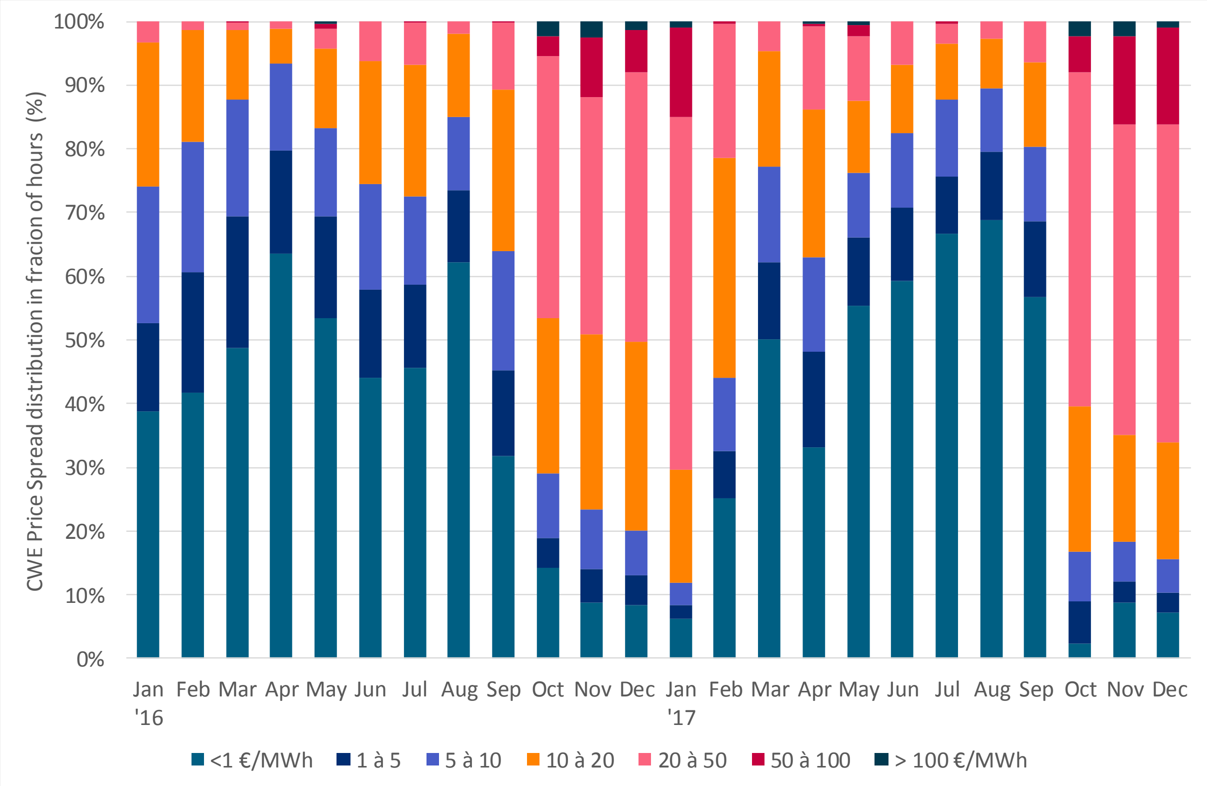


Figure 48: Monthly evaluation of the frequency and the magnitude of the hourly maximum price spread in the CWE region from 2016 to 2017.

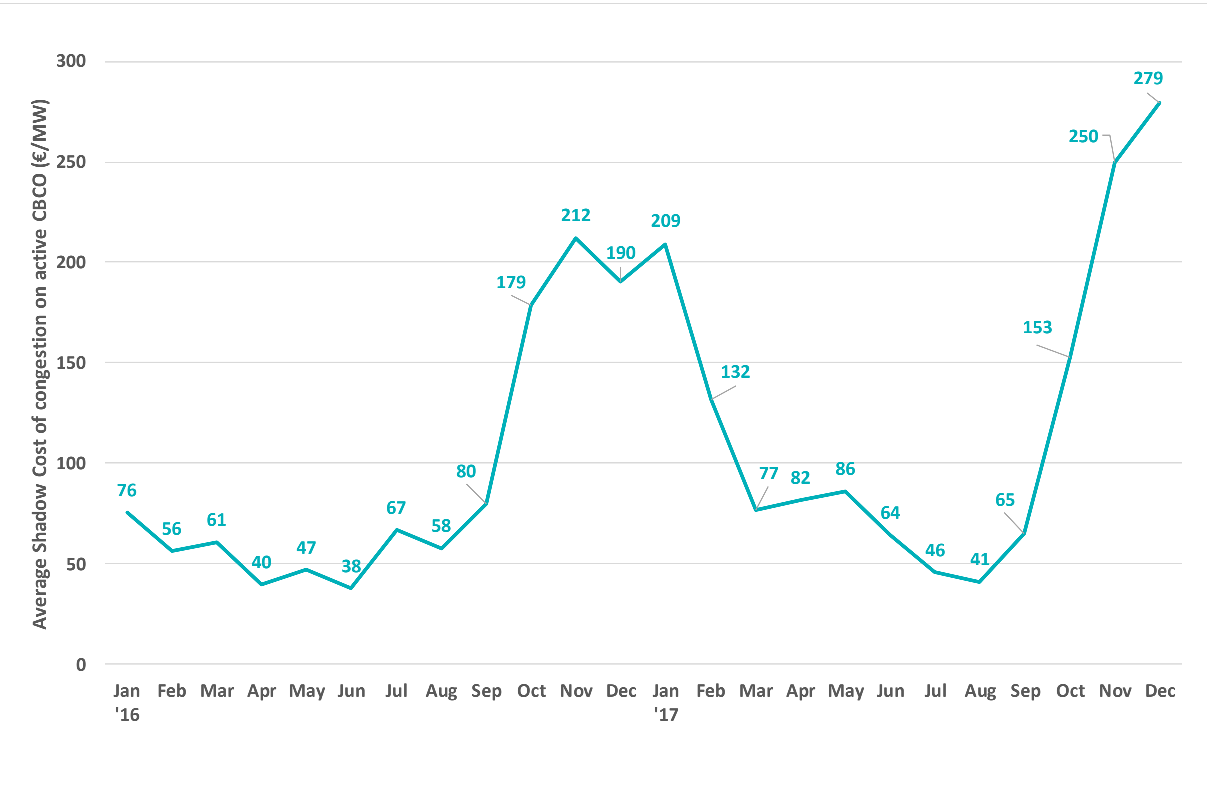


Figure 49 : Monthly average shadow cost of congestion (€/MW) from 2016 to 2017.

74. Until 2014, Elia applied seasonal ratings on all its lines. Inter-season limits and winter limits are respectively 6% and 12% higher than summer limits with fixed switching dates (Table 20).

Season	Start	End	Temp Min-Max	Lines	Transformers
Winter	16/11	15/03	0-11°C	112% Pnom	110% Pnom
Spring	16/03	15/05	11-20°C	106% Pnom	100% Pnom
Summer	16/05	15/09	20-30°C	100% Pnom	100% Pnom
Autumn	16/09	15/11	11-20°C	106% Pnom	100% Pnom
Heat wave	Depending on real temperature			90% Pnom	90% Pnom

Table 20: Switching dates and values for the seasonal rating of lines and transformers as applied by Elia[29].

75. From 2014 on, Elia started the gradual implementation of DLR on its lines. In 2017, 24 of the Belgian network elements are equipped with DLR. DLR technology forecasts the thermal line capacity based on weather forecasts. These forecasts are updated when new weather forecasts are available. Elia receives DLR forecasts at different time intervals, ranging from 58 hours ahead (H-58 or D-2) until one hour ahead (H-1). DLR forecasts in H-58 can be used in the day-ahead capacity calculation. DLR forecasts in H-1 are used for real-time system operation.

76. Table 21 shows that the majority of the network elements equipped with DLR are network elements which are included in the day-ahead Flow Based capacity calculation (second last column). However, not all of them are equipped with the DLR forecasts in D-2 needed for the day-ahead capacity calculation (last column). For those lines with no D-2 forecasts, DLR is only used for the operational process.

Line	Line name	Pnom (MVA)	Limit summer (MVA)	Limit Inter-season (MVA)	Limit Winter (MVA)	+ Inter-season/ Summer	+ Winter/ Summer	Monitored in FB?	Forecast D-2?
380.30	Zandvliet-Geertruidenberg	1645	1645	1744	1842	6%	12%	YES	NO
380.29	Zandvliet-Borsele	1645	1645	1744	1842	6%	12%	YES	NO
380.80	Avelgem-Avelin	1528	1528	1620	1712	6%	12%	YES	YES
380.74.H	Horta - Rodenhuize	1439	1439	1525	1612	6%	12%	YES	YES
380.27	Van Eyck-Maasbracht	1439	1439	1525	1611	6%	12%	YES	NO
380.23	Meerhout-Van Eyck	1439	1439	1525	1611	6%	12%	NO	NO
380.91	Van Eyck - Lixhe	1316	1316	1395	1474	6%	12%	YES	YES
380.79	Avelgem-Mastaing	1316	1316	1395	1474	6%	12%	YES	YES
380.28	Van Eyck-Maasbracht	1316	1316	1395	1474	6%	12%	YES	YES
380.26	Doel-Zandvliet	1316	1316	1395	1474	6%	12%	YES	YES
380.25	Doel-Zandvliet	1316	1316	1395	1474	6%	12%	YES	YES
380.19	Achène-Lony	1316	1316	1395	1474	6%	12%	YES	YES
380.74.M	Mercator - Rodenhuize	1316	1316	1395	1474	6%	12%	YES	YES
380.73	Horta - Mercator	1316	1316	1395	1474	6%	12%	YES	YES
380.31.G	Gramme - Tergnée	1316	1316	1395	1474	6%	12%	YES	NO
380.31.C	Courcelles - Tergnée	1316	1316	1395	1474	6%	12%	YES	NO
380.12	Gramme - Van Eyck	1316	1316	1395	1474	6%	12%	YES	NO
220.514	Aubange - Moulaine	442	442	469	495	6%	12%	YES	YES
220.513	Aubange - Moulaine	442	442	469	495	6%	12%	YES	YES
150.8	Langerbrugge - Nieuwvaart	220	220	233	246	6%	12%	NO	NO
150.7	Langerbrugge - Nieuwvaart	220	220	233	246	6%	12%	NO	NO
150.314	Baudour-Chièvres	175	175	186	196	6%	12%	YES	NO
150.313	Baudour-Chièvres	175	175	186	196	6%	12%	YES	NO
150.16	Brugge-Slijkens	156	156	165	175	6%	12%	NO	NO
150.15	Brugge-Slijkens	156	156	165	175	6%	12%	NO	NO
150.6	Brugge-Langerbrugge	155	155	164	174	6%	12%	NO	NO
150.5	Brugge-Langerbrugge	155	155	164	174	6%	12%	NO	NO

Table 21: Elia network elements equipped with DLR for the operational phase. The second-to-last column indicates whether the network element is included in the CWE DA FBMC capacity calculation. The last column indicates if DLR is used for day-ahead capacity calculation for which D-2 forecasts are needed. The seasonal ratings to which the DLR forecasts are compared, are also shown.

[29] http://www.elia.be/~/media/files/Elia/Projects/Flow-based%20market%20coupling%20in%20Central%20West%20Europe/20150313_Description_DA_FB_MC-NL.pdf

77. Today, Elia uses the seasonal ratings in compliment to the DLR forecasts. The forecasted values are capped by a percentage of the seasonal limit in order to keep the risk for an overestimation of the thermal capacity below a certain threshold. However, with growing experience with the technology and continuous improvement of the DLR forecast accuracy, the need for capping the DLR forecasts should decrease in time.

78. At the CREG's request, Elia submitted a first proposal for approval by the CREG on the application of the DLR methodology in October 2017, and a revised version in December 2017. The revised proposal, approved by the CREG in January 2018[30], provides for the possibility of capping the D-2 DLR forecasts to 105% of the seasonal rating during peak hours, and to 109% of the seasonal rating during off-peak hours. The capping values are defined in such a way that the risk for overestimating the thermal capacity is below 12%. With these capping values, the average capacity gain compared to the seasonal ratings is estimated at 6.2%, evaluated over the day. This method will be implemented by Elia in April 2018.

4.3. STATISTICS

4.3.1. Long-term transmission capacity auctions

Yearly auctions

79. Auctioned volumes of yearly long-term transmission rights at the Belgian borders have been relatively stable over the past 10 years, except from the drop in 2016 of the auctioned volumes at the southern border in the export direction (BE=>FR), from 400MW to 200 MW. In 2017, volumes were the same as in 2016, except from a slight increase of 468 MW to 473 MW at the northern border, in both import and export direction. The volumes of long-term capacity are the highest at the southern border, import direction (1,448 MW).

80. While the auctioned volumes in 2017 remained close to the same as in 2016, total revenues increased significantly, from €33.37m in 2016 to €41.95m in 2017. All transmission capacity prices increased, except for those for export at the northern border.

	FR=>BE			BE=>FR			NL=>BE			BE=>NL			Total
Year	**Cap**	**Price**	**Revenu**	**Cap**	**Price**	**Revenu**	**Cap**	**Price**	**Revenu**	**Cap**	**Price**	**Revenu**	**Revenu**
	(MW)	(€/MW)	(M€)	(MW)	(€/MW)	(M€)	(MW)	(€/MW)	(M€)	(MW)	(€/MW)	(M€)	(M€)
2007	1299	2.06	23.44	400	0.25	0.88	467	0.11	0.45	467	3.45	14.13	38.90
2008	1300	0.90	10.28	400	0.56	1.97	468	1.57	6.45	468	2.04	8.37	27.06
2009	1300	0.88	10.02	400	0.81	2.84	468	3.07	12.59	468	1.34	5.49	30.94
2010	1297	0.16	1.82	400	3.46	12.12	467	2.02	8.25	467	0.80	3.27	25.46
2011	1449	0.06	0.76	400	0.69	2.42	467	1.10	4.48	465	0.59	2.40	10.06
2012	1447	0.10	1.27	400	0.52	1.83	467	0.85	3.48	466	2.20	9.01	15.59
2013	1449	1.07	13.58	400	0.72	2.52	468	1.95	7.99	471	3.04	12.56	36.66
2014	1450	1.21	15.37	400	1.16	4.06	468	1.24	5.08	468	4.41	18.06	42.58
2015	1450	2.86	36.33	399	0.39	1.36	467	5.44	22.26	468	1.25	5.10	65.06
2016	1449	0.96	12.22	200	1.25	2.20	468	3.22	13.24	468	1.39	5.71	33.37
2017	1448	1.16	14.71	200	2.16	3.78	473	4.44	18.40	473	1.22	5.06	41.95

Table 22: Annual long term import and export capacities (MW), transmission rights (€/MW) and resulting revenues (€) at the Belgian border with France and the Netherlands. Sources: Elia, CREG

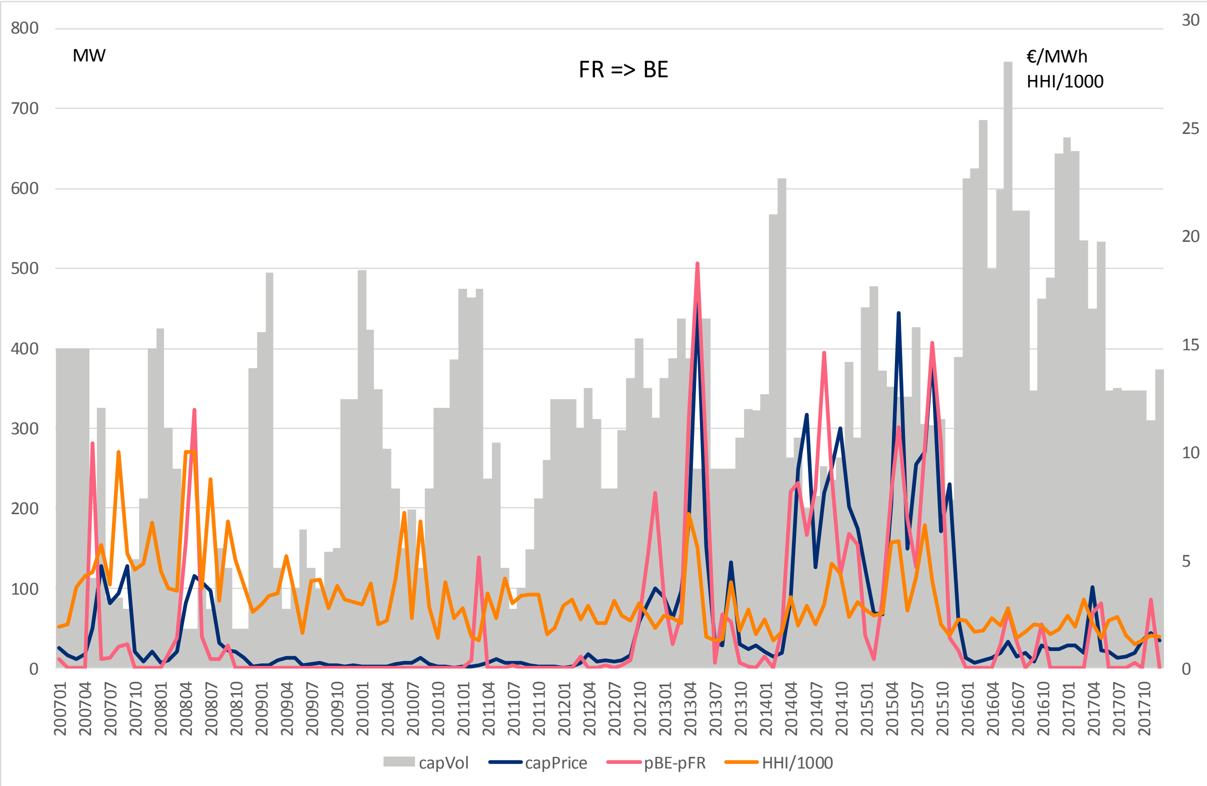
[30] http://www.creg.be/sites/default/files/assets/Publications/Decisions/B1712NL.pdf

Monthly auctions

Revenues of long-term transmission capacity auctions			
Year	Yearly auctions	Monthly auctions	Total
2007	38.9	16.0	54.9
2008	27.1	11.6	38.7
2009	30.9	12.3	43.2
2010	25.5	8.1	33.6
2011	10.1	5.2	15.3
2012	15.6	8.5	24.1
2013	36.7	20.7	57.4
2014	42.6	24.1	66.6
2015	65.1	37.1	102.1
2016	33.4	30.8	64.2
2017	42.0	22.7	64.6

Figure 50: Total revenues of long-term capacity rights from the yearly and monthly auctions.

81. Total revenues from long-term auctions in 2017 were more or less the same as in 2016. The higher revenues on the yearly auctions were offset by lower monthly revenues. This was mainly due to a substantial reduction in monthly auctioned capacity rights, especially in the second half of the year (Figure 51 and Figure 52). This reduction took place at both borders and both directions, except for the capacity from Belgium to France.



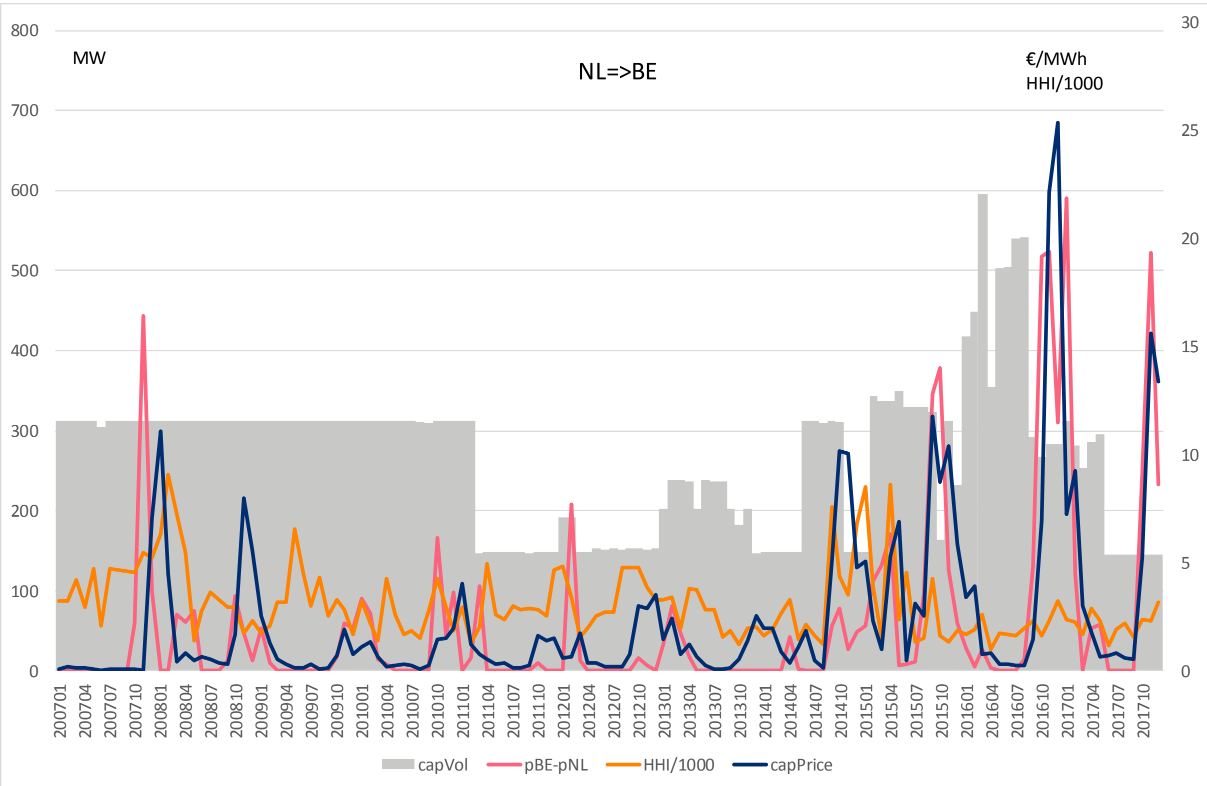


Figure 51: Monthly long term IMPORT capacity auctions at the French border (top) and at the Dutch border (bottom). The auctioned volumes (‘capVol’, MW) vary on a monthly basis. The better the auction price (‘capPrice’, in €/MW) and the monthly-averaged day-ahead price in the given direction (‘pBE-pFR’ and ‘pBE-pNL’, in €/MWh) are correlated, the better the market was able to anticipate the price spreads. The level of competition, which depends on the number of participating market players, is measured by the HHI index (‘HHI/1000’).

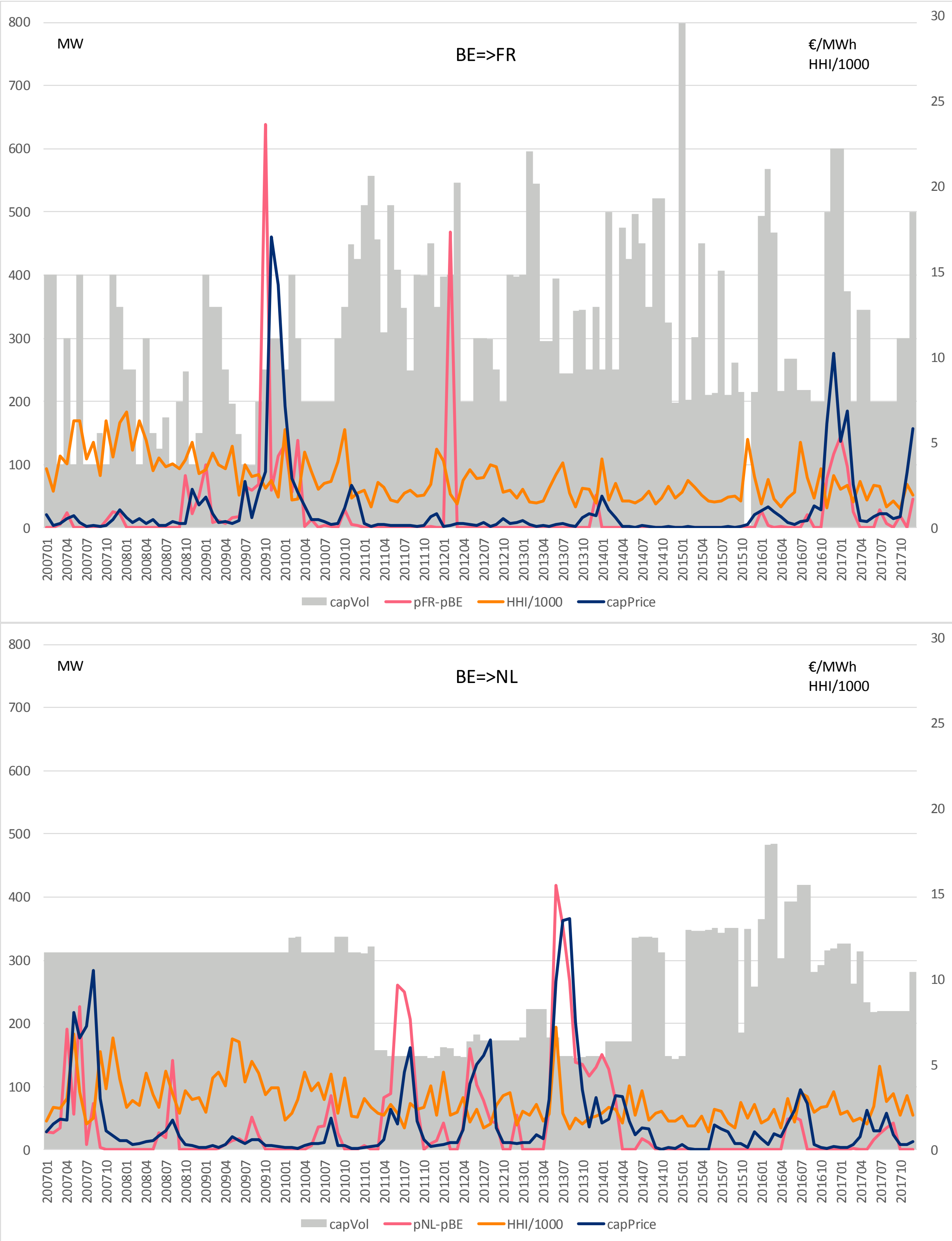


Figure 52: Monthly long-term EXPORT capacity auctions at the French border (top) and at the Dutch border (bottom). The auctioned volumes ('capVol', MW) vary on a monthly basis. The better the auction price ('capPrice', in €/MW) and the monthly-averaged day-ahead price in the given direction ('pFR-pBE' and 'pNL-pBE', in €/MWh) are correlated, the better the market was able to anticipate the price spreads. The level of competition, which depends on the number of participating market players, is measured by the HHI index ('HHI/1000').

4.3.2. Day-ahead cross-zonal exchange

82. Except for July and August, Belgium has been a net importer all months of 2017. Highest import net position was recorded in April, followed by January and November 2017. The highest export was observed in July.

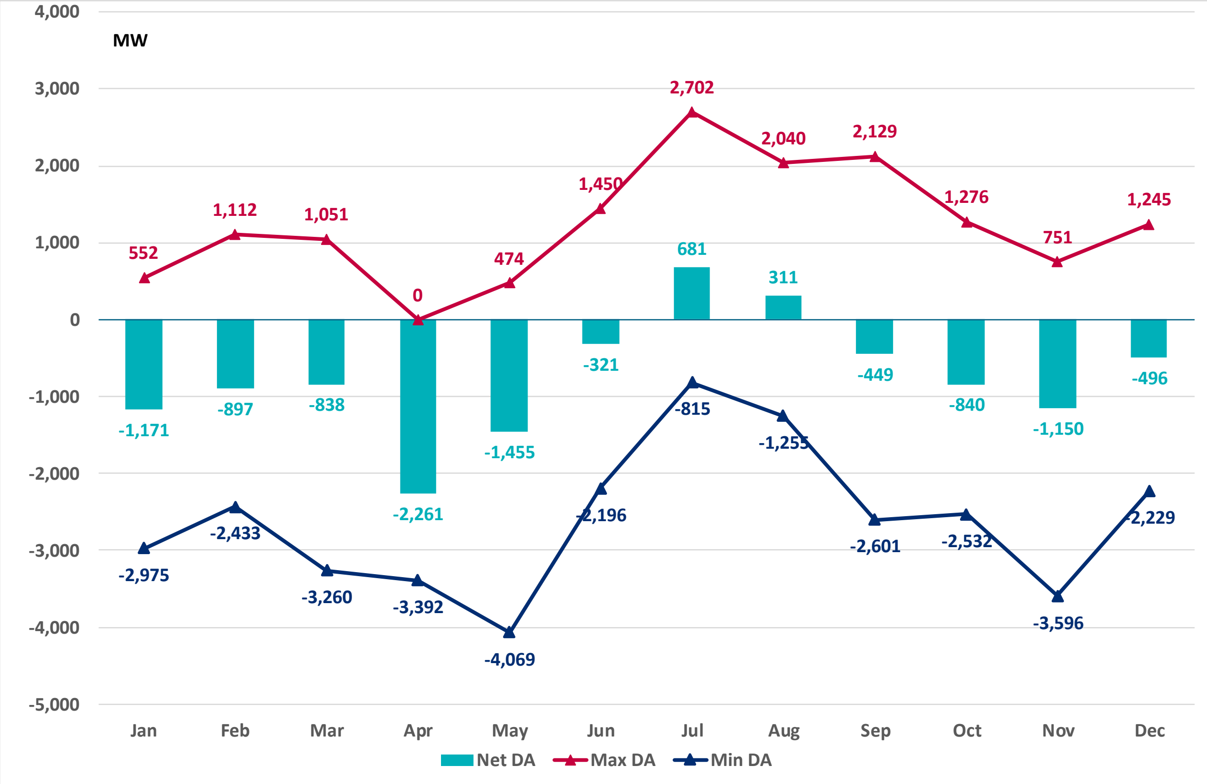


Figure 53: Monthly average ('Net DA'), maximum ('Max DA') and minimum ('Min DA') Day-ahead Net Position for Belgium. Positive values indicate export, negative values indicate import.

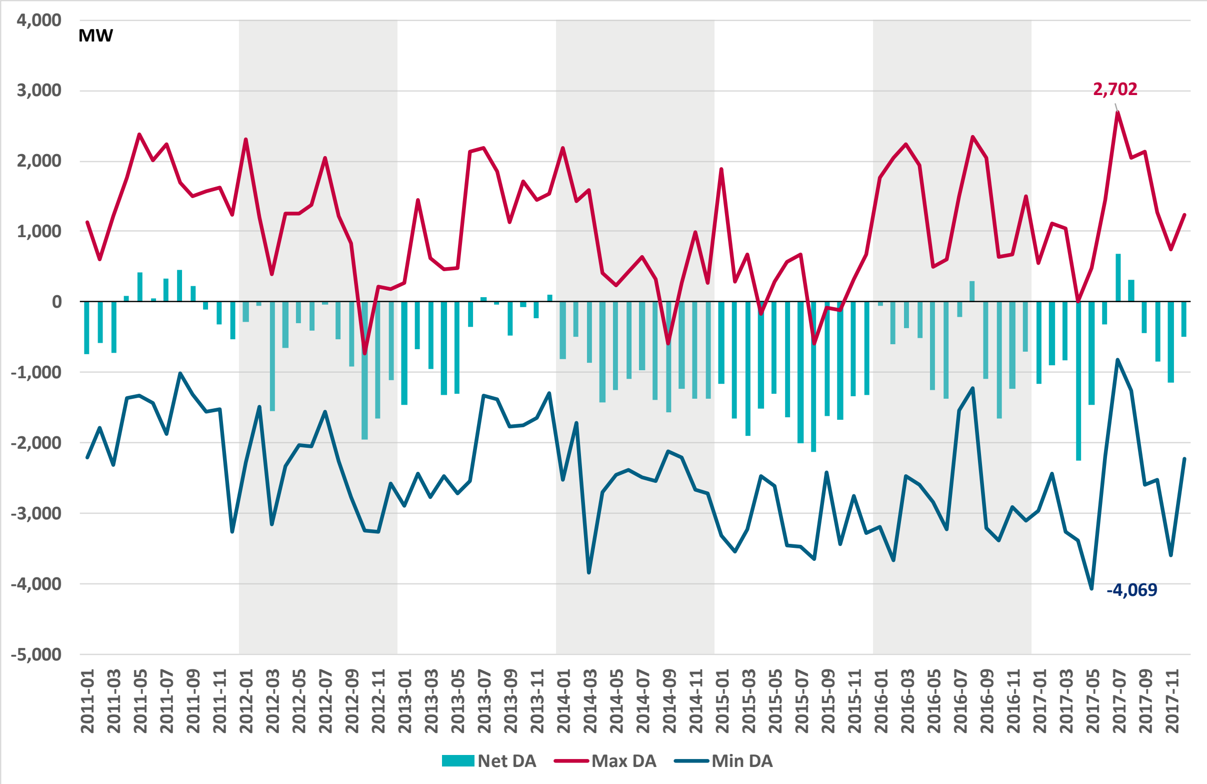


Figure 54: Evolution of the monthly average ('Net DA'), maximum ('Max DA') and minimum ('Min DA') Day-ahead Net Position (including long-term nominations) for Belgium since 2011. Positive values indicate export, negative values indicate import.

83. The day-ahead market in 2017 has broken records. The Belgian net export position of 2,702 MW, recorded in July 2017, was the highest Belgian export position ever. The same holds for the maximum day-ahead net import position of 4,069 MW in May 2017. Note that when the long term nominations (before the introduction of FTRs in 2016) are also taken into account, the maximum Belgian net import position amounts to 4,500MW. This value was recorded in June 2015 and corresponds to the Belgian import limit defined by Elia at that time.

84. On a yearly total, 2017 was similar to 2016, with an annual net import volume of 6.45 TWh (Table 23). This is only a fraction of the high annual net import volumes of 16.90 TWh and 20.96 TWh in respectively 2014 and 2015, related to the prolonged outage of 3 Belgian nuclear power plants. Prolonged outages of nuclear power plants were also the reason for France becoming a net importer in 2016. France imported 6.46 TWh in 2016 and 11.39 TWh in 2017. However, total exchanged cross-zonal volume in the CWE region remained the same as in 2016, well below the volumes exchanged between 2012 and 2015. The increase in French import by 4.93 TWh was achieved by the Netherlands importing 3.25 TWh less and Germany exporting 1.73 TWh more.

Yearly average Day-ahead + Long term net position (TWh)					
	BE	**NL**	**FR**	**DE/AT/LU**	**CWE**
2011	-2.23	-8.47	7.74	2.96	27.21
2012	-9.22	-17.74	2.86	24.09	35.62
2013	-9.72	-21.02	3.16	27.57	38.67
2014	-16.90	-17.65	10.86	23.69	37.68
2015	-20.96	-11.29	5.75	26.50	38.71
2016	-6.40	-9.06	-6.46	21.92	32.04
2017	**-6.45**	**-5.81**	**-11.39**	**23.65**	**32.73**
Average	-10.27	-13.01	1.79	21.48	34.67

Table 23: Annual net import (-) and export(+) volume on the CWE-day-ahead market, including the long-term nominations.

4.3.3. Intraday cross-zonal exchange

85. The contribution of the intraday cross-zonal exchanges to the annual Belgian net position remains small. The monthly contributions varied between -75 MW and +60 MW. Monthly averages for export varied from between 4 MW in June to 207 MW in September. Monthly averages for import varied from -2 MW in June to -267 MW in July.

86. While the contribution of intraday cross-zonal exchange to the annual and monthly basis remains small, the contribution on an hourly level is much higher. In 2017, the monthly maximum net intraday export position ranged from 408 MW to 1,714 MW. The monthly maximum net import positions ranged from -364 MW to 1,713 MW. The higher values for intraday import and export were recorded in the first half of 2017.

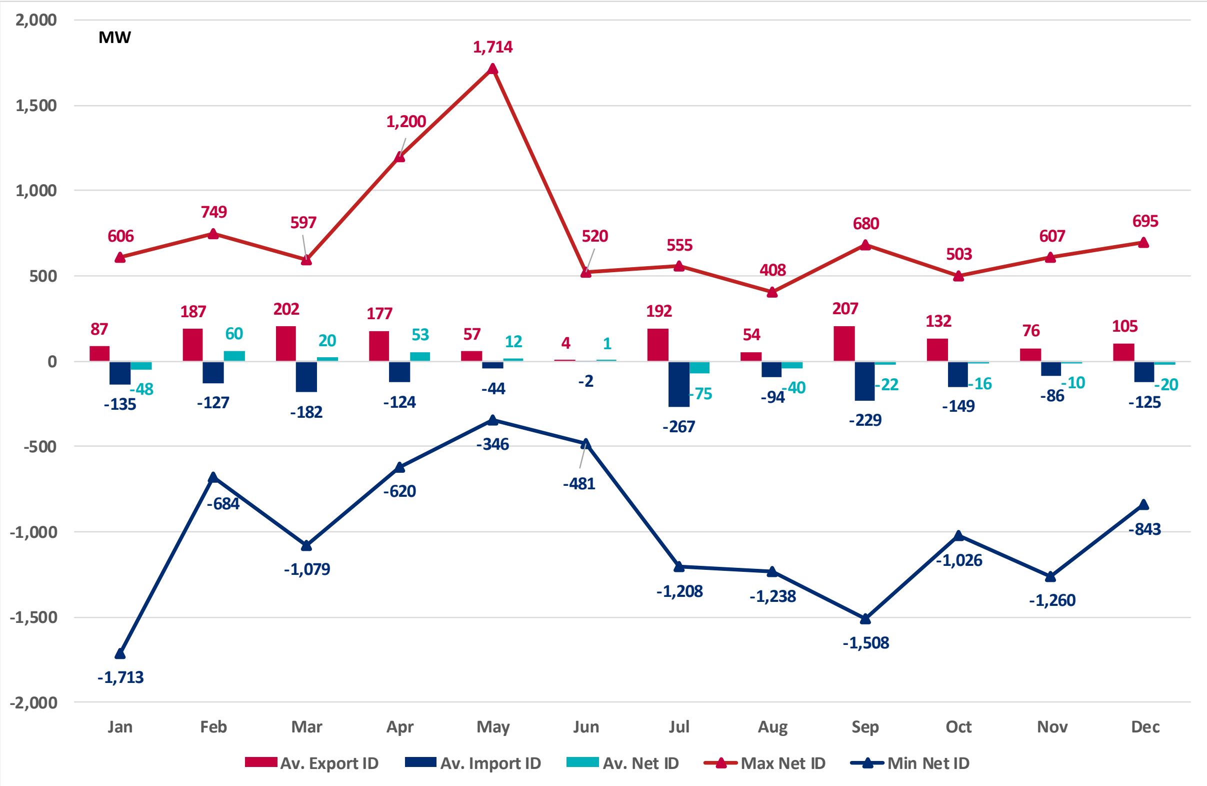


Figure 55: Monthly average export net positions ('Av Export ID'), average import nominations ('Av. Import ID') and resulting average net position ('Av. Net ID'), along with the monthly maximum levels ('Max Export ID', 'Max import ID') in 2017.

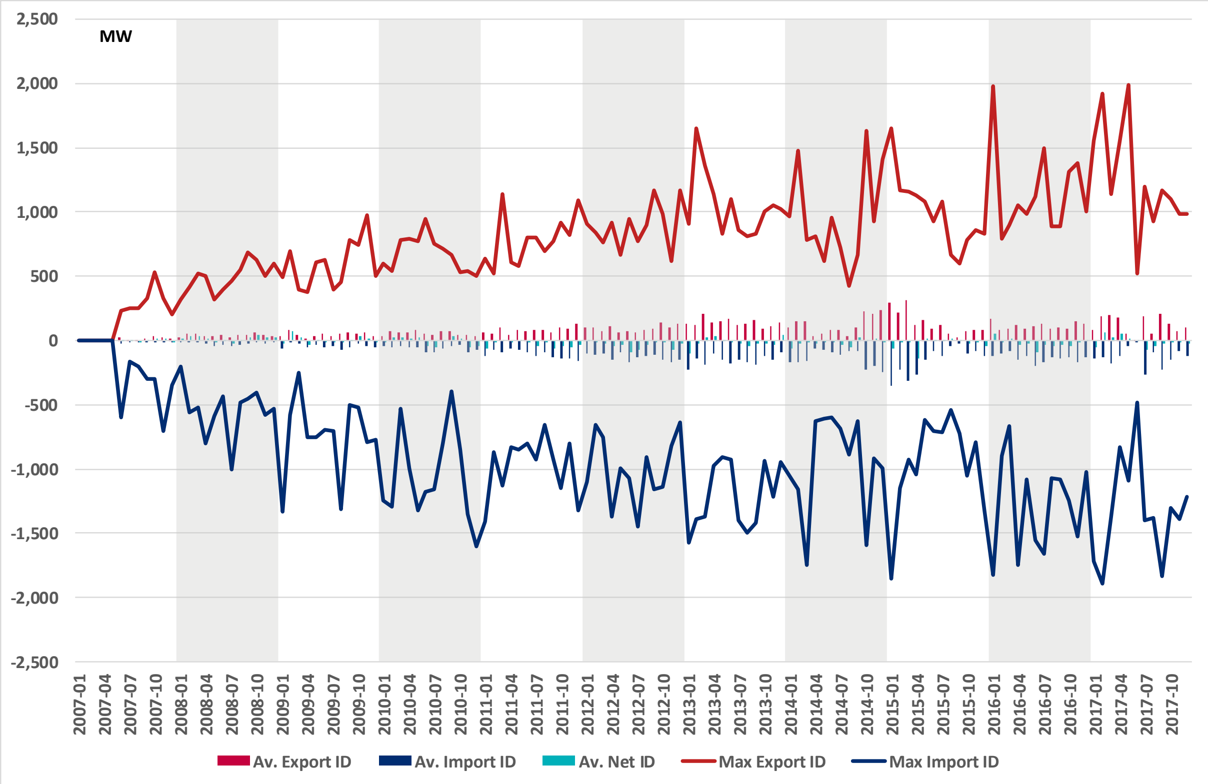


Figure 56: Evolution of the monthly average export net positions ('Av Export ID'), average import nominations ('Av. Import ID') and resulting average net position ('Av. Net ID'), along with the monthly maximum levels ('Max Export ID', 'Max import ID'), since 2007.

87. Since the start of the intraday market coupling in 2007, intraday exchanged volumes have shown an upward trend. In 2017, however, no significant further increase was observed, either in terms of maximum net import or export position, or in terms of monthly or annual averages. Especially the last three months of 2017, maximum export and import in intraday were at the lower end.

4.3.4. Overview of cross-zonal exchanges

88. Figure 57 and Table 24 summarise the contribution of the long term, day-ahead and intraday markets in the total annual Belgian imported and exported volume over the past 11 years. The figures confirm the main findings discussed above: the annual values for 2017 are almost the same as those for 2016. Since the introduction of Financial Transmission Rights (FTR) in January 2016, long-term transmission rights no longer have to be nominated. Their corresponding exchanges are included in the day-ahead exchanges. Firmness of long-term transmission rights is guaranteed through the so-called 'LTA-patch'[31]. The latter virtually increases the day-ahead flow based domain if it is too small to allow all long-term exchanges.

[31] For a discussion on the LTA-patch, see CREG monitoring report 2016, https://www.creg.be/nl/publicaties/studie-f1609

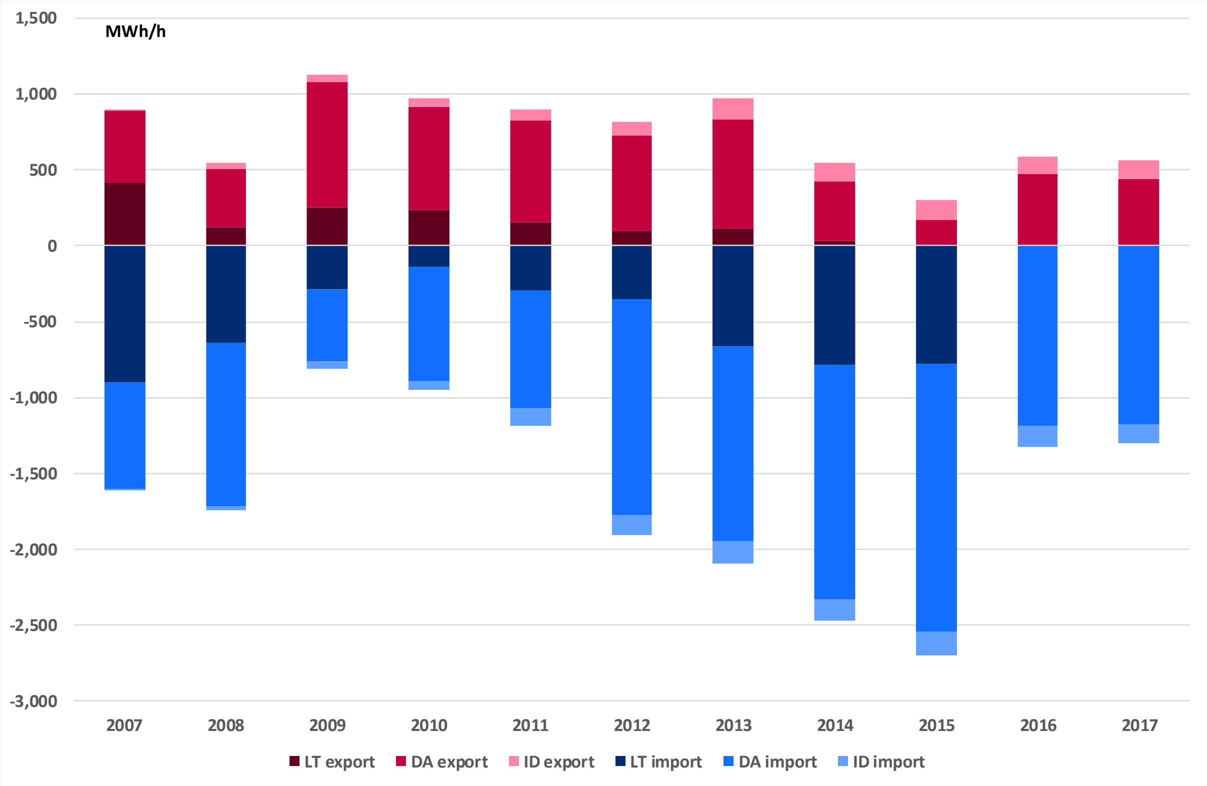


Figure 57: Imported and exported volumes on the long term (LT), day-ahead (DA) and intraday (ID) markets.

	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	1609	-709	46%	53%	1%	56%	43%	0%
2008	4.80	15.30	-10.50	546	1742	-1196	22%	71%	8%	36%	62%	1%
2009	9.88	7.08	2.80	1128	808	319	22%	74%	4%	36%	59%	5%
2010	8.50	8.35	0.15	970	953	17	24%	70%	6%	14%	79%	7%
2011	7.91	10.38	-2.47	903	1185	-282	17%	74%	9%	25%	66%	9%
2012	7.20	16.72	-9.52	820	1904	-1084	11%	77%	12%	19%	75%	7%
2013	8.54	18.39	-9.85	975	2099	-1124	11%	74%	14%	32%	61%	7%
2014	4.80	21.68	-16.87	548	2475	-1926	6%	72%	22%	32%	63%	6%
2015	2.68	23.69	-21.01	306	2705	-2398	0%	55%	45%	29%	65%	6%
2016	5.17	11.65	-6.48	589	1326	-738	0%	81%	19%	0%	90%	10%
2017	4.92	11.44	-6.51	562	1306	-744	0%	78%	22%	0%	90%	10%

Table 24: Share of the long term (LT), day-ahead (DA) and intraday (ID) markets in the Belgian electricity export and import.

4.3.5. Congestion rents

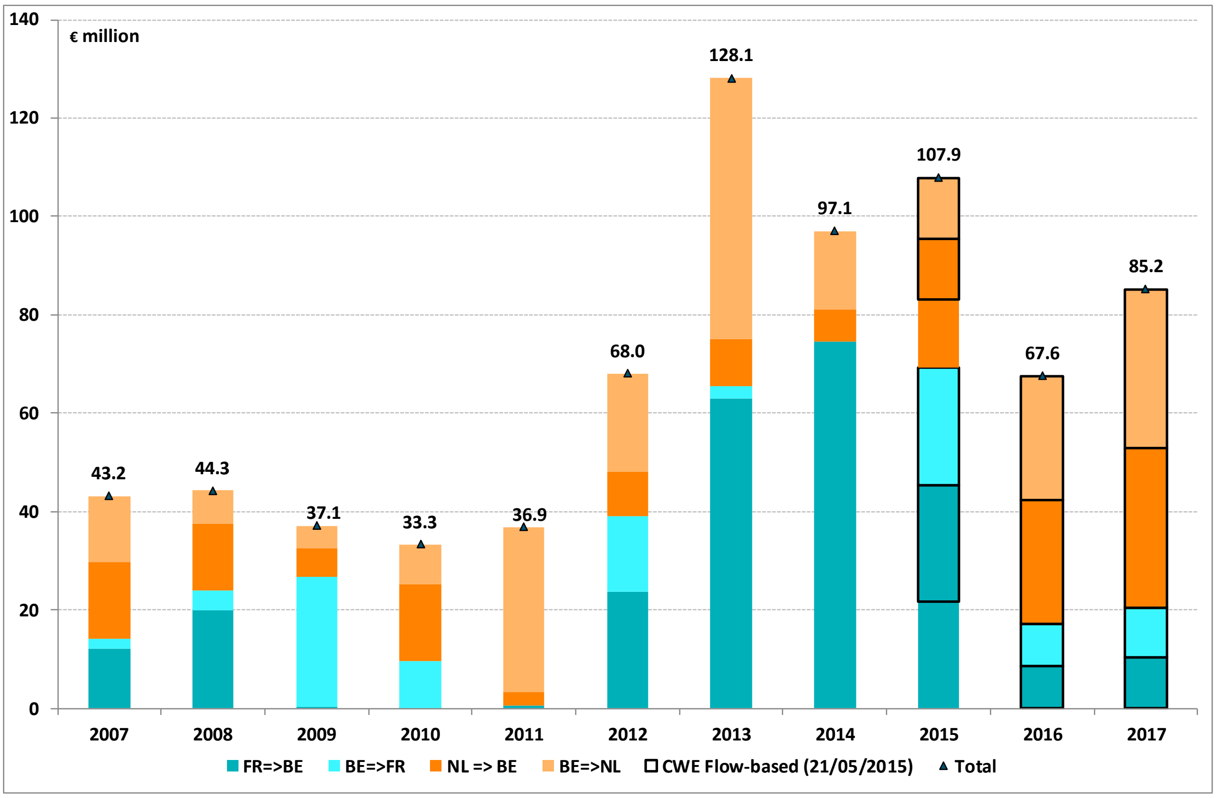


Figure 58: Congestion rents per border and per direction. For the years with FBMC, the values correspond to the total congestion income generated on the Belgian borders prior to resales. The values do not show how the income is distributed among long-term transmission rights holders on the one hand and the TSOs of the concerned bidding zones on the other.

89. 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.

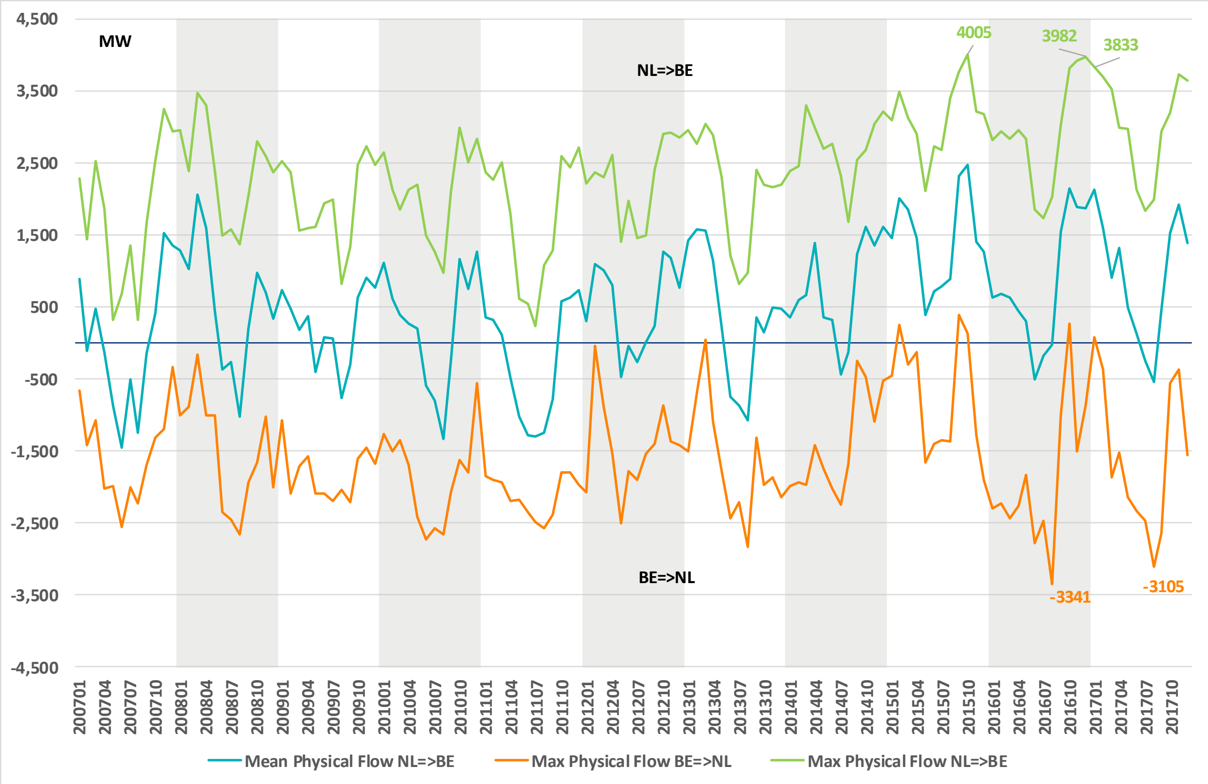
90. In 2017, the congestion rents generated at the Belgian borders were higher than in 2016, but still lower than in previous years (Figure 58). The congestion rents at the northern border further increased due to further increase in price spreads with the Netherlands. The congestion rents at the southern border remain smaller than in previous years, linked to the lower price spreads with France.

4.3.6. Physical flows

91. Since the go-live of FBMC, physical flows on the cross-zonal lines reached higher maximum values then previous years (Figure 59). In 2017, the following maximum levels were reached:

- On the Northern border, a maximum of 3,833 MW (NL=>BE) was recorded in January 2017 and a maximum of 3,105 MW (BE=>NL) in August 2017.
- On the Southern border, a maximum of 3,209 MW (BE=>FR) was recorded November 2017 and a maximum of 3,322 MW (FR=>BE) in April 2017.

These values remain below the maximum levels recorded in 2016. High physical flows arise from high volumes of cross-zonal exchange (Belgian import, Belgian export and Transit Flows through Belgium) and/or high loop flows.



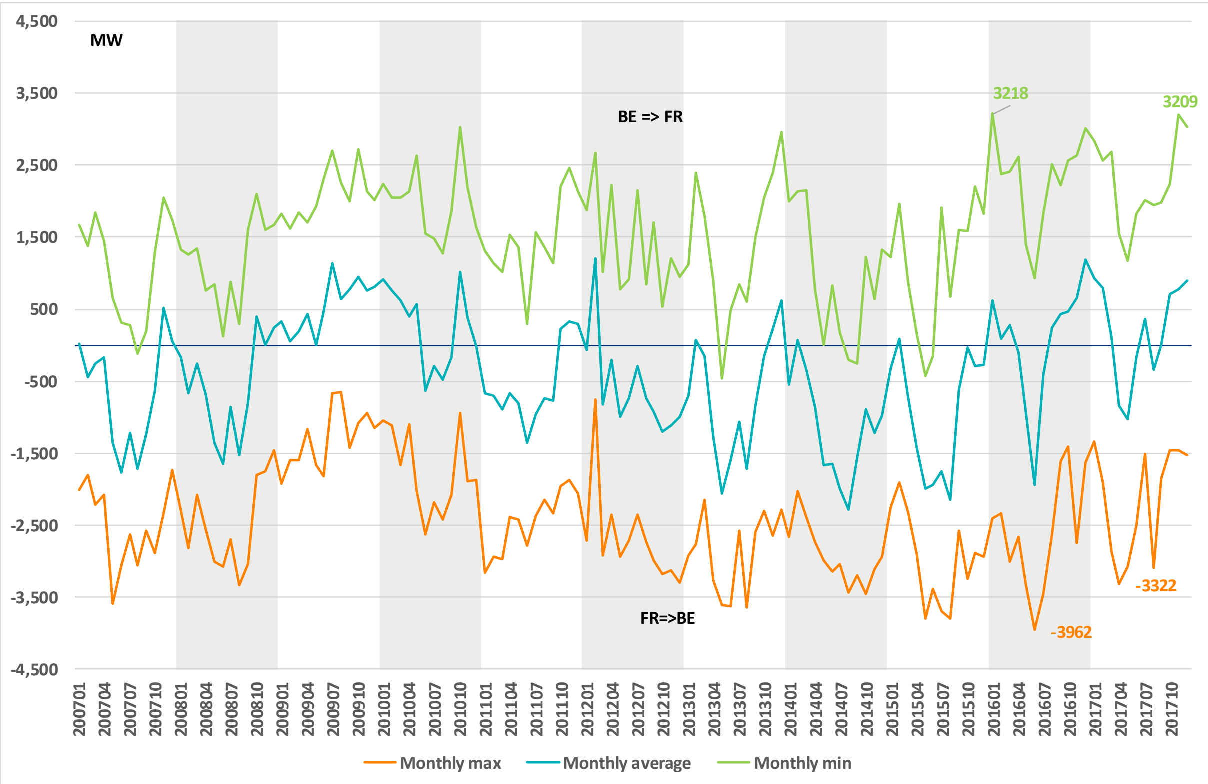


Figure 59: Physical flows on the Northern border (top) and the Southern border (bottom). Positive values indicate physical flows in the North-to-South direction.

4.3.7. Transit flows

92. Transit flows are physical flows crossing the Belgian control area, resulting from commercial exchanges between two other bidding zones. 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).

93. The net transit flow, shown in Figure 60, is the result of all transit flows resulting from the long-term, day-ahead and intraday exchanges. Positive flows indicate a resultant flow in the North-South direction. With ATC-market coupling, bilateral commercial exchanges are translated into capacity nominations on individual borders. With FBMC, the zonal net positions are translated into bilateral exchanges in a post-processing step. Note that there is no unique translation from zonal positions to zone-to-zone exchanges. The latter are therefore not uniquely defined, and depend on the computation method.

94. Before May 2015, the computed transit flows showed a clear pattern, with an almost constant value for the maximum transit flow from FR=>NL and with a seasonal pattern for the maximum transit flow from NL=>FR. After this date, the calculated transit flows vary much more, especially those in the direction FR=>NL. In addition, much larger transit flows are recorded in both directions. The difference between the periods before and after May 2015 may be due to the computation method, to the introduction of FBMC and/or to the situation in the French market resulting from the prolonged outage of some nuclear power plants.

95. In 2017, transit flows reached a record value in the North-South direction of 2,957 MW, compared to 2,302 MW in 2016. Transit flows in the South-North direction remained below the maximum of 4,245 MW in 2016.

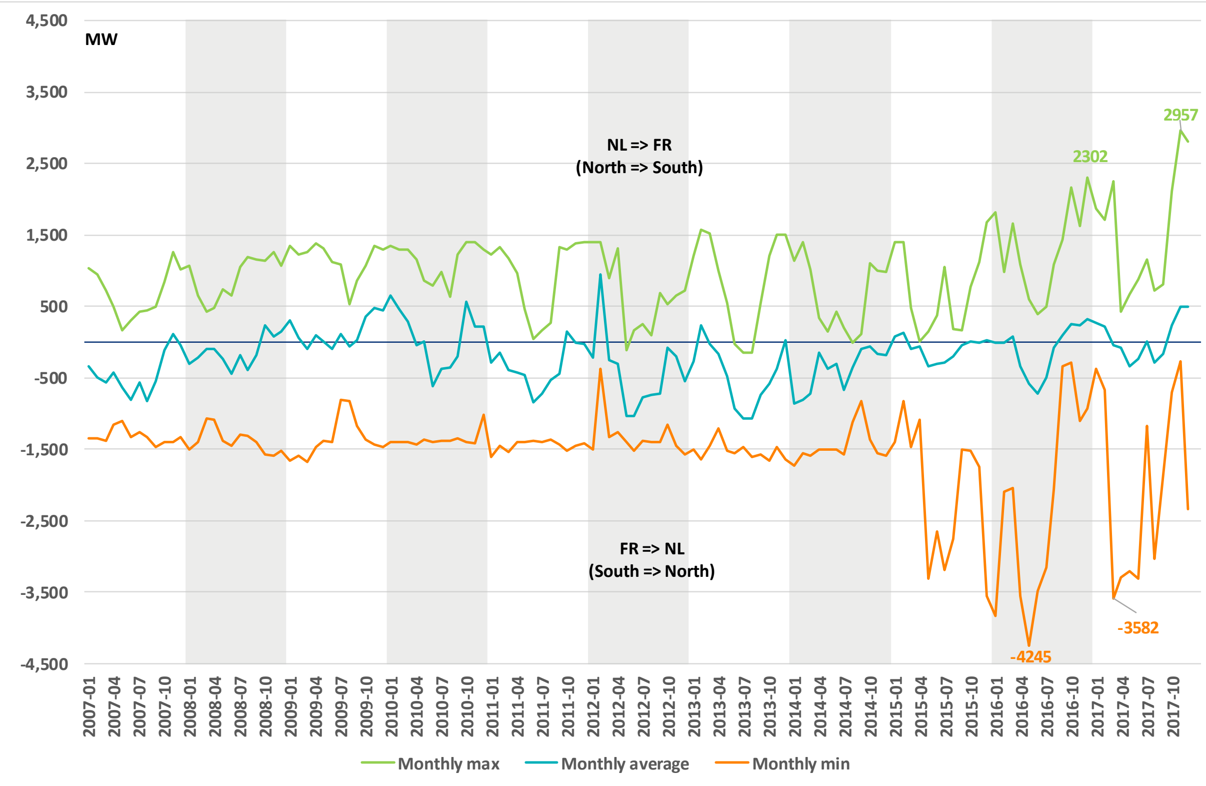


Figure 60: Monthly average, maximum and minimum net transit flows through Belgium.

96. Since the go-live of FBMC in May 2015, record values were recorded in both directions, with the highest values reached in the direction South-North. In 2017, transit flows were mainly South-North oriented in summer, when the Netherlands were importing, and mainly North-South oriented in winter, when France was importing.

Mean Transit via Belgium (MW)				
Year	**Transit NL=>FR**	**Transit FR=>NL**	**Transit Net NL=>FR**	**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
2017	207	-158	49	6
Average	155	-348	-192	-1

Table 25: Mean transit flows via Belgium from 2007 to 2017. Transit flows in 2017 were prominently more North-South oriented than in the past six years.
Sources: Elia and CREG

Net Position in day-ahead + long term (MW)				
2017	**BE**	**NL**	**FR**	**DE/AT/LU**
Jan	-1,171	765	-2,058	2,464
Feb	-897	153	-1,524	2,268
Mar	-838	-918	-732	2,489
Apr	-2,261	-580	525	2,317
May	-1,455	-1,783	930	2,308
Jun	-321	-1,525	-327	2,173
Jul	681	-634	-426	380
Aug	311	-2,111	-228	2,029
Sep	-449	-1,667	-907	3,023
Oct	-840	-74	-3,063	3,977
Nov	-1,150	645	-3,809	4,314
Dec	-496	-163	-3,984	4,643
Average	-663	-736	-1,300	2,699

Table 26: Monthly average Net Positions of the 4 CWE bidding zones in 2017 resulting from the CWE day-ahead and long term commercial exchanges. In 2017, Belgium was a net importer all months, except from July and August. The last 3 months of 2017 were characterised by high average import positions of the French bidding zone and high average export position of the German/Austrian/Luxembourg bidding zone.

97. Table 25 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, the Net Transit flows resulting from the set of zonal Net Positions are obtained. The breakdown of this Net Transit flow into Transit NL=>FR and Transit FR=>NL is not uniquely defined and is therefore somewhat arbitrary.

98. Since 2011, the net transit flows through Belgium are predominantly South to North (Table 25,). This was not the case for 2017, since France was importing for 10 of the 12 months, especially the last 3 months (see Table 26).

4.3.8. Loop flows

99. Since 1 January 2017, the loop flows through the Belgian zone are published on a daily basis on the Elia website[32]. 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.

100. 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 previously discussed, all commercial exchanges give rise to physical flows. Not all of these 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 are in competition for the use of the network transmission capacity. Physical flows arising from commercial exchanges *inside another zone*, by contrast, obtain priority access to the grid and are present in the base case[33]. 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.

101. Figure 61 shows the loop flows through Belgium calculated by Elia since the start of FBMC (May 2015 to December 2016). Most of the hours, the result of all loop flows generated in the CWE zones through Belgium flows in the North-South direction. For the monitoring period 2015 - 2016, loop flows through Belgium were Gaussian distributed with a mean of +873 MW (North=>South) and a standard deviation of 514 MW. Recorded maximums were +2,459 MW (North=>South) and -1,010 MW (South=>North). In 2017, loop flows in D-2 forecasts, decreased. The mean value was +840 MW (North=>South), standard deviation was 513 MW and maximums +2,413 MW and -504 MW.

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

[33] See also CREG study 1687, “Functioning and design of the Central West European day-ahead flow based market coupling for electricity: Impact of TSOs Discretionary Actions”, 21 December 2017

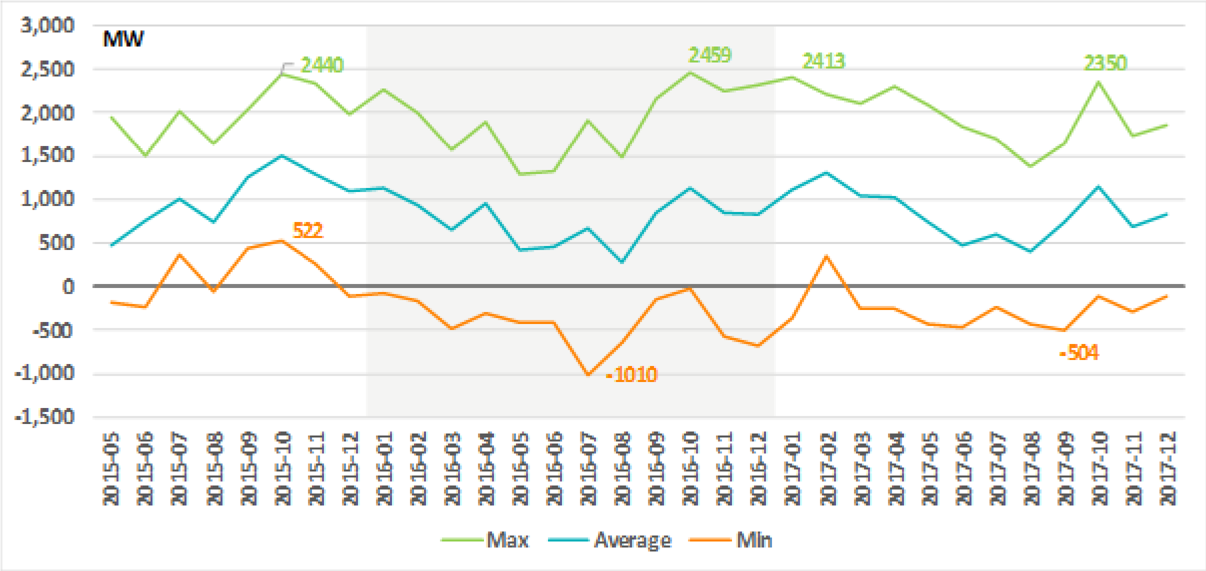


Figure 61: Maximum, minimum and monthly averaged loop flows through Belgium, forecasted in D-2. Positive values indicate loop flows in the direction North-to- South.
Sources: Elia and CREG

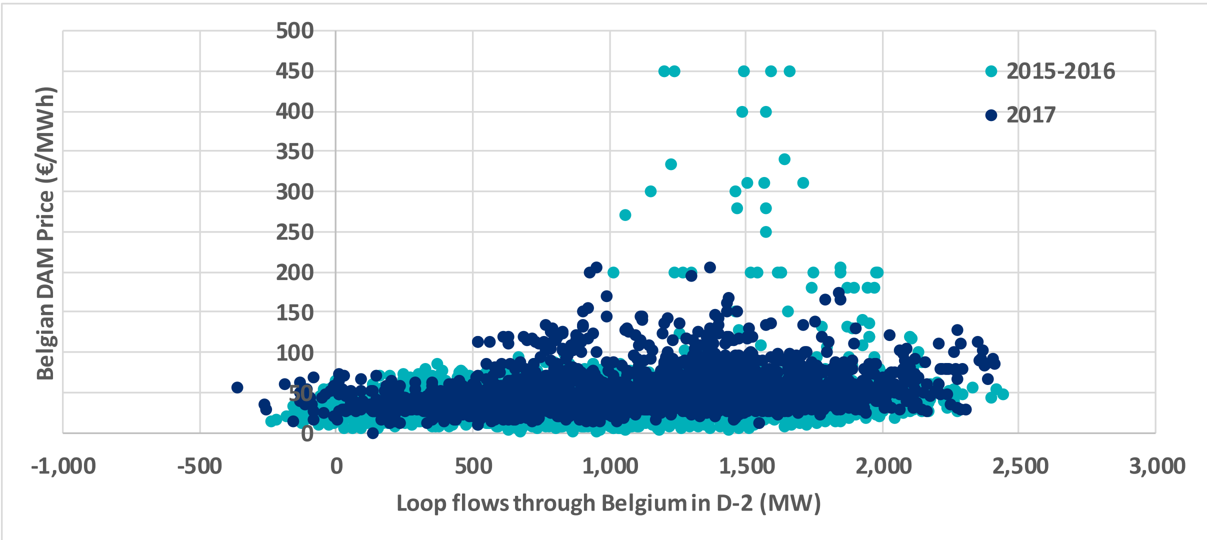


Figure 62: Belgian day-ahead prices versus D-2 loop flows for all hours in the monitoring period July 2015 to December 2016 (light) and 2017 (dark). Positive loop flows indicate physical flows crossing the Belgian network from North to South.
Sources: Elia and CREG

4.3.9. Evaluation of CWE day-ahead Flow Based Market Coupling

102. CWE day-ahead FBMC went live in May 2015, thereby replacing the former ATC method for coupling the day-ahead markets in the CWE region. Contrary to ATC, FBMC makes it possible to simultaneously optimise the zonal net positions of the bidding zones involved, based on an optimisation algorithm to maximize CWE social welfare while respecting network constraints. CWE FBMC makes it possible to be far less conservative than the ATC method. This potentially allows a more efficient use and allocation of the existing network capacity.

103. The first 2.5 years of CWE FBMC has revealed both strengths and weaknesses of the current implementation method. On the one hand, record volumes of cross-zonal exchanges have been achieved. In November 2017, CWE cross-zonal exchange reached 9,671 MW, which was a record. The

maximum exchange under ATC was 7,000 MW. On average, however, cross-zonal exchanges dropped below ATC values. The annual average CWE cross-zonal exchange in 2017 evaluated over all hours was 3,736 MW, and evaluated during congested hours only, 4,018 MW. In 2014, this was respectively 4,302 MW and 4,389 MW (Figure 65). The yearly average cross-zonal exchange in the CWE region in 2017 was slightly higher than in 2016 thanks to the last 3 months of 2017. From October 2017 to December 2017, CWE exchanges were significantly higher thanks to – inter alia - the increase in Fmax-values of frequently congested critical branches (see discussion in Section 4.2), and thanks to lower loop flows (Figure 61). Improved coordination of PST settings could also explain the increased volumes.

104. The specific details of the CWE FBMC methodology are defined by the CWE TSOs. In its decision of 2015, the CREG had identified major threads for inefficiency and discrimination, inherent to the design choices made. The first 2.5 years of CWE FBMC show that this thread has materialised. In the CREG study 1687, the CREG identified the role of collective and individual TSO discretionary actions which led to the current situation with cross-zonal exchanges being on average below the values promised by the parallel runs – and even below ATC values.

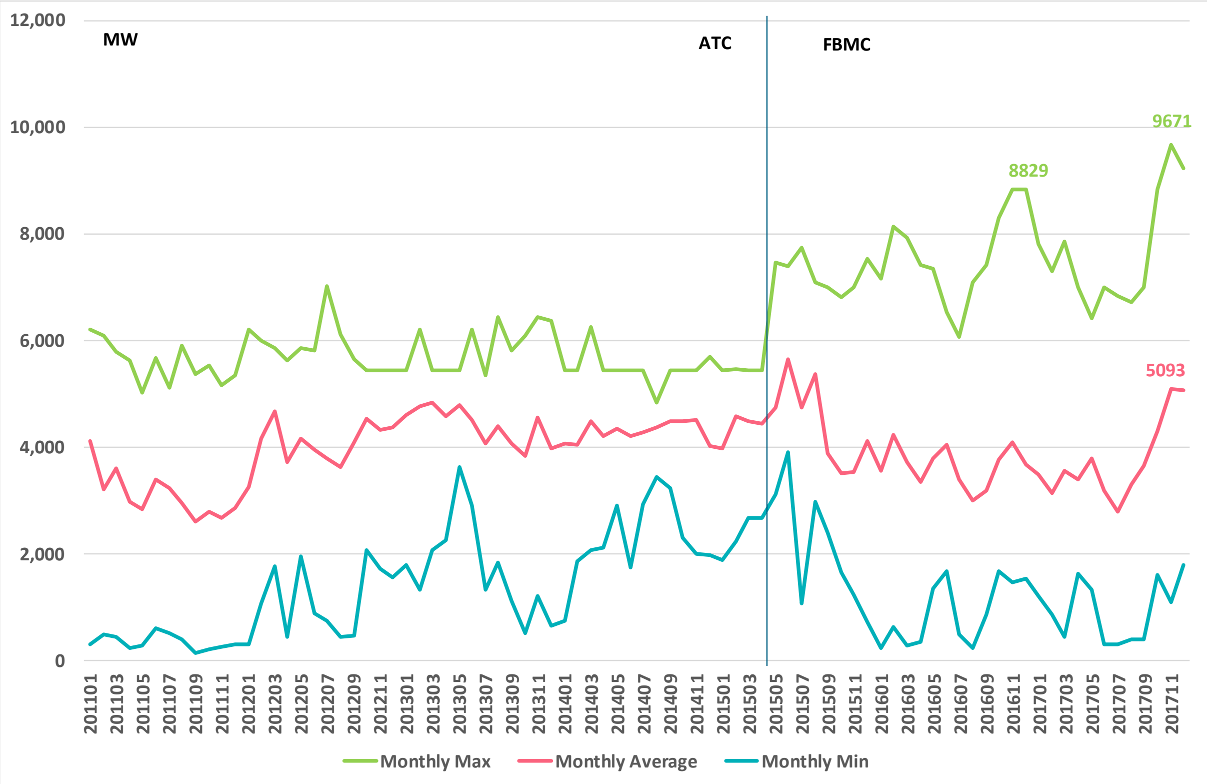


Figure 63: Maximum, average and minimum monthly values of CWE cross-border volume (day-ahead + long term) for 2011 – 2017. The vertical line indicates the start of FBMC for day-ahead market coupling.
Sources: CWE TSOs, CREG

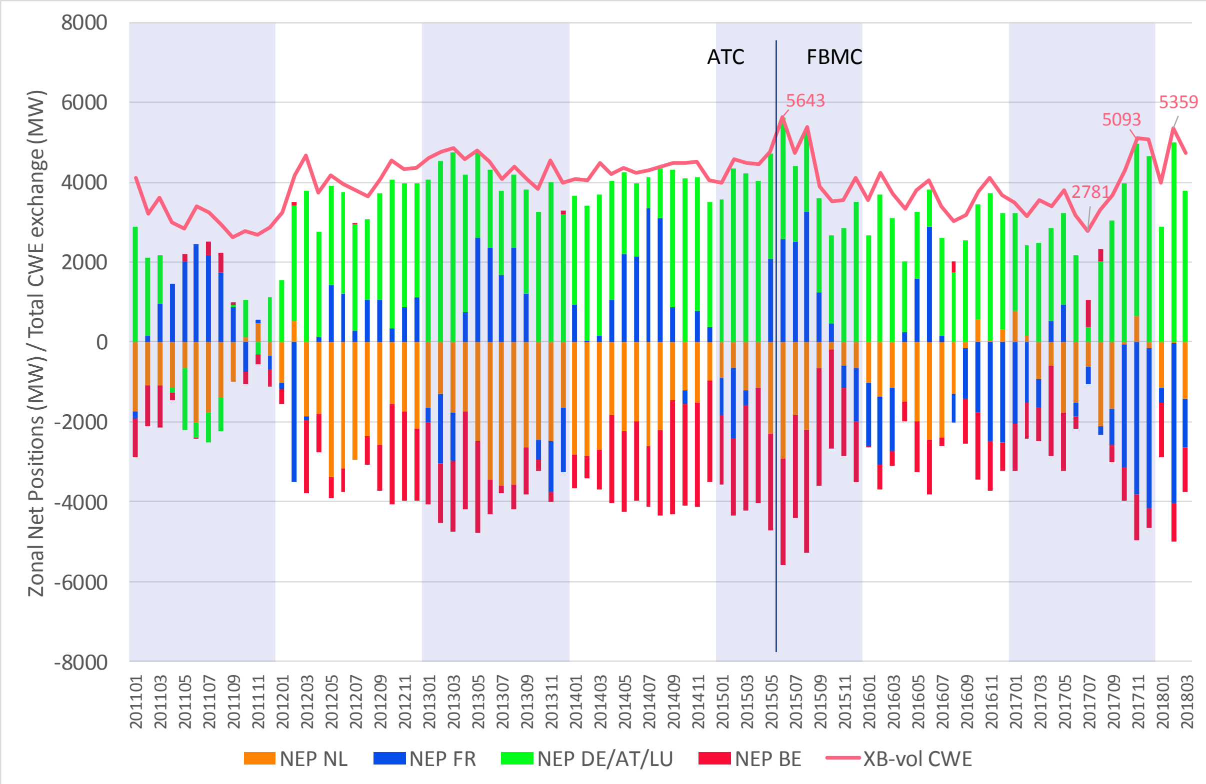


Figure 64: Monthly averaged Zonal Net Positions and CWE cross-zonal exchanges in day-ahead, including long term nominations, before and after the introduction of FBMC on 21 May 2015.

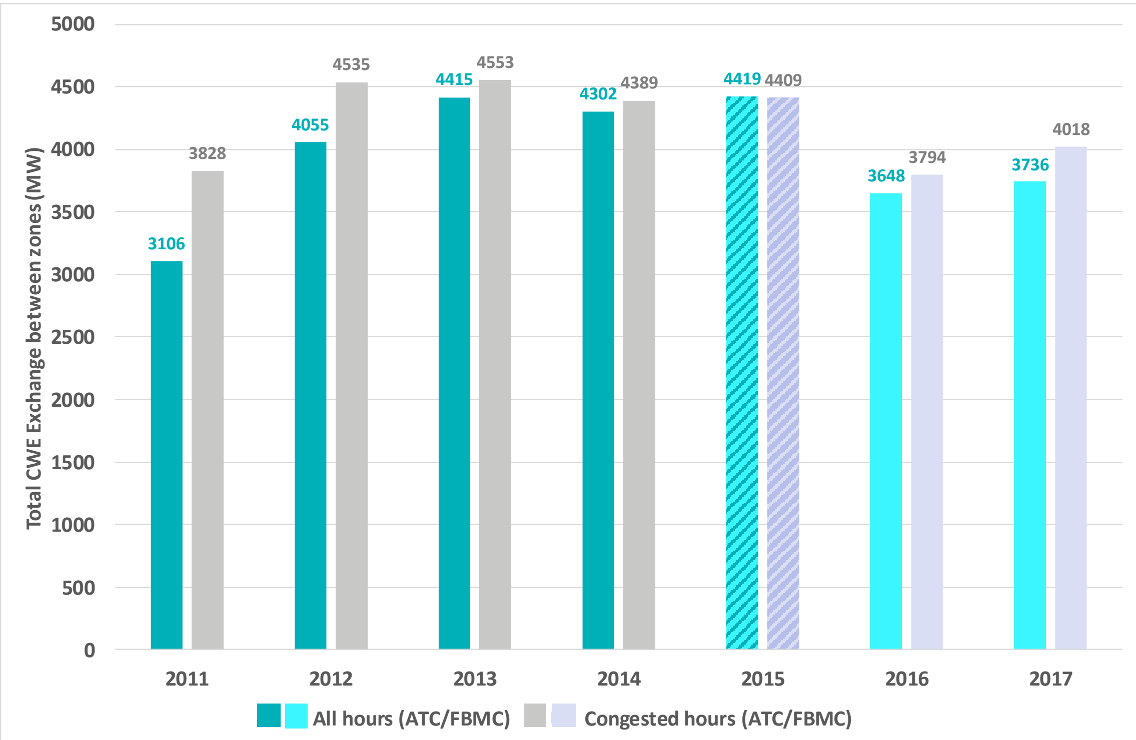


Figure 65: Yearly averaged day-ahead cross-zonal exchange in the CWE region, including long-term nominations. The blue and grey bars indicate the evaluated over all hours, respectively congested hours only. The darker bars show the results with ATC, the lighter bars the results with FBMC.

4.3.10. Evaluation of CWE day-ahead market coupling results

105. Overall day-ahead market prices in the CWE region increased from €29/MWh in 2016 to €34/MWh 2017 (Table 27). Full price convergence was achieved in 37% of hours, with an average CWE DAM price of €37.4/MWh (Table 29). The average CWE price spread during congested hours was €22.6/MWh (Table 29). Compared to 2016, the number of hours with full price convergence remained the same, although the price spread increased significantly. Average CWE exchange during congested hours was 4,018 MW, which is higher than the 3,794 MW all-year minimum recorded in 2016 but still roughly 10% lower than the values around 4,400 MW in 2014 and 2015.

The observed reduction in CWE day-ahead exchanges result from inefficiencies in the CWE FBMC implementation. It can be argued that the results in 2016 and in 2017 have also been affected by unfavorable CWE market conditions, since France was a net importer in contrast to previous years. However, the last 3 months of 2017 do not confirm this assumption. From October to December 2017, France was still importing, but CWE exchanges recovered (Figure 64). During these months, CWE cross-zonal exchanges reached pre-FBMC values. This shows that CWE cross-border exchange is not by definition affected by "unfavorable market conditions", and that network-related parameters are more dominant.

Year	Average Day-Ahead Market Clearing Price (€/MWh)						Average Day-Ahead Cross-zonal Exchanges and Net Positions incl. Long Term Nominations (MW)				
	Conv (% h)	CWE price spread	BE	NL	FR	DE	CWE XB-exchange	BE	NL	FR	DE
2011	69%	4	49	52	49	51	3,106	-255	-967	884	338
2012	50%	8	47	48	47	43	4,055	-1,049	-2,019	326	2,743
2013	16%	16	47	52	43	38	4,415	-1,109	-2,399	361	3,148
2014	21%	11	41	41	34	33	4,302	-1,929	-2,015	1,240	2,704
2015	21%	14	45	40	38	32	4,419	-2,392	-1,289	656	3,025
2016	38%	10	37	32	37	29	3,648	-728	-1,032	-736	2,496
2017	37%	14	44	39	45	34	3,736	-736	-663	-1,300	2,699
Average	36%	11	44	44	42	37	3,953	-1,167	-1,483	200	2,449

Table 27: Annual average results for the CWE day-ahead market clearing, evaluated over all hours.

Year	Average Day-Ahead Market Clearing Price (€/MWh) *during hours with price convergence*						Average Day-Ahead Cross-zonal Exchanges and Net Positions incl. Long Term Nominations (MW) - *Price convergence*				
	%hours	CWE price spread	BE	NL	FR	DE	CWE XB-exchange	BE	NL	FR	DE
2011	69%	0.0	53.7	53.7	53.7	53.7	2,775	-378	-790	624	544
2012	50%	0.0	47.3	47.3	47.3	47.3	3,570	-1,002	-1,821	653	2,171
2013	16%	0.0	57.2	57.2	57.2	57.1	3,701	-1,092	-1,512	-53	2,658
2014	21%	0.1	43.1	43.1	43.1	43.1	3,975	-1,857	-1,675	922	2,611
2015	21%	0.0	38.3	38.2	38.2	38.2	4,457	-2,407	-1,378	1,503	2,282
2016	38%	0.1	28.9	28.9	28.9	28.8	3,414	-638	-1,355	107	1,885
2017	37%	0.0	37.4	37.4	37.4	37.3	3,252	-575	-1,104	7	1,672
Average	36%	0.0	44.3	44.3	44.3	44.3	3,398	-907	-1,296	514	1,688

Table 28: Annual average results for the CWE day-ahead market clearing, evaluated over all non-congested hours.

Year	Average Day-Ahead Market Clearing Price (€/MWh) *during congested hours*						Average Day-Ahead Cross-zonal Exchanges and Net Positions incl. Long Term Nominations (MW) - *Congested*				
	%hours	CWE price spread	BE	NL	FR	DE	CWE XB-exchange	BE	NL	FR	DE
2011	31%	13.7	38.6	48.3	38.5	45.5	3,828	14	-1,352	1,448	-109
2012	50%	16.1	46.7	48.7	46.6	38.0	4,535	-1,096	-2,215	3	3,308
2013	84%	19.5	45.6	50.9	40.5	34.0	4,553	-1,113	-2,571	441	3,243
2014	79%	13.7	40.1	40.6	32.2	29.9	4,389	-1,948	-2,105	1,325	2,728
2015	79%	18.0	46.3	40.4	38.4	29.8	4,409	-2,389	-1,265	429	3,224
2016	62%	16.5	41.5	34.3	41.7	29.1	3,794	-785	-830	-1,263	2,877
2017	63%	22.6	48.6	40.4	49.4	32.4	4,018	-830	-407	-2,060	3,296
Average	64%	17.5	44.2	43.1	40.7	32.9	4,265	-1,313	-1,588	24	2,878

Table 29: Annual average results for the CWE day-ahead market clearing, evaluated over all congested hours.

4.3.11. Evaluation of network constraints

106. CWE FBMC makes it possible to know for each congested hour which were the active network constraint(s). Current CWE FBMC methodology makes it possible to manage congestion on both cross-zonal lines and on internal lines. In addition, some CWE TSOs also impose explicit import and export limitations or so-called external constraints ('EC'). Table 30 gives an overview of the occurrence of each category of network constraints for 2017. In the majority of cases, the constraint was on an internal line with an average RAM of 16%. In 35% of the cases, the constraint was on a cross-zonal element. The table shows the results for cross-zonal lines and phase shift transformers (PST) separately, to indicate that in the majority of cases, the active cross-zonal element was a PST. External constraints account for 6% of the active constraints.

Type of constraint ('CBCO')	Occurrence		max PTDF (%)			RAM (% Fmax)			Shadow price (€/MW)		
	Hours	%	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
Internal line (INT)	6518	59%	13%	1%	45%	16%	1%	94%	208	0.0	2521
Cross-border line (XB)	1668	15%	21%	4%	48%	39%	4%	91%	89	0.1	1660
Phase Shift Transformer (PST)	2211	20%	35%	10%	60%	46%	11%	84%	76	0.0	853
External constraint (EC)	641	6%	-	-	-	-	-	-	10	0.1	37
Total	11038	100%	23%	1%	100%	31%	1%	101%	152	0.0	2521

Table 30: Overview of active network constraints in 2017, evaluated per type.

107. The zone-to-zone PTDF values are typically lower for internal lines than for cross-zonal network elements. Zone-to-zone PTDFs are computed by CWE TSOs for each individual element and each individual hour, and express the expected impact of a zone-to-zone commercial exchange on the physical loading of that line. In the lower limit, internal lines with maximal zone-to-zone PTDFs down to 1% have been included, being below the currently adopted CBCO selection criterion of minimum 5% PTDF. In the upper limit, PTDFs on PSTs can be up to 60%.

108. The RAM values are typically lower on internal lines than on cross-zonal lines. The RAM represents the capacity available on a network element for cross-zonal exchange. Because of preloading of the lines by domestic exchanges, included as reference flows (Fref) with priority grid access, the RAM currently falls well below the thermal line capacity (Fmax). In 2017, RAM values on internal lines, expressed relatively to their corresponding Fmax-value, were 16% on average. For cross-zonal lines and PSTs the average RAM amounted to 39% and 49% respectively (Table 30). The breakdown of Fmax into Fref, FRM and RAM is shown in Figure 66 and Figure 67 on an individual network element level for congested cross-zonal lines and internal lines respectively.

109. Note that in all the RAM values shown are the commercial capacities offered to the day-ahead market coupling. This is the capacity after deduction of the capacity needed for the long-term nominations, resulting from nominations of long-term rights of the type Physical Transmission Rights

(PTR). Since the volumes of long-term nominations are low, this has no significant impact on the results and conclusions discussed.

110. The shadow price of congestion on internal lines is significantly higher than for congestion on cross-border elements. The shadow price represents the increase in CWE total welfare (€) for a unit increase of the available capacity on the congested element (MW) and depends on the specific market situation and on the multiplicative effect of a line. The latter represents the extra volume of cross-zonal exchange enabled by an extra unit of available capacity on that line. The smaller the zone-to-zone PTDF, the higher the multiplicative effect. High shadow prices reflect high opportunity costs of the congestion and typically arise when cross-zonal exchanges are heavily limited. In 2017, the shadow price of congestion on internal lines was €208/MW on average, with maximum levels up to €2521/MW. For congestion on cross-zonal lines and PSTs, shadow costs were respectively €89/MW and €76/MW on average. The average shadow cost of external constraints, being triggered at larger volumes of cross-zonal exchanges, was €10/MW.

111. Table 31 lists the 25 most frequently active network constraints for 2017. The average values for the max PTDF, Fmax, RAM and FRM are shown, evaluated for the hours when the considered network element was congested. The analysis at the individual network element level provides insight into the reasons for a specific network element being congested. As a first example, the PST Zandvliet is considered. This PST, located on the Belgian northern border, has been the most frequently congested network element in 2017 despite having the highest average RAM of the listed top 25 critical network elements (50% RAM). Relatively low cross-zonal exchanges could however trigger congestion, since it also had the largest zone-to-zone PTDF of the list (38% PTDF). An average RAM of 50% can be considered low for a cross-zonal network element. In the case of PST Zandvliet, this is partially due to the FRM value of 17% of the average Fmax of 1,505 MW. The remaining 33% of Fmax are used by loop flows. Similar observations hold for the Belgian internal line Doel-Zandvliet, directly connected to the PST Zandvliet. As a second example, D7HANE_DGRON in the Amprion network is considered. This internal line has been an active constraint during 1,197 hours, having on average only 9% RAM. Since the FRM values on that line are relatively low (7% of Fmax), the main reason for the low RAM are the reference flows arising from internal trade inside the DE/AT/LU bidding zone considered in the base case. As a result, D7HANE_DGRON has been congesting CWE FBMC in 14% of all hours, with RAM values of the same order of magnitude as the FRM. Similar observations hold for D7KNAP_DSECH and D7ROKI DSECH where the RAM values are even below the FRM values. As a third example, XDI_ME, the interconnector between Germany and the north of Netherlands, and ranked third in terms of occurrence, only had 37% RAM on average. This interconnector has a relatively small Fmax, relatively high FRM (20% of Fmax) and high loop flows (43% of Fmax).

Critical Branch	TSO	Type	Count (hours)	Average maxPTDF	Average Fmax (MW)	Average RAM (MW)	Average FRM (MW)	Average RAM (%Fmax)	Average FRM (%Fmax)	Average Shadow cost
PST ZANDV	BE	PST	1658	38%	1505	751	256	50%	17%	74
D7HANE DGRON	D7	INT	1197	8%	1933	164	130	9%	7%	280
XDI_ME	D2	XB	1135	18%	1061	392	211	37%	20%	109
NENS NLLS	NL	INT	893	15%	1732	380	173	22%	10%	114
BMERCA BRODE+	BE	INT	742	23%	1478	502	188	33%	13%	61
PST GRON	D7	PST	505	23%	1470	495	150	34%	10%	87
DE_export	DE	EC	477	-	6452	6323	-	-	-	11
D7NL_ME	D7	INT	378	9%	1441	163	137	11%	10%	258
D2GR DGR_ST	D2	INT	373	4%	1659	76	283	5%	17%	369
D7DO_HA	D7	INT	368	10%	1441	170	137	12%	10%	231
D7KNAP DSECH	D7	INT	351	6%	2095	139	185	7%	9%	281
D7ROKI DSECH	D7	INT	298	8%	1965	151	178	8%	9%	87
XSI_MB	D7	XB	287	27%	1801	890	112	49%	6%	33
D7BE_GU	D7	INT	234	5%	1884	102	169	5%	9%	647
BMERCA BHORTA	BE	INT	223	26%	1516	529	155	35%	10%	48
BHORTA BAVLGM	BE	INT	183	22%	1546	410	162	26%	10%	70
NLLS NDIM	NL	INT	155	13%	1732	290	173	17%	10%	179
D7OBZI DYDAH	D7	INT	122	13%	1877	207	178	11%	9%	125
D2DOEW DDO_HA	D2	INT	113	12%	1440	185	66	13%	5%	193
BDOEL BZANDV	BE	INT	110	26%	1425	657	275	46%	19%	25
D2YNLA DNL_ME	D2	INT	107	12%	1441	191	70	13%	5%	137
D7ROKI DKNAP	D7	INT	90	5%	1922	89	206	5%	11%	232
NL_import	NL	EC	77	-	4250	4225	-	-	-	4
D4DE_VO	D4	INT	76	5%	1787	147	357	8%	20%	165

Table 31: Characteristic of Top 25 active constraints in the CWE FBMC in 2017, ranked by number of occurrences. The averages are calculated over the hours the specific network element was an active constraint. RAM values are the commercial capacities given to the day-ahead market coupling, after long-term nominations.

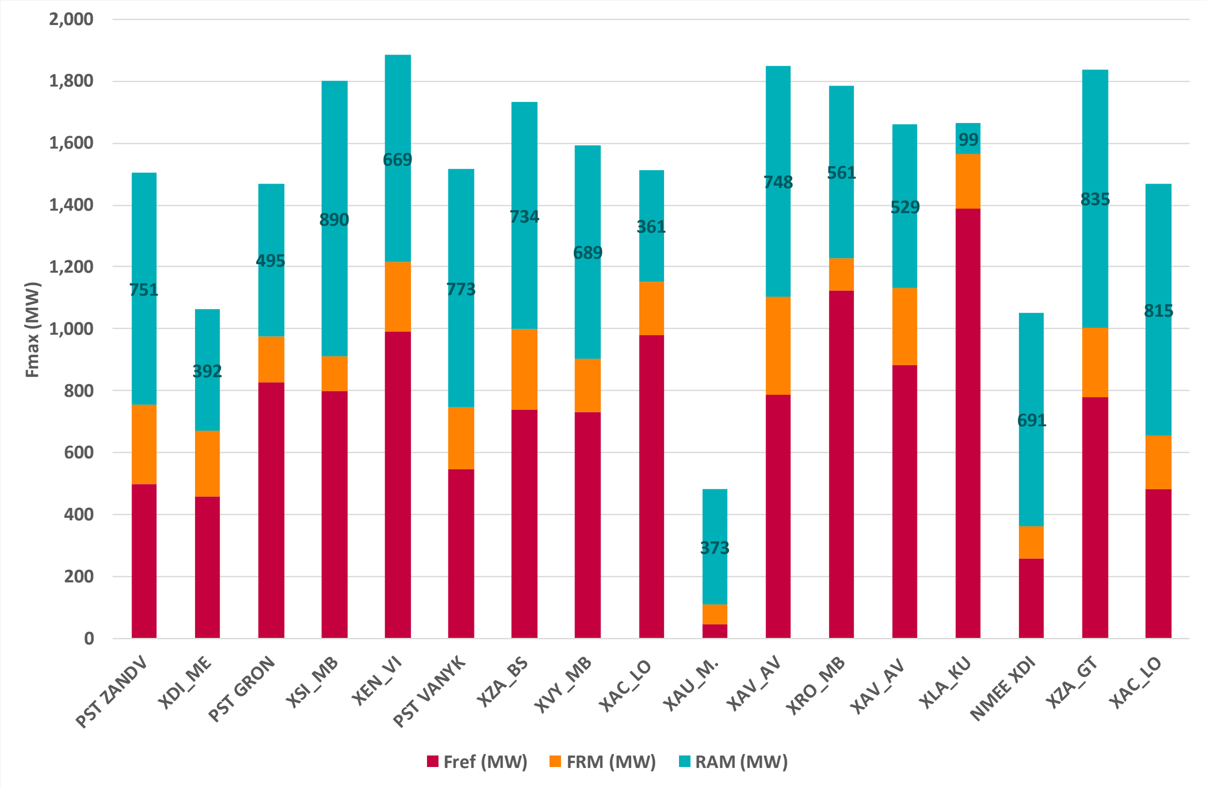


Figure 66: Use of the Thermal Line Capacity (Fmax, vertical axis) for Reference Flows (Fref), Flow Reliability Margins (FRM) and commercial flows from CWE DA cross-zonal exchange (equal to the RAM) for cross-zonal elements when congested, annual averages for 2017.

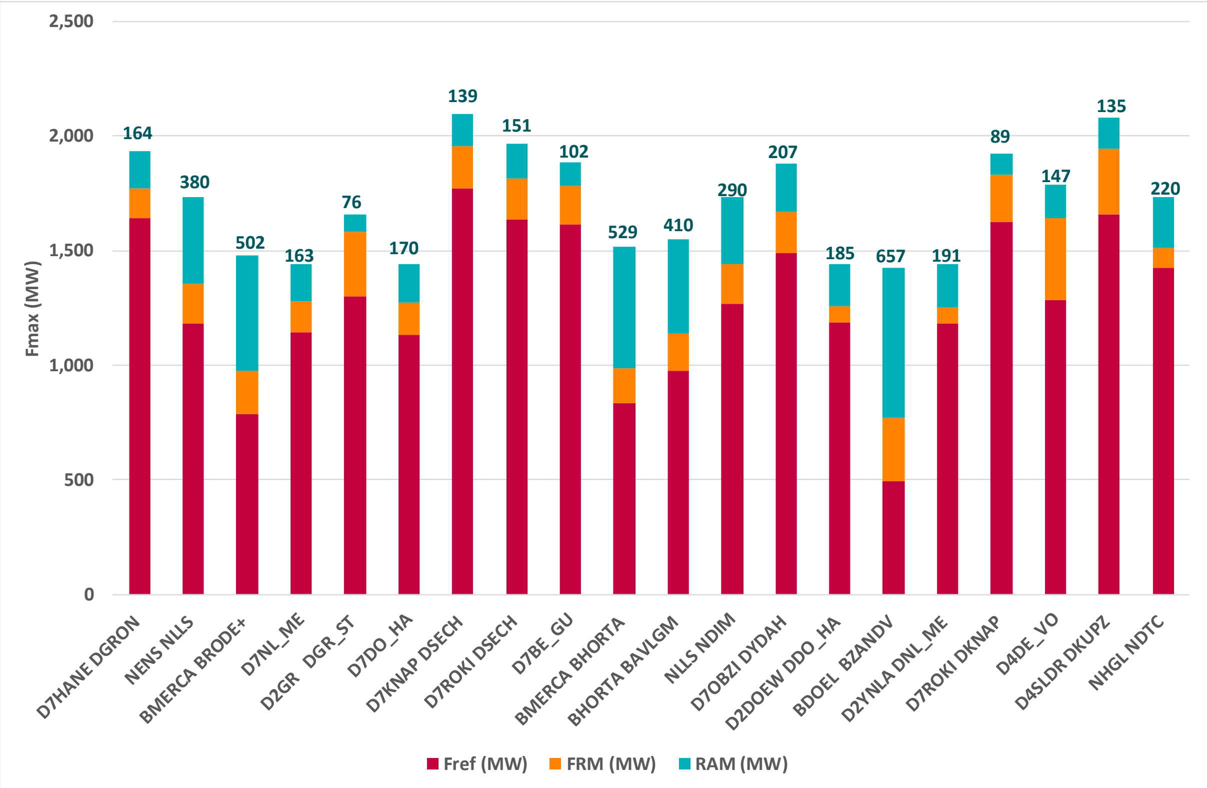


Figure 67: Use of the Thermal Line Capacity (Fmax, vertical axis) for Reference Flows (Fref), Flow Reliability Margins (FRM) and commercial flows from CWE DA cross-zonal exchange (equal to the RAM) for internal lines when congested, annual average for 2017.

112. Most of the congested network elements in 2017 were located in the Amprion network, followed by the Elia network (respectively 36% and 32% of cases) (Figure 68). In comparison to the network elements located in Amprion, RAM values on the Elia lines were higher (Figure 69). The high occurrence of Elia lines as active constraints can be attributed to the relatively high PTDF values.

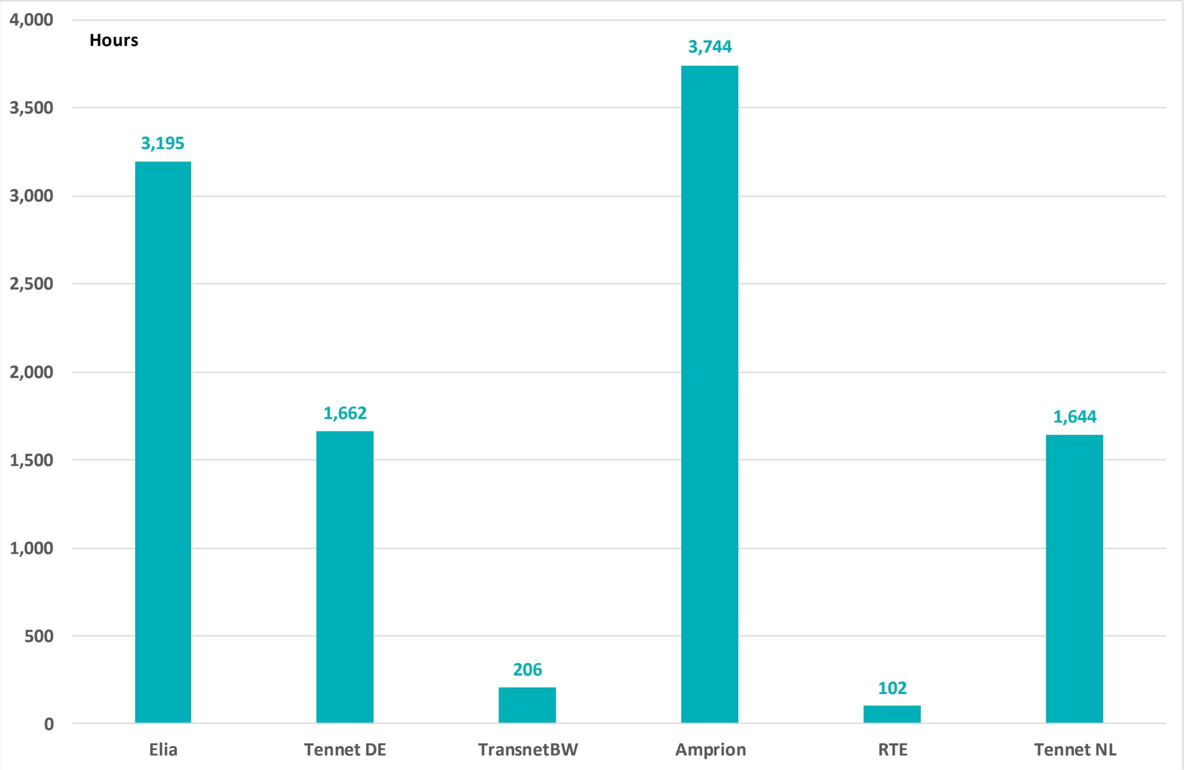


Figure 68: Locational distribution of the congested network elements per TSO in 2017

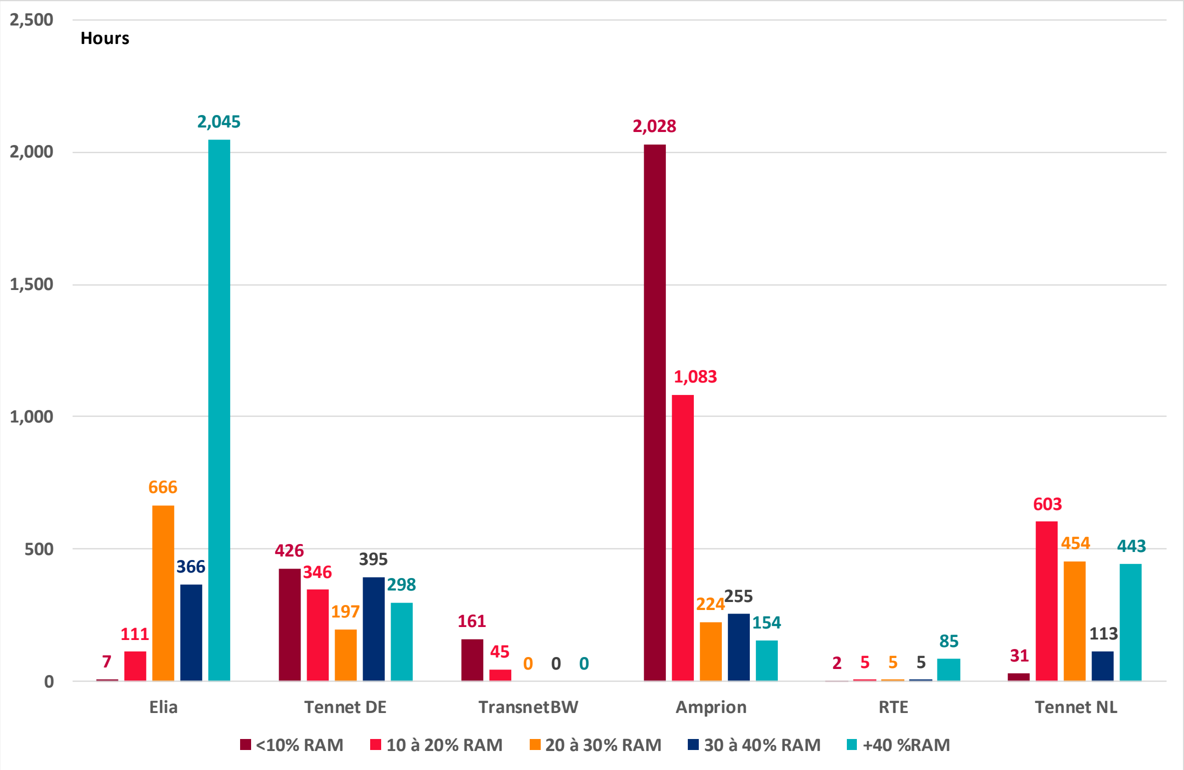


Figure 69: Histogram of the occurrence of congestion by RAM (%Fmax) per TS0 in 2017

113. External constraints have limited cross-zonal exchange in 641 hours, or in 7% of hours in 2017. In 75% of cases, this was a German export constraint. Especially during the last 3 months of 2017, when CWE cross-zonal exchanges were relatively high (see Figure 64), German exports were frequently limiting (369 hours). However, compared to 2016, the total number of active external constraints have decreased. In 2016, external constraints limited CWE cross-zonal exchange in up to 923 hours. The reduction is mainly due to the reduction of French export and Belgian import constraints.

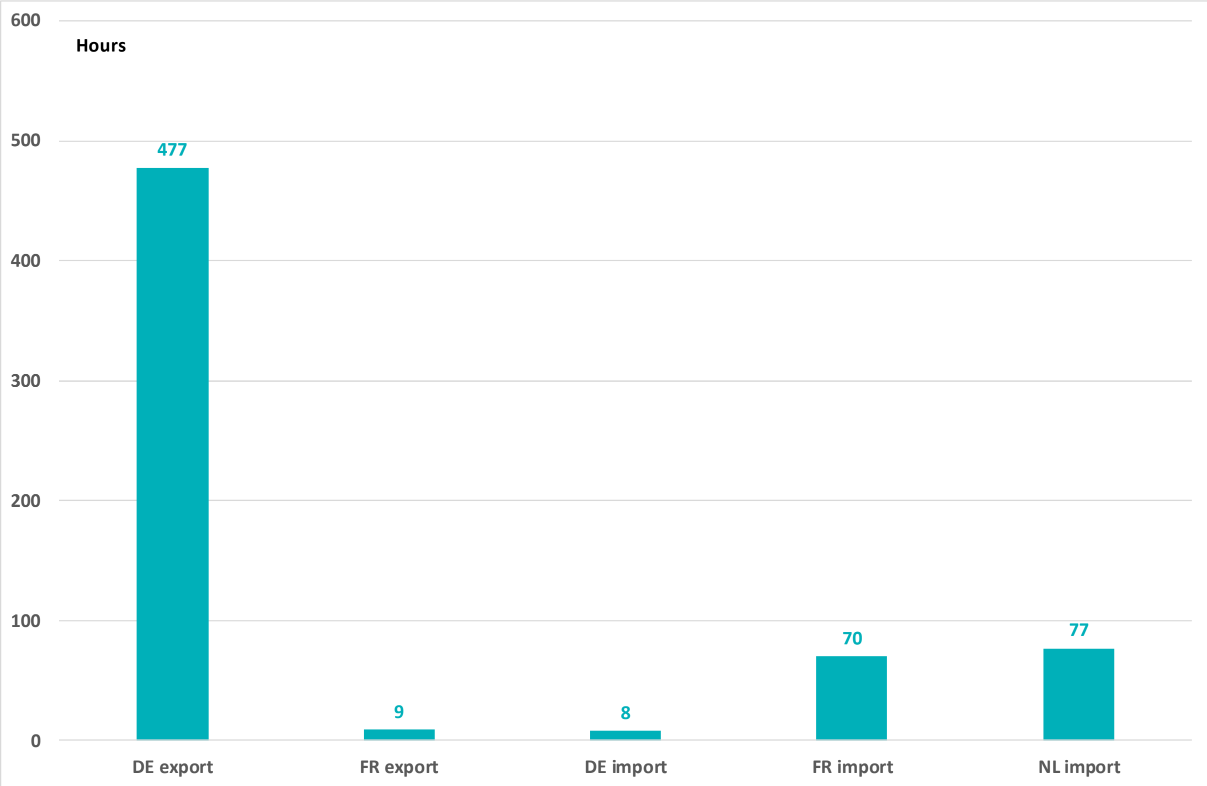


Figure 70: Number of hours an external constraint was limiting the CWE cross-zonal exchange.

5. BALANCING

5.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

2012 Single marginal prices for imbalance tariffs were introduced. At the end of June, a virtual resource with 0 MW capacity was introduced. The objective is to activate the virtual unit at a price equal to -€100/MWh in periods where all resources for downward activation are activated, but additional decremental activations are still needed. In October, Elia started participating in the International Grid Control Cooperation platform (IGCC) to optimise the balancing management of the system and optimise the quality of the frequency. Any imbalances are automatically compensated if they are in opposite directions experienced by system operators. The advantage of this system is that it enables TSOs to avoid activating secondary reserves in opposite directions. Other IGCC participants are Amprion, 50Hertz, TransnetBW and TenneT DE (the four German transmission system operators), Energinet.dk (Denmark), CEPS (Czech Republic), Swissgrid (Switzerland), TenneT NL (The Netherlands), APG (Austria) and RTE (France).

2014 Asymmetrical products for R1 were introduced, thereby opening the R1 market to demand response. Additionally, monthly auctions for contracting a part of the R1 and R2 volumes were introduced. The R3 DP product was introduced. Finally, a special tariff for the hours where strategic reserve is activated was introduced: €3,000/MWh in the event of a shortage of injection bids to reach the clearing of the day-ahead market price and €4,500/MWh in the event of a structural shortage and technical trigger in intraday and real time.

2015 Monthly R1 and R2 auctions were extended to contract the whole volume of R1 and R2.

2016 Monthly auctions were introduced to contract a part of the R3 volumes, except for the R3 ICH product. In August, the market for R1 products was fully opened: any supplier is allowed to participate in all primary control services, irrespective of the connection point of the resource involved. Additionally in August, weekly auctions for the whole R1 and R2 volume to be contracted were organised. Elia and market participants obtained access to the Regional (AT-BE-DE-NL) Auctions Platform for R1, to purchase or sell R1 standard products (symmetrical R1 200 MHz).

2017 In February, the '*BidLadder*' project was finalised, permitting non-CIPU units to offer free bids for the delivery of tertiary reserves. In March, Elia carried out a study on the extension of the existing secondary reserve market. Two extensions by the end of December were proposed: (i) to the intraday market for CIPU-units and (ii) to day-ahead and intraday for contracted non-CIPU units. In May, a new contractual framework for the delivery of primary reserves was introduced and market rules between CIPU and non-CIPU units were harmonised. The energy sources that qualify for the delivery of primary reserves was extended to include sources with limited energy volumes such as batteries.

5.2. SPECIAL TOPIC: TRENDS IN SYSTEM IMBALANCES

114. The demand for balancing services depends on how well Balancing Responsible Parties (BRPs) maintain balance of their portfolio. The net sum of all BRP imbalances amount to the System Imbalance (SI) which needs to be controlled back to complete equilibrium by the TSO Elia. Elia activates balancing energy sources of Balancing Service Providers (BSP) for this purpose. The volume activated for balancing purposes is the Net Regulated Volume (NRV). Any remaining imbalance is called the Area Control Error (ACE).

115. A positive (negative) value of SI indicates that there is more (less) injection than offtake in the Elia grid. The maximum positive quarterly system imbalance (long system) does not reveal structural seasonality over the years and has not exceeded 1,000 MW since 2016 (Figure 71). The minimum quarterly negative system imbalance exceeded -1,000 MW in December 2017. The average monthly positive and negative SI reaches 100 MW to 150 MW in each direction (Figure 72).

116. The average daily profile of positive and negative SI can reach 100 MW to 150 MW in each direction. The average profile has remained stable during the past four years and this for both the positive and negative system imbalance (Figure 73 and Figure 74). Compared with the period 2007-2013, system imbalances in 2017 are low except during the midday from hour 11 to hour 15. The lowest average system imbalances are found during the night, until hour 7.

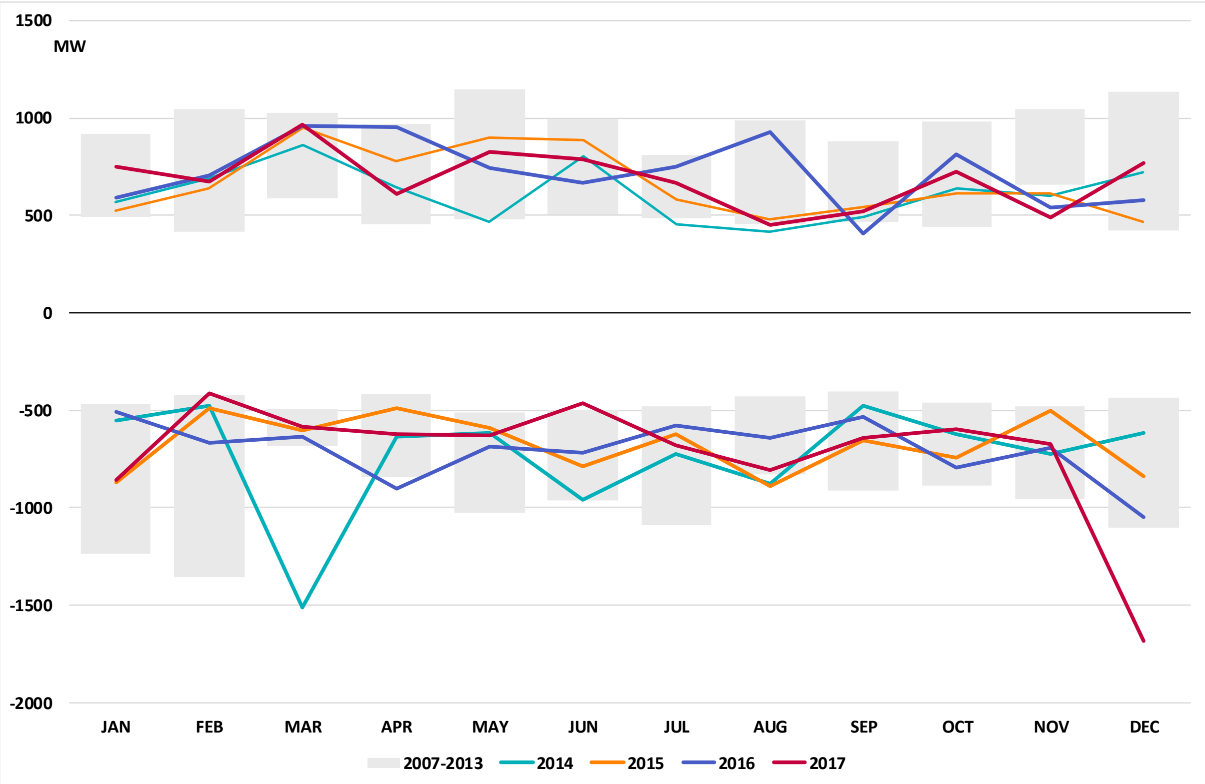


Figure 71 – Maximum quarterly system imbalance, per month of the year, 2007-2017. The grey area denotes the range of maximum quarterly system imbalances during 2007-2013.
Source: CREG based on data provided by Elia

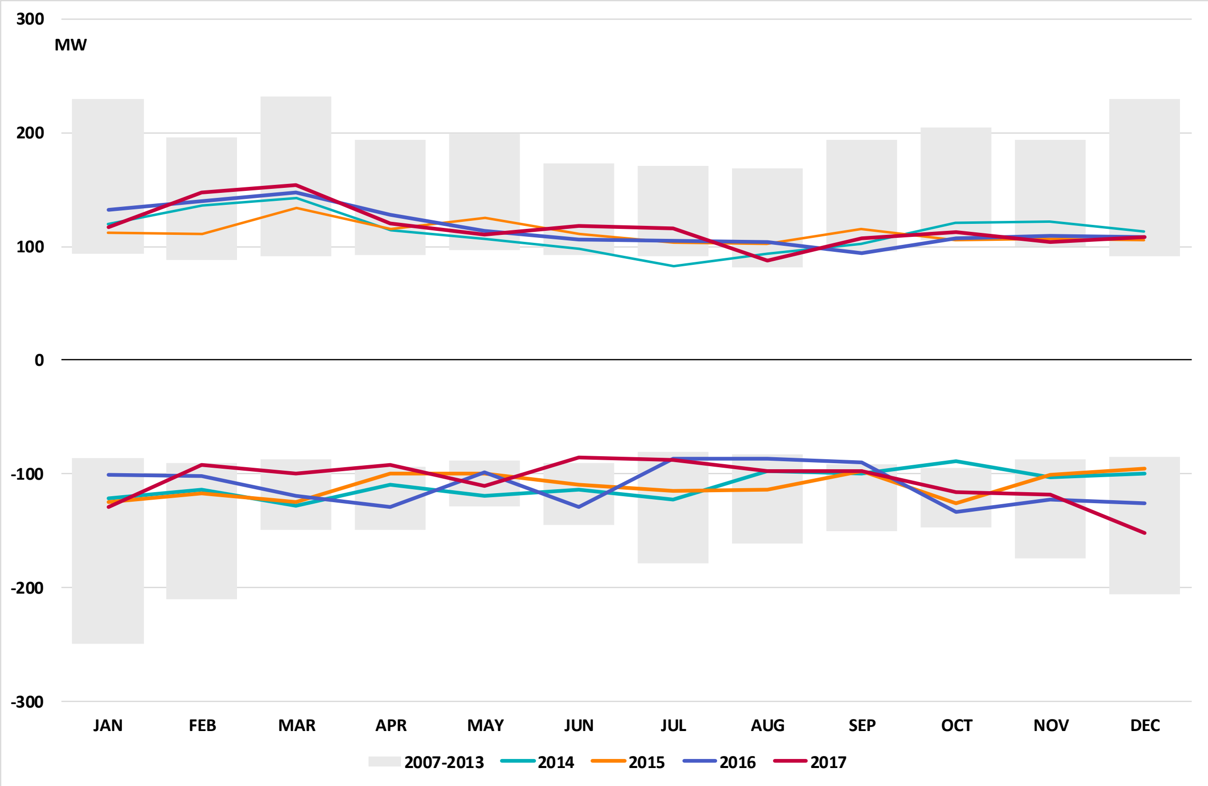


Figure 72 – Average quarterly system imbalance, per month of the year, 2007-2017. The grey area denotes the range of maximum quarterly system imbalances during 2007-2013
Source: CREG based on data provided by Elia

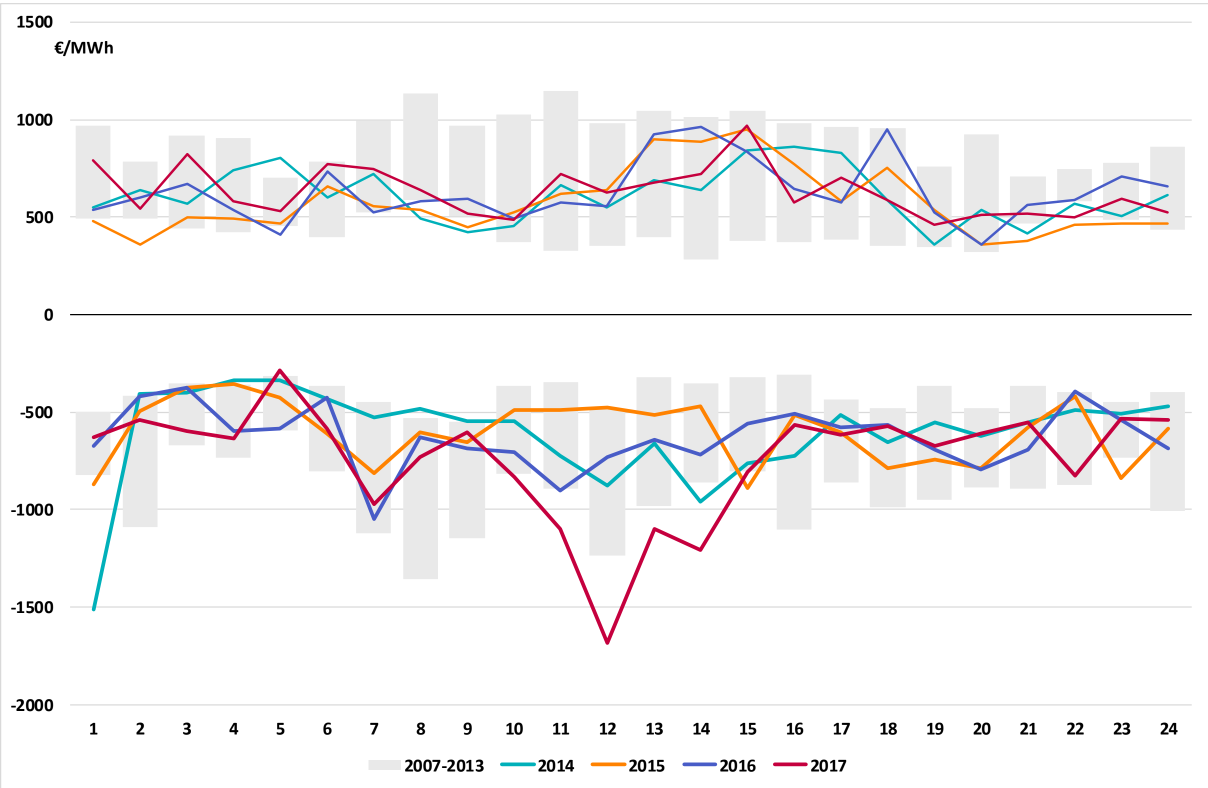


Figure 73 – Maximum hourly system imbalance, per year. The grey area denotes the range of maximum quarterly system imbalances during 2007-2013
Source: CREG based on data provided by Elia

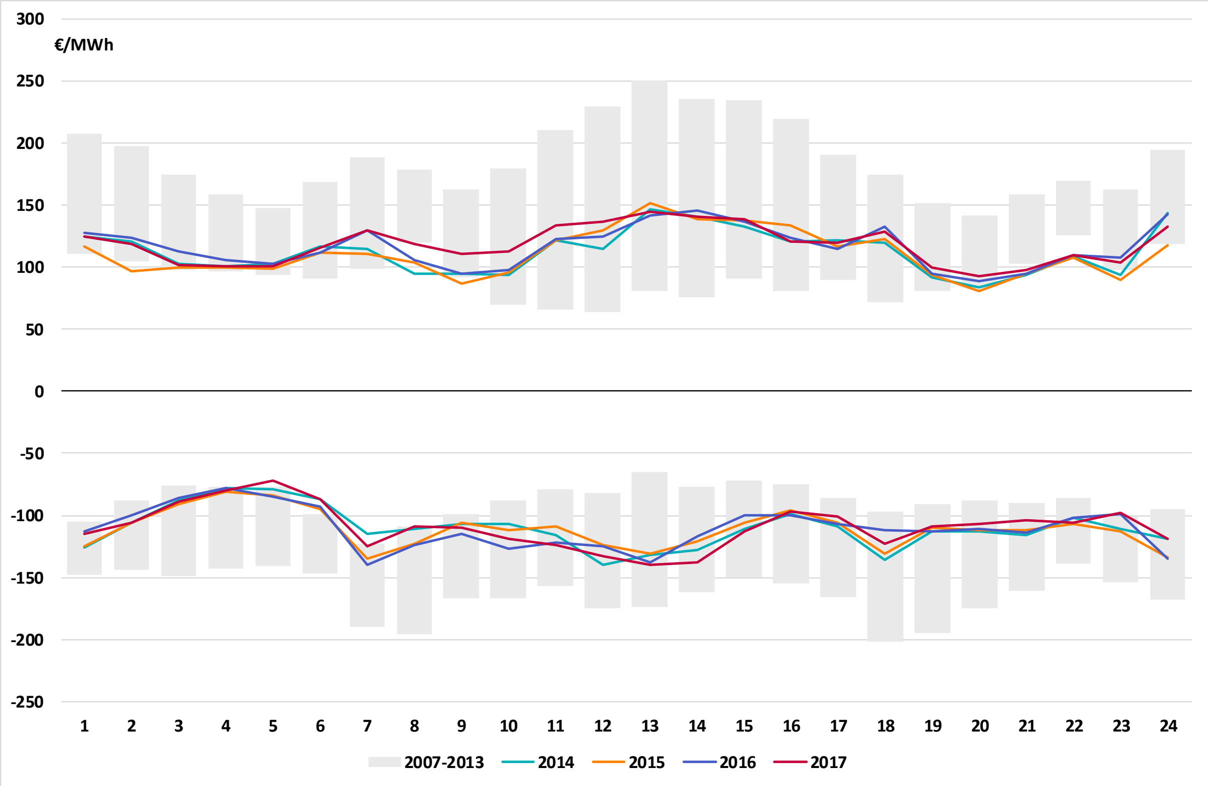


Figure 74 – Hourly average of the negative system imbalance (short system), per year.
Source: CREG based on data provided by Elia

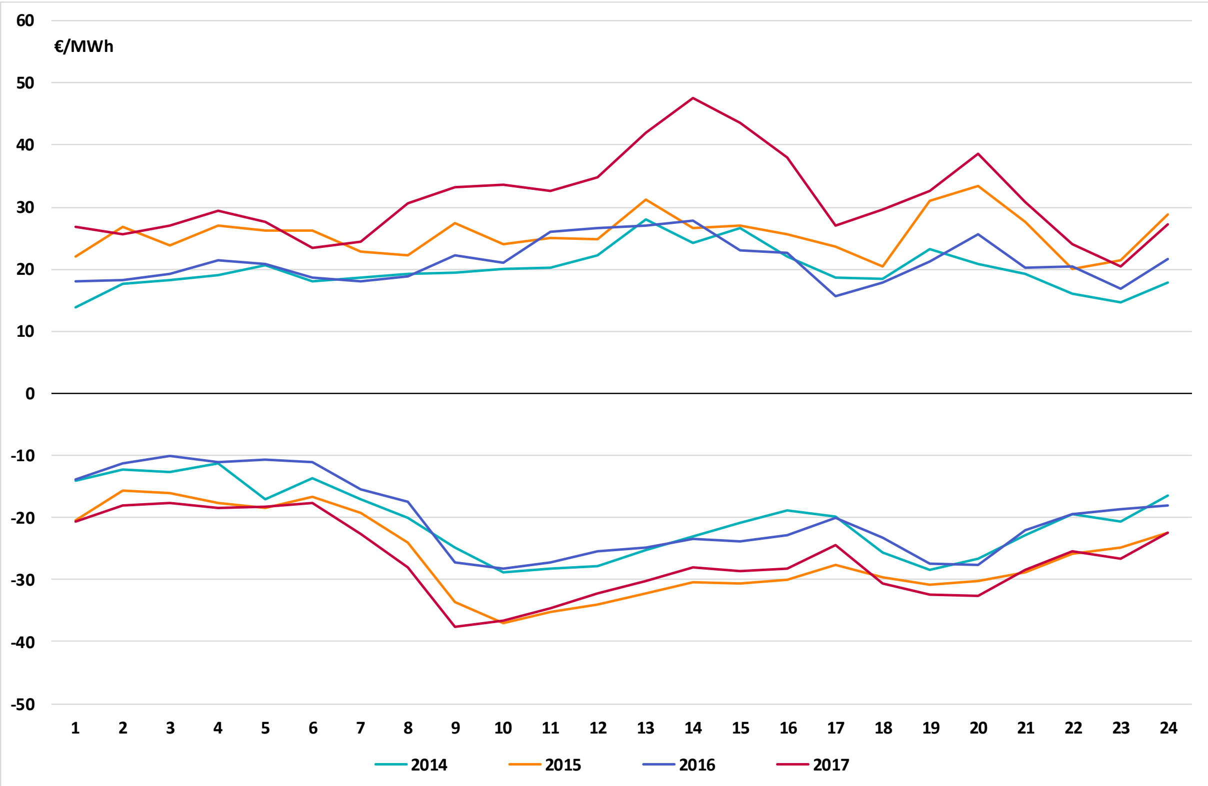


Figure 75 – Average of the difference between the imbalance tariff and the day-ahead market price, if the system is short (positive values) and long (negative values), per year.
Source: CREG based on data provided by Elia

117. By activating reserves, Elia is not only reducing the system imbalance but also incentivising BRPs to help it counteract the system imbalance. A BRP that is counteracting the system imbalance will be remunerated, while a BRP not reinforcing the system imbalance will have to contribute to cover the costs for the activation of reserves.

118. The average price signals to maintain system imbalance as a BRP have increased over the years, even though the average system imbalances have remained unchanged during the past four years (Figure 75). Counteracting a short system has therefore become more profitable over the years. In the absence of good predictors for the system imbalance, BRPs on average benefit more from being long from hour 13 to 16 and short during hours 9 to 11.

119. According to the ENTSO-E balancing quality indicators, the control of the system imbalance by Elia is outstanding. In 2017, Elia performed well if the standard deviation of the ACE was below 95 MW per month, the 90%-percentile of ACE (156 MW) was not exceeded for more than 288 15-minute intervals, and the 99%-percentile of ACE (245 MW) was not exceeded for more than 28 15-minute intervals. The actual measurements were well below each of these reference values (Table 32).

	Stdev	**ACE 90%**	**ACE 99%**
Jan	51,90%	23,20%	0,00%
Feb	48,50%	15,60%	0,00%
Mar	43,66%	17,80%	0,00%
Apr	32,36%	5,90%	0,00%
May	32,37%	3,40%	0,00%
Jun	30,91%	1,40%	0,00%
Jul	27,76%	2,00%	0,00%
Aug	21,72%	0,00%	0,00%
Sep	29,91%	0,00%	0,00%
Oct	44,74%	14,40%	0,00%
Nov	45,20%	13,20%	0,00%
Dec	49,73%	25,30%	53,60%
Average	39,80%	10,20%	4,50%

Table 32 – Overview of the monthly balancing quality indicators for the Elia control zone, relative to the reference values determined by ENTSO-E (a value more than 100% indicates the reference value has been exceeded).

5.3. STATISTICS

5.3.1. Contracted capacity

120. The federal grid code requires Elia to propose for the approval of the CREG (i) 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 (ii) the results of the evaluation.

121. By its decision 1526[34] of 19 July 2016, the CREG approved the proposal of Elia for the year 2017 (Table 33). Primary (FCR) and secondary (aFRR) control powers are contracted on a weekly basis. Primary volumes are locally contracted two weeks before the start of the delivery period via an auction. Additionally, Elia can procure part of its primary reserves regionally by an auction in which the TSOs of Germany, Austria, the Netherlands, Switzerland and Denmark participate. Tertiary reserves (mFRR) provided by interruptible industrial consumption (R3 Flex ICH) are contracted annually. Monthly auctions are organised to procure tertiary reserves from generation units. R3 Flex products are tailored to suit limited energy sources, while R3 Standard products apply for any other generation unit

Type	Contracted volume [MW]	Contracted period	Details on the contracting method
FCR	68	weekly	maximum 47 MW regionally minimum 21 MW locally
aFRR	144	weekly	
mFRR	780	annually	maximum 200 MW of R3 Flex ICH
		monthly	minimum 250 MW of R3 Standard undefined limits on R3 Flex

Table 33- Types of reserves to be bought by Elia for 2017
Source: CREG

122. The cost associated with the contracting of reserves has been relatively constant for the past 3 years (Figure 76). The 35% drop in reservation costs from 2014 and 2015 is attributed to the introduction of short term auctions for the combined reservation of R1 and R2, which had a significant impact on the reserved capacity to provide aFRR (R2). Starting from January 2015, FCR and aFRR capacity was reserved monthly. Since August 2016 the contracting period became weekly. Contracting for FCR (primary reserves, R1) is at its least costly level for a decade.

The reservation of the capacity required by R3 Flex and R3 Standard remained annually until 2016, when 70 MW were procured by monthly auctions. Since 2017 the full capacity required were procured by monthly auctions. R3 Flex ICH remains procured on an annual basis.

[34] Dutch version: http://www.creg.be/nl/publicaties/beslissing-b160719-cdc-1526
French version: http://www.creg.be/fr/publications/decision-b160719-cdc-1526

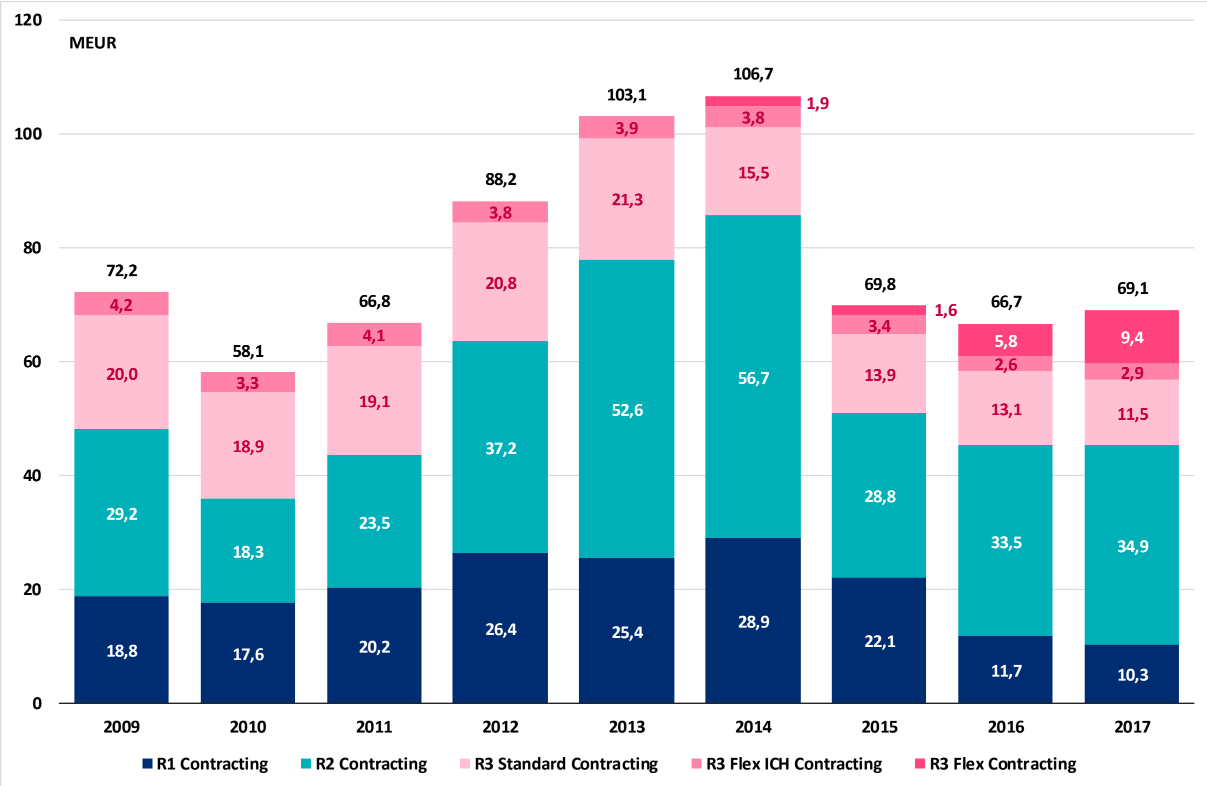


Figure 76 – Cost of contracting reserves, per year of contracting, per type of reserve. The red-shaded bars together form the reservation cost for tertiary reserves (mFRR).
Source: CREG based on data provided by Elia

123. The cost of reserving black start ancillary services has increased in recent years, from €6.25m in 2014 to €7.28m in 2017 (Table 34). Ancillary services for the provision of reactive power have seen a significant reduction from €7.05m to €0.50m.

124. The reservation costs of power reserves are borne equally by consumers and producers, including the reservation cost for the black start service. The cost for contracting reactive power reserve is fully covered by consumers. Dividing the respective costs with the amount generated to and taken off the Elia grid gives the actual cost for individual producers and consumers in EUR/MWh.

125. The actual cost differs compared with the required tariff as estimated by Elia for the tariff period 2016-2019[35]. Any deviation will be recovered (or added if the tariff was underestimated) during the next tariff period.

	2009	2010	2011	2012	2013	2014	2015	2016	2017
Power Reserves [€]	72.192.000	58.067.000	66.847.000	88.247.000	103.090.000	106.730.000	69.775.880	66.700.340	69.097.580
Black-start [€]	6.780.000	5.928.000	6.292.000	6.188.000	6.200.000	6.246.000	6.262.000	7.191.900	7.273.929
Reactive Power [€]	12.716.000	11.138.000	8.447.000	7.722.000	7.391.000	8.380.000	7.046.000	634.535	500.527
Covered by producers [€]	39.486.000	31.997.500	36.569.500	47.217.500	54.645.000	56.488.000	38.018.940	36.946.120	38.185.754
Covered by consumers [€]	52.202.000	43.135.500	45.016.500	54.939.500	62.036.000	64.868.000	45.064.940	37.580.655	38.686.281
Cost for producers [€/MWh]	0,46	0,37	0,45	0,66	0,77	0,94	0,68	0,53	0,54
Cost for consumers, excluding reactive power [€/MWh]	0,48	0,37	0,44	0,58	0,68	0,73	0,49	0,48	0,49

Table 34 – Reservation costs for contracting ancillary services, per year, per ancillary service. Reactive power is excluded when calculating the cost for consumers in EUR/MWh.
Source: CREG based on data provided by Elia

[35] http://www.creg.be/sites/default/files/assets/Tarifs/Elia/171222_ELIA_Tarifs2016_2019_NL.pdf

5.3.2. Activated reserves

Positive tariffs for negative imbalances indicate that the Balancing Responsible Party (BRP) pays the TSO for its underdelivery of energy injection compared to its scheduled position. In this case, another entity picks up the slack between the actual generation schedule and the commercial position of the short BRP to maintain system balance, either at the activation request of the TSO or by balancing reactively based on the negative imbalance tariff. The TSO remunerates this third party. In order for the pricing to give correct incentives to BRPs, and assuming markets are competitive, the negative imbalance tariff needs to be higher than the day-ahead market price.

Similarly, positive tariffs for positive imbalances indicate that the TSO pays the BRP for its additional energy injection compared to its scheduled position. In this case, another entity compensates for the difference between the actual generation schedule and the commercial position of the long BRP to maintain system balance, either at the activation request of the TSO, or by balancing reactively, based on the positive imbalance tariff. The third entity remunerates the TSO. In order for the pricing to give correct incentives to BRPs, and assuming markets are competitive, the positive imbalance tariff needs to be lower than the day-ahead market price.

126. From 2012, a single marginal pricing method was applied. Under this scheme, BRPs compensating the system imbalance are not penalised[36] while those aggravating the system imbalance continue to be penalised[37], but only if the system imbalance exceeds 140 MW, or roughly equal to the contracted aFRR reserves. The marginal pricing method initiated a gradual decline in imbalance prices and provided convergence between the day-ahead reference price and the imbalance prices. The negative imbalance price is slightly lower than the day-ahead price, possibly indicating that positive system imbalances over 140 MW occur or that BRPs do not solve all portfolio imbalances on the day-ahead market.

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[36] BRPS are penalised by adding a parameter β to the marginal price of the last activated resource to compensate for the system imbalance. The aim of the parameter is to create a positive (negative) imbalance tariff that is lower (higher) than the marginal price of the last activated upward (downward) regulation resource. It discourages BRPs from helping compensate for the system imbalance.

[37] BRPs are penalised by adding a parameter α to the marginal price of the last activated resource to compensate for the system imbalance. The aim of the parameter is to create a positive (negative) imbalance tariff that is lower (higher) than the marginal price of the last activated downward (upward) regulation resource. It discourages BRPs from being imbalanced if they aggravate the system imbalance.

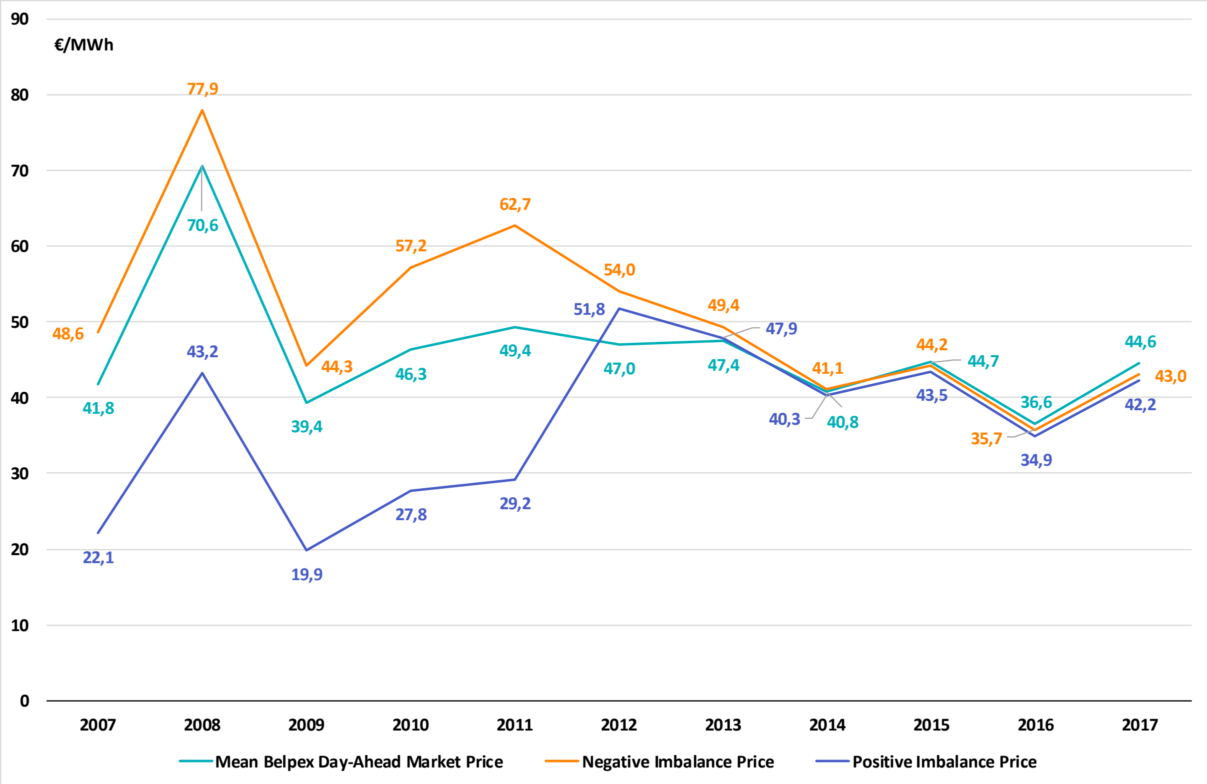

Figure 77 – Yearly averaged positive and negative imbalance tariffs. The yearly averaged day-ahead price serves as a reference.
Source: CREG based on data provided by Elia

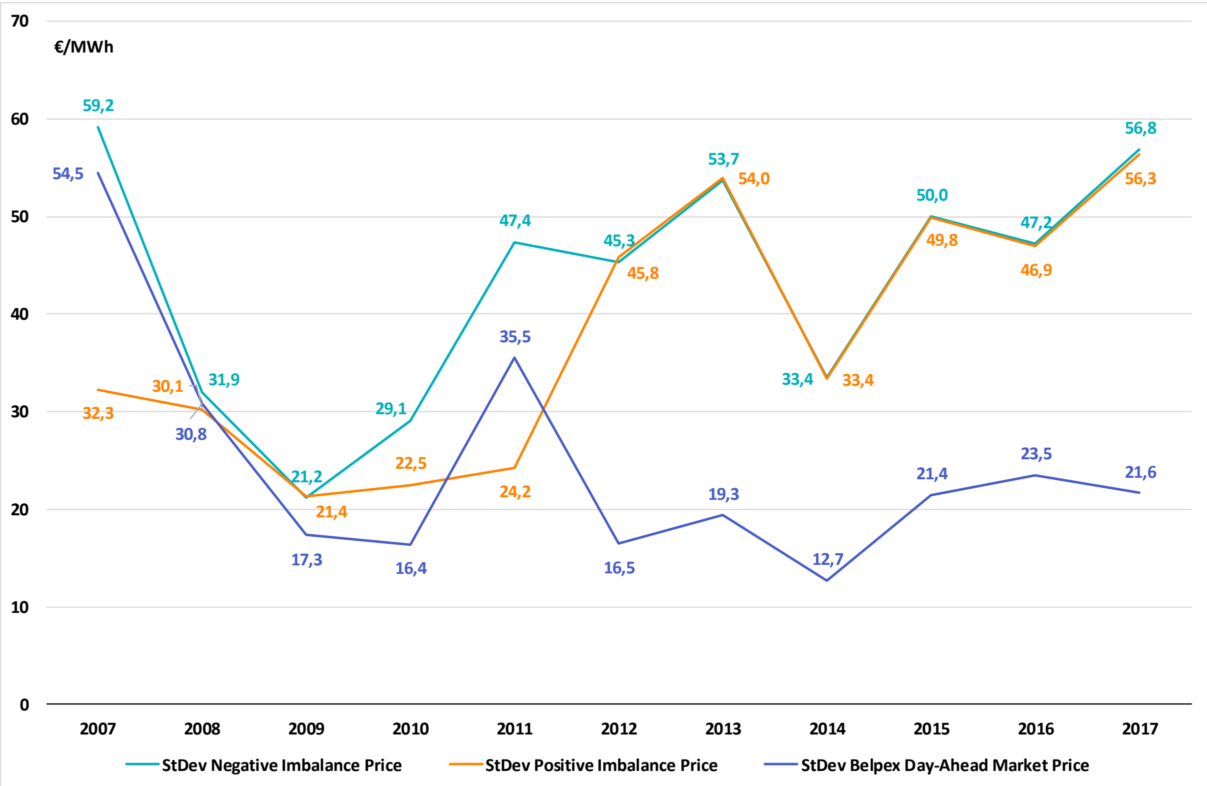

Figure 78 – Standard deviation of the positive and negative imbalance tariff
Source: CREG based on data provided by Elia

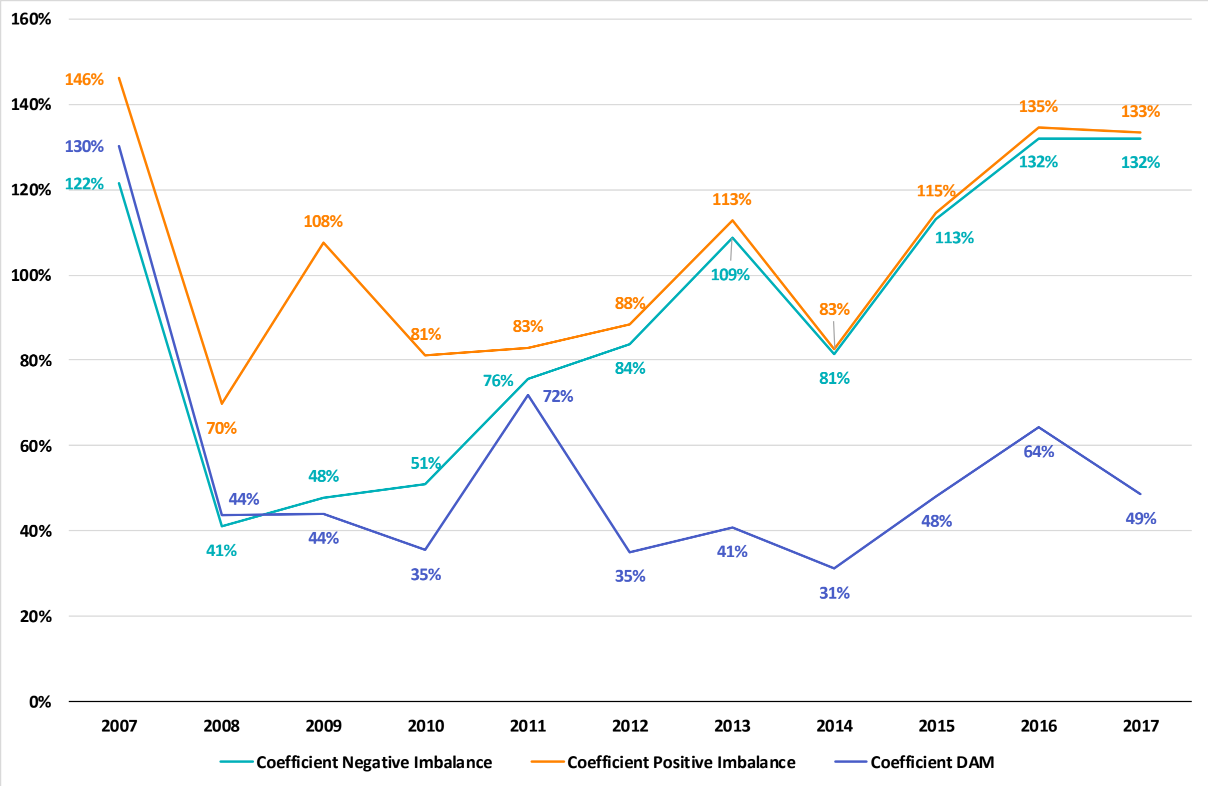

Figure 79 – Coefficient of variation of balancing tariffs and the day-ahead market price
Source: CREG based on data provided by Elia

127. The yearly standard deviation of positive and negative imbalance tariffs increased by €9.6/MWh in 2017 compared to 2016, while that of the day-ahead market price decreased slightly. The standard deviations of the positive and negative imbalance tariff are closely coupled. A slight divergence is however visible in 2017 and can only be caused by an increasing frequency of system imbalances of over 140 MW.

128. The annual coefficient of variation[38] of the balancing tariffs has remained stable in 2017 compared to 2016, indicating that the relative risk has remained the same. The coefficient on the day-ahead market has nonetheless decreased.

129. The activated energy including imbalance netting (IGCC) has increased in 2017 in comparison to 2016, to 1.09 TWh. IGCC has only been used 0.82 GWh less with respect to the previous year, leading to a share of 42% in covering total balancing needs in 2017, compared with 47% in 2016. Non-contracted mFRR, IGCC, and aFRR cover 97.7% of all balancing needs.

130. Of the remaining balancing needs, the upward mFRR activations represent 68.0% of which 88 GWh can be attributed to contracted tertiary reserves.

131. Imbalance netting and secondary control (R2/aFRR) are closely linked in nature. As it is calculated before activating aFRR, IGCC avoids aFRR activations and frees aFRR capacity for additional activations. As such, IGCC and aFRR 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 sum is relevant to show the increasing importance of automatic control of imbalance compensation. This also shows that applying imbalance netting with a positive financial outcome helps reduce the need for additional balancing capacity being contracted beforehand.

[38] The coefficient of variation equals the standard deviation divided by the average. It is a scaled, relative value of volatility.

Figure 80 – Balancing energy activated by product type
Source: CREG based on data provided by Elia

6. CONCLUSIONS

132. Total electricity demand in Belgium and its neighbouring countries, France, the Netherlands, Germany and the United Kingdom region amounted to 1,477 TWh in 2017; this has been more or less constant since 2011. **Belgium accounts for 6% of the total demand in this region.** If the UK is excluded, the Belgian share rises to 7.5%.

133. The Elia grid load in Belgium amounted to 77.4 TWh in 2017, at a level similar to that of the three previous years. This **stabilisation of the Belgian electricity offtake** comes after a continuous decline since 2007. At the same time, the estimated solar electricity generation stabilised at around 3 TWh in 2017, similar to 2015 and 2016.

134. In a special topic on electricity consumption, the impact of wind capacity on the residual peak demand is briefly analysed. Wind capacity only has a marginal impact on the residual peak demand in MW. However, wind capacity significantly reduces the number of hours that the residual peak demand reaches top levels. As a consequence, peak capacity that needs to supply peak demand will have lower running hours due to more installed wind capacity. **Already in 2017, the installed wind capacity reduced the running hours of peak capacity by more than 50 percent.** If wind capacity were to increase threefold, this would again reduce the running hours of peak capacity by more than 50 percent. As such, **more wind capacity creates opportunities for peak capacities which can only run for limited hours per year, such as demand response and emergency generators**.

135. Average yearly day-ahead prices have increased in each country in Central-West Europe (CWE) in 2017 compared with 2016. The increase is the result of higher day-ahead prices during the last quarter of 2017 following a decrease in nuclear capacity in France and Belgium. Prices never exceeded €500/MWh, in contrast with 2016. The increase in day-ahead prices **rippled through to forward markets in the CWE region**, illustrating that scarcity prices in an energy-only market can provide the necessary longer term price signals, for example for the continued operation of existing peak power plants. Additionally, the electricity volume traded on the Belgian intraday market has increased significantly, to almost 2 TWh. Primarily originating from cross-border trade, it indicates an increasing need for providing flexibility near real-time, which provides opportunities for flexible generation units or demand facilities.

136. A special topic on interconnection reveals that the approach to defining the thermal line ratings for the critical network elements monitored in the CWE day-ahead market coupling differs significantly from TSO to TSO, and even from line to line. Some CWE TSOs still **use summer limits throughout the year**, even on lines frequently limiting the CWE day-ahead market coupling. Especially in the winter months, the use of static limits has a very high opportunity cost.

137. The volume of **long-term transmission capacities** on the Belgian borders provided to the market in the yearly auctions remained stable, while the volumes provided in the monthly auctions during the second half of 2017 were lower compared to 2016, suggesting downward pressure on the volumes of long-term transmission rights.

138. The results of the **day-ahead market coupling with CWE FBMC** remained very poor, especially during the first 9 months of 2017. In the last 3 months of 2017, cross-zonal exchanges increased and reached pre-FBMC values. As was the case in 2016, the majority of the limiting network elements were highly preloaded internal lines of Amprion in the German bidding zone. At the same time, there were significantly more congestions on Dutch and Belgian network elements compared to 2016. The underperforming results triggered regulatory actions, resulting in, inter alia, the implementation of the **20% minimum RAM threshold** as a short-term solution, and which is applicable from 26 April 2018.

139. Since the start of **intraday market coupling** in 2007, intraday cross-border exchanged volumes are on the rise. In 2017, however, no significant further increase was observed. Especially during the last three months of 2017, maximum import and export in intraday were at the lower end.

140. Since 2013, following 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 2017. As such, **the average day ahead price serves as a more or less unbiased predictor of the average real-time price**. Significant hourly differences exist however, providing opportunities for small, flexible generation units or demand facilities.

141. In 2017, 144 MW of aFRR and 780 MW of mFRR were contracted. The use of reserves for balancing the Elia grid was 664 GWh (down and up regulation combined). Activation of 427 GWh of reserves was avoided with IGCC, a mechanism through which the imbalance of one country can be netted with other countries participating in the mechanism. Consequently, **the IGCC mechanism highlights, also for balancing and reserves, the importance for Belgium in cooperating at the European level in the interest of Belgian consumers**. Lastly, 504 GWh of aFRR were activated (up and down) as well as 153 GWh of mFRR (up, down, contracted and non-contracted).

For the Commission of Electricity and Gas Regulation:

Andreas TIREZ
Director

Marie-Pierre FAUCONNIER
Chairwoman of the Board of Directors

7. ANNEXES

7.1. 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 in recent years. Consequently, 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 TSOs 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 TSOs. 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 Elia control area, 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 area, 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/.

7.2. 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 TSO 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	European Guideline on Capacity Allocation and Congestion Management, EU 1222/2015 of 24 July 2015
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, Czech Republic, 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, etc.) 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 Italian 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 decentralised 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 TSOs 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

7.3. LIST OF FIGURES

7.4. LIST OF TABLES