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COMMISSION FOR ELECTRICITY
AND GAS REGULATION

STUDY

(F)160324-CDC-1520

on

"the price spikes observed on the Belgian day-ahead spot exchange Belpex on 22 September and 16 October 2015"

carried out in application of Articles 23, §2, second paragraph, of the Law of 29 April 1999 concerning the organization of the electricity market

24 March 2016

CONTENT

EXECUTIVE SUMMARY

This document is the result of discussions the CREG had with market participants during its workshop on the 18th of November on the one hand and Elia during bilateral meetings on the other. The objective of this study is to present the analysis and final conclusions of the CREG concerning the occurrence of elevated prices and price peaks on the Belgian day-ahead power exchange Belpex on September, 22 and October, 16 2015. The main focus is on the day ahead market, although selected topics of the intra-day and real time market are also analyzed.

The CREG found that limited import volumes due to non-competitive flows are responsible for the elevated prices observed. Combined with limited capacity of available generation and a low availability of certain reserve products, elevated prices were observed on the day-ahead, intra-day, and balancing markets.

During all hours on 22 September and 16 October the Belgian bidding zone was importing electricity. During the periods of elevated prices, the commercial import came mainly from France, while there was no or limited commercial import from the Netherlands. However, the physical flows were mainly measured on the border with the Netherlands and much less on the border with France. The most important explanation for the difference between expected physical flows (due to commercial cross-border exchange) and the real physical flows are non-competitive flows. These flows are not put in competition with flows generated by commercial exchanges in the flow-based market coupling and get priority access to the network capacity. The vast majority of these non-competitive flows during the hours when price spikes were observed consisted of loop flows, namely flows generated by commercial transactions within one bidding zone. A small part of these non-competitive flows are commercial cross-border exchanges between bidding zones where at least one bidding zone is not coupled by the flow-based market coupling in the CWE-region, such as for example a commercial exchange from Denmark to Italy or Spain.

Non-competitive flows could have caused a more extreme result without LTA coverage. On the 22nd of September the baseload price would have been 1293,16 €/MWh, or almost 7 times higher than observed. On the 16th of October Belgium would have been awarded a net position of zero while prices during a 16-hour period would have amounted to €3000/MWh in contrast to an average of €287/MWh. The result would have been an increase in baseload prices from the realised €211,23/MWh to €2149,01/MWh (+917%).

This analysis, explained in detail in section II.4.1.3, was discussed with and confirmed by Elia and leads to the conclusion that non-competitive flows, for the largest part loop flows, can make up (sometimes much) more than half of the observed physical flows on Belgian borders. This occurs even if market participants are paying very high prices, much higher than in other countries: by design, these non-competitive flows cannot be outbid by market participants. This leads to a discriminatory use of the available cross-border transmission capacity, favouring non-competitive flows and over commercial cross-border exchange between bidding zones in the flow-based market coupling, leading to an inefficient market outcome. Therefore, this method is not in line with Regulation 714/2009 and its Annex 1.

There are several solutions to limit non-competitive flows, such as an efficient use of phase shifting transformers, re-dispatching within one bidding zone, splitting up bidding zones and implementing the so-called advanced hybrid flow-based day ahead market coupling.

Finally, during both days, there was no or limited available intra-day capacity from France to Belgium and from the Netherlands to Belgium. It is in both cases difficult to understand that no intra-day capacity was available on the French border, since physical flows on the French-Belgian border did not exceed 1000 MW during peak hours. Also on the Dutch-Belgian border, physical flows remained relatively low during peak hours, especially during 22 September 2015, implying more intra-day capacity on this border could have been given to the market.

I. Goal of the document

1. The objective of this document is to present the final analysis and conclusions of the CREG concerning the occurrence of elevated prices and price peaks on the Belgian day-ahead power exchange Belpex and intraday and balancing markets. The cases of the 22nd of September and the 16th of October are elaborately treated and serve as illustration for similar cases during the fall of 2015 in Belgium.

This document informs the market and other stakeholders on the causes leading to elevated prices and price peaks. According to the CREG, the high prices were caused by existing market coupling inefficiencies and discrimination between energy exchanges within and between price zones.

The main focus is on the day ahead market, although relevant topics of the intra-day and real time market are also analyzed.

II. Analysis

2. The analysis focuses on four domains: the triggers for investigation, the Belgian context, balancing and reserves, and the cross-border electricity exchanges with other bidding zones in the CWE-region.

II.1 Trigger: extremely high prices

II.1.1 22/09/2015

3. The day-ahead market price for the delivery of baseload power on the 22nd of September was on average €188,74/MWh, while on 21/09/2015 and on 23/09/2015 the average baseload price was €48,65/MWh and €53,64/MWh respectively (Figure 1). The price during hours 8-21 did not fall below the level of €150/MWh. At hours 8, 9, and 15, price peaks of €448,70/MWh appeared. Only on the 23rd is another price peak observed at €150/MWh.

4. Day-ahead spot prices observed on the same day in other bidding zones of the CWE-region are far below those observed in the Belgian bidding zone. The price spread between Belgium and Germany is on average €240,8/MWh during hours 8-21 with the highest price spreads observed during hours 8 (€416,17/MWh), 9 (€416,13/MWh), and 15 (€410,45/MWh).

5. Intra-day prices are generally lower than day-ahead prices, but still relatively high with a price peak at hour 15 at €350/MWh. Intraday liquidity is concentrated during hours 14-21. Imbalance prices are also elevated for an extended period of time on the 22nd of September compared with the 21st and 23rd: from 07h15 to 12h45 the averaged upward imbalance price was €400/MWh (Figure 3).

6. It seems that acute factors caused commercial scarcity in day-ahead and intra-day markets. Further analysis is required in order to evaluate the extent other factors contributed to these observations.

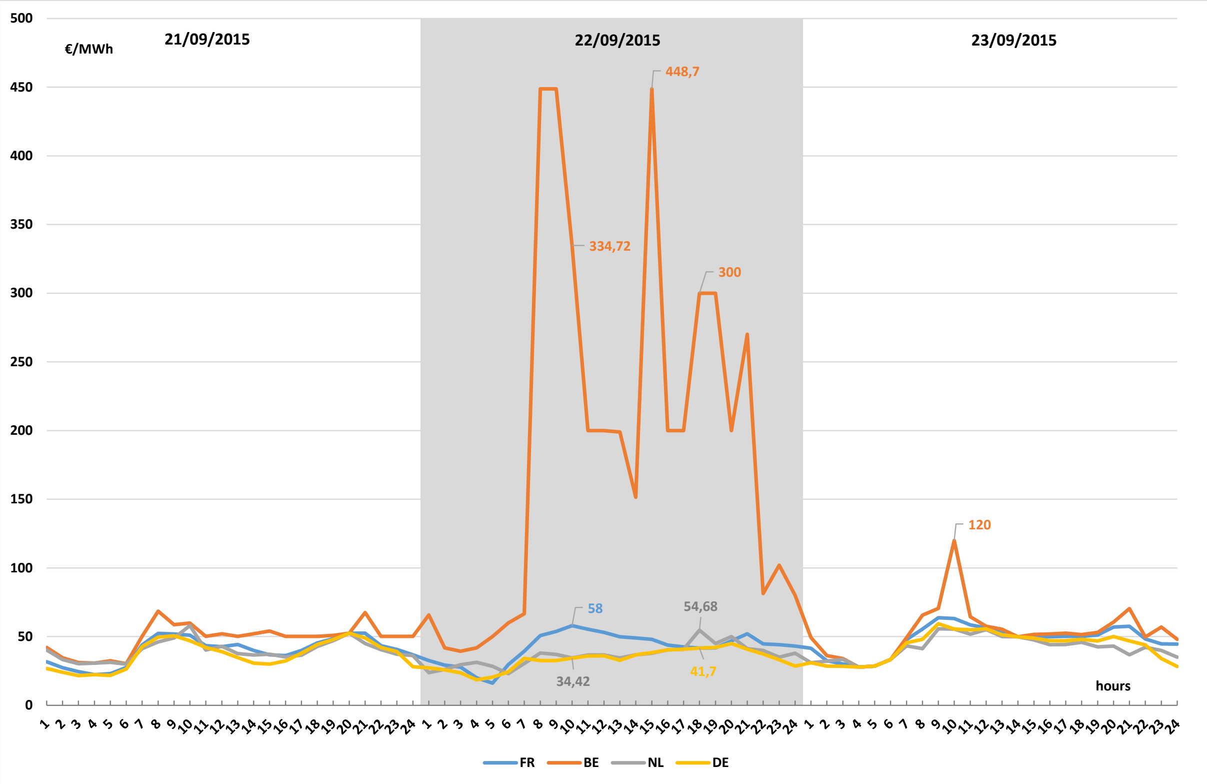

Figure 1 - Day-ahead spot prices on the Belpex DAM as a result from the matching of orders in and the coupling of the bidding zones in the CWE-region on the 21st, 22nd, and 23rd of September 2015
Source: Belpex, EEX, APX

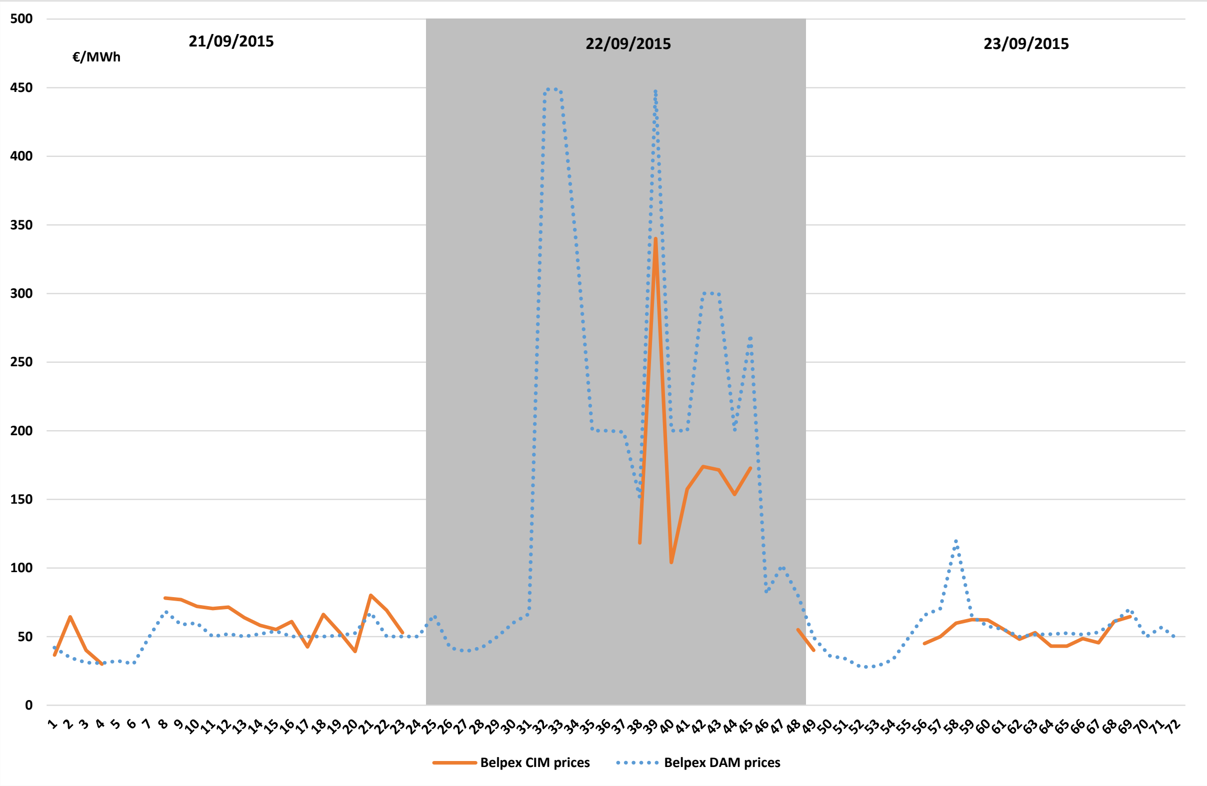

Figure 2 - Intraday prices on the Belpex CIM on the 21st, 22nd, and 23rd of September 2015
Source: Belpex

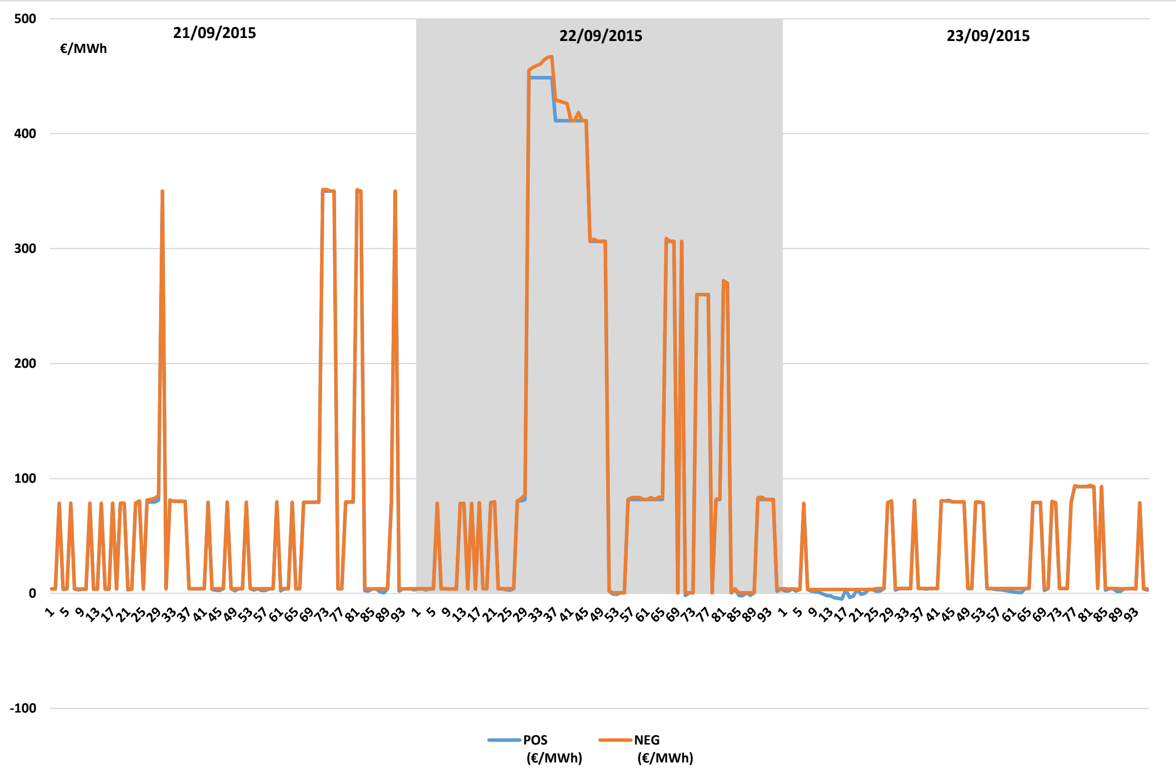

Figure 3 – Imbalance prices in the Belgian control area on the 21st, 22nd, and 23rd of September 2015
Source: Elia

II.1.2 16/10/2016

7. Day-ahead baseload prices increased consecutively over a time span of the three days analysed: from €81,85/MWh on the 14th of October, to €122,91/MWh on the 15th and finally €207,92/MWh on the 16th of October 2015 (Figure 4). The maximum price is €448,7/MWh, a price identical to the maximum price observed on the 22nd of September.

8. Prices in neighbouring countries are far lower than those in the Belgian bidding zone. Compared with the German bidding zone, the maximum price spread amounted to €387,7/MWh at hour 12 on the 16th of October.

9. Similar to the observations on the 22nd of September, intra-day prices are lower or equal to day-ahead prices (Figure 5). A price peak of €372,65/MWh is observed at hour 11 on the 15th and one of €389,37/MWh is observed at hour 14 on the 16th. Imbalance prices are also elevated on the 15th and especially on the 16th of October with an imbalance price peak of €800/MWh from 19:15 to 20:15 (Figure 6).

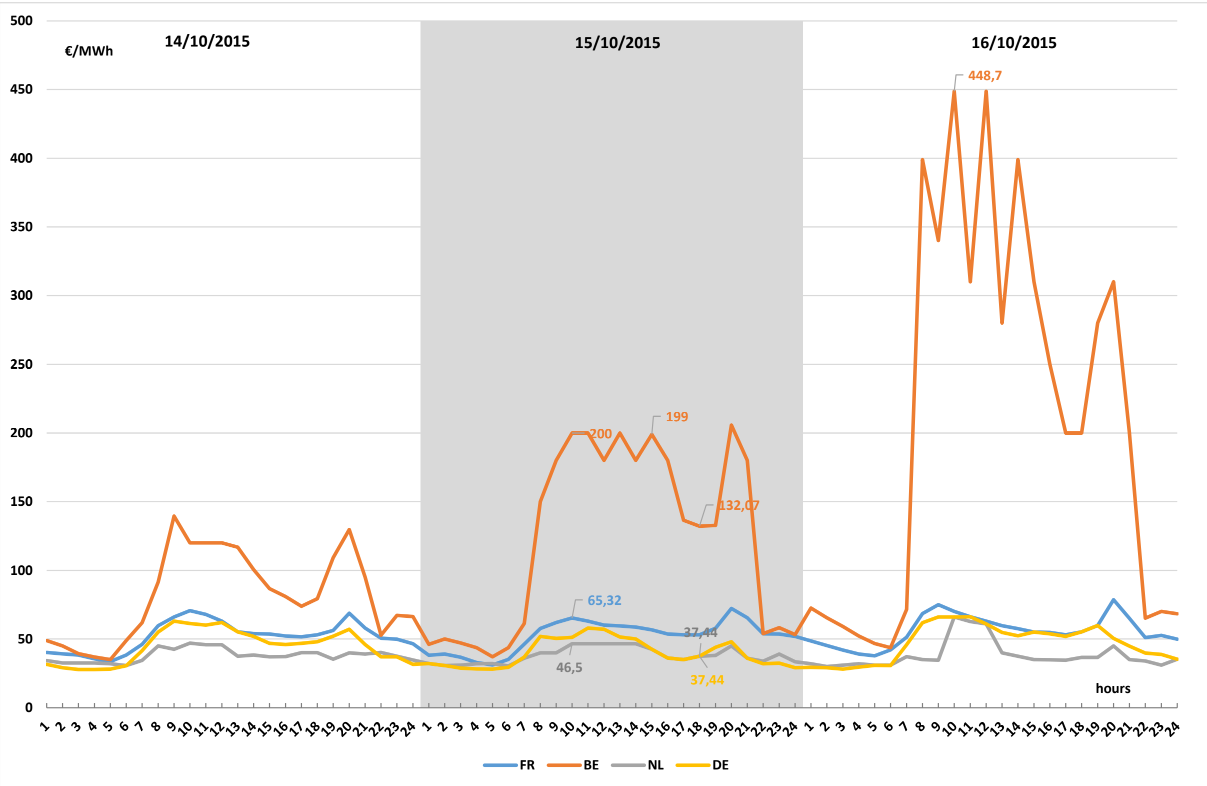

Figure 4 – Day-ahead spot prices as a result from the matching of orders in and the coupling of the bidding zones in the CWE-region on the 14th, 15th, and 16th of October 2015
Source: Belpex, EEX, APX

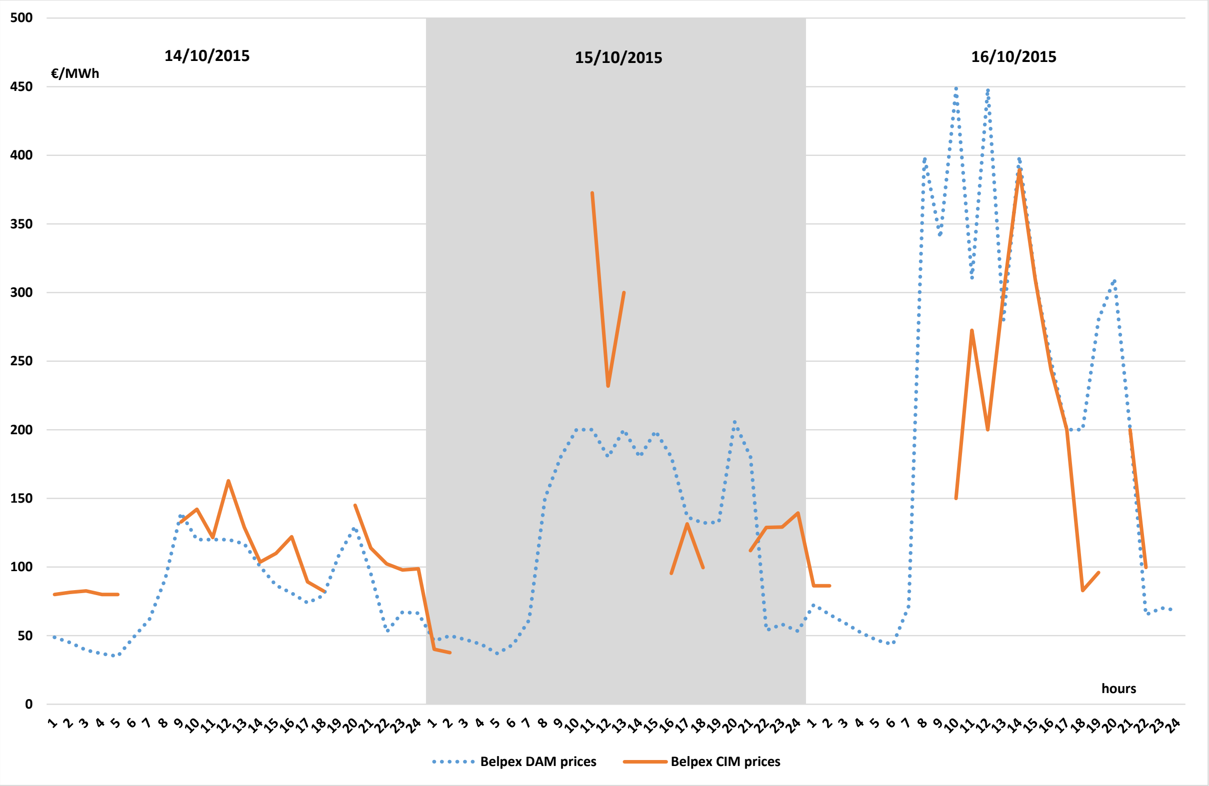

Figure 5 – Intraday prices on the Belpex CIM on the 14th, 15th, and 16th of October 2015
Source: Belpex

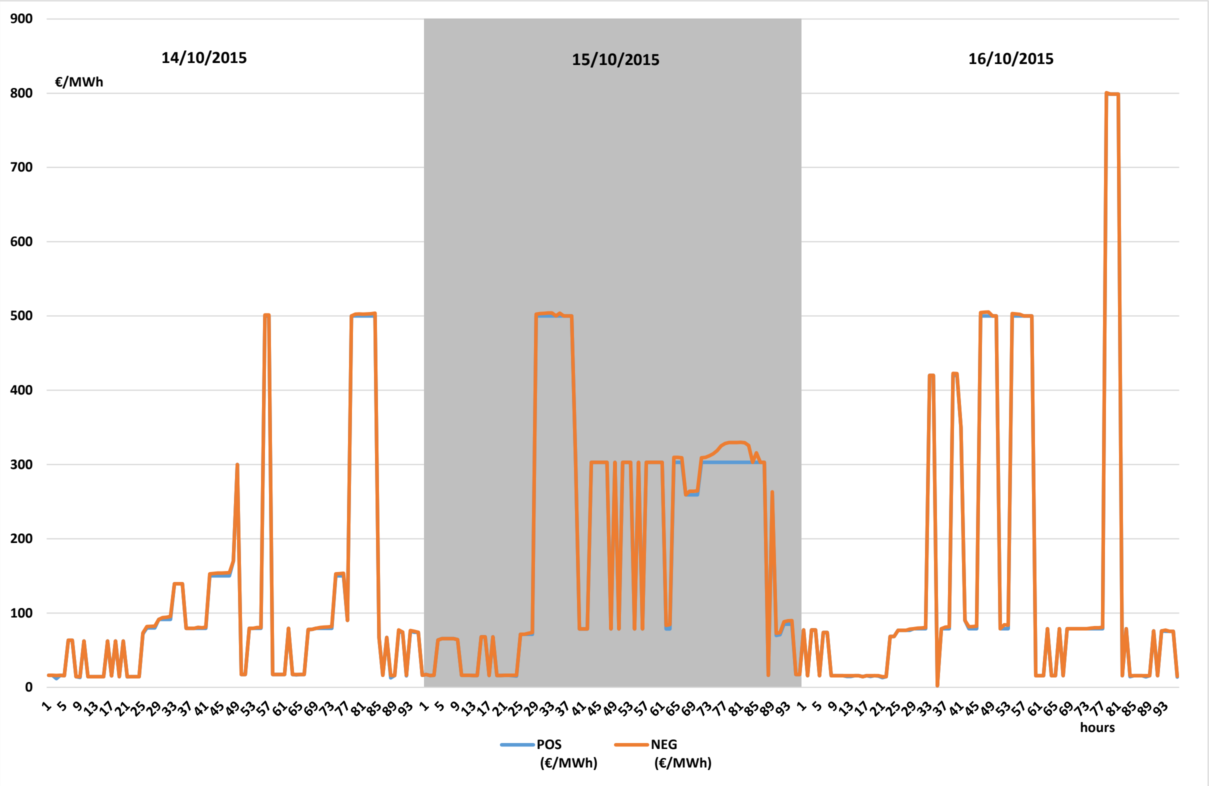

Figure 6 – Imbalance prices in the Belgian control area on the 14th, 15th, and 16th of October 2015
Source: Elia

II.2 The Belgian context

II.2.1 22/09/2015

II.2.1.1 Balance between real-time Elia net load and generation

10. On the 22nd of September, during the hours 8-21 the hourly load as measured and validated by Elia averaged 9585 MW. Focusing on hours 8, 9, and 15, the hourly load was 9629 MW, 9739 MW, and 9334 MW respectively. Wind production by wind units connected to the Elia grid was relatively low on the 22nd of September. Less than 100 MW of hourly wind production was measured during the periods ranging from hour 8 to 10 and from hour 13 to 17. The lowest hourly volumes of wind production were situated at hour 15 (20 MW) and hour 9 (32 MW).

11. Net Elia load, i.e. measured Elia load minus electricity generated by wind units, amounted to 9468 MW on average during the period ranging from hour 8 to 21. The periods of highest volumes of net load were situated during hour 9 (9708 MW) and hour 21 (9718 MW). Comparing with the net load measured on the 21st of September and 23rd of September, there seems not to be much of a difference (Figure 7, green line). The 21st is characterised by a similar morning and evening net load, while on the 23rd a similar net load have been measured starting from hour 11. The net load of the 23rd of September resembles most that of the 22nd of September.

12. Comparing the validated measured Elia grid load with the energy generated by controllable units and the physical import volumes per border reveals that Belgium relies heavily on gas generation and import volume from the Netherlands during all analysed days (Figure 7, bars versus green line). Gas-fired units accounted for over 53% of the total energy generated on the 22nd of September. Hydro plants generated 3860 MWh or 2,7% of the total energy generated (Table 1).

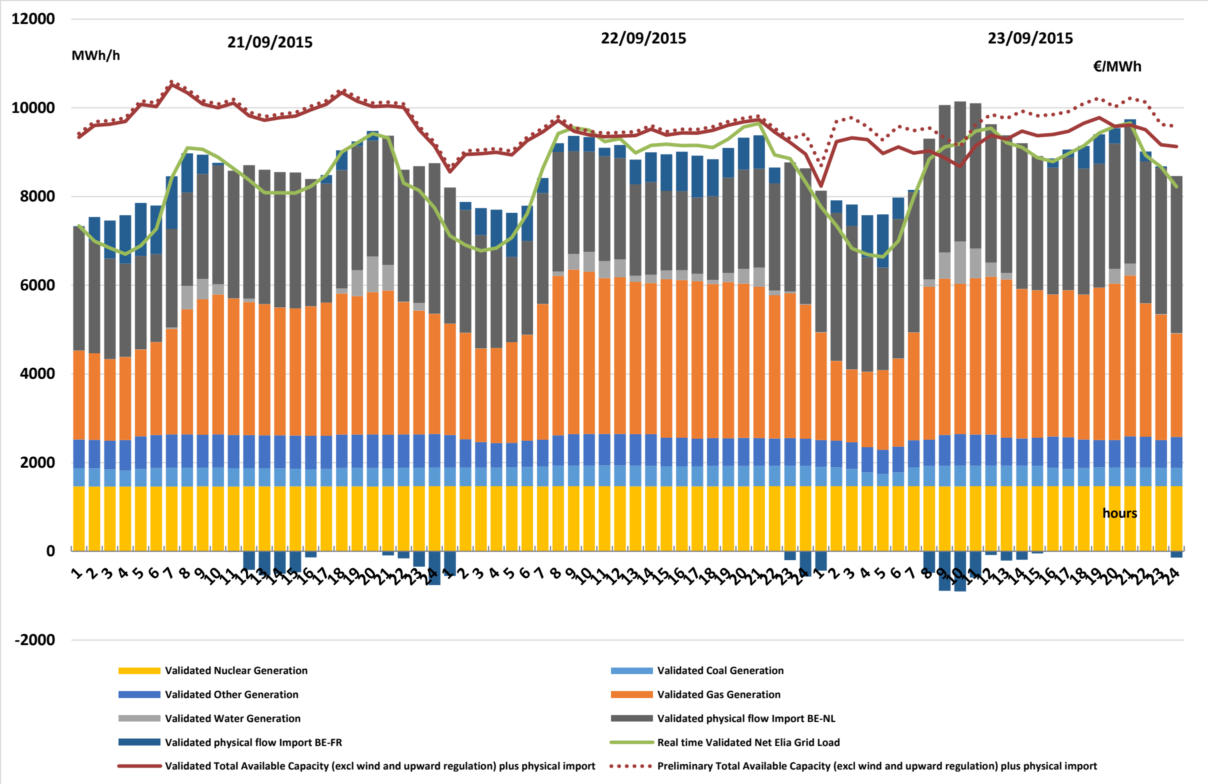

Figure 7 –Measured net Elia grid load, volume of energy generated, and total available controllable generation capacity on the 21st, 22nd, and 23rd of September.
Source: Elia

hour	Validated Coal Generation	Validated Gas Generation	Validated Water Generation	Validated Nuclear Generation	Validated Other Generation
1	419	2315	2	1469	664
2	421	2438	2	1468	636
3	419	2315	2	1469	664
4	422	2137	2	1468	628
5	421	2176	2	1467	712
6	424	2276	2	1467	740
7	437	2479	2	1467	749
8	453	3254	2	1466	756
9	468	3649	179	1467	753
10	464	3697	392	1468	746
11	466	3631	438	1468	748
12	469	3512	381	1468	747
13	468	3517	355	1467	744
14	466	3414	118	1466	740
15	463	3458	198	1466	747
16	456	3566	220	1465	750
17	458	3560	200	1463	752
18	458	3516	150	1464	750
19	460	3487	109	1466	753
20	458	3518	253	1465	749
21	458	3499	355	1467	755
22	460	3353	401	1469	753
23	457	3203	43	1469	752
24	459	3251	53	1469	755

Table 1 – Energy generated per hour and generation type during the 22nd of September
Source: Elia

13. Comparing the measured Elia grid load with the available capacity of controllable units including physical import volumes (Figure 7, green line versus solid brown line), controllable generation facilities could not ensure load to be fully covered during hours 9 to 12 on the 22nd and during hours 10 to 13 on the 23rd. Scarcity could hence explain the highest imbalance price peak on the 22nd and the morning and evening imbalance price peak on the 23rd.

14. Note that the available capacity of controllable units does not include upward regulation reserve capacity, indicating that if generation (bars) exceeds capacity (brown solid line), reserves are activated. Besides the contractual reserves for R1, R2 and R3, an ARP with units bigger than 500 MW is obliged to hold a reserve capacity of 343 MW to cope with an unexpected outage of these units (see CREG decision 1328 on reserve power for 2015). This additional reserve is not accounted for in the graph.

15. Consequently, during both days the capacity margin that is still available after satisfying load is very low: from hours 8 to 21 on the 22nd the margin was lower than 250 MW. For the same period on the 23rd the margin is lower than 350 MW. On the 21st of September, sufficient controllable generation capacity was still available. Other imbalance price peaks could hence indicate a need for real-time flexibility in the system.

16. The relatively low available capacity of controllable generation capacity is attributed to the prolonged outage of Doel 3 and Tihange 2 (2000 MW combined), the temporary discontinuation of exploitation of Doel 1 (433 MW), and the unavailability of Doel 4 (1038 MW). Additionally, CCGT plants Esch-sur-Alzette (Twinerg, 376 MW) and Amercoeur (451 MW) were planned unavailable. Twinerg was restarted on the 23rd of September in reaction to the elevated prices and after finishing its maintenance with regard to its application to the Strategic Reserves (Figure 7, dotted brown line).

17. The nuclear power plant Tihange 1 (962 MW) was unexpectedly forced unavailable only a few days after a maintenance period on the 18th of September. The publication of this unavailability has been investigated and it has been found that the market was timely informed of the outage before the gate closure time of the day-ahead market for delivery of electricity on the 22nd of September.

18. Also, the phase shifter in Zandvliet was out of service which has an effect on the available import capacity from the Netherlands to Belgium. The impact of this unavailability is further detailed in section II.4.1.

II.2.1.2 Balance between commercial day-ahead supply and demand

19. Comparing the day-ahead generation schedules with the real-time generation (Figure 8, orange line versus solid green line) each day the morning ramping of consumption is correctly followed by generation units. Comparing the scheduled generation with the real-time Elia net load excluding imports (Figure 8, orange line versus dotted green line) market participants tend to correctly align their generation schedule with the ramping of the load to be satisfied by domestic generation facilities in real time. However, the morning net load peak is underestimated.

20. Must-buy demand, buy orders priced at €3000/MWh, is higher during the 22nd of September from hour 8 to 21: on average 2526 MW compared with 2076 MW on the 21st and 1612 MW on the 23rd during the same period (Figure 9). The matched volume is on average 2803 MW on the 21st of September, slightly lower than the averaged matched volume on the 22nd of September during the same period (2927 MW). The 23rd of September also shows a reduction in matched volume to 2238 MW.

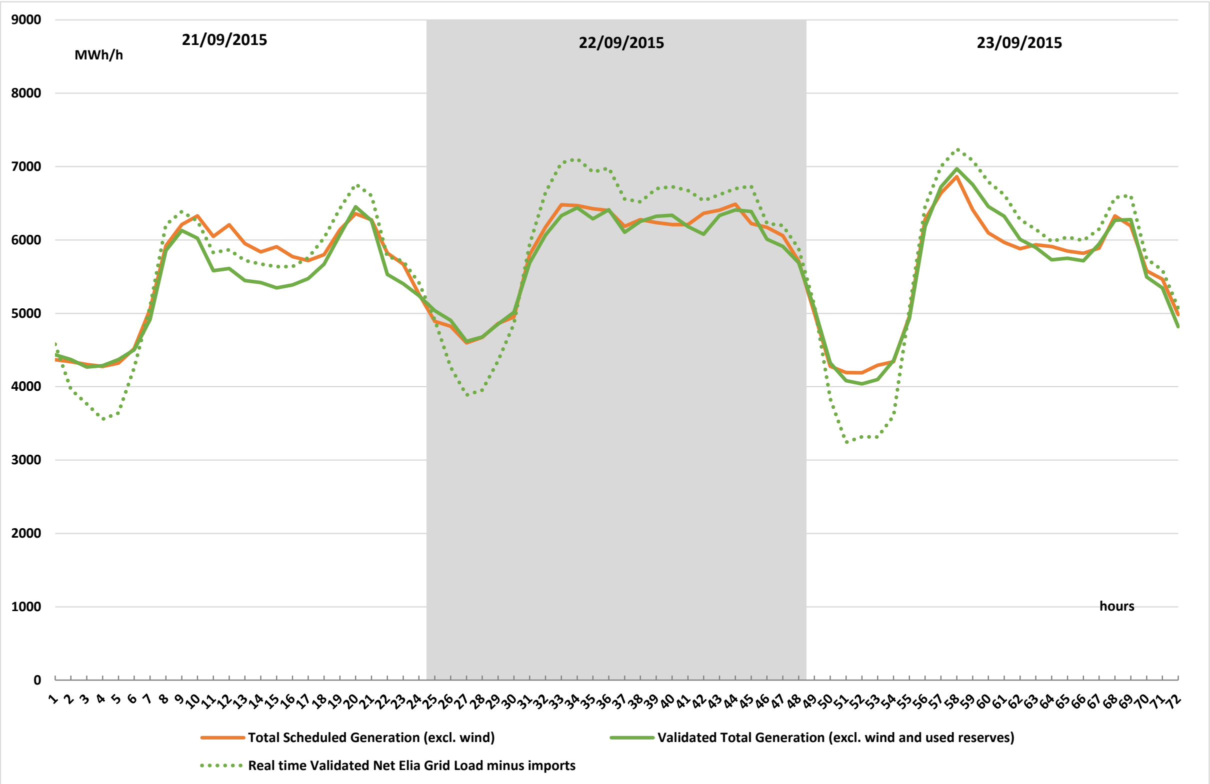

Figure 8 – Validated scheduled generation capacity, generated energy, and net real-time Elia grid load excluding load covered by imports
Source: Elia

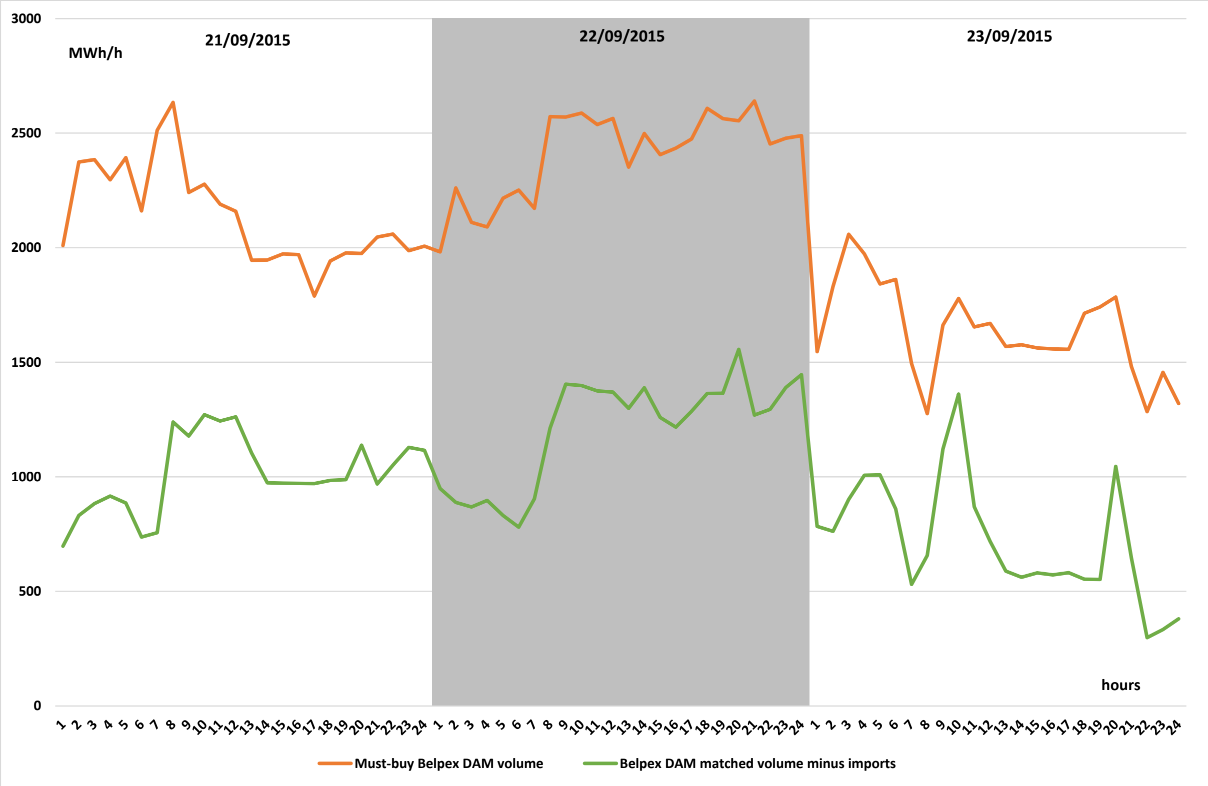

Figure 9 – Matched demand volume on the day-ahead Belpex exchange minus the commercial import volume as allocated by the flow-based market coupling relative to the offered must-buy demand volume
Source: Belpex

21. During all considered hours the Belgian bidding zone was commercially importing. The illustrated commercial volumes hence represent offered demand. Both reductions in must-buy and matched volume on the 23rd of September signal a market reaction following the elevated prices on the 22nd. Because measured net Elia grid load on the 23rd attained similar volumes to that measured on the 22nd, on average 900 MW of must-buy demand would need to be supplied in alternative ways than within the framework of the Belpex DAM.

Total available generation capacity increased with around 370 MW because of the start-up of CCGT-plant Twinerg (Figure 7). As will be seen in section II.4, 460 MW of long-term commercial interconnection capacity was nominated for import to Belgium from the Netherlands on the 23rd compared with the 22nd. These additional capacities largely explain why the volume of must-run demand was reduced on the Belpex DAM.

22. Using the supply and demand curves as offered on the Belpex DAM, the still unmatched must-buy demand can be calculated when considering the Belgian bidding zone as an isolated zone. A negative value indicates that insufficient commercial volumes were offered on the Belpex DAM to satisfy all must-buy demand without additional import volumes.

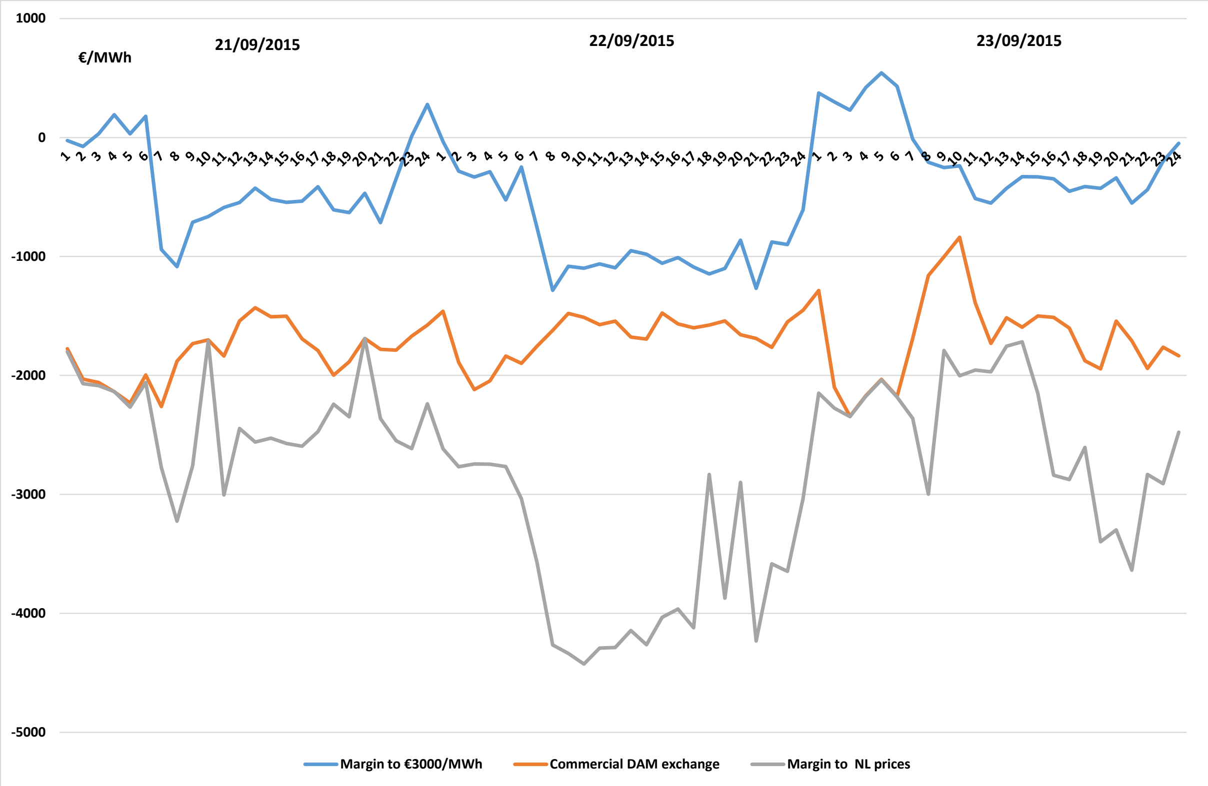

Figure 10 – Minimum required commercial import volume needed to avoid the market ceiling price to be reached (blue), commercial import volume needed to attain price convergence with the Dutch bidding zone, relative to the available import volumes allocated by the flow-based market coupling mechanism.
Source: CREG, Belpex

At hour 8 and hour 21 on the 22nd of September, commercial import volumes of 1280 MW and 1270 MW are required to avoid commercial shortages (Figure 10, blue line). In order to avoid prices of €3000/MWh, from hours 8 to 21, on average, the Belgian power exchange needed 1080 MW of import volumes. Comparing the commercial import volumes allocated to the Belgian bidding zone with the import volumes needed to avoid curtailment on Belpex DAM, the Belgian bidding zone only had on average 500 MW of spare commercial supply during hours 8 to 21 (Figure 10, blue line versus orange line). A similar calculation has been done to determine what volumes were required to attain full price convergence with the Dutch bidding zone: an estimated average import volume of 4000 MW was needed during hours 8-21, or 3600 MW on average during the day. This compares with a daily average of 2780 MW on the 21st of September and 2450 MW on the 23rd of September.

23. The price spikes of 448,7 €/MWh on hours 8, 9 and 15 were fixed by an hourly sell order of less than 50 MWh by one market participant. The sell orders partially cleared during these hours. This kind of behavior of this market participant was already observed and examined for the price spikes on 24 March 2015[1]. For that day it became clear that the bidding

[1] See §63-§67 of CREG-study 1454 on strategic reserves during winter 2014-2015, available in:
- Dutch: http://www.creg.info/pdf/Studies/F1454NL.pdf

behavior was made with the objective of offering demand response. The CREG verified this behavior for the 22nd of September. This result clearly shows the importance of demand response for the day ahead market.

II.2.2 16/10/2015

II.2.2.1 Balance between real-time Elia net load and generation

24. The net load as measured by Elia exceeded during hours 8 to 21 10000 MW on the 15th and the 16th of October (Figure 11, solid green line). The net load was nevertheless consistently higher during the same period on the 15th (10418 MW) than on the 16th (10270 MW) during the same period. The net load was also higher than on the 22nd of September.

25. During all three days Belgium relies heavily on imports from the Netherlands and gas generation. Comparing the available generation capacity with measured net Elia grid load the still available margin is on average 146,5 MW during hours 8-21 on the 15th of October. Accounting for the missed start-up of Doel 4 at the end of the 16th, during the same hours, on average, a margin of 195 MW was available. Even though a higher average margin is available, during hours 10-12, available generation capacity plus imports are insufficient to fulfill net Elia grid load. Considering that besides the contractual reserves for R1, R2 and R3, an access responsible party (ARP) with units bigger than 500 MW is obliged to hold a reserve capacity of 343 MW to cope with an unexpected outage of these units (see CREG decision 1328 on reserve power for 2015), this margin is very small.

26. This low available margin is attributed to the unavailability of multiple generation plants, among which CCGT units Amercoeur (451 MW), Twinerg (376 MW), and T-Power (425 MW), and the nuclear power plants Doel 1 (433 MW), Doel 2 (433 MW), Doel 4 (1038 MW), and Tihange 2 (1000 MW).

The 1038 MW increase in available generation capacity at the end of the 16th of October is attributed to the start-up of nuclear power plant Doel 4. According to the Urgent Market Message (UMM) history the start-up was first planned on the 15th at noon, was revised on the 13th to the situation depicted in the figure, and then again changed on the 15th to the 17th at noon. Since Doel 4 did not generate energy on the 16th the increase of available generation capacity (Figure 11) does not reflect the underlying physical reality on the 16th of October and should be disregarded.

- French: http://www.creg.info/pdf/Etudes/F1454FR.pdf

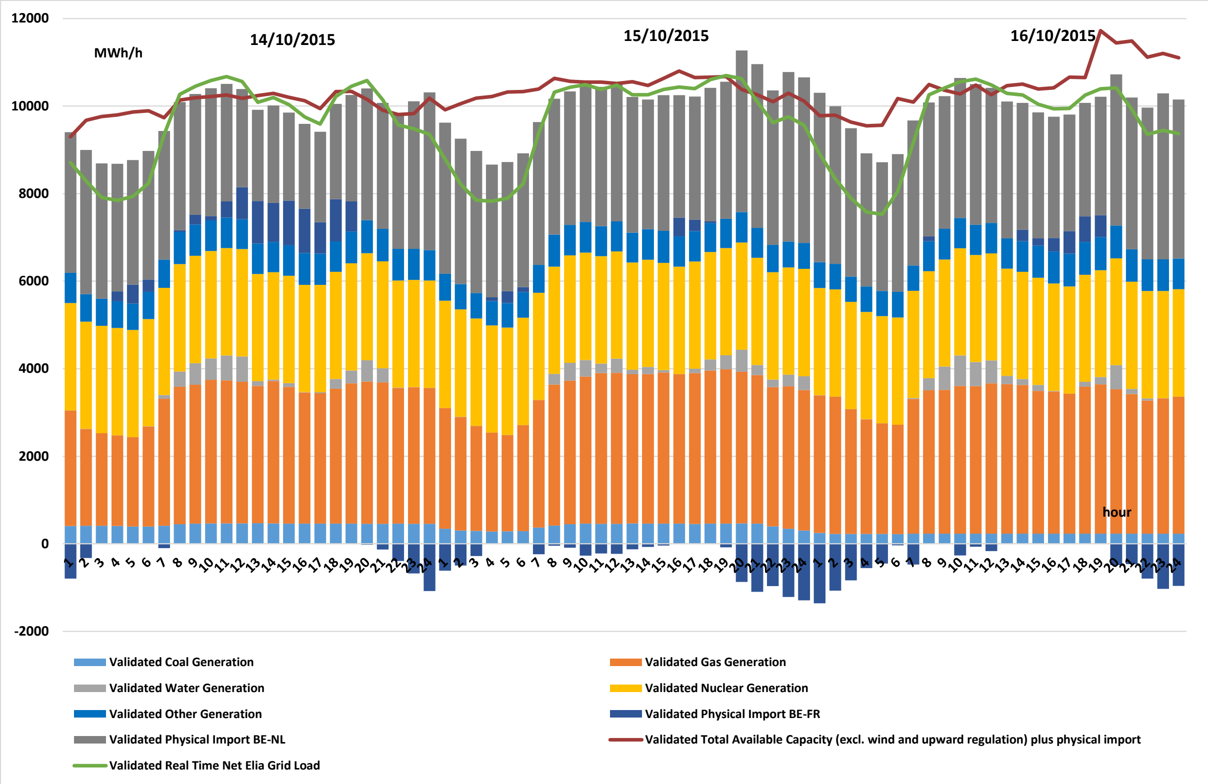

Figure 11 – Measured net Elia grid load, volume of energy generated, and total available controllable generation capacity on the 14th, 15th, and 16th of October.
Source: Elia

II.2.2.2 Balance between commercial day-ahead supply and demand

27. Comparing the day-ahead generation schedules with the real-time generation (Figure 12, orange line versus solid green line) each day ARPs have accurately followed their generation schedules as communicated to Elia. Comparing the total generation with the real-time net Elia grid load, on both the 15th and the 16th of October, from hour 8 onward, a rather large difference in volume can be observed between the two. The increase in net Elia load is closely followed by the scheduled and real generation.

28. The volume of must-buy demand on the 15th (2666 MW) is lower compared with the 14th (2849 MW) and the 16th (2801 MW). Must-buy demand exceeds 3000 MW on the 14th of October at hours 9 to 12 and at hour 20, and on the 16th of October at hours 10-12 (Figure 13, orange line). Day-ahead demand to be covered by domestic generation facilities fluctuates between 1000 MW and 1500 MW with higher values emerging on the 14th of October.

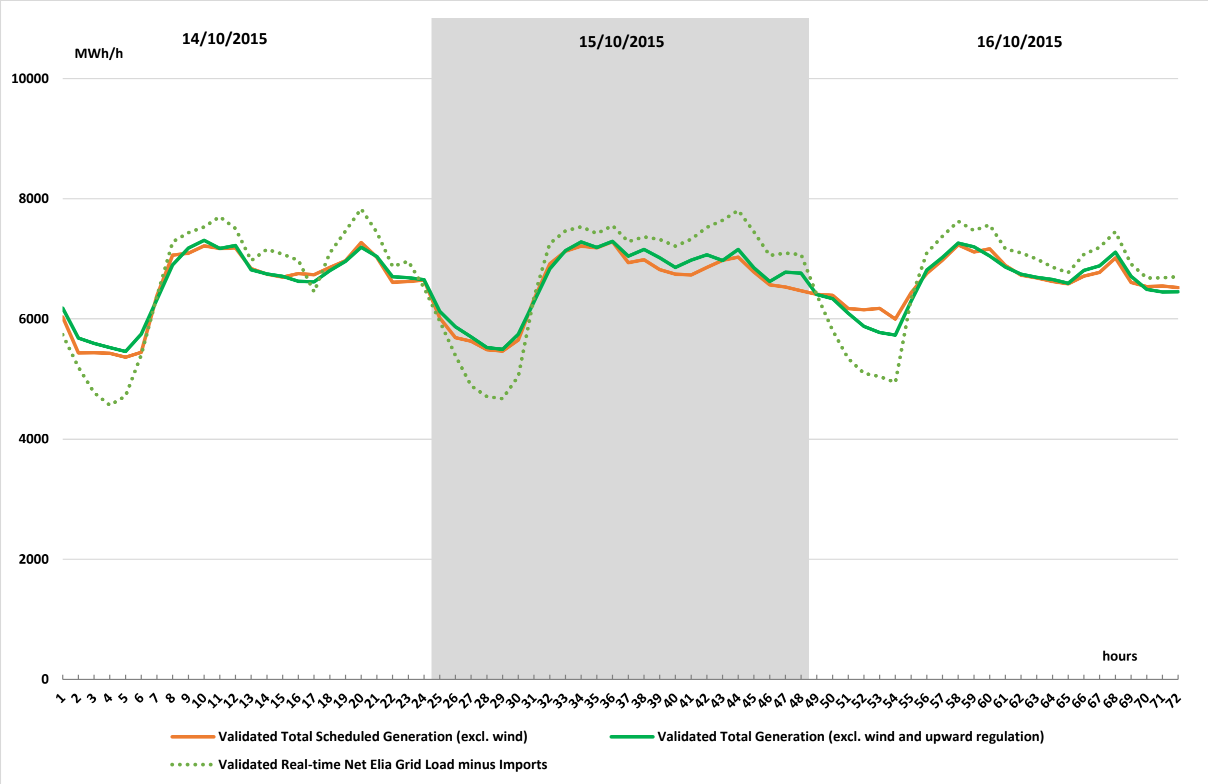

Figure 12 – Validated scheduled generation capacity, generated energy, and net real-time Elia grid load excluding load covered by imports
Source: Elia

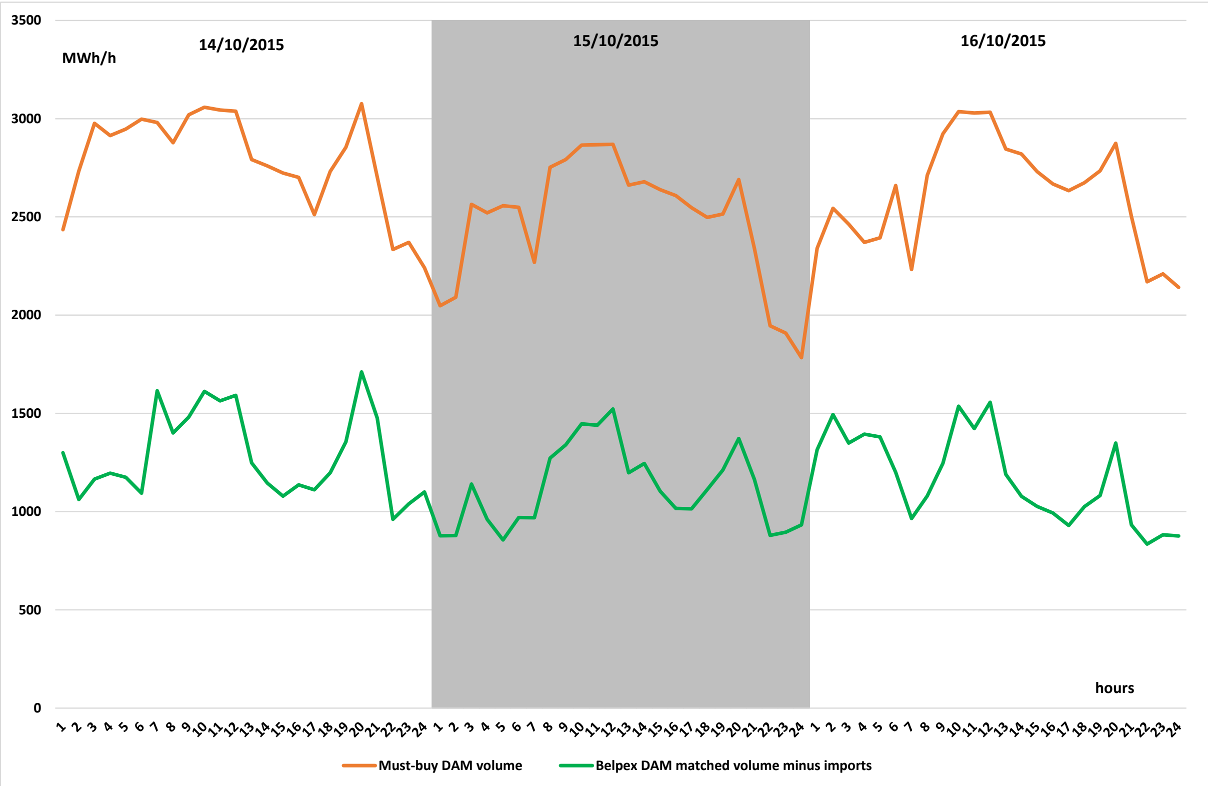

Figure 13 – Matched demand volume on the day-ahead Belpex exchange minus the commercial import volume as allocated by the flow-based market coupling relative to the offered must-buy demand volume
Source: Belpex

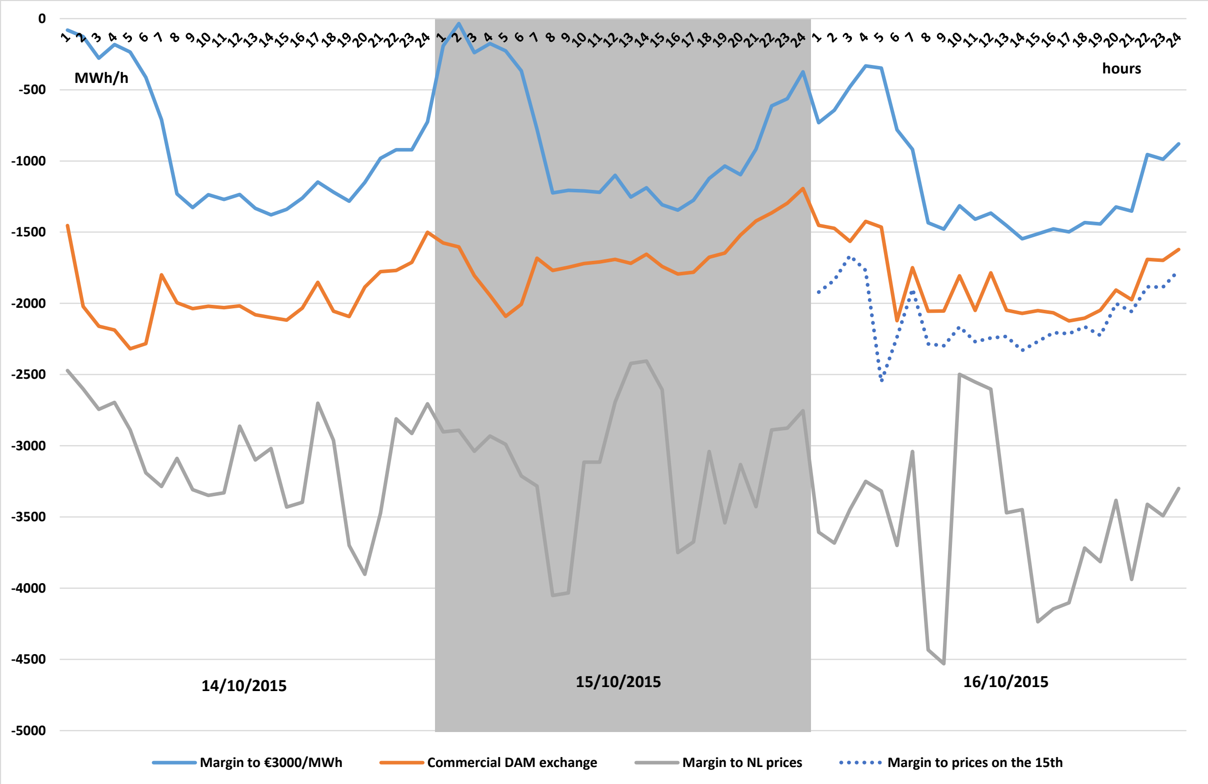

Figure 14 – Minimum required commercial import volume needed to avoid the market ceiling price to be reached (blue), commercial import volume needed to attain price convergence with the Dutch bidding zone, relative to the available import volumes allocated by the flow-based market coupling mechanism. Source: CREG, Belpex

29. Using the supply and demand curves as offered on the Belpex DAM, the minimum import volumes needed to avoid prices of €3000/MWh are calculated (Figure 14, blue line). The required import to fulfil all must-buy demand is on average the highest during hour 8-21 on the 16th (1431 MW) with lower margins on the 14th (1242 MW) and 15th (1179 MW).

30. Given the above figures and numbers, the 15th and the 16th of October are very similar. The most elevated prices emerged on the 16th only because of small differences in terms of commercial volumes: on average, during hours 8-21, 200 MW of additional offered supply capacity or allocated imports were needed to obtain similar prices as those observed on the 15th (Figure 14, dotted blue line versus solid orange line).

31. Lastly the price spikes of €448,7/MWh were caused by an hourly sell order of less than 50 MWh by one market participant. The sell orders partially cleared during these hours. This kind of behavior of this market participant was already observed and examined for the price spikes on 24 March 2015[2]. For that day it became clear that the bidding behavior was

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[2] See §63-§67 of CREG-study 1454 on strategic reserves during winter 2014-2015, available in:
- Dutch: http://www.creg.info/pdf/Studies/F1454NL.pdf
- French: http://www.creg.info/pdf/Etudes/F1454FR.pdf

made with the objective of offering demand response. As for the 22nd September, this clearly shows the importance of demand response for the day ahead market.

II.2.3 Synthesis

32. On both days around 4000 MW of generation capacity was not available. Unavailability of generation capacity led to elevated prices for the Belgian bidding zone throughout the fall of 2015. The extremely elevated prices observed on the 22nd of September and the 16th of October could have been avoided if only small volumes of additional supply were available in the Belgian bidding zone.

From the analysis in this section, reduced generation capacity (excluding reserves) is a factor leading to elevated prices, however, there was never a risk of structural shortage using commercial criteria. The next sections analyze whether additional supply could be sourced from reserves, and whether available commercial import capacity has been efficiently used.

II.3 The Belgian Control Area – Balancing and reserves

II.3.1 Principles of balancing price formation

II.3.1.1 Introduction

33. Where access responsible parties (ARPs) are unable to balance their portfolio, Elia itself has to take the necessary steps to balance the control area. Since Elia does not own generation units, in such situations it will ask relevant market parties to provide several ancillary services[3]:

- primary reserve (Frequency Containment Reserve – *FCR*)
- secondary reserve (Automatic Frequency Restoration Reserve – *aFRR*)
- uncontracted and / or contracted tertiary reserve (Manual Frequency Restoration Reserve – *mFRR*), including reserve assistance contracts with neighboring TSO.

Primary reserves are activated automatically in order to compensate at short notice an imbalance occurring in continental Europe, secondary reserves are activated automatically in order to compensate an imbalance occurring in the Belgian control zone, while other reserves

[3] Terms in brackets are the new names used in the “Balancing Framework Guidelines” of ACER.

are activated 'manually' according to the balancing rules, proposed by the TSO and approved by the CREG.

In theory, primary, secondary and tertiary reserves are activated in sequence. Nevertheless, the trigger for the activation of primary reserves is the difference between a frequency set point and the frequency measured at the resource's connection point, and the trigger for the activation of the secondary reserve is an automatic command computed by the TSO and sent almost continuously to the reserve provider. The trigger for the tertiary reserve is a manual command sent by the TSO to the service provider.

34. When the secondary reserve is estimated insufficient to maintain the quarter hourly balance of the Belgian control area, or in order to restore the secondary reserve potential of the system, Elia activates sequentially the bids from the following tertiary reserve[4] classes at its disposal:

- uncontracted reserve ('free bids', ID bids)
- contracted tertiary reserve on generation units (R3 production)
- contracted tertiary reserve bids on dynamic profile customers (R3 DP)
- contracted tertiary reserve on interruptable customers (R3 ICH)
- reserve contracts with neighboring system operators (R3 inter-TSO)

Within a class, the bids are activated owing to their economic merit order[5]. Nevertheless, all the bids of a class must be activated before Elia activates the bids of the next class, even if the activation price of some/all bids of the next class are economically more interesting for Elia.

Free bids and tertiary reserve bids contracted on generation units are activated sequentially bid by bid in their class, according to a principle of technical and economic merit order, notably on the basis of the activation costs, startup costs and minimal activation power.

If all volumes activated in the previous classes have been activated and are not sufficient, and there is a strategic reserve unit spinning but partially activated for strategic reserve, thus leaving unused spinning power, Elia will activate this unused spinning power as a last resort before activating the load shedding emergency plan.

The activations are remunerated in accordance with the pay as bid method.

[4] mFRR
[5] By order of increasing price for the upward regulation, and of decreasing price for downward regulation.

II.3.1.2 Balancing Price Formation

35. Unless mentioned explicitly, all volumes relate to a quarter of hour period or are averaged over a quarter of hour.

In the next sections, activations are considered as if they were ordered to equivalent production resources, so that:

- activation of an injection resource in order to increase the volume injected is named "upward activation",
- activation of an injection resource in order to decrease the volume injected is named "downward activation",
- activation of an offtake resource in order to increase the offtake is named "downward activation",
- activation of an offtake resource in order to decrease the offtake is named "upward activation".

Regulation ordered by Elia (automatically as well as manually) for a quarter of hour can be composed of both upward and downward activations, upward regulation consists of upward activations and downward regulation consists of downward activations. So:

- R1 and R2 reserves are symmetric products that can be activated upward or downward;
- R3 contracted products (R3 production, R3 DP & R3 ICH) can only be activated upward;
- free (uncontracted) R3 bids are most of the time defined in both directions and can be activated upward and/or downward.

36. The ***Net Regulation Volume*** (NRV) is defined as the difference between:

- on one hand, the sum of the ***gross volume of upward regulation*** as ordered by Elia, for the considered quarter of hour, for maintaining the balance in the Belgian control area, expressed in MW, and the ***strategic reserve volume injected in the balancing control area*** for the same quarter;
- and on the other hand, ***gross volume of downward regulation*** as ordered by Elia, for the considered quarter of hour, for maintaining the balance in the Belgian control area, expressed in MW.

The ***Area Control Error*** (ACE) is, for a considered quarter of hour and expressed in MW, the difference between the nominated (program) and actual (measured) values of the interchanges of the Belgian control area with neighbouring countries, taking into account the effect of frequency deviation from the frequency set point.

The ***System Imbalance*** (SI) is calculated by taking the difference between the Area Control Error (ACE) and the Net Regulation Volume (NRV). The System Imbalance is obtained by neutralising the activated means (NRV) – deployed by Elia for managing balance in the Belgian control area – out of the ACE.

SI = ACE – NRV

As a consequence, the ACE can be considered as the residual system imbalance after taking into account the effect of the regulation (activations of reserves) ordered by Elia, while system imbalance is the "original" imbalance of the system determined before activating any correcting regulation. In most cases, the sign of SI is the opposite of the sign of NRV[6].

37. The ***marginal price for upward regulation*** (MIP[7] or HUP[8]) is, for a given quarter of hour, the highest unit price of all upward activations[9] ordered by Elia for maintaining the balance in the Belgian control area. The MIP is defined in detail in the functioning rules of the market for the compensation of the quarterly hour imbalances[10].

The ***marginal price for downward regulation*** (MDP[11] or LDP[12]) is, for a given quarter of hour, the lowest price of all downward activations[13] ordered by Elia for maintaining the balance in the Belgian control area. This price also takes into account the additional incentives applicable on the marginal price for downward regulation if the mutual emergency power between grid

[6] That is why NRV and –SI are displayed on figure 15, in order to be able to compare their magnitude more easily.
[7] Marginal Incremental Price
[8] HUP as defined in the functioning rules of the market for the compensation of the quarterly hour imbalances; "Highest Upward Price"
[9] When positive, these prices are paid by Elia to the providers (pay as bid). Therefore, the marginal price is the highest price of upward activated resources.
[10] Available on the Elia website either in French http://www.elia.be/~/media/files/Elia/Products-and-services/Balancing/20150825_R%C3%A8gles_Balancing_FR.pdf or in Dutch http://www.elia.be/~/media/files/Elia/Products-and-services/Balancing/20150825_Balancing-Rules_NL.pdf
[11] Marginal Decremental Price
[12] LDP as defined in the functioning rules of the market for the compensation of the quarterly hour imbalances; "Lowest Downward Price"
[13] When positive, these prices are paid by the providers to Elia (pay as bid). Therefore, the marginal price is the lowest price of downward activated resources.

operators has been activated. The MDP is defined in detail in the functioning rules of the market for the compensation of the quarterly hour imbalances.

38. The ***imbalance tariff*** is established on the basis of computation formulas in the table below. These formulas relate to the quarter of hour imbalance of one given ARP, for one given quarter of hour. Imbalances can be positive (the ARP or the Belgian control zone is long, its injection is greater than its offtake) or negative (the ARP or the Belgian control zone is short, its injection is smaller than its offtake). When either an ARP is long and the control zone ("the system") is short or the ARP is short and the control zone is long, the ARP is said "helping the zone" because its imbalance helps reducing the imbalance of the zone. In this case, the alpha coefficient is equal to zero, even if the system imbalance is large. Conversely, when the ARP and the system are either both long or both short, the ARP is said to "act against the zone". In this case, the alpha coefficient is greater than zero when the system imbalance is large (> 140 MW), and the alpha coefficient can be considered as an additional incentive for the ARP to help the zone, or at least to reduce his imbalance.

Tariffs for positive imbalance can either be positive or negative. A positive tariff for positive imbalance (injection exceeds offtake) means a payment from Elia to the ARP and a negative tariff for positive imbalance means a payment from the ARP to Elia.

Tariffs for negative imbalance (offtake exceeds injection) can either be positive or negative. A positive tariff for negative imbalance means a payment from the ARP to Elia and a negative tariff for negative imbalance means a payment from Elia to the ARP.

		Net Regulation Volume (NRV)	
		Negative **(Net downward regulation)**	**Positive** **(Net upward regulation)**
ARP Imbalance	**Positive**	MDP - α1	MIP - β1
	Negative	MDP + β2	MIP + α2

where:

- β1 (€/MWh) = 0
- β2 (€/MWh) = 0
- If the absolute value of the System Imbalance (SI) is smaller than or equal to 140 MW:
    - α1 (€/MWh) = 0

- $\alpha2$ (€/MWh) = 0

- If the absolute value of the System Imbalance (SI) is bigger than 140 MW:
  - $\alpha1$ (€/MWh) = average {(System Imbalance $_{QH-7}$)², …, (System Imbalance $_{QH}$)²} /15.000
  - $\alpha2$ (€/MWh) = average {(System Imbalance $_{QH-7}$)², …, (System Imbalance $_{QH}$)²} /15.000

The value(s) of the tariff for maintaining and restoring the individual balance of access responsible parties while activation of the strategic reserves is (are) defined in the functioning rules for strategic reserves.[14] This is beyond the scope of this study.

II.3.2 22/09/2015

II.3.2.1 Activation and imbalance price

39. On 22 September, the Belgian TSO activated relatively high volumes of balancing reserves with high imbalance tariffs.

40. In the following analysis, old names of reserve products are used: secondary reserves (R2) for automatic Frequency Restoration Reserve (aFRR) and tertiary reserve (R3) for manual Frequency Restoration Reserves (mFRR). R3 can be done on generation units (R3 production), on dynamic profiles (R3DP) and on interruptible load (R3 ICH).

41. The chart below shows the activations of IGCC, R2 and R3 bids (both R3 free bids and R3 reserved bids) for the day 22nd of September, 2015, as well as the imbalance tariff (blue line with cyan markers).

[14] See Elia website http://www.elia.be/fr/produits-et-services/R%C3%A9serve%20strat%C3%A9gique/Documents

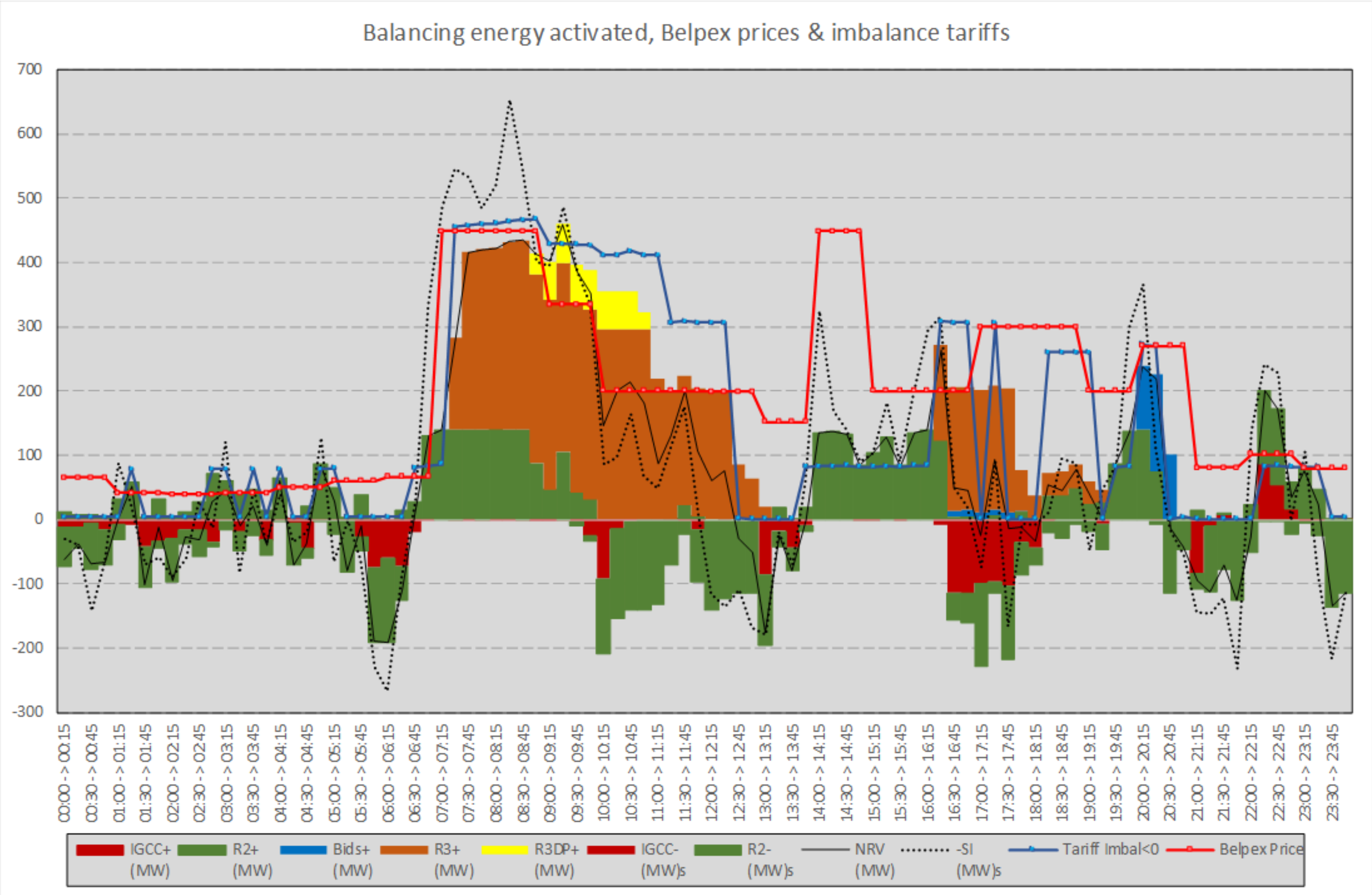


Figure 15 - Balancing energy activated, Belpex DAM price, and imbalance tariff on the 22nd of September
Source: Elia, Belpex

42. It is clear that activation of reserve by the TSO tends to follow the system imbalance. From 7:00 to 11:00 up to 420 MW of balancing reserves were activated. First, R2 was activated, which has a maximal capacity of 140 MW. Since this was not sufficient, also R3 was activated, which could also desaturate R2. Normally, R3 is activated when there is an unplanned outage, which was not the case during 22 September, or in case of forecast error on load and intermittent RES generation. However, also when there is an unexpectedly higher load, R3 can be activated.

43. Comparing day-ahead (nominations) and real time (activations) bids volume and price characteristics for reserved mFRR on production units (R3 prod) and ID bids, it is clear that several important observations can be made for which the reasons have been clarified with Elia:

- the day ahead nomination and real time activation bid prices differ strongly. Since 2014 the activation price can be redefined up to one hour before activation. This procedure is explained on page 28 of the “Balancing Rules”.

- A certain volume of ID bids were nominated but not activated, even though the procedure justifies their activation (section II.3.1), and bids are in-the-money. The volume of ID bids is calculated using data received from market participants. The data provided could be incorrect, leading to actual bid volumes being different than the ones expected by Elia. If, for example, the nominated production volume of the unit has not been updated when the unit is in fact running at maximum capacity, then no ID bid volume would be available.
- A certain volume of R3 production bids were not activated while being offered at a lower price than other activated bids. Two reasons were provided. Firstly, similar to the response above, if small volumes are offered for a small period, Elia assumes the likelihood of the volume of ID bids being available as low. Instead of spending precious time interacting with plant owners for balancing energy that is likely not to be available, Elia deems it safer for maintaining system balance to immediately activate tertiary reserves. Volume offered by another plant (<50 MW) was not activated due to its location in a congested zone.

II.3.2.2 Operation of pumped storage plants

44. The pumped storage turbines of Coo generated 3,748 MWh between 7:00 and 22:00 on 22nd September. Deduced from the energy capacity of the upper reservoirs of Coo (~5,000 MWh), that leaves an unused capacity of about 1,500 MWh.

Under normal conditions, Electrabel, that operates Coo, must keep 500 MWh in the upper reservoir for the black start ancillary service from the Coo site; that leaves 1,000 MWh unused reservoir capacity in the upper reservoir.

Moreover, in 2015 Electrabel needs to keep 343 MW tertiary reserve for the additional risk linked to the large size of nuclear power plant that it operates, as this additional risk is not covered by the reserves contracted by Elia[15].

II.3.2.3 Availability of R3 ICH

45. ICH contracts were not activated on 22nd September 2015.

[15] Final decision (B)140626-CDC-1328 of the CREG on 26th June 2014 about “la demande d’approbation de la méthode d’évaluation et de la détermination de la puissance de réserve primaire, secondaire et tertiaire pour 2015”, particularly §§ 29-30.

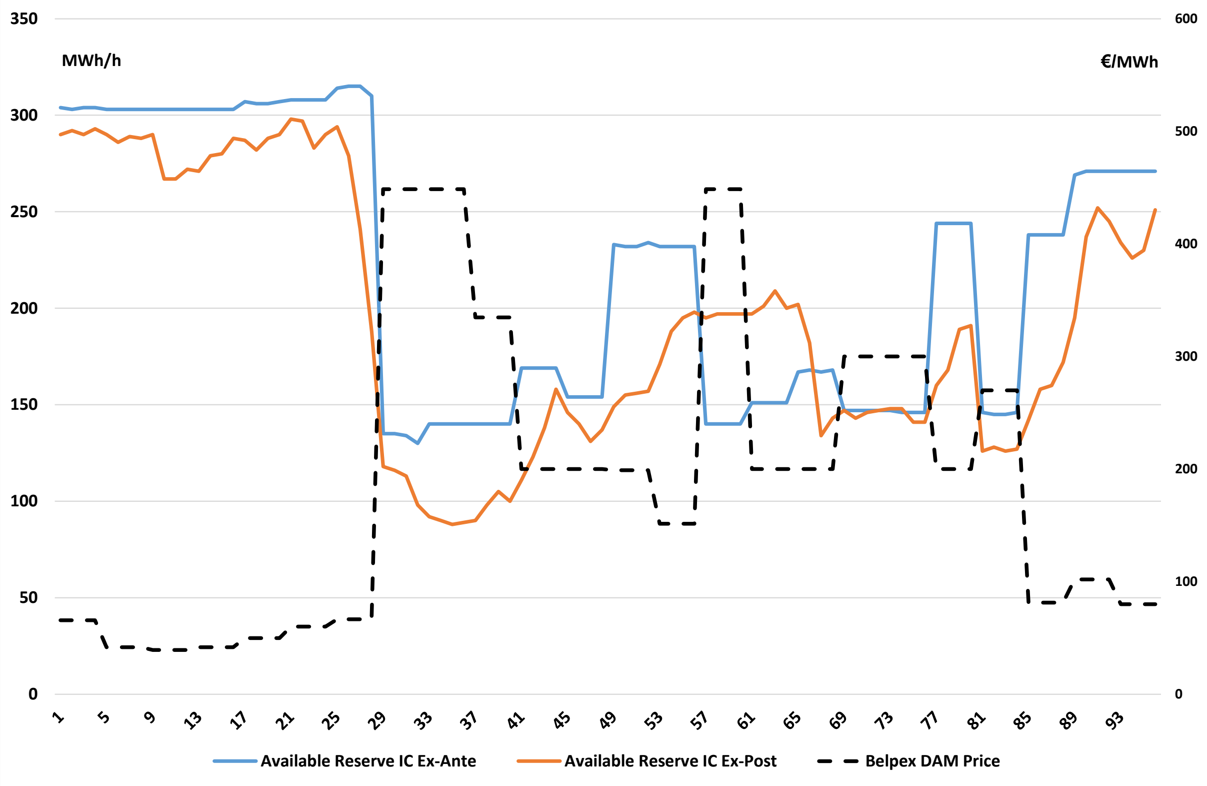


Figure 16 – Availability of the ICH reserve on the 22nd of September and the Belpex DAM price
Source: Elia, Belpex

The above figure illustrates the availability of ICH contracts, as well in day ahead (ex-ante) as in real time (ex-post). Elia contracts maximum 300 MW of ICH contracts. The Belpex DAM price was added to the figure (€/MWh).

The figure shows that the ex-ante availability of the ICH contracts is very sensitive to Belpex DAM prices for that day. When the Belpex DAM price reaches about 450 €/MWh during the morning and the afternoon, the availability rate of the ICH contracts decreases to about 51%, with a lowest value equal to 47% around 7:45 am.

As illustrated in the next figure, the availability in real time is more impacted by the balancing tariff than by the day ahead price, but the link does not seem to be as strong as the link between the Belpex DAM price and the availability in day ahead. This could be partially due to the uncertainty associated with imbalance tariff in real time compared to the certainty associated with the possible sale of demand response through the clearing process of the Belpex DAM depending on the relative position of the Belpex DAM (clearing) price and the offered prices of the demand response bids.

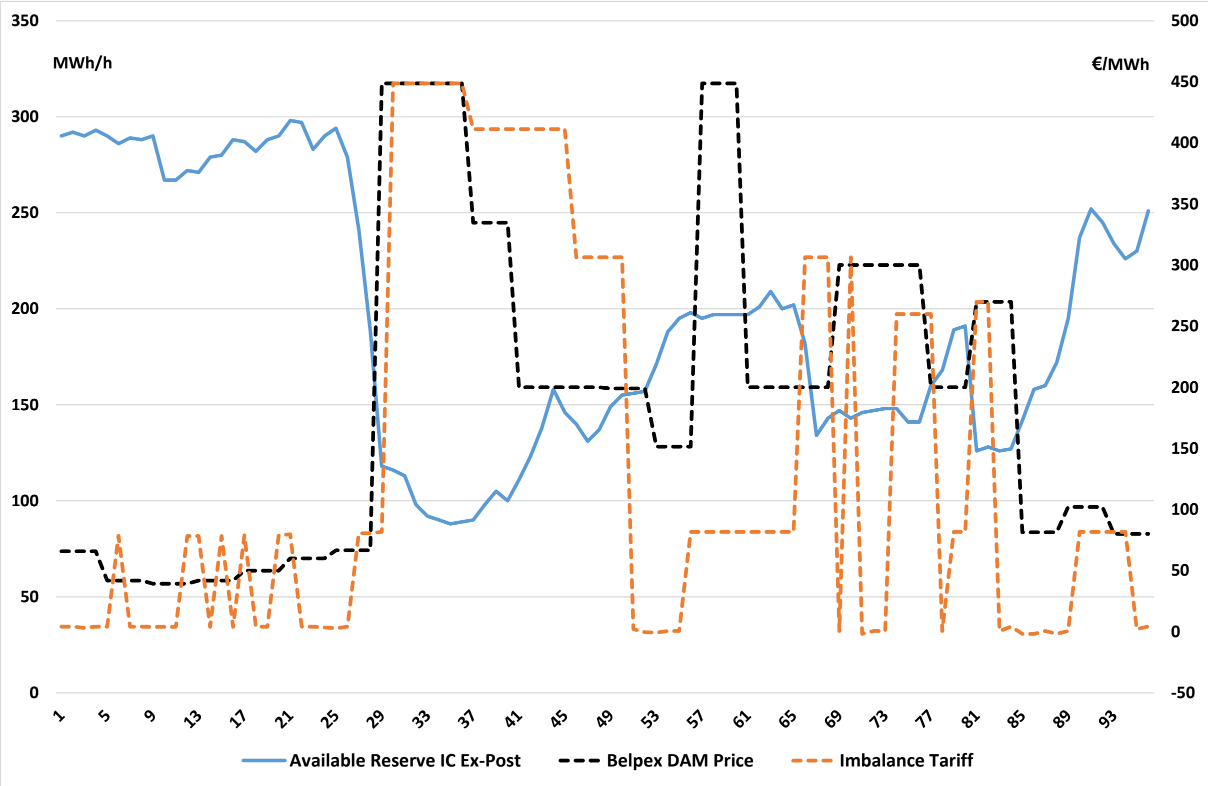


Figure 17 – Availability of the ICH reserve on the 22nd of September and the imbalance tariff
Source: Elia, Belpex

These observations, if confirmed by other ones in the presence of peaks in the Belpex DAM prices, suggest to adapt the product design, as well by defining an increased availability target (100%?) for the ICH contracts, as by including an exclusivity clause in these contracts. On the other hand, with the return of several nuclear power plants, the probability of having high price spikes on the day ahead market is considerably lower for the coming years. In the future, these problems should be resolved when the ICH-product will be ended after 2017 and replaced by a more short-term product.

II.3.2.4 <u>Balancing and Adequacy</u>

46. Elia sent the data on which the risk of a structural shortage is assessed as if the 22nd of September 2015 would be a day in the winter period during which the strategic reserve may be activated.

a) Detection of the risk for structural shortage

47. The figure below presents the four curves based on which the risk of a structural shortage is derived, in day-ahead.

The production forecasting curve 1 (C1) shows the total production of the Elia zone while the load forecasting curve 2 (C2) shows the total load of the Elia zone. For intraday, curve 2 uses the real time load forecast. In theory, both curves are identical except for differences between forecasts of market participants and those of Elia. The curve 3 (C3) takes into account the total production forecasting (curve 1) plus the margin that can be activated within 15 minutes and is available to Elia as incremental bids on units covered by a CIPU contract. The curve 4 (C4) illustrates the upper limit of production based on the curve described in curve 3 plus the available balancing reserves.

The red curve (S1) illustrates when the production margin made available by the market does not correspond with the total consumption in the control zone. If negative, the balancing reserves need to be dispatched to accommodate consumption demand. In turn the margin to compensate sudden imbalances is reduced. S1 attains its lowest value at 08h45 (258 MW) and stays below 1.000 MW during the remainder of the day.

When negative, the yellow curve (S2) illustrates when the production margin of the market, balancing reserves included, is insufficient to accommodate a forced outage of a nuclear power plant (1.000 MW). The smallest margin is noticed at 08h45. The curve corresponds to S1 for the remainder of the day.

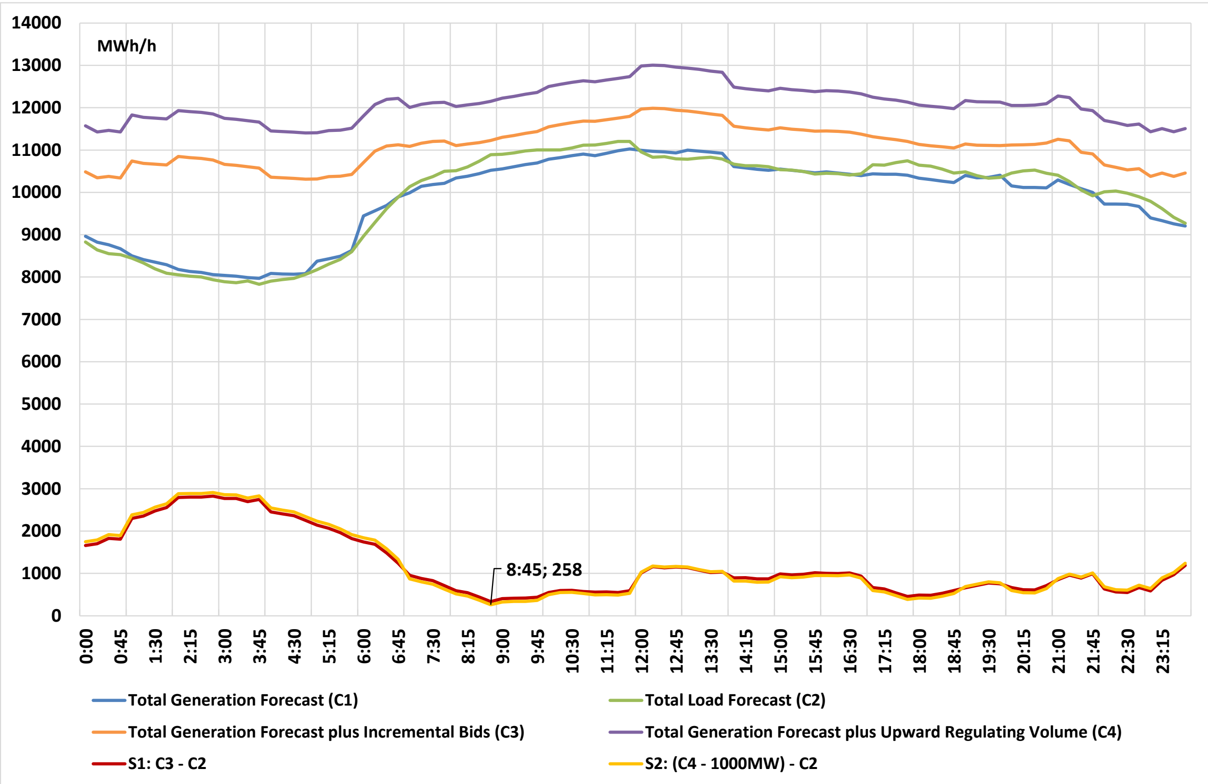


Figure 18 – Curves, as observed in day-ahead, on which the technical trigger is invoked to activate the strategic reserves
Source: Elia

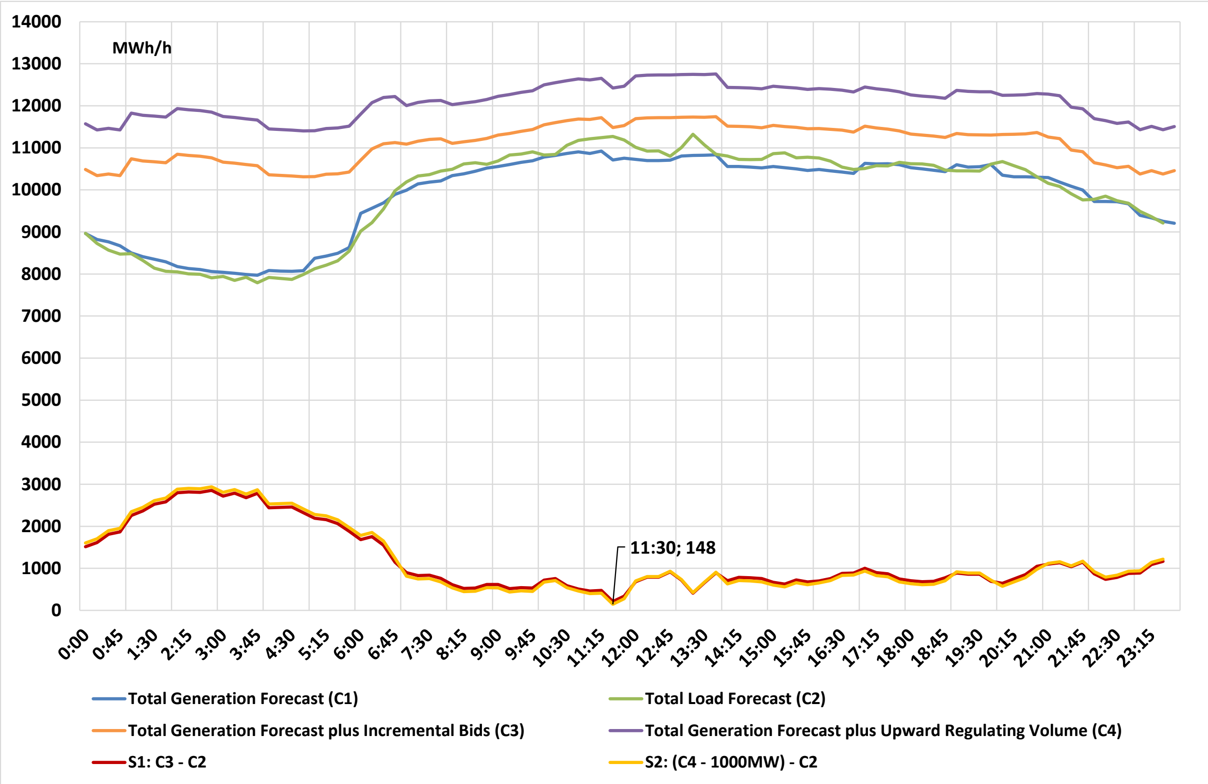


Figure 19 – Curves, as observed in intra-day, on which the technical trigger is invoked to activate the strategic reserves - Source: Elia

The figure above presents the four curves based on which the risk of a structural shortage is derived, at the end of day-ahead (D-1). The impact of forecast errors is smaller since the forecasts occur closer to real time.

The red curve (S1) attains its lowest value at 11h30 (148 MW). The same conclusion holds for the yellow curve (S2). The closer to real time, the lower the margins between production and demand.

48. The procedure for activating the strategic reserves followed by the technical trigger would never have been initiated. The red curve (S1) attains a minimum at 09h45 (158 MW).

b) Forecast errors

49. The two figures below show the segmentation of the forecast error between wind generation, solar generation and other sources of forecast error.

The former addresses day ahead forecast error while the latter addresses the intraday forecast error.

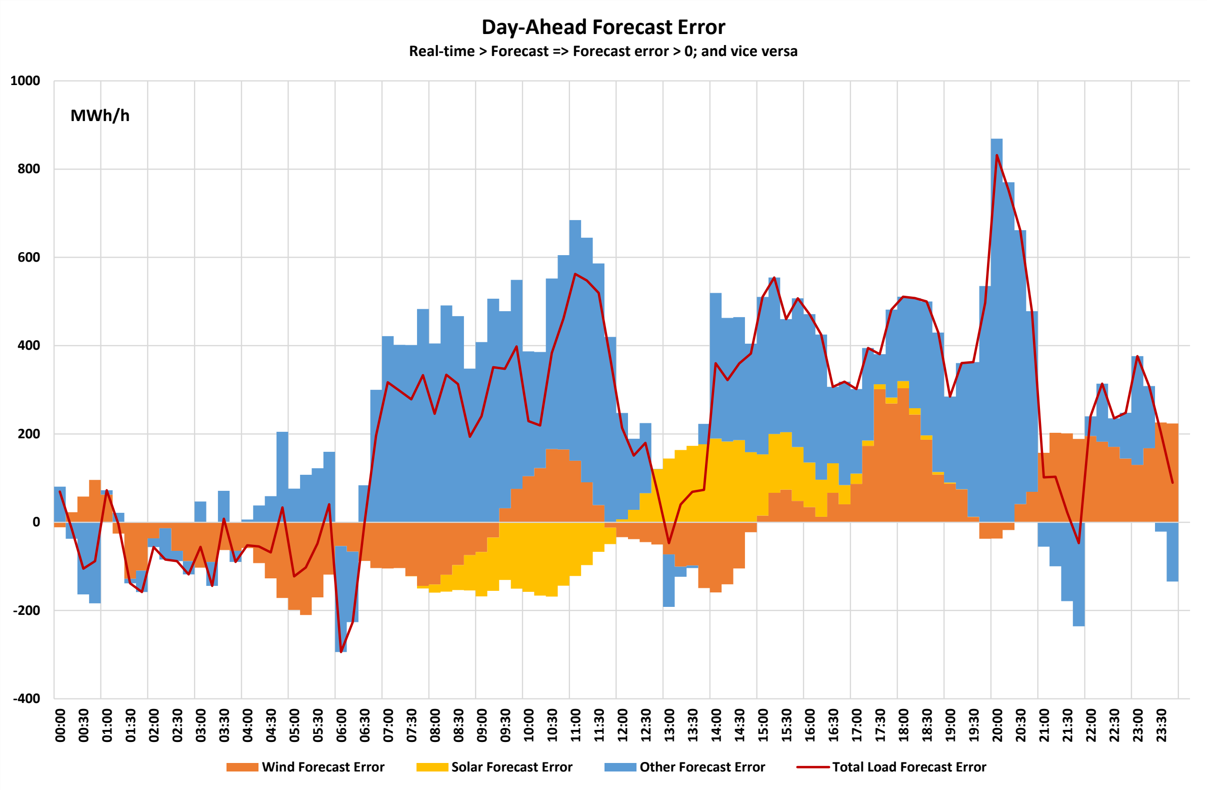


Figure 20 – Stacked day-ahead net load forecast error segmented by different contributing factors
Source: CREG, Elia

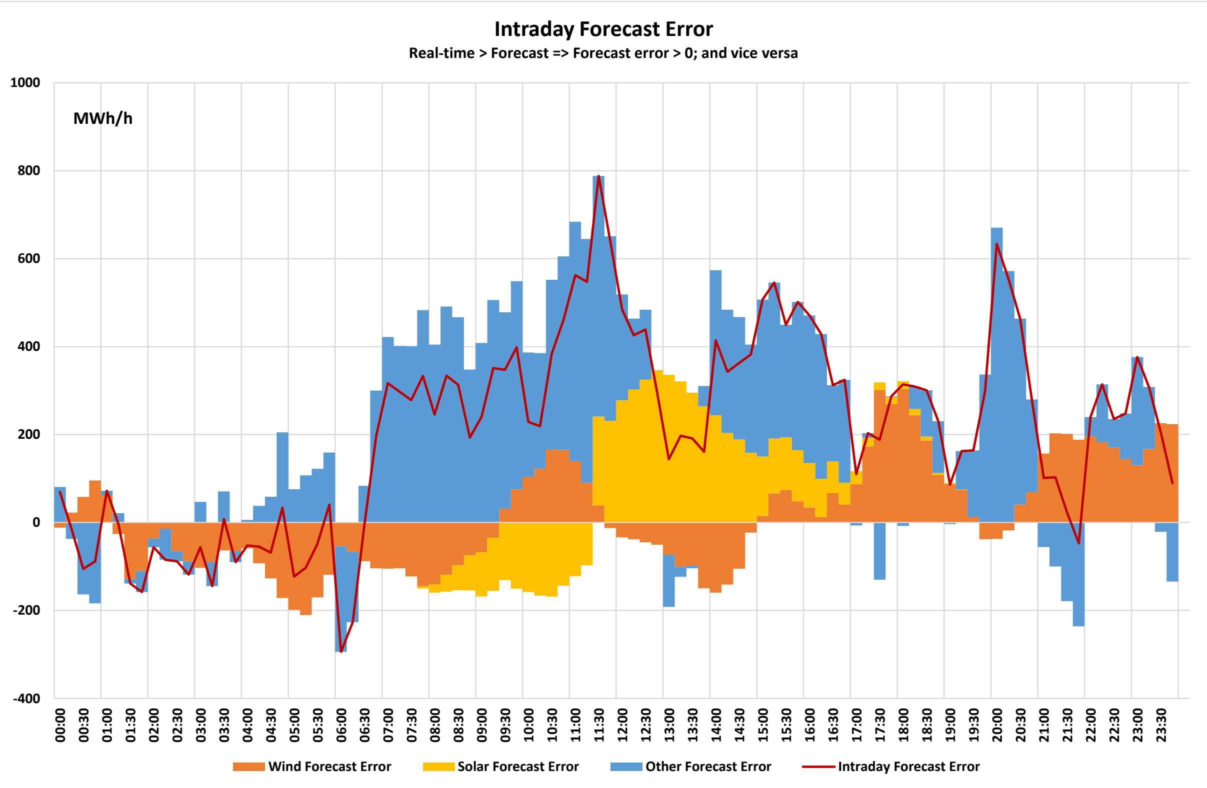


Figure 21 – Stacked intraday net load forecast error segmented by different contributing factors
Source: CREG, Elia

It can be observed that a large part of the forecast errors during the morning, during the afternoon as well as during the peak around 20:00 is due to other sources (in blue) than wind and solar forecast errors.

50. Due to high prices on the day-ahead market, not all market participants were able to buy their energy demand on the day-ahead market. In order to reduce collateral requirements on the day-ahead market, market participants can opt to buy their demand at prices far lower than the maximum allowed price (€3000/MWh), but higher than expected market prices. For example, buying the same volume of demand at €200/MWh instead of €3000/MWh reduces the collateral to be posted in order to guarantee the market participant's ability to buy the demanded energy by around 95% while only slightly increasing the risk of not being able to buy electricity at this price.

The figure below illustrates, based on the day-ahead offers and bids submitted to Belpex, the total volume of demand offered at price between €150/MWh and the market clearing price during the day-ahead market minus any balancing attempts by market participants during intra-day (market + OTC). It approximates in other words, the aggregate remaining negative imbalance in the positions of market participants after intra-day. Although it does not explain the total volume of 'other sources' causing the imbalance in the control zone of Elia, it does represent a significant part of it.

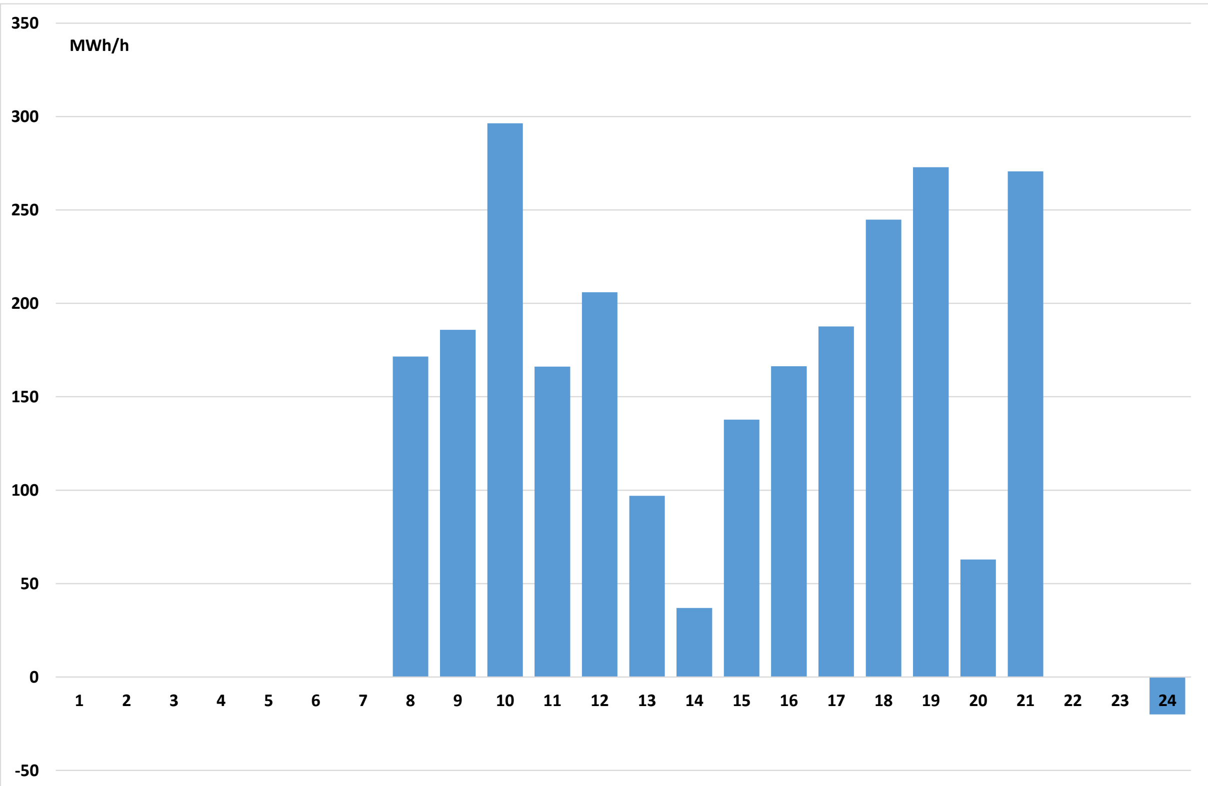


Figure 22 – Difference in volume between unsourced commercial demand volume and the change in nominated intraday schedule versus the nominated schedule in day-ahead
Source: CREG, Belpex, Elia

c) *Forecast errors and activation of balancing reserves*

The figure below shows three curves. The first (blue) one illustrates the reserves activated. The second (orange) one illustrates the difference between the day ahead (DA) load forecast error and the Ibids available, that is the deficit of Ibids volume to cover the load forecast error. The third (dashed) one illustrates the difference between the intraday (ID) load forecast error and the Ibids available, that is the deficit of Ibids volume to cover the load forecast error. In these last two curves, free power on the pumped storage plants is not taken into account.

51. The figure shows that a large part of the activations of R3 on generation units (R3 prod) during the morning is due to load forecast errors that could not be covered with Ibids on thermal generation.

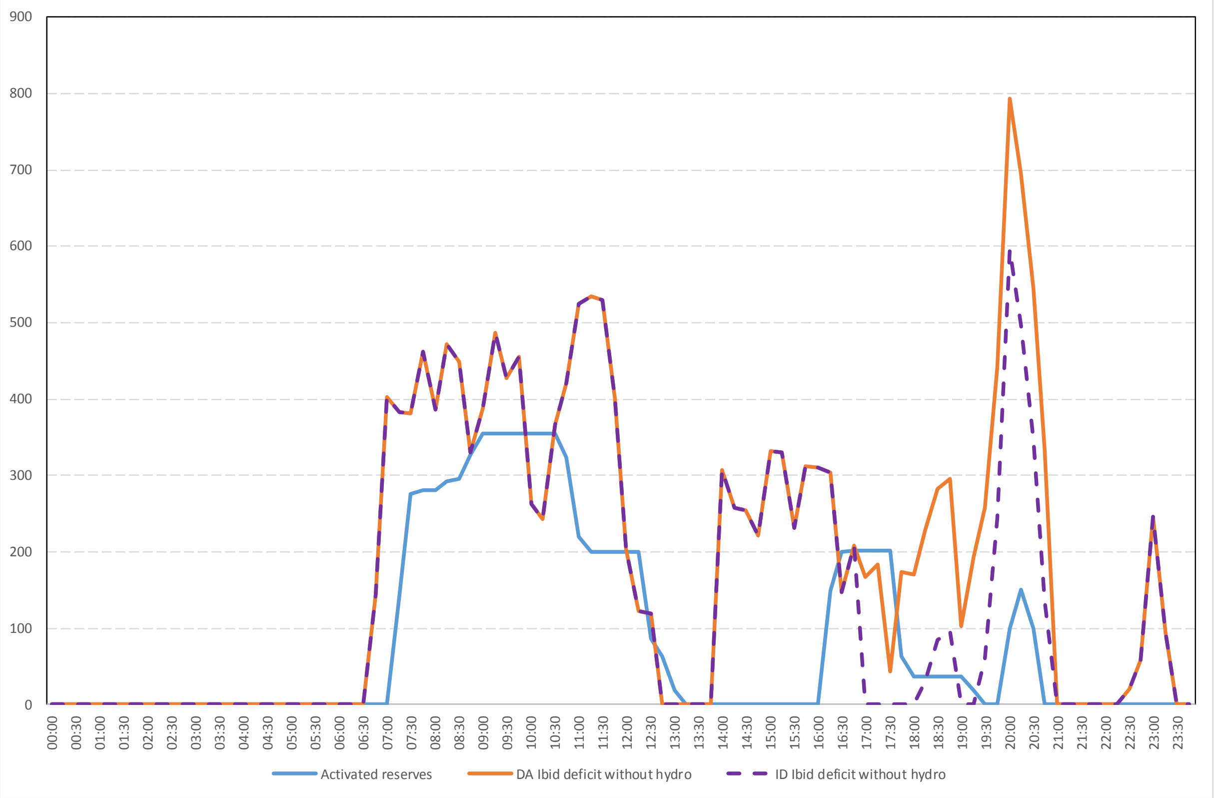


Figure 23 – Activated reserves (blue, MWh/h), difference between the day-ahead (orange) and intraday (dashed) load forecast error and available Ibids (MWh/h)
Source: CREG, Elia

II.3.3 16/10/2015

II.3.3.1 Activation and imbalance price

52. The activated volumes of balancing reserves were relatively high during specific hours of the 16th of October (Figure 24). Especially at hour 11 activated volumes were high, while at hour 19 the imbalance tariff is highest (€798/MWh).

53. In the following analysis, old names of reserve products are used: secondary reserves (R2) for automatic Frequency Restoration Reserve (aFRR) and tertiary reserve (R3) for manual Frequency Restoration Reserves (mFRR). R3 can be done on generation units (R3 production), on dynamic profiles (R3DP) and on interruptible load (R3 ICH).

54. The chart below shows the activations of IGCC and FRR bids (aFRR-R2, mFRR-free bids and reserved mFRR-R3) for the day 16th of October, 2015, as well as the imbalance tariff (blue line with cyan markers).

55. The activation of reserve by the TSO does not fully follow the system imbalance. For example, the peak in system imbalance around quarter 50 coincides with a reduction in net regulating volume. The procedure of activation of reserves at first sight follows the procedure set out in section II.3.1: first R2 is activated up to 140 MW, then tertiary reserves are used to desaturate R2. First, free bids (Bids+) are used, then R3 prod.

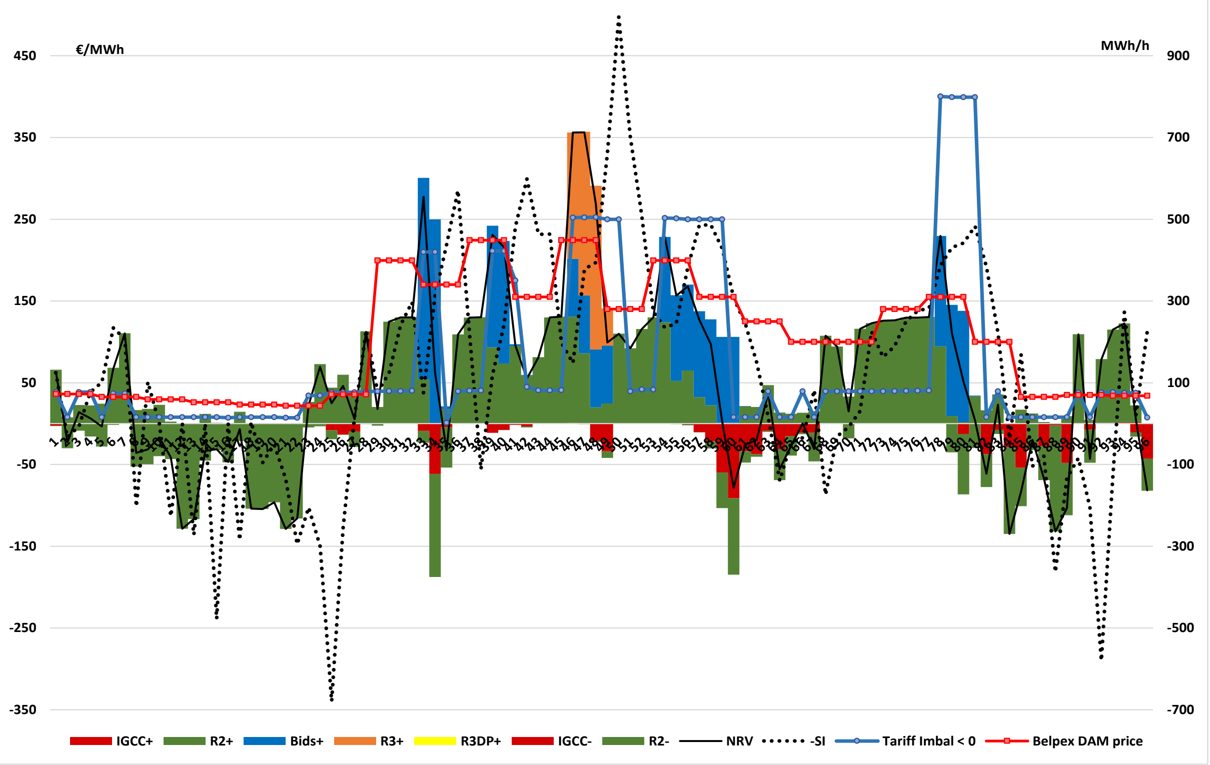


Figure 24 - Balancing energy activated, Belpex DAM prices, and imbalance tariffs for the 16th of October Source: Elia, Belpex

56. Focusing at quarters 19:15-19:45, the only free bids activated are those reserved on a single power plant at an activation price of €798,68/MWh and a total volume of 135 MW. This price and volume compares with a maximum price of €316/MWh for a total volume of 290 MW of still available R3 prod capacity, and a maximum price of €310/MWh at a total incremental volume of 78,6 MW of available ID reserves.

57. Comparing day-ahead (nominations) and real time (activations) bids volume and price characteristics for reserved mFRR on production units (R3 prod) and ID bids, it is clear that similar observations can be made as on the 22nd of September (see paragraph 43).

II.3.3.2 Operation of pumped storage plants

58. The pumped storage turbines of Coo generated 3314 MWh from hour 8 (07:00) onwards until midnight on the 15th of October. On the 16th, from midnight to hour 8, 4179 MWh was pumped to refill the reservoir. From hour 8 to 22 (07:00-22:00) 3370 MWh was again turbined. Given the reflections presented on this topic for the 22nd of September (section II.3.2.2) it seems the full potential of Coo has been exploited.

II.3.3.3 Availability of R3 ICH

59. ICH contracts were not activated on the 16th of September 2015. Similar observations can be made when looking at the relation between availability of ICH reserves and prices (Figure 25 and Figure 26): when the day-ahead price is elevated a reduction in volumes of available ICH reserves is observed.

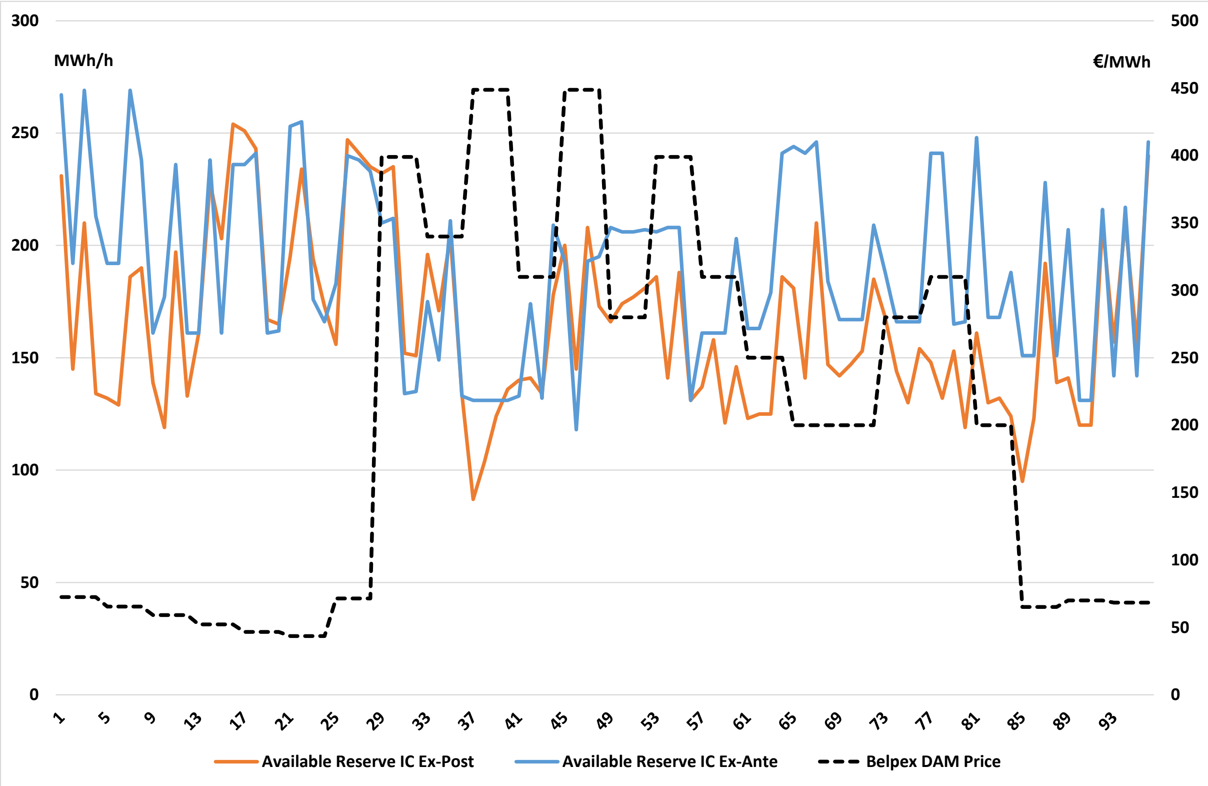


Figure 25 – Ex-ante and ex-post available ICH reserve and the Belpex DAM price
Source: Elia, Belpex

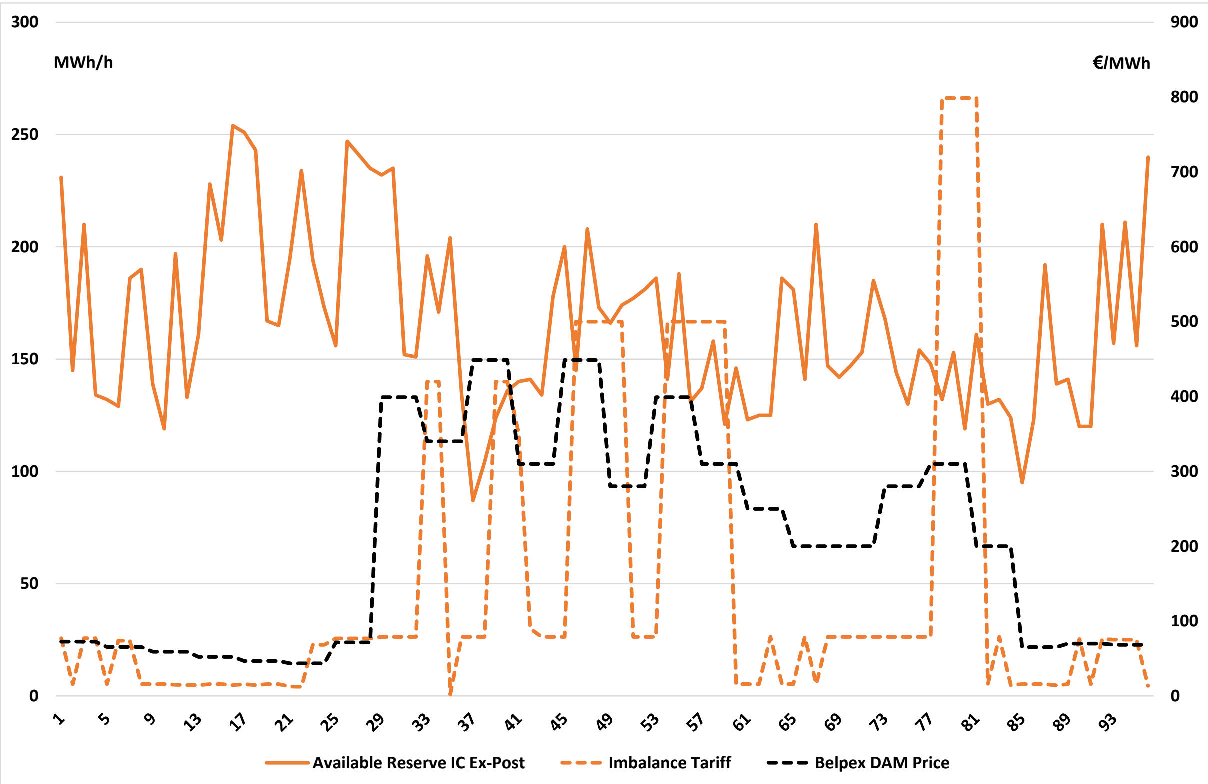


Figure 26 – Ex-post available ICH reserve, the Belpex DAM price, and the Imbalance Tariff
Source: Elia, Belpex

II.4 The CWE-regional scope – Cross-border exchanges

II.4.1 22/09/2015

II.4.1.1 Long-term and day-ahead commercial exchanges

60. For the 21st, 22nd and 23rd of September around 1076 MW of import capacity was nominated on yearly and monthly interconnection capacity from the French to the Belgian bidding zone, and 525 MW from the German to the Dutch bidding zone (Figure 27). On the 23rd 460 MW to 486 MW of long-term nominations were made from the Dutch to the Belgian bidding zone resulting in the nominated commercial exchanges from the German to the Dutch bidding zone almost being fully redirected to the Belgian bidding zone.

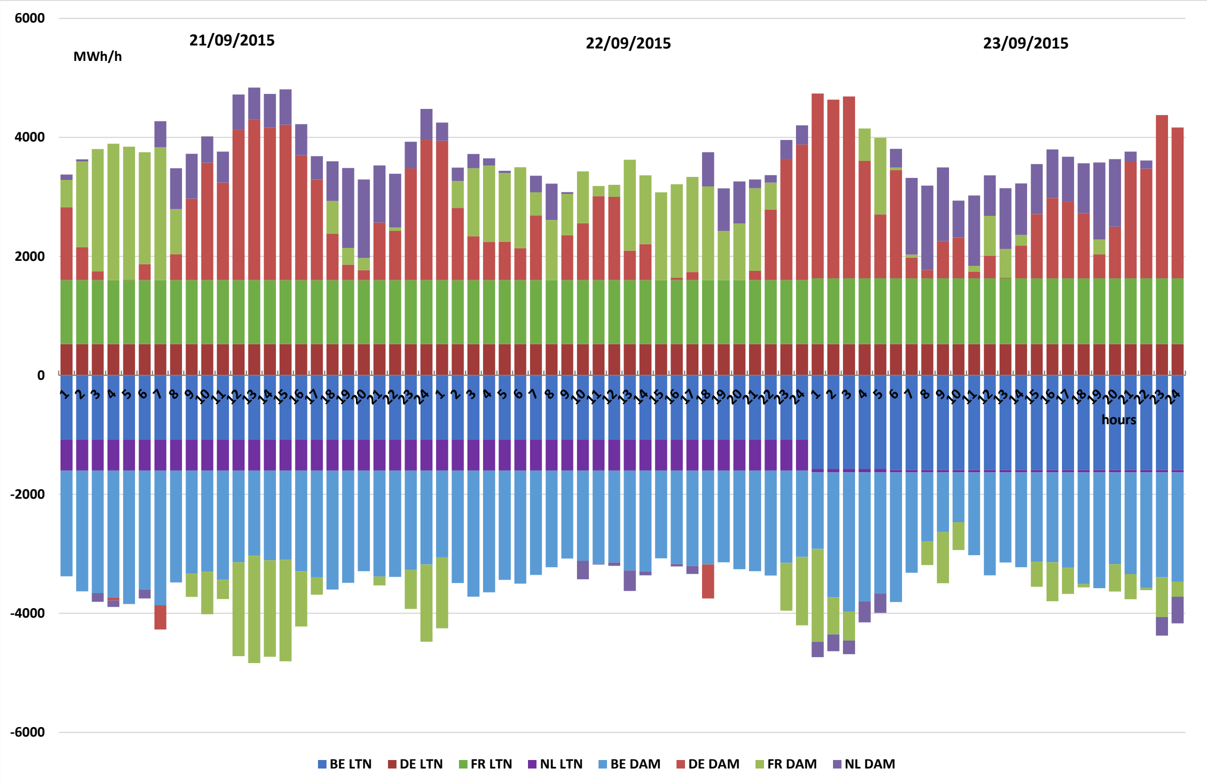


Figure 27 –Commercial exchanges between bidding zones based on long-term nominations of import (negative)/export (positive) volumes, and the allocated commercial exchange volumes during day-ahead by the flow-based algorithm, on the 21st, 22nd, and 23rd of September
Source: Elia, CASC

61. Since the 20th of May the remaining available commercial capacity between bidding zones that are part of the CWE-region is calculated and allocated, on day-ahead, among all bidding zones by the flow-based market coupling irrespective of whether bidding zones are directly connected with each other. The calculated day-ahead commercial capacity for the exchange of electricity is based on a representation of the topology of the grid in the CWE-region. The allocation of this commercial capacity is based on the orders in the order books of

each bidding zone and is a process with multiple steps. Steps 1 to 3 are part of the so-called 'base case', namely the procedure before social welfare optimisation step in the flow-based market coupling:

1) Two days ahead TSOs calculate physical flows resulting from the expected commercial transactions within each of the bidding zones. This leads to the "two days ahead congestion forecast" (D2CF). Some of these flows exit the zone on one place and re-enter the same zone on another place, passing through other bidding zones; these flows are called loop flows (see infra).

2) Early in day ahead, market participants can nominate long-term cross-border capacity.

3) Given this information, TSOs calculate in day ahead the physical flows resulting from internal exchanges, explicit cross-border nominations and other expected transactions. This leads to the "day ahead congestion forecast" (DACF).

4) Based on the "Reference Flows" resulting from the DACF TSOs calculate the remaining capacity on each transmission line that can be given to the day ahead flow-based market coupling. Order books for this auction are closed at 12:00.

It is important to fully grasp the cross-border impact of the first step in the allocation process. A commercial transaction within a large bidding zone, for example the German bidding zone from the renewable-rich north to consumption mainly located in the south (Figure 28, brown arrow) creates a physical flow passing through the Dutch, Belgian, and French bidding zone (and another physical flow through the countries at the east of Germany). These physical flows use the physically available interconnection capacity in a certain direction which in turn lowers the remaining capacity for commercial exchange in the same direction (Figure 28, blue arrow).

In this example, the import capacity from the Dutch to the Belgian bidding zone would be reduced due to the loop flows. Additionally, and at first sight surprisingly, it could lower import capacity from the French bidding zone to the Belgian bidding zone. Indeed, while around 75% of the physical flow will take the direct path, a commercial exchange between France and Belgium also generates a physical flow going through Germany and the Netherlands to Belgium. Annex II shows that loop flows, which cannot be forecasted without uncertainty, almost always decrease the remaining capacity for commercial exchange irrespective of its direction.

Considering the high volumes traded over long distances within the German bidding zone, the volume of loop flows and subsequently the reduction of remaining capacity, can be very significant compared with the commercial transmission capacity made available by the TSOs.

Larger zones can create larger loop flows because of (i) higher exchanged volumes (ii) which can be exchanged over longer distances. The impact of these flows will be explained in more detail in section II.4.2.

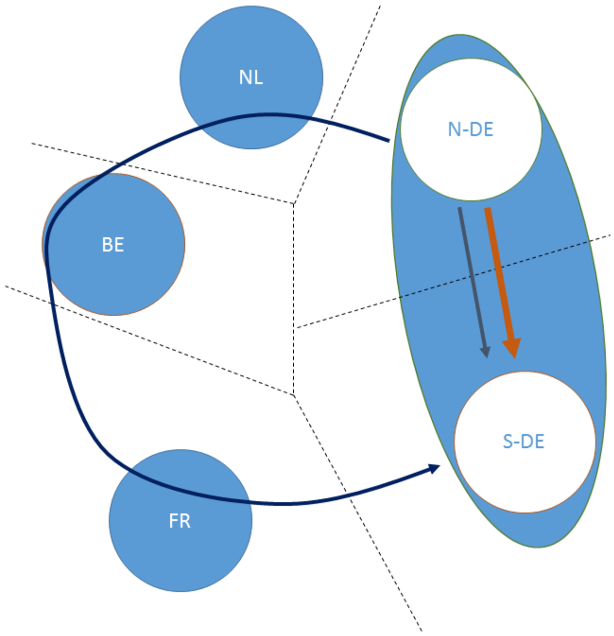


Figure 28 – Commercial flows and generated physical flows after the first step in the flow-based market coupling process, considering the strongly interconnected electricity network in the CWE-region
Source: CREG

62. During all hours of all days, including the 22nd of September, day-ahead commercial exchange volumes aimed at importing electricity to Belgium (Figure 29, Figure 30). There was always congestion, meaning that at least one “critical branch” (a transmission line or other constraint) was active. The average allocated commercial import position to the Belgian bidding zone on day-ahead, during hours 8-21, is 1587 MW. The day-ahead import position at hours 8, 9, and 15 was 1622 MW, 1479 MW, and 1476 MW respectively. Although these hours are characterised by the highest prices in the Belgian bidding zone (€448,7/MWh), the day-ahead allocated net import position during hours 9 and hour 15 is below the average allocated during hours 8-21.

63. On average, on the 21st of September the average daily total net import position of the Belgian bidding zone (i.e. aggregating long-term nominations and allocated day-ahead commercial exchanges) was 2888 MW (Figure 31, Figure 32). Despite higher prices the average daily total net import position on the 22nd of September was 146 MW lower (2742 MW). The total net import position on the 23rd of September increased 523 MW to 3265 MW. Electricity is mainly imported from France and partly from Germany.

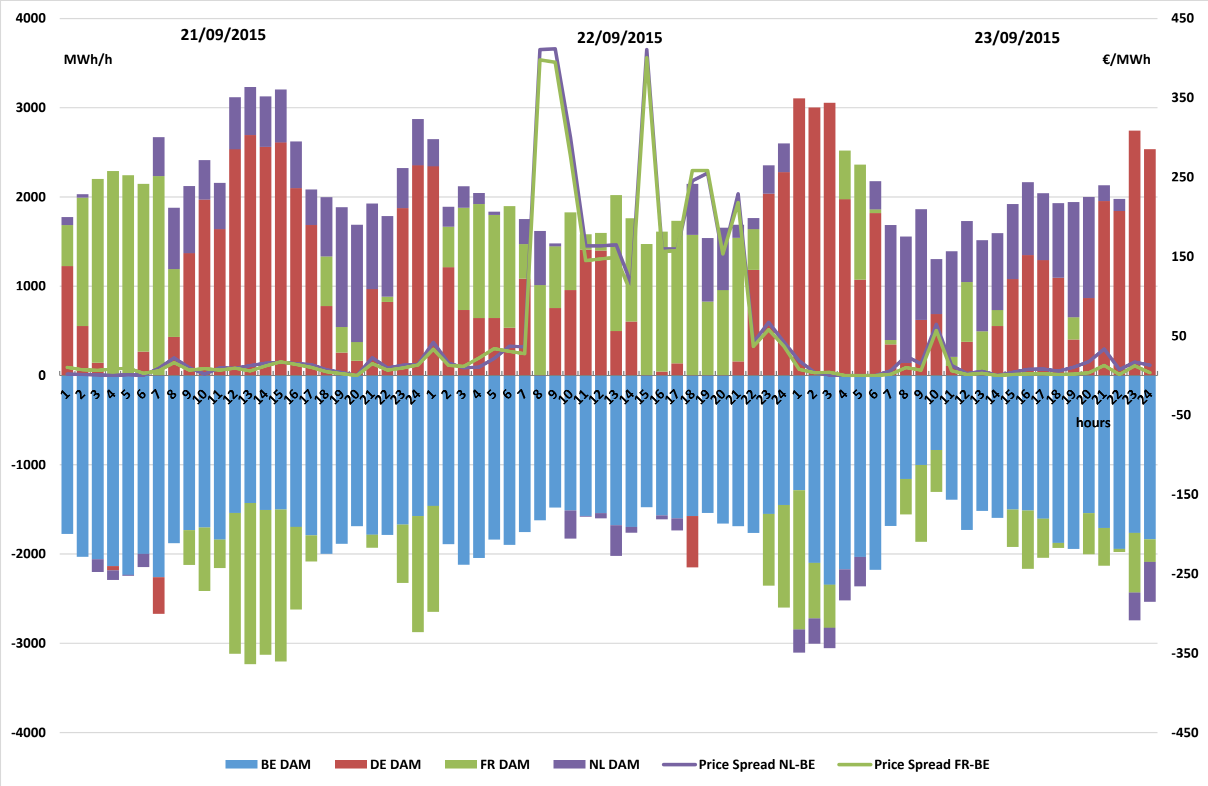


Figure 29 - Allocated commercial exchanges by the flow-based market coupling mechanism between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 21st, 22nd, and 23rd of September.
Source: CASC

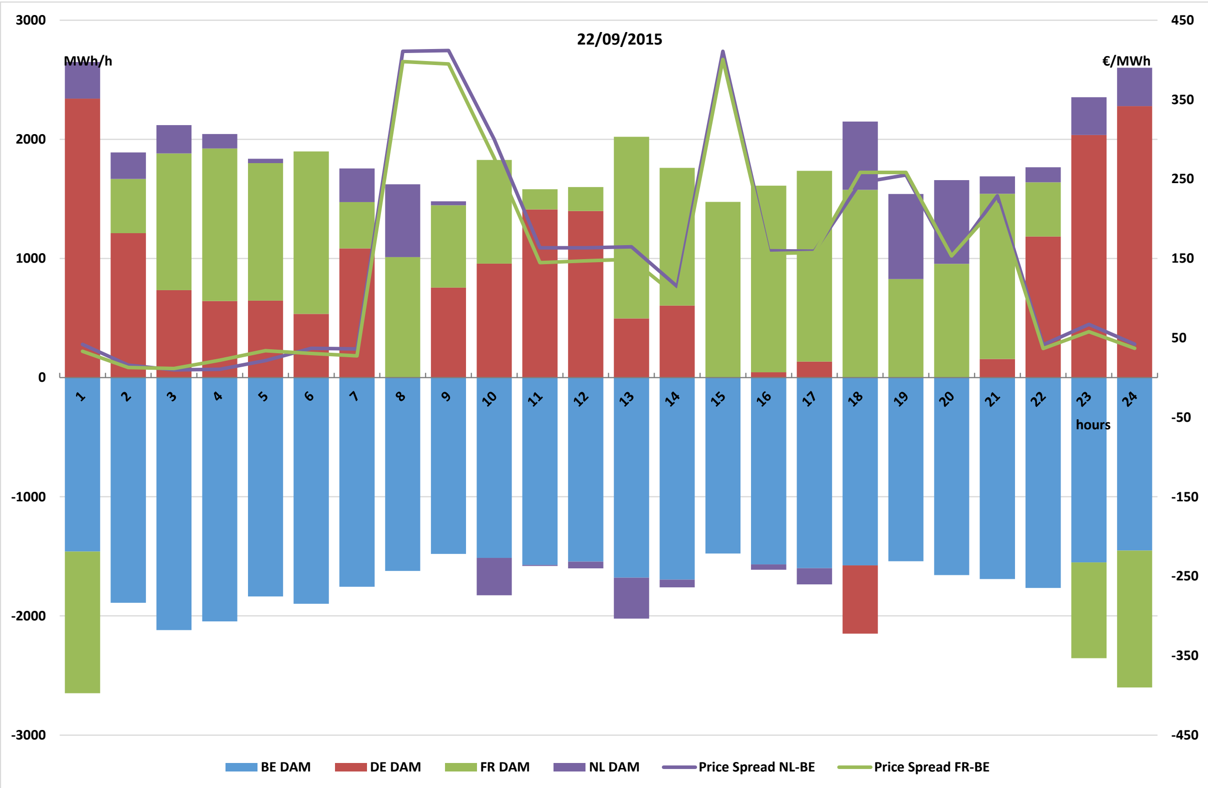


Figure 30 - Allocated commercial exchanges by the flow-based market coupling mechanism between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 22nd of September.
Source: CASC

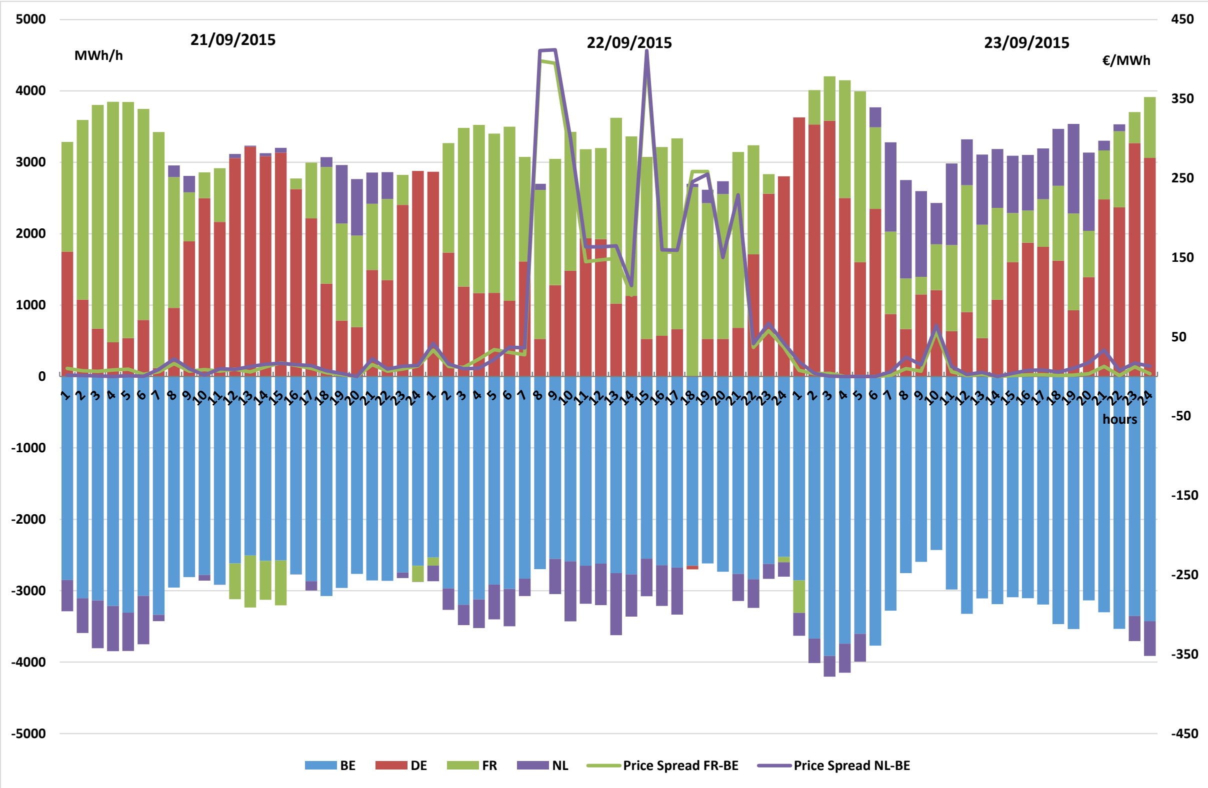


Figure 31 – Net total commercial exchanges between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 21st, 22nd, and 23rd of September.
Source: CASC

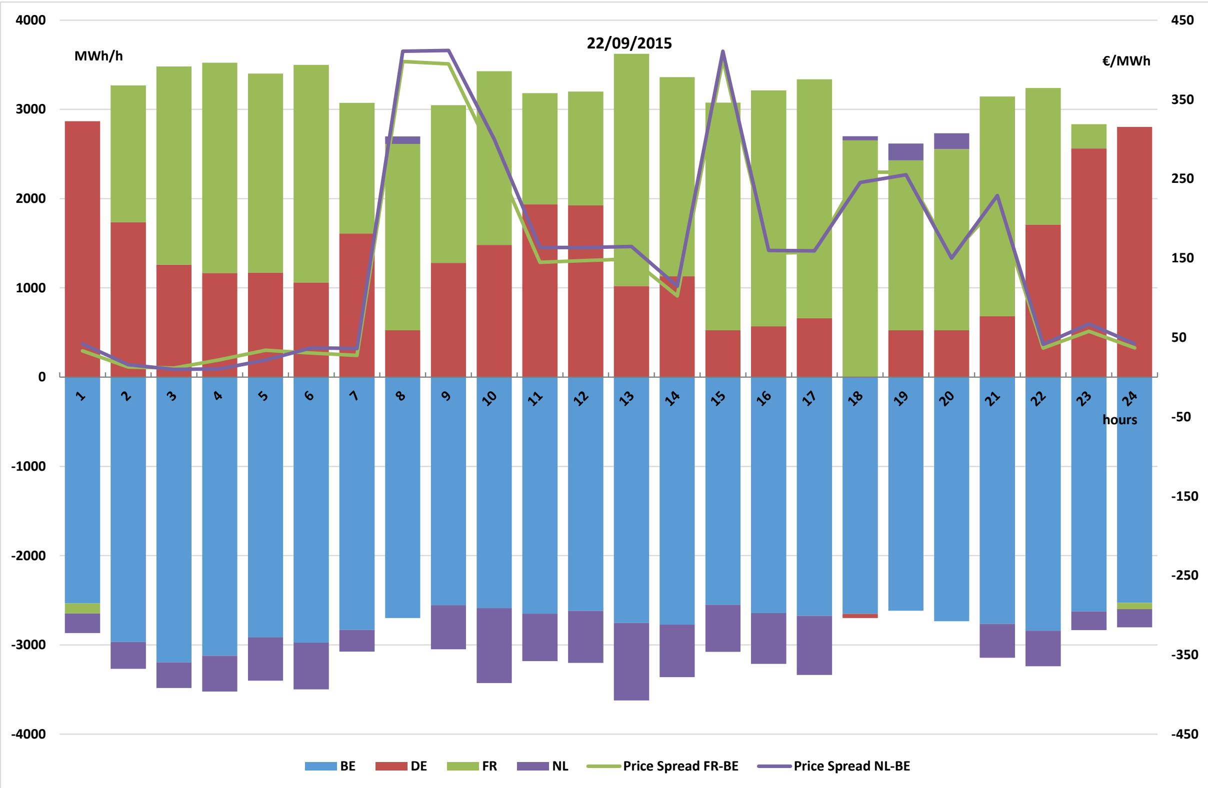


Figure 32 - Net total commercial exchanges between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 22nd of September.
Source: CASC

The total commercially allocated import volumes to the Belgian bidding zone during hours 8-21 on the 22nd of September are on average 2662 MW. The total allocated commercial import capacity at hours 8, 9, and 15 are respectively 2698 MW, 2555 MW, and 2552 MW. These import capacities are all below the minimum guaranteed import capacity under extremely stressful conditions (2750 MW) and far below the expected available import capacity under normal circumstances (4500 MW).

The total physical N-1 cross-border capacity with France is close to 4000 MW in normal conditions; with the Netherlands it is close to 3000 MW in normal conditions. The CREG reminds that physical cross-border capacity is not a synonym but related to the total physical and commercial import capacity.

One could rightly argue that whether or not the full 4500 MW of capacity can be used is dependent of the market situation in neighbouring countries, technical limitations in the Belgian control area (voltage control, short-circuit currents, etc) and technical limitations in neighbouring countries (e.g. congestions on critical branches). The case of the 22nd of September clearly illustrates that non-competitive flows, which cannot be influenced by stakeholders located in the Belgian control area, impact prices to which these stakeholders are exposed. In fact, investments in transmission grid components are required in order to maintain the cited maximum import capacity. It is unacceptable that costs are borne by Belgian stakeholders while they are not exposed to the associated benefits following the increased European market integration, irrespective of how much could actually be imported.

64. Even with significantly higher prices in the Belgian bidding zone the flow-based market algorithm did not allocate more commercial capacity for the import of electricity to the Belgian bidding zone on the 22nd September. Section II.4.1.2 evaluates whether commercial capacity has been made available during intraday. Section II.4.1.3 evaluates which physical flows have emerged given the commercial transactions up to intraday.

II.4.1.2 *Intraday commercial exchanges*

65. During 22 September 2015, there was no available intra-day commercial capacity from France to Belgium. On the Dutch-Belgian border, there was only 200 MW of intra-day capacity available for hours 18 to 21, made available at 14h24, of which 198 MW was nominated. Later on the day (at 18h17), 200 MW was available for hours 22 to 24, of which none was nominated.

66. It is difficult to understand that there was no intra-day capacity made available on the French border. As seen above, physical flows on the French-Belgian border did not exceed

1000 MW during peak hours, very far from the N-1 physical interconnection capacity of about 4000 MW. At the time (September-October 2015), however, there was no calculation of intra-day cross border capacity on the French-Belgian border: only capacity that is left after the day-ahead market coupling is given to the intra-day market. This is clearly not an optimal outcome.

67. But also on the Dutch-Belgian border, physical flows remained relatively low on 22 September during peak hours. The figure below shows the physical flow on the Dutch-Belgian border for 22 September. During night, physical flows are much higher than during the day: the highest physical flow is 3211 MW, the lowest 1626 MW, almost half the highest flow.

68. For hours 8-17, Elia rejected a 200MW increase in intraday import capacity on the Dutch-Belgian border because of technical limitations in Doel-Zandvliet. At 11h30, this limitation was alleviated. From 9h30 to 13h30 Tennet rejected the same increase in intraday import capacity because of limitations on ENS-Lelys.

II.4.1.3 Physical flows

1) Direct and transit flows

69. The relatively low volume of allocated commercial import to Belgium despite price spreads of up to 400 €/MWh requires a deeper analysis of the distribution of physical flows on the borders of Belgium.

70. When there is a commercial exchange from one bidding zone to another, only part of this power transfer will follow the direct path, resulting in the direct flow. The rest will take the indirect path, leading to a so-called transit flow, namely a flow that is generated by a cross-border power transfer that is not taking the direct path of this power transfer (see white lines on the left of Figure 33).

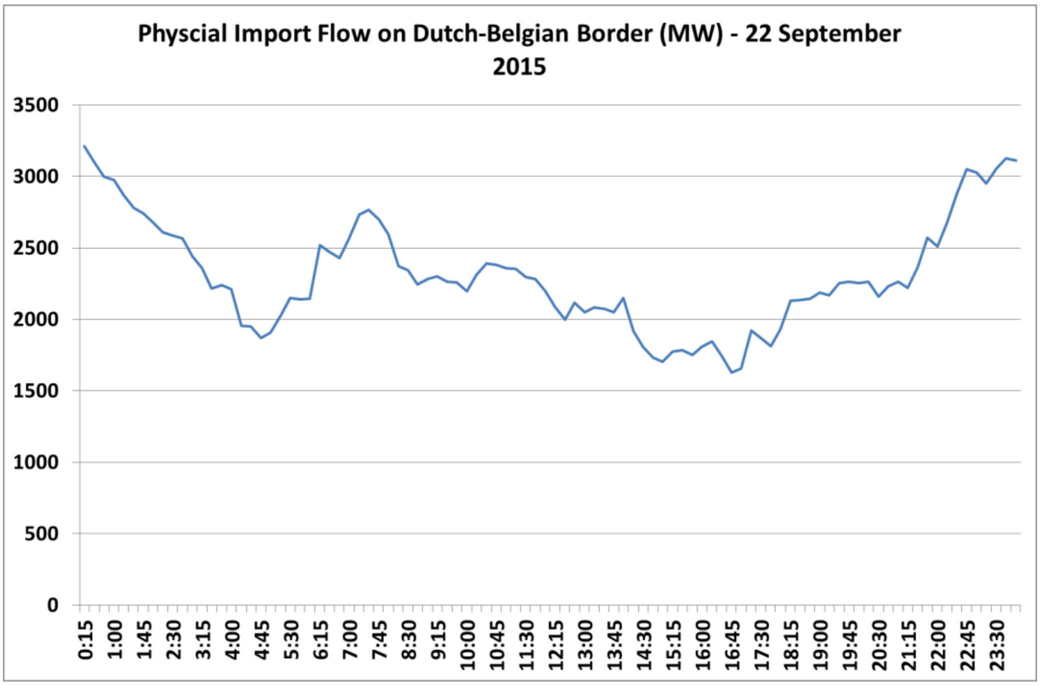


Figure 33 – Physical import flow on Dutch-Belgian border (MW) on 22 September 2015 and 16 October 2015 Source: Elia

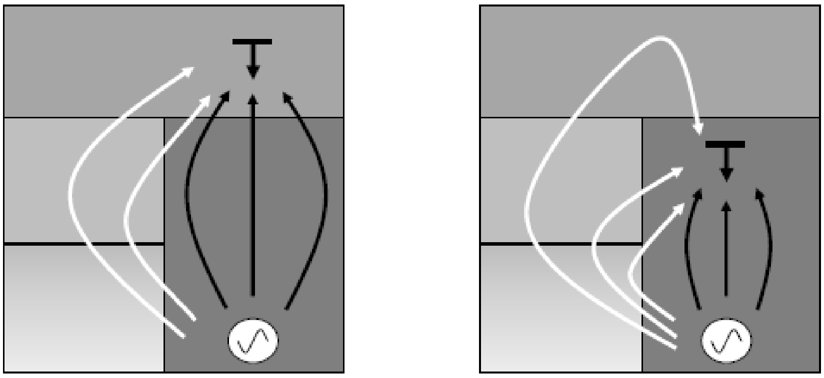


Figure 34 – Transit flows (left) and loop flows (right)
Source: Schavemaker & Beune, 2013

71. For example, if France is exporting 2500 MW to Belgium, as was the case on 22nd September, about 75% of 2500 MW (1875 MW) will be a direct flow going through the transmission lines between France and Belgium. The remaining 25%, will follow the indirect path via Germany and the Netherlands (and via Switzerland, Italy,…) to Belgium. This is called a transit flow: a power transfer between two bidding zone that physically passes through other bidding zones. To summarize, a power shift of 2500 MW from France to Belgium will result in the following physical flows on the Belgian borders:

- 1875 MW physical flow on the French-Belgian border (direct flow)
- 625 MW physical flow on the Dutch-Belgian border (transit flow)

72. Hence, if a large commercial import volume of about 2500 MW from France to Belgium is concluded on the markets, a large physical flow from France to Belgium and a small physical flow from the Netherlands to Belgium is expected. However, the real observed physical flows on the 22nd were exactly the opposite: less than 1000 MW was physically being imported on the French-Belgian border; most of the import was entering via the Dutch-Belgian border, as can be seen on Figure 35.

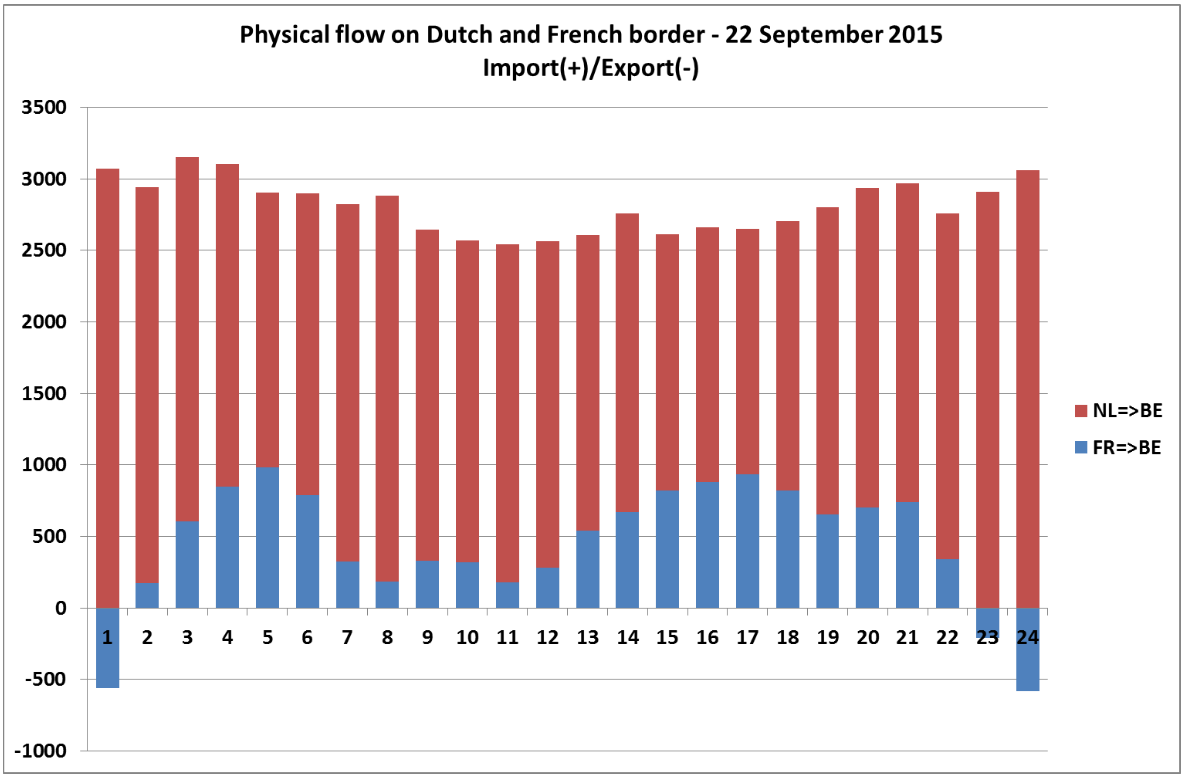


Figure 35 – Measured physical import flows from the Dutch and the French bidding zone
Source: Elia

2) Loop flows and other non-competitive flows

73. The most important explanation for the difference between expected physical flows (due to commercial cross-border exchange) and the real physical flows are <u>non-competitive flows</u> of which the vast majority consists of <u>loop flows</u>. Loop flows are generated by <u>power transfers within one bidding zone</u>, but physically passing through other bidding zones (see white lines on the right Figure 33). Loop flows are non-competitive because intrazonal exchanges are included in the ‘base case’ and have consequently priority access to the total installed transmission capacity, leaving a smaller amount of remaining transmission capacity for the flow-based market coupling to facilitate market-based commercial exchanges.

74. So if 1800 MW of physical flows are measured on the Dutch-Belgian border (as was the case for example during hour 15 on 22 September) whereas only 625 MW was expected

due to the imports from France, 1175 MW out of 1800 MW on the Dutch-Belgian border are (mostly) loop flows[16] (1800 MW – 625 MW = 1175 MW).

75. This means that 65% of the physical flow on this border are non-competitive flows, meaning that these flows are estimated in the 'base case', the step *before* the market coupling, and are not put in competition with flows resulting from commercial exchange within the market coupling. Since these flows are not put into competition with flows generated by the flow-based market coupling, a market participant cannot outbid these non-competitive flows: market participants in Belgium were obliged to pay up to 400 €/MWh more than in other bidding zones without being able to decrease the non-competitive flows calculated in the base case. This clearly results in an inefficient market outcome and hence a loss of welfare in the region.

76. Even if a market participant in Belgium is obliged to pay the maximal price on the power exchange, whatever this price level is[17], these non-competitive flows will not be influenced. This means an increased risk for security of supply due to inefficient and discriminatory use of cross-border interconnection capacity.

77. By far the largest part of these non-competitive flows during the price spikes on 22 September 2015 were loop flows, namely flows generated by commercial exchange within one bidding zone. A small part of these non-competitive flows are generated by commercial cross-border exchange between bidding zones where at least one bidding zone is not in the flow-based market coupling, for example a commercial exchange from Denmark to Italy or Spain.

78. As a conclusion for the observations on 22 September, the combination of loop flows with several other constraints in the grid have caused the price peaks:

a) Absence of loop flows would have strongly mitigated the price spikes in the given technically constrained grid situation.

b) Absence of the other grid constraints would also have allowed to mitigate the price spikes by buy and sell transactions with and between neighbouring zones, partially offsetting the loop flows.

79. Annex I of this working paper gives a more detailed calculation of the non-competitive flows on 22 September 2015.

[16] A part of these flows may also be generated by exchanges outside the capacity calculation region (see also below).
[17] Currently, the price cap on the day ahead markets is 3000 €/MWh.

80. Annex II of this working paper illustrates with a simplified example the effect of loop flows in general on the available transmission capacity.

II.4.2 16/10/2015

II.4.2.1 Long-term and day-ahead commercial exchanges

81. The Belgian bidding zone is commercially consistently importing between 2430 MW and 3347 MW. The exporting country is Germany during off-peak hours and France during peak hours.

Focusing on long term nominated volumes, on the 15th the Belgian bidding zone is importing around 200 MW extra volume from the Dutch bidding zone. There does not seem to be a significant impact on the total commercially allocated import capacity towards the Belgian bidding zone. The maximum net position for import that could be allocated to the Belgian bidding zone was reduced by on average 260 MW during the day and 212 MW during hours 8-21. Similarly, the maximum capacity that could be allocated on the 14th is similar to the one allocated on the 15th.

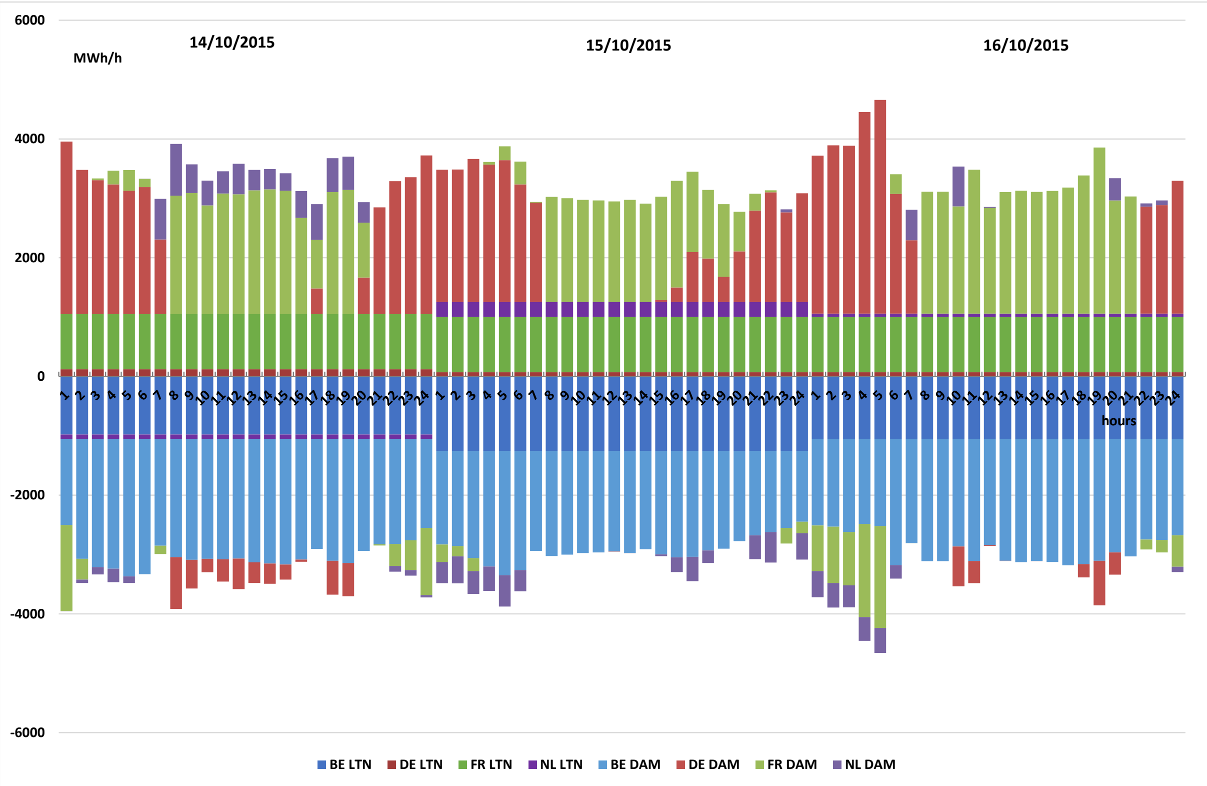


Figure 36 – Commercial exchanges between bidding zones based on long-term nominations of import (negative)/export (positive) volumes, and the allocated commercial exchange volumes during day-ahead by the flow-based algorithm, on the 14th, 15th, and 16th of October
Source: Elia, CASC

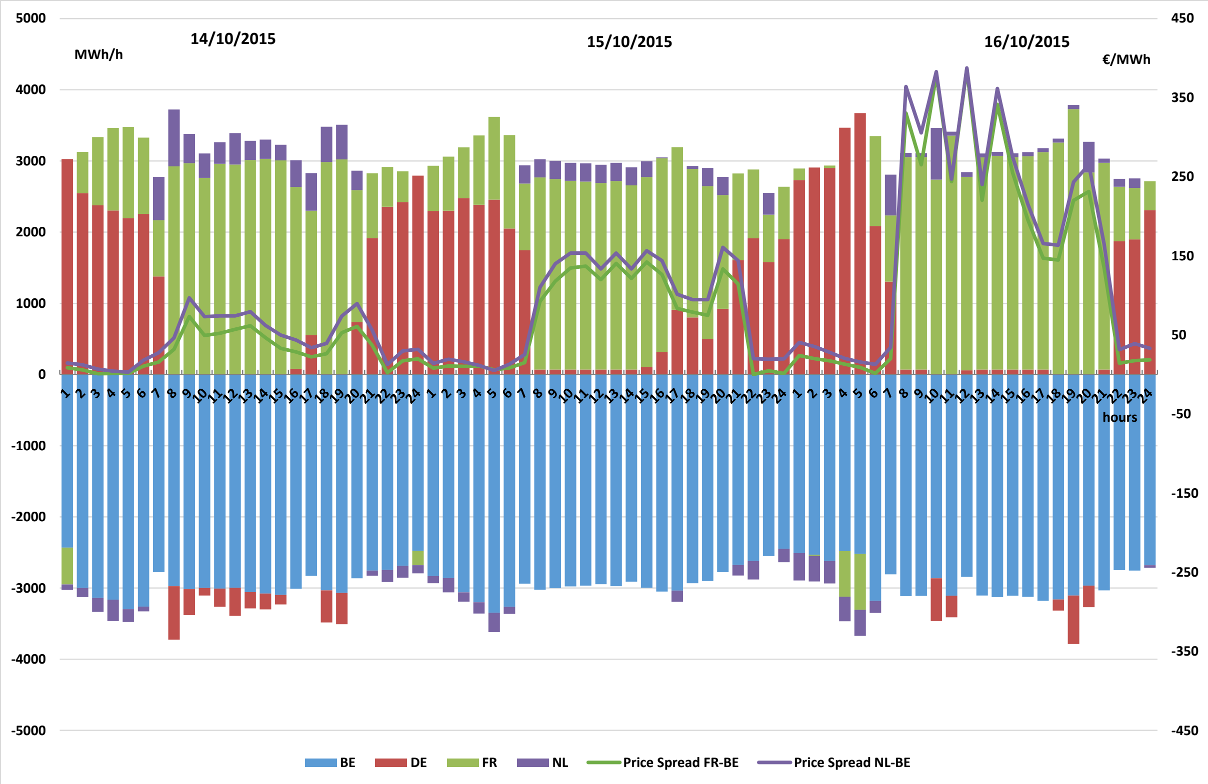


Figure 37 – Allocated commercial exchanges by the flow-based market coupling mechanism between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 14th, 15th, and 16th of October.
Source: CASC

82. The occurrence of elevated prices is correlated with energy being imported from the French bidding zone. In contrast to the observations made on the 22nd, the Belgian bidding zone is the sole importing bidding zone on the majority of the hours when prices are elevated. However, during price peaks on the 16th the German bidding zone is importing as well which is counterintuitive as the German bidding zone had far lower prices than the Belgian bidding zone. Note that the Dutch bidding zone had the cheapest prices during the three days, while the French bidding zone was the second most expensive market.

II.4.2.2 Intraday commercial exchanges

83. Commercial intraday exchanges remained low. Nominated intraday capacity only occurred at hours 14 (26 MW), 15 (51 MW), 16 (19 MW), and 19 (20 MW) on the 15th of October, and at hours 18 (11 MW) and 19 (56 MW) on the 16th of October. During all other hours, no nominations have been done.

Intra-day capacity was also available on the market on the 15th at hour 16 (11 MW), hour 17 (21 MW), hour 18 (9 MW), and hour 21 (7 MW). On the 16th intraday capacity was available at hour 17 (6 MW), hour 18 (24 MW)

II.4.2.3 Physical flows

84. The physical flows as measured by Elia illustrates a large volume of electricity imported from the Netherlands while import volumes from France fluctuate in a range of 1000 MW import and 1500 MW export. Note that the physical import volume from France is mainly negative during periods of elevated prices. Similarly to the case of the 22nd of September, the physical reality does not correspond with the commercial volumes reported.

85. The discrepancy between commercial import volumes and physical flows can only be explained by loop flows. A reference is made to the explanation in section II.4.1.3. Approximating the difference in volume of the expected physical flows because of commercial transactions and observed physical flows, on average during hours 8-21, this would amount to 1495 MW on the 14th, 1768 MW on the 15th, and 1981 MW on the 16th. There is clearly a correlation between the level of elevated prices and the volume of non-competitive flows.

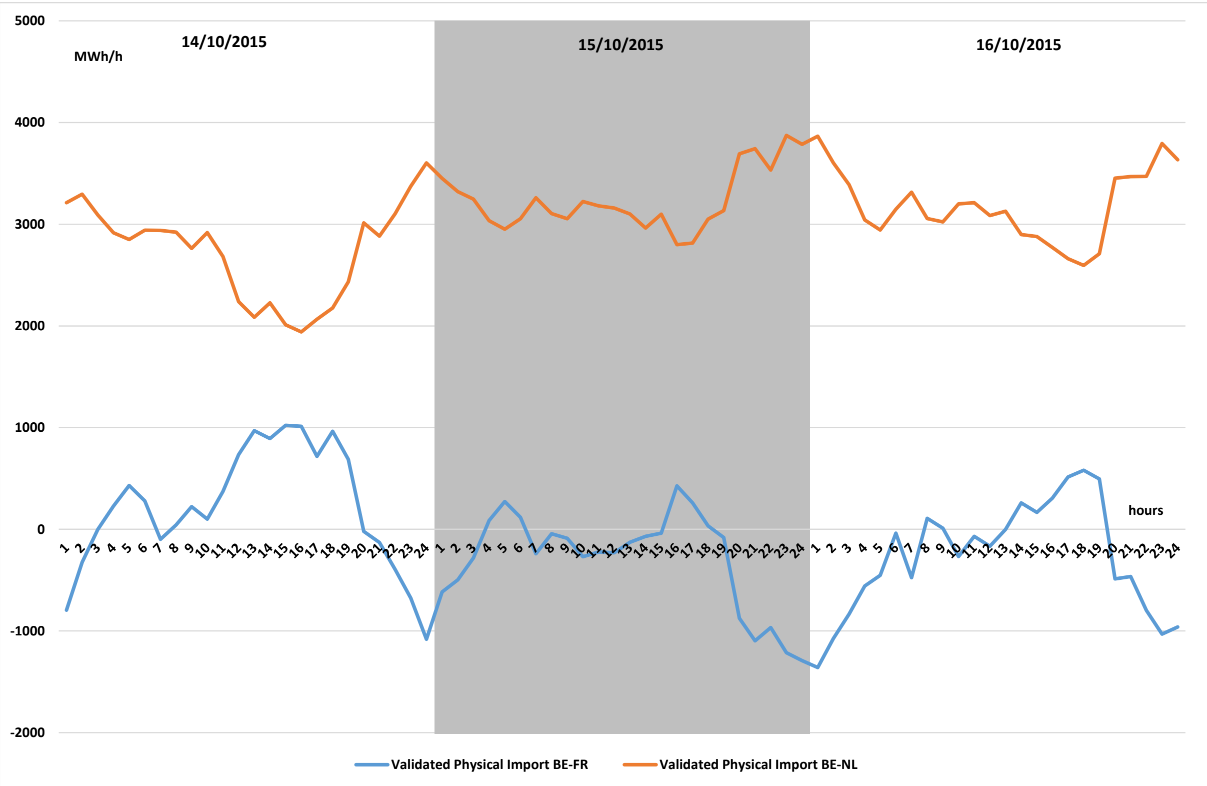


Figure 38 – Measured physical import flows from the Dutch and the French bidding zone on the 14th, 15th, and 16th of October
Source: Elia

II.4.3 Synthesis

86. The expected physical flows resulting from commercial day-ahead exchanges do not correspond with the observed physical flows. The discrepancy is explained by non-competitive

flows of which the majority is attributed to loop flows and the minority to assumptions made within the framework of the hybrid flow-based market coupling. These loop flows are not insignificant compared with the physically available interconnection capacity: the average volume of non-competitive flows observed during hours 8-21 is 1358 MW on the 22nd of September and 1981 MW on the 16th of October.

II.5 Considerations and solutions

87. The above analysis, of which the analysis of the 22nd of September was discussed with and confirmed by Elia, leads to the conclusion that non-competitive flows, for the largest part consisting of loop flows, can make up (sometimes much) more than half of the observed physical flows on Belgian borders. This occurs even if market participants are paying very high prices, much higher than in other countries.

88. Until the end of October 2015, there were three PSTs in the Elia control area near the Dutch-Belgian border; one PST, located in Zandvliet, was unavailable during September and October due to installation works of a fourth PST. This fourth PST went into service at the end of October 2015. There are 18 taps on each PST and 6 taps of all four PSTs can be used to limit the volume of non-competitive flows. Since a single TSO cannot unilaterally determine the rules without coordination, the CREG insists that Elia investigates with the other TSOs of the CWE region:

a) the possibility to use PSTs to reduce loop flows in the 'base case'

b) the possibility to use more than 6 taps of the PSTs. However, it has to be taken into account that not all taps can be used during capacity calculation because between D-2 and real-time many deviations can occur and sufficient regulation margin has to be kept available in order not to endanger grid security.

89. It is acknowledged that re-dispatching within a bidding zone can be used to manage the intra-zonal congestions, with as consequence that the volume of loop flows in neighbouring areas can be limited. In order for such measures to be effective in reducing market constraints, it is necessary to adequately take into account the effects of these measures in the calculations of the base case from D-2 on.

90. The CREG supports these solutions that are being put forward by Elia. Given the legal consequences of this clear discrimination between cross-border commercial exchange and commercial exchange within one bidding zone, these quick solutions should be implemented relatively easily with the goal to increase efficiency, security of supply and, as mentioned

before, decrease discrimination between internal and cross-border commercial exchanges. This is a necessary condition for the European internal market and the Energy Union.

91. However, to come to a structural and efficient solution, an adequate delineation of the bidding zones needs to be implemented as quickly as possible. It is without any doubt that if large bidding zones would have been split into adequate, and thus smaller, zones, loop flows would have been much smaller, leading to more transmission capacity available for flow-based market coupling. Splitting a large zone will transform some internal commercial transactions into cross-zonal commercial exchanges. Therefore, smaller zones will decrease the volume of (loop) flows which are present in the base case. Given that Belgian market participants were willing to pay high prices, imports to the Belgian bidding zone would have been higher which would have resulted in lower prices and higher welfare overall in the CWE-region.

92. There is some opposition against breaking up large bidding zones, claiming a negative impact on liquidity and an increase of the possibility to exercise market power. The CREG disagrees with this view, as was also written in the CREG decision 1410 of 23 April 2015 on the flow-based market coupling (see §222): smaller zones will lead to higher available transmission capacities for commercial exchange and hence will increase competition. Moreover, larger zones need more frequent internal corrective re-dispatch measures which reduce transparency on the efficiency of the market outcome (with the TSO as a sole buyer passing through costs to consumer via network tariffs and producers with more market power at the moment of the need for re-dispatch). The argument of higher possibility to exercise market power in smaller bidding zones is also dismissed by Harvey and Hogan[18]:

> *One principle often applied is that the existence of local market power must necessarily be exacerbated in a market model that applies nodal pricing principles. The argument is that if the prices are different at every node, so must be the markets and, therefore, use of nodal pricing must enhance the ability of the monopolist to increase its profits. A common conclusion follows that administrative aggregation of many nodes into larger zones would ensure competition across a wider area and constrain this power of the monopolist. Hence, nodal pricing or splitting of zones should be pursued only when there is workable competition at each node or in each new zone.*
>
> *This argument is incorrect. In fact, as stated it is exactly backwards. Other things being equal, zonal pricing always subsidizes the dominant local generator and increases monopoly profits above those that would occur under nodal pricing.*

93. The CREG wants to stress that reducing loop flows means increasing the capacity available for commercial exchanges in the flow-based market coupling for all market

[18] See Scott M. Harvey and William W. Hogan, "Nodal and Zonal Congestion Management and the Exercise of Market Power," January 10, 2000, http://www.hks.harvard.edu/fs/whogan/zonal_jan10.pdf

participants taking part in the market coupling, not only for market participants in Belgium: available commercial capacity will be accessed by the transactions that are creating the largest welfare, regardless whether the involving market participants are situated in Belgium or any other bidding zone in the market coupling.

94. Finally, the CREG insists that Elia uses the results of its one year experience with dynamic line rating for explicitly increasing (or sometimes decreasing) the day ahead transmission capacity that is used as input for the day ahead flow-based market coupling. Dynamic line rating is a technique that calculates the real capacity of a transmission line based on the (expected) atmospheric conditions, such as wind speed and ambient temperature. Since the end of 2014, dynamic line rating is used by Elia in real-time. A reasonably sufficient level of experience with dynamic line rating in real time is soon expected to start integrating dynamic line rating when calculating interconnection capacities in day-ahead and intraday. The CREG considers it a breach of law, if Elia does not aptly use the additional information of dynamic line rating for calculating the available commercial capacity on its transmission lines.

II.5.1 Legal consequences of loop flows and other non-competitive flows

95. The result of the priority access of non-competitive flows leads to welfare losses and higher risks for security of supply. It is also a clear discrimination between cross-border commercial exchange and commercial exchange within one bidding zone.

96. CREG repeatedly criticized this discrimination, also in §§120-127 of its decision 1410 of 23 April 2015 on the flow-based market coupling[19]:

> *120. The proposed flow-based market coupling is built on a common network model that also meets the coordination requirements related to the use of a common transmission model to manage the interdependent physical flows (transit flows) effectively. However, for effective management of loop flows (from exchanges internal to a zone) there is also a requirement for an appropriate definition of the bidding zones. Therefore, the proposed method is contrary to Article 3.5 of Annex 1 of Regulation 714/2009.*
>
> *121. Using a base case (see paragraph 114 above) as the starting point of the allocation process gives priority to internal exchanges over exchanges between zones. In other words, the proposed method of capacity calculation favours exchanges included in the base case, i.e. exchanges within a country (or a bidding zone) that are always and automatically accepted in contrast to cross-border (or cross-zonal) exchanges that are limited ex ante to country borders (or to zone boundaries). Consequently, the proposed method discriminates against cross-border*

[19] Free translation of §§120-127 of the CREG Decision 1410 of 23 April 2015. Decision 1410 is available in:

- Dutch: http://www.creg.info/pdf/Beslissingen/B1410NL.pdf
- French: http://www.creg.info/pdf/Decisions/B1410FR.pdf

exchanges within the CWE region in favour of internal exchanges[20]. The proposed method is not consistent with Article 16.1 of Regulation 714/2009, which provides that network congestion problems are to be treated with non-discriminatory solutions.

122. The proposed flow-based congestion management method also uses critical branches located both on the interconnections between the bidding zones (country) and within the zones (country). The inclusion of critical branches located within the bidding zones allows network managers to better and more easily take into account the limits of operational security of the system. However, this structural inclusion of the critical branches located within the bidding zones in the congestion management method is not in conformity with Article 1.7 of the Annex of Regulation 714/2009, which specifies that TSOs should not limit (in a regular and structural manner) interconnection capacity in order to solve a congestion problem located within their own control area and if that were the case, a long-term solution must be found.

123. It should also be noted that very often the impact of exchanges between zones on critical branches located inside these zones is very low (PTDF zone to zone of a few percent), and that therefore congestion management on these critical branches through CWE market coupling is particularly ineffective and that internal re-dispatching within the zone (country) could be much more effective.

124. The method used by transmission system operators to calculate the Generation Shift Keys (GSK)[21] can lead to problems of non-compliance with the requirement for a market-based allocation that is contained in Article 16.1 of Regulation 714/2009, insofar as these GSKs are determined by transmission system operators and not by the market. This is why network managers in particular are requested, in section VI.13 below, to make improvements to the proposed method in order to achieve further harmonisation, greater transparency, intervention in the GRT that is reduced as far as possible and better representation (e.g. an automatic inclusion of weather forecasts).

125. As stated in section III.3 above, the application of a flow-based method further complicates the (potential) problems of discrimination of market participants active in small zones to the extent that the applied modelling means that in most cases exchanges between large zones will have priority over exchanges between a large zone and a small zone, which in turn will have priority over exchanges between small zones. For this reason, this issue, called flow factor competition, will be subject to a specific monitoring (see sectionVI.5) and if necessary amendments to the flow-based method.

126. The elements of non-compliance, referred to in paragraphs 120, 121, 122 and 124 above, are inherent in a zonal approach in which the delineation of bidding zones has not been optimised and are all related to the question of the delineation of bidding zones. Article 1.7 of Regulation 714/2009 indicates that transmission system operators must define the portions of the network concerned in and between which congestion management is to apply. The definition of the proper delineation of bidding zones may resolve non-justified discrimination issues of cross-zonal exchanges in favour of internal exchanges and the question of taking into account the issue of critical branches located within bidding zones. In addition, adequate boundaries can limit the 'arbitrary' intervention of TSOs in determining the GSKs. These three issues should be addressed within the framework of the advanced implementation project of

[20] *Among the CWE countries there is no country that consists of multiple bidding zones. However, this should not be the rule: Sweden, Norway, Italy and the United States manage smaller zones or even a nodal system.*

[21] *The impact of GSK is more important for large zones where a poor forecast of the location of production has a greater impact on PTDFs and therefore on prices.*

the guideline on the Capacity Allocation and Congestion Management (CACM Guideline) relative to the review of bidding zones in the Central West, Central East, Northern Italy and Switzerland regions undertaken by Entso-E and supervised by ACER. The CREG considers that these three nonconformities should be treated as part of this pilot project and requests ELIA to actively participate in this project and resolve these three nonconformities.

127. It should be noted here that the issues of non-compliance mentioned in paragraph 126 above need to be addressed at the latest in the context of the implementation of the CACM Guideline (see section I.7 above and paragraph 180 above), which should come into force in June 2015. That is why the conditions laid down in the decision in this area are in line for the most part with those in the new regulation.

II.5.2 "LTA coverage" avoided prices of 3.000 €/MWh

97. The flow-based market coupling on 22 September 2015 was performed with an automatic inclusion of the long term allocated capacities or "LTA coverage" and an import limitation of 4000 MW. CREG has asked Elia to simulate the same day without the LTA coverage and with an import limitation of 4500 MW.

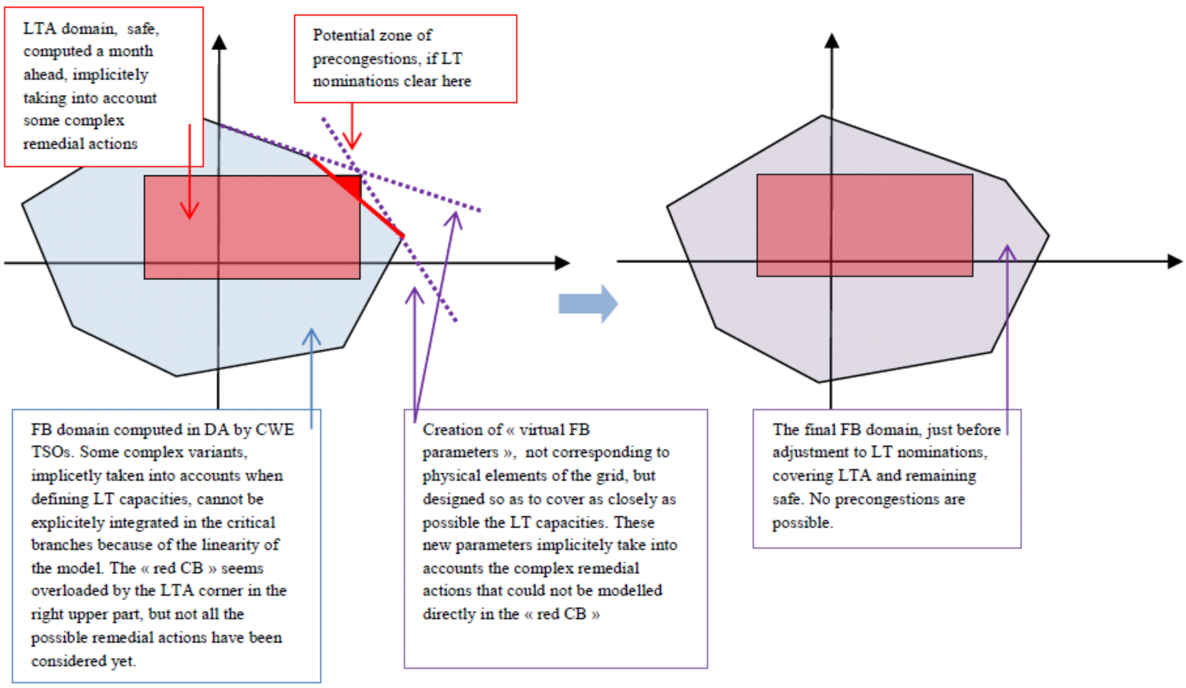
98. The import limitation had only a limited impact on the results. The LTA coverage, however, had a major impact on the exchanged volumes in CWE and on the Belgian prices: the simulated situation results in prices of 3000 €/MWh for nine(!) hours and CWE exchanged volumes are drastically reduced when the LTA coverage is not applied.

99. This section will explain what the LTA coverage does and why it is used, as well as look into the detailed impact of the simulations without LTA coverage.

100. From the flow-based market coupling approval package (annex 16.6 Information regarding LTA inclusion[22]), following definition of the LTA coverage can be used:

The "LTA coverage" method consists in enlarging the FB domain so as to cover long term allocated capacities when they are not fully encompassed by the former. This coverage is performed automatically as a final step of the capacity calculation process (just before adjustment to LT nominations), in case some parts of the FB domain are exceeded by LT allocated capacities (which means that the realization of some long term rights would result in overloads on some flow based critical branches, that is a so called "LTA check failure"). This step results in the creation of "virtual flow based parameters", in the sense that they are not directly related to a physical element of the grid, as illustrated in the sketch below

[22] http://www.casc.eu/media/pdf/FB/Annex%2016_6%20Information%20regarding%20LTA%20inclusion.pdf



101. The Report "CWE Flow Based Market- coupling project: Parallel Run performance report"[23] also delves into the use of the LTA coverage. It states:

> ***In theory**, such artefacts* (i.e. the LTA coverage) *are not to be used: indeed the FB domain gives the reference in terms of security of supply, and CWE TSOs have at hand a selection of remedial actions (RAs), that can be considered at capacity calculation stage (that is, embedded in the critical branches (CB) definition) in order to enlarge the dimensions of the domain. These RAs can be embedded either explicitly within the CB definition (i.e. directly taken into account via a specific load flow computation) or implicitly (via a manual usage of FAV).*
>
> ***In practice,** however, resorting to the "LTA coverage algorithm" can be necessary in case the FB model does not allow TSOs to reproduce exactly some complex operating conditions. For example, if the D2CF model (starting point of FB calculation) reflects a situation with high import in BE, the corners with full BE export are far away from the starting point. In this case, the FB model will most likely not be able to predict the CB loadings in the BE export situation appropriately. In addition, such corners far away from the starting point can be often considered as unlikely (see below). On the other hand, long term rights are safe and firm at the moment of capacity calculation, and therefore need to be covered by the day-ahead capacity domain: which is why CWE TSOs have designed and implemented an algorithm that ensures the coverage of the previously exceeding "LTA corner", but in the same time minimizing the distortion of the initial FB domain. So, LTAs do not overcommit the grid.*

102. In short, it can be said that the LTA inclusion does not coincide with the strict application of the flow-based principles, since it is actually a bypass of critical branches that are defined in a flow-based market coupling setting. It should be seen as an exception measure

[23] http://www.casc.eu/media/Parallel%20Run%20performance%20report%2026-05-2015.pdf

that is meant to cover the Long Term Rights by the day-ahead capacity domain and not as a measure to consistently give more capacity to the market.

103. On 22 September 2015, the LTA coverage principle was applied to enlarge the Flow-Based domain. This particular LTA coverage was bypassing the Doel-Zandvliet critical branch, located in Belgium near the Dutch-Belgian border, so that this critical branch could not become an active constraint in the flow-based market coupling.

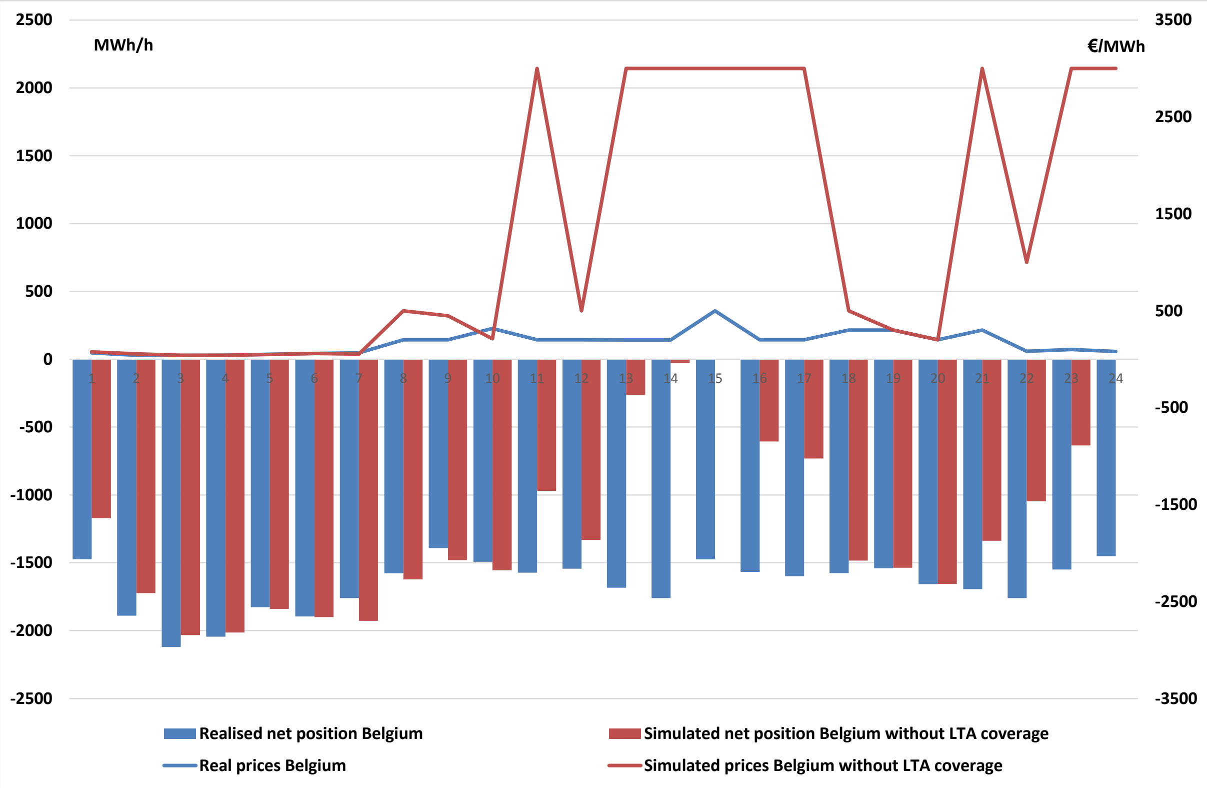


Figure 39: Actual and simulated (without LTA coverage) Belgian net exchange positions and DAM prices on 22/09/2015
Source: CASC, Elia, Belpex

104. Figure 39 clearly shows that without LTA coverage, the import situation in Belgium would have been much worse, with several hours showing no or almost no import in the day-ahead timeframe.

105. It also shows that without LTA coverage, the Belgian DAM prices would have soared to 3000 €/MWh. Hours of 3000 €/MWh coincide with hours where no import is possible on the Belpex DAM. This means that even when offering the maximum price, Belgian cannot import any energy in the day-ahead market.

106. With LTA inclusion, the baseload price on Belpex DAM for 22 September was 188,74 €/MWh. Without LTA inclusion, the baseload price would have been 1293,16 €/MWh, or almost 7 times higher.

107. The starting point in day-ahead is one where the transmission lines are already saturated with flows that do not originate from the market coupling: these are long term nominations, forecasted intraday exchanges, loop flows and flows from exchanges outside CWE. These flows are calculated in the base case (see above). The flows that cannot be put in competition are the main source of congestion, as will be shown hereafter for hour 15.

108. The hour 14:00-15:00 (hour 15) is interesting to look at for the simulation of 22 September 2015 without LTA coverage, since almost no exchanges are made for that hour, meaning the congestion that is apparent in the flow-based market coupling originates from flows that are not subject to market mechanisms.

109. The long term nominations, day-ahead market coupling exchanges and intraday[24] exchanges are presented in the following table.

	FR-BE	BE-FR	NL-BE	BE-NL	NL-DE	DE-NL	FR-DE	DE-FR
Long Term	0	1076	0	0	0	525	0	0
Day Ahead	0	0	0	0	0	0	0	0
Intraday	0	0	0	0	0	207	0	0

Table 2: Exchanges (in MW) via market mechanism on the three relevant time horizons for the hour 14:00-15:00 of 22/9/2015 simulated without LTA coverage.
Source: CASC, Elia

110. The key conclusion that can be drawn from the table above is that even with very low (market-based) exchanges for this particular hour, there would still have been a congestion in the day ahead market coupling that would have led to prices of 3000 €/MWh.

111. The conclusion of this exercise is that almost all of the available transmission capacity in CWE was used by loop flows (or other flows that are not in competition with each other). This would have led to prices of 3000 €/MWh if not for the 'LTA inclusion', which was a particular TSO choice to include it in the approved CWE FB method, and the reasoning of the TSOs to include it had nothing to do with it having a beneficial market impact, let alone avoiding price spikes.

112. While the goal of LTA coverage is covering the allocated long term rights, the secondary effect of offering more capacity (i.e. a larger flow-based domain) to the market, was the reason why prices of 3000€/MWh have been avoided. Concretely the LTA coverage resulted in additional capacity being offered, not only for unlikely market outcomes ("unlikely corner") but also for the likely market outcomes ("likely corners"). It needs to be stressed that, although LTA coverage should be considered as an exception and a non-strict application of

[24] The assumption is made that intraday nominations would not have changed after the situation in Day Ahead, which is different in the simulated case.

the flow-based market coupling method, both the situation with and without LTA coverage were considered as feasible and secure by the TSOs on 22 September 2015: the situation without LTA coverage is the result of the regular application of the flow-based method; the situation with LTA coverage can only be applied with the acceptance of all relevant TSOs. Although both resulting flow-based domains were considered secure by CWE TSOs, they do not have the same impact on prices and exchanged volumes.

113. In other words, the application of LTA coverage was a particular CWE TSO choice to be included in the approved CWE FB method, and the reasoning of the TSOs to include it had nothing to do with it having a beneficial market impact, let alone avoiding price spikes. In this case it had a vast impact on the final outcome of the market coupling and hence on the market prices: with LTA coverage, price peaks of 448.7 €/MWh instead of 3000 €/MWh were noted and a baseload price that is almost 7 times lower than without the 'LTA inclusion'.

114. An additional conclusion is that in a situation without LTA coverage, even with a price of 3000 €/MWh, there would have been very little or (for hour 15) no commercial exchanges importing electricity in Belgium. In other words, even with a price of 3000 €/MWh there was no way to push back loop flows, which is a feature of the current design.

115. Similar observations can be made for the 16th of October (Figure 40). During hours 8 to 23, without LTA coverage, Belgium would have been awarded a net position of zero while prices during the whole 16-hour period would amount to €3000/MWh in contrast to an average of €287/MWh. The result would be an increase in baseload prices from the realised €211,23/MWh to €2149,01/MWh (+917%) At all hours of the day, Belgium would have been awarded lower import net position in absolute terms than with LTA coverage.

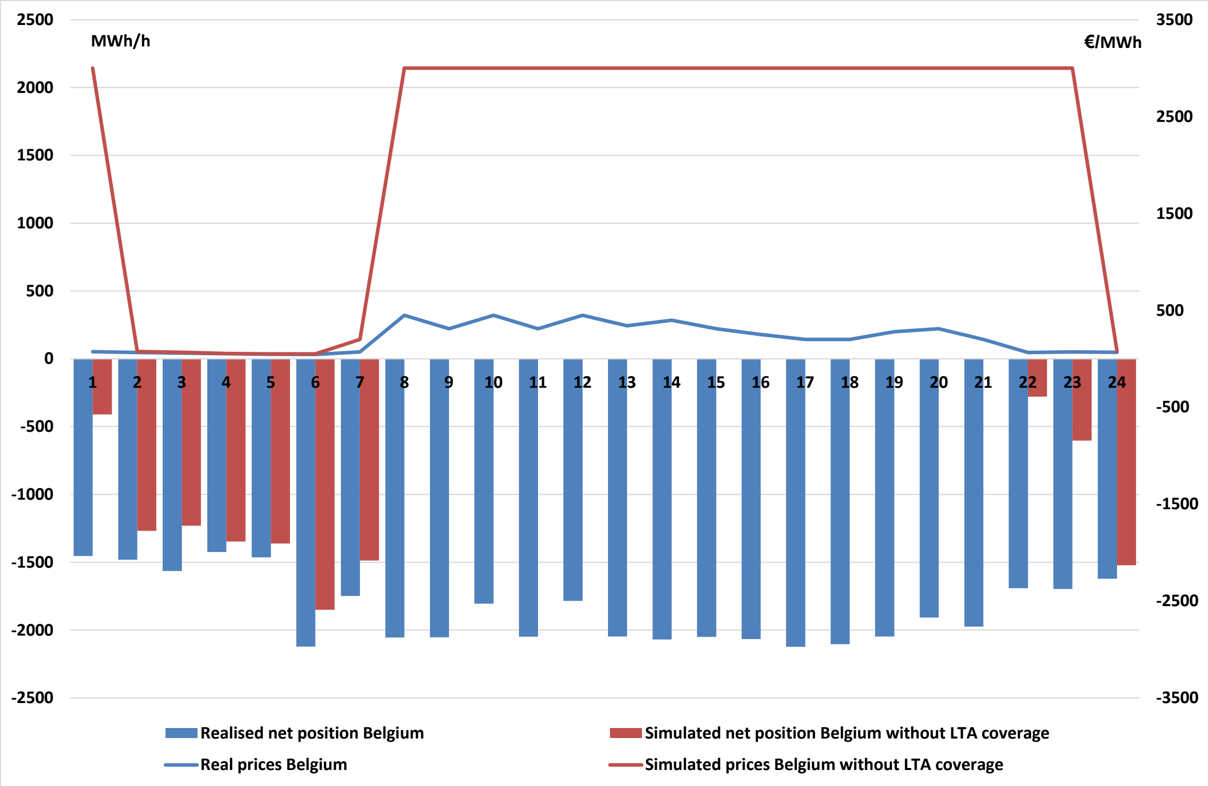


Figure 40 – Realised and simulated (without LTA coverage) Belgian net exchange positions and DAM prices on 16/10/2015
Source: CASC, Elia, Belpex

II.5.3 Advanced hybrid flow-based day ahead market coupling

116. As stated above, apart from loop flows, also transit flows that are not put in competition with flows from the CWE region can impact the usage of CWE critical branches and therefore limit cross-border exchanges in CWE. Although these transit flows were not predominant on the above cases compared to the loop flows, they were still impacting flows through active critical branches and contributed to the import limitations for Belgium in a non-competitive way.

117. At this time, with the current application of flow-based market coupling[25] in the CWE region and ATC capacity calculation and allocation on all other borders, the exchanges on non-CWE borders (both between two non-CWE countries as between a CWE country and a non-CWE country) are not put in full competition with exchanges on CWE borders. A concrete example is a commercial exchange between Norway and Spain that physically utilizes critical branches which limit cross-border commercial exchange in CWE-region. This impact on the critical branch within CWE is currently not taken into account when deciding to exchange between Norway and Spain.

[25] Also referred to as the “rough” Flow-Based ATC hybrid coupling.

118. With the “rough” hybrid coupling TSOs must take the worst hypothesis of ATC exchange when computing flow-based parameters, in order to guarantee the security of supply. With an “advanced” hybrid coupling[26], no such hypothesis is made. Indeed, the ATC transaction on external CWE borders is computed simultaneously, taking into account its influence on all critical branches of the flow-based model. This results overall in more capacity (because not the worst, but the real case is taken into account) and a better use of scarce resources (because the resulting flows are put into competition with each other). This is in fact an enlargement of flow-based main advantage to neighbouring ATC borders. This would ensure that the exchanges over ATC-calculated interconnections would be put in full competition with exchanges within the CWE region.

119. Technically speaking, the market coupling algorithm can apply advanced hybrid coupling to external CWE borders. The algorithm can take into account both FB and ATC constraints, and ensures compatibility between FB areas and ATC areas.

II.5.4 Non-intuitiveness and possible impact on import possibilities

120. Currently the flow-based market coupling is applying an “intuitiveness patch”. This flow-based intuitive approach avoids non-intuitive exchanges where low-priced bidding zones import from higher-priced zones or where high-priced bidding zones export to lower-priced zones. It was a choice from the CWE Project partners and NRAs, based on market consultation to start CWE FBMC with intuitiveness but also to follow-up on the implications.

121. Additional constraints are needed for enforcing the flow-based market coupling to have intuitive results. The CREG is currently examining whether relaxation of (part of) these constraints would enable to increase the import capacities for countries within the CWE region that are faced with very high day-ahead prices. It is possible that by allowing non-intuitive flows, more import capacities are created. As a fictitious example: if export from Germany to the Netherlands were considered to be non-intuitive but nevertheless allowed, possibly additional transport capacities from the Netherlands to Belgium could be given to the market at the same time.

[26] See CWE enhanced Flow-Based MC feasibility report: http://www.casc.eu/media/CWE%20FB%20Publications/CWE_FB-MC_feasibility_report_2.0_19102011.pdf

III. CONCLUSION

122. The elevated day-ahead prices on the 22nd of September and the 16th of October is caused by a combination of the inefficient and discriminatory use of cross-border capacity and low available generation capacity due to planned and forced outages. The analysis of both cases makes it very clear that non-competitive flows, for the largest part loop flows, have priority access to the cross-border capacity, regardless of the scarcity of this capacity or the willingness to pay for it. Sometimes much more than half of the observed physical flow are non-competitive flows. This is even true if market participants are willing to pay the maximal price of 3000 €/MWh[27], which increases the risk for security of supply.

123. This is clearly not compliant with Regulation 714/2009 and its Annex 1.

124. According to the CREG, to be compliant with the Regulation 714/2009 and its Annex 1 at least the following solutions are necessary to achieve an efficient and non-discriminatory use of cross-border capacity. First, the phase shifters should already be used to limit the non-competitive flows in the base case of the flow-based market coupling. Also the possibility of re-dispatching within one bidding zone should be considered in the base case to limit loop flows. This can be done relatively quickly. Second, an increase of the available regulating power on the phase shifters for reducing non-competitive flows should be considered by the TSOs. A clear justification should be given for the decision whether to give more or not. This can be done relatively quickly. Third, the implementation of an advanced hybrid flow-based market coupling should be proposed to the relevant NRAs as fast as possible. Fourth, an analysis of non-intuitive flow-based market coupling should be performed, thereby avoiding small zones can be put at a structural disadvantage with non-intuitive flow-based market coupling. Fifth, the most efficient and sustainable solution is an adequate delineation of the bidding zones. This would solve the problem of the negative impact of loop flows and their priority access to the cross-border capacity.

125. These solutions will increase the efficient and non-discriminatory use of the sometimes very scarce cross-border capacity, not only for Belgian market participants but for all market participants who participate in the flow-based market coupling. These solutions are a necessary condition to achieve the European internal market and Energy Union.

[27] This is shown by the simulation when the 'LTA coverage' would not have been active during the flow-based market coupling, resulting in nine(!) hours with prices of 3.000 €/MWh

126. LTA coverage, where the TSOs ensure the domain of allocated Long Term rights is always covered by the Flow-Based domain, is a CWE TSO choice to include it in the approved CWE FB method, and the reasoning of the TSOs to include it had nothing to do with it having a beneficial market impact or having an impact on market behaviour. A simulation of the market outcome without LTA coverage resulted in nine hours with prices of 3.000 €/MWh and a baseload price 1293 €/MWh on Belpex DAM on 22 September. This is almost seven times higher than with LTA coverage. On the 16^{th} of October Belgium would have been awarded a net position of zero while prices during a 16-hour period would amount to €3000/MWh in contrast to an observed average with LTA coverage of €287/MWh. The result would be an increase in baseload prices from the realised €211,23/MWh to €2149,01/MWh (+917%). This clearly shows choices made by TSOs can have a vast impact on the final outcome of the market coupling and hence on market prices, regardless of the physical context (like the available network and capacity) and the behaviour of producers and consumers.

127. Finally, it seems clear TSOs could have given more cross-border intraday capacity to the market, especially on 22 September 2015. For the French-Belgian border, this was not yet possible. For the Dutch-Belgian border, some capacity has been allocated to and used by the market, but it seems more capacity could have been given.

For the Commission for Electricity and Gas Regulation:

Andreas TIREZ
Director

Marie-Pierre FAUCONNIER
President of the Board

ANNEX I – Calculation of non-competitive flows

128. Based on the net commercial positions (Figure 32) and the Bilateral Exchange Computation procedure proposed by the TSOs in the CWE-region[28], during hour 8, a physical flow from the French to the Belgian bidding zone of around 1850 MW and from the Dutch to the Belgian bidding zone of around 850 MW is calculated. When comparing with the actually observed physical flows of 200 MW from the French bidding zone to the Belgian bidding zone, and 2700 MW from the Dutch to the Belgian bidding zone, approximately 1650 MW of loop flows are occupying the physically available interconnection capacity with Belgium. In other words 61% of the measured flow from the Netherlands to Belgium are not market-driven during hour 8.

129. Similarly, during hour 19, the net physical flows to be expected amount to 1750 MW from the French to the Belgian bidding zone and 900 MW from the Dutch to the Belgian bidding zone. When comparing with the actually observed physical flows of 670 MW from the French bidding zone to the Belgian bidding zone, and 2150 MW from the Dutch to the Belgian bidding zone, around 1100 MW of loop flows are occupying the physically available interconnection capacity with Belgium. In other words, during that hour, 51% of the available transmission line capacity from the Netherlands to Belgium was not used to maintain price convergence between bidding zones.

130. Calculations have been carried out for all hours on the 21st, 22nd and 23rd of September (Figure 41). On average non-competitive flows accounted during each day for 57.6%, 62,6% and 50,3% of the total available physical import capacity on the border between the Netherlands and Belgium. On the 22nd of September, the share of non-competitive flows fluctuates between 49,5% and 75,3%, with a volume of 1050 MW up to 1850 MW during peak hours.

[28] See chapter 12 in https://www.acm.nl/nl/download/bijlage/?id=11810

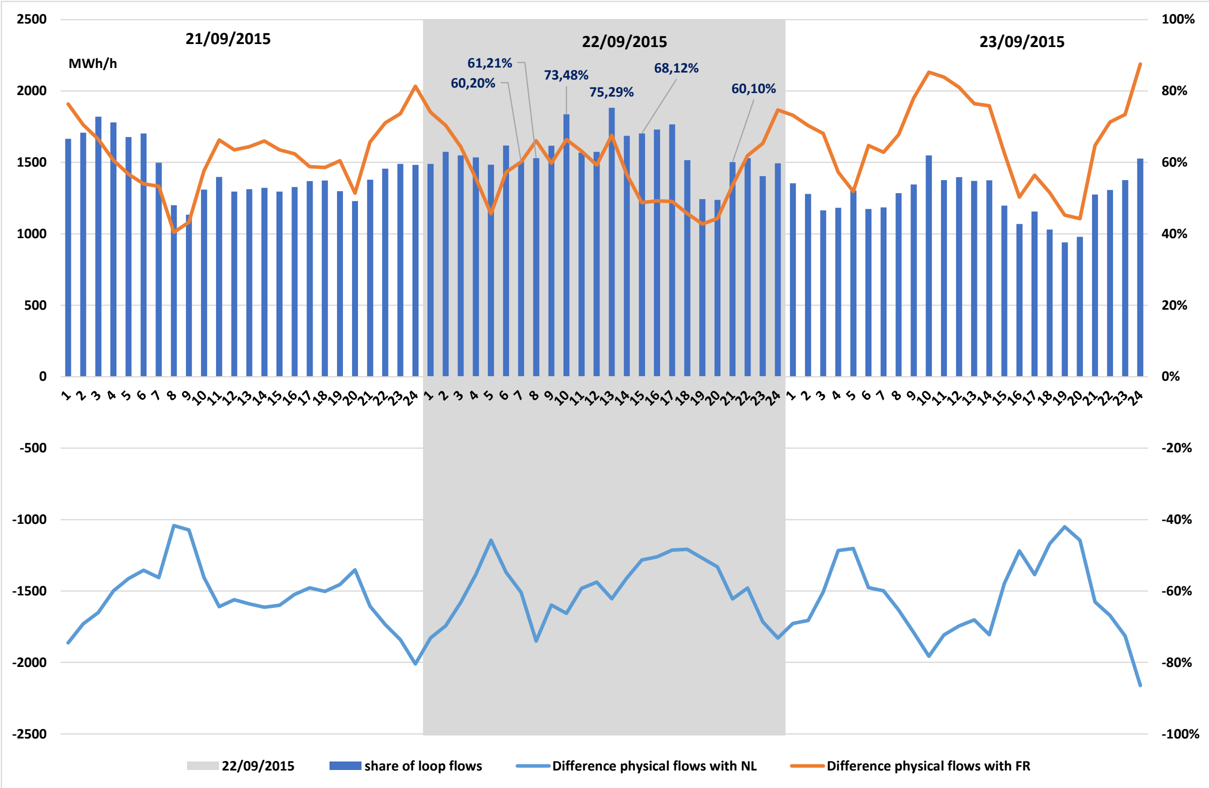


Figure 41 –Difference between measured physical flow and calculated physical flow based on long-term nominated and day-ahead allocated commercial exchanges as a measure for non-competitive flows, including their share relative to the available physical import capacity on the border between the Netherlands and Belgium.. Source: CREG

131. According to a simple analysis performed by the CREG based on supply and demand curves in the Belpex orderbook on the 22nd of September, an increase of 1000 MW of import would have led to market clearing prices in the range of €45/MWh to €55/MWh during hours 8-21.

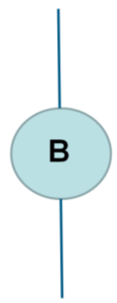
ANNEX II – Impact of loop flows on cross-border capacity – simplified example

132. In this annex it will be shown that even loop flows in the “good” economic direction almost never help and decrease the available commercial transmission capacity for market coupling.

133. Assume a simplified example where Belgium is importing as much as possible from France. The Power Transfer Distribution Factor (PTDF) from France to country Belgium is 0.7 (70% is following the direct path). Hence, the PTDF from the Netherlands to Belgium is 0.3.

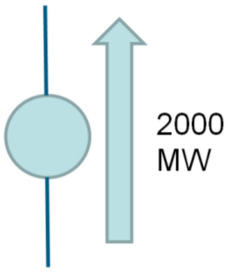
134. Both interconnections have a theoretical capacity of 3000 MW, leading to a total of 6000 MW.

135. Initially, three situations will be compared: one with loop flows of 2000 MW through Belgium from France to the Netherlands, a second with the same loop flow but in the opposite direction and a third without loop flows. For all three situations the maximal import capacity of Belgium will be calculated. Additionally, a more general calculation will be made for different levels of loop flows with and without a forecast error.



a) Situation with loop flow of 2000 MW through Belgium from France to the Netherlands

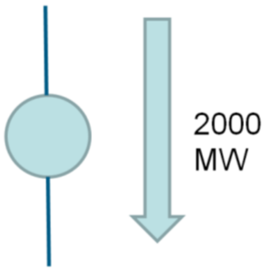
136. Giving the loop flow of 2000 MW from France to the Netherlands and an interconnection capacity of 3000 MW between France and Belgium only 1000 MW is available for importing from France to Belgium. Given the PTDF from France to Belgium of 0.7, Belgium can import 1000 MW / 0.7 = 1429 MW from France. This will result in a direct flow of 1000 MW from France to Belgium and an transit flow of 429 MW from the Netherlands to Belgium.



b) Situation with loop flow of 2000 MW through Belgium from the Netherlands to France

137. Giving the loop flow of 2000 MW from the Netherlands to France and an interconnection capacity of 3000 MW between France and Belgium there is 5000 MW available on the interconnection between France and Belgium for importing from France to Belgium.

138. One would think loop flows are helping the import from France to the Netherlands. However, importing 1 MW from France to Belgium also leads to a transit flow of 0.3 MW from the Netherlands to Belgium. So, if Belgium would actually import 5000 MW from France, this would result in a transit flow of 5000 MW * 0.3 = 1500 MW. However, given the fact that there is already a loop flow of 2000 MW in this direction, this would lead to an insecure situation and cannot be accepted. This means the remaining interconnection capacity from the Netherlands to Belgium is the limiting factor. The maximal import is then (3000-2000) / 0.3 = <u>3333 MW</u>.



c) No loop flows

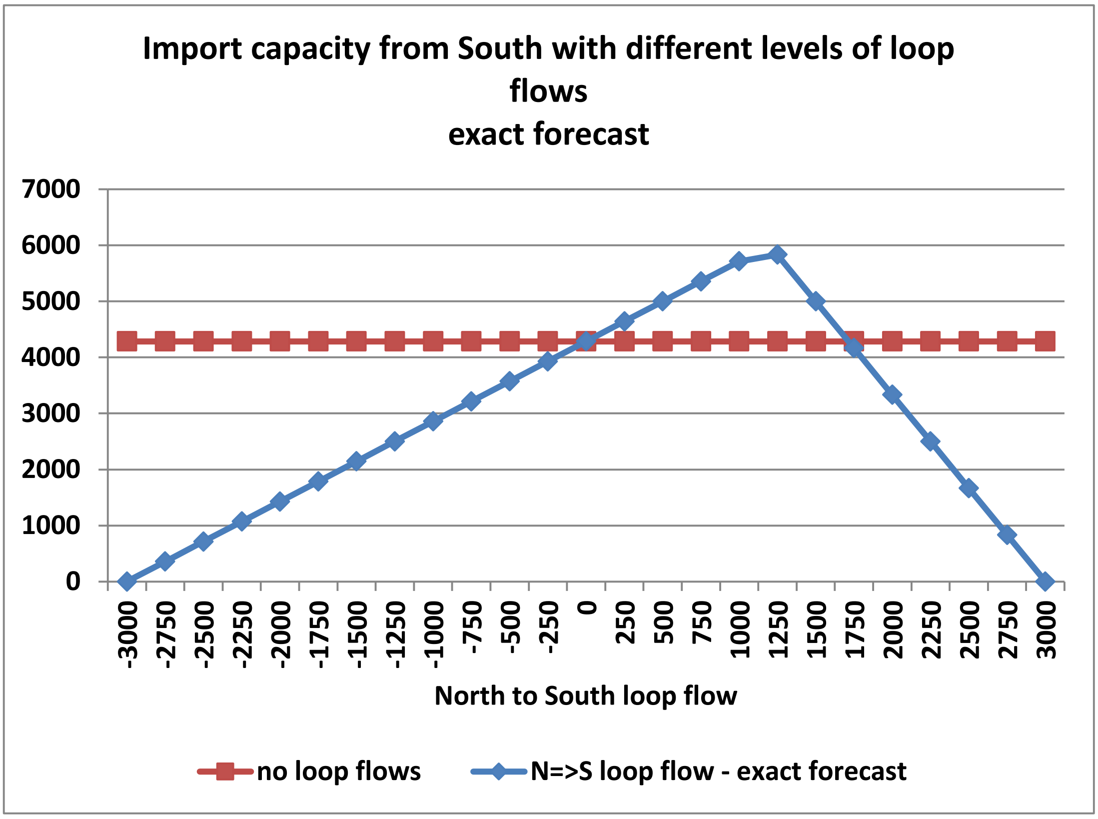
139. Now the limiting interconnection capacity is from France to Belgium. The maximal import is 3000 MW / 0.7 = <u>4286 MW</u>, the highest of all situations.

d) Different levels of loop flows – exact forecast

140. Only when loop flows are relatively small <u>and</u> in the opposite direction of the import, loop flows can increase import capacity if they can be forecasted with sufficient precision. This

is shown on the figure below with regard to import capacity from the South (based on the parameters of the simplified example of above). The horizontal axis gives the level of the loop flow. Positive values indicate a loop flow in the “good” direction, namely from North to South which is the opposite direction of the import. In this case loop flows can be forecast without uncertainty.

- The red line gives the import capacity when there are no loop flows.
- if the loop flow goes from South to North (negative values), the import capacity from the South always decreases when loop flows increase
- if the loop flow goes from North to South (positive values), the import capacity from the South increases when loop flows increase. However, when loop flows become too big, import capacity from the South also starts to decrease.

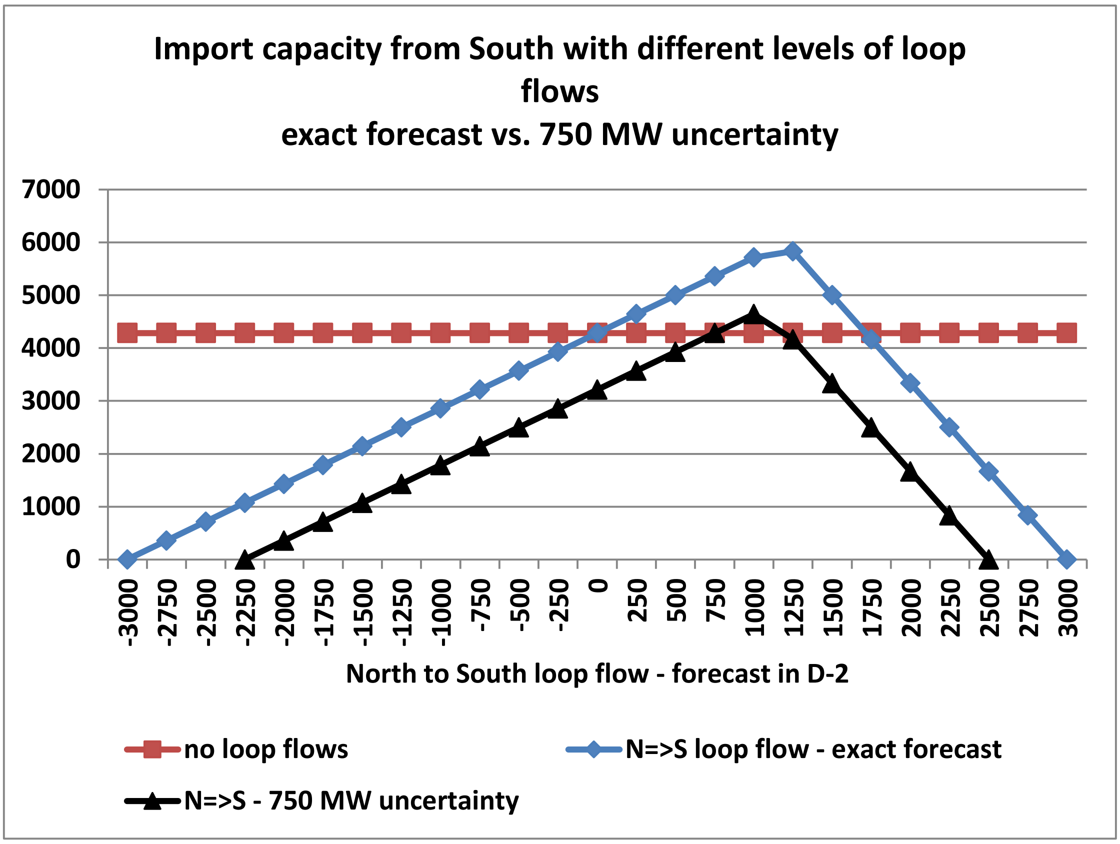


e) Different levels of loop flows in the "good" direction – with forecast errors

141. Loop flows need to be estimated two days ahead (in the D2CF) which means there are sometimes large forecast errors, especially because of a lot of renewables and large bidding zones[29]. The figure below is the same as above, but adds a black line.

142. The black line gives the import capacity from the South when there can be a forecast error of up to 750 MW in both directions. Only in one specific and small interval of around 1000 MW of expected loop flows in the good direction, there is a small increase of import capacity. For all other situations, import capacity is severely limited by the (possibility of) loop flows.

143. It is clear that based on this example, which according to the CREG is realistic, loop flows can almost never increase import capacity, even if the loop flow is in the "good" direction (namely flowing towards the exporting bidding zone). Even small, but unpredictable loop flows in the good direction can decrease import capacity.



[29] The larger a bidding zone, the more it can become difficult to forecast the location where there will be generation and consumption within that large bidding zone, leading to larger potential forecast errors of loop flows compared to the situation where the larger zone is split up into smaller bidding zones.

f) *Loop flow never help: formal explanation for Belgium with liquid markets in France, Netherlands and Germany*

144. Elia reacted to the above explanation that loop flows can help if one assumes there are liquid markets (so imports can come from every connected market). According to the CREG, this does not change the conclusion that loop flows never help.

145. The following will provide a formal explanation of this conclusion, implemented for the Belgian situation:

- Belgium has two interconnections: one with the Netherlands of about 3000 MW and one with France of about 4000 MW
- PTDF from France to Belgium is 0,75; PTDF from the Netherlands to Belgium is 0,75; from Germany to Belgium is 0,5.
- Loop flows (LF) running from North to South are positive by convention.
- Loop flows are uncertain. The assumed uncertainty (D_LF) is 750 MW in both directions.

146. This leads to the following formulae regarding the maximal import capacity to Belgium from the three other countries:

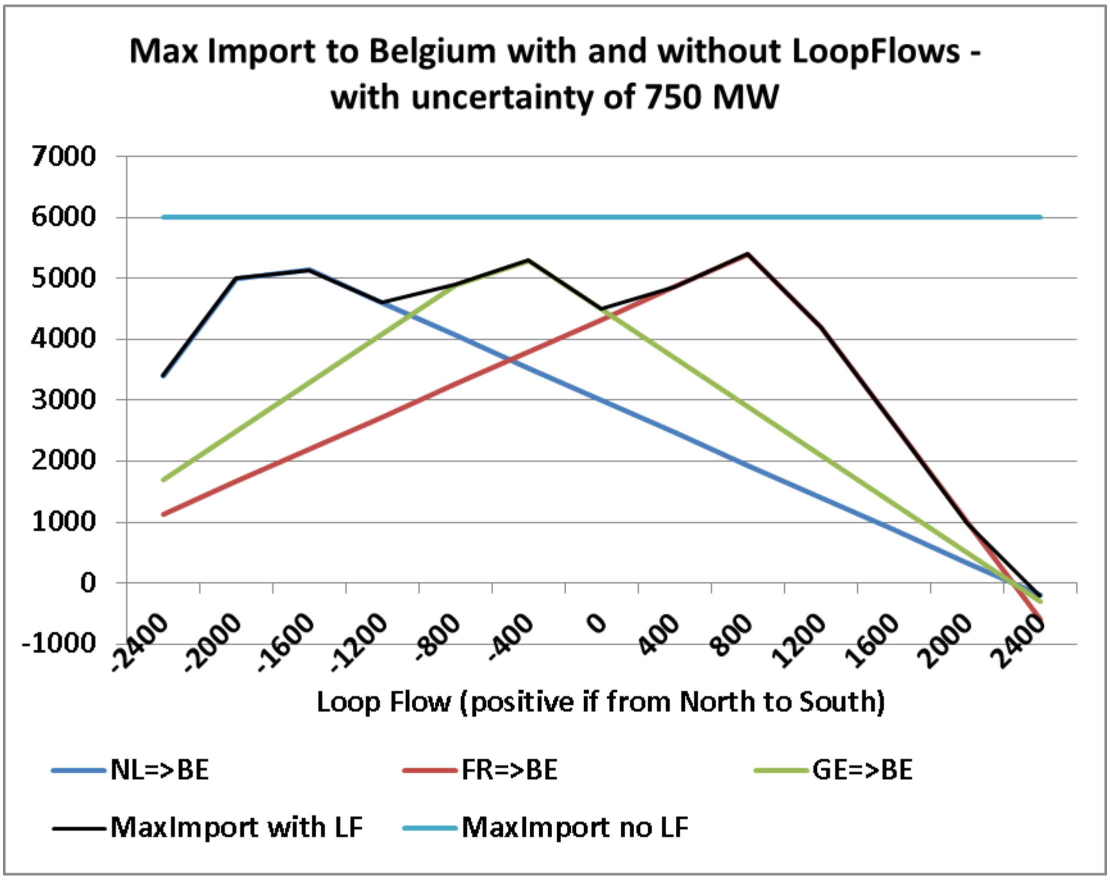
- Maximal import from Netherlands is the minimal value of (3000 – LF – D_LF)/0,75 and (4000 + LF – D_LF)/0,25
- Maximal import from Netherlands is the minimal value of (3000 – LF – D_LF)/0,25 and (4000 + LF – D_LF)/0,75
- Maximal import from Germany is the minimal value of (3000 – LF – D_LF)/0,5 and (4000 + LF – D_LF)/0,5

The maximal import to Belgium is the maximal of these three values.

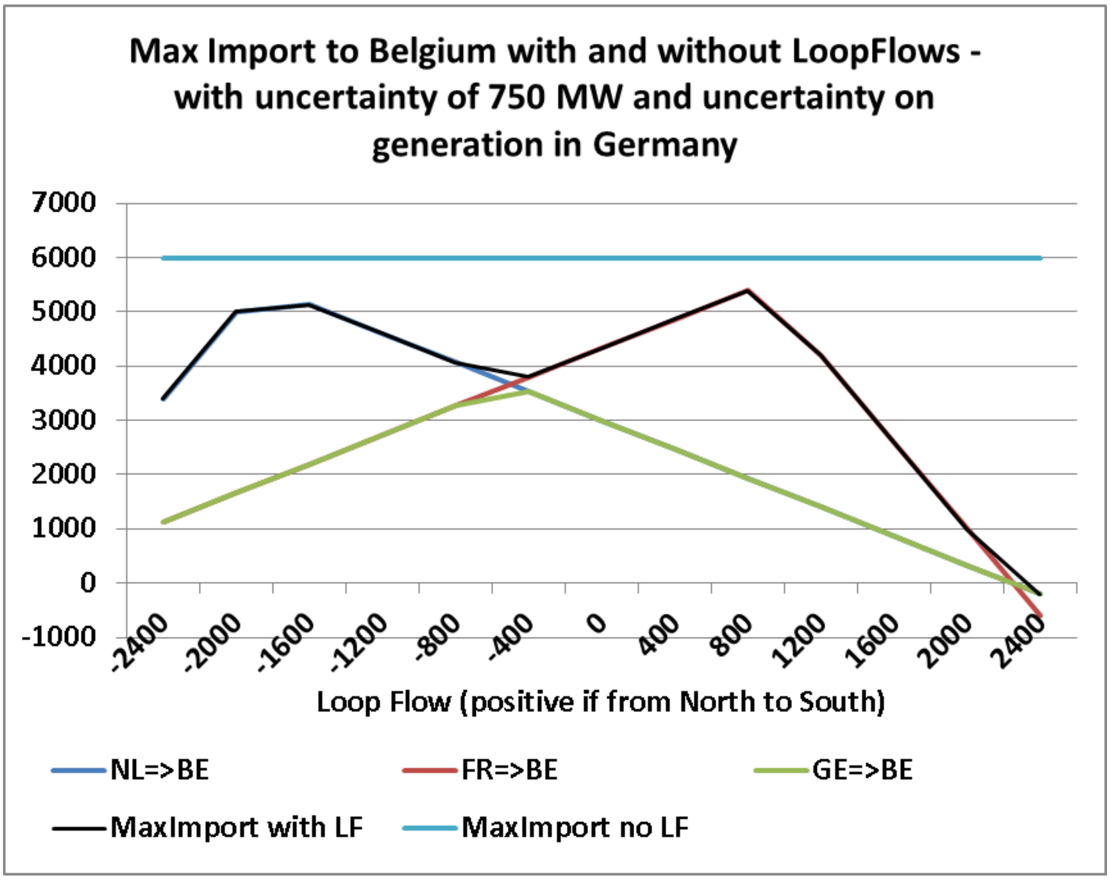
If there would be no loop flows and no uncertainty, the maximal import would be 6000 MW and would be coming from Germany.

147. The figure below gives the import capacity from the three countries with different levels of loop flows. It is clear that, depending on the size and direction of the loop flows, the country from which Belgium can import the most is changing. With high loop flows from south to north (negative loop flows), the Netherlands can export the most to Belgium; with small loop flows, Germany can export the most; with high loop flows from north to south (positive loop flows), France can export the most. The overall import capacity, however, is always significantly lower than 6000 MW, the maximal import when there are no loop flows and no

uncertainty on loop flows. Moreover, import capacity drastically decreases when loop flows from north to south (positive values) become high. Around 1600 MW of loop flows and 750 MW of uncertainty, import capacity decreases to 2600 MW, a level of import capacity to Belgium that corresponds with the observations of 22 September 2015.



148. In addition, the resulting maximal import capacity in the figure above might be optimistic. This is due to the fact Germany is a very large price zone. This is not only resulting in possibly high loop flows (and uncertainty on these loop flows), but also uncertainty on the PTDF of the import. If generation is mainly in the north of Germany, PTDF's will be more like the ones for the Netherlands, namely 0,75 for the border with the Netherlands and 0,25 for the border with France, instead of two times 0,5. If generation is mainly in the south of Germany, PTDF's will be more like the ones for France. Since production in Germany could be anywhere, TSOs could always take the worst case. This leads to the counter-intuitive result of even lower import capacity if loop flows are low, as is shown in the figure below.



149. From a relative position, one could argue that import capacity is higher when there are loop flows. However, the section should make it very clear that the presence of loop flows, the uncertainty of loop flows and the uncertainty of the location of production in large price zones decrease import capacity if compared with the situation of low loop flows and low uncertainty of loop flows. For this, one has to come with an adequate delineation of bidding zones.