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COMMISSION FOR ELECTRICITY
AND GAS REGULATION

WORKING PAPER

(Z)151113-CDC-1476

on

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

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

13 november 2015

CONTENT

EXECUTIVE SUMMARY

The objective of this working paper is to present the preliminary analysis and conclusions of the CREG concerning the occurrence of elevated prices and price peaks on the Belgian day-ahead power exchange Belpex on 22 September 2015. The main focus is on the day ahead market, although some topics of the intra-day and real time market are also analyzed. To facilitate the discussion the CREG organizes a workshop on this working paper on 18 November 2015. Based on the comments received and on more detailed information, the CREG will finish its analysis and update this working paper. This update will also include an analysis of the prices spikes on 16 October 2015.

The day-ahead price on 22 September is on average €188,74/MWh, with price spikes of €448,70/MWh. Day-ahead spot prices in other bidding zones are far below the Belgian prices; the price spread between Belgium and Germany is on average €240,8/MWh during hours 8-21 with the highest price spreads observed during hour 15 (€410,45/MWh).

On 22 September 93% of all controllable generation capacity was used during peak hours. Some capacity needs to be available for reserves. The price spikes of 448,7 €/MWh were determined by an hourly sell order of less than 50 MWh. This kind of behavior was already examined for the price spikes on 24 March 2015. For that day it became clear that the bidding behavior was explained by demand response being offered. The CREG will conduct a more detailed analysis of bidding behavior once the detailed data on generation units are fully analyzed. Also the formation of the balancing price needs more analysis. However, for the CREG there are at this moment no indications there was anti-competitive behavior causing price spikes.

During all hours on 22 September the Belgian bidding zone was importing electricity. The commercial import was mainly from France, while there was no commercial import from the Netherlands. However, the physical import came mainly from via the Netherlands and much less via France. 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>. 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 <u>loop flows</u>, 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.

This analysis, which was discussed with and confirmed by Elia, 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 for limiting 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 22 September 2015, there was no available intra-day capacity from France to Belgium and only 200 MW on the Dutch-Belgian border during hours 18 to 24. It is 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 on 22 September during peak hours, implying more intra-day capacity on this border could have been given to the market.

I. Goal of the Working Paper

1. The objective of this working paper is to present the preliminary 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 case of the 22nd of September is elaborately explained. In the meantime similar cases have been observed, such as on the 15th and 16th of October.

This working paper, published on the CREG-website, serves as a discussion paper in order to inform the market and to obtain feedback from the market participants and other stakeholders. The main focus is on the day ahead market, although some topics of the intra-day and real time market are also analyzed. To facilitate the discussion the CREG organizes a workshop on this working paper on 18 November 2015 at 10 am. Based on the comments received and on more detailed information, the CREG will finish its analysis and publish a final update of this working paper on its website.

II. Preliminary Analysis

2. The analysis focuses on four domains: its context, the Belgian market, balancing and reserves, and the cross-border commercial exchange with other bidding zones. Multiple factors influencing the market results are analysed: the observed prices, the actually measured load and the requested day-ahead demand, the available generation capacity, the bidding behaviour of market participants, and the import volumes.

II.1 Context: high prices

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 peak hours (hour 9-20) did not fall below the level of €150/MWh. During 14 hours of the day (hour 8-21) elevated prices €150/MWh were observed. At hours 8, 9, and 15, price peaks of €448,70/MWh appeared.

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).

Baseload Belgian prices observed on the 21st and 23rd of September are respectively €140,1/MWh and €135,1/MWh lower than those observed on the 22nd of September. Only at hour 10 a price of €120/MWh was visible.

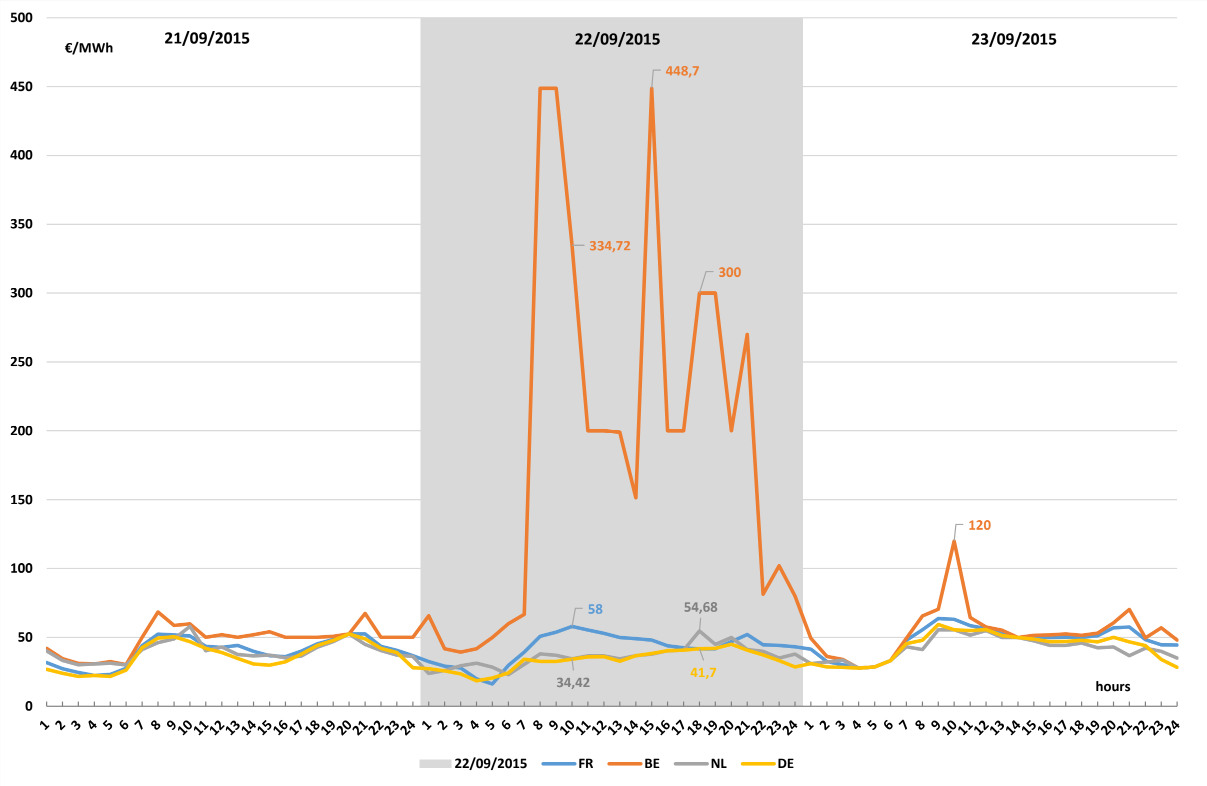


Figure 1 - Day-ahead spot prices as a result from the matching of orders in and the coupling of the bidding zones in the CWE-region on the 21st, 22nd, and 23rd of September
Source: Belpex, EEX, APX

4. Intra-day prices moved in line with day-ahead prices. Baseload intraday prices were €48,65/MWh on the 21st, €188,74/MWh on the 22nd, and €53,64/MWh on the 23rd of September.

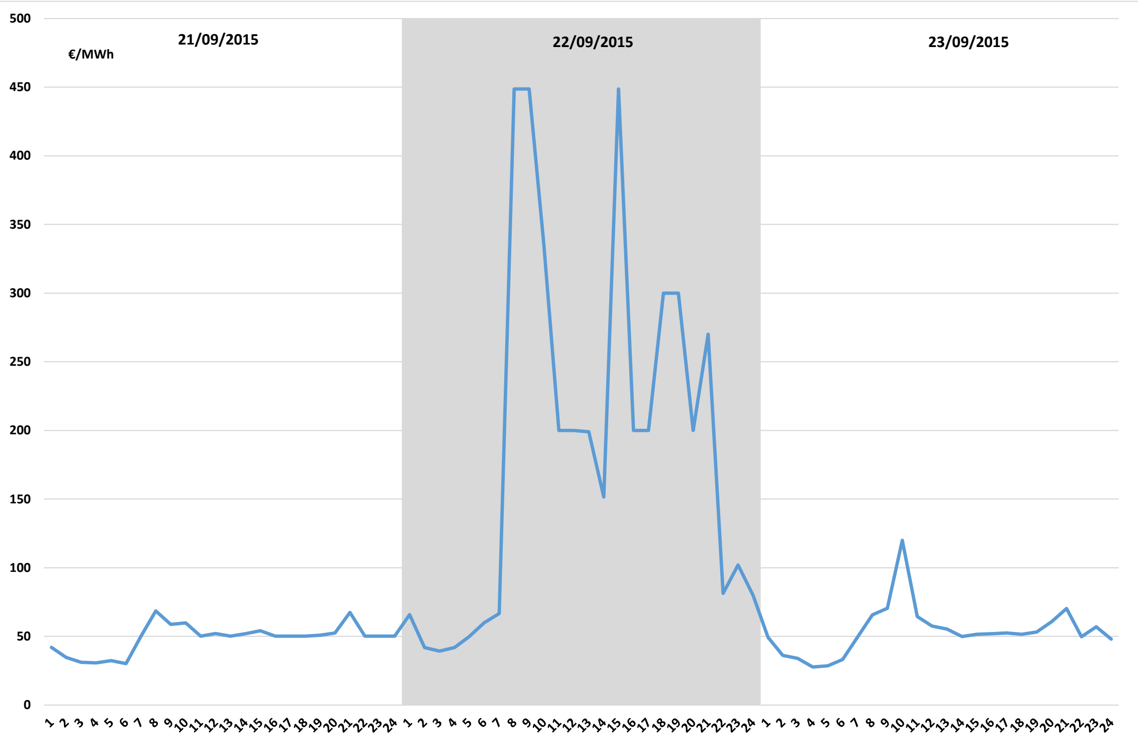


Figure 2 - Intraday prices in Belgium on the 21st, 22nd, and 23rd of September
Source: Belpex

5. Imbalance prices are also elevated on the 22nd of September compared with the 21st and 23rd. From 07h15 to 12h45 the averaged upward imbalance price was €400/MWh.

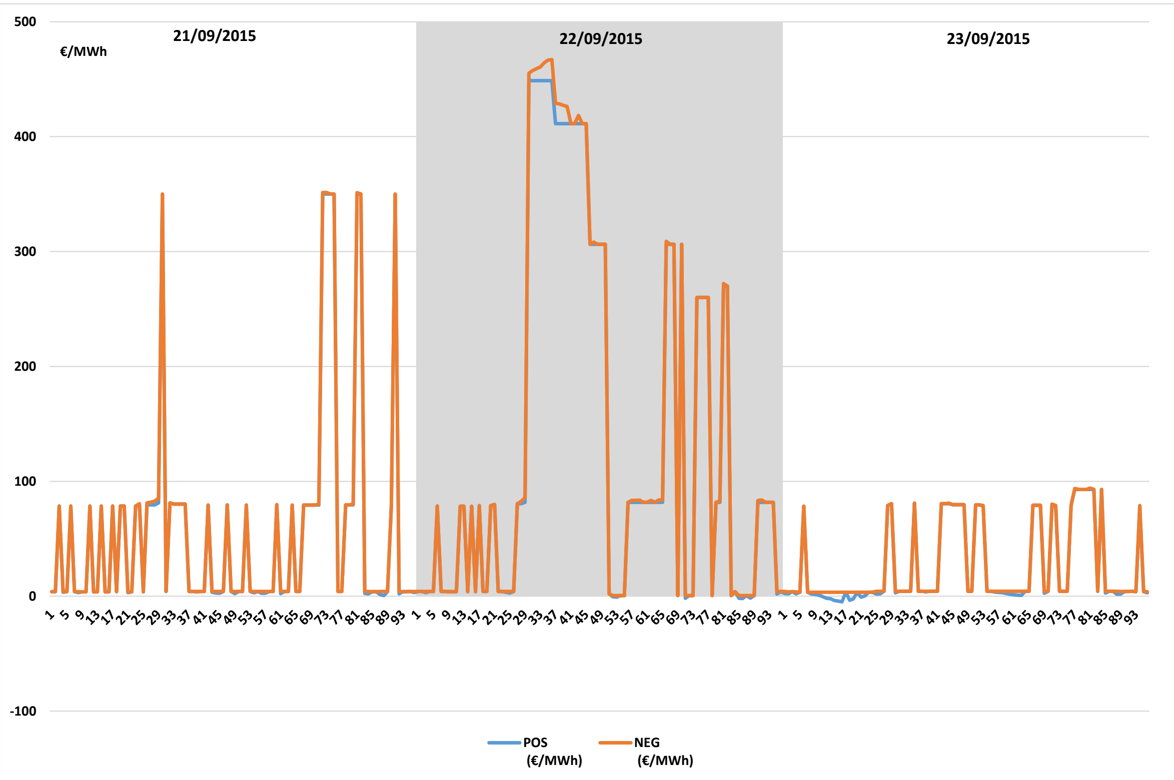


Figure 3 – Imbalance prices in Belgium on the 21st, 22nd, and 23rd of September
Source: Elia

II.2 The Belgian market

II.2.1 Real-time Elia net load

6. On the 22nd of September, during the hours 8-21 the load as measured by Elia averaged 9580 MWh/h. Focusing on hours 8, 9, and 15, the load was 9628 MWh/h, 9739 MWh/h, and 9334 MWh/h respectively (Figure 4).

7. Wind production was relatively low on the 22nd of September. Less than 100 MWh/h of 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 MWh/h) and hour 9 (31 MWh/h).

Consequently, net Elia load (i.e. measured Elia load minus electricity generated by wind units) amounted to 9463 MWh/h on average during the period ranging from hour 8 to 21. The periods of highest volumes of net load were situated during hour 9 (9707 MWh/h) and hour 21 (9717 MWh/h).

Comparing with the net load measured on the 21st of September and 23rd of September, there seems not to be much of a difference. 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.

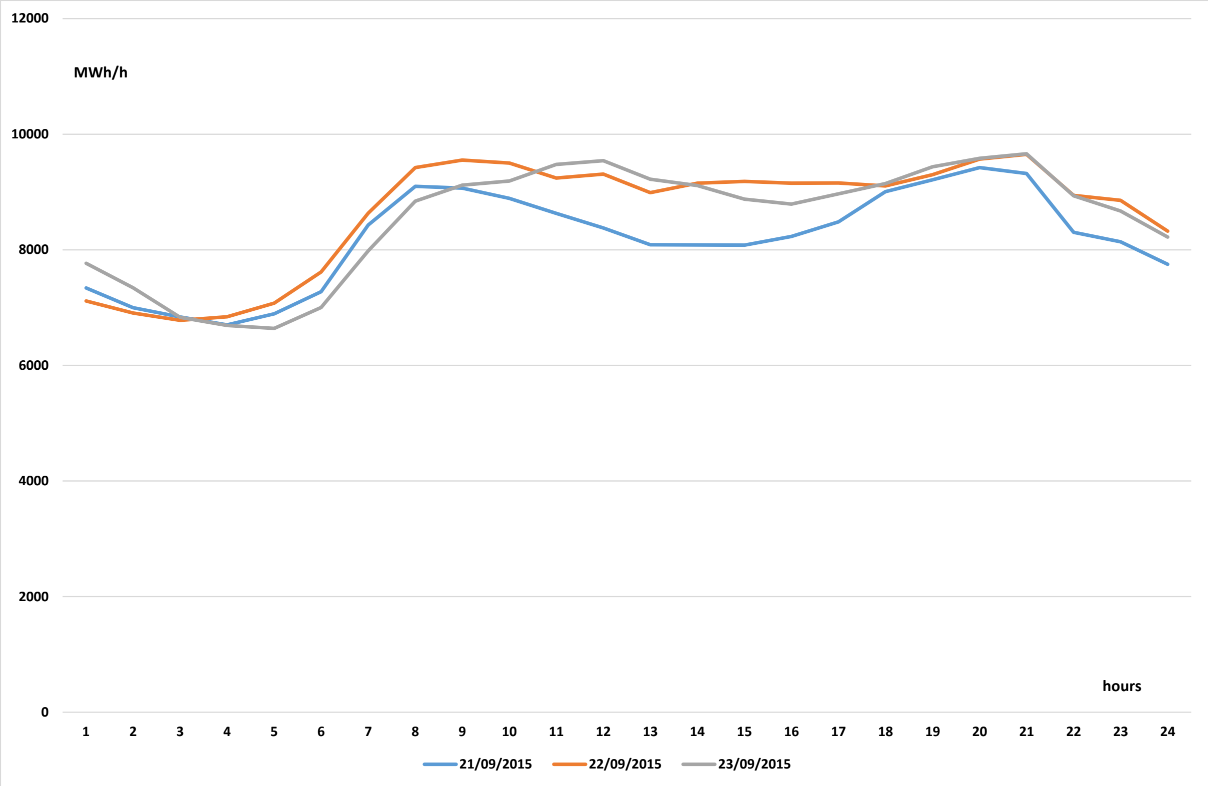


Figure 4 - Net Elia Grid Load, calculated by subtracting measured wind power injection from the measured Elia Grid Load, on the 21st, 22nd, and 23rd of September 2015
Source: Elia

II.2.2 Day-ahead demand

8. When considering 'must-buy' demand (i.e. buy orders priced at €3000/MWh), demand is higher during the 22nd of September from hour 8 to 21: on average 2526 MWh/h compared with 2076 MWh/h on the 21st and 1612 MWh/h on the 23rd during the same period (Figure 5).

The matched volume is on average 2803 MWh/h on the 21st of September, slightly lower than the averaged matched volume on the 22nd of September during the same period (2927 MWh/h). The 23rd of September also shows a reduction in matched volume to 2238 MWh/h.

9. During all considered hours the Belgian bidding zone was importing electricity. The illustrated commercial volumes hence represents Belgian demand. Both reductions in asked and matched volume on the 23rd of September could illustrate a market reaction to the elevated prices on the 22nd. As the measured Elia grid load on the 23rd attained a similar profile to that measured on the 22nd, must-buy demand will rather have found alternative ways to supply itself out of the framework of the day-ahead power exchange (see below).

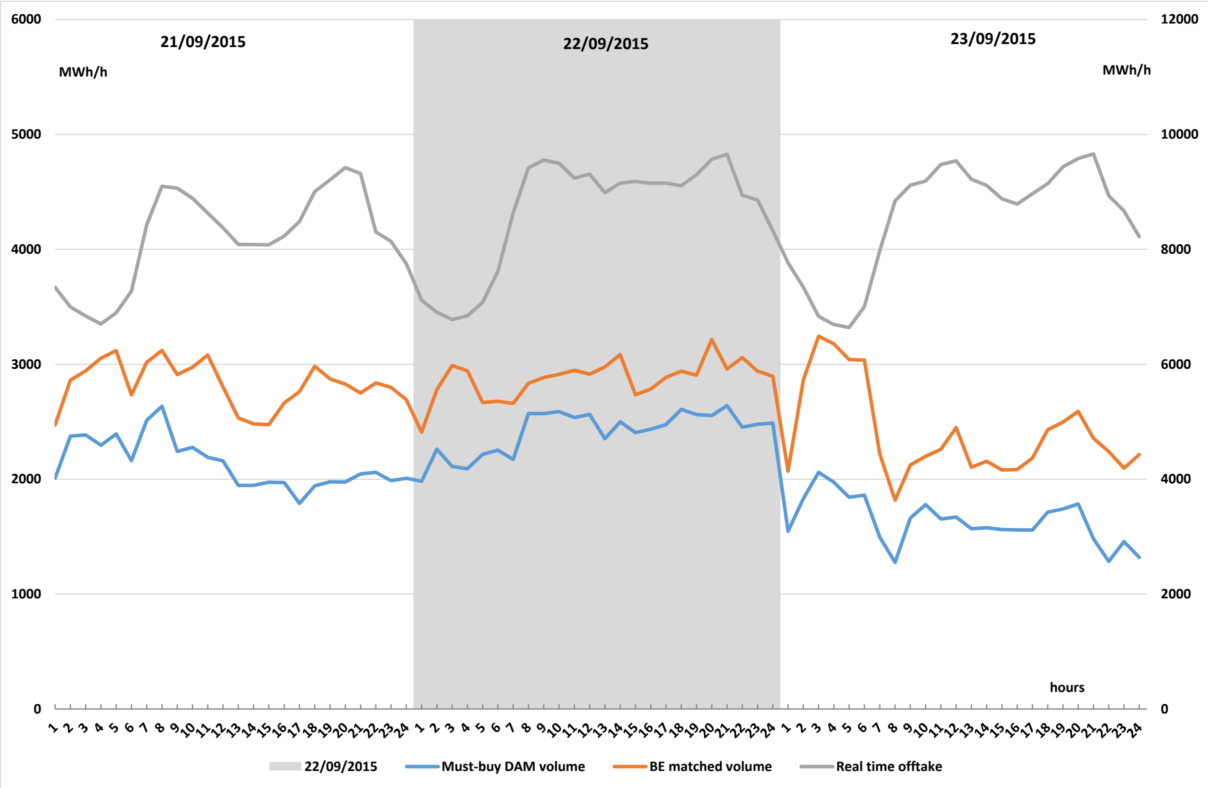


Figure 5 - Volume matched by and must-buy volume offered to the Belgian day-ahead spot exchange (left axis), and the real-time measured net Elia grid load on the 21st, 22nd and 23rd of September 2015
Source: Elia, Belpex

II.2.3 Available generation capacity

10. On the 22nd of September, an average available capacity of 7380 MW of controllable generation capacity (thermal, nuclear, biomass, gas, etc) was available for dispatch during hours 8 to 21 (Figure 6). Part of this capacity is reserved to take part in ancillary services during real-time, leading to an available capacity of on average 6800 MW of controllable generation capacity to participate to the market during this period.

11. The relatively low available capacity of controllable generation is attributed to the prolonged outage of Doel 3 and Tihange 2 (2000 MW combined), the (temporary) discontinuation of exploitation of Doel 1 in the context of the nuclear phase-out (433 MW), and the unavailability of Doel 4 (1038 MW).

More importantly, 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 unavailability seemed to be only temporary as an Urgent Market Message was sent to the market indicating that the plant would be available again on the 19th at 16h00. This message was updated 10 times during the 19th and 20th, each time shifting the end time of the unavailability by a few hours. At 22h45 on the 20th of September an update was sent that the unavailability would take longer than a few hours, shifting the end time from 23h59 on the 21st of September to the 30th of September. The market was hence timely informed of the outage before the gate closure time of the day-ahead market for delivery of electricity on the 22nd of September.

Additionally, CCGT plants Esch-sur-Alzette (Twinerg, 376 MW) and Amercoeur (451 MW) were planned unavailable. The plant of Twinerg was restarted on the 23rd of September after finishing its maintenance with regard to its application to the Strategic Reserves.

Also, the phase shifter in Zandvliet was out of service.

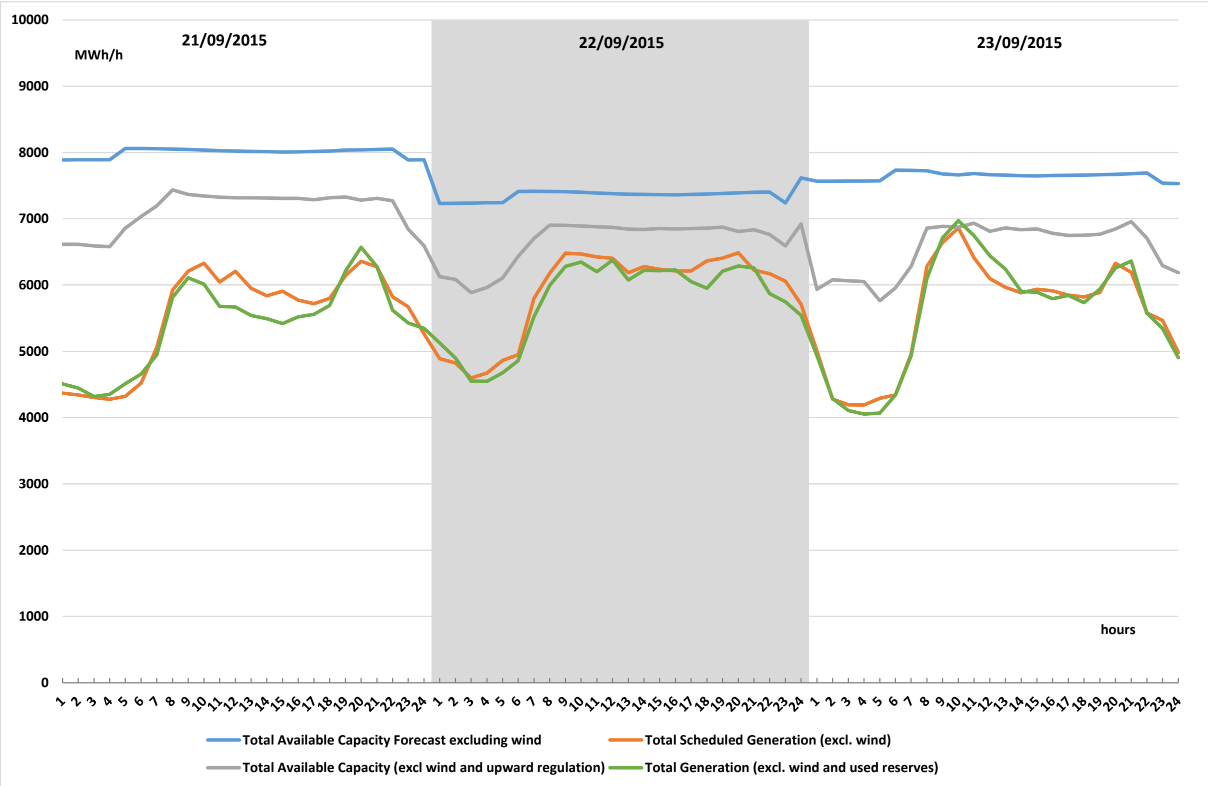


Figure 6 – Total available controllable generation capacity, excluding wind and excluding generation capacity reserved for upward regulation, scheduled generation capacity, and generated energy
Source: Elia

The share of scheduled capacity versus total available controllable generation capacity is high on the 22nd of September: during hours 8-21, on average, 93% of all generation capacity was used compared with 83% on the 21st and 91% on the 23rd during the same hours. On the 23rd however, during hours 8-12 a high use of available generation capacity is observed, while on the 22nd the high use is visible from hour 8 throughout the remainder of the day.

These numbers indicate a high share of generation to be actually dispatched. The volume of generated energy does not extend the volume of scheduled generation to the total capacity available to the market however. Some capacity was hence not dispatched at the observed day-ahead, intra-day, and balancing prices. A more detailed analysis regarding which individual plants were not dispatched and the economic reasons why will be carried out once the validated data related to individual units is communicated by Elia.

It should be noted that 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).

12. Comparing the measured Elia grid load with the energy generated, available controllable generation schedule, and physical import flows per border reveals a tight generation-load balance in the Belgian bidding zone on the 22nd and the 23rd (Figure 7).

Gas units accounted for over 53% of the total energy generated on the 22nd of September. Hydro plants generated 3860 MWh or 27% of the total energy generated (Table 1).

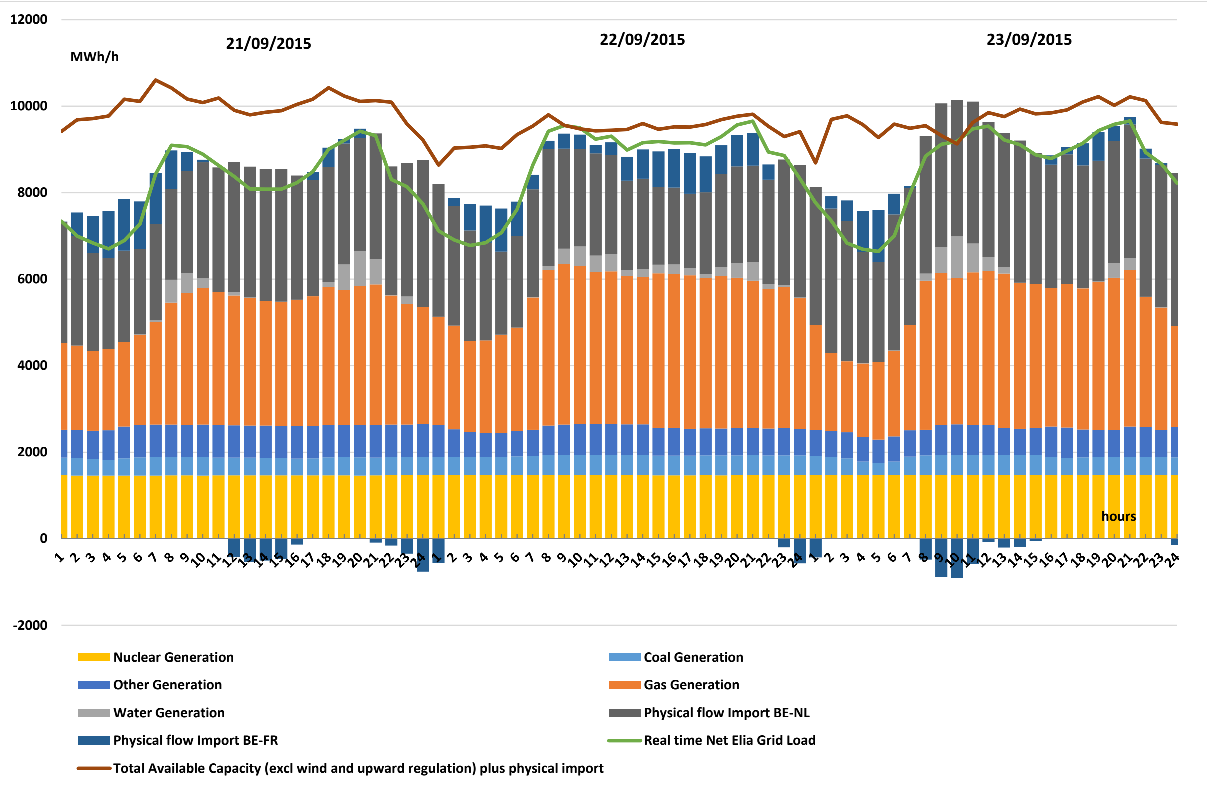


Figure 7 –Measured net Elia grid load, volume of energy generated, and total available controllable generation capacity on the 21st, 22nd, and 23rd of September.
Source: Elia

hour	Coal Generation	Gas Generation	Water Generation	Nuclear Generation	Other Generation
1	421	2508	2	1468	735
2	420	2399	2	1469	639
3	421	2110	2	1468	577
4	422	2142	2	1468	554
5	424	2267	2	1467	557
6	433	2389	2	1467	593
7	446	3061	2	1466	605
8	467	3596	98	1467	680
9	466	3714	354	1467	707
10	465	3658	452	1469	713
11	468	3518	383	1468	710
12	469	3533	407	1467	710
13	466	3432	137	1466	711
14	464	3407	186	1466	713
15	456	3572	202	1465	642
16	458	3555	221	1463	642
17	458	3548	169	1463	619
18	460	3477	94	1466	627
19	459	3524	206	1465	624
20	457	3477	336	1466	634
21	460	3410	436	1469	625
22	458	3227	109	1469	619
23	458	3262	43	1469	628
24	456	3023	17	1470	612

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

While on the 21st of September total available controllable generation capacity and imports always exceeded 500 MW compared with the Elia grid load, on the 22nd this was not the case during hours 8-21 and hour 23. Also on the 23rd the margin fell below 500 MW during hours 9-13 and hours 20-21.

II.2.4 Bidding behaviour

13. Besides the concerns expressed in paragraph 11 concerning generation capacity not being fully offered to the market, during the preliminary investigation no indication has been found of capacity being offered at excessive prices. Further analysis is however being carried out.

14. The situation of scarcity (paragraph 12) is visible in the orderbook of the Belgian power exchange Belpex (Figure 8). The average volume of demand accepted between the market clearing prices observed and the market ceiling price equals around 486 MWh/h. Interestingly, at hour 3, the must-run demand was fully satisfied by imports. From hour 8 to 12, on average, 962 MWh/h residual must-run demand still needed to be fulfilled (i.e. must-run

demand minus imports). From hour 15 to 21 the demanded volume was, on average, 940 MWh/h.

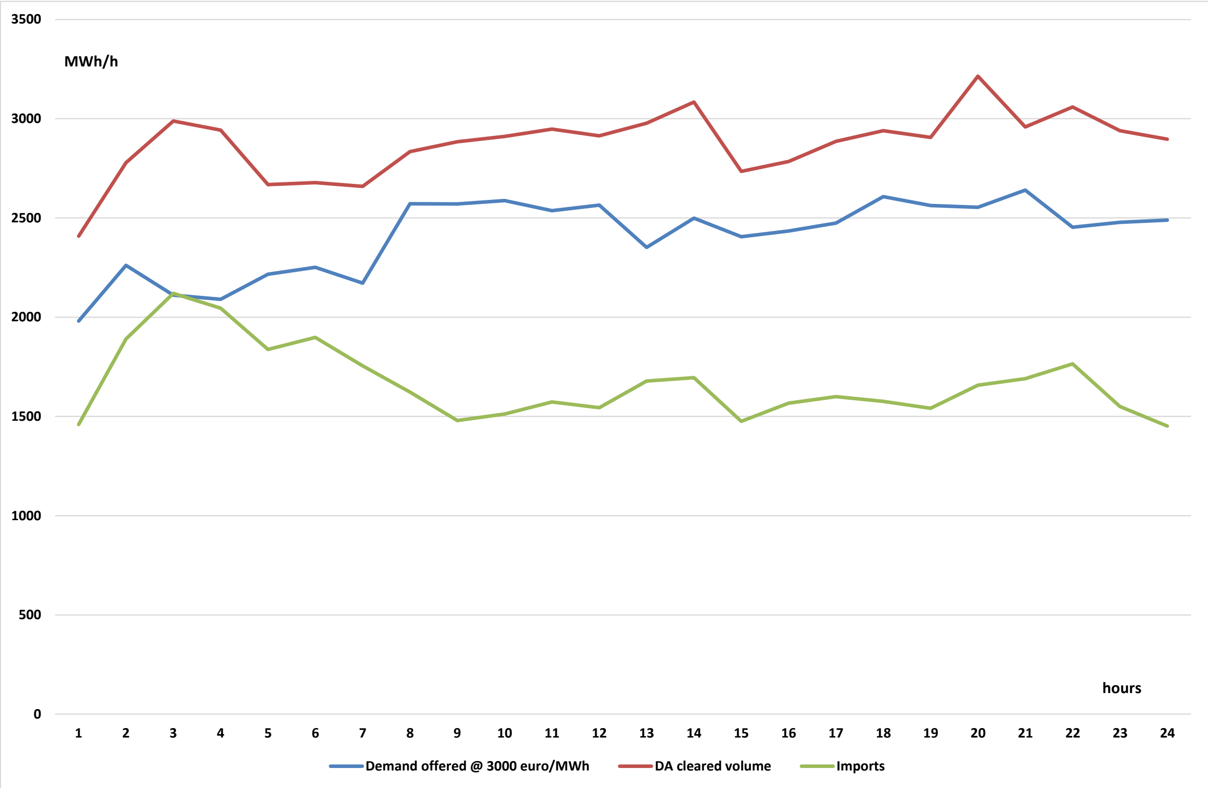


Figure 8 – Cleared (matched) demand volume on the day-ahead Belpex exchange relative to the offered must-buy demand volume and the commercial import volume as allocated by the flow-based market coupling – 22 September 2015
Source: Belpex

15. The commercial balance between supply and demand offered on the day-ahead market was also analysed (Figure 9). The balance, in terms of volume of demand and supply that has not yet been matched, is calculated as if the Belgian bidding zone is isolated. The volume not matched until prices would reach the market ceiling price of €3000/MWh is calculated. The difference between the allocated day-ahead import capacity and the balance calculated indicates the distance in terms of volume between the observed market results and prices of €3000/MWh and is termed "economic margin".

During the 22nd of September the supply offered in the Belgian bidding zone on the Belpex DAM was commercially not able to satisfy its must-run demand without imports. At hour 8 and hour 21, shortages of 1280 MWh/h and 1270 MWh/h are observed. In order to avoid prices of €3000/MWh, from hours 8 to 21, on average, the Belgian power exchange needed 1080 MWh/h of import volumes. Matching the maximum observed import volumes allocated to the Belgian bidding zone with the import needs in order to avoid curtailment on Belpex DAM, the Belgian bidding zone only had on average 500 MWh/h of spare supply commercially during hours 8 to 21.

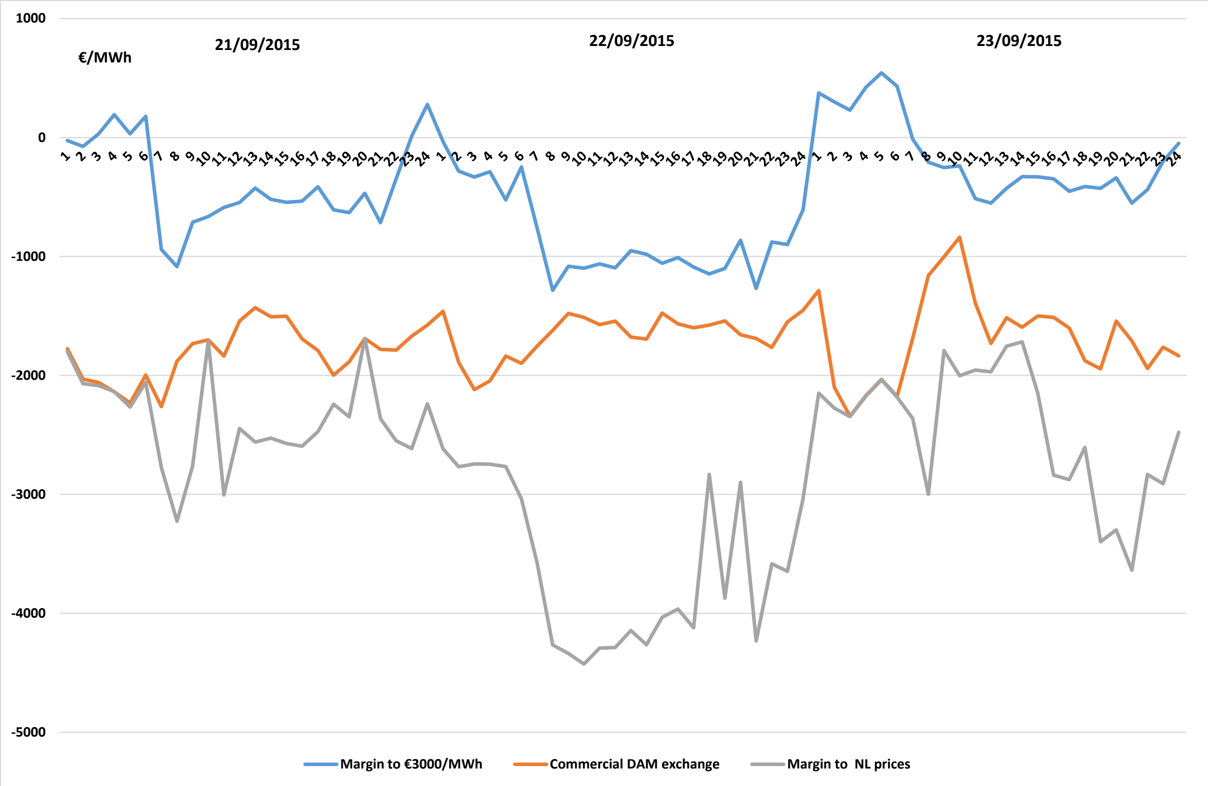


Figure 9 – Required commercial imports needed based on volume of demand and supply in the orderbook until the market ceiling price would have been reached without curtailing demand and until prices in the Netherlands would have been reached, relative to the available import volumes allocated by the flow-based market coupling mechanism to reach the observed market results.22 September 2015
Source: CREG, Belpex

To attain similar prices to those observed in the Dutch bidding zone, the Belgian bidding zone required an estimated average import volume of 4000 MWh/h during hours 8-21, or 3600 MWh/h on average during the day. This compares with an average of 2780 MWh/h on the 21st of September and 2450 MWh/h on the 23rd of September.

16. Based on the order book, the price spikes of 448,7 €/MWh on hours 8, 9 and 15 were determined 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 behavior was explained by demand response being offered. The CREG will also verify this for 22 September and 16 October.

17. The CREG will conduct a more detailed analysis of bidding behavior once the detailed data on generation units are fully analyzed. However, for the CREG there are at this moment no indications there was anti-competitive behavior causing price spikes.

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

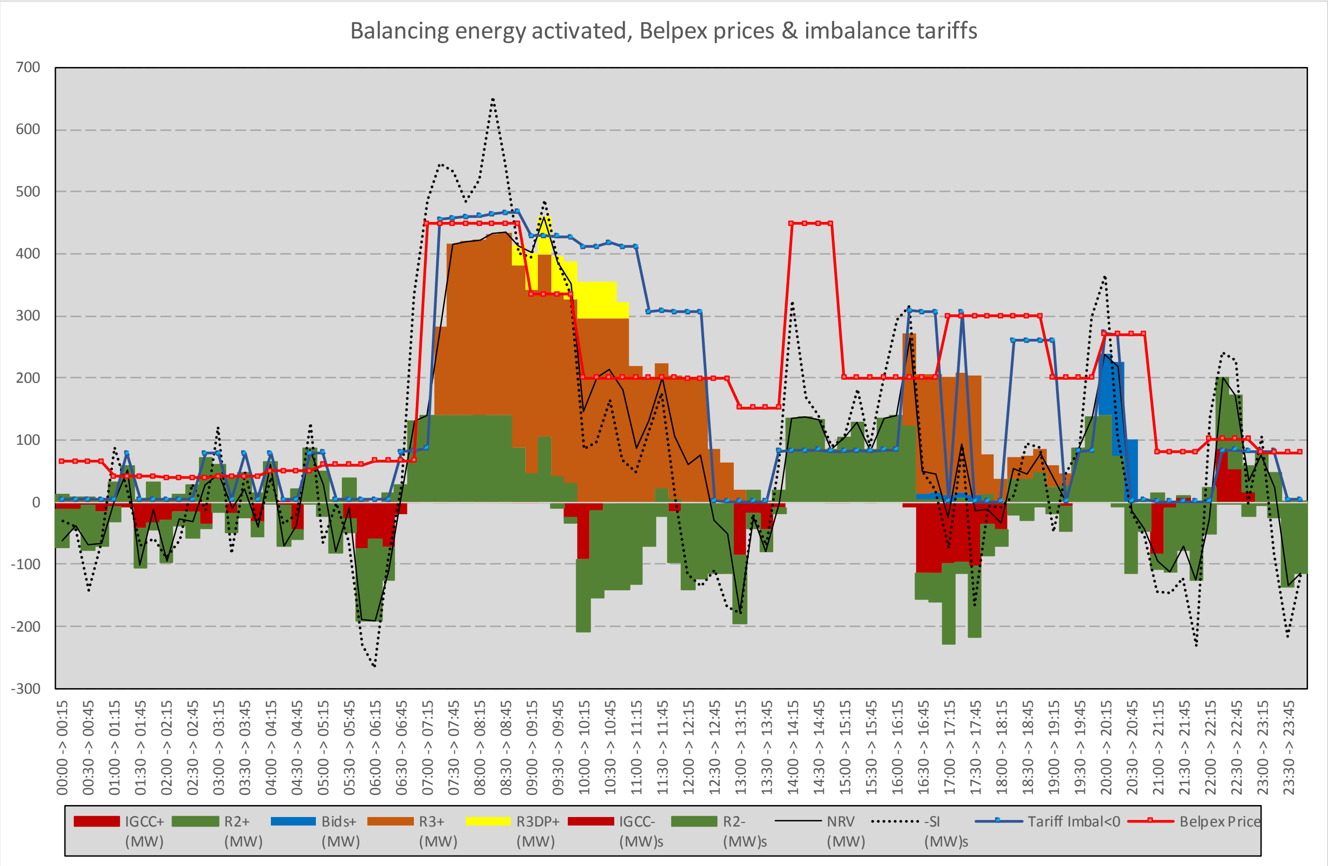
II.3 Balancing and reserves

II.3.1 Activation and imbalance price

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

19. 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).

20. The chart below shows the activations of reserves for the day 22nd September 2015, as well as the imbalance tariff (blue line with cyan markers). Also the system imbalance (SI) is shown (dotted line).



21. It is clear that activation of reserve by the TSO follows 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. However, also when there is an unexpectedly higher load, R3 can be activated.

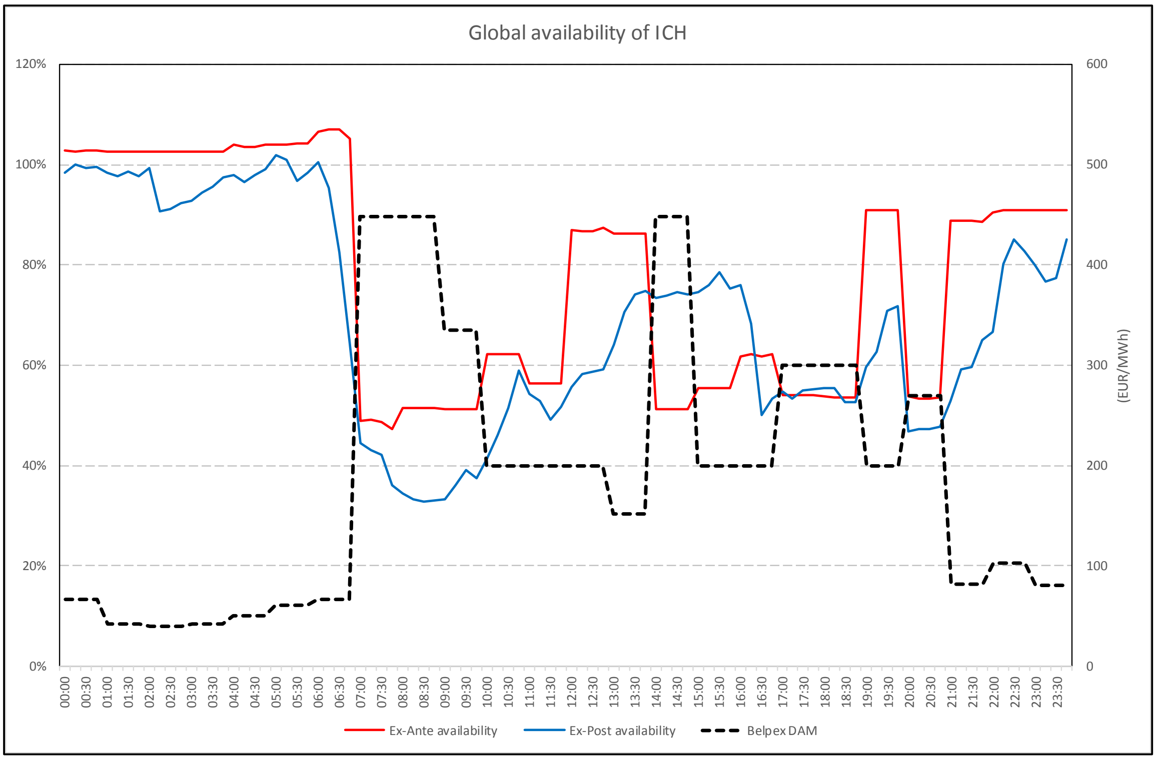
22. The price formation of the imbalance tariff was based on the activated reserves. Based on the information the CREG already received from Elia, there are some aspects of price formation that are unclear for the CREG. This will be further discussed with Elia.

II.3.2 Availability of R3 ICH

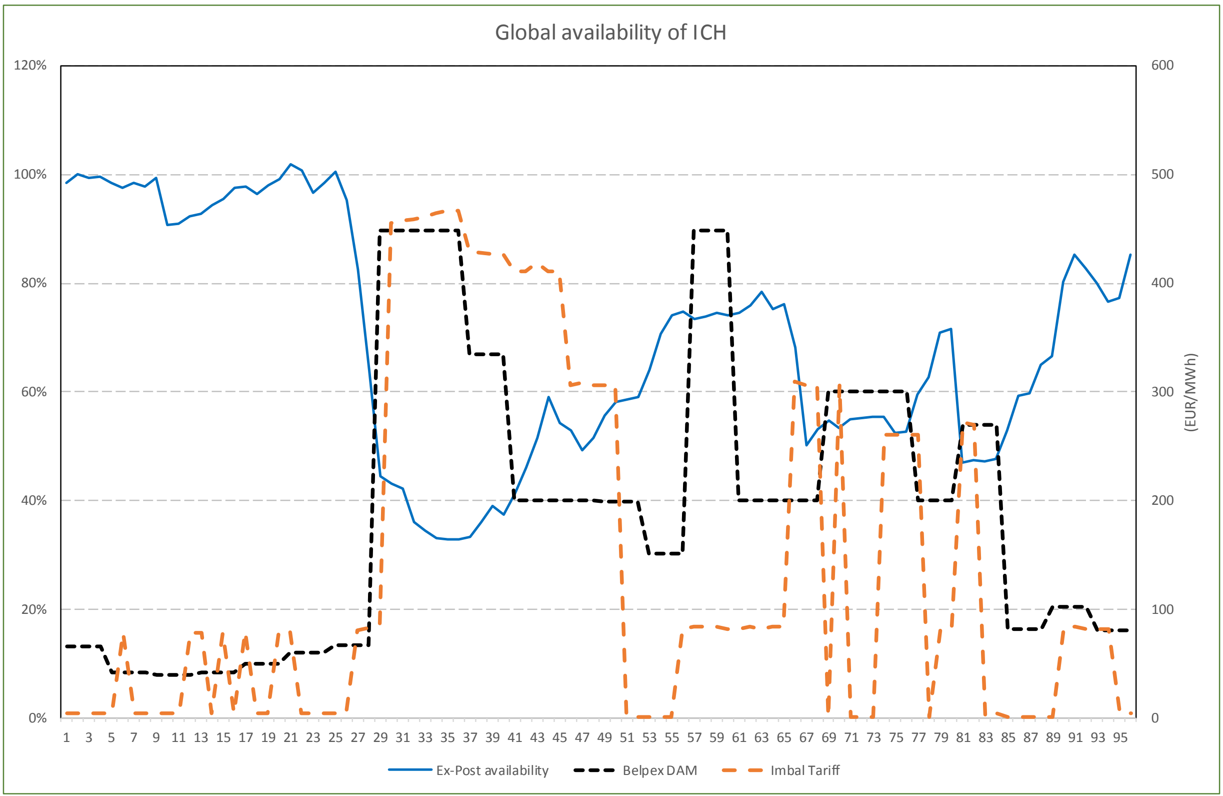
23. There was no activation of interruptible load (R3 ICH) by Elia. However, the availability of this type of R3 decreased during peak hours.

24. The figure below illustrates the availability of ICH contracts, as well in day ahead (ex-ante) as in real time (ex-post). The availability is shown as a percentage of the sum of the contractual reserve target values (R_{ref}) of the ICH contracts. The Belpex DAM price is added to the figure (€/MWh).

The figure shows that the ex-ante availability of the ICH contracts is very sensitive to Belpex DAM price 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.



25. As illustrated in the figure below, 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.



26. Since R3 ICH is an increasingly important flexibility instrument for balancing the grid, these observations, if confirmed by other observations in the presence of price spikes on the Belpex DAM, suggest to adapt the product design, for example by defining an increased availability target (100%) for the ICH contracts.

II.4 Cross-border electricity exchanges

II.4.1 Commercial exchanges

27. For 21, 22 and 23 September, around 1076 MWh/h of import capacity was nominated on yearly and monthly interconnection capacity from the French to the Belgian bidding zone, and 525 MWh/h from the German to the Dutch bidding zone (Figure 10 and Figure 11). For

the 23rd of September 460 MWh/h to 486 MWh/h 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 to be almost fully transferred to the Belgian bidding zone, thereby almost nullifying the long term import position of the Dutch bidding zone.

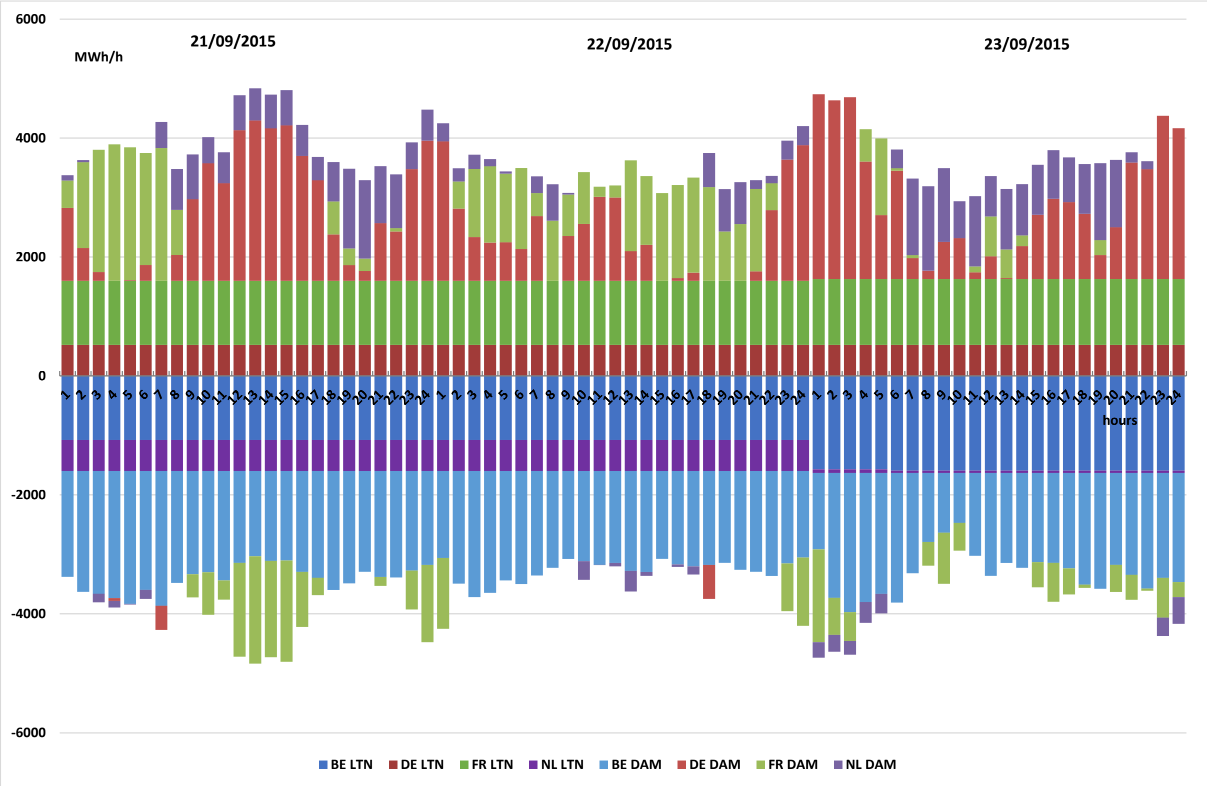


Figure 10 – Commercial exchanges between bidding zones based on long-term nominations of import/export volumes, and the allocated commercial exchange volumes during day-ahead by the flow-based algorithm, on the 21st, 22nd, and 23rd of September
Source: Elia, CASC

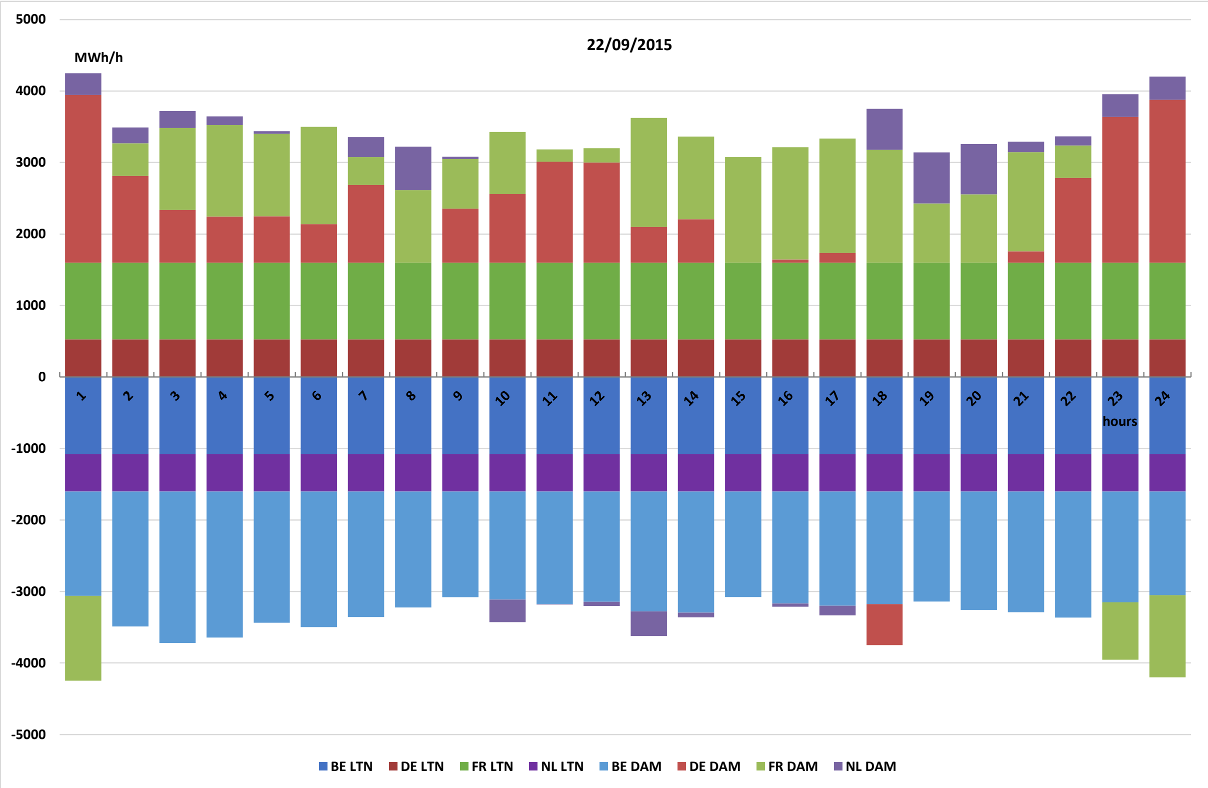


Figure 11 - Commercial exchanges between bidding zones based on long-term nominations of import/export volumes, and the allocated commercial exchange volumes during day-ahead by the flow-based algorithm on the 22nd of September
Source: Elia, CASC

28. Since the 20th of May, the remaining commercially available 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 commercial day-ahead exchange capacity is based on a representation of the topology of the grid in the CWE-region. The allocation of this commercial capacity to commercial exchanges between bidding zones is based on the orders in the order books of each bidding zone.

Allocating capacity by the flow-based market coupling is a process with multiple steps. Steps 1 to 3 are part of the so-called 'base case', namely the procedure before 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" or 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) Based on this information, TSOs calculate in day ahead the physical flows resulting from internal exchanges and explicit cross-border nominations and other expected transactions. This leads to the “day ahead congestion forecast” or DACF.

4) Based on the “Reference Flows” resulting from the DACF, TSOs can 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 realise the cross-border impact of the first step in the allocation process (Figure 12). A commercial transaction within, for example, the German bidding zone (typically from the renewable-rich north to consumption mainly located in the south, brown arrow) creates a physical flow passing through the Dutch, Belgian, and French bidding zone (and through the countries at the east of Germany). These physical flows hence use the physically available transmission capacity in a certain direction which in turn lowers the remaining capacity for commercial exchange between bidding zones.

In this example, the import capacity from the Dutch to the Belgian bidding zone would be reduced due to the loop flows going from north to south (through Netherlands, Belgium and France). But also, and maybe surprisingly, it could also lower import capacity from the French bidding zone to the Belgian bidding zone, because part of the commercial exchange from France to Belgium will physically take the indirect path through Germany and the Netherlands to Belgium. In annex II it is shown that loop flows, which cannot be forecasted without uncertainty, almost always decrease the remaining capacity for commercial exchange, whatever the direction loop flows are going.

Considering the high volumes traded within the German bidding zone, this reduction can be very significant compared with the commercial transmission capacity allowed by the TSOs. Larger zones can create larger loop flows because of higher exchanged volumes in the larger zone which can be exchanged over longer distances. The impact of these flows will be explained in more detail in section II.4.2.

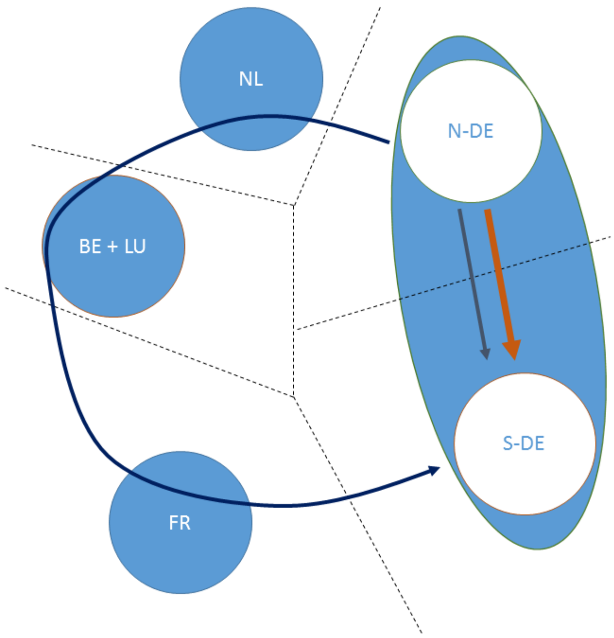


Figure 12 – Commercial flows and generated physical flows after the first step in the flow-based market coupling process, considering the strongly interconnected electricity network in the CWE-region
Source: CREG

29. During all hours of all days, including the 22nd of September, commercial day-ahead exchange volumes were aimed at importing electricity to Belgium (Figure 13 and Figure 14). There was always congestion, which means at least one “critical branch” (a transmission line or other constraint) was active. The average commercially allocated import position to the Belgian bidding zone on day-ahead, during hours 8-21, is 1587 MWh/h. The day-ahead import position at hours 8, 9, and 15 were 1622 MWh/h, 1479 MWh/h, and 1476 MWh/h respectively. Although these hours are characterised by the highest prices (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.

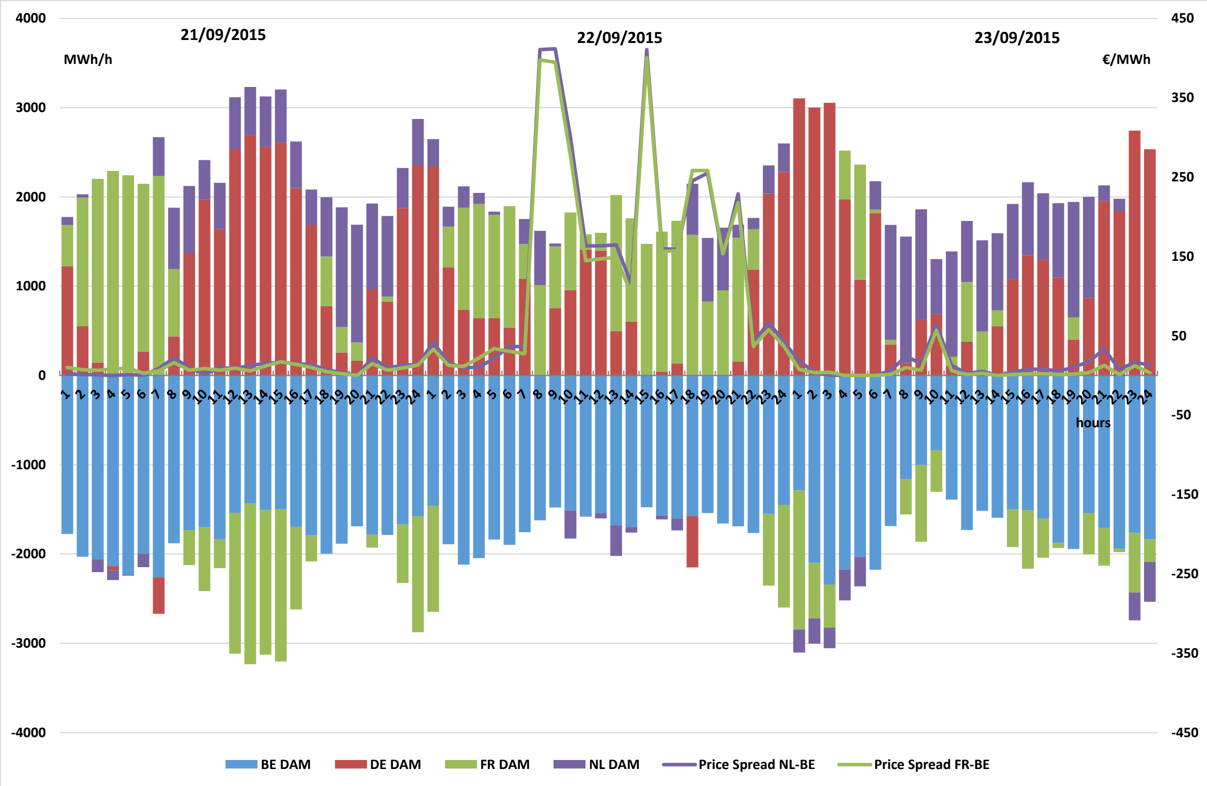


Figure 13 - Allocated commercial exchanges by the flow-based market coupling mechanism between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 21st, 22nd, and 23rd of September.
Source: CASC

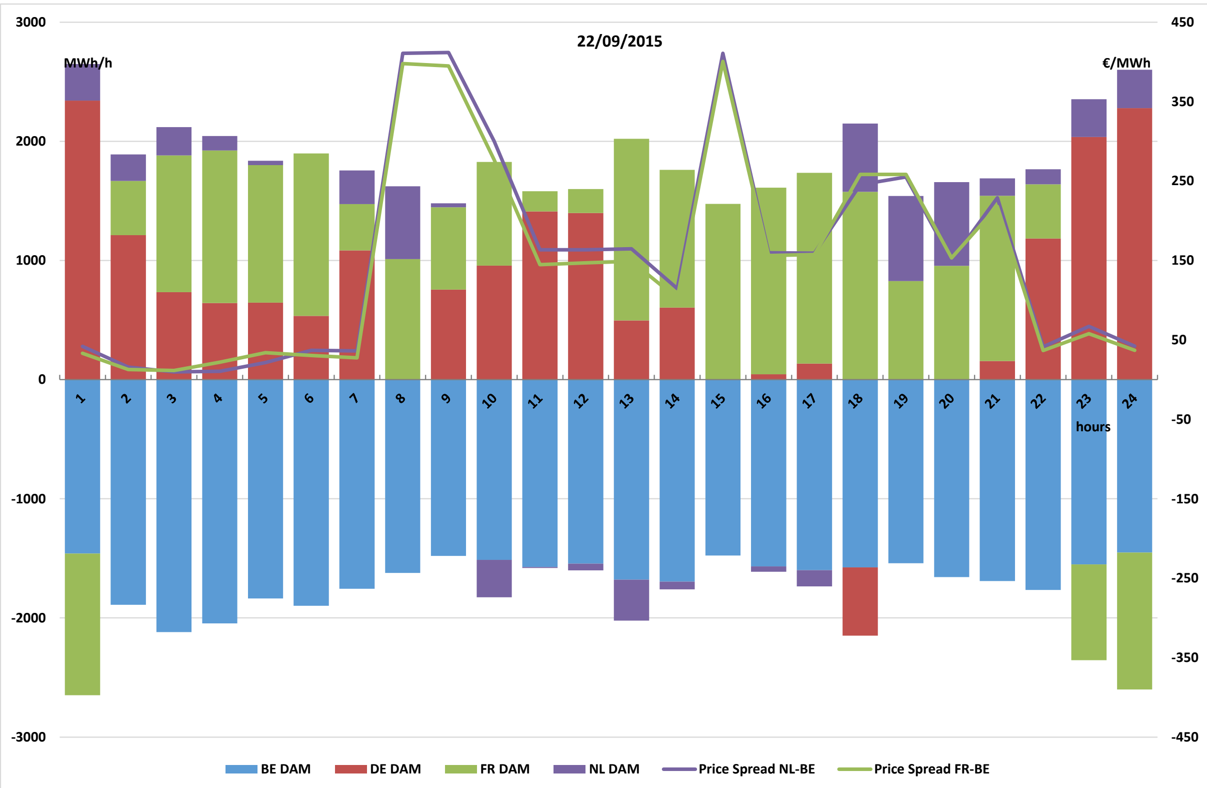


Figure 14 - Allocated commercial exchanges by the flow-based market coupling mechanism between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 22nd of September.
Source: CASC

30. 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 commercial day-ahead exchanges) was 2888 MWh/h (Figure 15 and Figure 16). Despite higher prices the average daily total net import position on the 22nd of September was 146 MWh/h lower (2742 MWh/h). The total net import position on the 23rd of September increased 523 MWh/h to 3265 MWh/h. Electricity is mainly imported from France and partly from Germany.

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

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.

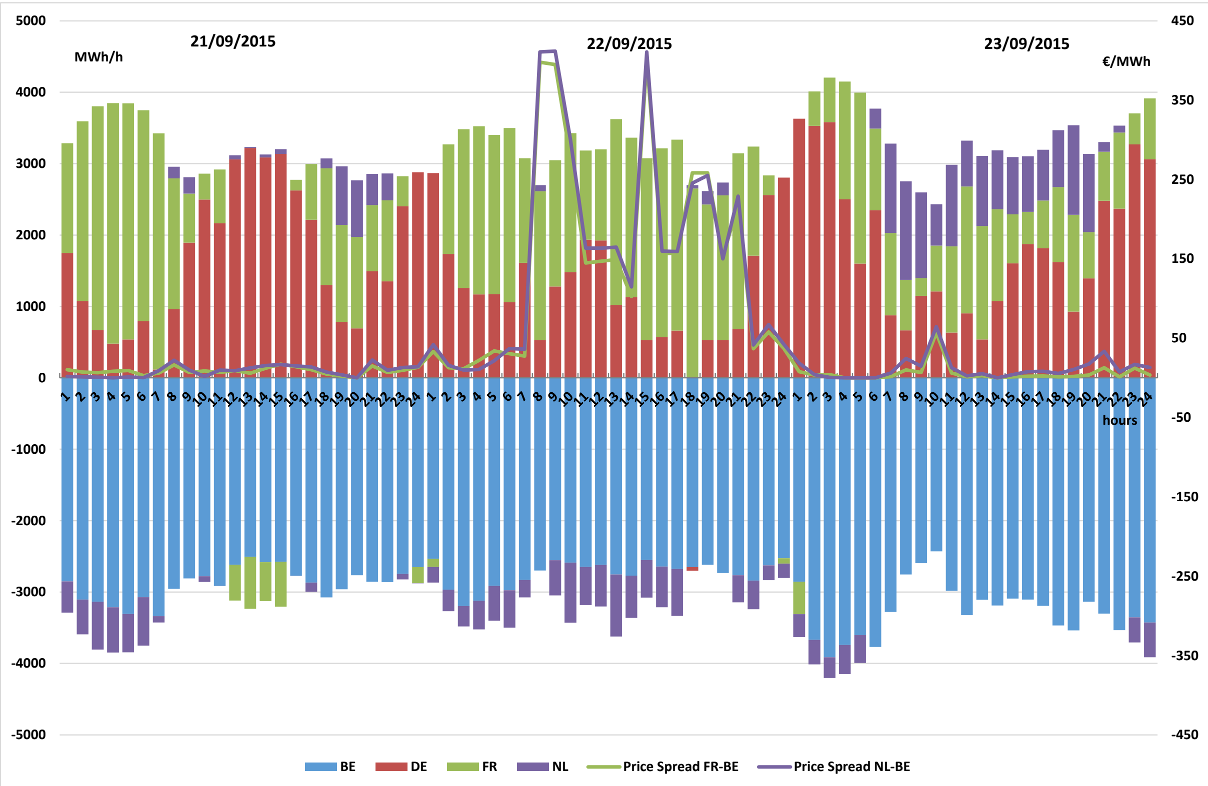


Figure 15 – Net total commercial exchanges between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 21st, 22nd, and 23rd of

September.
Source: CASC

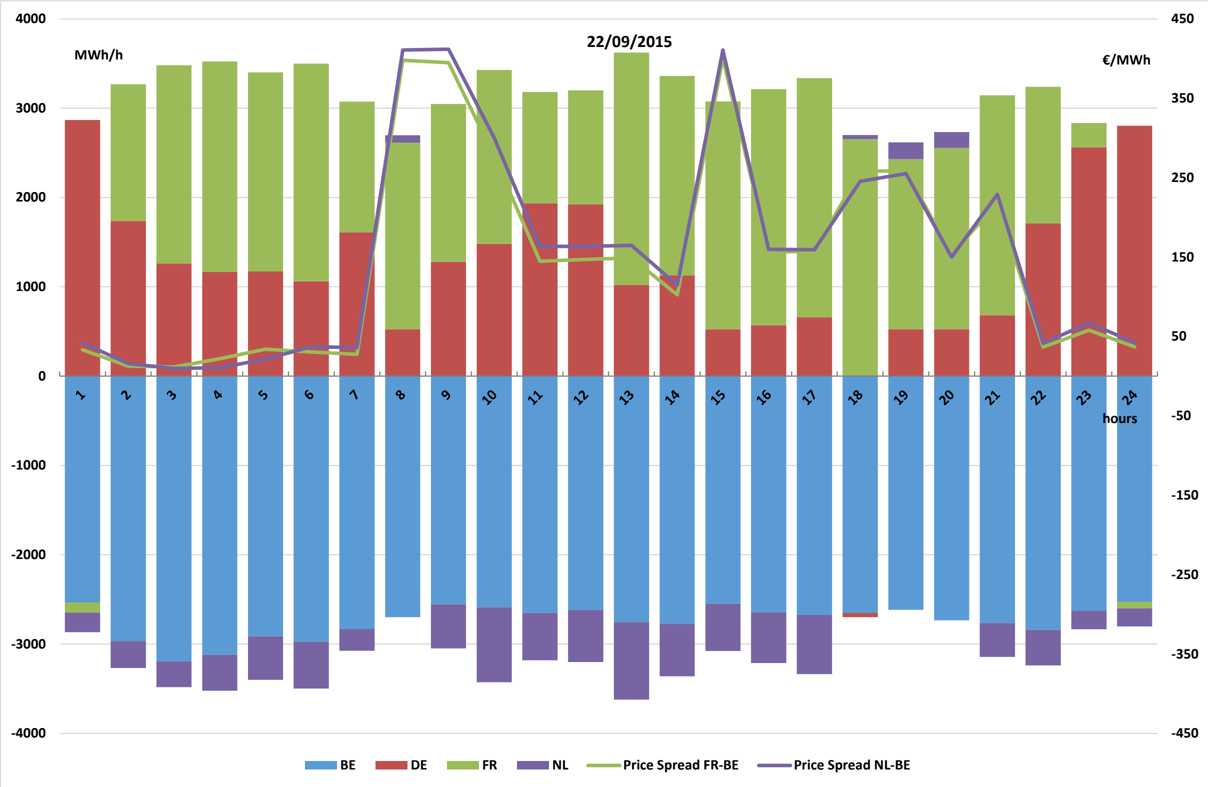


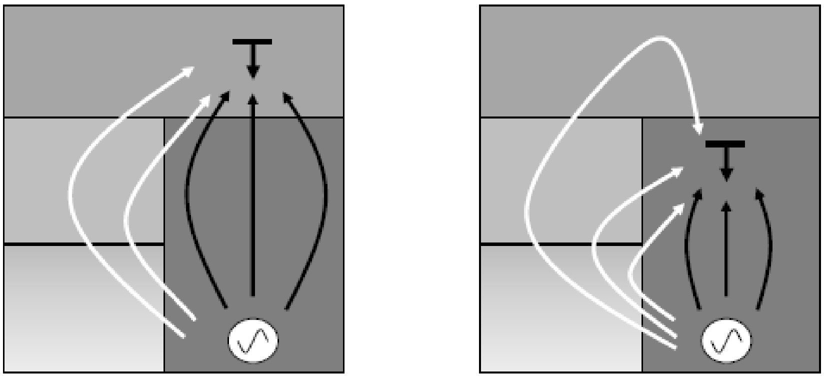
Figure 16 - Net total commercial exchanges between bidding zones, and the price spread between the Belgian bidding zone and the bidding zones with which it is physically interconnected, on the 22nd of September. Source: CASC

II.4.2 Physical flows

II.4.2.1 <u>Direct and transit flows</u>

31. The relatively low 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.

32. When there is a <u>commercial exchange from one bidding zone to another</u>, only part of this power transfer will follow the direct path, resulting in the <u>direct flow</u>. The rest will take the indirect path, leading to a so-called <u>transit flow</u>, 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 Figuur 17).



Figuur 17: Transit flows (left) en loop flows (right) (Schavemaker & Beune, 2013)

33. For example, if France is exporting 2500 MWh/h to Belgium, as was the case on 22nd September, only about 75% of 2500 MWh/h will be a direct flow going through the transmission lines between France and Belgium. The rest, about 25%, will follow the indirect path via Germany and the Netherlands (and via Switzerland, Italy,…) to Belgium. This is the transit flow. This means a power shift of 2500 MWh/h from France to Belgium will result in the following physical flows on the Belgian borders:

- 1875 MWh/h physical flow on the French-Belgian border (direct flow)
- 625 MWh/h physical flow on the Dutch-Belgian border (transit flow)

34. Hence, due to the large import of about 2500 MWh/h from France to Belgium, one would expect a large physical flow from France to Belgium and a small physical flow from the Netherlands to Belgium. However, the real observed physical flows were exactly the opposite: less than 1000 MWh/h 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 18.

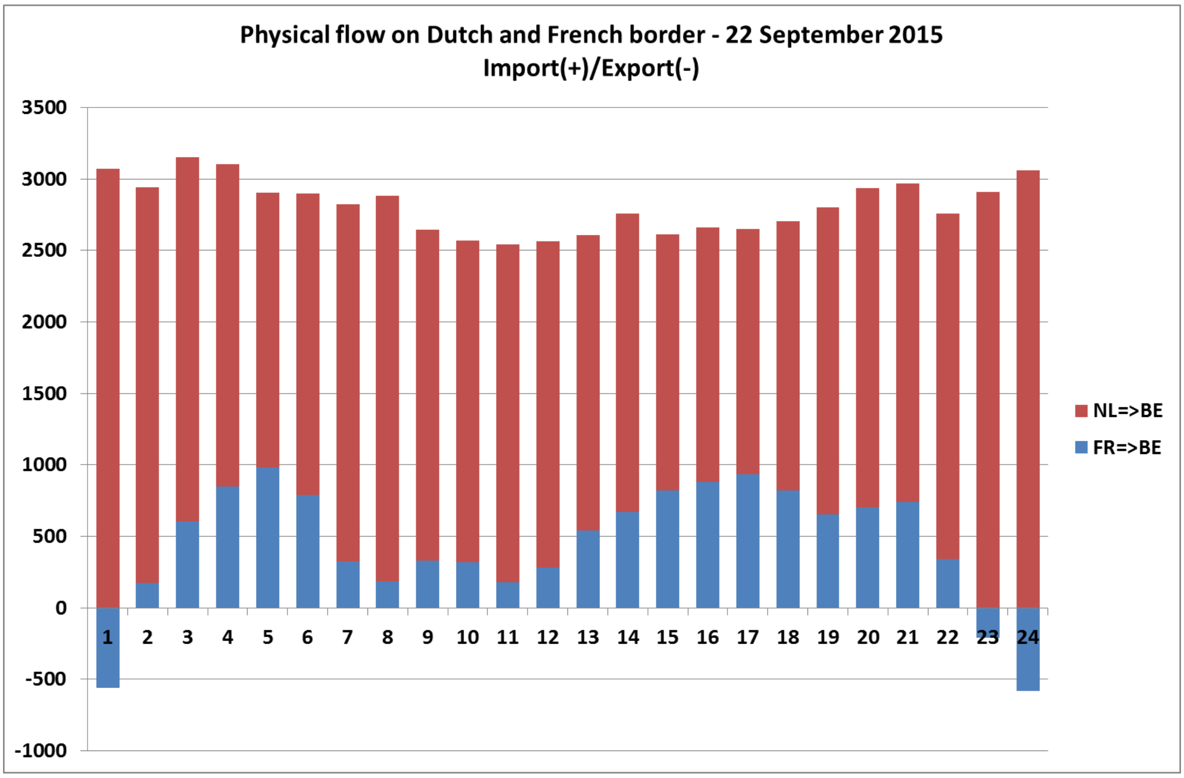


Figure 18 – Measured physcial import flows from the Dutch and the French bidding zone Source: Elia

II.4.2.2 <u>Loop flows and other non-competitive flows</u>

35. 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 going through other bidding zones (see white lines on the right Figuur 17). These exchanges are included in the 'base case' and have 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.

36. So if 1800 MWh/h 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 MWh/h was expected due to the imports from France, 1175 MWh/h out of 1800 MWh/h on the Dutch-Belgian border are (mostly) loop flows[2] (1800 MWh/h – 625 MWh/h = 1175 MWh/h).

37. 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,

[2] A part of these flows may also be generated by exchanges outside the capacity calculation region (see also below).

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.

38. Even if a market participant in Belgium is obliged to pay the maximal price on the power exchange, whatever this price level is[3], 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.

39. 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.

40. 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.

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

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

II.4.2.3 <u>Solutions</u>

43. The above analysis, which 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

[3] Currently, the price cap on the day ahead markets is 3000 €/MWh.

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.

44. Until the end of October 2015, there were three PSTs in the Elia control area near the Dutch-Belgian border. A 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.

45. 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.

46. The CREG supports these solutions that are being put forward by Elia. These solutions could be implemented relatively quickly and will increase efficiency, security of supply and decrease discrimination between internal and cross-border commercial exchanges. This is a necessary condition for the European internal market and the Energy Union.

47. 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. Giving 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.

48. 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[4]:

> *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.*

49. 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 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.

50. 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.

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[4] 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

II.4.2.4 <u>Legal consequences of loop flows and other non-competitive flows</u>

51. 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.

52. CREG repeatedly criticized this discrimination, also in §§120-127 of its decision 1410 of 23 April 2015 on the flow-based market coupling[5]:

> *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 exchanges within the CWE region in favour of internal exchanges[6]. 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.*

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[5] 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

[6] *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.*

124. The method used by transmission system operators to calculate the Generation Shift Keys (GSK)[7] 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 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.4.3 "LTA coverage" avoided prices of 3.000 €/MWh

53. 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

[7] *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.*

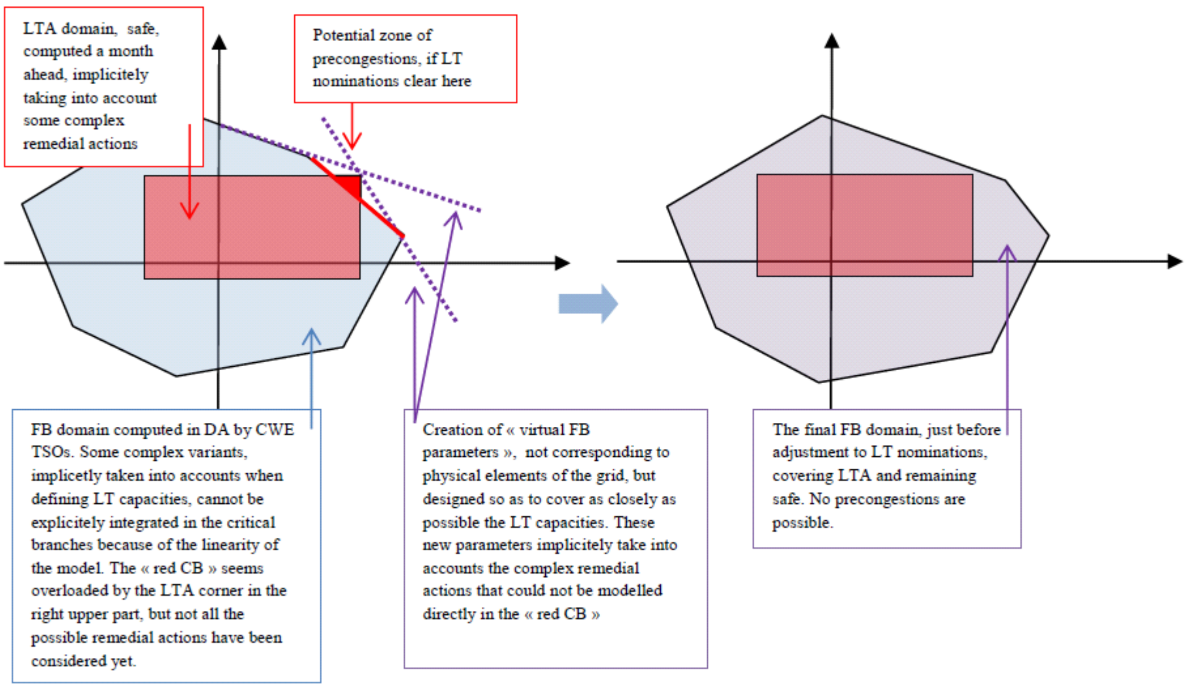
limitation of 4000 MW. CREG has asked Elia to simulate the same day without the LTA coverage and with an import limitation of 4500 MW.

54. 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.

55. 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.

56. From the flow-based market coupling approval package (annex 16.6 Information regarding LTA inclusion[8]), 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*



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

57. The Report "CWE Flow Based Market- coupling project: Parallel Run performance report"[9] 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.*

58. 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 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.

59. 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.

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

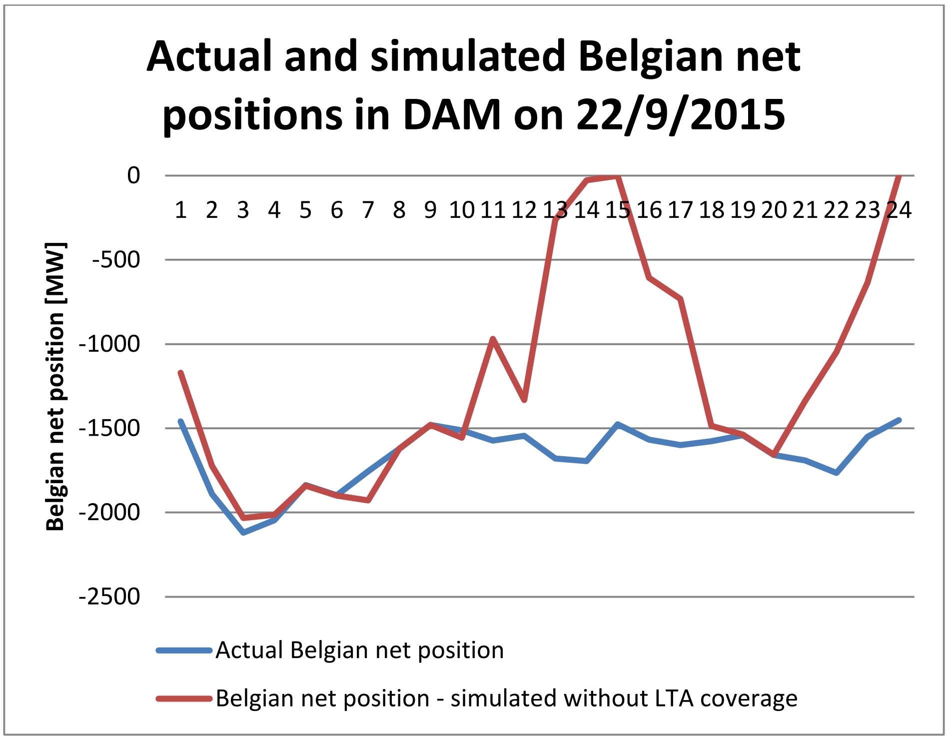

Figure 19: Actual and simulated (without LTA coverage) Belgian net exchange positions on 22/9/2015

60. Figure 19 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.

61. Figure 20 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 DAM. This means that even when offering the maximum price, Belgian cannot import any energy in the day-ahead market.

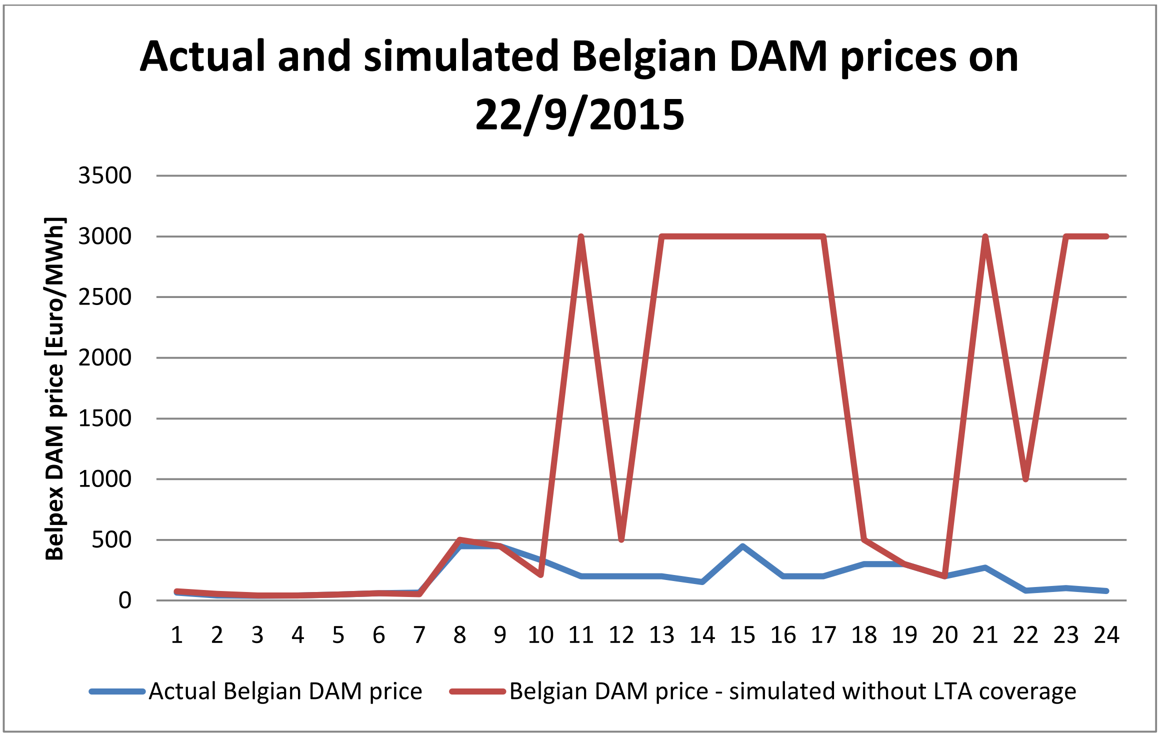

Figure 20: Actual and simulated (without LTA coverage) Belgian DAM prices with Flow-Based market coupling on 22/9/2015

62. 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.

63. 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.

64. 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.

65. The long term nominations, day-ahead market coupling exchanges and intraday[10] exchanges are presented in the following table.

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

	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.

66. 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.

67. 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 is a particular TSO choice that has nothing to do with avoiding price spikes.

68. 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 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.

69. In other words, the application of LTA coverage is a CWE TSO choice and not a market behaviour. In this case the TSO choice 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'.

70. 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.

II.4.4 Advanced hybrid flow-based day ahead market coupling

71. 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 22 September 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.

72. At this time, with the current application of flow-based market coupling[11] 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.

73. 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[12], 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.

74. 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.

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[11] Also referred to as the "rough" Flow-Based ATC hybrid coupling.
[12] 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

II.4.5 Non-intuitiveness and possible impact on import possibilities

75. 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.

76. 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.

II.4.6 Intraday cross-border capacity

77. During 22 September 2015, there was no available intra-day 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.

78. It seems difficult to understand 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 this point, however, there is 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.

79. 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. Based on this information, it is not clear for the CREG why no intra-day capacity was offered for hours 8 to 17.

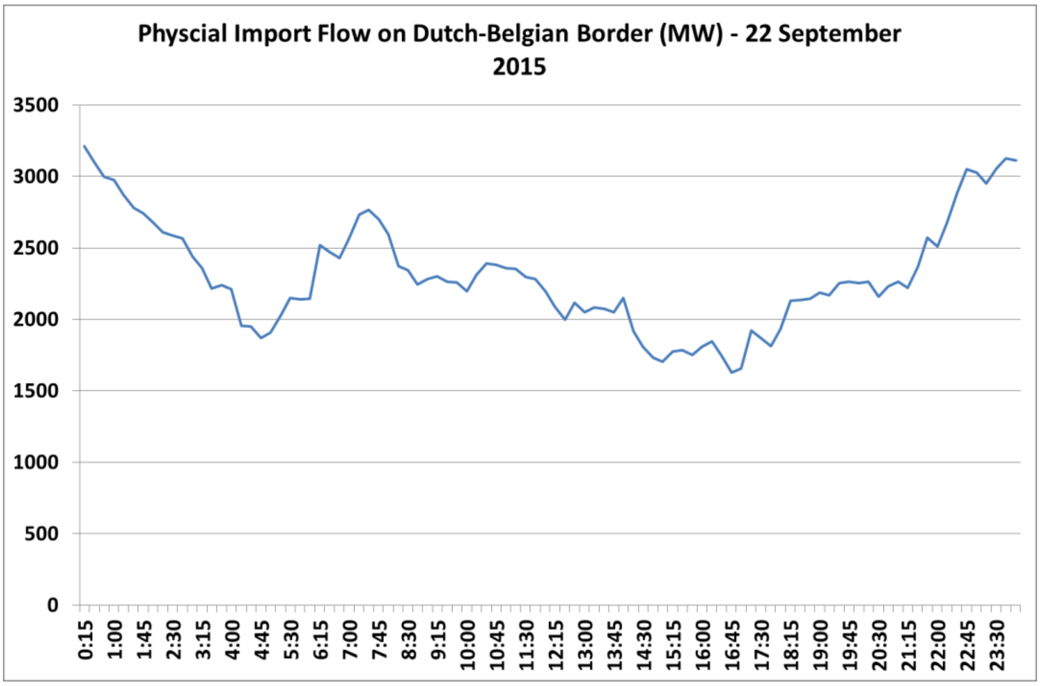


Figure 21: Physical import flow on Dutch-Belgian border (MW) on 22 September 2015 and 16 October 2015

III. CONCLUSION

80. The day-ahead price on 22 September is on average €188,74/MWh, with price spikes of €448,70/MWh.

81. The CREG will conduct a more detailed analysis of bidding behavior once the detailed data on generation units are fully analyzed. However, for the CREG there are at this moment no indications there was anti-competitive behavior causing price spikes.

82. The main conclusion is the inefficient and discriminatory use of cross-border capacity. The case of 22 September 2015 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[13], which increases the risk for security of supply.

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

84. According to the CREG, 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.

[13] 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

85. 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.

86. 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 and not a market behaviour. A simulation of the market outcome without LTA coverage, which could be possible, 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. 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 market behaviour.

87. Finally, it seems clear TSOs could have given more cross-border intraday capacity to the market. 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
Chairwoman of the Board of Directors

ANNEX I – Calculation of non-competitive flows

88. Based on the net commercial positions (Figure 16) and the Bilateral Exchange Computation procedure proposed by the TSOs in the CWE-region[14], during hour 8, a physical flow from the French to the Belgian bidding zone of around 1850 MWh/h and from the Dutch to the Belgian bidding zone of around 850 MWh/h is calculated. When comparing with the actually observed physical flows of 200 MWh/h from the French bidding zone to the Belgian bidding zone, and 2700 MWh/h from the Dutch to the Belgian bidding zone, approximately 1650 MWh/h 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.

89. Similarly, during hour 19, the net physical flows to be expected amount to 1750 MWh/h from the French to the Belgian bidding zone and 900 MWh/h from the Dutch to the Belgian bidding zone. When comparing with the actually observed physical flows of 670 MWh/h from the French bidding zone to the Belgian bidding zone, and 2150 MWh/h from the Dutch to the Belgian bidding zone, around 1100 MWh/h 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.

90. Calculations have been carried out for all hours on the 21st, 22nd and 23rd of September (Figure 22). 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.

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

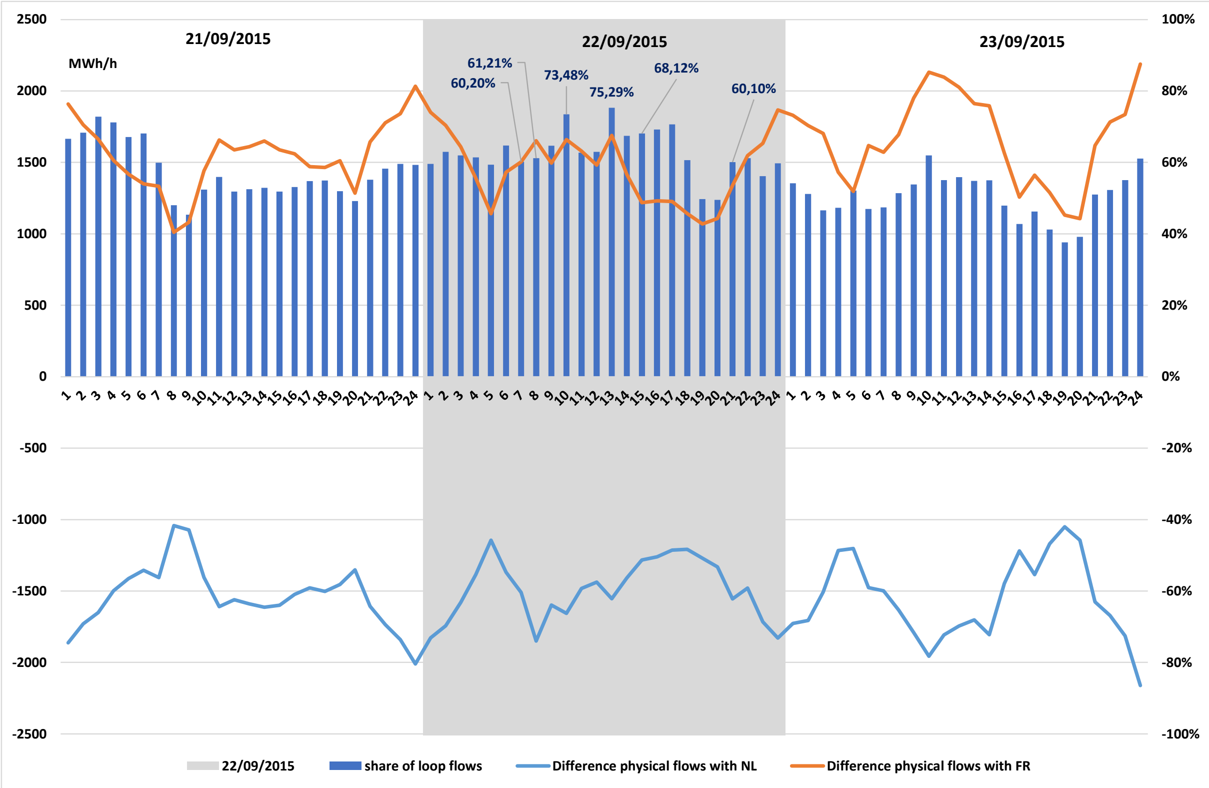


Figure 22 –Difference between measured physical flow and calculated physical flow based on long-term nominated and day-ahead allocated commercial exchanges as a measure for non-competitive flows, including their share relative to the available physical import capacity on the border between the Netherlands and Belgium.. Source: CREG

91. 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 MWh/h of import would have led to market clearing prices in the range of €45/MWh to €55/MWh during hours 8-21.

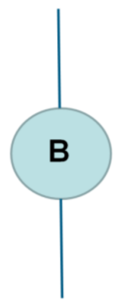
ANNEX II – Impact of loop flows on cross-border capacity – simplified example

92. 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.

93. 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.

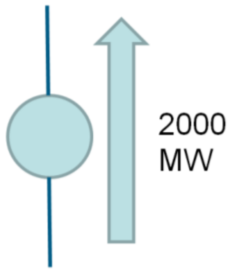
94. Both interconnections have a theoretical capacity of 3000 MW, leading to a total of 6000 MW.

95. 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

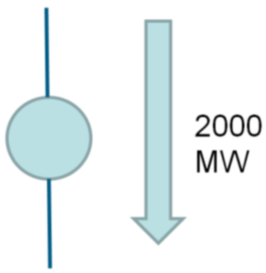
96. Giving the loop flow of 2000 MW from France to the Netherlands and an interconnection capacity of 3000 MW between France and Belgium only 1000 MW is available for importing from France to Belgium. Given the PTDF from France to Belgium of 0.7, Belgium can import 1000 MW / 0.7 = 1429 MW from France. 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

97. 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.

98. 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

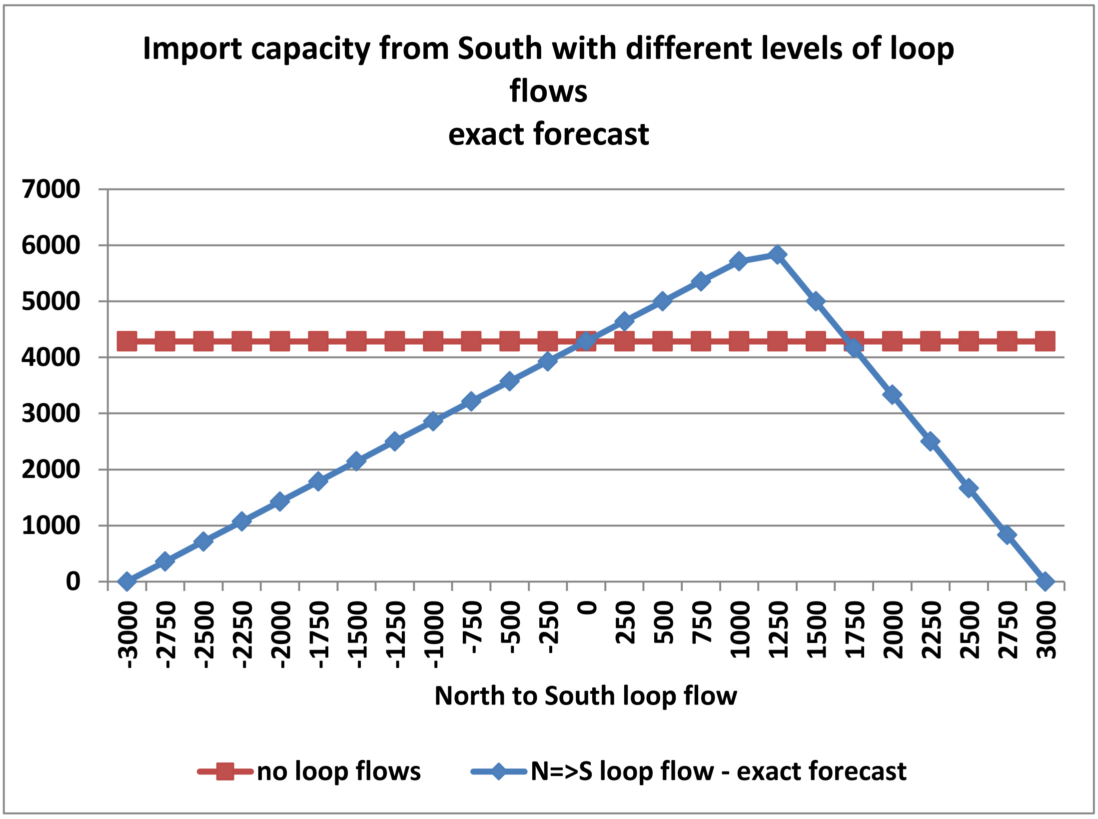
99. Now the limiting interconnection capacity is from France to Belgium. The maximal import is 3000 MW / 0.7 = <u>4286 MW</u>, the highest of all situations.

d) Different levels of loop flows – exact forecast

100. 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.

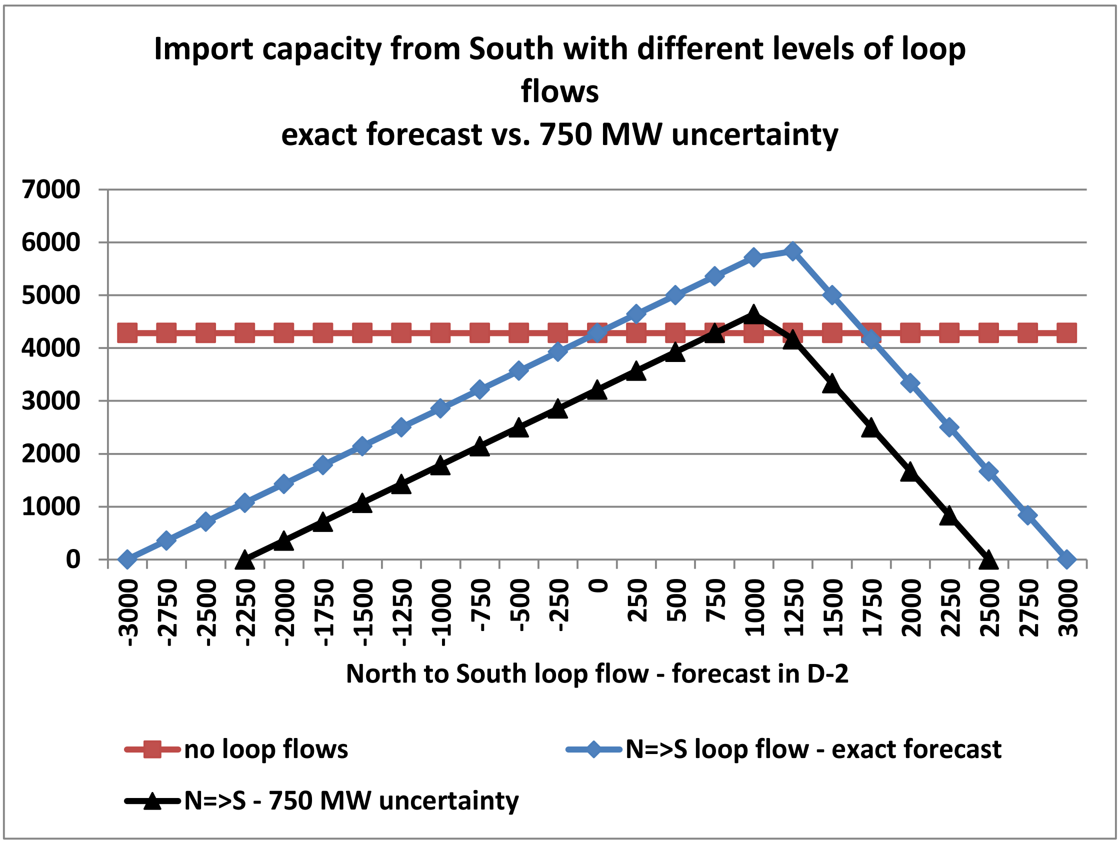


e) Different levels of loop flows in the "good" direction – with forecast errors

101. 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[15]. The figure below is the same as above, but adds a black line.

102. 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.

103. 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.



[15] 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.