Commission voor de Regulering
van de Elektriciteit en het Gas

CREG

Paper

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Paper on the Belgian day-ahead wholesale electricity market from 1 to 7 October 2018, focusing on the market outcomes for 3 October 2018

pursuant to Article 23, §2, 2nd paragraph, 20° and 27° of the Electricity Act

Non-confidential

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EXECUTIVE SUMMARY

During the afternoon of Friday 21 September 2018, Engie Electrabel announced via its transparency website that Tihange 2 and Tihange 3 would not be restarted for the coming winter. This meant that approximately 2,000 MW of production capacity would be lost, on top of the previous announcement that the re-commissioning of Doel 1 and 2 had been abandoned (and would only be available again in mid-December and early January).

As a result, production capacity in Belgium for the coming months is much lower than expected. According to the information provided by Elia in the Parliamentary Commission on 2 October 2018, they anticipate a shortfall of between 700 and 900 MW for the coming winter, in order to meet the legal criteria regarding security of supply. Belgium will remain highly dependent on imports to ensure its security of supply and to keep electricity prices as low as possible. All of these elements have led to a sharp rise in prices in the *forward markets* for delivery in Belgium, especially in the last months of 2018.

Along with the Netherlands, France, Luxembourg, Germany and Austria, Belgium belongs to the Central Western European region (hereinafter referred to as the 'CWE region'). Since 2015, this region has applied *day-ahead flow-based market coupling* (DA FBMC). Given the current situation, the functioning of this market coupling will be crucial for security of supply and pricing in Belgium in the coming months.

Until 1 October 2018, Germany, Luxembourg and Austria belonged to one price area. Since 1 October 2018, Austria has been in a separate price area. This split was the consequence of the implementation of European regulations. This means that different prices may occur between Austria and Germany/Luxembourg if there is network congestion and cross-border trade needs to be restricted for operational security reasons, as was already the case with the price areas of Belgium, the Netherlands and France.

This paper will examine the market outcomes of the *day-ahead flow-based market coupling* of the first week following the splitting of the German-Austrian price area. The period in question runs from Monday 1 until Sunday 7 October 2018. Compared to the planning which was known up until 30 August 2018, there was approximately 1,500 MW less nuclear generation capacity available in Belgium during the period in question. As regards market outcomes, the relatively high prices during this period for Belgium (€96.7/MWh on average) and the low prices in Germany (€18.3/MWh on average) on 3 October 2018 are especially striking at first glance.

The conclusion of this paper is that, based on the period in question, the splitting of the price areas of Austria and Germany/Luxembourg has so far progressed in a technically correct manner: the market coupling appears to be the same as before the split. In addition, on 3 October, the Belgian electricity market was much more robust than might initially be concluded: with an additional demand of 1,000 MW, imports appear to have increased by an average of 866 MW, raising the average market price from €96.7/MWh to €125.1/MWh (an increase of 30%). With an additional demand of 2,000 MW, imports appear to have increased by an average of 1,700 MW, raising the average market price from €96.7/MWh to €183.9/MWh (an increase of 90%).

Part of the reason for this robust result for 3 October 2018 was that the *loop flows* through Belgium (from north to south) were lower than average on that day. If *loop flows* are high, the CREG expects imports to Belgium to increase less strongly, and these are also accompanied by faster rising prices on the Belgian *day-ahead* market, especially given the situation of low availability of nuclear capacity.

INTRODUCTION

1. During the afternoon of Friday 21 September 2018, Engie Electrabel announced via its transparency website that Tihange 2 and Tihange 3 would not be restarted for the coming winter. The FANC had previously communicated that there were problems with the bunkers. This meant that approximately 2,000 MW of production capacity would be lost, on top of the previous announcement that the re-commissioning of Doel 1 and 2 had been postponed (and would only be available again in mid-December and early January).

2. As a result, production capacity in Belgium for the coming months is much lower than expected. According to the information provided by Elia in the Parliamentary Commission on 2 October 2018, they anticipate a shortfall of between 700 and 900 MW for the coming winter, in order to meet the legal criteria regarding security of supply. Belgium will remain highly dependent on imports to ensure its security of supply and to keep electricity prices as low as possible. All of the elements described above have led to a sharp rise in prices in the *forward markets* for delivery in Belgium, especially in the last months of 2018.

3. Along with the Netherlands, France, Luxembourg, Germany and Austria, Belgium belongs to the Central Western European region (hereinafter referred to as the 'CWE region'). Since 2015, this region has applied *day-ahead flow-based market coupling* (DA FBMC). Given the current situation, the functioning of this market coupling will be crucial for security of supply and pricing in Belgium in the coming months.

4. Until 1 October 2018, Germany, Luxembourg and Austria belonged to one price area. Since 1 October 2018, Austria has been in a separate price area. This split was the consequence of the implementation of European regulations. This means that different prices may occur between Austria and Germany/Luxembourg if there is network congestion and cross-border trade needs to be restricted for operational security reasons, as was already the case with the price areas of Belgium, the Netherlands and France before the split.

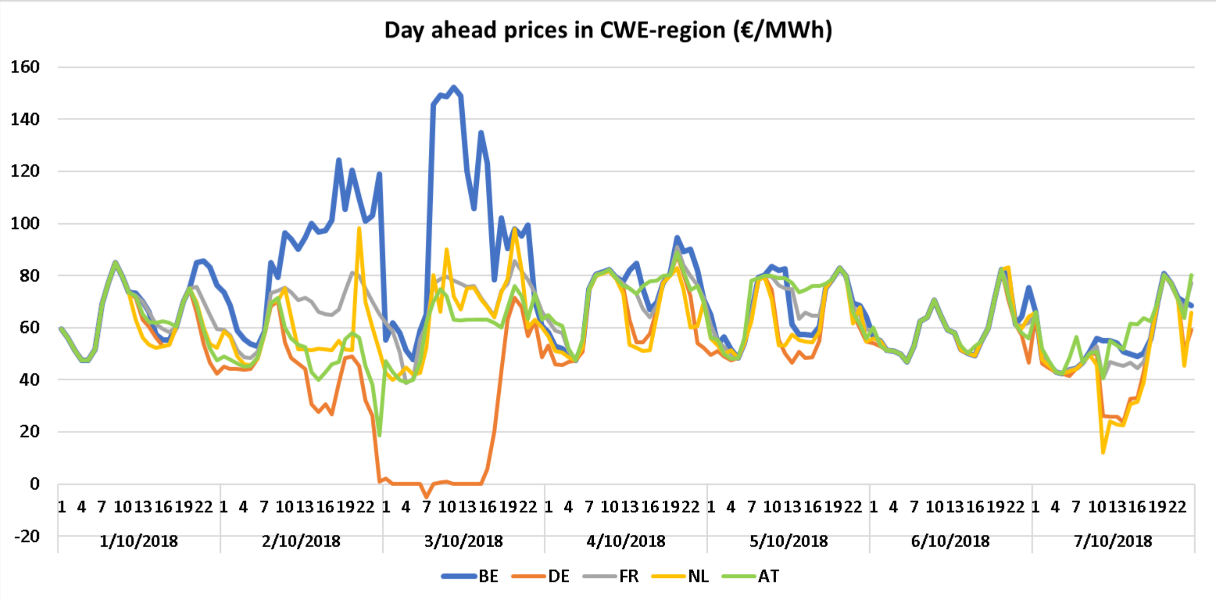
5. This paper will examine the market outcomes of the *day-ahead flow-based market coupling* of the first week following the splitting of the German-Austrian price area (the period examined runs from Monday 1 to Sunday 7 October 2018). Compared to the planning which was known up until 30 August 2018, Belgium had approximately 1,500 MW less nuclear generation capacity available during the period in question. The CREG has taken the initiative to publish this summary paper quickly, as the market results for 3 October 2018, with relatively high prices for Belgium and low prices in Germany, was striking at first glance. Given the tense situation for the coming months, the CREG believes it is important to share its findings on the period in question with the market players, in the context of transparency.

6. The CREG also consulted with Elia regarding the market outcome for 3 October 2018. The CREG also requested the EPEX SPOT BE trading exchange to carry out a number of simulations for this specific day. The results of the consultation with Elia and the simulation requested from EPEX SPOT BE are also discussed in this paper.

1. MARKET OUTCOME 1 TO 7 OCTOBER 2018

7. The figure below shows the hourly *day-ahead* wholesale price for the five countries of the CWE region (in €/MWh). The period in question runs from Monday 1 until Sunday 7 October 2018. The blue line shows the price for Belgium. This price is generally comparable to the other prices, except on 2 October, and especially not on 3 October. During this week, the average wholesale price in Belgium was €72.8/MWh. This was higher than Germany (€50.5/MWh), France (€64.6/MWh), the Netherlands (€59.6/MWh) and Austria (€61.8/MWh).

8. For 3 October, the price difference with Germany was particularly noticeable during hours 8 to 16. During these hours, Belgium recorded prices of €105-152/MWh, while in Germany the price fluctuated around €0/MWh. The average Belgian price was €96.7/MWh compared to €18.3/MWh in Germany. This is remarkable and is explained below in this section.



Source: CREG, JAO, EntsoE

9. The following figure shows the volumes exchanged per hour for each price area of the CWE region (in MW). A positive value indicates exports; a negative value indicates imports. As expected, Belgium imported throughout the week, with an average import of 2,232 MW. The minimum import to Belgium was 505 MW on hour 2, on 3 October 2018; the maximum import was 3,956 MW on hour 9, on 4 October 2018.

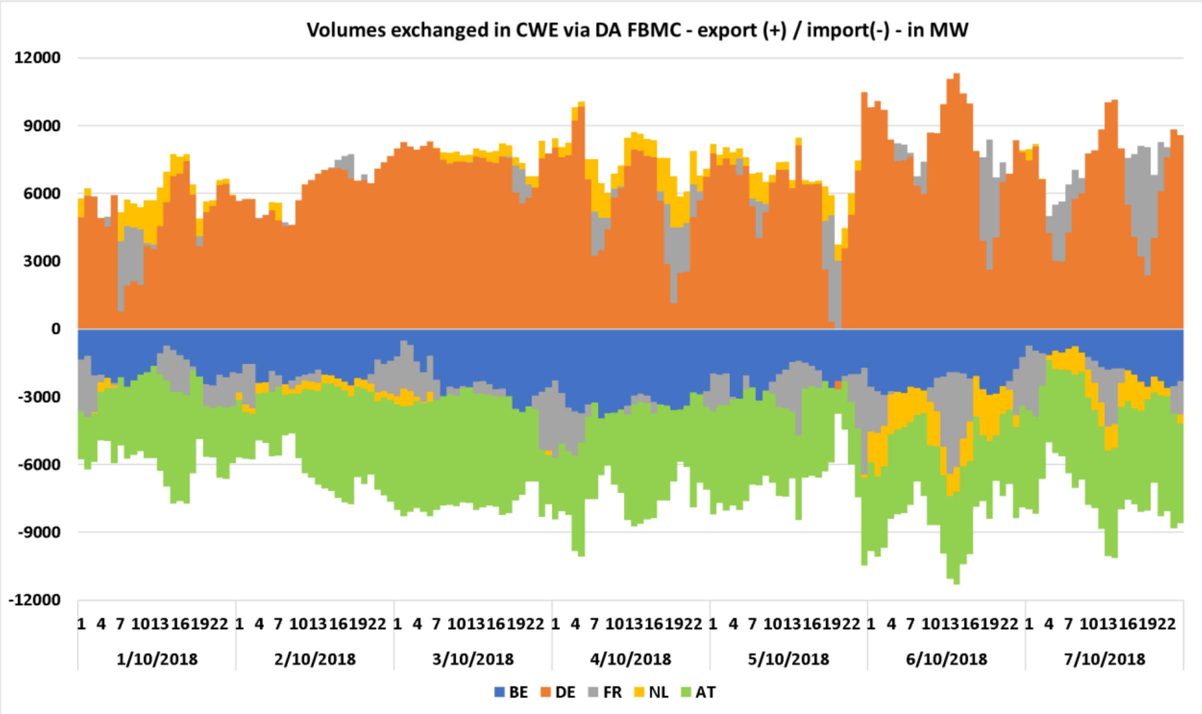
10. It could be expected that the maximum imports would coincide with the highest price difference in the CWE region, particularly during hours 8-16 on 3 October. The average imports to Belgium during these hours were 2,560 MW, only several hundred MW higher than the average import of the week in question, and 3,000 MW lower than the maximum import to Belgium (5,500 MW). Imports to Austria during these hours were almost 5,000 MW, twice as high as to Belgium, while the price difference between Austria and Germany was around half compared to the price difference between Belgium and Germany.

11. The above can be explained by the limited available network capacity and the inefficiencies[1] of *day-ahead flow-based market coupling*, but also because the aim of market coupling is to optimise welfare within the CWE region[2]. This welfare pertains not just to profit for consumers (the consumer surplus), but also profit for producers (the producer surplus). As such, market coupling is designed not only to avoid high prices, as this will be detrimental to the consumer surplus, but also to avoid very low prices, as this will be detrimental to the producer surplus. On Wednesday 3 October, it was a national holiday in Germany (the anniversary of German reunification in 1990), resulting in low consumption. The low consumption combined with the relatively high supply of solar and wind production resulted in a large production surplus in Germany, which led to the low prices. If Germany had not been able to export to the other countries in the CWE region, the price according to the EPEX SPOT simulation would have been around -€50/MWh during those hours, which is detrimental to the producer surplus in Germany.

12. In addition, there was also a phase shift transformer (PST) within the Belgian network which limited higher imports to Belgium, as congestion had been predicted, partly due to the requested imports to Belgium, but also due to the *loop flows* from the CWE region and especially from Germany. Given that this PST is located at the border with the Netherlands, it is heavily loaded during imports from the Netherlands to Belgium, less so during imports from Germany, and by the least amount during imports from France. It is therefore more favourable for Belgium to import from France in this situation, because Belgium will then be able to import a larger volume. However, by importing from France, prices in France rise, while by importing less from Germany, prices in Germany fall even lower. The result of the welfare optimisation for this day was that Belgium imported a smaller volume from Germany instead of a larger volume from France.

13. The fact that imports were only 2,560 MW during hours 8 to 16 can be explained by the fact that the phase shift transformer (PST) risked being overloaded. Belgium has installed 4 PSTs, each with a capacity of around 1,500 MW. Since one is unavailable until 15 December 2018, Belgium has approximately 3,000 MW of capacity in PSTs in N-1 situation. However, this capacity is also partly taken up by *loop flows* and a safety margin of around 250 MW per PST, further reducing import capacity.

[1] See CREG study number 1687 published at the end of 2017:
https://www.creg.be/sites/default/files/assets/Publications/Studies/F1687EN.pdf
[2] The legal basis for this is Article 38 of European Regulation 2015/1222 (NC CACM).



Source: CREG, JAO

Impact of the split of the price area for Germany and Austria: loop flows are partly transit flows

14. Germany generally exports a lot of electricity to Austria. A large proportion of these energy flows follow the direct route via interconnection lines between Germany and Austria. A small but significant part follows the route via the Netherlands, Belgium, France, Germany/Switzerland/Italy to Austria. Elia estimates that approximately 8 percent of exports from Germany to Austria pass through Belgium en route to Austria. An export of 5,000 MW from Germany to Austria therefore generates 400 MW of electricity through the Belgian grid.

15. Before the splitting of Austria and Germany/Luxembourg, this indirect side flow of 400 MW would be considered by Belgium as a *loop flow* and would therefore have priority access to Belgium's network, thereby significantly reducing Belgium's import capacity[3]. Even if Belgian consumers needed the network capacity much more than Austrian consumers, Belgium would still have to tolerate the fact that this *loop flow* of 400 MW takes up the network capacity in this situation, even if the Belgian market players wanted to pay the highest possible price of €3,000/MWh on the *day-ahead* market.

16. Nevertheless, because of the splitting of Austria and Germany/Luxembourg, this indirect side flow of 400 MW is not a *loop flow* but only a *transit flow*. The main difference with a *loop flow* is that a *transit flow* can be "competed away". In other words, if Belgium wants to pay higher prices because electricity is scarce here, the *transit flow* of e.g. 400 MW will be reduced to favour imports to Belgium.

17. The consequence of the split is that import capacity to Belgium can now be increased more strongly if the market in Belgium is tighter, which has a favourable impact on security of supply and a reduction in the risk of having to pay up to €3,000/MW on the Belgian *day-ahead* market.

[3] A *loop flow* of 400 MW reduces the import capacity from Germany by around 800 MW (given that the Belgian network is restrictive).

2. SIMULATION OF THE MARKET OUTCOME 3 OCTOBER 2018

18. It was explained in the previous section that import capacity to Belgium can increase significantly if Belgium wants to pay higher prices on the *day-ahead* market. With the splitting of Austria - Germany, this effect is enhanced since part of the "non-competitive" *loop flows* are transformed into "competitive" *transit flows*. *Transit flows* can be competed away, but *loop flows* cannot.

19. The CREG requested EPEX SPOT BE[4] to simulate the market results[5] if, during all the hours of 3 October 2018, an additional demand at €3,000/MWh were offered in Belgium for five different volumes: 250 MW, 500 MW, 1,000 MW, 1,500 MW and 2,000 MW. The figure below shows the historical price and the 5 simulated price series. The table below shows a number of statistics with the averages per day. The source is EPEX SPOT.

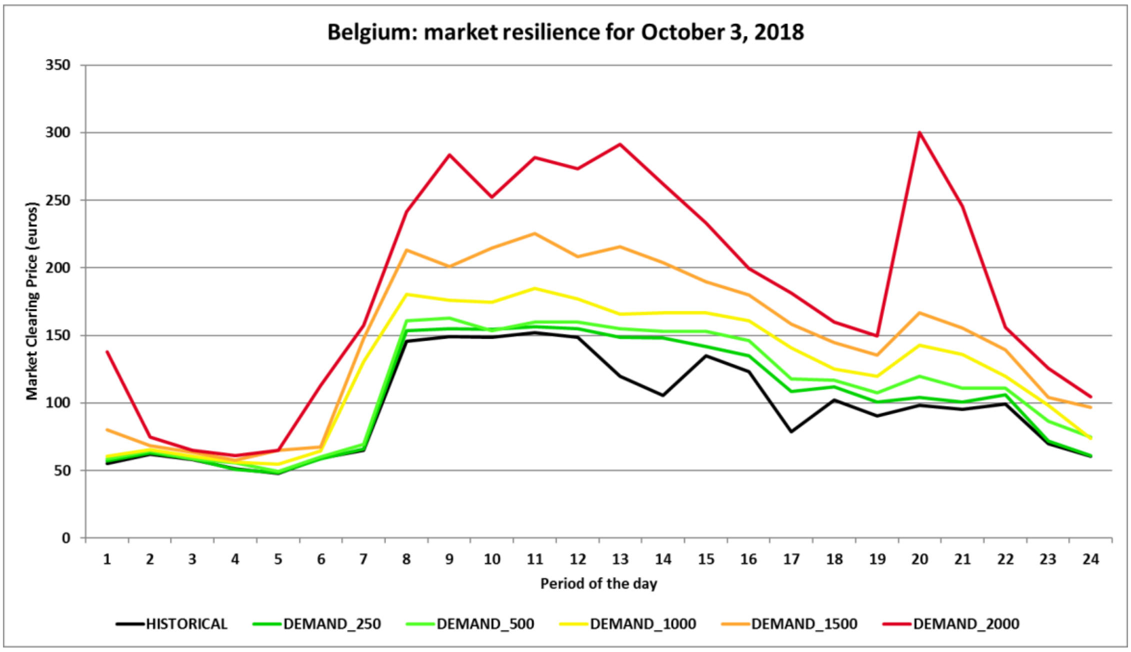
20. These results show that the market is relatively robust, in the sense that the price changes relatively little if there is more electricity demand: 1,000 MW of extra demand results in a price increase of 30%. 2,000 MW of additional demand will result in a price increase of 90%. With 2,000 MW additional demand, the price for one hour rises to €300/MWh.

	market resilience BE day-ahead market - 3 October 2018					
additional demand (MW)	**historical**	**+250 MW**	**+500 MW**	**+1000 MW**	**+1500 MW**	**+2000 MW**
average price (€/MWh)	96.71	104.79	111.09	125.06	145.94	183.95
price increase (€/MWh)		8.08	14.39	28.36	49.24	87.24
relative price increase (%)		8.4%	14.9%	29.3%	50.9%	90.2%

Source: CREG, EPEX SPOT

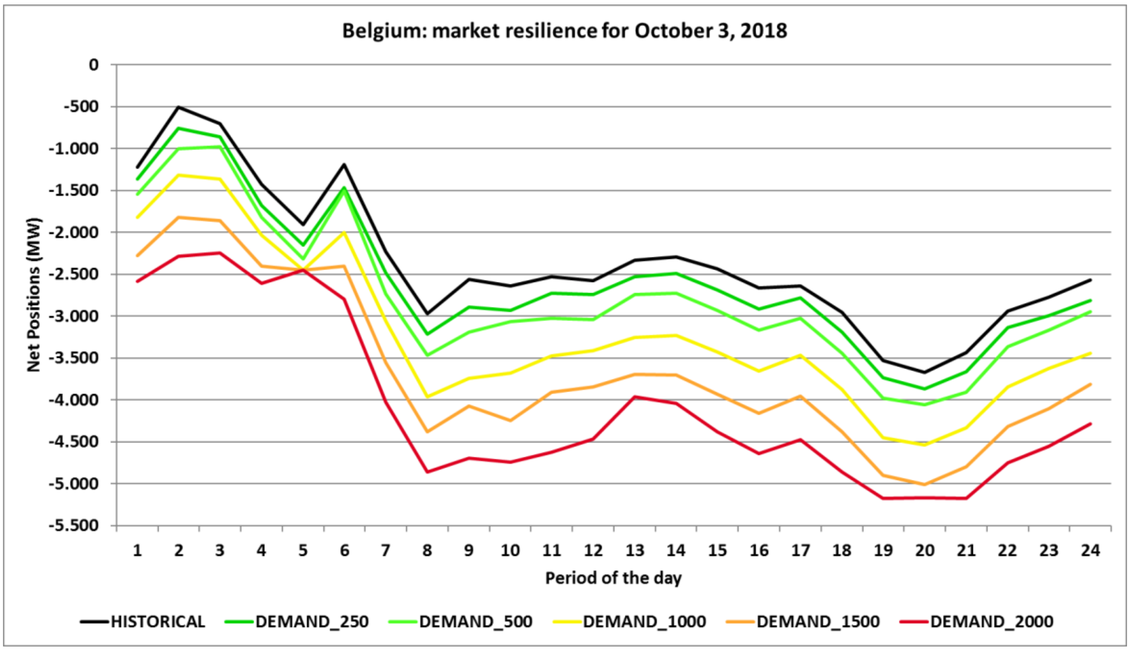
[4] EPEX SPOT is a market operator and can carry out simulations based on the existing order books in the event of a change in supply or demand as regards the historical order book.

[5] EPEX SPOT simulates these results with the order books offered by market players at EPEX SPOT. As such, the simulation does not provide an exact result, because the impact of other price areas not managed by EPEX SPOT cannot be accurately calculated. However, the price areas that EPEX SPOT does not manage do not border on the Belgian price areas, so the CREG estimates that it is highly likely that the simulated results do not differ significantly from the same results as if more distant price areas were also accurately included.



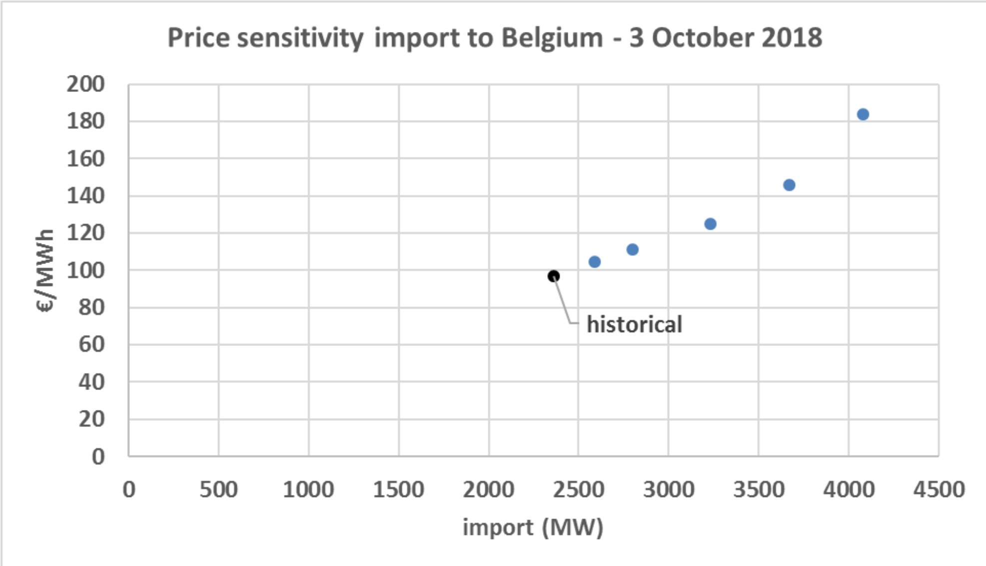
Source: EPEX SPOT

21. These results can largely be explained by the increased imports to Belgium. The figure below shows imports to Belgium for the various levels of additional demand (imports are negative by convention). We can see that imports increase sharply as demand in Belgium rises. For 1,000 MW of additional demand, imports increase by an average of 866 MW; at peak times, imports increase from around 3,200 MW to 4,500 MW. With 2,000 MW of additional demand, imports increase by an average of 1,715 MW; with this additional demand, imports increase above 5,000 MW during peak hours. This higher import is because of the mechanism described above: since electricity is scarcer in Belgium, Belgium records higher prices. As a result, Belgium receives more imports via welfare optimisation.



Source: EPEX SPOT

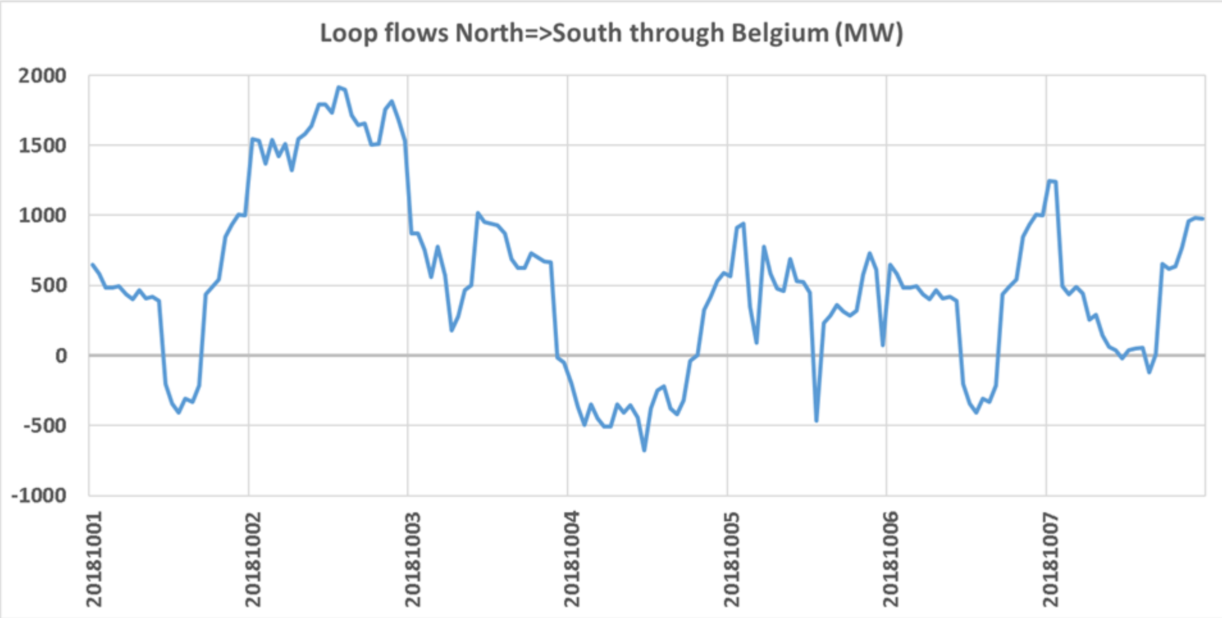
22. The figure below combines the two previous charts. It shows the price sensitivity of average imports to Belgium for 3 October 2018 if there had been 250 MW, 500 MW, 1,000 MW, 1,500 MW and 2,000 MW additional demand. The figure shows the average price compared to the average import for the various levels of additional demand.



Source: CREG, EPEX SPOT

23. It is important to note that these high import levels are only possible if the *loop flows* are limited to an acceptable level. The figure below shows the *loop flows* through Belgium predicted in D-2, for the period from 1 to 7 October 2018. For 3 October 2018, the *loop flows* were 632 MW on average. On the days following Wednesday 3 October, the *loop flows* were much lower and prices in the CWE region were also much more converged. However, on Tuesday 2 October, the *loop flows* were 1,623 MW on average, or nearly 1,000 MW higher than on 3 October and well above the level of 300 MW that the CREG deems acceptable (as also mentioned in the Parliamentary Committee on Business on 2 October 2018). Prices in Belgium were already significantly higher that day compared to the rest of the CWE region. In the event of high *loop flows*, it would have been much more difficult to increase imports to Belgium on 3 October. In other words, the favourable price sensitivity of imports before 3 October was possible due to a large extent to the relatively low *loop flows* on that day.

24. As explained in the previous section, the CREG expects that the *loop flows* should decline on average from 1 October 2018 on, resulting from the splitting of the German-Austrian price area



Loop flows North=>South through Belgium (MW)
2000
1500
1000
500
0
-500
-1000
20181001
20181002
20181003
20181004
20181005
20181006
20181007

Source: Elia

CONCLUSION

25. The conclusion of this paper is that, based on the period in question, the splitting of the price areas of Austria and Germany/Luxembourg has so far progressed in a technically correct manner: the market coupling appears to be the same as before the split[6].

26. In addition, on 3 October, the Belgian electricity market was much more robust than might initially be concluded: with an additional demand of 1,000 MW, imports appear to have increased by an average of 866 MW, raising the average market price from €96.7/MWh to €125.1/MWh (an increase of 30%). With an additional demand of 2,000 MW, imports appear to have increased by an average of 1,700 MW, raising the average market price from €96.7/MWh to €183.9/MWh (an increase of 90%).

27. Part of the reason for this robust result for 3 October 2018 was that the *loop flows* through Belgium (from north to south) were lower than average on that day. If *loop flows* are high, the CREG expects imports to Belgium to increase less strongly, and these are also accompanied by faster rising prices on the Belgian *day-ahead* market, especially given the situation of low availability of nuclear capacity.

For the Commission for Electricity and Gas Regulation (CREG):

Andreas TIREZ
Director

Marie-Pierre FAUCONNIER
Chairwoman of the Board of Directors

[6] This does not mean that the CREG is satisfied with the functioning of *day-ahead flow-based market coupling* (DA FBMC). On the contrary: the problems with high *loop flows* and low RAM values persist. The CREG published a study on this at the end of 2017 (https://www.creg.be/sites/default/files/assets/Publications/Studies/F1687EN.pdf) and addresses the issue in its monitoring reports on the wholesale electricity market. However, an evaluation of DA FBMC is beyond the remit of this paper.