Commission de Régulation
de l'Électricité et du Gaz

Note

(Z)1715
28 June 2018

Review of the day-ahead market results in November 2017

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

Non-confidential

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TABLE OF CONTENT

EXECUTIVE SUMMARY

The CREG received by e-mail 12 informal enquiries on the results of the day-ahead electricity market for the delivery of wholesale energy products in Belgium, as organised by EPEX SPOT Belgium. All enquiries were related to the daily results on specific days in October and November 2017 and are jointly addressed in this document.

One enquiry was received on the 10th of November 2017 regarding a doubt concerning the reported outages of generation plants in Belgium. Another enquiry was received on the 16th of November 2017 concerning the publication time of reported outages. The other 10 enquiries were received from the 3rd of October to the 13th of November asking the CREG to have a detailed look at the orderbook. Given that a gas-fired power plant is typically the marginal power plant when prices are high, underlying gas price movements did not explain the elevated electricity prices.

The reason of the unavailability of large nuclear and gas-fired power plants connected to the Elia-grid during September to November 2017, all of them owned by Engie Electrabel, was either related to a technical failure or a technical constraint. Tihange 1 and Doel 3 were scheduled to be in maintenance during the same period before the technical failure triggering their unplanned and prolonged unavailability. Tihange 1 required works for its prolongation, and Doel 3 needed a refuel. Given other constraints to be accounted for when scheduling a maintenance of a nuclear power plant – safety measures, required (third party) expertise, and logistics – neither the nature nor the timing of the scheduled maintenance seem unjustified. The analysis of historic reductions of nuclear generation levels since 2014 also did not provide reasonable grounds to suspect that the unavailability of nuclear power plants was not of a genuine nature.

In terms of market transparency, articles 2(1) and 4 of REMIT state that all information that a reasonable market participant would be likely to use as part of the basis of its decision to enter into transactions must be published as long as the information is of a precise nature and it would significantly affect prices of wholesale energy products. The CREG welcomes arguments if market participants reasonably need additional information to be published.

Following the reception of the 10 other enquiries, the CREG questioned five market participants to justify their orders introduced in the Belgian day ahead order book. While the demand side has indicated that must-buy demand is not always bid at the market ceiling price with the claim that commercial risk is mitigated, bid prices on the supply side appear to be cost-reflective.

The Belgian day-ahead orderbook however did not contain an order at a price equal to the market clearing price indicating that the elevated prices are caused by congestions on cross-border elements and/or due to the price formation, which is based on the flow-based market coupling algorithm. Congestions were present on multiple grid elements in Germany, the Netherlands and Belgium, and were caused by the presence of high loop flows. This note also explains the price formation in the day ahead flow-based market coupling, explaining that prices are not necessarily set at the marginal cost of the marginal capacity, but are the result of the incremental optimization of the welfare in the CWE-region.

The CREG welcomes formal and informal enquiries on events that have occurred and encourages market participants to continue this active engagement. The CREG highly appreciates feedback and comments on this note and encourages stakeholders to communicate other interesting or remarkable events. The CREG aims to timely review enquiries it receives and, if deemed relevant, will publish its results.

1. INTRODUCTION

1. The CREG received by e-mail 12 informal enquiries on the results of the day-ahead electricity market for the delivery of wholesale energy products in Belgium. All enquiries were received between the 3rd of October and the 13th of November and concerned delivery in Belgium in October and November. The CREG was asked to have a detailed look at the orderbook. Given that a gas-fired power plant is typically the marginal power plant when prices are high, underlying gas price movements did not explain the elevated electricity prices. Enquiries on the one hand expressed doubts concerning the genuineness of the reported outages of generation plants in Belgium, and on the other hand expressed doubts concerning the publication time of reported outages.

2. The goal of this document is to provide feedback to all market participants and any other stakeholders on the reasons why observed prices in October 2017 and November 2017 were elevated. In the process of explaining the elevated prices, the CREG also reviewed the nature and the publication time of generation power plant outages. Given that internal network constraints in Germany and the Netherlands were found to be the principal reason for elevated power prices in Belgium in the past, the cross-border aspects are once again assessed.

3. The CREG highly appreciates feedback and comments on the document and encourages stakeholders to communicate other interesting or remarkable events. The CREG aims to timely review communicated events. If said review results in a useful insight, the CREG will publish a summary of the results to inform all relevant stakeholders, thereby guaranteeing a level playing field and an equal understanding among market participants. Additionally, by publishing its reviews, the CREG invites market participants to provide feedback.

2. REVIEW

2.1. CONTEXT OF THE ENQUIRIES

4. From September, and continuing until the end of 2017, baseload day-ahead power spot prices for delivery in Belgium, as cleared on EPEX SPOT Belgium, increasingly diverged from baseload ZTP gas prices for delivery in Belgium (Figure 1). The divergence is measured by the difference of the electricity price with the double of the gas price. A gas power plant with an average efficiency of 50% is assumed to be the most expensive generation plant to supply the demand in Belgium.

Baseload power spot prices reached record highs of €122/MWh on the 9th of November and of €90/MWh on the 16th of November.

5. During the same period, a reduction in daily generated volumes from nuclear power plants is observed, leaving Belgian gas power plants and imports to supply the volumes needed to fully cover the Elia-load (Figure 2). From the end of September, nuclear generation remains constant, however, except for the sudden reduction on the 10th of November. Physical imports are increasingly relied on to cover the Elia-load, but on the 9th of November and the 16th of November they were limited to only 2.000 MWh/h. On both days, gas power plants generated on average 2.820 MWh/h.

6. The above observations merit a more detailed analysis of the situation to determine whether the high prices emerged because of generation capacity scarcity, trading behaviour, transmission capacity scarcity, or a combination thereof. The analysis focuses on the availability of power plants (section 2.2), the bidding behaviour and the general state of the Belgian power market (section 2.3), and cross-border aspects (section 2.4).

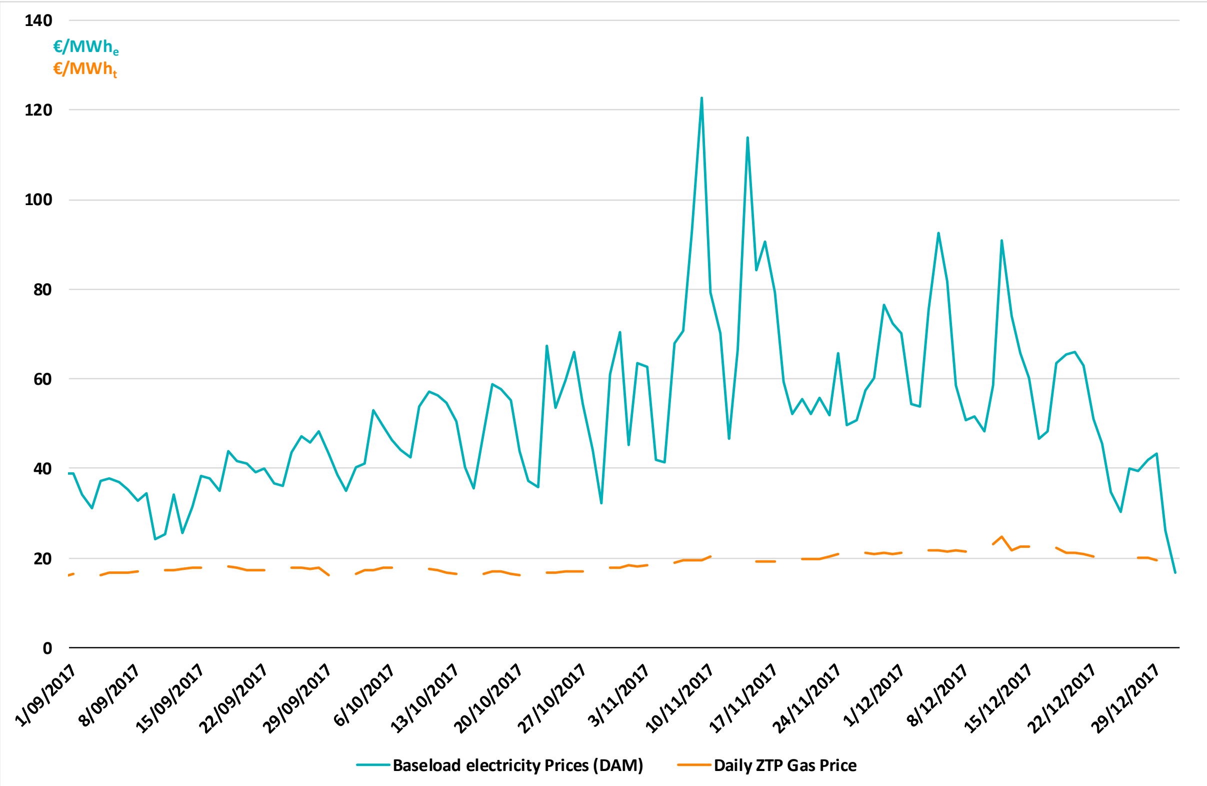

Figure 1 : Wholesale baseload day-ahead electricity prices for the supply of the Belgian bidding zone (DAM) and wholesale baseload day-ahead gas prices for delivery in the ZTP trading hub. Assuming an efficiency of around 50% for the marginal gas-fired power plant, baseload electricity prices should be around twice the value of baseload natural gas prices.

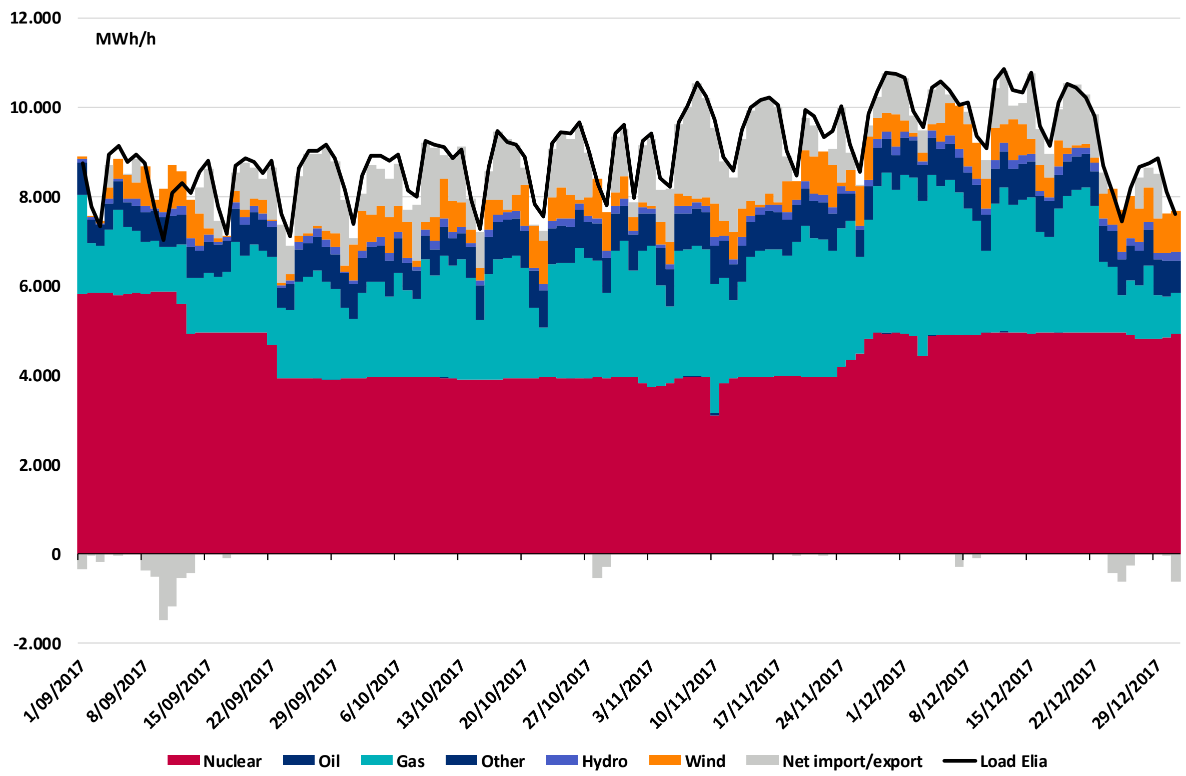

Figure 2 : Average volume injected by power plants connected to the Elia grid, per day and per generation type, and average volume withdrawn from the Elia-grid. To balance both, in grey, the import/export balance is shown as well

2.2. ANALYSIS OF THE AVAILABLE GENERATION CAPACITY

7. Generation capacity in Belgium has declined, during September 2017, from 12.000 MW to 10.000 MW including wind capacity (Figure 3). Only in the second half of November, available generation capacity is expected to gradually increase to 12.000 MW.

The 2.000 MW loss of capacity corresponds to 20% of the served load on working days during the same period (peaks of the black line, Figure 2). On working days in November, the load even exceeds 10.000 MWh/h.

8. The decline of 2.000 MW in Belgian generation capacity is practically fully attributable to the decline in baseload nuclear generation capacity (red area, Figure 3). Gas-fired power plants in Belgium and cheaper imports are relied on to replace nuclear generation and supply the load. The 3.500 MW to 4.000 MW of available generation capacity fuelled by natural gas (turquoise area, Figure 3) however gradually increases its supply during the analysed period, reaching an output of 2.800 MWh/h (turquoise area, Figure 2), indicating that 700 to 1.200 MW available generation capacity has not been used to generate electricity.

9. Two analyses have been carried out. Firstly, the genuineness of the unavailable generation capacity is verified (section 2.2.1). Secondly, the actual generation levels of all available generation capacity are verified to assess whether all available generation capacity has indeed been offered to the market (section 2.2.2).

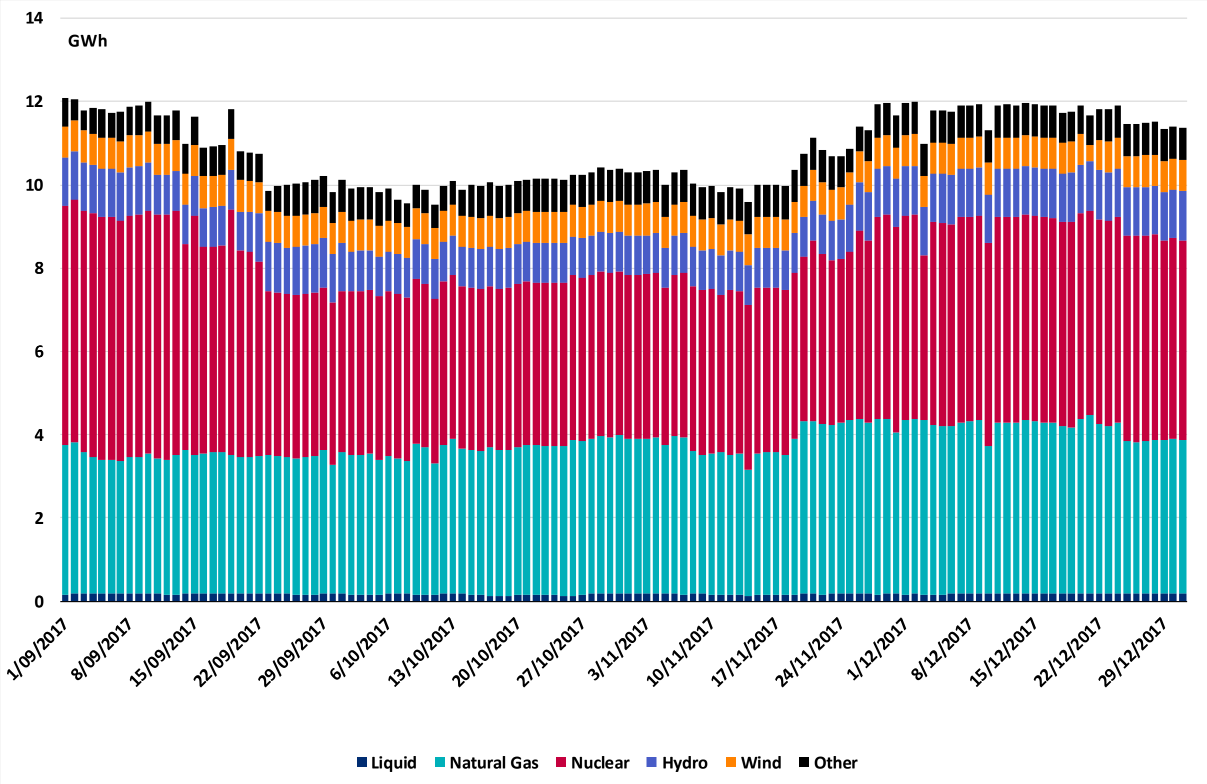

Figure 3 : Available generation capacity in Belgium, per generation type.

2.2.1. Genuineness of unavailable generation capacity

10. Table 1 lists the large Belgian power plants (> 100 MW) that were unavailable during the analysed period[1].

Unit	Fuel Type	Capacity affected (MW)	Outage start date	Outage end date
Tihange 3	nuclear	1038	10/11/2017	10/11/2017
Doel 3	nuclear	1006	22/09/2017	30/11/2017
Tihange 1	nuclear	962	12/09/2017	15/11/2017
Zandvliet	gas	386,2	15/09/2017 5/11/2017	10/10/2017 18/11/2017
St-Ghislain	gas	350	1/09/2017	20/11/2017
Drogenbos	gas	230	1/09/2017	10/11/2017
Coo 4	hydro	215	2/10/2017	27/11/2017
Rodenhuize	other	205	1/09/2017 23/10/2017 6/10/2017 24/11/2017	5/09/2017 24/10/2017 14/10/2017 27/11/2017
Doel 4	nuclear	189	2/11/2017	5/11/2017

Table 1 – Reported outages of generation units during the period from 01/09/2017 until 30/11/2017. Outages that started earlier than 01/09/2017 or lasted longer than 30/11/2017 will have the outer date of the observed period as outage start or end date.

[1] The periods of unavailability listed here apply only for the analysed period. A start date of 01/09/2017 or an end date of 30/11/2017 is also listed if the unavailability occurred before, or lasted beyond, the analysed period. Non-structural unavailabilities of a single day or a limited number of consecutive days are excluded

For completeness, the power generation plants **Zelzate Knippegroen** (other), **Amercoeur** (gas) and **Herdersbrug** (gas) were also unavailable on a few inconsecutive days during the analysed period. All listed power plants are owned by ENGIE-Electrabel.

11. Adding[2] the unavailable capacity caused by the outages of all listed power plants in paragraph 10 to the available generation capacity excluding wind capacity, shows that 12.000 MW would have been available if no outage would have occurred (Figure 4). The structural reduction of available generation capacity in Belgium is primarily caused by the unavailability of Tihange 1, Doel 3, Zandvliet, Saint-Ghislain, and Drogenbos[3]. After the discussion of the unavailability of the nuclear power plants, those of gas-fired power plants is analysed.

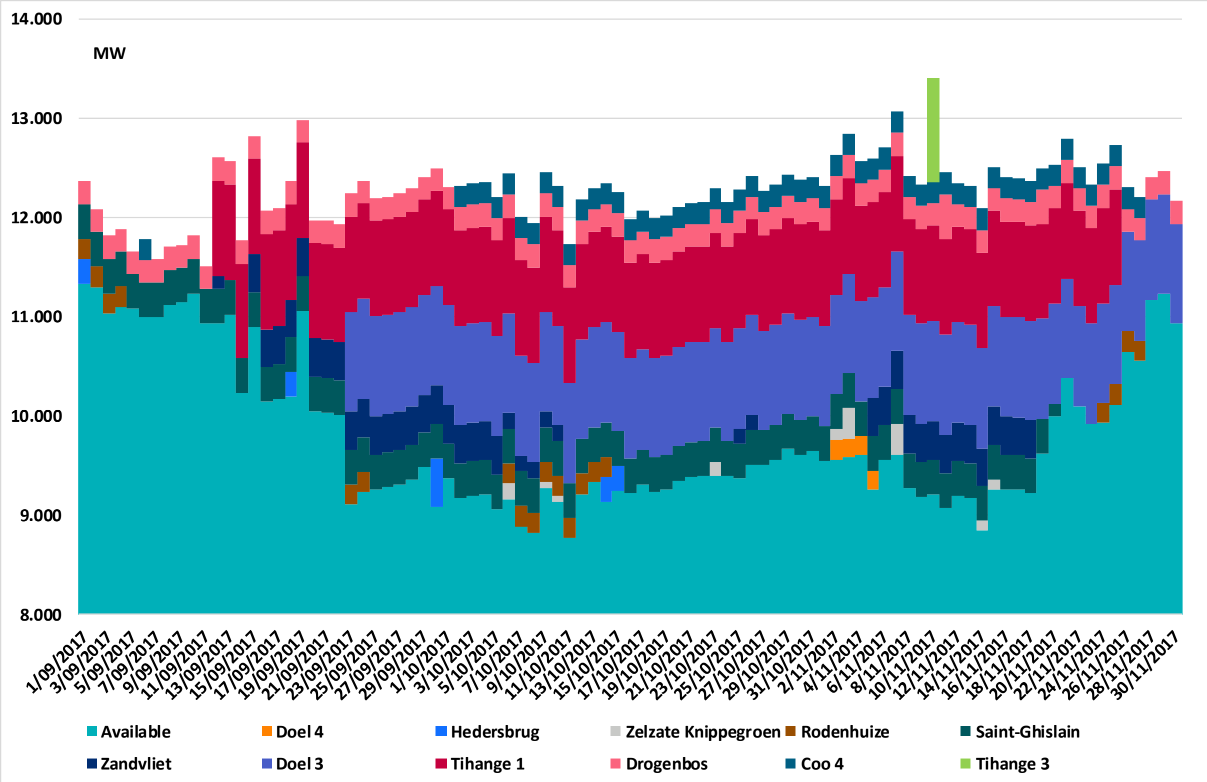

Figure 4 : Unavailable generation capacity in Belgium, from September to November 2017, per generation plant directly connected to the Elia grid. Since only plants with a generation capacity of 100 MW or more are included, and given the daily granularity of the outages, the total available capacity is not constant. The values are hence only indicative and the figure is primarily intended for illustrative purposes.

2.2.1.1. Nuclear power plants

12. The outage of Tihange 1 on the 12th of September, 6 weeks before the planned outage to carry out works in the framework of its life time prolongation, is the result of a malfunctioning of a coolant pump, which is required for the safe functioning of the nuclear power plant. The nuclear reactor cannot restart as long as the pump is not replaced. The replacement part needed to be shipped to the site from abroad. The planned maintenance period was shifted with 3 weeks, and ended on November 24.

[2] The granularity of the addition is daily, and the full unavailable capacity was added. This rigid analysis does not produce an exact or accurate value of the daily capacity in absence of the unavailabilities, and is only performed to give insight as to how much each unavailable power plant contributed to the total unavailable generation capacity.

[3] The detailed treatment in this document of only a subset of all mentioned outages does not imply that the CREG only analysed these outages.

13. An inspection during the yearly maintenance of Doel 3, planned from the 22nd of September to the 7th of November, found that the concrete in the bunker where the emergency systems – pumps and diesel engines – are housed was in a progressive state of degradation. As the functioning of the emergency systems must always be guaranteed, the concrete needs to be reinforced before Doel 3 can be restarted, pushing the end date of the unavailability to the 10th of December[4]. The most recent assessment of the complexity of the works estimates the unavailability to last until August 2018[5].

14. Both outages are caused by a technical failure. Both require works to be carried out from a nuclear safety perspective and are hence conform the procedures and provisions. Both nuclear power plants were already scheduled for planned maintenance around the time of the technical failure: Tihange 1 needed required works for its safe prolongation; Doel 3 needed to be refuelled.

15. In terms of historic occurrence of reduced availabilities, starting from 2012 the average monthly volume generated by nuclear power plants in Belgium becomes lower than those during the years before (lines versus grey bars, Figure 5). April and May consistently show reduced nuclear generation volumes. Generated volumes of nuclear power plants in April are on average 1.400 MWh/h lower than those in February, corresponding to a reduction of one fourth of the installed nuclear capacity. Generated volumes increase during summer but drop again in September and October.

16. The following paragraphs list reasons that were identified to explain the yearly recurrent minima in nuclear generation levels around spring and autumn.

17. During April and May 2012, Doel 2 was in planned maintenance for refuelling when an anomaly in the circuit taking samples of the water coming from the steam generator was found. The anomaly was categorised as a level one incident on the International Nuclear Event Scale (INES 1)[6]. Additionally, three diesel emergency generators were installed. In July 2012, cracks in the steel reactor castings were found during a planned inspection of reactor vessels Doel 3 which had already started in June. In September, similar cracks were found in the steel reactor vessel of Tihange 2, which was fabricated by the same company as the one of Doel 3. After conducting several additional tests, the Belgian supervisory authority on nuclear safety permitted the restart in May 2013[7].

18. In 2014, the Doel 4 nuclear reactor was offline until the end of the year after major damage to its turbine[8]. Doel 3 and Tihange 2 were closed in March after unexpected results were obtained during fracture toughness tests, which were part of the required tests after the discovery of cracks in steel reactor castings in 2012.

19. In 2015, the Belgian supervisory authority on nuclear safety concluded its additional investigations regarding cracks in the steel reactor castings of Doel 3 and Tihange 2 and permitted the restart of both nuclear power plants in November. Doel 1 was shut down on the 15th of February, in line with article 4 §1 of the law of 31 January 2003 on the gradual phasing out of nuclear energy for the purposes of industrial electricity production. Doel 1 could legally not restart until after the 30th of November, after the Belgian government and the owner of Doel 1 reached an agreement on the modalities of the prolongation.

[4] See also http://fanc.fgov.be/nl/nieuws/incident-op-doel-3-ingedeeld-op-ines-niveau-1 [Dutch]

[5] See Urgent Market Message http://transparency.engie.com/REM_REMIT/UMMDetail.aspx?CommodityId=3&UMMId=22689&IsUMM=True#AutomaticScrollingAnchor

[6] Further information is found on http://www.belv.be/images/pdf/rapport_annuel_belv_2012_fr.pdf [French]

[7] Further information is found on http://fanc.fgov.be/nl/informatiedossiers/kerncentrales-belgie/actualiteit/de-foutindicaties-de-stalen-wanden-van-de [Dutch]

[8] Further information is found on http://fanc.fgov.be/nl/informatiedossiers/kerncentrales-belgie/actualiteit/sabotage-van-de-stoomturbine-van-doel-4 [Dutch]

Tihange 3 was out for several weeks in August following a failed test of an isolation valve, while Tihange 1 was out since July 2015 following human errors. Both units could only be restarted once all stipulations and provisions were fulfilled: August for Tihange 3 and October for Tihange 1.

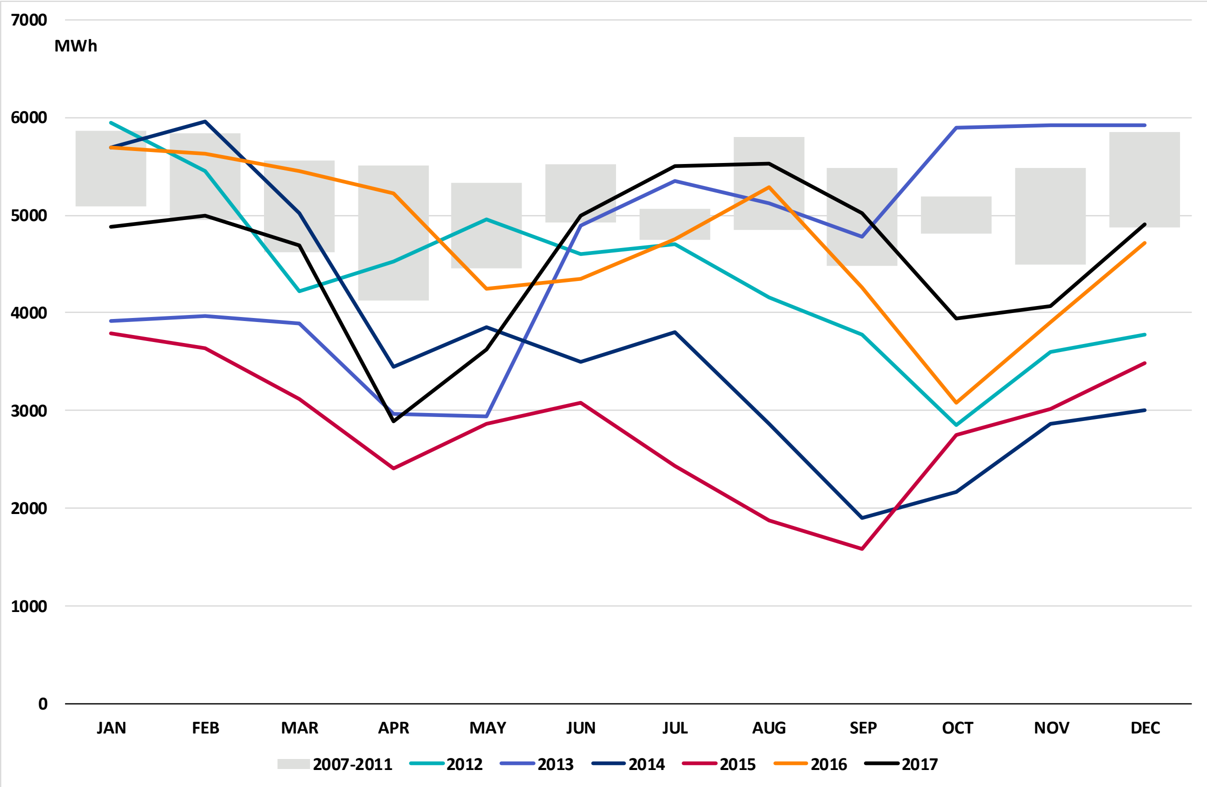

Figure 5 : Monthly averaged generation volumes by nuclear power plants in Belgium, from 2007 to 2017. The area in grey indicates the maximum and minimum monthly averaged generation volume from 2007 to 2011.

20. In October 2016, a building in the non-nuclear part of Tihange 1 was damaged, including safety equipment located at the facility, following required works to prepare the plant for its prolonged operation. The damage occurred because of an overestimation of the resistance of the embankment surrounding the reactor at Tihange 1, which caused the ground the building was built on to move during the works[9]. Tihange 3 was also unavailable in the beginning of October following a failure in an emergency cooling circuit[10]. The failure was discovered on the 6th of October while Tihange 3 was in maintenance, which started on the 9th of September and was announced in March.

21. At the end of March 2017, Doel 4 was unavailable for scheduled maintenance for 1 week. Following an incident on the grid, the unavailability of Doel 4 was prolonged until the beginning of May, to facilitate works on the unavailable grid element. Tihange 2 was unavailable in April 2017 until the end of May for planned maintenance, among others to perform required inspections concerning the state of the micro-fissures and hydrogen flakes in its reactor vessel. Satisfactory results permitted Tihange 2 to restart[11].

22. The CREG observes that, in most cases, nuclear power plants were unavailable because of a technical failure or a technical constraint. The nuclear generation output has been structurally reduced since 2012 because of such events. In four instances – Doel 2 during April and May in 2012, Doel 3 in

[9] Further information is found on http://plus.lesoir.be/94034/article/2017-05-16/electrabel-corrige-un-vice-de-construction-tihange [French]
[10] Further information is found on http://afcn.fgov.be/fr/content/tihange-3-anomalie-classee-au-niveau-ines-1 [French]
[11] Further information is found on http://www.fanc.fgov.be/nl/content/geen-toename-van-waterstofvlokken-tihange-2 [Dutch]

September 2016, Tihange 1 in October 2016 and Tihange 2 in April 2017 – the nuclear power plant was planned to be in maintenance. Maintenance is typically planned to perform works required for the prolongation of nuclear plants or to refuel the plant. Based on these elements, the CREG cannot establish reasonable grounds to suspect that the unavailability of nuclear power plants is structurally not of a genuine nature, even though vigilance might have prevented some outages according to the Belgian Nuclear Safety Authority (FANC)[12].

23. In terms of the timing of the planned maintenance, it is important to note that the strategic reserve[13] can be activated from November until March. During this winter period, the probability of generation scarcity is elevated compared with any other period during the year. The transmission system operator Elia can refuse a scheduled maintenance if system security would not be guaranteed. An accepted scheduled maintenance during the winter period, such as the one of Doel 3 (paragraph 13), indicates that Elia deemed the system sufficiently secure to handle the reduction of generation capacity.

24. During the winter period, and considering the forced outages of nuclear power plants, generated nuclear injected volumes are near the maximum available capacity. Consequently, it can be considered that power producers schedule maintenance periods either before November or after March, resulting in an elevated unavailability of nuclear power plants during September/October and April/May.

25. Planned maintenance to carry out works for the prolongation of a nuclear power plant or to refuel a plant are subject to additional constraints, ranging from the availability of (third party) experienced personnel to the organisation of transporting goods. When maintaining nuclear power plants, safety is given priority over utilisation. Moreover, maintenances plans are jointly determined with the transmission system operator who can propose changes if security of supply is at risk.

26. The CREG could hence not establish reasonable grounds to suspect that the planned maintenances of nuclear power plants are structurally not of a genuine nature. The CREG however does acknowledge that an improved level of transparency, provided by Engie Electrabel to the public by means of additional comments or remarks accompanying notifications concerning the reasons of an outage is welcomed.

2.2.1.2. Gas-fired power plants

27. Volumes generated by Belgian gas-fired power plants are correlated with load, which is typically higher during winter than during summer (Figure 6). Typically, gas-fired power plants ramp up their generation volumes starting from September to March, thereby also covering the winter period.

28. The plant of Zandvliet faced a technical incident on a circuit breaker. Repair works were required and started once technically experienced personnel was present on the site.

29. The plant Saint-Ghislain is unavailable following a technical failure of the alternator. The alternator could be replaced by using a spare element instead of ordering a new one, resulting in the plant being unavailable for a shorter period than foreseen.

30. The plant of Drogenbos has been operating as an open cycle gas turbine (OCGT) since 01/05/2016. When operating as an OCGT, the maximum capacity is 230 MW. In other words, the full capacity of Drogenbos as OCGT was available during the analysed period.

[12] http://www.lesoir.be/132235/article/2018-01-04/nucleaire-arret-de-longue-duree-pour-doel-3-mal-entretenu

[13] The strategic reserve has been into effect since 2014, partly explaining why the behaviour is not structurally visible before 2014.

Before being operated as an OCGT, it operated as a closed cycle gas turbine with a maximum available capacity of 460 MW. The plant can be temporarily reconverted to this state, as has been the case from 01/01/2018 until 28/02/2018. The reconversion was announced after several days with baseload electricity prices of €100/MWh or more, during October and November 2016. Each reconversion requires each gas turbines to be offline resulting in a temporary lower operating level of the plant. On 12/01/2018 Drogenbos' full 460 MW of capacity was available even though no notification was found of the conversion to CCGT mode. The available capacity of the plant was reverted to 230 MW starting from the first of March.

31. Each unavailability of gas-fired power plants finds it origin in a technical failure or a technical constraint. The CREG could not establish reasonable grounds to suspect that a reported outage of gas-fired power plants are not of a genuine nature.

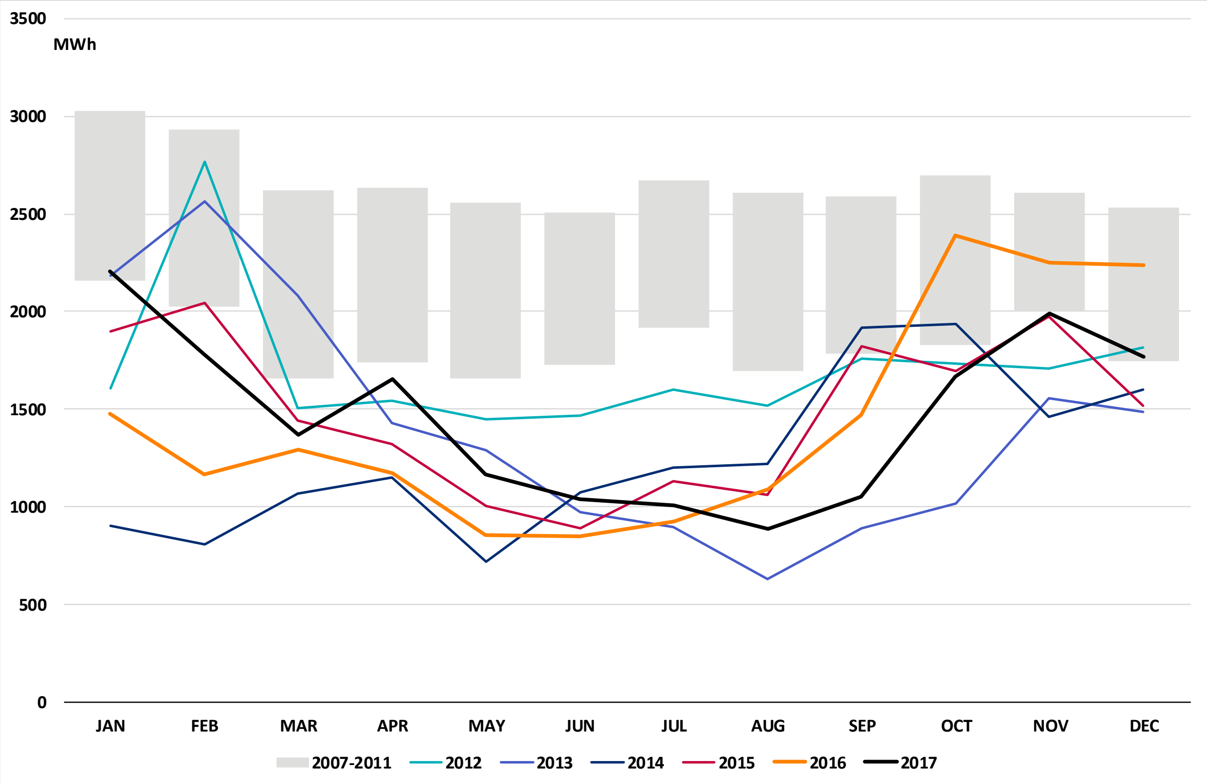

Figure 6 : Monthly averaged generation volumes by gas-fired power plants in Belgium, from 2007 to 2017. The area in grey illustrates the maximum and minimum monthly averaged generation volume during 2007-2011.

2.2.2. Use of available generation capacity

32. Given the elevated baseload electricity prices with respect to gas prices, the CREG expects that all available power plants have generated electricity at full capacity. Comparison of the generated volumes (Figure 2) with the available capacity (Figure 3) already indicates that most available capacity effectively also generated electricity.

33. A detailed analysis confirms that available gas power plants were indeed operating at close to full available capacity during most hours when the Clean Spark Spread was positive, after accounting for the capacity that was procured for the provision of upward reserves.

2.3. ANALYSIS OF THE BELGIAN POWER MARKET

34. The analysis regarding the Belgian power market focuses on the days with the most elevated baseload day-ahead electricity prices. The two days analysed are the 9th of November, with a baseload price of €122/MWh, and the 16th of November, with a baseload price of €90/MWh.

2.3.1. November 9, 2017

35. On the 8th of November, for delivery on the 9th of November, the Belgian day-ahead market price was higher than €100/MWh for 14 hours of the day, from hour 8 to hour 21 (Figure 7). The price reached its daily maximum value of €330,77/MWh at hour 19.

36. The analysis of the orderbook revealed that no order with a price of €330,77/MWh was submitted in the Belgian orderbook, for delivery at hour 19. This indicates that congestions were present in the CWE-region at hour 19, limiting price convergence between bidding zones.

37. During the peak period, the following relevant bids could be found in the Belgian orderbook, on the **supply** side (only offers with a volume of higher than 50 MWh/h are listed):

- A limit order offered at close to €80/MWh
- Multiple block orders divided over 1, 2, or 3 hours, offered at an average price of close to €60/MWh
- A limit order offered at €1.000/MWh

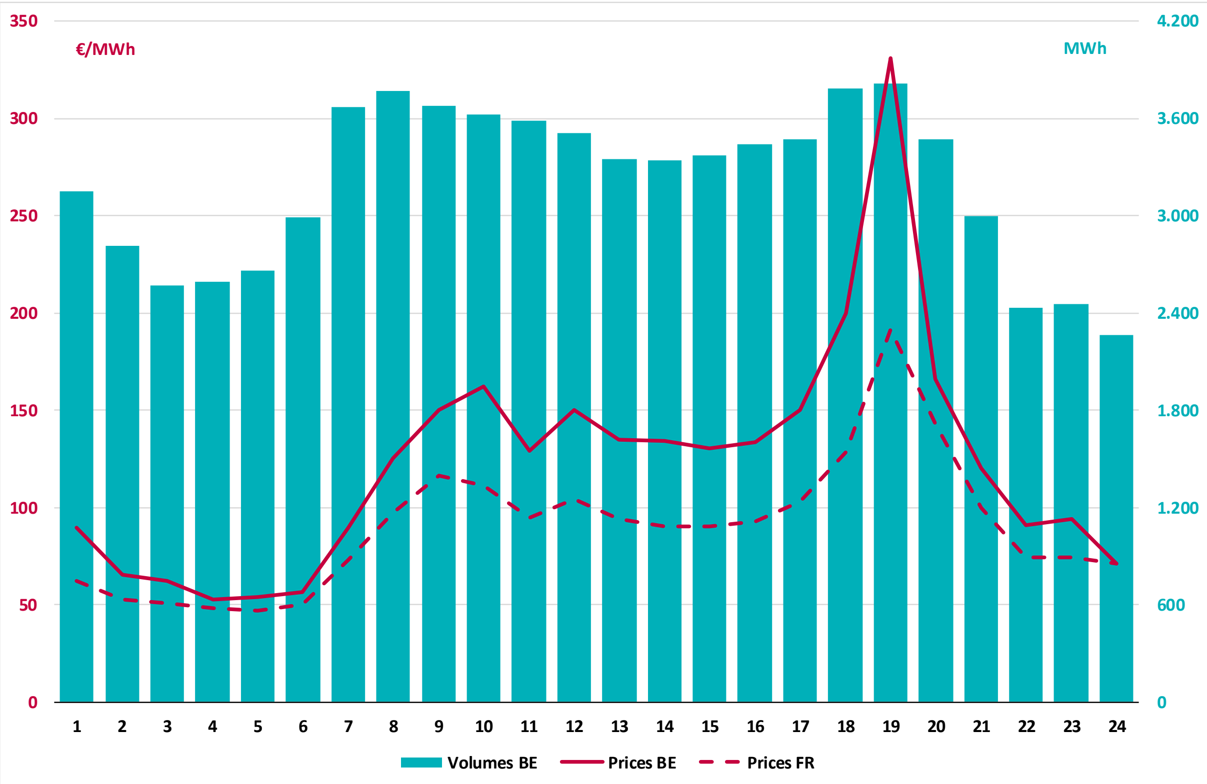

Figure 7 : Day-ahead volumes traded in the Belgian bidding zone (bars) and day-ahead prices in Belgium (full line) and France (dotted line), for delivery on November 9, 2017.

38. On the **demand** side, the relevant bids are the following (only bids with a volume of higher than 50 MWh/h are listed):

- A limit order to buy at €500/MWh
- A limit order to buy at €580/MWh

2.3.2. November 16, 2017

39. On the 15th of November, for delivery on the 16th of November, the Belgian day-ahead market price was higher than €100/MWh for 11 hours of the day, from hour 8 to hour 20, except for hours 11 and 13 (Figure 8). The price reached its daily maximum value of €185,46/MWh at hour 19.

40. The analysis of the orderbook revealed that no order with a price of €185,46/MWh was submitted in the Belgian orderbook, for delivery at hour 19. This indicates that congestions were present in the CWE-region at hour 19, limiting price convergence between bidding zones.

41. During the peak period, the following relevant bids could be found in the Belgian orderbook, on the **supply** side (only offers with a volume of higher than 50 MWh/h are listed):

- Multiple block orders divided over 1, 2, or 3 hours, at an average price of close to €100/MWh
- Multiple block orders offered at €100/MWh

42. On the **demand** side, the relevant bids are the following (only bids with a volume of higher than 50 MWh/h are listed):

- A limit order to buy at €1.000/MWh
- A limit order to buy at €350/MWh
- A limit order to buy at close to €90/MWh

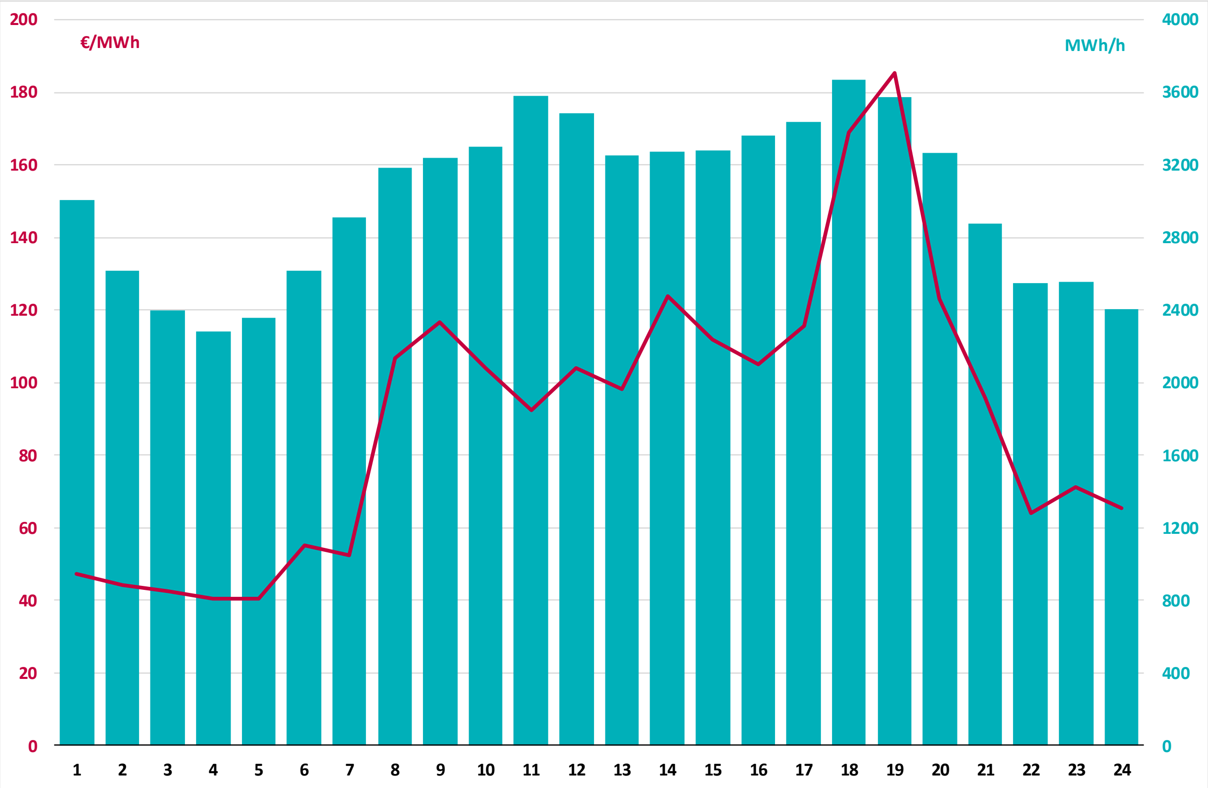

Figure 8 : Day-ahead volumes traded in the Belgian bidding zone (bars) and day-ahead prices in Belgium (full line), for delivery on November 16, 2017.

2.3.3. Responses to the Request for Information

43. Five market participants that have offered the supply and demand bids mentioned in sections 2.3.1 and 2.3.2 have been contacted by the CREG to provide a justification for their order volumes, prices and trading behaviour in general. This section provides an overview of the reasons market participants provided.

44. Must-buy **demand** is not necessarily priced at the market ceiling price of €3.000/MWh. Each market participant determines the price at which to buy must-run demand by taking into account the risks they face when placing a demand bid at €3.000/MWh. Market participants cite the collateral requirements imposed by EPEX SPOT Belgium, and cheaper opportunities to source on the intraday market if day-ahead prices exceed the chosen willingness to buy.

Elevated prices of **supply** bids have also been investigated by the CREG. The aim was to verify whether the order prices can be economically justified, i.e. whether the prices to generate the order volumes are cost-reflective. Because of the limited number of linked orders market participants can use (5 per portfolio[14]), the capacity of storage plants was offered by exclusive orders. The volatility of hourly prices within the trading day had increased significantly during the days preceding the investigated days, hence explaining the high offer prices.

45. The CREG sees in the limited number of linked order products and in the collateral requirements potential barriers for an optimal functioning of the day-ahead market. Even though these barriers cannot be fully avoided, their interference with the determination of market results should be kept to a minimum as not to distort market fundamentals.

Opportunities in Belgium to source on the intraday typically stem from cross-border trade. Market participants are confident in being able to source cheaper supply in the intraday market instead of the day-ahead market despite elevated prices. The next section illustrates that underrepresentation of the available cross-zonal capacity in day-ahead is a recurrent problem in the CWE-region.

2.4. ANALYSIS OF CROSS-BORDER ASPECTS

2.4.1. Price formation under flow-based market coupling in the Central West European region

46. Market prices under the Central West European day ahead flow-based market coupling (CWE DA FBMC) obey two conditions. First, all accepted supply and demand bids have to be ‘in the money’. This means that all accepted demand bids pay less or equal the price they are willing to pay, and all accepted supply bids are paid more or equal the price they at which they are willing to sell. Second, the price spreads between the bidding zones are determined by the optimality condition linked to maximizing CWE social welfare under the given network constraints.

47. We can distinguish two cases : price convergence and price divergence.

48. In the first case, the commercially available capacity on the transmission grid is enough to host all the cross-zonal exchanges to maximize the overall CWE cross-zonal welfare. In that case, there is no network constraint active and there is full price convergence. This single market price is determined by the cross-section of the aggregated demand and supply curves. In case there is no single cross-section, the midpoint rule is applied.

[14] For more details, see https://www.epexspot.com/en/product-info/auction/belgium

49. In the second case, the commercially available capacity is not enough to allow the volumes of cross-zonal exchanges necessary for providing full price convergence. The maximal potential of cross-zonal trade is achieved before price convergence is attained because of bottlenecks on one or more network elements. This results in a loss in overall social welfare than what would have been attained in absence of the bottleneck. This opportunity cost in terms of reduced welfare is represented by the shadow price (€/MW) associated to each congested line.

50. The shadow price is reflected in the price spreads between bidding zone areas. More specifically, fore each pair of bidding zone areas (A,B), the following equilibrium condition holds [15]:

$$MCP_A - MCP_B = \sum_{l\,\in\{active\ network\ constraints\}} \left(PTDF_{A,h}^{l} - PTDF_{B,h}^{l}\right).\mu_l$$

Or

$$MCP_A - MCP_B = \sum_{l\,\in\{active\ network\ constraints\}} \left(PTDF_{A,B}^{l}\right).\mu_l$$

with

- MCP_A and MCP_B the market clearing price in respectively zone A and zone B, in €;
- *{active network constraints}* the set of active network constraints for the considered hour;
- μ_l the shadow price of the active network constraint *l*, in €/MW.
- $PTDF_{A,h}^{l}$ and $PTDF_{B,h}^{l}$ the zone-to-hub Power Transfer Distribution Factor (PTDF) of zone A, resp. zone B, of the active network constraint *l*, in (MW/MW or -);
- $PTDF_{A,B}^{l}$ the zone-to-zone Power Transfer Distribution Factor (PTDF) for a commercial exchange from zone A to zone B, calculated as the difference of the zone-to-hub PTDFs $\left(PTDF_{A,h}^{l} - PTDF_{B,h}^{l}\right)$

51. The equation in paragraph 50 shows that price formation under CWE DA FBMC depends on the parameters of the congested network elements. The impact of these parameters will be illustrated in §2.4.2 and §2.4.3**Error! Reference source not found.** for the price spikes at hour 19 on November 9th a nd November 16th 2017. Below, the background and consequences of this equilibrium condition is discussed.

52. The equation in paragraph 50 shows that the price spread between each pair of bidding zones (k, l) is the weighted sum of the shadow prices over all congested lines, with the zone-to-zone PTDF as a weighting factor. The lower the zone-to-zone PTDF between bidding zones k and l, relatively to the other zone-to-zone PTDFs, the lower the cost for one MWh/h of commercial exchange between bidding zones k and l (as reflected by the price spread), in case the line is the limiting factor, to achieve optimal social welfare.

53. If a network element becomes active, commercial exchanges have to compete to make use of this scarce resource. In general, maximization of the total CWE social welfare favours the commercial exchanges which make the least usage of the bottleneck, i.e. those with the lowest zone-to-zone PTDFs. To make use of the scarce capacity on the congested lines, commercial exchanges with a large

[15] See Chapter 7.1.5 'Price - PTDF link with the FB "plain" MC model', in 'CWE Enhanced Flow-Based MC intuitiveness report', Annex 16.12 Intuitiveness Report of the *Documentation of the CWE FB MC solution as basis for the formal approval-request* (Brussels, 9th May 2014)

physical usage of the bottleneck, thus high zone-to-zone-PTDF, will have to increase the price spread between the importing and exporting country accordingly: a zone with a high PTDF will need to pay more in order to import, or to supply at a lower price in order to export, than a zone with a lower PTDF on that line. In CWE, this is referred to as "flow factor competition"

54. This property of flow factor competition can be illustrated using a simple example of two zones, A and B, which want to import from a same zone C. For enabling this commercial exchange, both need to make use of the physical capacity of line L. If the line gets congested, the willingness to pay for the last marginal unit of capacity on line L, will determine the price spreads.

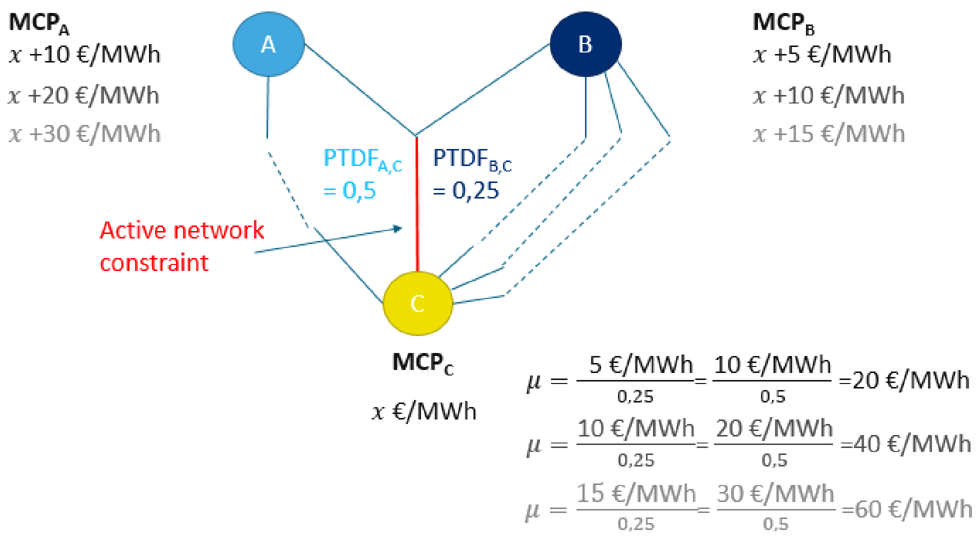

Figure 9 : In the case of network congestion, the set of zone-to-zone PTDFs of the active network constraint, defines the price spreads between the zones. Together, they determine the shadow price associated to this network constraint.

55. The shadow price µ reflects the value of an extra MW of cross-zonal exchange in terms of overall welfare. It depends on both the shape of the welfare function, defined by the market conditions, and on the flow based domain, defined by TSOs. When cross-border exchange is limited at low volumes because of a small flow based domain, the shadow price is typically higher than when limited at higher volumes. This is because the value of a first MW of import/export is the largest one, with the marginal benefit of an extra MW of import/export steadily decreasing till approaching zero at the optimum of full price convergence (see Figure 10). From the monitoring data, one can indeed observe that very high shadow prices on active constraints typically appear on lines with low available commercial capacity (remaining available margin or 'RAM').

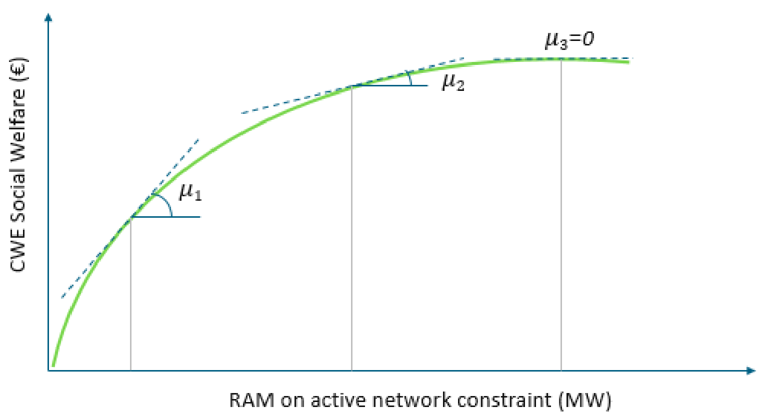

Figure 10 : The shadow price µ (€/MW) related to a network constraint defines the change in CWE Social Welfare (expressed in €) with respect to an additional unit of remaining available capacity on that line (RAM, measured in MW).

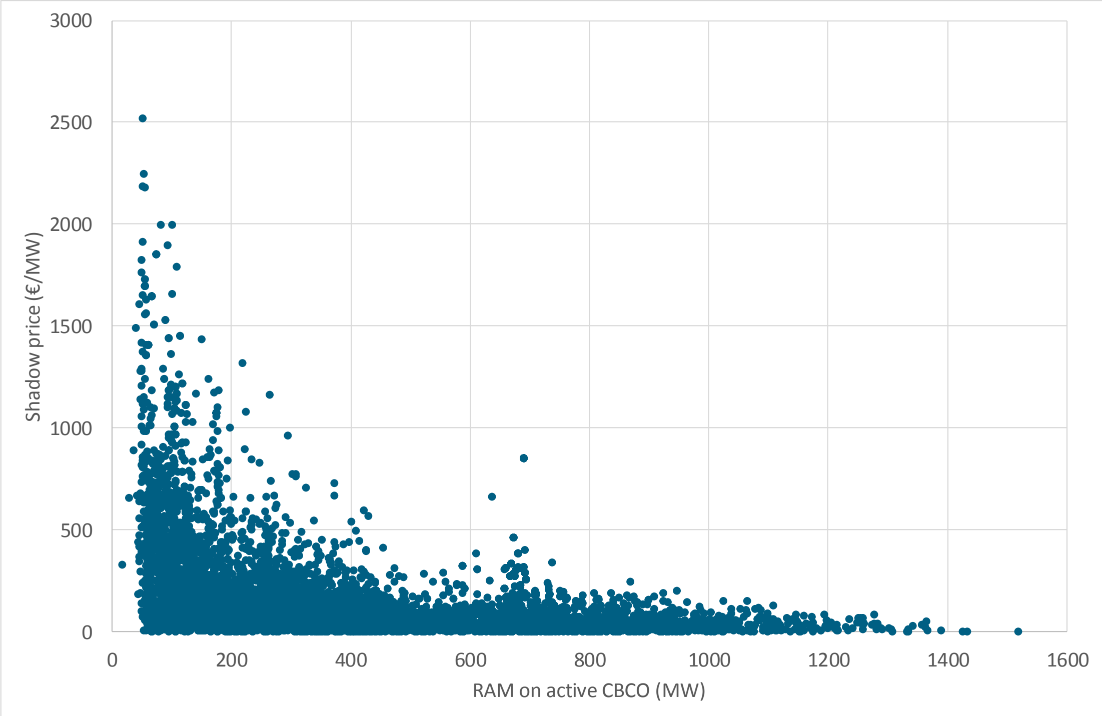

Figure 11 : The highest shadow prices are recorded on network constraints with very low Remaining Available Margin (RAM), limiting the cross-border exchange at low volumes. Data for 2017. Source: CWE TSOs

2.4.2. Price formation on 9 November 2017, hour 19

56. According to the equilibrium condition presented in paragraph 50, the CWE price spreads are determined by the properties of the active network constraints. This way, once the market clearing price in one of the zones is known, all other market clearing prices are uniquely defined.

The CWE market clearing prices and corresponding price spreads on 9 November 2017, hour 19, were:

	BE	FR	NL	DE	BE-DE	FR-DE	NL-DE
€/MWh	330,77	191,58	44,90	55,93	274,84	135,65	-11,03

For this hour, there were two active network constraints, being a phase shift transformer, *PST Zandvliet* (Elia) and the internal line *Ent-Lelystad* (Tennet NL), with the following set of zone-to-hub PTDFs, zone-to-zone PTDFs and shadow price (€/MW):

	PTDF BE-hub	PTDF FR-hub	PTDF NL-hub	PTDF DE-hub	PTDF BE-DE	PTDF FR-DE	PTDF NL-DE	Shadow price
PST Zandvliet	-0,38562	-0,23882	0	-0,13642	-0,21506	-0,1024	0,13642	**853,2513**
Ent - Lelystad	-0,11919	-0,05793	-0,1317	0,00446	-0, 11803	-0,06239	-0,13616	**773,8741**

We can now show that indeed, the price spreads fulfil the optimality condition:

- MCP BE – MCP DE = **853,2513***-0,21506 + **773,8741***-0,11803 =! 274,8406 €/MWh
- MCP FR – MCP DE = **853,2513***-0,1024 + **773,8741***-0,06239 =! 135,6549 €/MWh
- MCP NL – MCP DE = **853,2513***0,13642 + **773,8741***-0,13642 =! -11,0298 €/MWh

57. The data on the active network constraints and associated shadow prices, shown in paragraph 55, are provided by CWE TSOs to CWE NRAs for monitoring purposes and are not publicly available. However, based on the data publicly available on JAO, one can relatively accurately retrieve which network constraints had been active by checking for each of the network constraints *p*, the following equation: $\sum_{i=1}^{4} NEP_i \, PTDF_{i,h}^{p} \leq RAM$. If $\sum_{i=1}^{4} NEP_i \, PTDF_{i,h}^{p} = RAM$ or $\sum_{i=1}^{4} NEP_i \, PTDF_{i,h}^{p} = RAM + \delta$, with δ being a small value to account for round-off errors, than this network constraint was active. The associated shadow prices can then be determined based on the market clearing prices for that hour.

2.4.3. Price formation on 16 November 2017, hour 19

58. The CWE market clearing prices and corresponding price spreads for this hour were:

	BE	FR	NL	DE	BE-DE	FR-DE	NL-DE
€/MWh	185,46	150,58	67,7	53,93	131,5272	96,64981	13,77203

For this hour, the constraining network elements were again *PST Zandvliet and Ent-Lelystad*, with the following set of zone-to-hub PTDFs, zone-to-zone PTDFs and shadow prices (€/MW):

	PTDF BE-hub	PTDF FR-hub	PTDF NL-hub	PTDF DE-hub	PTDF BE-DE	PTDF FR-DE	PTDF NL-DE	Shadow price
PST Zandvliet	-0,38562	-0,38562	0	-0,19552	-0,1901	-0,1901	0,19552	**309,6871**
Ent - Lelystad	-0,11919	-0,06184	-0,12193	2,80E-04	-0,11947	-0,06212	-0,12221	**608,1503**

Again we can now show that the price spreads fulfil the optimality condition represented by Eq. 1:

MCP BE – MCP DE = **309,6871***-0,1901 + **608,1503***-0,11947=! 131,5272

MCP FR – MCP DE = **309,6871***-0,1901+ **608,1503***-0,06212=! 96,64981

MCP NL – MCP DE = **309,6871***0,19552+ **608,1503***-0,12221=! 13,77203

2.4.4. Discussion on available commercial capacity on active network elements

59. The shadow price of the active network constraints *PST Zandvliet* and *Ent-Lelystad* on the investigated hours ranged from 310 €/MW to 853 €/MW. As discussed in § 2.4.1, high shadow prices represent tight market conditions and/or low available commercial capacity for cross-border exchange (see Figure 10 and Figure 11). The table below shows that the available commercial capacity (RAM) on both lines was low for both hours. More than 50% of the capacity of *PST Zandvliet* was used by reference flows (%Fref'), which for interconnectors – constitute almost only of loop flows. On *Ent-Lelystad*, only 16% - 18% of the thermal line rating (Fmax), was available for commercial cross-zonal exchange. The table also shows the Flow Reliability Margin (FRM) and the applied Final Adjustment Values (FAV) for each critical branch.

Time stamp	Critical Branch	Fmax (MW)	Fref' (MW)	FRM (MW)	FAV (MW)	RAM (MW)	% Fref'	% RAM	Shadow price (€/MW)
20171109-19	PST Zandvliet	1508	795	256	0	689	53%	46%	**853,25**
20171109-19	Ens - Lelystad	1732	1526	173	0	307	88%	18%	**773,87**
20171116-19	PST Zandvliet	1614	892	256	0	659	55%	41%	**309,69**
20171116-19	Ens - Lelystad	1732	1418	173	0	274	82%	16%	**608,15**

3. CONCLUSION

Based on the analysis of the available generation capacity during October and November 2017, the CREG could not establish reasonable grounds to suspect that the unavailability of nuclear power plants is not of a genuine nature. Technical failures of elements which are required by the regulated provisions for the safe operation of a nuclear power plant and technical constraints such as refuelling were the cause of many failures. Safety has priority over utilisation.

The systematic reduction of nuclear power plant availability during the weeks after March or before November can be explained by the fact that power producers need to avoid as much as possible to schedule maintenance during the winter period, when the generation adequacy can be at risk.

The CREG additionally asked five market participants to justify orders introduced in the Belgian order book. The limited number of linked order products and in the collateral requirements potential seem to have interfered with an optimal functioning of the day-ahead market. Market participants also rely on sufficient cheaper cross-border intraday opportunities being available despite elevated day-ahead prices, suggesting that market participants expect that not all cross-zonal capacity at Belgian borders has been allocated in the day-ahead market. Congestions were present on multiple grid elements in Germany, the Netherlands and Belgium, and were increased by the presence of high loop flows. Market clearing prices in Belgium were linked to those of the other CWE bidding zones through the PTDFs of the active network constraints and their associated shadow prices

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