Evaluation Report 2026
The Baltic Balancing Capacity Market for FRR products

04.08.2026

Table of Contents

Executive Summary

This report evaluates the Baltic Balancing Capacity Market (BBCM) for the frequency restoration reserve products, aFRR and mFRR, over the reporting period from 1 October 2025 to 30 June 2026. It is prepared under the market-based allocation methodology adopted in accordance with Article 41(1) of the EBGL and under the Baltic balancing capacity market rules. This is the second reporting cycle, and it covers a more settled market than the first. Alongside the assessments the methodologies require, the report adds a broader view of how the BBCM performs as a market, so that the regulatory findings can be read against the market's actual development.

The overall picture is of a market that is maturing in the intended direction. It is more stable and more competitive than in its first months, concentration is falling in every segment and for most of the period the three bidding zones clear at a single common price. Where difficulties remain, they are concentrated in two places: the upward direction reserves, which stays the more expensive, more volatile and more concentrated side of the market due to lower liquidity and the Estonia-Latvia border congestion, which is the main point of interaction between the BBCM and the day-ahead market and the main source of forecast error. Reserve demand was met throughout the period, but sufficiency still rests on the participation of a few large assets.

The central finding is that cross-zonal exchange and the reserves the TSOs hold themselves remain essential to secure and affordable procurement. The scenarios tested in the report show how much depends on integration: withdrawing TSO-owned resources or cross-zonal capacity raises costs steeply, up to **€2.02 billion if no TSO resources are utilised** and a fully fragmented market in which each state procured locally would raise total nine-month period procurement cost from about **€108.6 million** to roughly **€6.34 billion**. Security of supply is also not fully guaranteed in case of the local market sceanrio, 20% of the balancing capacity demand would not be fulfilled across the Baltics, although if TSO resources would cease to be used, this would result in 0,17% of demand not being covered. This is the clearest quantitative case in the report for maintaining and extending the joint Baltic market, in which TSO resources are still a necessity for ensuring economical efficiency.

On the mechanics the methodologies require the report to assess, the allocation process performed within its bounds. The forecast of the market value of cross-zonal capacity was accurate on average, with the error it does produce concentrated on the Estonia-Latvia border; the 50% allocation limit was never breached on any border direction; and the impact of the allocation process on day-ahead price formation and welfare was limited when compared to the benefits of a common balancing capacity market: the gained welfare in the case of no cross-zonal capacity reservations was **€19.6 million** and up to **€28.8 million** based on a pessimistic approach. Throughout the period the adjustment of the forecasted market value operated with its sensitivity parameter set to zero, so the market relied on the reference-day forecast alone. A detailed examination of the pattern behind the forecast errors, and a decision on whether to activate the volume-sensitive adjustment, are carried out and will be moved off zero when the positive impact is evident.

Overall the BBCM is more liquid, more competitive and better integrated than a year ago and TSO demand for the reserves was always covered with no risk to security of supply. However, BBCM is still dependent on TSO-owned resources and on a small number of large market participants for reserve sufficiency. The report finds no case for changing the current cross zonal capacity allocation limits and identifies upward mFRR and the Estonia-Latvia forecast error as the areas that most warrant continued attention. The detailed results, figures and supporting data behind these findings are set out in the sections that follow and drawn together in the conclusions.

1. Introduction

This report evaluates the operation of the Baltic Balancing Capacity Market (BBCM) for the frequency restoration reserve products, aFRR and mFRR, over the reporting period from 1 October 2025 to 30 June 2026. The BBCM is the common market through which Estonia, Latvia and Lithuania procure balancing reserve capacity, exchange balancing capacity between bidding zones and share reserves, to the extent allowed by the available cross-zonal capacity (CZC) and by the applicable market rules.

The report covers the frequency restoration reserve products only, and frequency containment reserve (FCR) is outside its scope. The market-based allocation of CZC that the report evaluates, established under Article 41(1) of the Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (the EBGL) and implemented through the market-based methodology (MB Methodology), applies to the exchange of balancing capacity and sharing of reserves for aFRR and mFRR. Baltic FCR is dimensioned and exchanged under the load-frequency-control regime of the System Operation Guideline, Commission Regulation (EU) 2017/1485, in particular its Article 153 on FCR dimensioning and Article 163 on the exchange of FCR within a synchronous area. It is procured without any allocation of CZC and clears at a single common marginal price across the three bidding zones. Because no CZC is allocated to FCR, the assessments the report is required to make, that is the forecast of the market value of CZC, the allocations above the 50% limit and the impact on the single day-ahead coupling (SDAC), do not arise for it and cross-zonal indicators such as inter-zonal price divergence and cross-border spreads have no meaning for a product priced identically across the three zones. FCR is therefore referred to only where it provides context.

The report is prepared in accordance with the MB Methodology, which establishes the market-based allocation process used to allocate CZC for the exchange of balancing capacity and sharing of reserves under Article 41(1) of EBGL. Article 12(8) of the MB Methodology requires the Baltic TSOs to monitor the efficiency of the forecasting methodology, to analyse the default limit for the maximum volume of cross-zonal capacity, and to submit a report to the relevant regulatory authorities six months after the go-live of the market-based allocation process and at least once a year thereafter. This is the annual report that follows the first report submitted in October 2025.

Further reporting requirements follow from the Augstsprieguma tīkls, Elering and Litgrid proposal for the Baltic balancing capacity market rules in accordance with Articles 33(1) and 38(1) of the EBGL (the "Market Rules Methodology"). Article 14(2) of that methodology requires the Baltic TSOs to publish and submit to the relevant regulatory authorities, on the same annual basis.

Accordingly, the report contains the analysis required under Article 12(8) of the MB Methodology:

- (a) a comparison of the forecasted and actual market values of cross-zonal capacity for the exchange of energy;
- (b) an assessment of the occurred increases of the limits for the maximum volume of cross-zonal capacity allocated for the exchange of balancing capacity and sharing of reserves in accordance with Article 5(1)(b), including statistics on the number of incidents, the increased volumes and percentages, the reasons for them, and an analysis of the economic surplus effects on the SDAC;
- (c) an assessment of the impact on price formation in the single day-ahead coupling (SDAC) due to the allocation of cross-zonal capacity for the exchange of balancing capacity and sharing of reserves;
- (d) an assessment of the impacts on the economic surplus of the SDAC and on the economic surplus from the exchange of balancing capacity and sharing of reserves, including the specific impact following an increase of a default limit pursuant to Article 5(1)(c);
- (e) an assessment of the adjustment process according to Article 6(2), including the number of hours in which the adjustment has been made and the magnitude of the adjustments;
- (f) where necessary, proposals to improve the accuracy of the forecasted market values, including a different limit for the maximum volume of cross-zonal capacity pursuant to Article 5(1) or different mark-up values per bidding-zone border pursuant to Article 6(2); and
- (g) an assessment on the need to adjust the percentage limits on cross-zonal capacity allocation described in Article 5(1).

And, in accordance with Article 14(2) of the Market Rules Methodology, the report contains information on the volumes and usage of demand reduction resources and back-up resources.

The 2025 Evaluation Report covered the first months of live operation, from the first delivery day on 5 February 2025 to 30 September 2025, and was the first report submitted after go-live under Article 12(8) of the MB Methodology. It set out the initial analytical framework: the reference-day forecast of the market value of CZC, the use of mark-ups, the cases in which allocations exceeded the default limit, the effect of balancing-capacity allocation on the SDAC, and the role of TSO-owned resources during the early phase of the market. This report keeps that framework but covers a longer and more settled period, with more operational history and a wider set of data.

Beyond the assessments required by the two methodologies, this report gives more weight to how the BBCM functions as a market. The Joint Regulatory Feedback on the Evaluation Report 2025, issued by the Estonian, Latvian and Lithuanian regulatory authorities on 19 June 2026. The regulators requested, for the upcoming reports, the BBCM Herfindahl-Hirschman Index, comparisons of BBCM prices with other European balancing capacity markets, the total volume of prequalified assets with a distinction between dispatchable and renewable assets, and an indicative analysis relating the volume of TSO-owned resources under different market conditions to unmet demand and to Baltic balancing prices, supported by the TSOs' own evaluations rather than raw data alone. These requests are addressed in the market performance indicators of Section 2 and in the assessment of TSO-owned resources in Section 7. The regulators' request to show the effect of TSO-owned resources in fine volume steps of 5 to 10 MW is met here in a coarser form, through reduction scenarios of 25%, 50% and 100% that establish the direction and the non-linearity of the relationship.

On the notification of allocations above the 50% CZC limit under Article 5(1)(b) and (c) of the MB Methodology, the compliance concern the regulators raised in respect of the 2025 period does not recur here, since no allocation exceeded the default limit during this reporting period and no notification was therefore due. Section 4.2 sets out the automatic detection and notification process that the Baltic TSOs will implement in response, and the report's assessment of the allocation limits is consistent with the regulators' view that there is currently no basis to change them. The regulators' separate request for the TSOs' viewpoint on elastic demand in the balancing markets is being provided as a standalone document rather than within this report, in line with the regulators' own suggestion.

The main findings of this report are set out in the Executive Summary and developed in the sections that follow. Two matters are taken forward as further work rather than resolved here: a detailed investigation of the patterns behind the forecast errors on the internal Baltic borders, and an assessment of whether a change to the reference-day forecast, or use of the volume-sensitive adjustment of the forecasted market value under Article 6(2), would improve forecast accuracy.

The structure of the report follows this logic. Section 2 sets out the key market performance indicators including the demand/supply ratio for the evaluation of the security of the supply. Sections 3 to 6 contain the regulatory assessment required under Article 12(8) of the MB Methodology: the comparison of forecasted and actual cross-zonal capacity values and the related proposals to improve forecast accuracy (Section 3.2), the allocations above the 50% limit and the assessment of the need to adjust the current limits (Section 4), the impact on SDAC price formation (Section 5), and the impacts on economic surplus together with the adjustment process (Section 6). Section 7 assesses the volumes and usage of demand reduction and back-up resources under Article 14(2) of the Market Rules Methodology. Section 8 evaluates the benefits of the joint Baltic Balancing Capacity Market against an isolated-markets scenario, in which the bidding zones would procure reserves locally without cross-zonal exchange. The conclusions summarise the findings.

2. Key Market Performance Indicators

2.1. Market Shares & Concentration (HHI)

BBCM Concentration Index

The Herfindahl-Hirschman Index (HHI) is an economic measure used to assess market concentration and competitive conditions, calculated by summing the squares of the market shares of all firms operating in the market. It measures the degree of market power held by the largest participants. The higher the index value, the less competitive the market, and the closer it is to a monopoly.

The index ranges from 0 to 10,000, with the following interpretive thresholds:

- **<1,500:** Low concentration (competitive market)
- **1,500–2,500:** Moderate concentration
- **>2,500:** High concentration (oligopoly or near-monopoly)
- **10,000:** Full monopoly, where a single firm controls 100% of the market

The HHI is calculated using the following formula:

$$HHI = \sum_{i=1}^{n} s_i^2$$

where s_i is the market share of BSP *i* (in percent) and *n* is the number of BSPs.

It is important to emphasize that the following analysis covers the Baltic market as a whole, since market participants offer balancing reserve capacity across the entire Baltic region, and country-specific view would give a distorted picture of the actual competitive situation in the shared market. The input data consisted of accepted bids from market participants, not submitted bids.

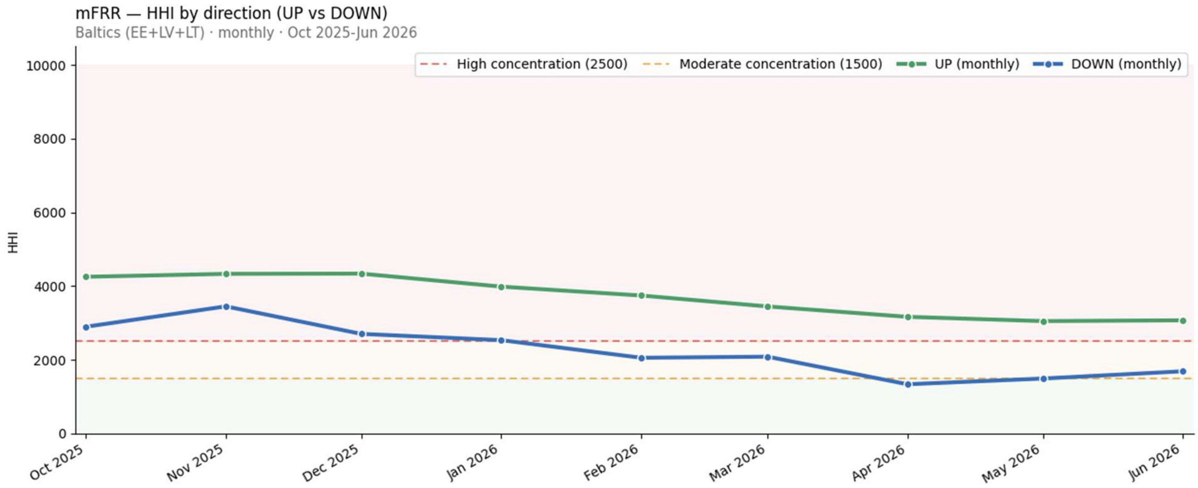

Figure 1. mFRR Up & Down Market Concentration Index on the Baltics level

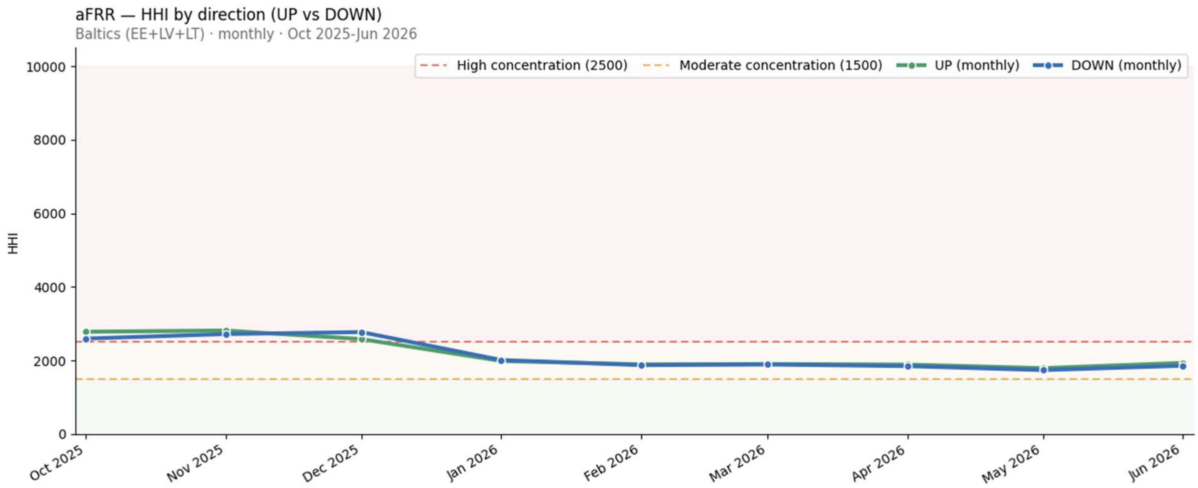

Figure 2. aFRR Up & Down Market Concentration Index on the Baltics level

Looking only at the endpoints of the period rather than the monthly path (Table 1), concentration eased in both directions for both products. mFRR Down improved the most (-42%), moving from high to moderate concentration, while mFRR Up eased the least in relative terms (-28%) and stays the most concentrated segment in absolute terms, still above 3,000, which is considered high concentration. aFRR's two directions moved together (-28% to -30%) and now both sit under 2,100, comfortably inside the moderate band and closer to the low threshold (1,500) than the high one (2,500).

Table 1. HHI reporting period endpoints % change

Segment	HHI Oct 2025	HHI Jun 2026	Δ %
mFRR UP	4254	3073	-28
mFRR DOWN	2898	1690	-42
aFRR UP	2783	1936	-30
aFRR DOWN	2597	1859	-28

The market is still moderately to highly concentrated, but it is moving toward more competition, with concentration down in every segment. The concern now is less the overall level and more where it sits. For example. upward mFRR, where two providers still supplies about 80% of accepted volume and the index stays high (around 3,700). This is the same segment that has the highest prices, the most cross-zone divergence and the most volatility as described in Section 2.2 below, so the concentration on the up side is probably part of why up-regulation prices are high, and not just a coincidence. More competition and lower prices would be the natural fix and will support further decrease in the market concentration.

BBCM Market Shares

This section looks at competition in the Baltic balancing capacity market, using the accepted bids of Balancing Service Providers (BSPs). Following the report's method, it treats the Baltic market as one pool, because providers offer capacity across the whole region and a single-country view would distort the picture.

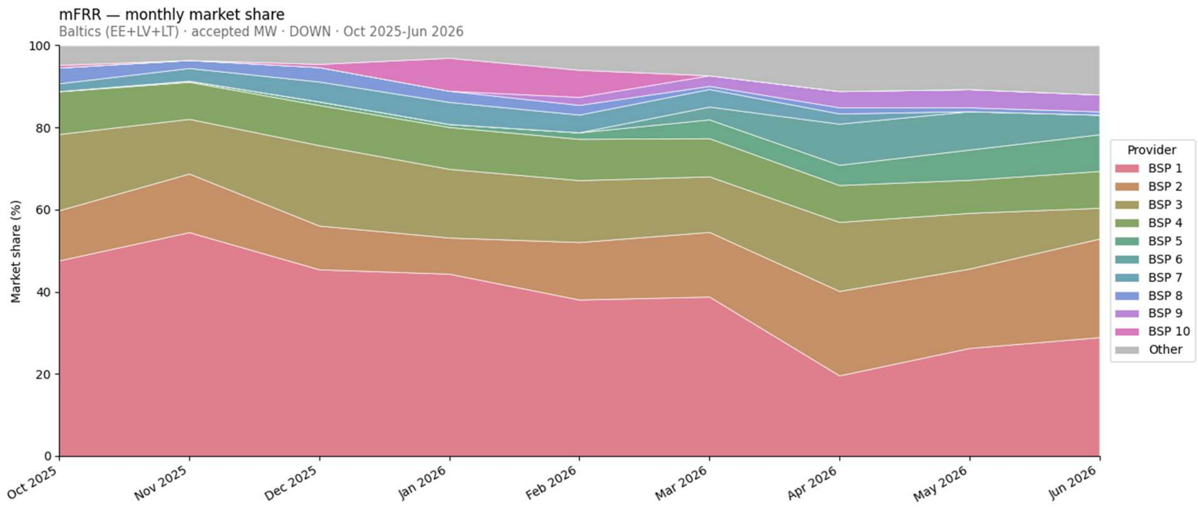

Figure 3. mFRR Down monthly market share

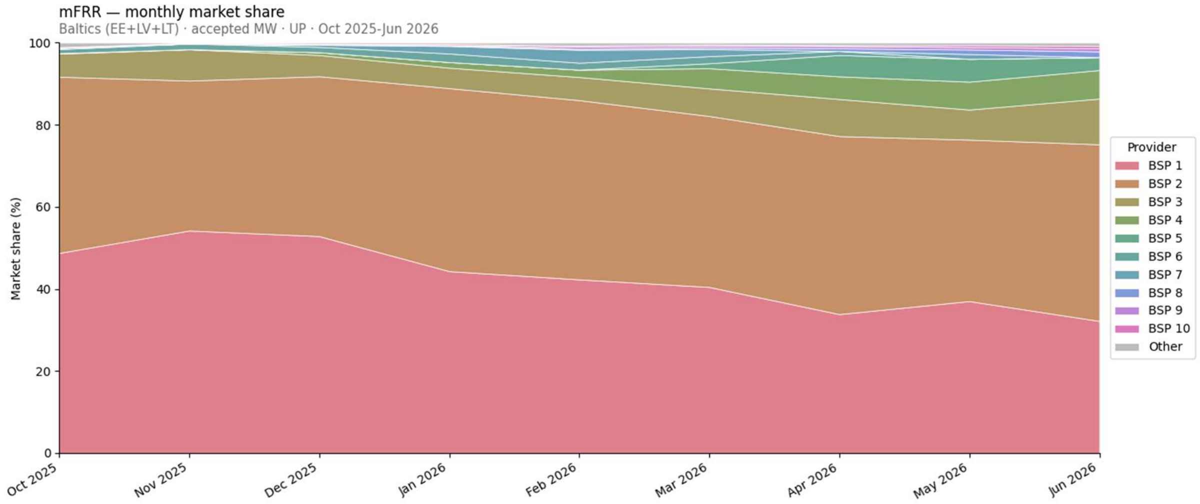

Figure 4. mFRR Up monthly market share

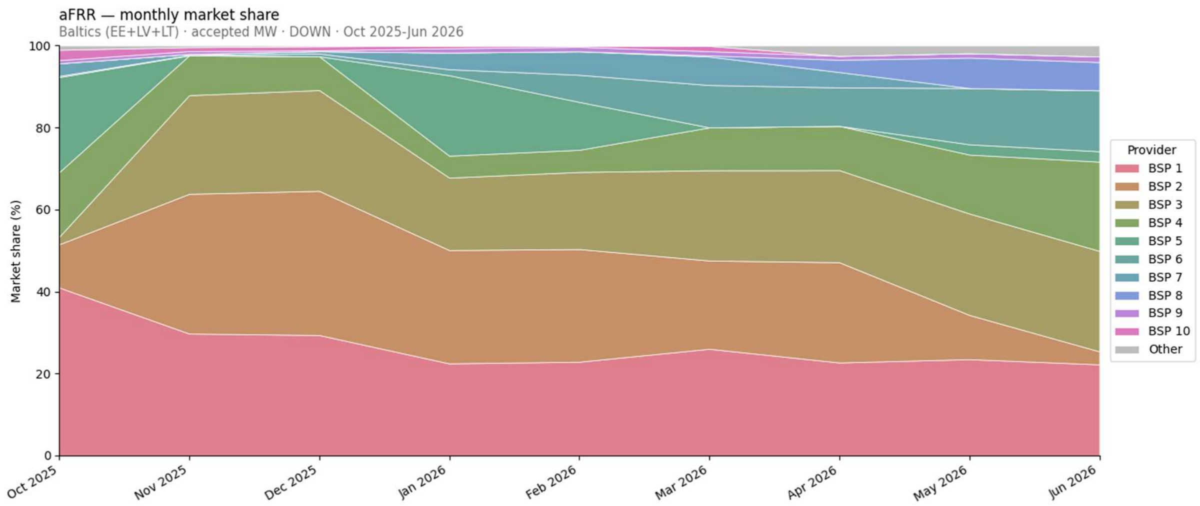

Figure 5. aFRR Down monthly market share

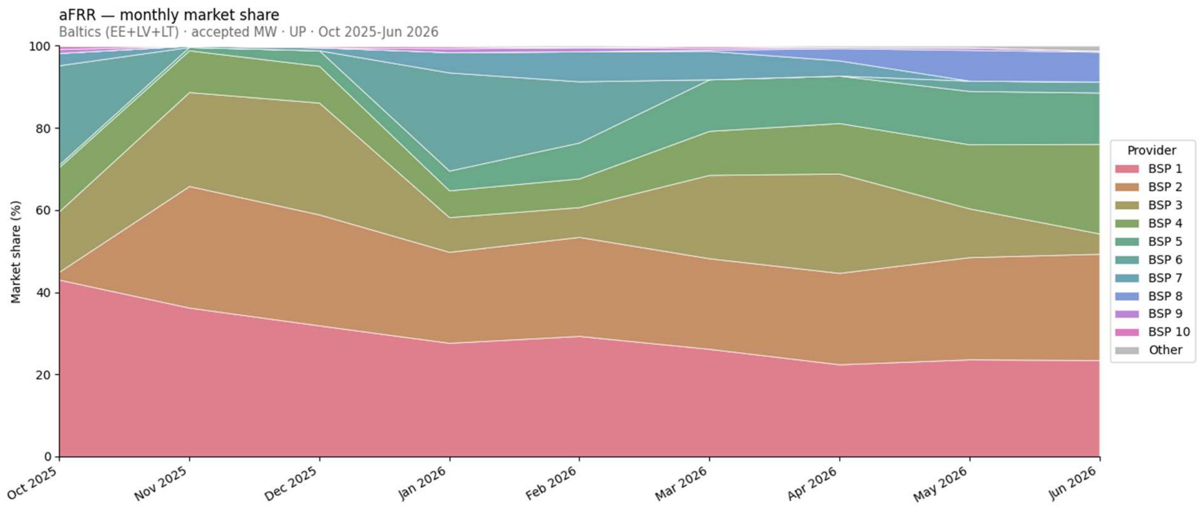

Figure 6. aFRR Up monthly market share

On individual shares, the largest providers take about 41% of accepted mFRR volume and 28% of aFRR, and the three largest together hold roughly 80% and 73%. Those are high, but trending down over the long run as market evolves naturally.

2.2. Prices & Volatility

This section describes how balancing reserve capacity cleared over the period. For each product it looks at three things:

- the level of prices (monthly averages by zone and direction);
- how often the three zones cleared at the same price (divergence);
- and how much daily price averages moved day to day (volatility).

Monthly averages and divergence statistics are used to summarize price behavior without a chart for every zone, product and direction. With three zones, two products and two directions, a full period chart series of prices, their volatility and distributions would resolve in over 30 figures, mostly showing three overlapping lines because the zones are mostly cleared at the same price – that is why a more general approach was taken. Divergence statistics report the same information, how often the zones agree, how often one splits off, and by how much.

Volatility measures how much a price moves from one day to the next, as opposed to divergence, which measures how much the three zones differ on the same day. Unlike the monthly price tables, each figure below is a single value covering the full reporting period, October 2025 to June 2026, not a month-by-month series.

The calculation runs in three steps. First, the 15-minute market time unit (MTU) prices are collapsed to one average price per calendar day:

$$P_d = \frac{1}{n_d}\sum_{i=1}^{n_d} P_i$$

Where:

P_d – is the average price for day *d*;

p_i – is the clearing price of MTU *i* on day *d;*

n_d – is the total number of MTUs on day *d* (normally 96).

Intraday movement is averaged away at this step and only the day-to-day pattern remains. Second, the day-over-day change is taken as a plain level difference, not a percentage or log return:

$$r_d = P_d - P_{d-1}$$

Where:

r_d – is the absolute price change on day *d* relative to the previous day;

P_d and P_{d-1} – are the average prices for day *d* and day *d – 1*, respectively.

A level difference is used rather than a relative one because aFRR clears at exactly €0 on 32 to 42% of MTUs, which would make a percentage or log-based measure undefined or extreme on those days.

Third, the reported figure is the standard deviation of these daily changes over the whole period:

$$\sigma = \sqrt{\frac{1}{N-1}\sum_{d=1}^{N}(r_d - \bar{r})^2}$$

Where:

σ – is the period volatility (expressed in €/MWh);

$\bar{r}$ – is the mean of the daily price changes over the period, calculated as:

$$\bar{r} = \frac{1}{N}\sum_{d=1}^{N} r_d$$

For example, an mFRR DOWN volatility of €27.8/MWh for Estonia means that, over October 2025 to June 2026, Estonia's daily average mFRR DOWN price typically swung by about €27.8 from one day to the next, relative to its own average day-to-day move over the period. Since the period's average mFRR DOWN price in Estonia is about €17.7/MWh, a typical daily swing of €27.8 is larger than the price level itself: the price does not sit steadily near €17.7 and drift a little, it moves in large jumps relative to where it usually sits.

It should also be considered that the pricing logic of the current optimization algorithm may itself be a source of higher volatility, not only market depth. The algorithm optimizes cost and socio-economic welfare, but the non-negative surplus requirement on bids means that an accepted resource bid must not end up in a loss overall. In certain situations the algorithm may push marginal prices on individual market time units into the hundreds or thousands of €/MW/h in order to bring the bid into the money (for example, make the block bid financially whole), which does not necessarily reflect market instability, but partly the natural behaviour of the optimization mechanism.

The Baltic TSOs are aware of this mechanism and are looking into how block-bid cost recovery is handled in the pricing algorithm. One direction being explored is to distribute the uplift that makes a block bid financially whole across several MTUs, rather than concentrating it on individual intervals as the current logic tends to do. Such an approach would accept a small deviation from the optimal solution in exchange for smoother price formation and fewer isolated price spikes. After thorough analysis, when it has been deduced that the pricing change brings significant benefits, it shall be implemented in the optimisation algorithm of the BBCM platform. The Baltic TSOs expect to present an overview of the new pricing mechanism and its results in the next evaluation report.

MFRR Average Prices

Table 2 shows monthly average mFRR clearing prices. Upward regulation is the more expensive direction throughout (period averages of €23.44/MWh in LV and €23.94/MWh in LT). Estonia is cheaper on the up side, at a steady discount to its neighbours (€16.28/MWh). Downward prices are lower and very close across the three zones, around €16.9 to €17.7/MWh. Prices are seasonal and right-skewed, so they dip in April 2026 and rise into the summer.

Table 2. mFRR average monthly clearing price (€/MWh)

Area	Direction	Oct 2025	Nov 2025	Dec 2025	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Period avg
EE	UP	26,28	7,53	12,74	22,06	33,80	11,92	8,47	8,33	16,52	**16,28**
EE	DOWN	29,61	15,33	13,83	17,78	17,12	17,33	10,03	12,84	25,25	**17,70**
LV	UP	36,09	12,95	17,89	22,61	33,07	19,16	10,80	26,12	32,75	**23,44**
LV	DOWN	26,98	12,17	12,21	17,77	17,12	16,79	10,36	12,89	25,26	**16,85**
LT	UP	36,09	12,96	17,89	22,03	33,12	22,84	11,69	26,18	33,04	**23,94**
LT	DOWN	26,98	12,17	12,21	17,77	17,12	16,77	10,37	12,90	25,39	**16,86**

Figure 7. mFRR Down monthly average clearing price by area

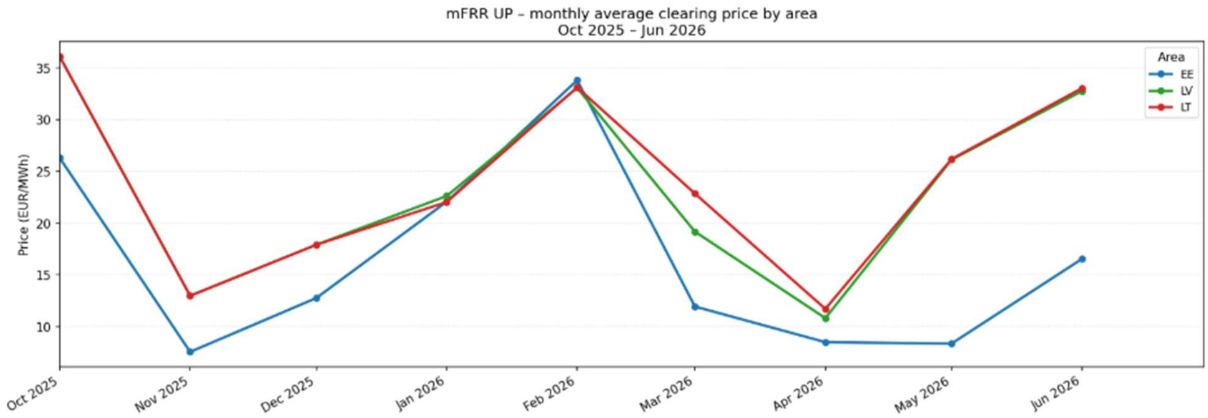

Figure 8. mFRR Up monthly average clearing price by area

mFRR Price Divergencies

Table 3 measures the share of MTUs where the three zones did not all clear at the same price and two directions are very different. Upward mFRR prices differed across zones in 29.4% of intervals, downward in only 4.3%. When they did differ, it was nearly always one zone breaking away from a coupled pair. All three zones differing at once almost never happens (0.1% and 0.0%). The average spread over all intervals is small (€8.47/MWh upward), but when prices do diverge the average gap is €28.81/MWh, and individual congestion events reach the price cap.

Table 3. mFRR cross-area price divergence

Product	Direction	All equal (%)	Diverged (%)	One area differs (%)	All three differ (%)	Mean spread (EUR/MWh)	Mean spread | diverged (EUR/MWh)	Max spread (EUR/MWh)
mFRR	UP	70,60	29,40	29,30	0,10	8,47	28,81	3999,99
mFRR	DOWN	95,70	4,30	4,30	0,00	0,96	22,22	822,21

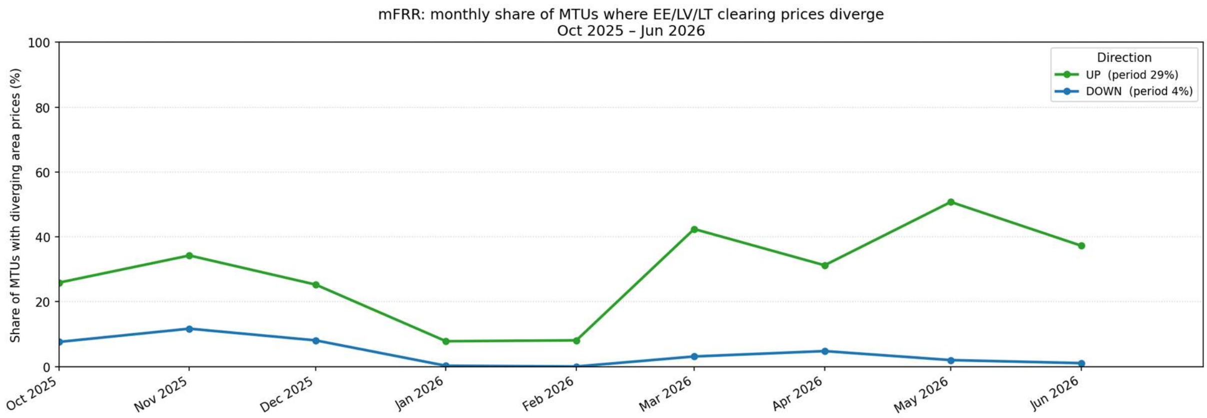

Figure 9. mFRR monthly clearing prices divergencies between the countries

mFRR Volatilities

Table 4 gives price volatility as the average absolute day-over-day change in the clearing price. The values are moderate and fairly even across zones. The downward direction moves a little more day to day (about €28/MWh) than the upward one (about €20 to €23/MWh).

Table 4. mFRR volatility of daily price changes (€/MWh)

Product	Area	Direction	Volatility of daily average price (€/MWh)
mFRR	EE	UP	19,90
mFRR	EE	DOWN	27,80
mFRR	LV	UP	23,00
mFRR	LV	DOWN	28,00
mFRR	LT	UP	23,20
mFRR	LT	DOWN	27,90

aFRR Average Prices

Table 5 gives the same monthly averages for aFRR. Notably, aFRR prices are quite similar to mFRR, and can often be even lower despite the reserve being of higher quality. Upward prices are again the higher ones (LV and LT around €26/MWh on the period, against Estonia's €13.32/MWh), and downward prices are low and clustered near €10/MWh. One feature of aFRR is that a large share of intervals clears at exactly zero, roughly a $1/3$ to $2/5$ of MTUs depending on the series. That drags the monthly averages down, well below the occasional high-price months such as the upward spikes in January and February 2026.

Table 5. aFRR average monthly clearing price (€/MWh)

Area	Direction	Oct 2025	Nov 2025	Dec 2025	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Period avg
EE	UP	23,09	0,02	2,44	37,74	33,58	6,63	2,90	6,22	8,25	**13,32**
EE	DOWN	16,07	5,79	5,72	15,61	12,78	12,83	5,28	10,84	12,87	**10,88**
LV	UP	56,74	2,42	5,00	52,41	38,67	11,95	3,75	26,97	36,30	**26,02**
LV	DOWN	13,29	3,19	3,46	15,59	12,60	12,57	5,57	12,25	12,87	**10,16**
LT	UP	56,74	2,42	5,00	51,56	38,67	11,85	3,79	26,98	36,35	**25,93**
LT	DOWN	13,29	3,19	3,46	15,59	12,60	12,46	5,60	12,29	12,88	**10,16**

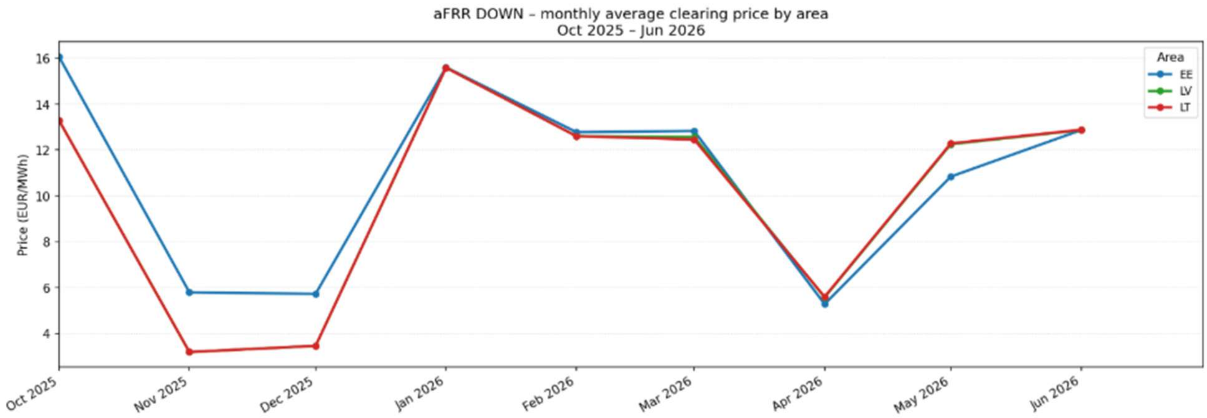

Figure 10. aFRR Down monthly average clearing price by area

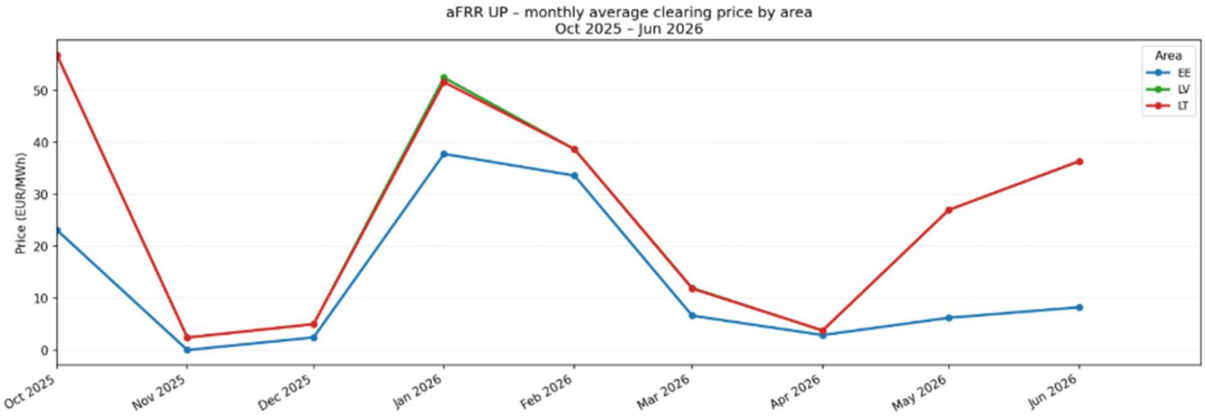

Figure 11. aFRR Up monthly average clearing price by area

aFRR Price Divergencies

Table 6 shows aFRR following the same pattern as mFRR – upward prices diverged in 21.1% of intervals, downward in only 3.4%. Divergence is again a two-zone event. When it happens, though, the average spread is the widest of any series here, €62.91/MWh upward, which fits the sharper moves aFRR can make.

Table 6. aFRR cross-area price divergence

Product	Direction	All equal (%)	Diverged (%)	One area differs (%)	All three differ (%)	Mean spread (EUR/MWh)	Mean spread | diverged (EUR/MWh)	Max spread (EUR/MWh)
aFRR	UP	78,90	21,10	21,10	0,00	13,29	62,91	3997,32
aFRR	DOWN	96,60	3,40	3,40	0,00	1,23	36,35	3998,55

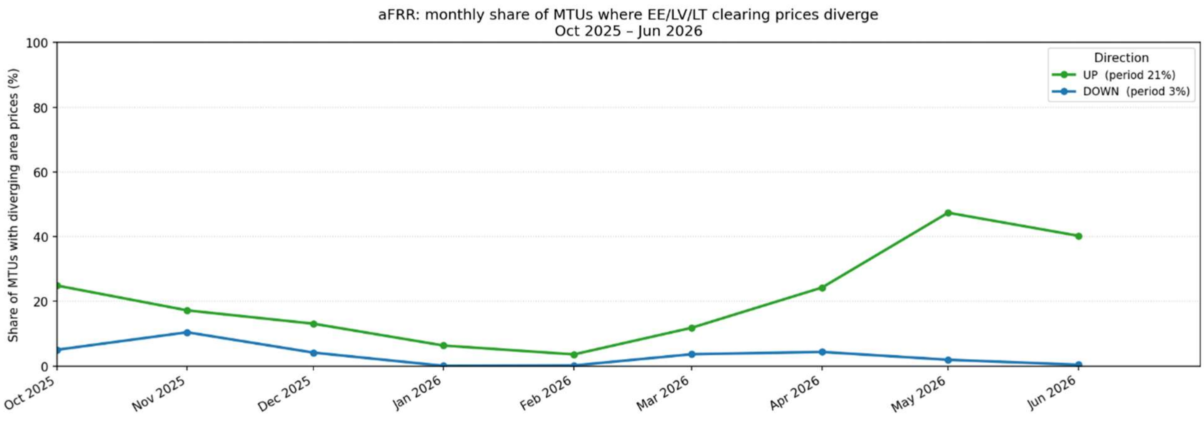

Figure 12. aFRR monthly clearing prices divergencies between the countries

aFRR Volatilities

Table 7 confirms aFRR is the more volatile product, and that the movement sits on the upward side in Latvia and Lithuania (€45.1/MWh average daily change, about double the mFRR figures). That matches the higher, more frequently spiking upward prices above.

Table 7. aFRR volatility of daily price changes (€/MWh)

Product	Area	Dir	Volatility of daily average price (€/MWh)
aFRR	EE	UP	25,90
aFRR	EE	DOWN	22,00
aFRR	LV	UP	45,10
aFRR	LV	DOWN	21,80
aFRR	LT	UP	45,10
aFRR	LT	DOWN	21,80

Conclusions of the topic

Price formation over the period is healthy, but it is two-sided. Almost everything difficult sits on the upward direction, namely:

- the higher prices;
- the more frequent cross-zone divergence (29.4% for mFRR and 21.1% for aFRR, against roughly 4% and 3%);
- and the biggest day-to-day swings (aFRR-UP in LV and LT at €45.1/MWh).

This is due to the limited flexibility of upward regulation, where the clearing is highly dependent on a few select large assets. The effects are significantly more apparent when there is congestion, resulting in large price differences between the cheaper Estonia and more expensive Latvia/Lithuania. Therefore, more flexible upward regulation capacity in Latvia and Lithuania is needed in order to lessen the impact of congestions.

The downward direction is cheaper, better aligned across the three zones and steadier, which is based on the lower overall aFRR demand compared to mFRR and plenty of down-regulation supply. For most of the time the zones clear at one common price, so the market is well integrated.

Additionally, a unique BBCM effect can be observed where aFRR and mFRR clearing prices are very similar despite the different nature of the products – reserve substitution drives the convergence of prices. Due to FRR coverage and ample supply, aFRR is almost always over procured, and both mFRR and aFRR bids compete with one another, resulting in price similarity. aFRR price formation is primarily driven not by aFRR demand, but rather FRR demand and mFRR supply.

2.3. Comparison of Baltic and Neighboring Countries' Balancing Reserves Capacity Prices

This chapter compares the prices of BBCM with balancing reserves capacity market prices in neighboring countries. The comparison includes Finland (FI), Poland (PL) and Sweden's SE4 bidding zone. The analysis covers mFRR and aFRR upward and downward capacity products.

Figure 13. Comparison of monthly average mFRR downward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones illustrates the monthly average prices for mFRR downward capacity from October 2025 to June 2026 and Figure 14. Comparison of monthly average mFRR upward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones shows mFRR upward capacity prices for the same period. mFRR upward and downward capacity prices in the Baltic region have stabilized compared to 2025. They also follow a seasonal trend, increasing again in June when fewer dispatchable capacities are available on the market compared to, for example, the spring period with high water inflows. Compared to neighboring countries, mFRR downward capacity prices in the Nordic countries have been consistently lower, while Baltic prices have been approximately at the same level as in Poland. In the mFRR upward capacity market, prices in Finland remain lower, while prices in the SE4 bidding zone are at a similar level to those in the Baltic region. In 2026, Polish mFRR upward capacity prices have generally been higher than Baltic prices. It can also be noted that in Estonia, mFRR upward capacity prices have been slightly lower than in Latvia and Lithuania.

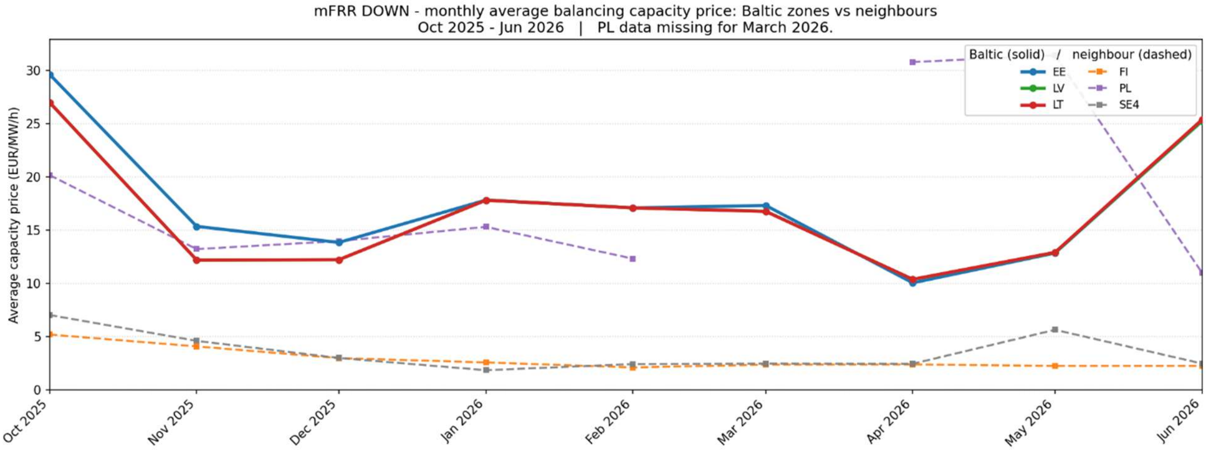

Figure 13. Comparison of monthly average mFRR downward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones

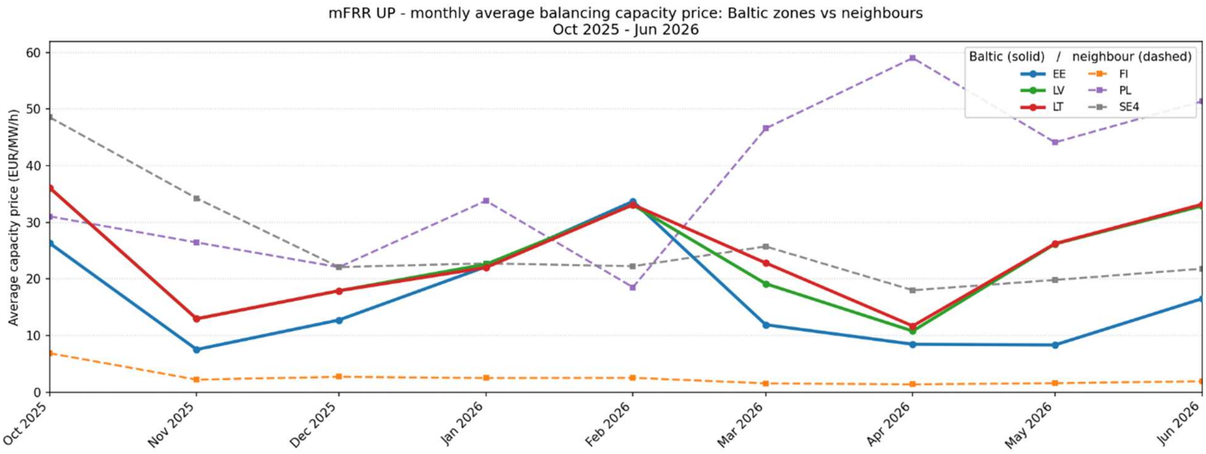

Figure 14. Comparison of monthly average mFRR upward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones

Figure 15. Comparison of monthly average aFRR downward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones illustrates the monthly average prices for aFRR downward capacity from October 2025 to June 2026 and Figure 16. Comparison of monthly average aFRR upward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones shows aFRR upward capacity prices for the same period. At the beginning of the BBCM in 2025, both upward and downward aFRR regulation capacity prices were high and volatile. By the beginning of 2026, these prices have decreased and stabilized in the Baltic region. During the spring and autumn periods, Baltic prices have been similar to those in Finland. However, on average, Finnish aFRR capacity prices have remained lower. Compared to Polish aFRR capacity prices, prices in the Baltic region have generally been lower. A comparison with the SE4 bidding zone cannot be made, as the SVK data did not include an SE4 price. This was because all accepted capacity was provided from other Swedish bidding zones, resulting in zero aFRR capacity volume in SE4.

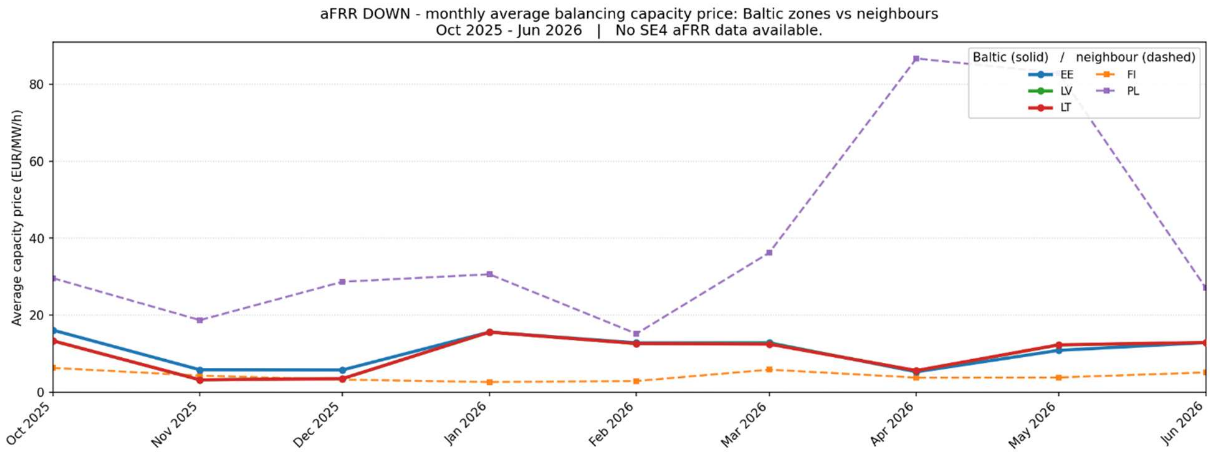

Figure 15. Comparison of monthly average aFRR downward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones

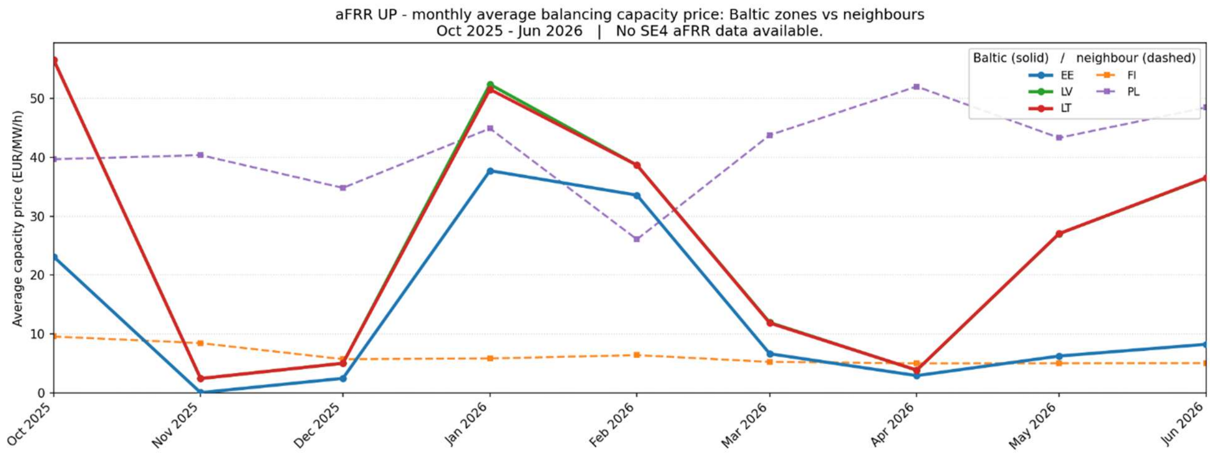

Figure 16. Comparison of monthly average aFRR upward capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones

The Baltic FCR market operates without CZC allocation constraints, resulting in identical prices across Estonia, Latvia, and Lithuania. After staying at high levels in 2025, FCR prices decreased significantly in December of 2025 and during the spring of 2026. The general trend from the beginning of BBCM in 2025 is downwards, but a seasonal pattern can be observed to some extent. However, Baltic prices remain higher than in neighboring markets.

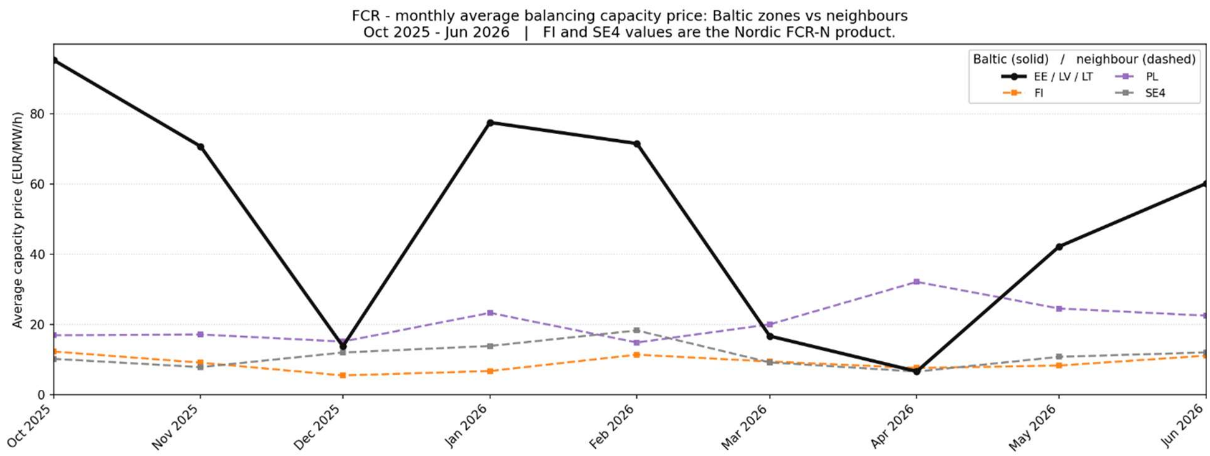

Figure 17. Comparison of monthly average FCR capacity prices in the Baltic, Finnish, Polish and SE4 bidding zones.

Table 8. 2025 annual average balancing capacity prices in the BBCM, Polish, Finnish and SE4 bidding zones (based on data from market operators' websites)

2025	FCR	aFRR up	aFRR down	mFRR up	mFRR down
EE	88,21	65,32	101,36	43,9	63,42
LV	88,21	77,11	90,56	42,06	21,49
LT	88,21	76,86	90,52	32,56	21,13
FI	18,27*	15,52	11,63	8,31	14,43
PL	19,10**	38,23	28,55	35,67	22,35
SE4	23,24*	0***	0***	51,25	19,09

* The Finnish and Swedish FCR price is for the symmetrical FCR-N product.

**The Polish FCR price is the average of the FCR up and FCR down products.

***SE4 aFRR prices are shown as 0 EUR/MW/h due to zero local cleared volume.

Table 9. 2026 January to June average balancing capacity prices in the BBCM, Polish, Finnish and SE4 bidding zones (based on data from market operators' websites)

2026 01-06	FCR	aFRR up	aFRR down	mFRR up	mFRR down
EE	45,49	15,7	11,71	16,62	16,71
LV	45,49	28,31	11,93	23,99	16,67
LT	45,49	28,16	11,92	24,73	16,7
FI	9,02*	5,4	4	1,9	2,31
PL	22,95**	43,3	46,88	42,5	18,6
SE4	11,67*	0***	0***	21,74	2,88

* The Finnish and Swedish FCR price is for the symmetrical FCR-N product.

**The Polish FCR price is the average of the FCR up and FCR down products.

***SE4 aFRR prices are shown as 0 EUR/MW/h due to zero local cleared volume.

2.4. Total Prequalified Asset Volumes

As of writing of this report, a total of 14,18 GW of capacity has been prequalified for participation in the BBCM, excluding TSO owned resources. The split between reserve types and direction can be seen in ***Table 10*** and distribution per bidding zone can be seen in Figure 18. Prequalified assets per country per product and direction (MW).

Table 10. Distribution of prequalified volumed (MW)

FCR	aFRR Up	aFRR Down	mFRR Up	mFRR Down
405	1629	1756	4894	5501

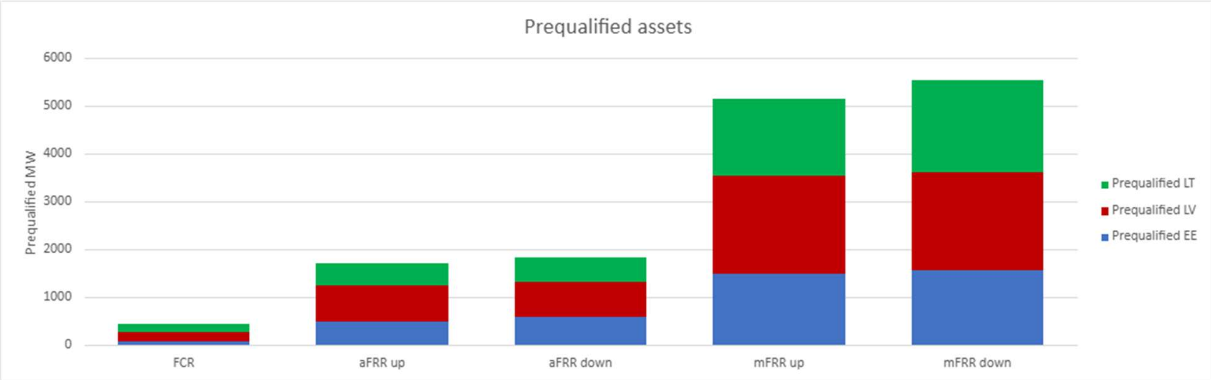

Figure 18. Prequalified assets per country per product and direction (MW)

Table 11. Distribution of prequalified asset volumes by type and country

Type	Location	Sum of FCR	Sum of aFRR up	Sum of aFRR down	Sum of mFRR up	Sum of mFRR down
BESS	EE	76	314	309	388	393
BESS	LT		40	40		
BESS	LV	40	163	162	101	100
Demand	LV				16	16
Gas	EE				250	40
Gas	LT	71	126	133	246	246
Gas	LV	58	132	132	266	265
Hybrid	EE		64	64	184	201
Hybrid	LT	68	144	139	199	233
Hybrid	LV		6	6	12	12
Hydro	LT	8	154	155	935	966
Hydro	LV	102	356	356	1459	1459
Other	EE		93	87	210	208
Other	LT	10	0	0	7	6
Other	LV		35	35	35	35
Solar	EE		2	3	269	320
Solar	LT			2	36	55
Solar	LV	0	6	6	108	102
Solar+BESS	LV		16	16	19	19
Wind	EE		18	116	182	395
Wind	LT			35	182	430
Wind	LV		40	40	40	40

The exact makeup of the prequalified reserve units in the Baltics is constantly shifting, however, the majority of prequalified reserves are hydro units, with sizeable gas, wind, solar and hybrid plants. A recent surge of BESS and BESS-combined assets during the report period has occurred, edging gas assets out of the second most abundant position by capacity.

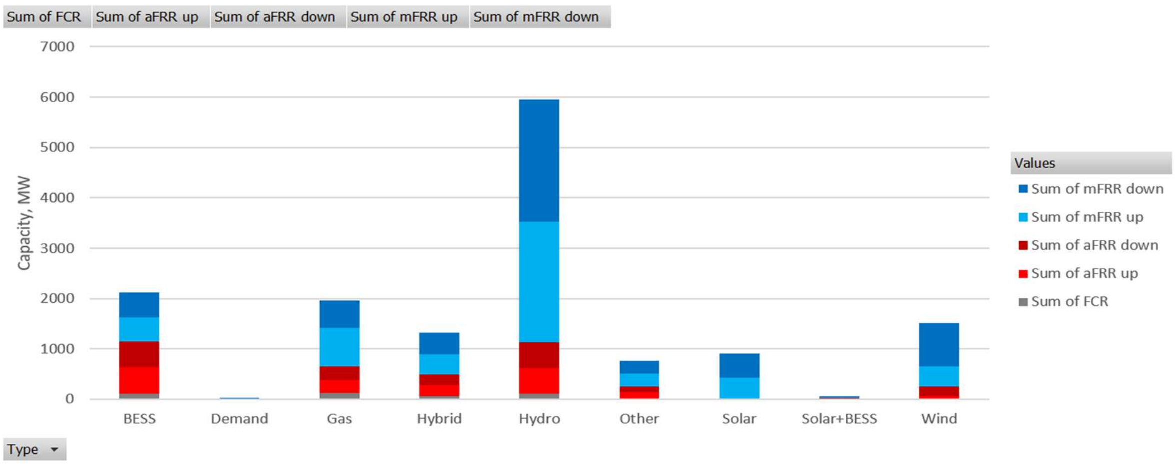

Figure 19. Amount of prequalified assets per type, per product and direction

It should be noted that although prequalified, 808 MW of Latvian Hydro unit mFRR volume in each direction has no intention of participating in the provision of FRR. The reason stated is sequential start/stop requirements and technical limitations in unit operation time - required minimum uninterrupted load time exceeds minimum product activation time of 15 minutes. The published market information on this specific unit is available [1].Nord Pool UMM platform)[2].

2.5. Security of Supply & Demand Coverage and Liquidity

This chapter evaluates the security of supply and market liquidity within the BBCM by analyzing the actual market supply margin, which is calculated for each MTU by subtracting the actual demand from bids submitted to the market, accounting for process types and directions. To evaluate the true available supply volume, one must account for various bid types. To ensure an accurate and realistic assessment of available liquidity, the methodology handles exclusive bid structures conservatively to avoid inflating total market volume.

[2] https://umm.nordpoolgroup.com/#/messages/d709712f-2083-404d-8374-0b951ac9ffa5/1

The following figures present the difference between supply and demand for mFRR, aFRR and FRR capacity in the BBCM from October 2025 to June 2026. A negative spread indicates that the system operators' demand has not been fully covered.

Figure 20 and Figure 21 show that the Baltic mFRR upward and downward spreads have been negative for some MTUs, while the FRR spread has always remained positive. This indicates that mFRR capacity has been substituted by aFRR capacity. The figures show a noticeable decrease in available capacity from the end of May until mid-June. This reduction was primarily of large market assets[3].

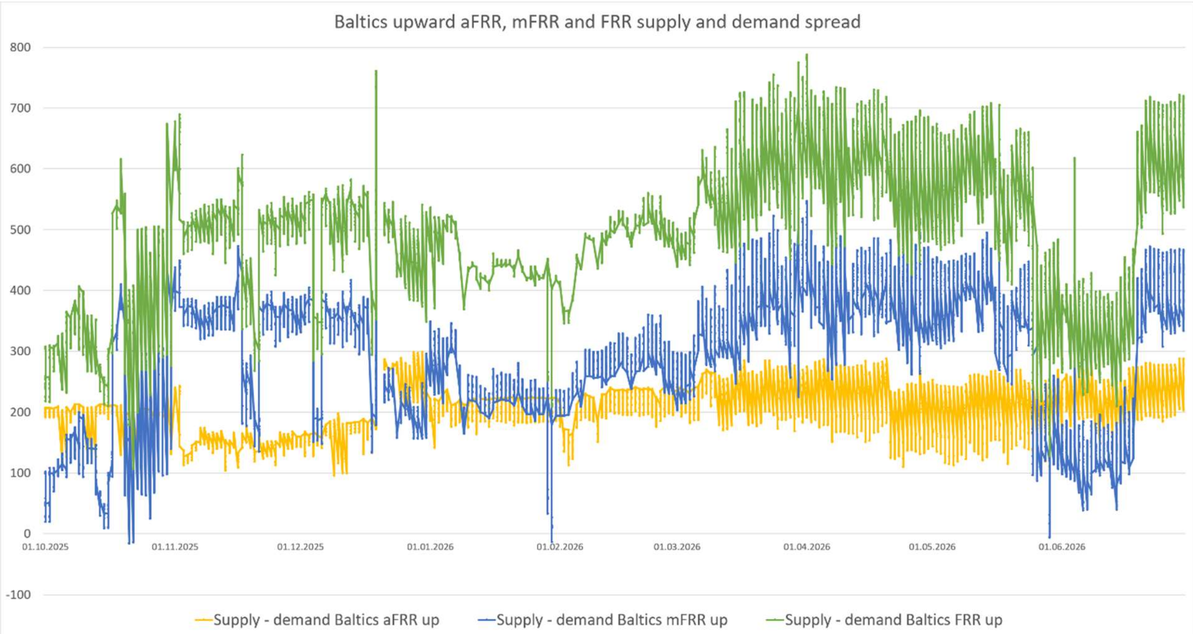

Figure 20. Supply margin of Baltics mFRR, aFRR and FRR upward regulation capacity

[3] https://umm.nordpoolgroup.com/#/messages/f7789d99-6e6d-4bbe-bdd8-6a622cf20db2/3
https://umm.nordpoolgroup.com/#/messages/ed758b33-d609-4232-9513-4029c9f9f9b8/2

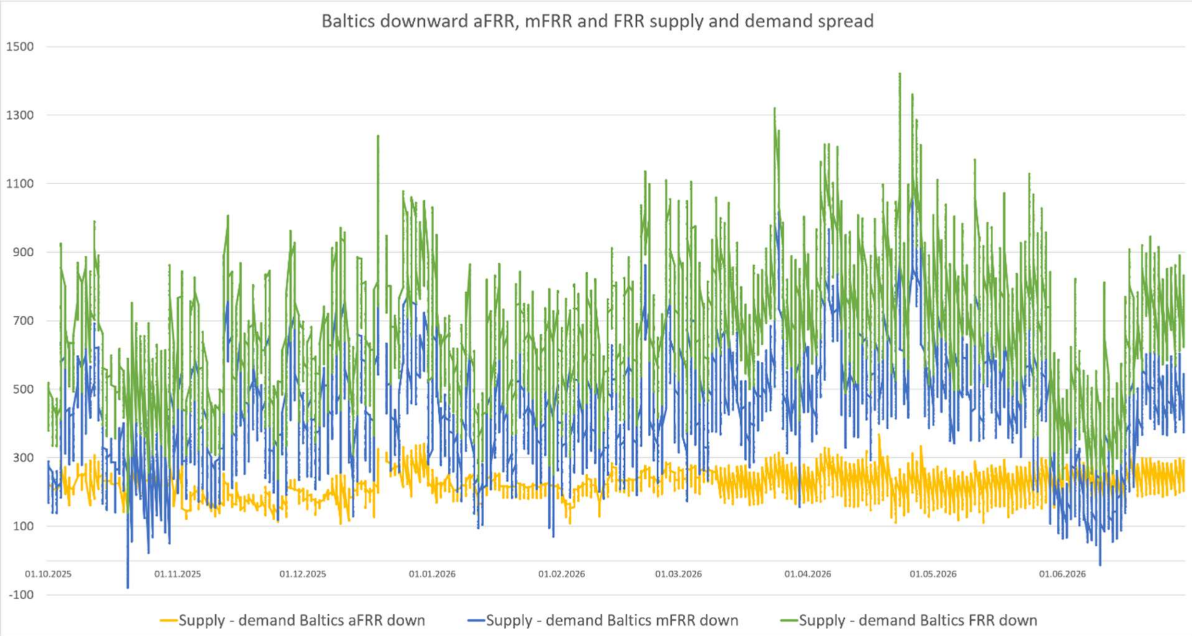

Figure 21. Supply margin of Baltics mFRR, aFRR and FRR downward regulation capacity

Additionally, security of supply can be assessed by performing the same analysis while excluding TSO asset bids from the set of total bids. The results are presented in ***Table 12***, where the total number of MTUs with a potential shortage is counted, that is the period when the demand for a specific product exceeded the total supply. FRR demand and supply are calculated simply as the sum of mFRR and aFRR. Since the volume of prequalified assets is larger than the submitted bid volume, it can be assumed that in the event of such shortage scenarios actually occurring, the market could have some additional supply available. Due to missing data in some MTUs, the analysis includes a total of 26 108 MTUs from October 2025 to June 2026.

Table 12. Coverage of mFRR, aFRR and FRR upward and downward regulation demand in the Baltics (FRR) by MTU under different scenarios

Count of MTUs when the demand is not met	mFRR		aFRR		FRR	
	UP	DOWN	UP	DOWN	UP	DOWN
Actual total supply	24	55	0	0	0	0
Supply without Elering assets	8730	74	0	0	184	0
Supply without AST assets	24	55	0	0	0	0
Supply without Litgrid assets	24	55	0	0	0	0
Supply without 50% of prequalification volume of all TSO assets	1674	62	0	0	12	0
Supply without any TSO assets	8730	74	0	0	1092	0

Across all evaluated scenarios, aFRR demand (both upward and downward) is fully covered in every period. Downward regulation across all products shows high resilience, with mFRR Down having only a few deficit MTUs (ranging between 55 and 74 MTUs out of the total analyzed period) regardless of TSO asset availability. In the real scenario of total supply, total FRR demand is fully met, as was shown on Figure 20 and Figure 21. Removing AST or Litgrid assets from the aFRR capacity market has no standalone effect on demand coverage of aFRR in this analysis, since the analysis evaluates only capacity supply and does not account for procurement costs. However, these assets still reduce the FRR deficit when comparing scenarios without Elering assets and any TSO assets. Reducing TSO prequalified capacity by 50% still leads to unmet FRR upwards demand.

An examination of when the shortages occurred reveals that they frequently coincide with maintenance outages at larger power plants. This suggests that the security of FRR procurement still remains somewhat dependent on the participation of major market participants, especially in the scenario where TSO bids are excluded from the market. Detailed supply and demand graphs for each scenario are provided in the Appendix.

2.6. TSO FRR Costs & Congestion Income

This section covers the balancing reserves capacity costs the three TSOs actually paid over the period and the congestion income TSOs gathered from their respective borders. ***Table 13*** gives monthly FRR costs (excluding FCR) by country. Balancing capacity costs total €108.6 million, where Lithuania alone accounts for €66.6 million, 61.4% of the Baltic total, against €23.7 million for Latvia and €18.3 million for Estonia. Costs do show seasonality signs, highest in June 2026 (€17.9 million) and October 2025 (€15.7 million), and lower in spring (flood period).

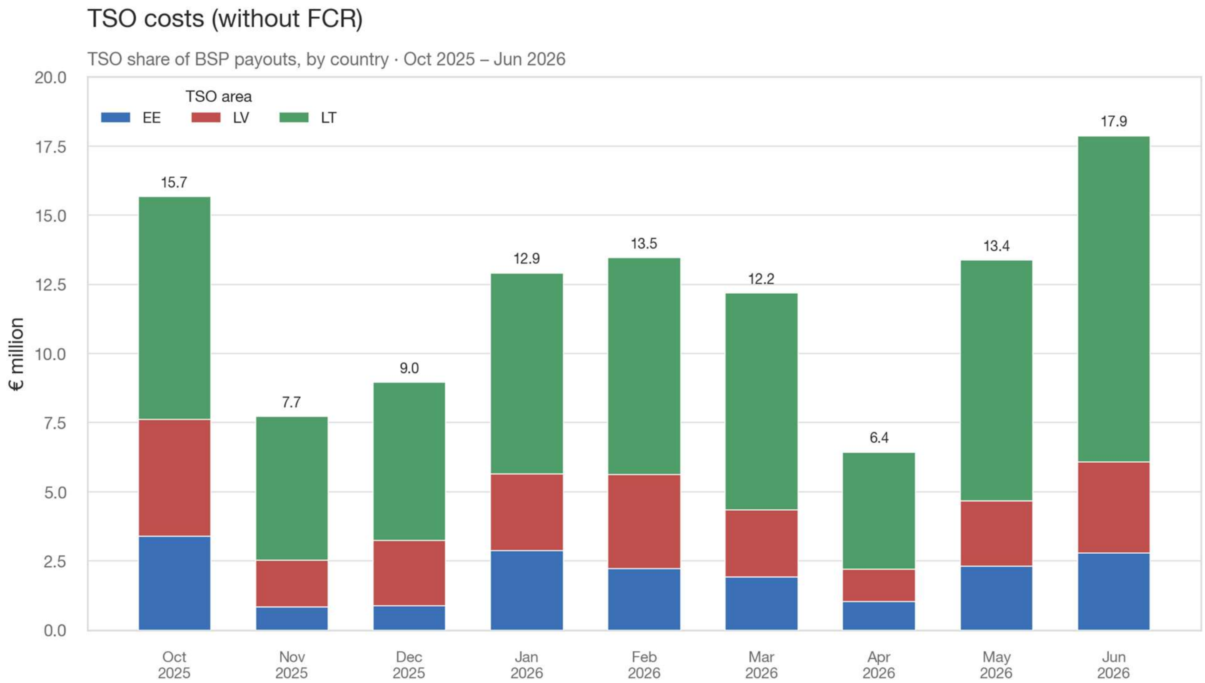

Figure 22. TSO costs for FRR capacity without FCR

Table 13. TSO costs for FRR capacity (without FCR), € (monthly and period total)

TSO Costs (without FCR)				
Month	**EE**	**LV**	**LT**	**Total**
Oct 2025	€ 3 401 623,73	€ 4 209 640,21	€ 8 057 238,60	€ 15 668 502,54
Nov 2025	€ 836 949,52	€ 1 698 597,23	€ 5 192 166,54	€ 7 727 713,29
Dec 2025	€ 883 930,78	€ 2 356 081,40	€ 5 722 441,46	€ 8 962 453,64
Jan 2026	€ 2 870 172,52	€ 2 774 927,36	€ 7 266 423,39	€ 12 911 523,27
Feb 2026	€ 2 224 915,15	€ 3 402 035,85	€ 7 832 965,11	€ 13 459 916,11
Mar 2026	€ 1 930 062,26	€ 2 417 144,40	€ 7 839 517,54	€ 12 186 724,20
Apr 2026	€ 1 033 038,59	€ 1 167 848,38	€ 4 229 282,23	€ 6 430 169,20
May 2026	€ 2 313 527,14	€ 2 351 541,41	€ 8 710 672,03	€ 13 375 740,58
Jun 2026	€ 2 794 819,71	€ 3 285 847,66	€ 11 792 024,14	€ 17 872 691,51
Total	€ 18 289 039,40	€ 23 663 663,90	€ 66 642 731,04	€ 108 595 434,34

Congestion Incomes

Congestion Income (CI) and Additional Congestion Income (ACI) both come from cross-zonal price differences, but they are earned in different markets under different rules. CI is the congestion income from the market-based allocation of cross-zonal capacity for the exchange of balancing capacity and sharing of reserves. According to the MB Methodology congestion income is the product of the price difference between the two bidding zones and the allocated cross-zonal capacity for the exchange and/or sharing of balancing capacity per day-ahead market time unit. It is the rent that arises when joint Baltic procurement clears at different balancing capacity prices on the two sides of a constrained border, e.g. a zone that imports reserves across a constrained border has a price that is higher or equal to that of the exporting zone. That is why most of the CI sits almost entirely on the Estonian-Latvian border and is negligible for Lithuania, which was rarely constrained during the period. CI is shared under Article 11(2) of the MB Methodology in line with Article 73 of the CACM Regulation and Article 41(4) of the EBGL.

ACI can be understood as the theoretical additional day-ahead market congestion income that could have been generated if the cross-zonal capacity that was allocated for balancing capacity exchange and sharing was instead given to the day-ahead market. It is calculated as the product of the day-ahead market price difference between two bidding zones and respective cross-zonal capacity allocation. This calculation is performed for each MTU of a given month, and then it is compared to the total monthly congestion income generated in BBCM. If the found value is larger than the BBCM CI, the difference between the two CI is then evaluated. The obligation to evaluate ACI falls under Article 11(2) and Article 11(3) of the MB methodology. The report shows it next to CI so that total congestion-related revenue on the Baltic borders can be compared with gross FRR procurement cost. Balancing capacity congestion income falls under Article 19 of Regulation (EU) 2019/943, and under the CID methodology the balancing capacity CI is itself distributed as day-ahead congestion income.

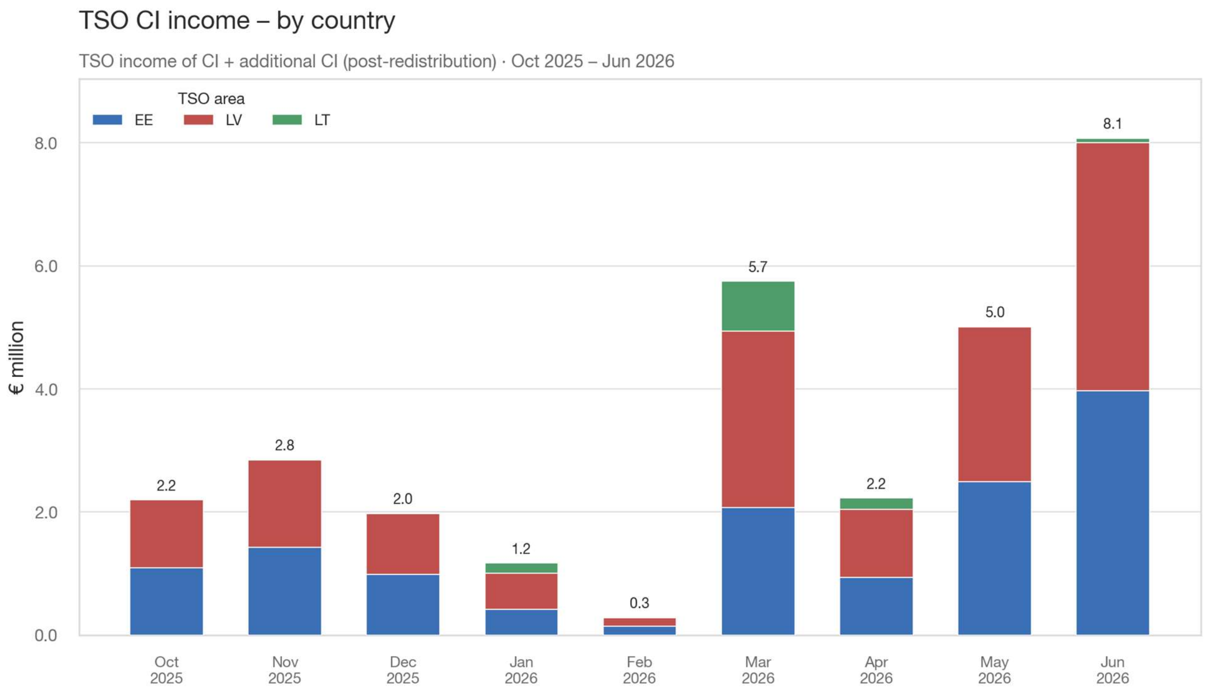

Figure 23. TSO Congestion Income by Country

Table 14 and ***Table 15*** show the Congestion Income (CI) totals €12.0 million over the period. With Additional Congestion Income (ACI) of €17.5 million, income related to congestion comes to €29.5 million, about 27% of gross FRR cost. Estonia and Latvia each received around €6.0 million of CI, Lithuania only €0.33 million (2.7%), because Lithuania was almost never on a constrained border. Congestion income accrues where the limit binds and for nearly the whole period that was the Estonian–Latvian border. Lithuania separated only in March and April 2026, which is exactly where its only CI shows up.

Table 14. Congestion Income (CI) by country, € (period total)

Month	EE	LV	LT	Total
Oct 2025	€ 832 491,88	€ 832 491,88	€ -	€ 1 664 983,76
Nov 2025	€ 253 103,64	€ 253 242,57	€ 138,93	€ 506 485,14
Dec 2025	€ 275 175,80	€ 275 175,80	€ -	€ 550 351,60
Jan 2026	€ 92 374,29	€ 129 277,91	€ 36 903,63	€ 258 555,83
Feb 2026	€ 139 105,69	€ 145 055,27	€ 5 949,59	€ 290 110,55
Mar 2026	€ 484 566,79	€ 673 623,67	€ 189 056,87	€ 1 347 247,33
Apr 2026	€ 314 846,88	€ 375 717,60	€ 60 870,72	€ 751 435,20
May 2026	€ 1 619 800,35	€ 1 628 488,24	€ 8 687,89	€ 3 256 976,48
Jun 2026	€ 1 659 303,08	€ 1 687 607,33	€ 28 304,25	€ 3 375 214,66
Total	**€ 5 670 768,40**	**€ 6 000 680,27**	**€ 329 911,88**	**€ 12 001 360,55**

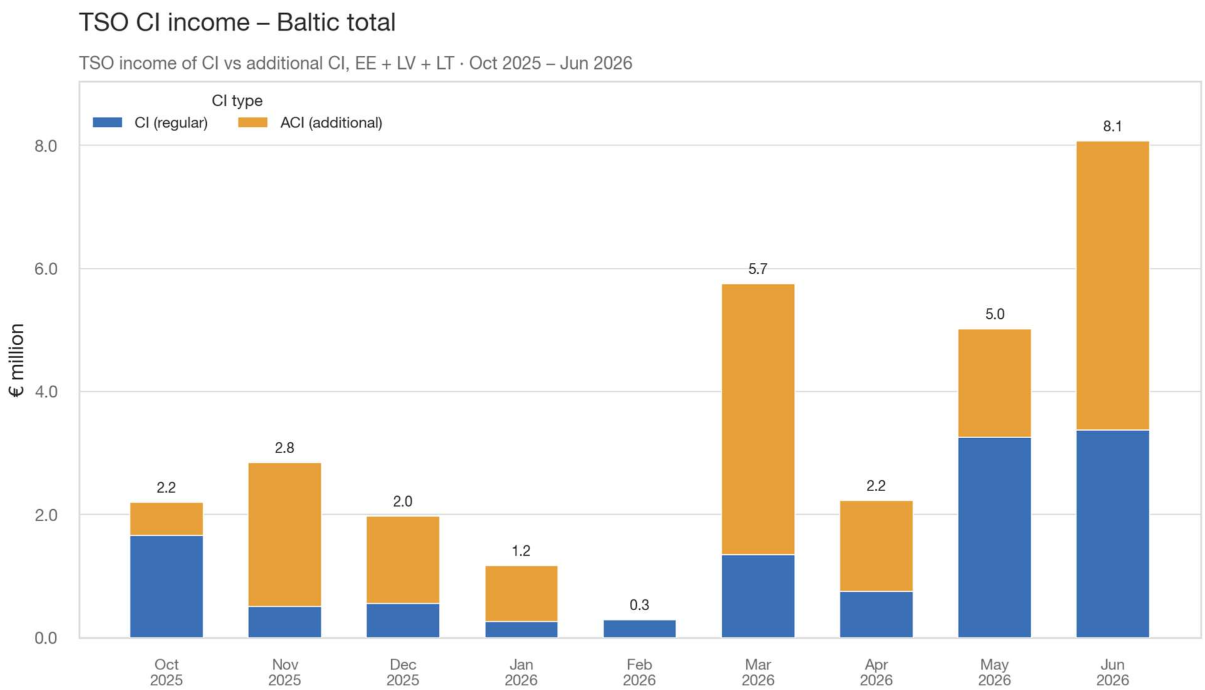

Figure 24. TSO Congestion Income & Additional Congestion Income in the Baltics

Table 15. Congestion Income and Additional Congestion Income, € (period total)

Month	CI total	ACI total	Total
Oct 2025	€ 1 664 983,76	€ 530 771,72	€ 2 195 755,48
Nov 2025	€ 506 485,14	€ 2 340 649,49	€ 2 847 134,63
Dec 2025	€ 550 351,60	€ 1 425 481,48	€ 1 975 833,08
Jan 2026	€ 258 555,83	€ 910 397,85	€ 1 168 953,68
Feb 2026	€ 290 110,55	€ -	€ 290 110,55
Mar 2026	€ 1 347 247,33	€ 4 401 854,27	€ 5 749 101,60
Apr 2026	€ 751 435,20	€ 1 475 528,36	€ 2 226 963,56
May 2026	€ 3 256 976,48	€ 1 760 149,03	€ 5 017 125,51
Jun 2026	€ 3 375 214,66	€ 4 699 737,80	€ 8 074 952,46
Total	**€ 12 001 360,55**	**€ 17 544 570,00**	**€ 29 545 930,55**

3. Comparison of Forecasted and Actual CZC Market Values for the Exchange of Energy

3.1. SDAC Spread Forecast Errors

Under Article 6(1) of the MB Methodology, the initial forecasted market value of cross-zonal capacity (CZC) for the exchange of energy equals the positive single day-ahead coupling (SDAC) price spread of the corresponding market time unit of the reference day and zero where that spread is negative or zero:

$$SDAC\_spread_{t',r,r'} = max(0, SDAC\_price_{t',r'} - SDAC\_price_{t',r})$$

Where:

$SDAC\_price$ – the SDAC clearing price;

r – the exporting bidding zone;

r' – the importing bidding zone;

t – the delivery MTU;

t' – the corresponding MTU of the reference day as defined in Article 6(6).

For example, the forecast component of the CZC cost on the EE→LV border for MTU 6 of 5 March is the greater of zero and the LV price minus the EE price in MTU 6 of 4 March.

The realized market value is computed on the same basis from delivery-day prices and the forecast error is as follows:

$$e = SDAC\_spread_{actual} - SDAC\_spread_{forecasted}$$

A positive error means the forecast understated the realized opportunity cost of the capacity, while negative error means it overstated it. Values are expressed in EUR/MW of cross-zonal capacity per day-ahead market time unit, consistent with Article 10(3) of the Methodology for the market-based allocation process of cross-zonal capacity for the exchange of balancing capacity for the Baltic CCR.

Frequency of Forecast Errors

Figure 25 splits the errors into no difference, positive difference (forecast above realised) and negative difference (forecast below realised), by border and direction.

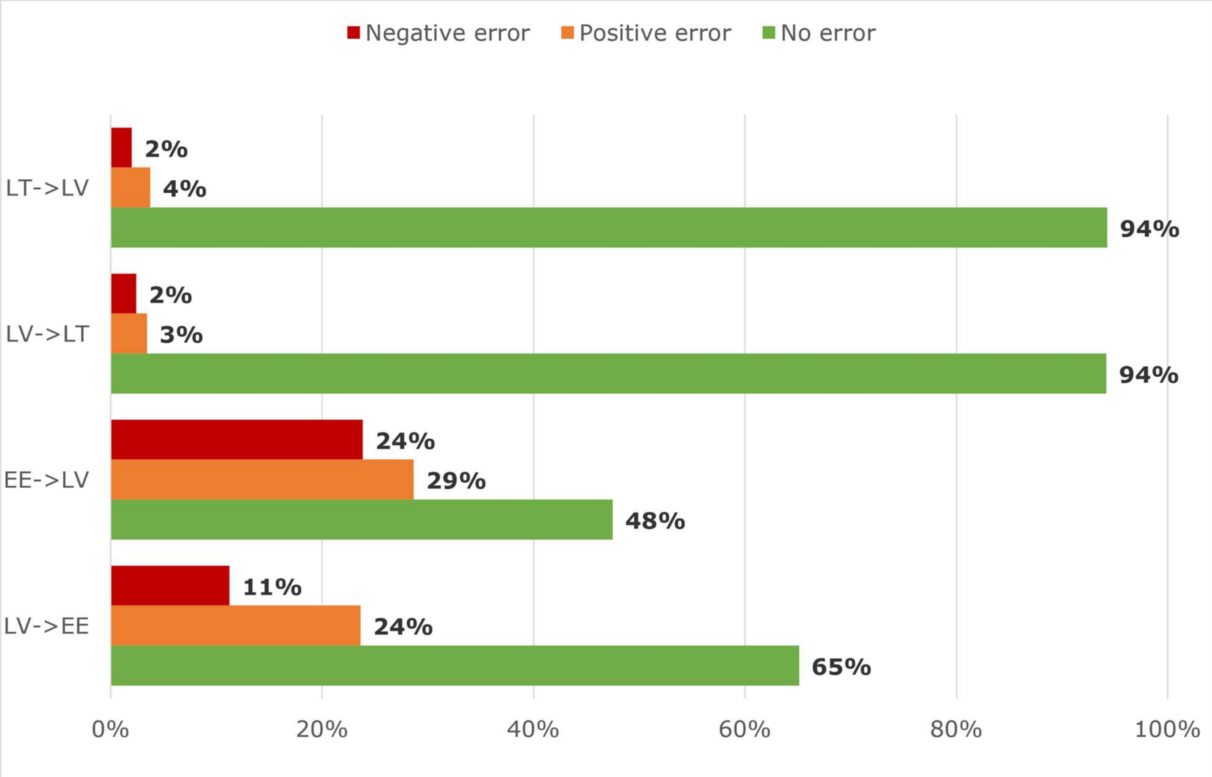

Figure 25. Day-Ahead market spread forecast errors shared by direction

Errors on the Latvian‑Lithuanian border remain relatively infrequent, with 6% of MTUs in the LT→LV direction and 5% in LV→LT. On the Estonian‑Latvian border they occur frequently: 53% of MTUs in EE→LV and 35% in LV→EE. The immediate cause is the persistent day-ahead market price differential between Estonia and Latvia, driven in turn by lower Finnish prices and the resulting north-to-south flow through Estonia.

It should be noted that congestion frequency alone does not generate forecast error. A border congested at a stable spread would be forecasted accurately by the reference-day method. What generates error is day-to-day variability in the spread, and it is on this measure that the Estonian–Latvian border differs from the Latvian–Lithuanian one.

The split between over- and under-estimation is close to even on the EE→LV direction (24% against 29%), but markedly asymmetric on LV→EE, where under-estimation occurs in 24% of MTUs against over-estimation in 11%. This asymmetry is a direct consequence of the zero floor in Article 6(1): because Estonian prices are typically at or below Latvian prices, the LV →EE forecast is pinned at zero for most MTUs and can only be wrong in one direction.

Average SDAC Spread Errors

Forecast error is reported here as the realised spread minus the forecast spread, so that a positive error denotes an underestimate (the realised value exceeded the forecast) and a negative error an overestimate.

The unconditional average is taken over all MTUs in the period, including those where the forecast matched the realised value exactly. It measures the total mispricing accumulated across the period and is the basis used in the BBCM 2025 Evaluation Report; it is retained here for continuity and feeds the welfare assessment in Section 6. On this basis the mean absolute error is 25.02 EUR/MWh on EE→LV, 6.66 on LV→EE, 2.30 on LV→LT and 1.37 on LT→LV, with mean signed errors of 1.35, 3.02, 0.45 and 0.48 EUR/MWh respectively.

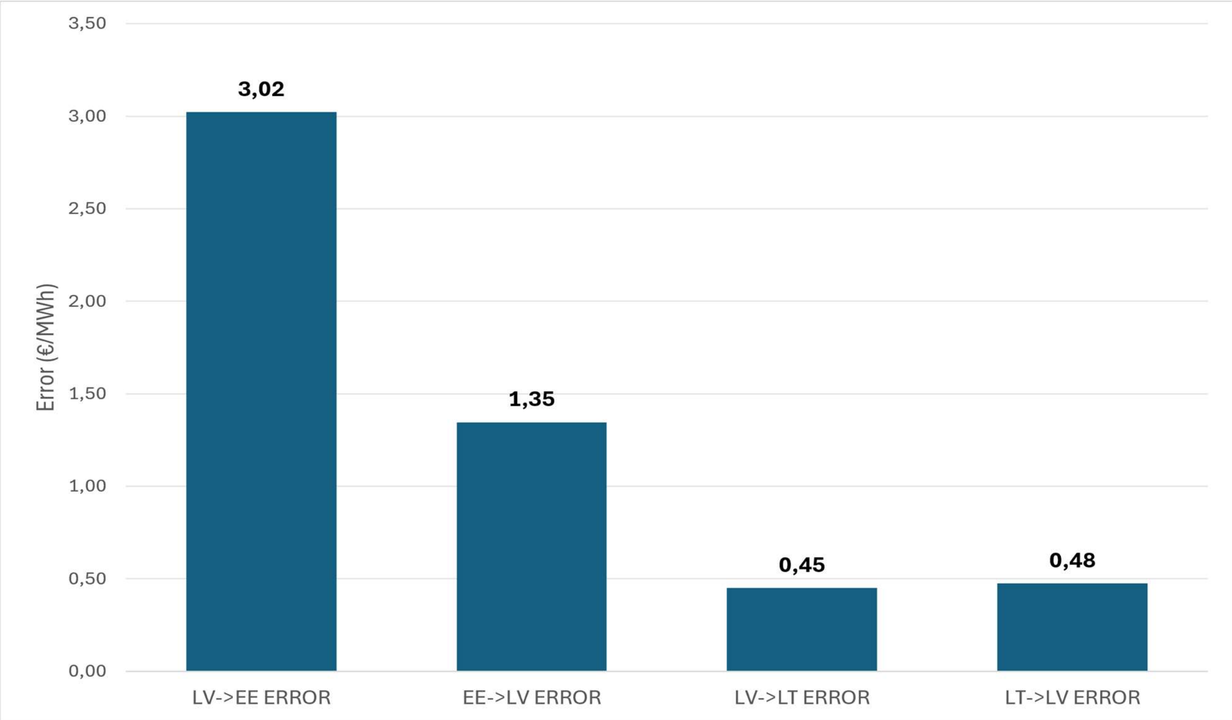

Figure 26. Unconditional signed SDAC average error

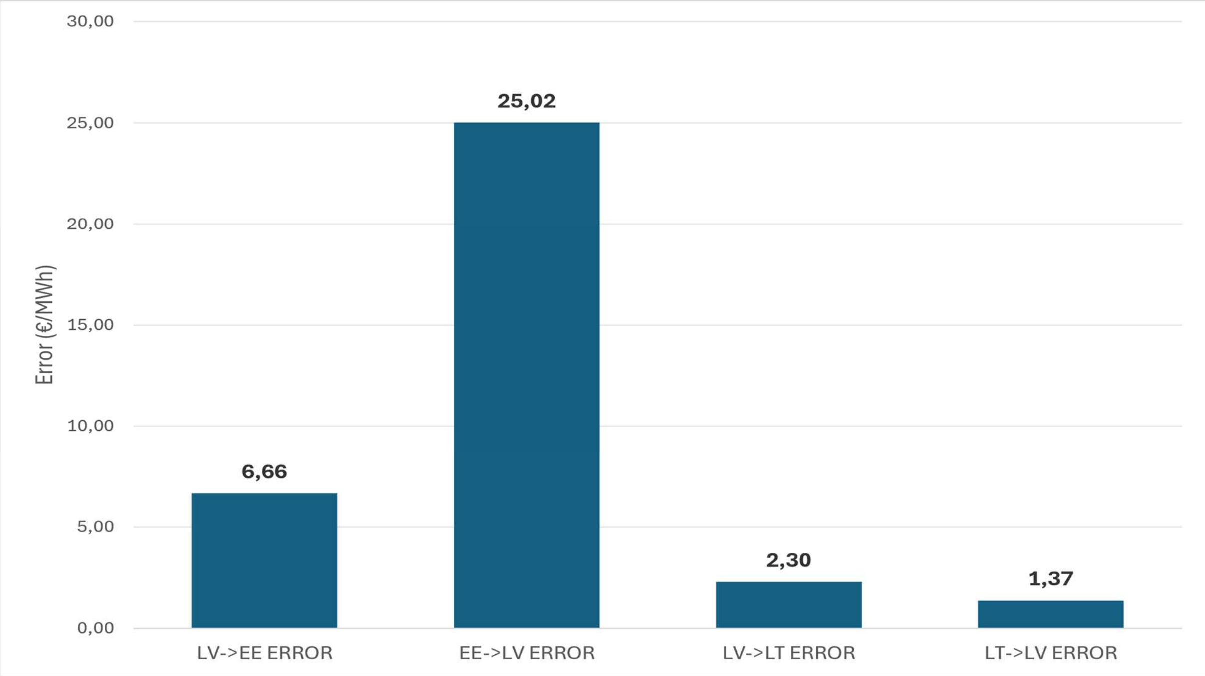

Figure 27. Unconditional mean SDAC absolute error (MAE)

The conditional average is taken only over the MTUs in which an error actually occurred, because the internal Baltic borders are uncongested in the large majority of MTUs with 94% of zero-error on both Latvian–Lithuanian directions and 65% on LV→EE. The unconditional figures are heavily weighted by MTUs in which the forecast could not be wrong. The conditional figures isolate the remaining cases and show by how much the forecast missed when the two markets did diverge. This is the measure relevant to the assessment of forecast accuracy under Article 12(8)(f).

On this basis the mean absolute error is 47.65 EUR/MWh on EE→LV, 19.08 on LV→EE, 39.51 on LV→LT and 23.91 on LT→LV. The mean signed error is positive in all four directions, at 2.56 on EE→LV, 8.66 on LV→EE, 7.74 on LV→LT and 8.31 on LT→LV. The two bases are consistent with one another: the conditional error multiplied by the frequency of error in Figure 25 reproduces the unconditional figure in each direction.

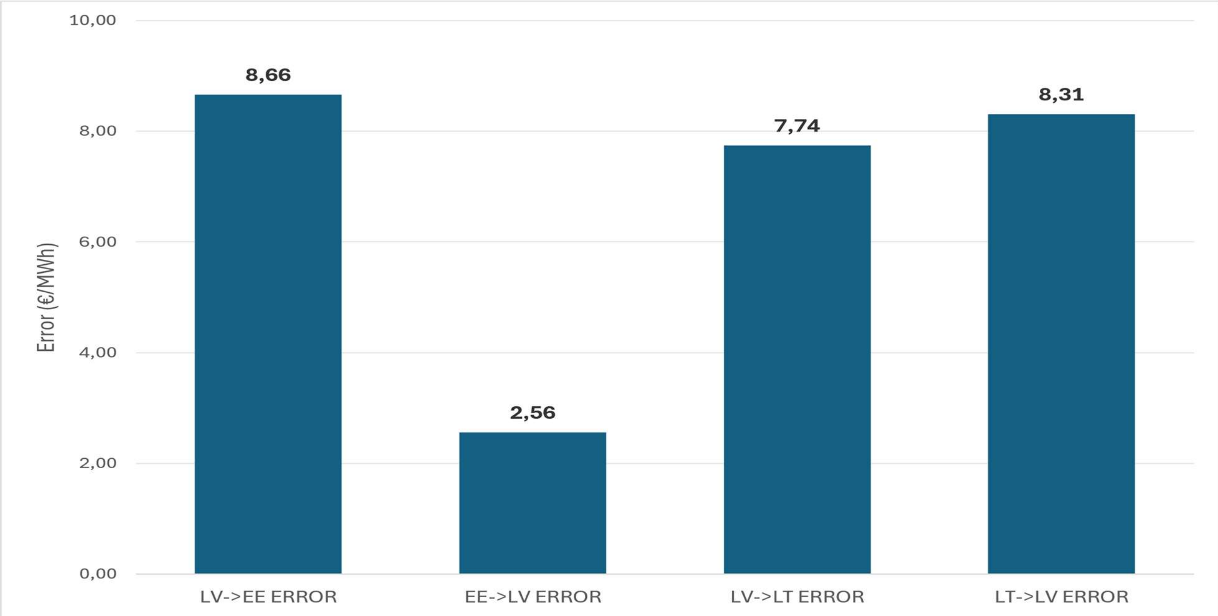

Figure 28. Conditional signed SDAC average error

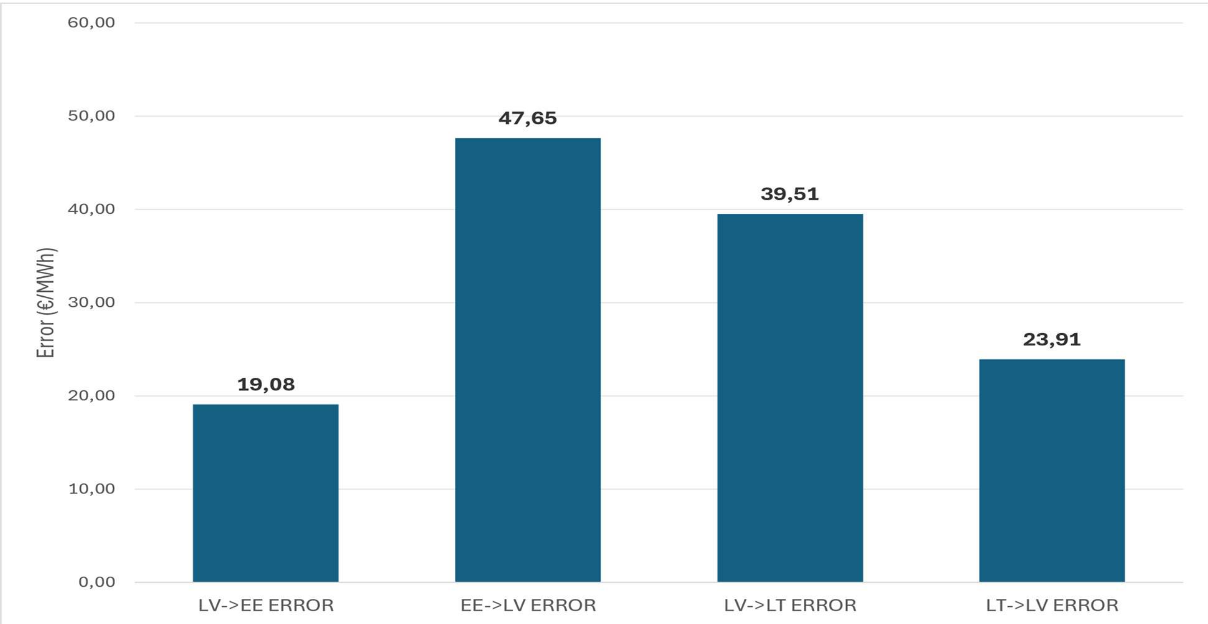

Figure 29. Conditional absolute SDAC average error

First, the positive sign in every direction is a structural property of the floored forecast rather than evidence of a biased estimator. Article 6(1) sets the forecast to zero wherever the reference-day spread is negative or zero, so on a border that is uncongested on most days the forecast sits at zero and can be wrong only when the realized spread turns out positive, that is only by underestimating it. Errors on such borders are therefore one-sided by construction, and the signed mean is correspondingly positive. This is visible in the contrast between EE→LV, where the two zones are frequently at different prices, the forecast is usually non-zero, and over- and under-estimation are close to balanced (24% against 29% of MTUs), and the other three directions, where the forecast is floored on most days and under-estimation predominates.

Second, the conditional errors are of a magnitude that warrants closer examination. Conditional on divergence, the average miss ranges from 19 to 48 EUR/MWh, which is material against prevailing day-ahead price levels in the Baltic bidding zones during the period. The reference-day method delivers a low average error across the period as a whole, but the error it does produce is concentrated in a relatively small number of market time units and is substantial within them.

The Baltic TSOs consider it appropriate to establish, before proposing any change to the forecast methodology, whether this concentration follows an identifiable pattern. Article 6(6) sets the reference day as the previous working day for working days and the previous weekend day for weekend days, which means the interval between reference day and delivery day is one day for most of the week but three days for Mondays and up to six days for Saturdays and bank holidays. Whether forecast error rises with this interval is a directly testable question, as is whether errors cluster by day type, by time of day, or around specific market conditions such as periods of high import from Finland. If the error proves concentrated in identifiable circumstances, a targeted refinement addressing those circumstances is likely to be more effective and less disruptive, than a general change to the forecasting method. The TSOs intend to carry out this analysis, make necessary adjusments and report on the impact of the changes in the next Evaluation Report.

3.2. Proposals to improve forecast accuracy of forecasted market values

The day-ahead market graphs show fluctuations of EE energy prices which do not correlate with LT and LV prices (Figure 30; Figure 31). The EE 4 MTU average on 29.06. 21:00 - 22:00 is 59 €/MWh with a market spread of 66 €/MWh; on 30.06. 21:00-22:00 it’s 415 €/MWh with a market spread of 148 €/MWh

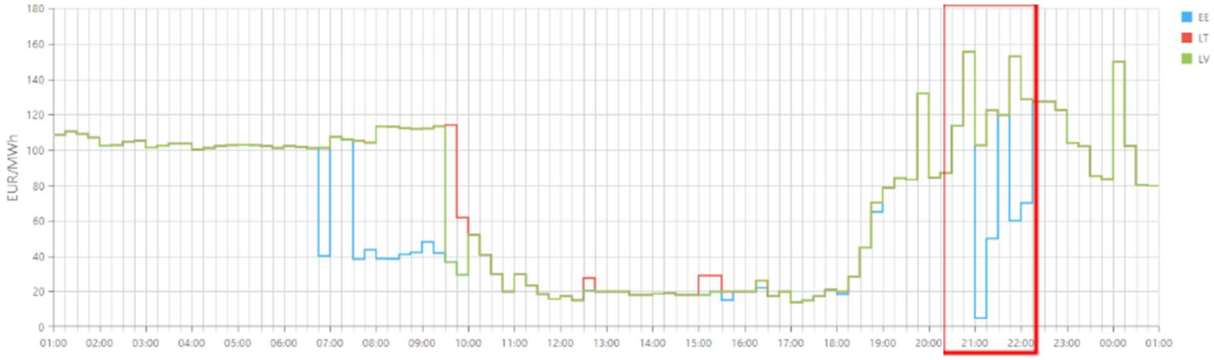

Figure 30. Nord Pool clearing prices on 29.06.2026

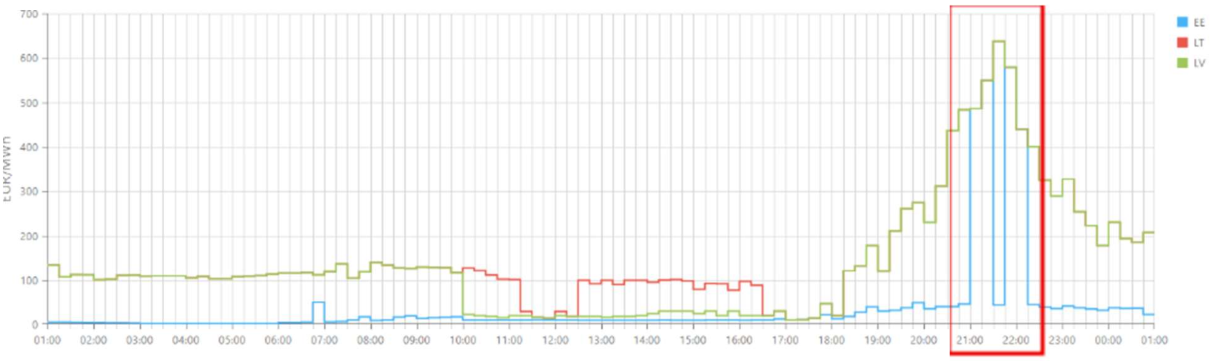

Figure 31. Nord Pool clearing prices on 30.06.2026

One reason for this is the allocation method between BBCM and SDAC. BBCM algorithm uses a reference day forecast methodology to determine the correct price for the MTU. At the moment, the reference value is simply the previous day's MTU price at the exact same moment (business and non-business days are calculated separately). The algorithm has limitations because it cannot predict volatile changes in market spreads and thus loses accuracy. When there is no forecasted market spread, the algorithm overcompensates by allocating too much capacity, whereas with a large forecasted SDAC spread, the algorithm allocates too little capacity. Furthermore, when the BBCM algorithm allocates very little CZC for balancing due to forecasted SDAC spread, the spread does not realize due to large volume of CZC left to SDAC. Moreover, due to the nature of the reference day calculation, the algorithm overcorrects and, once again, loses accuracy, which in turn results in daily cyclical fluctuations. This creates an oscillating feedback loop between the BBCM and SDAC markets which causes non-optimal allocations and large unnatural shifts in market spreads, as well as large forecast errors in BBCM SDAC forecast. Recently, this has happened in the evenings of the end of June and start of July. Incidents like this have also caught the attention of Estonian market-participants.

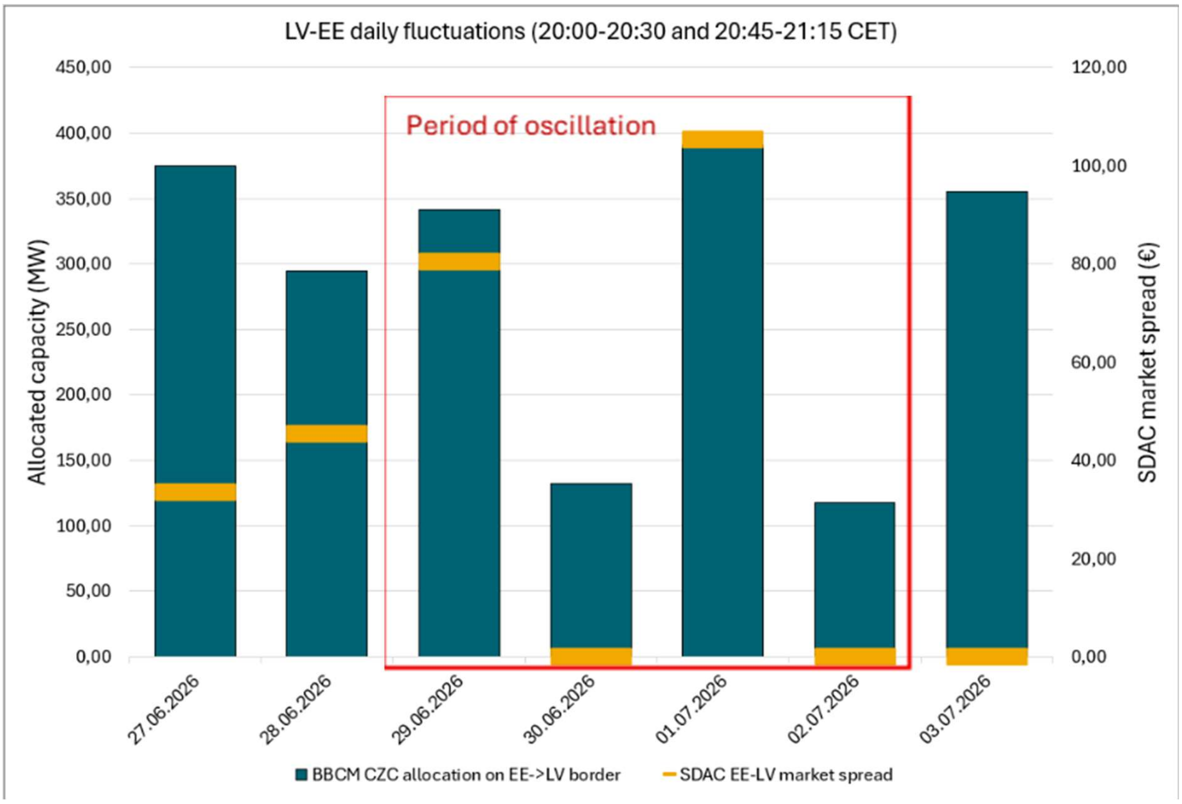

Figure 32. Daily SDAC market spread fluctuations on the LV-EE border

The described oscillations have also been noticed at least on the following periods:

- 03-06.03.2026;
- 09-10.05.2026;
- 16-17.05.2026;
- 19.-20.05.2026;
- 29.06-02.07.2026.

In order to mitigate the oscillation between the SDAC and BBCM, several remedies can be used. For instance, a more advanced forecast method can be used instead of a simple reference day, which uses price data from more than one day to smooth the sudden changes in SDAC. The other option would be to implement a volume sensitive CZC value forecast in BBCM, for which the functionality is already present, but is not used so far per Section 6.2

TSOs have experimented with different reference value calculations to find the best fit. This includes the current solution – previous day MTU (D-1), additionally the 2-day average MTU (D-2), the 7-day average MTU (D-7), and variations where the MTUs are grouped by 8-hour blocks or 24 hours and their respective averages are used. See table below (***Table 16***).

Table 16. Analysed reference day price values

MTU based	3 blocks of 8h	Daily average
D-1	1/3 D-1 AVG	D-1 AVG
D-2	1/3 D-2 AVG	D-2 AVG
D-7	1/3 D-7 AVG	D-7 AVG

Each reference value calculation had a corresponding spread error from SDAC spread values with their own unique bell curve distribution. Since most days/MTUs EE-LV spread (price difference) is „0“, the reference day forecast is correct and logically, the deviation value (spread error) is also „0“. The issue arises when fluctuations start between EE and LV prices. We found that for small deviations (+/- 10), D-1 was still the best fit. Interestingly, larger deviations were less common with multi-day averages, best fit was 1/3 D-7 AVG. Best fit was measured by comparing the average absolute error of respective reference value calculations. Small fluctuations are more easily accepted by market participants, therefore the focus was on eliminating discrepancies related to larger price fluctuations. Based on the aforementioned reference value calculations, we developed a simple formula:

$$\text{If } -10 < \text{D} - 1 < 10, \text{ choose D} - 1, \text{ else choose } 1/3 \text{ D} - 7 \text{ AVG}$$

In practice, the formula determines the magnitude of forecasted spread (D-1) and decides on the correct reference value calculation. The formula’s design is based on the notion that cases of zero/small fluctuations in SDAC spread correlate with previous day’s spread and large fluctuations correlate with the average spread of the past 7 day’s 8-hour blocks or rather, the large fluctuations are treated as extreme cases which are to be aggregated with previous MTUs.

3.3. Mark-ups

According to the Market-Based Allocation Methodology, a mark-up shall be added to the initial forecasted market value of cross-zonal capacity calculated in order to take into account the uncertainty of the forecasted day-ahead market value of cross-zonal capacity. In essence, the mark-up value means an applied penalty in EUR/MWh for the allocation of balancing capacity – the higher the mark-up, the less slightly favorable is the sharing of balancing capacity versus energy exchange in SDAC. The default markup values are as follows:

- if there is a negative or zero market spread for the initial forecasted market value of cross zonal capacity in accordance with paragraph 1, the mark-up will be 0.1 EUR/MWh; and
- if there is a positive market spread, for the initial forecasted market value of cross-zonal capacity in accordance with paragraph 1, the mark-up will be 1 EUR/MWh.

From the 2nd of March, 2026, the higher mark-up calculation process was applied during live BBCM runs, meaning that, if there is a positive market spread, the mark-up value may become larger than 1 EUR/MWh. The higher mark-up calculation is performed as follows:

1) Non-negative forecast errors per bidding zone border are calculated by finding the positive differences between the actual DA prices and the forecast DA prices:
$$\Delta P_{a \to b} = \mathrm{MAX}\left[\mathrm{MAX}\left(P_{b,actual} - P_{a,actual}\right) - \mathrm{MAX}\left(P_{b,forecasted} - P_{a,forecasted}\right); 0\right]$$
   Where:
   a – bidding zone a;
   b – neighbouring bidding zone b;
   $P_{a,actual}$ – actual day-ahead market price in bidding zone a [EUR/MWh];
   $P_{a,forecasted}$ – BBCM forecasted day-ahead market price in bidding zone a [EUR/MWh];
   $P_{b,actual}$ – actual day-ahead market price in bidding zone b [EUR/MWh];
   $P_{b,forecasted}$ – BBCM forecasted day-ahead market price in bidding zone b [EUR/MWh].
2) The 95th percentile is calculated for the derived $\Delta P_{a \to b}$ values;
3) The average is taken of those values that are lower than the 95th percentile and higher than 0;
4) The applied higher-markup is then derived by comparing the average value computed during 3) with the default applicable higher mark-up value:
   - If the average value is higher than the default mark-up value by 1 EUR/MWh; then the default mark-up value is increased by 1 EUR/MWh;
   - If the average value is lower than the default mark-up value by 1 EUR/MWh; then the default mark-up value is decreased by 1 EUR/MWh;
   - If otherwise, the default mark-up value remains unchanged;
   - At any given point the default mark-up value cannot be lower than 1 EUR/MWh and higher than 5 EUR/MWh.
5) The calculation is performed every weekday for the previous 30-day period, for each MTU separately.

The calculated default higher mark-up values are shown in the graph below (Figure 33. BBCM higher mark-up value evolution for each Baltic bidding zone border by direction). As a starting point, higher mark-ups were initially calculated for the business day period 2026.02.01-2026.03.02, but no changes in the default values were observed. From 2026.03.04 the EE-LV default mark-up value increased to 2, resulting from the increasing day-ahead market price differences between Estonia and Latvia. The default value then quickly ramped up to the maximum value of 5 EUR/MWh, which, as of July, is still the current default value. Increases in the default values were also observed for LV-LT and LV-EE, but these were short lasting, as the much more frequent occurrences were lower day-ahead prices in Estonia and higher day-ahead prices in Latvia.

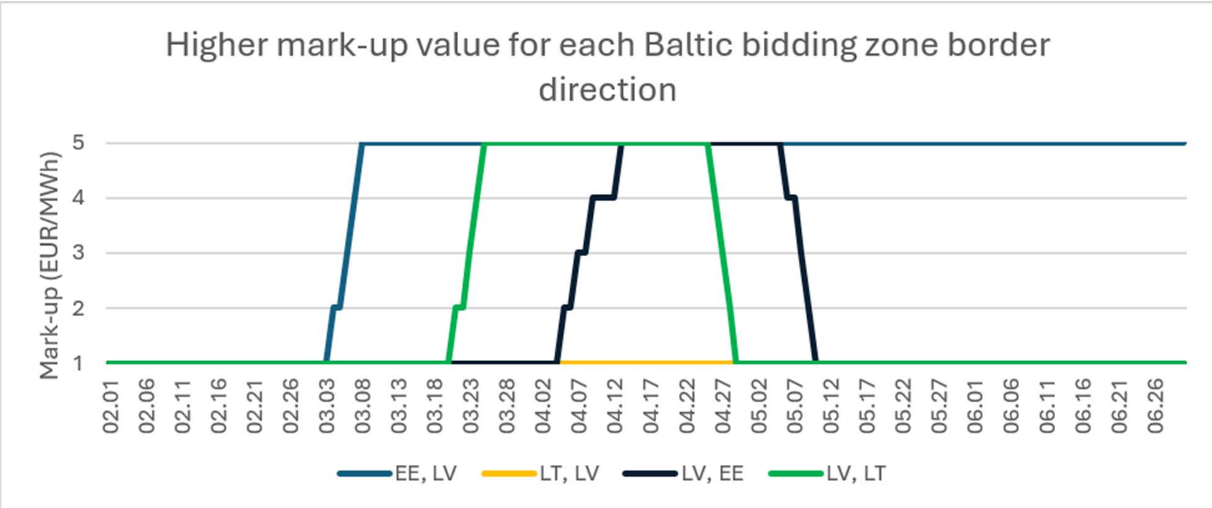

Figure 33. BBCM higher mark-up value evolution for each Baltic bidding zone border by direction

It is likely that the higher mark-up value for EE-LV shall stay higher, considering the day-ahead price differences between the bidding zones. However, more extensive data coverage is needed in order to assess whether the mark-up limits should be changed.

4. Assessment of CZC Allocations Above 50% Limit

During the reporting period, for all Baltic bidding zone border directions, the 50% limit was never breached. In the graphs below (Figure 34 and Figure 35), the CZC allocation statistics are shown. Although the default limit was never crossed, allocations reaching 50% were fairly common for the EE-LV border direction, especially during May and June. This is due to the lower NTC values when compared to the LT-LV or LV-LT border directions, and the impact can especially be more apparent during transmission line maintenance.

The average allocation values during the reporting period can be found in ***Table 17***. Overall, the allocations across the Baltics are similar, but due to the lower NTC values of the EE-LV transmission lines, the percentage of NTC allocated can be considerably higher.

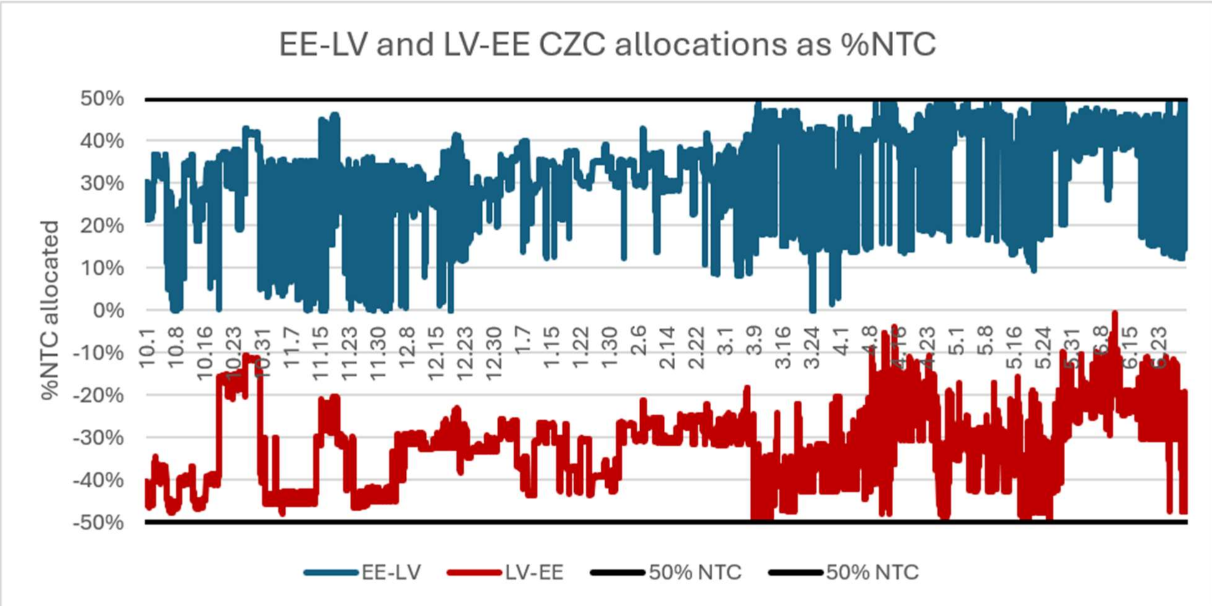

Figure 34. Cross-zonal capacity allocations per MTU as a percentage of the net transmission capacity for balancing capacity exchange and/or sharing, for EE-LV and LV-EE border directions

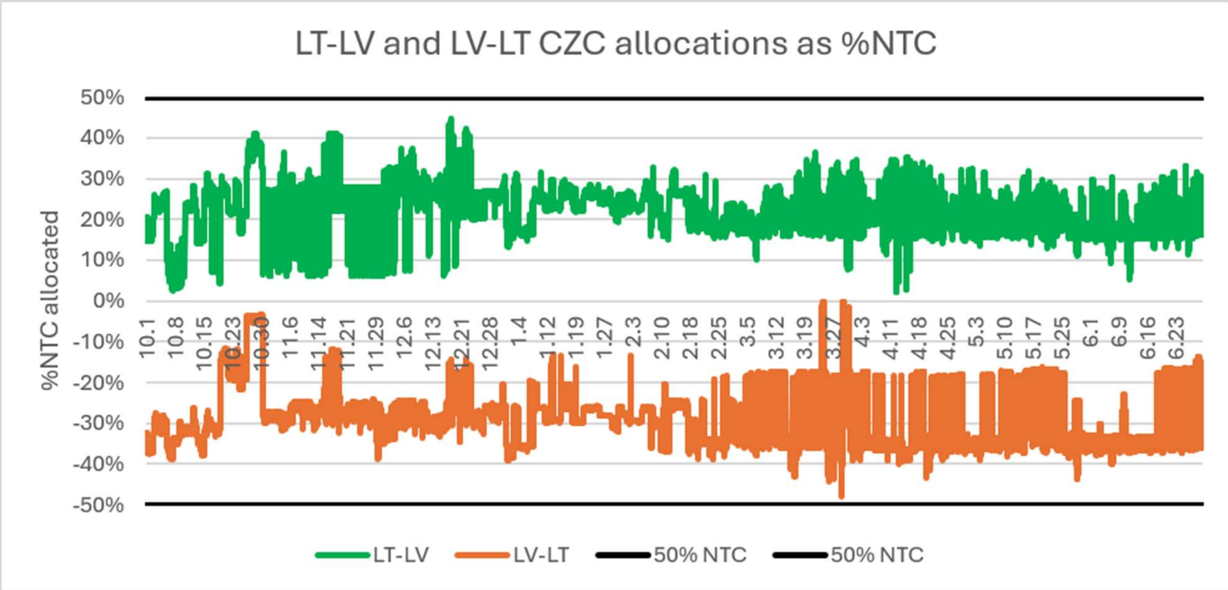

Figure 35. cross-zonal capacity allocations per MTU as a percentage of the net transmission capacity for balancing capacity exchange and/or sharing, for LT-LV and LV-LT border directions

Table 17. average cross-zonal capacity allocation for the exchange and/or sharing of balancing capacity during the reporting period for all Baltic borders

Border direction	EE-LV	LV-EE	LT-LV	LV-LT
Average CZC allocation (%NTC)	32,80	31,70	22,40	29,50
Average CZC allocation (MW)	280,10	317,30	270,10	349,60

4.1. Economic Surplus Effect of >50% Allocations on SDAC

As there were no 50% limit breaches, the economic surplus effect was not evaluated.

4.2. Notification Compliance & Proposed Process

Baltic TSOs shall implement an automatic process in the BBCM platform for identifying 50% limit breaches and communicating such events (for example, via email) to the Baltic NRAs by the end of 2026.

4.3. Assessment & justification for using current CZC allocation limits

Given that there were no default limit breaches during the reporting period, and that the average allocation for balancing capacity exchange and/or sharing was from 22,4% to 32,8% (see Table 16) across the different Baltic directions, there is no indication that the default limit should be higher than 50%. However, the default limit could potentially be reduced, but this highly dependent on the liquidity and flexibility of the market, which is still fairly limited – as seen in Figure 34, the 50% maximum was commonly reached during March-June for the EE-LV border direction. Therefore, any change of the default limit cannot be statistically justified.

5. Assessment of the Impact on SDAC Price Formation

Reserving cross-zonal transmission capacity (CZC) for balancing services reduces the capacity available for the day-ahead (DA) market. This reduction can have a notable impact on DA market prices.

The impact of reserving CZC for BBCM on the SDAC price formation and economic surplus has been assessed using the Simulation Facility. To calculate the change in price formation in the SDAC and economic surplus, we utilize a pan-European Simulation Facility tool allowing us to conduct the analysis based on the actual DA market supply and demand curves. The Simulation Facility tool allows us to rerun the DA market clearing with increased capacities (actual capacity + CZC reservation) to estimate the changes caused by the allocation.

For the purpose of analysis in this report, other impacts on balancing capacity market clearing on the SDAC are disregarded, such as reservation of assets by the balancing capacity market as well as bringing new generation into the DA market due to accepting bids form thermal power plants in the balancing capacity market. Thus, as the only impacting factor on SDAC investigated is the CZC allocation for the exchange of balancing capacity and sharing of reserves, the impact on SDAC should be strictly zero or negative.

The Figure 36 below shows the price differences between the base case (actual reserved CZC values) and the scenario without CZC reservation for BBCM. A positive difference indicates that the actual DA price was higher, meaning the CZC reservation increased prices in that bidding zone. Conversely, a negative difference indicates that prices were lower in the base case, implying the reservation had a mitigating effect on prices in that zone.

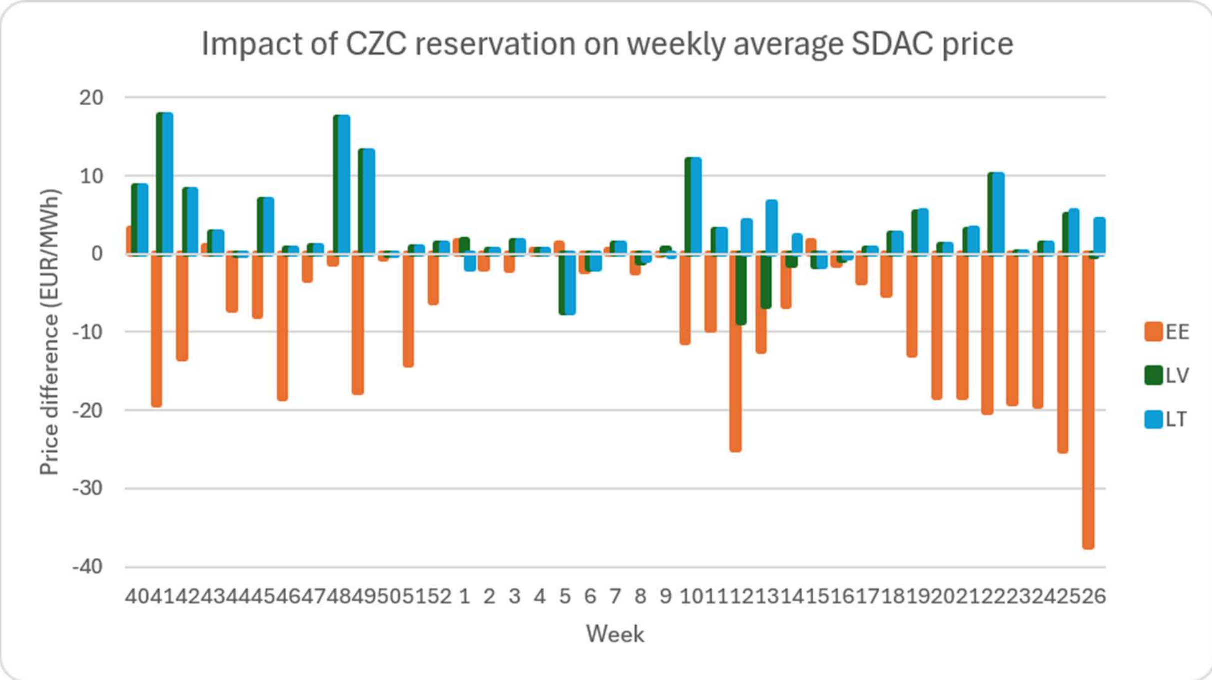

Figure 36. Impact of CZC reservations on weekly average SDAC prices (October 2025 – June 2026

The Figure 36 highlights the differences in price impacts between Estonia and the other Baltic countries, Latvia and Lithuania as congestion shifts from Finnish-Estonian border to Estonian-Latvian border if CZC is reserved for BBCM. In Estonia, prices are often lower due to CZC reservation, as this strengthens the connection to typically lower Finnish prices. In contrast, when CZC is reserved, Finnish prices have a weaker influence on Latvia and Lithuania, resulting in somewhat higher DA market prices in these zones compared to the situation without reservation. Over the entire period, the analysis shows that average price difference with CZC reservation was -9,12 €/MWh in Estonia, +2,45 €/MWh in Latvia, and +3,23 €/MWh in Lithuania, confirming that the reservation tends to lower prices in Estonia while slightly increasing them in Latvia and Lithuania. The Impact has been higher in the summer months.

In ***Table 18*** we can see the monthly average price differences in each region.

Table 18. Impact of CZC reservations on monthly average SDAC prices

MONTH	EE, Δ€/MWh	LV, Δ€/MWh	LT, Δ€/MWh
October 2025	-6,83	8,11	8,11
November 2025	-8,72	5,77	5,77
December 2025	-8,7	3,44	3,44
January 2026	-0,03	-0,69	-1,52
February 2026	-1,2	-0,39	-0,34
March 2026	-13,11	-0,02	5,8
April 2026	-3,55	0,02	0,87
May 2026	-15,63	4,36	4,43
June 2026	-24,34	1,49	2,56
AVERAGE	**-9,12**	**2,45**	**3,23**

6. Assessment of Impacts on Economic Surpluses

6.1. Economic Surplus of the SDAC

The impact of reserving cross-zonal capacity for BBCM on the total welfare has been assessed using the Simulation Facility. We calculate the economic surplus by summing, for each MTU, the total consumer surplus, producer surplus, and congestion income of the entire Capacity Calculation Region (CCR). The congestion income is calculated for each MTU by summing the net position and clearing price of each region and multiplying the result by -1:

$$CI_{CCR} = -\sum_{j \in CCR} NP_j \times P_j, \text{ where}$$

NP_j is regional net position of bidding zone j resulting from the SDAC,

P_j is clearing price of bidding zone j resulting from SDAC,

Z_{CCR} is set of bidding zones in the CCR.

The graph below illustrates the weekly impact of cross-zonal capacity reservation on consumer surplus, producer surplus, and congestion income across the entire Capacity Calculation Region. Compared to the scenario without reservation, both producer surplus and congestion income generally increased, whereas consumer surplus decreased. This growth in congestion income was primarily driven by a higher frequency of congested hours across the region, resulting in an average daily increase of €23,684.

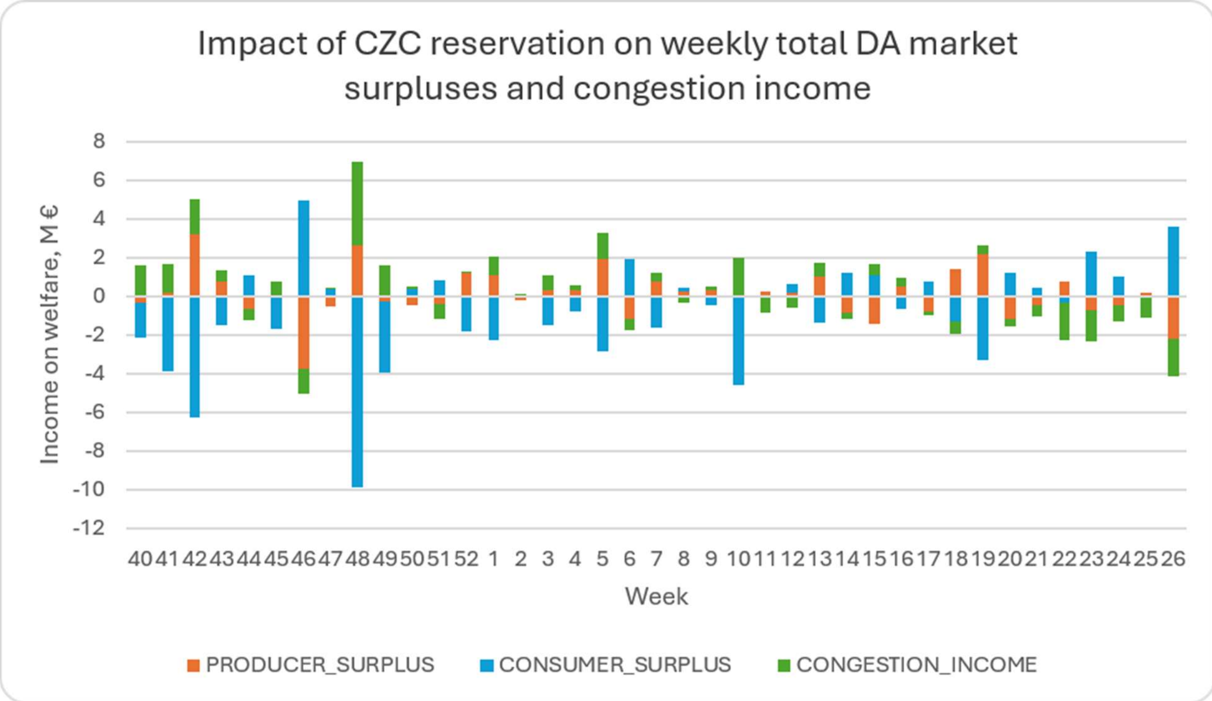

Figure 37. Impact of CZC reservation on weekly total Baltic DA market surpluses and congestion income (October 2025-June 2026)

When allocating CZC for the exchange for balancing capacity, the capacity is by default reduced in other markets. The possibility of exchanging balancing capacity between price areas has thus affected SDAC by reducing the available transfer capacity and, consequently and isolated seen, a negative economic effect on the market. In summary, the total economic surplus has decreased, which is also expected when considering the context of this specific simulation. On average, the economic surplus declined by 73 393 € per day.

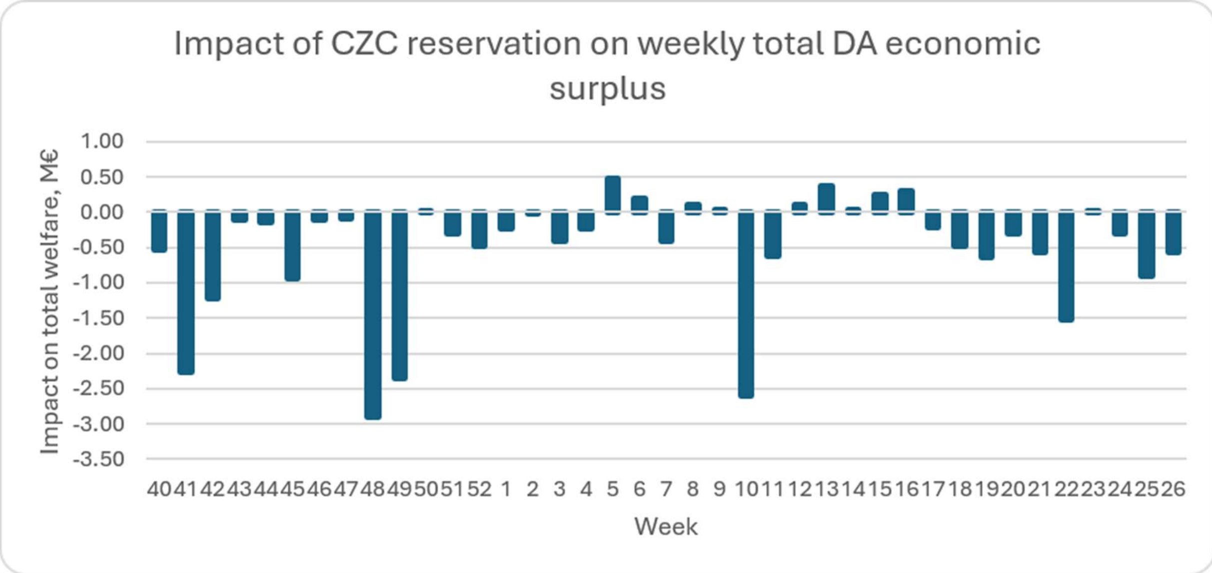

Figure 38. Impact of CZC reservations on weekly total Baltic DA market economic surplus (October 2025-June 2026)

In the table below, we can see the monthly total differences in economic surplus, which consists of producer surplus, consumer surplus and congestion income.

Table 19. Impact of CZC reservations in monthly Baltic DA welfare components

MONTH	Producer surplus (M€)	Consumer surplus (M€)	Congestion income (M€)	Economic surplus (M€)
October 2025	3,78	-13,7	5,69	-4,24
November 2025	-2,34	-4,77	3,05	-4,06
December 2025	0,72	-4,97	1,08	-3,17
January 2026	2,83	-6,6	3,41	-0,37
February 2026	-0,49	1,06	-0,56	0,01
March 2026	1,21	-5,31	1,47	-2,64
April 2026	-1,05	0,48	0,26	-0,31
May 2026	2,16	-2,55	-2,66	-3,05
June 2026	-3,27	6,91	-5,4	-1,77
TOTAL	**3,55**	**-29,47**	**6,32**	**-19,6**

The ***Table 19*** indicates that the impact of CZC allocation for balancing during the month of February is positive. This is not theoretically possible as explained in the beginning of chapter. However, in practice as Euphemia is not guaranteed to find the fully optimal solution, and in different situations the Euphemia algorithm might end up choosing a different slightly non-optimal solution.

6.1.1. Alternative Assessment on Impact on SDAC due to Allocation of CZC for the Exchange of Balancing Capacity and Sharing of Reserves

Here a pessimistic evaluation is given for the welfare loss of SDAC in a simplified manner and in pessimistic terms, ignoring the change of CZC value for SDAC due to changes in available CZC. In essence here the SDAC welfare loss is estimated by multiplying the realized SDAC price spreads between the Baltic bidding zones and multiplying them with the CZC which was allocated for the exchange of balancing capacity and sharing of reserves:

$$\begin{aligned}&for\ each\ border\ (r,r')\ and\ hour\ t:\\&\qquad loss_{t,(r,r')} = CZCreservation_{t,(r,r')} \times \max\left(0, DAMprice_{t,r'} - DAMprice_{t,r}\right)\end{aligned}$$

The overall impact on SDAC according to the above-described calculation principles was found to be 28,8 million Euros during the period. Due to the border EE->LV being most heavily congested, most of the impact is identified to being on that border. The distribution of welfare loss across the borders is displayed in Figure 39. Notably, the impact here is roughly 10 million larger than it was indicated by the Simulation Facility analysis. This is impacted mostly by the pessimistic nature of the calculation performed in this chapter.

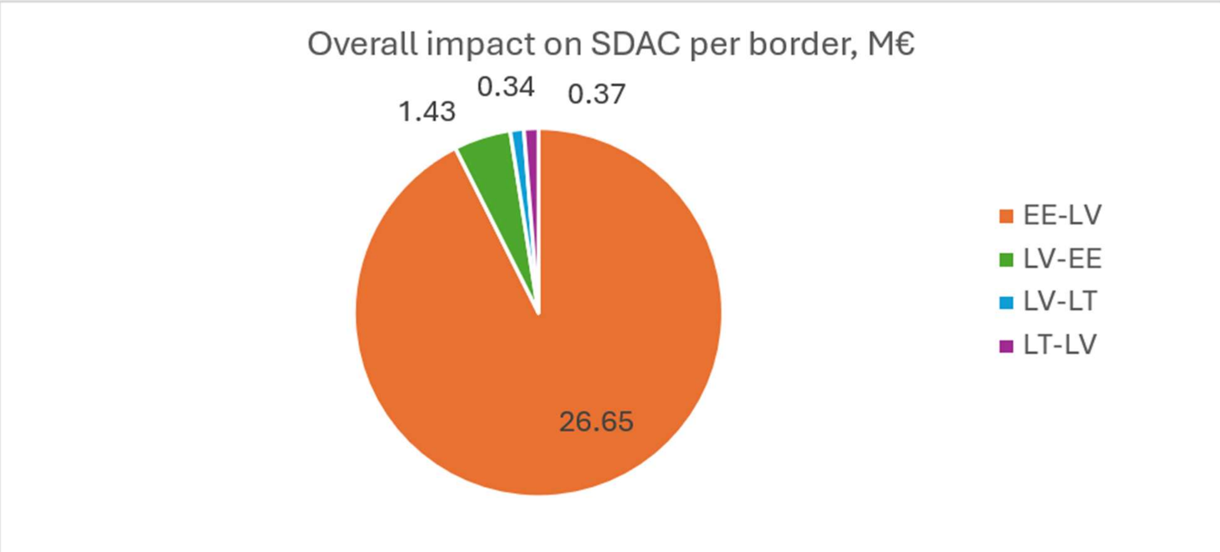

Figure 39. Overall distribution of SDAC welfare impact per borderis also visualized per calendar months. (in MEUR)

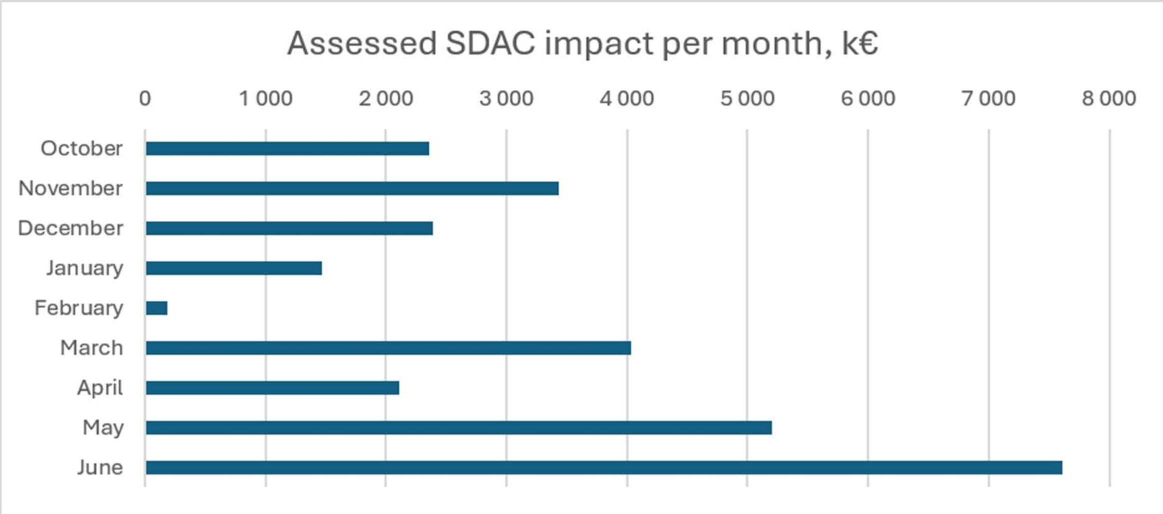

Figure 40. Monthly SDAC welfare impact of CZC allocations to BBCM (October 2025- June 2026)

6.2. Adjustment Process

The BBCM procurement optimization function values cross-zonal capacity (CZC) for the Single Day-Ahead Coupling (SDAC) through a linearized representation of each bidding zone's aggregate supply-demand curve. For each area and market time unit, the anticipated SDAC marginal price after CZC reallocation is:

$$MCP_{1,a} = MCP_{0,a} + \alpha_a \times \Delta V_a$$

Where:

α_a – *DAM price volume sensitivity of bidding zone a [€/MWh^2];*

$MCP_{0,a}$ – *the forecast DAM price from the reference day methodology in bidding zone a [€/MWh];*

$MCP_{1,a}$ – *the anticipated DAM price after the shift in net position in bidding zone a [€/MWh];*

ΔV_a – *change of net position from the forecast value for bidding zone a [MWh].*

CZC is allocated to the sharing of balancing capacity only where the net reserve procurement savings exceed the anticipated SDAC price spread plus the applicable mark-up. Where $\alpha_a > 0$, diverting CZC from SDAC to balancing widens the anticipated spread, which means that the exporting zone's price falls and the importing zone's price rises as arbitrage capacity is withdrawn. As result the hurdle that balancing must clear increases with the volume diverted. This constitutes a self-correcting, price-volume feedback that limits marginal overallocation. Where $\alpha_a = 0$, the anticipated spread is held at its reference-day value irrespective of the volume diverted, and this feedback is disabled.

Throughout the reporting period, $\alpha_a = 0$ for all zones and all market time units. The BBCM has therefore relied on the reference-day methodology alone, with no correction of the forecast SDAC price.

$\alpha_a = 0$ was adopted as the conservative default at market go-live for two reasons:

1) A mis specified sensitivity degrades forecast quality as readily as a well-specified one improves it; and
2) empirical validation on production-like market data was not feasible prior to go-live, as a BBCM simulation environment suitable for this purpose was not initially available. In the absence of validated values, reliance on the proven reference-day methodology was the prudent choice.

The TSOs now have the necessary tools and data to carry out this work: a simulation environment suitable for estimating and backtesting candidate α values, and a full reporting period of production 15-minute market data providing a realized benchmark for comparison. α will be moved off zero only once a value is shown, with sufficient confidence, to improve forecast quality without a net welfare loss; until then, $\alpha_a = 0$ is retained.

7. Volumes and Usage of Demand Reduction Resources and Back-up Resources

Baltic TSOs identified already in 2021 that at the start of the joint balancing capacity market between the three Baltic TSOs, that the market could face high costs and a shortage of balancing products from market-based assets provided from market participants. Therefore, as a measure to curb extreme costs at the start of the market, mitigate the risk of lack of reserves and risks for the security of supply while the market develops, TSOs developed a methodology to temporarily reduce the amount of reserves procured from the market by using TSO resources (hereinafter: “TSO resources”). TSO resources are assets capable of providing ancillary services which are in the control of Baltic TSOs. As such, TSO resources are used to ensure reserve sufficiency and security of supply but are not remunerated from the Balancing capacity (BBCM) market according to the marginal price principle as opposed to ordinary market participants.

Figure 41presents TSO resources as demand reduction resources, totaling 312 MW FRR Up, 102 MW FRR Down and 8 MW of FCR have supported the market.

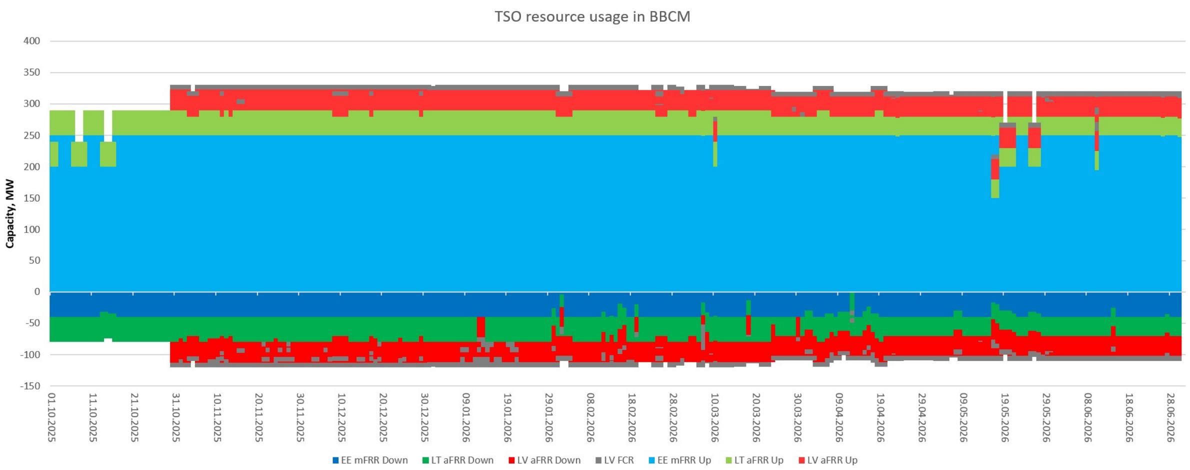

Figure 41. Usage of TSO-owned resourced in BBCM (accepted bids)

Table 20. Average accepted volume of reserves per MTU, per TSO resource and direction during October 2025-June 2026

EE mFRR Down	EE mFRR Up	LT aFRR Down	LT aFRR Up	LV aFRR Down	LV aFRR Up	LV FCR
39.35 MW	246.85 MW	36.04 MW	36.19 MW	28.28 MW	28.51 MW	5.98 MW

Table 21. Changes in the Use of TSO Resources in the BBCM

Date	TSO	Resource	Development
30.10.2025	AST	BESS Rēzekne & Tume	Entry of AST BESS into BBCM at capacity of 33 MW aFRR Up/Down and 7 MW FCR
01.01.2026	AST	BESS Rēzekne & Tume	Redistribution of capacity in line with 2026 dimensioning values 32 MW aFRR Up/Down and 8 MW FCR
01.05.2026	Litgrid	Energy Cells BESS	aFRR up/down balancing capacity volume reduced from 40 MW to 30 MW
01.07.2026	Elering	Kiisa powerplant	Elering decreased Kiisa emergency power plant's participation in the Baltic balancing capacity market to a maximum of 225 MW in upward reserves.

7.1. Usage of Back-Up Resources

Baltic TSOs had not employed the use of back-up resources during the report period.

7.2. Reduction of TSO-owned Resources

The scenario cuts the demand-reduction resources that the TSOs currently hold themselves, so more of the balancing need has to be met from the market. Two levels are modelled, a 25% cut and a 50% cut. The purpose is to see how much the current price levels, costs and market integration depend on TSO-owned resources.

In the 25% scenario, Kiisa's mFRR Up bids were reduced from 250 MW to 190 MW (an average cut of 59.5 MW), and Down bids from 40 MW to 30 MW (average cut 9.9 MW); LV/LT aFRR bids were reduced by an average of 3.84 MW per quarter-hour (24.87%). In the 50% scenario, Kiisa Up bids were reduced from 250 MW to 125 MW (average cut 123.6 MW), Down bids from 40 MW to 20 MW (average cut 19.8 MW, exact); aFRR bids were reduced by an average of 7.70 MW per quarter-hour (49.87%). The applied reductions sit marginally below the targets by design, because reductions must land on whole, biddable MW values, so where a target falls between two feasible bids sizes, the volume is rounded to the nearest achievable value.

Procurement cost impact

The tables below give the cost impact by product and country for the two reduction levels for nine month period.

Table 22. Cost impact by product in the 25% reduction scenario

EUR	Current	TSO res. reduced 25%	Absolute Change	% Δ
BBCM AFRR	15 347 970,05	31 401 665,40	16 053 695,35	105%
BBCM MFRR	93 247 464,31	132 186 963,39	38 939 499,08	42%
BBCM Total	108 595 434,35	163 588 628,78	54 993 194,43	51%

(The "Δ %" column gives the increase as a percentage change of current cost)

Table 23. Cost impact by country in the 25% reduction scenario

EUR	Current	TSO res. reduced 25%	Absolute Change	% Δ
BBCM EE	18 289 039,40	34 501 525,24	16 212 485,84	89%
BBCM LV	23 663 663,90	36 375 028,15	12 711 364,25	54%
BBCM LT	66 642 731,04	92 712 075,39	26 069 344,35	39%
BBCM Total	108 595 434,35	163 588 628,78	54 993 194,43	51%

(The "Δ %" column gives the increase as a percentage change of current cost)

The two levels show the response accelerating rather than scaling in step. A quarter cut raises total cost by half (+51%, €108.6M → €163.6M), then doubling the cut to a half raises it more than fourfold (+229%, → €357.7M). The second 25 points of reduction costs far more than the first, the same convex pattern the isolated scenario shows at the extreme. aFRR is the more sensitive product in proportional terms (+105% then +436%), though mFRR carries the larger absolute increase.

Table 24. Cost impact by product in the 50% reduction scenario

EUR	Current	TSO res. reduced 50%	Absolute Change	% Δ
BBCM AFRR	15 347 970,05	82 313 438,08	66 965 468,03	436%
BBCM MFRR	93 247 464,31	275 422 626,31	182 175 162,01	195%
BBCM Total	108 595 434,35	357 736 064,39	249 140 630,03	229%

(The "Δ %" column gives the increase as a percentage change of current cost)

Table 25. Cost impact by country in the 50% reduction scenario

EUR	Current	TSO res. reduced 50%	Absolute Change	% Δ
BBCM EE	18 289 039,40	101 400 993,88	83 111 954,48	454%
BBCM LV	23 663 663,90	74 921 550,54	51 257 886,64	217%
BBCM LT	66 642 731,04	181 413 519,97	114 770 788,93	172%
BBCM Total	108 595 434,35	357 736 064,39	249 140 630,03	229%

(The "Δ %" column gives the increase as a percentage change of current cost)

Once the cost is shared out under the agreed cost-sharing methodology, for nine-month period the increase lands most heavily on Estonia, whose cost rises +89% at a quarter cut and +454% at a half, then Latvia (+54% and +217%), with Lithuania the least exposed in proportional terms (+39% and +172%). Lithuania still carries the largest absolute bill (€92.7M then €181.4M), but its share of the Baltic total falls from about 61% today to 57% and then 51%, while Estonia's share climbs from 17% to 21% and then 28%. Latvia's share stays close to 21% throughout. Cutting the TSO-owned resources therefore shifts the balancing burden towards Estonia, the zone whose prices are most exposed to scarcity, rather than spreading it evenly.

Price Impact (25% reduction)

The milder cut lifts prices too, but far more gently than the 50% case, and with one telling difference – the zones move together. The 25% cut raises mFRR Up by roughly half in every zone at once (EE €16.28 → €25.99, LV and LT about €23 → €37), and Estonia does not break away. aFRR Down roughly doubles across all three zones (+92% to +100%), which is the largest proportional move at this level. This fits the cost picture on (The "Δ %" column gives the increase as a percentage change of current cost)

Table 23, where a quarter cut is the gentle part of the response, and Estonia's price only explodes once the cut goes deeper.

Table 26. Cross-area price divergence in 25% reduction scenario

Product	Direction	All equal (%)	Diverged (%)	One area differs (%)	All three differ (%)	Mean spread (€/MWh)	Mean spread | diverged (€/MWh)	Max spread (€/MWh)
mFRR	UP	72,50	27,50	27,20	0,40	14,67	53,25	3999,99
mFRR	DOWN	96,10	3,90	3,90	0,00	2,68	68,74	3995,78
aFRR	UP	78,00	22,00	22,00	0,00	29,93	135,81	4000,00
aFRR	DOWN	96,60	3,40	3,40	0,00	1,55	45,36	3990,8

Cutting a quarter of the reserves barely changes how often the zones diverge (mFRR Up differs in 27.5% of intervals against 29.4% today, aFRR Up in 22% against 21.1%), but the gaps grow when they do occur: the mean spread when diverged is €53/MWh on mFRR Up against €29 today. So a quarter cut widens congestion without making it more frequent; only the deeper 50% cut pushes the frequency up as well.

Table 27. Monthly average mFRR Down price impact (€/MWh) in 25% reduction scenario

Month	EE			LV			LT		
	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ
Oct 2025	29,61	37,70	27,30	26,98	19,38	-28,20	26,98	19,38	-28,20
Nov 2025	15,33	15,87	3,50	12,17	13,08	7,50	12,17	13,08	7,50
Dec 2025	13,83	14,23	2,90	12,21	12,64	3,50	12,21	12,64	3,50
Jan 2026	17,78	18,78	5,60	17,77	18,77	5,60	17,77	18,77	5,60
Feb 2026	17,12	18,25	6,60	17,12	18,25	6,60	17,12	18,25	6,60
Mar 2026	17,33	19,07	10,00	16,79	18,62	10,90	16,77	18,55	10,60
Apr 2026	10,03	10,57	5,40	10,36	10,91	5,30	10,37	10,92	5,30
May 2026	12,84	11,22	-12,60	12,89	11,21	-13,00	12,90	11,23	-12,90
Jun 2026	25,25	20,65	-18,20	25,26	20,65	-18,30	25,39	20,67	-18,60
Period avg	**17,70**	**18,52**	**4,60**	**16,85**	**15,93**	**-5,50**	**16,86**	**15,93**	**-5,50**

Downward mFRR is the one place where the cut lowers prices on the period rather than raising them, with Latvia and Lithuania both about 5% below their actual levels. This is a feature of how the market clears rather than a contradiction. The procurement optimization does not move each zone along a fixed supply curve – it re-solves the whole problem, choosing which bids to accept and how much cross-zonal capacity to allocate for sharing so as to meet all three zones' demand at least total cost. When the reduction changes that least-cost solution, the price-setting bid in a given zone and market time unit can change with it. In some intervals the new solution procures more from a cheaper neighboring zone, or drops an expensive local bid, so the marginal price in the importing zone is set lower than before. This can be caused by normally paradoxically rejected bids being accepted when the offered supply decreases. The same mechanism explains the scattered monthly falls in the other products above or below, even where the product rises on average.

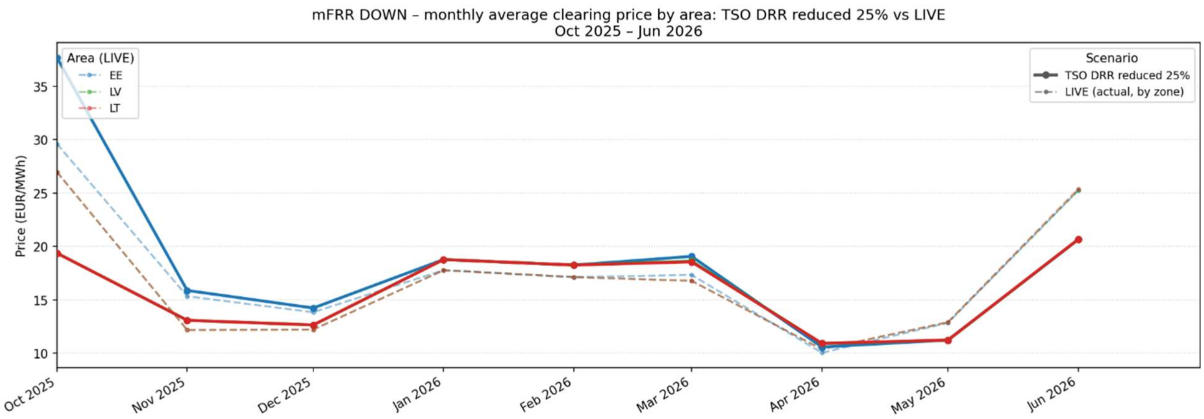

Figure 42. mFRR Down monthly average price comparison

Table 28. Monthly average mFRR Up price impact (€/MWh) in 25% reduction scenario

Month	EE			LV			LT		
	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ
Oct 2025	26,28	42,87	63,10	36,09	61,33	69,90	36,09	61,33	69,90
Nov 2025	7,53	36,28	381,80	12,95	33,97	162,30	12,96	33,97	162,10
Dec 2025	12,74	23,59	85,20	17,89	25,76	44,00	17,89	25,76	44,00
Jan 2026	22,06	32,07	45,40	22,61	32,94	45,70	22,03	32,34	46,80
Feb 2026	33,80	30,28	-10,40	33,07	31,22	-5,60	33,12	31,42	-5,10
Mar 2026	11,92	17,40	46,00	19,16	28,32	47,80	22,84	31,69	38,70
Apr 2026	8,47	15,31	80,80	10,80	17,50	62,00	11,69	18,31	56,60
May 2026	8,33	20,63	147,70	26,12	65,07	149,10	26,18	65,11	148,70
Jun 2026	16,52	15,51	-6,10	32,75	30,26	-7,60	33,04	30,59	-7,40
Period avg	**16,28**	**25,99**	**59,60**	**23,44**	**36,42**	**55,40**	**23,94**	**36,88**	**54,10**

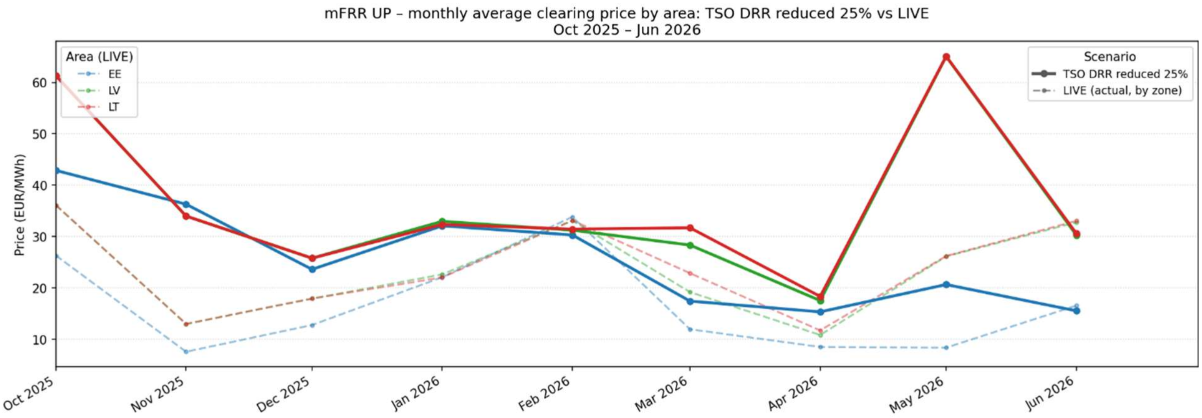

Figure 43. mFRR Up monthly average price comparison in 25% reduction scenario

Table 29. Monthly average aFRR Down price impact (€/MWh) in 25% reduction scenario

Month	EE			LV			LT		
	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ
Oct 2025	16,07	47,08	193,00	13,29	45,47	242,10	13,29	45,47	242,10
Nov 2025	5,79	8,07	39,40	3,19	3,80	19,10	3,19	3,80	19,10
Dec 2025	5,72	8,23	43,90	3,46	6,53	88,70	3,46	6,53	88,70
Jan 2026	15,61	31,85	104,00	15,59	31,04	99,10	15,59	31,04	99,10
Feb 2026	12,78	29,35	129,70	12,60	29,35	132,90	12,60	29,35	132,90
Mar 2026	12,83	19,69	53,50	12,57	19,09	51,90	12,46	18,94	52,00
Apr 2026	5,28	5,44	3,00	5,57	9,90	77,70	5,60	9,93	77,30
May 2026	10,84	11,86	9,40	12,25	11,94	-2,50	12,29	11,95	-2,80
Jun 2026	12,87	26,43	105,40	12,87	26,43	105,40	12,88	26,44	105,30
Period avg	**10,88**	**20,88**	**91,90**	**10,16**	**20,37**	**100,50**	**10,16**	**20,36**	**100,40**

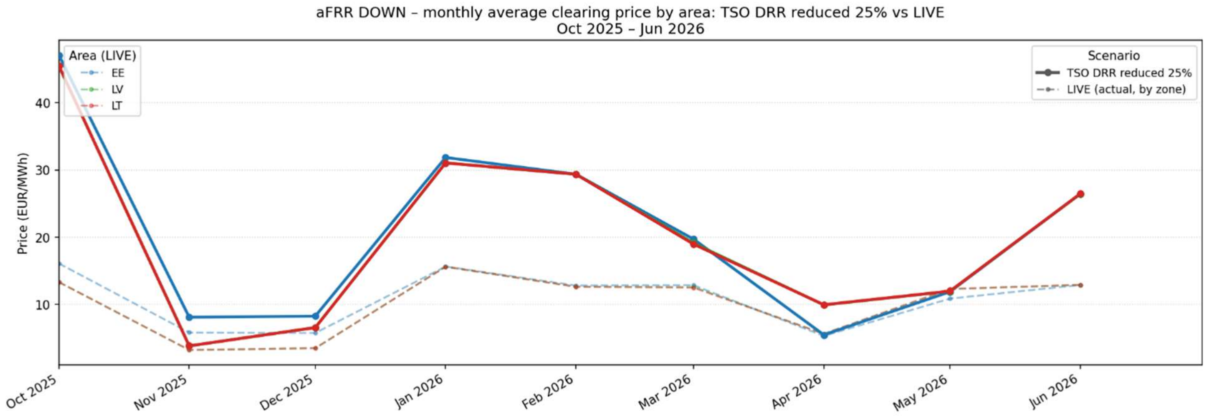

Figure 44. aFRR Down monthly average price comparison in 25% reduction scenario

Table 30. Monthly average aFRR Up price impact (€/MWh) in 25% reduction scenario

Month	EE			LV			LT		
	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ	LIVE	DRR-25%	% Δ
Oct 2025	23,09	37,38	61,90	56,74	92,97	63,90	56,74	92,97	63,90
Nov 2025	0,02	18,41	91950,00	2,42	9,92	309,90	2,42	9,92	309,90
Dec 2025	2,44	9,37	284,00	5,00	11,19	123,80	5,00	11,19	123,80
Jan 2026	37,74	27,38	-27,50	52,41	44,03	-16,00	51,56	43,22	-16,20
Feb 2026	33,58	31,24	-7,00	38,67	37,78	-2,30	38,67	37,78	-2,30
Mar 2026	6,63	9,22	39,10	11,95	15,35	28,50	11,85	15,22	28,40
Apr 2026	2,90	8,20	182,80	3,75	55,89	1390,40	3,79	55,91	1375,20
May 2026	6,22	24,89	300,20	26,97	89,09	230,30	26,98	96,71	258,50
Jun 2026	8,25	9,67	17,20	36,30	38,01	4,70	36,35	38,05	4,70
Period avg	**13,32**	**19,49**	**46,30**	**26,02**	**43,97**	**69,00**	**25,93**	**44,74**	**72,50**

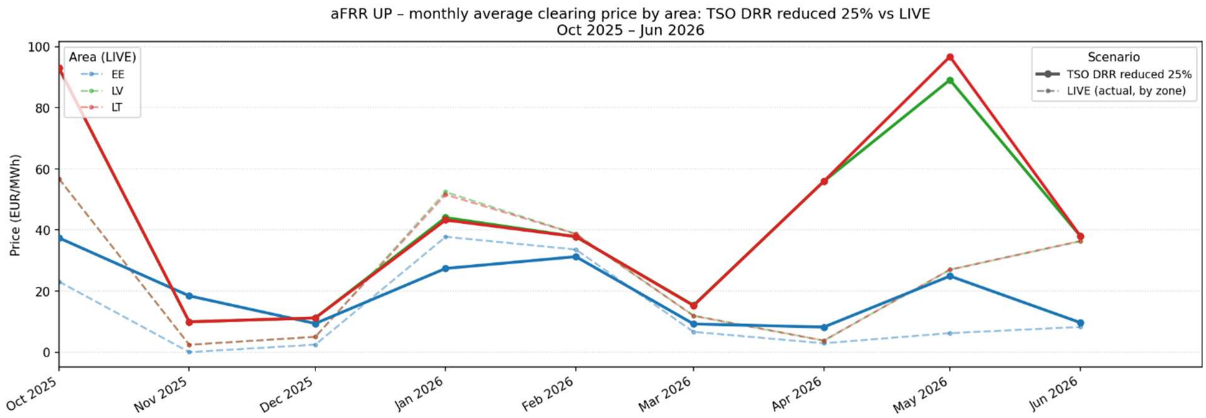

Figure 45. aFRR Down monthly average price comparison in 25% reduction scenario

At a quarter cut the market absorbs the loss fairly smoothly, where upward prices rise by roughly half, the zones stay together and divergence is no more frequent than today. The sharp escalation in Estonia belongs to the deeper cut below.

Price Impact (50% reduction)

Cutting the TSO-owned reserves tightens supply and prices rise across every product and direction. The increases are uneven and, in places, extreme. On the period average, Estonian mFRR Up jumps from €16.28 to €167.70, roughly tenfold, pulled up by scarcity months such as November 2025 (€616.61) and May 2026 (€215.06). Latvia and Lithuania rise more gently on mFRR Up, from about €23 to €51 (a little over double). aFRR Up roughly quadruples in Latvia and Lithuania (to €95–100), and the downward directions rise least. Estonia is the most exposed zone throughout and amongst other factors its mFRR Up spikes suggest it leans on TSO-owned resources more heavily than its neighbors.

Table 31. Monthly average mFRR Down price impact (€/MWh) in 50% reduction scenario

Month	EE			LV			LT		
	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ
Oct 2025	29,61	54,80	85,10	26,98	40,59	50,40	26,98	40,59	50,40
Nov 2025	15,33	207,25	1251,90	12,17	33,63	176,30	12,17	33,63	176,30
Dec 2025	13,83	21,05	52,20	12,21	15,41	26,20	12,21	15,41	26,20
Jan 2026	17,78	18,72	5,30	17,77	18,68	5,10	17,77	18,68	5,10
Feb 2026	17,12	18,38	7,40	17,12	18,34	7,10	17,12	18,34	7,10
Mar 2026	17,33	19,62	13,20	16,79	18,88	12,40	16,77	18,87	12,50
Apr 2026	10,03	10,86	8,30	10,36	11,08	6,90	10,37	11,08	6,80
May 2026	12,84	11,34	-11,70	12,89	11,13	-13,70	12,90	11,13	-13,70
Jun 2026	25,25	20,45	-19,00	25,26	20,45	-19,00	25,39	20,47	-19,40
Period avg	**17,70**	**42,36**	**139,30**	**16,85**	**20,93**	**24,20**	**16,86**	**20,93**	**24,10**

Figure 46. mFRR Down monthly average price comparison

Table 32. Monthly average mFRR Up price impact (€/MWh)

Month	EE			LV			LT		
	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ
Oct 2025	26,28	239,50	811,30	36,09	56,98	57,90	36,09	56,98	57,90
Nov 2025	7,53	616,61	8088,70	12,95	37,35	188,40	12,96	37,35	188,20
Dec 2025	12,74	125,95	888,60	17,89	43,57	143,50	17,89	43,57	143,50
Jan 2026	22,06	148,68	574,00	22,61	32,42	43,40	22,03	31,82	44,40
Feb 2026	33,80	34,13	1,00	33,07	34,09	3,10	33,12	34,25	3,40
Mar 2026	11,92	55,86	368,60	19,16	30,21	57,70	22,84	33,81	48,00
Apr 2026	8,47	24,14	185,00	10,80	26,37	144,20	11,69	27,59	136,00
May 2026	8,33	215,06	2481,80	26,12	123,66	373,40	26,18	123,76	372,70
Jun 2026	16,52	42,11	154,90	32,75	70,81	116,20	33,04	70,49	113,30
Period avg	**16,28**	**167,70**	**930,10**	**23,44**	**50,85**	**116,90**	**23,94**	**51,32**	**114,40**

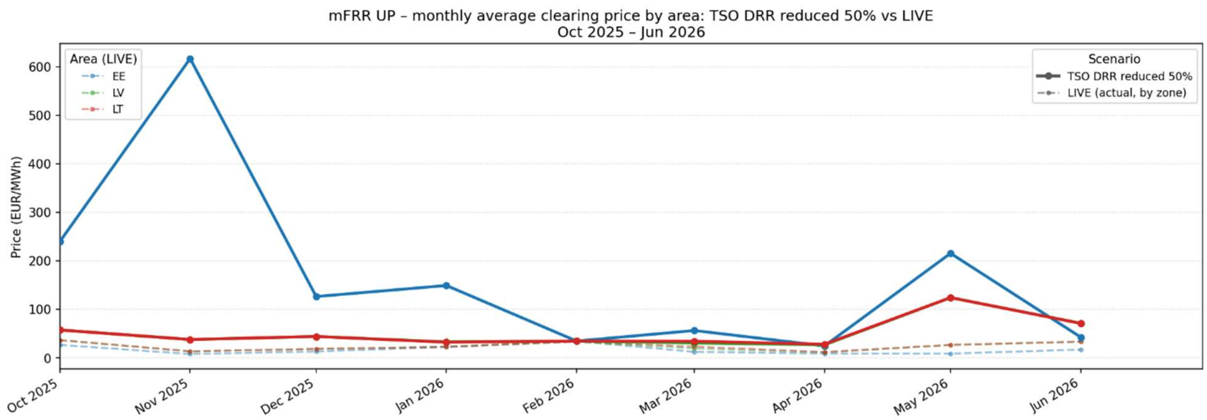

Figure 47. mFRR Up monthly average price comparison

Table 33. Monthly average aFRR Down price impact (€/MWh)

Month	EE			LV			LT		
	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ
Oct 2025	16,07	34,79	116,50	13,29	33,60	152,80	13,29	33,60	152,80
Nov 2025	5,79	20,95	261,80	3,19	11,15	249,50	3,19	11,15	249,50
Dec 2025	5,72	13,26	131,80	3,46	7,94	129,50	3,46	7,94	129,50
Jan 2026	15,61	56,96	264,90	15,59	55,96	258,90	15,59	55,96	258,90
Feb 2026	12,78	33,41	161,40	12,60	33,37	164,80	12,60	33,37	164,80
Mar 2026	12,83	26,28	104,80	12,57	21,81	73,50	12,46	21,74	74,50
Apr 2026	5,28	24,06	355,70	5,57	28,35	409,00	5,60	28,38	406,80
May 2026	10,84	45,86	323,10	12,25	45,83	274,10	12,29	45,83	272,90
Jun 2026	12,87	18,37	42,70	12,87	18,37	42,70	12,88	26,65	106,90
Period avg	**10,88**	**30,51**	**180,40**	**10,16**	**28,53**	**180,80**	**10,16**	**29,44**	**189,80**

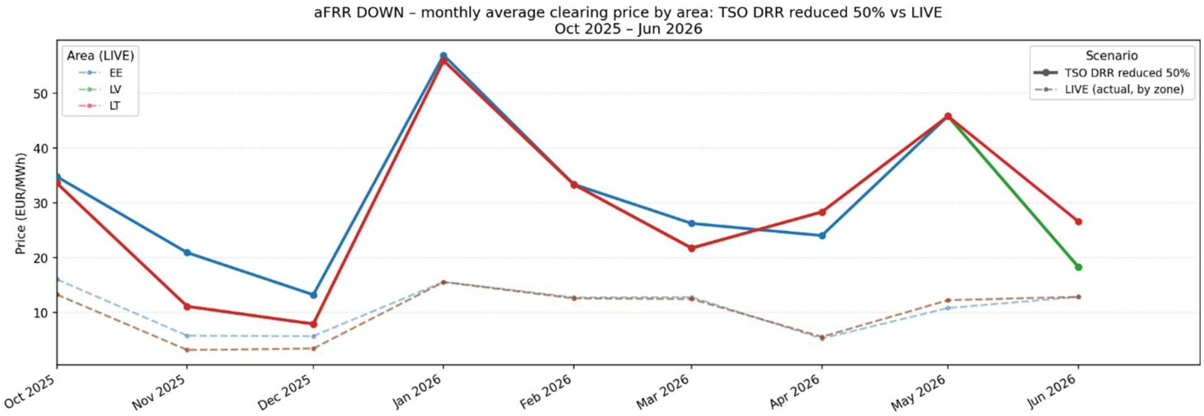

Figure 48. aFRR Down monthly average price comparison in 50% reduction scenario

Table 34. Monthly average aFRR Up price impact (€/MWh) in 50% reduction scenario

Month	EE			LV			LT		
	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ	LIVE	DRR-50%	% Δ
Oct 2025	23,09	49,44	114,10	56,74	120,12	111,70	56,74	120,12	111,70
Nov 2025	0,02	35,71	178450,00	2,42	16,25	571,50	2,42	16,25	571,50
Dec 2025	2,44	21,85	795,50	5,00	31,67	533,40	5,00	31,67	533,40
Jan 2026	37,74	65,75	74,20	52,41	118,65	126,40	51,56	118,65	130,10
Feb 2026	33,58	46,12	37,30	38,67	55,37	43,20	38,67	55,37	43,20
Mar 2026	6,63	20,94	215,80	11,95	31,86	166,60	11,85	48,60	310,10
Apr 2026	2,90	26,97	830,00	3,75	141,96	3685,60	3,79	145,89	3749,30
May 2026	6,22	39,67	537,80	26,97	194,88	622,60	26,98	209,22	675,50
Jun 2026	8,25	15,69	90,20	36,30	144,19	297,20	36,35	149,87	312,30
Period avg	**13,32**	**35,79**	**168,70**	**26,02**	**95,38**	**266,60**	**25,93**	**99,96**	**285,50**

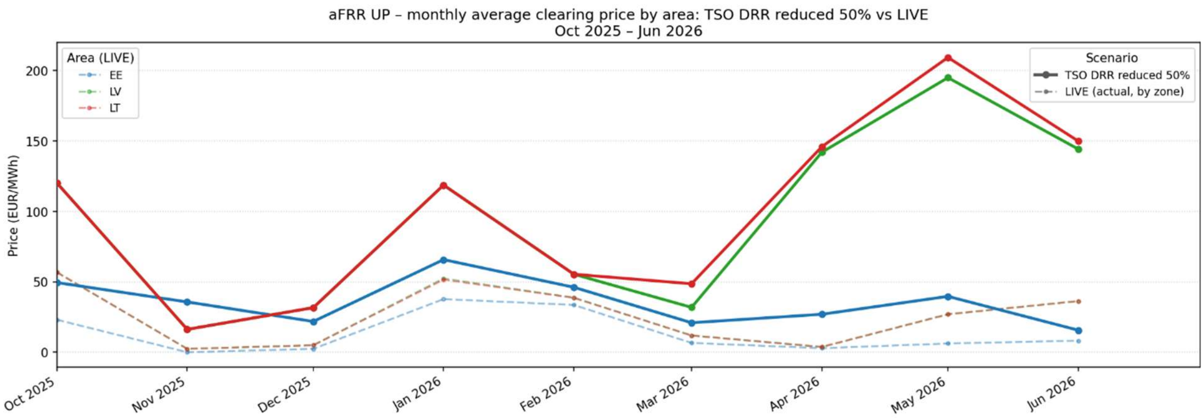

Figure 49. aFRR Up monthly average price comparison in 50% reduction scenario

Table 35. Cross-area price divergence in 50% reduction scenario in 50% reduction scenario

Product	Direction	All equal (%)	Diverged (%)	One area differs (%)	All three differ (%)	Mean spread (€/MWh)	Mean spread | diverged (€/MWh)	Max spread (€/MWh)
mFRR	UP	60,80	39,20	37,80	1,40	144,95	369,62	4000,00
mFRR	DOWN	95,70	4,30	4,30	0,00	21,48	497,73	3996,61
aFRR	UP	68,60	31,40	30,90	0,40	75,39	240,44	4000,00
aFRR	DOWN	96,40	3,60	3,60	0,00	3,84	106,92	3990,80

The scenario also pulls the zones further apart rather than together and cross-zone divergence becomes both more frequent and much wider. On mFRR Up the zones differ in 39.2% of intervals against 29.4% today, and when they do differ the average gap is €369.62/MWh against €28.81 today, more than ten times as large. aFRR Up diverges in 31.4% of intervals against 21.1%. The three zones now even split all at once often enough to register (1.4% of mFRR-UP intervals, against almost never in the actual market). Removing the shared reserves adds a great deal of congestion.

Intermediate Conclusions

The scenarios show how much current price levels depend on the reserves the TSOs hold themselves. Halving them roughly triples total payouts and lifts clearing prices in every product and direction, most sharply for Estonian mFRR Up, which rises about tenfold on the period and climbs above €600 in the tightest month. It also works against integration: cross-zone divergence goes up rather than down, because the shared reserves that used to smooth congestion are no longer there. In short, the TSO-owned resources are holding down both the level and the spread of Baltic balancing prices and cutting them would leave the market much more exposed to scarcity. Read against the 25% case, the response is clearly non-linear: a quarter cut raises upward prices by about half and leaves the zones coupled, while the second quarter is where Estonia breaks away and prices multiply. The same acceleration shows in cost, +51% at 25% against +229% at 50%

7.3. Scenario Without TSO-owned Resources in Baltics

In case TSO resources are completely removed from the market, so the entire balancing need is met from the market. CZC is left at its normal level, so unlike the isolated scenario in Section 8.1 the zones can still trade across the borders and still diverge. It sits at the far end of the same curve the 25% and 50% cuts trace, and it shows how far Baltic balancing prices and costs would move if the TSO-owned resources were removed entirely.

Procurement cost impact

Table 36. FRR procurement cost without TSO resources by product (nine moth period)

EUR	Current (LIVE)	No DRR	Absolute Change	Δ %
BBCM aFRR	15 348 103,00	214 118 578,25	198 770 475,25	1295%
BBCM mFRR	93 252 680,76	1 913 822 259,74	1 820 569 578,98	1952%
BBCM TOTAL	108 600 783,76	2 127 940 837,99	2 019 340 054,23	1859%

(The "Δ %" column gives the increase as a percentage change of current cost)

Removing the TSO-owned resources multiplies the Baltic procurement cost roughly twentyfold, from €108.6M to about €2.13bn, an increase of about €2.02bn over the nine months. This is the figure the isolated scenario approaches from the other direction, and it confirms the convex pattern already visible at 25% and 50%: each further cut costs far more than the last, +51% at a quarter, +229% at a half, and +1 859% at full removal. mFRR carries almost all of the absolute increase (€1.82bn of the €2.02bn), while aFRR rises by a similar proportion off a much smaller base.

Table 37. FRR procurement cost without TSO resources by country (nine month period)

EUR	Current (LIVE)	No DRR	Absolute Change	Δ %
BBCM Estonia	18 289 380,31	772 774 726,08	754 485 345,77	4125%
BBCM Latvia	23 664 653,45	397 070 576,22	373 405 922,77	1578%
BBCM Lithuania	66 646 750,02	958 095 535,69	891 448 785,67	1338%
BBCM Total	108 600 783,78	2 127 940 837,99	2 019 340 054,21	1859%

(The "Δ %" column gives the increase as a percentage change of current cost)

On this basis Estonia is by far the most exposed zone at full removal, for nine moth period its cost rising about forty-twofold, against roughly seventeenfold for Latvia and fourteenfold for Lithuania. This is the country-level counterpart to the price result below, where Estonian mFRR-UP is the series that breaks away hardest. In absolute terms Lithuania still carries the largest single bill (€958M) as the largest procurement zone, but the proportional shock falls heaviest on Estonia, and its share of the Baltic total keeps climbing across the reduction series (from 17% today to 21%, 28% and 36% at the four levels).

Price Impact

Prices rise across every product and direction, and far beyond the 50% case. On the period average, Estonian mFRR Up jumps from €16.28 to €732.84, about forty-five times, with monthly averages above €1,000/MWh in the tightest months (November 2025 €1,315, May 2026 €1,051). Latvia and Lithuania rise about sixteen to seventeenfold on mFRR Up (to roughly €395–398). The downward and aFRR directions rise less steeply, five to elevenfold, and on aFRR Up Lithuania is actually the most exposed zone rather than Estonia. The Estonia blow-out is specific to upward mFRR, the same scarcity-prone segment that already stands out in the actual market and at the 50% cut.

Full removal of TSO resources decouples the market rather than tightening it into one price. cross-zone divergence on mFRR Up reaches 45.2% of intervals against 29.4% today, and when the zones differ the average gap is €1,257/MWh against €28.81 today, more than forty times as large. All three zones split at once in 1.7% of mFRR Up intervals. Removing the shared reserves removes the mechanism that used to keep the three zones on a common price, so both the level and the spread of prices explode together.

Table 38. Cross-area price divergence in scenario without TSO resources by product and direction

Product	Direction	All equal (%)	Diverged (%)	One area differs (%)	All three differ (%)	Mean spread (€/MWh)	Mean spread | diverged (€/MWh)	Max spread (€/MWh)
mFRR	UP	54,76	45,24	43,55	1,69	568,87	1257,52	3999,99
mFRR	DOWN	93,20	6,80	6,80	0,00	97,08	1426,76	4000,00
aFRR	UP	70,02	29,98	28,64	1,34	142,38	474,86	4000,00
aFRR	DOWN	96,47	3,53	3,53	0,00	7,78	220,08	4000,00

Table 39. Monthly average mFRR Down price impact (€/MWh) in scenario without TSO resources

Month	EE			LV			LT		
	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ
Oct 2025	29,61	366,15	1136,60	26,98	153,40	468,60	26,98	153,40	468,60
Nov 2025	15,33	520,05	3292,40	12,17	149,30	1126,80	12,17	149,30	1126,80
Dec 2025	13,83	173,94	1157,70	12,21	51,65	323,00	12,21	51,65	323,00
Jan 2026	17,78	255,44	1336,70	17,77	219,51	1135,30	17,77	219,51	1135,30
Feb 2026	17,12	28,00	63,60	17,12	27,93	63,10	17,12	27,93	63,10
Mar 2026	17,33	86,55	399,40	16,79	41,70	148,40	16,77	37,54	123,90
Apr 2026	10,03	35,55	254,40	10,36	16,01	54,50	10,37	16,01	54,40
May 2026	12,84	94,59	636,70	12,89	39,44	206,00	12,90	39,44	205,70
Jun 2026	25,25	126,33	400,30	25,26	124,41	392,50	25,39	124,43	390,10
Period avg	**17,70**	**188,73**	**966,30**	**16,85**	**92,13**	**446,80**	**16,86**	**91,66**	**443,70**

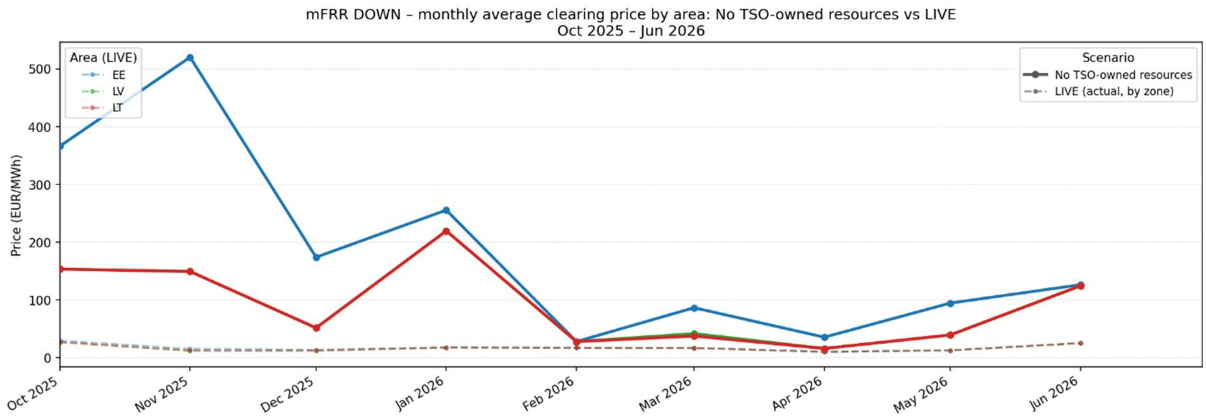

Figure 50. mFRR Down monthly average price comparison in scenario without TSO resources

Table 40. Monthly average mFRR Up price impact (€/MWh) in scenario without TSO resources

Month	EE			LV			LT		
	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ
Oct 2025	26,28	1004,04	3720,50	36,09	708,82	1864,00	36,09	708,82	1864,00
Nov 2025	7,53	1315,27	17367,10	12,95	250,41	1833,70	12,96	250,41	1832,20
Dec 2025	12,74	439,87	3352,70	17,89	354,61	1882,20	17,89	324,99	1716,60
Jan 2026	22,06	417,12	1790,80	22,61	144,66	539,80	22,03	144,66	556,70
Feb 2026	33,80	116,15	243,60	33,07	82,37	149,10	33,12	82,51	149,10
Mar 2026	11,92	756,23	6244,20	19,16	58,42	204,90	22,84	64,72	183,40
Apr 2026	8,47	603,22	7021,80	10,80	35,21	226,00	11,69	34,28	193,20
May 2026	8,33	1050,73	12513,80	26,12	619,19	2270,60	26,18	622,01	2275,90
Jun 2026	16,52	851,72	5055,70	32,75	1306,17	3888,30	33,04	1306,22	3853,50
Period avg	**16,28**	**732,84**	**4401,50**	**23,44**	**397,55**	**1596,00**	**23,94**	**395,14**	**1550,50**

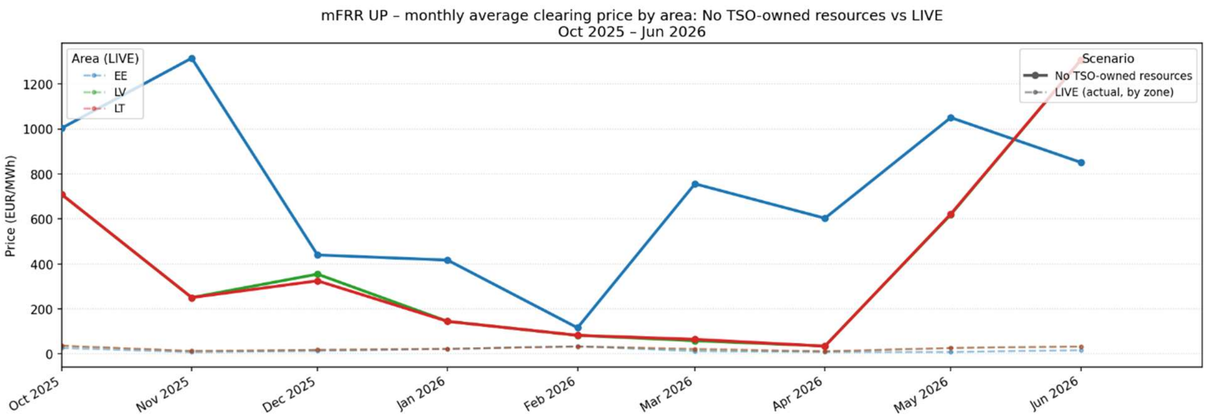

Figure 51. mFRR Up monthly average price comparison in scenario without TSO resources

Table 41. Monthly average aFRR Down price impact (€/MWh) without TSO resources

Month	EE			LV			LT		
	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ
Oct 2025	16,07	46,55	189,70	13,29	45,78	244,50	13,29	45,78	244,50
Nov 2025	5,79	73,07	1162,00	3,19	69,61	2082,10	3,19	69,61	2082,10
Dec 2025	5,72	80,24	1302,80	3,46	77,04	2126,60	3,46	77,04	2126,60
Jan 2026	15,61	99,62	538,20	15,59	99,58	538,70	15,59	99,58	538,70
Feb 2026	12,78	58,26	355,90	12,60	58,16	361,60	12,60	58,16	361,60
Mar 2026	12,83	100,57	683,90	12,57	93,40	643,00	12,46	93,40	649,60
Apr 2026	5,28	108,42	1953,40	5,57	149,30	2580,40	5,60	150,69	2590,90
May 2026	10,84	50,96	370,10	12,25	62,96	414,00	12,29	62,96	412,30
Jun 2026	12,87	46,11	258,30	12,87	46,10	258,20	12,88	46,93	264,40
Period avg	**10,88**	**73,90**	**579,20**	**10,16**	**78,10**	**668,70**	**10,16**	**78,34**	**671,10**

Figure 52. aFRR Down monthly average price comparison in scenario without TSO resources

Table 42. Monthly average aFRR Up price impact (€/MWh) without TSO resources

Month	EE			LV			LT		
	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ	LIVE	No-DRR	% Δ
Oct 2025	23,09	93,78	306,10	56,74	190,19	235,20	56,74	190,19	235,20
Nov 2025	0,02	41,54	207600,00	2,42	64,15	2550,80	2,42	64,15	2550,80
Dec 2025	2,44	26,10	969,70	5,00	40,46	709,20	5,00	38,55	671,00
Jan 2026	37,74	60,47	60,20	52,41	69,86	33,30	51,56	69,86	35,50
Feb 2026	33,58	88,82	164,50	38,67	99,20	156,50	38,67	101,63	162,80
Mar 2026	6,63	42,70	544,00	11,95	169,72	1320,30	11,85	300,12	2432,70
Apr 2026	2,90	76,64	2542,80	3,75	244,53	6420,80	3,79	336,55	8779,90
May 2026	6,22	19,18	208,40	26,97	306,98	1038,20	26,98	332,42	1132,10
Jun 2026	8,25	61,63	647,00	36,30	272,01	649,30	36,35	273,03	651,10
Period avg	**13,32**	**56,38**	**323,30**	**26,02**	**162,24**	**523,50**	**25,93**	**190,18**	**633,40**

Figure 53. aFRR Up monthly average price comparison in scenario without TSO resources

The scenario without TSOs resources also crosses a line the actual market never did. Over the reporting period supply always covered the reserve demand in full, but with the TSO-owned resources removed entirely about 0.17% of reserve demand could no longer be met. The share is small, but it marks the point where the effect stops being only about cost and becomes a question of security of supply: the market can be made to pay far more, but it cannot fully replace the volume the TSO-owned resources provide.

Full removal of the TSO-owned resources is the extreme point and it lands where the 25% and 50% cuts suggested. Cost rises about twentyfold, to roughly €2.13bn, an increase of about €2.02bn over the period, and the response is sharply convex, where the last increment of reduction is far more expensive than the first. Prices rise in every product and direction, most violently on Estonian mFRR Up (about forty-five times the actual level, with monthly averages above €1,000/MWh), and the market decouples rather than converging, with mFRR Up zones diverging 45% of the time at average spreads above €1,200/MWh. Taken with the 25% and 50% results, this scenario shows that the TSO-owned resources are not a marginal input but the main thing holding Baltic balancing prices down and holding the three zones on a common price. At full removal the strain is no longer only financial – about 0.17% of reserve demand goes uncovered, where the live market met demand in full throughout the period. Read across the three reduction levels, the response is clearly non-linear and the burden falls increasingly on Estonia, whose share of the Baltic cost keeps climbing as more of the reserves are removed.

7.4. BBCM cost model of DRR reduction

The Baltic TSOs ran the full market simulation at three levels of DRR removal and recorded the total balancing cost over the nine-month reporting period (October 2025 to June 2026). Unsurprisingly, the more reserves are removed, the more each further cut adds. Removing a quarter of the reserves adds about €55 million to BBCM costs. The following quarter adds close to €195 million in costs. Lastly, removing the rest of DRR adds over €2 billion to the cost of provisioning balancing reserve capacity in the Baltics.

The Baltic TSOs drew a single smooth curve through these four measured points. Once it is fitted, it gives an estimated cost for any reserve level in between, not only the four levels that had been simulated. Assuming that there are no irregularities in cost formation along the drawn curve, the costs represented in this graph can be assumed to closely resemble the results the Baltic TSOs would find if stepwise, parallel DRR reduction were simulated.

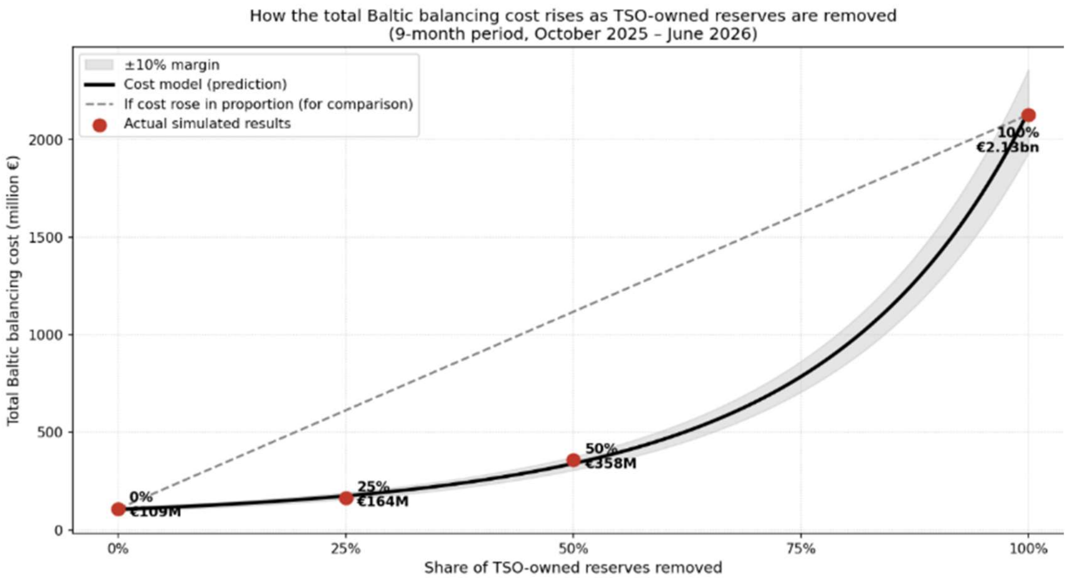

Figure 54. Baltic DRR reduction cost curve

In the chart the red dots are the one actual market results and three simulation results, the solid black line is the model, and the grey band around it is a margin of plus or minus 10%. The dashed line shows what the cost would look like if it simply rose in proportion to the amount of reserves removed. The real cost sits far above that straight line towards the right of the chart. It does not rise in step with the cut – it accelerates.

Model accuracy

Using only the other data points, it predicted the cost of the 25% reduction as €183 million. The actual simulation then came in at €164 million, about 12% away. Once that measured point was added, the model is expected to reproduce every level within about 10% for the Baltic total. In short, one simple curve predicts the whole Baltic balancing bill across the full range to roughly one part in ten. Adding additional data points would increase the model's accuracy.

Limits of the model

The Baltic TSOs highlight that although accurate, neither this model nor simulations done as originally requested by NRAs can represent the future performance of DRRs in BBCM. The results are representative of the conditions during the reporting period.

The model is an indicative planning tool, not a precise forecast. It should be read as giving the right shape and the right order of magnitude, with an accuracy of about 10% for the total Baltic cost. It should be used only within the range that was tested, that is between today's level and full removal, and it should not be extended beyond that range. The single most reliable output is the total Baltic figure. Splitting the cost between the three countries is less certain and should be addressed separately.

8. Benefits of the Joint Baltic Balancing Capacity Market

8.1.Isolated Markets Scenario (Without Net Transfer Capacity)

This section looks at a counterfactual where each Baltic state procures its balancing reserves locally, with no cross-zonal transfer capacity. In practice that is the joint BBCM switched off. Procurement becomes national, so costs are no longer shared across borders and each TSO carries its own. The point of the exercise is to put a number, in both cost and price terms, on what the integrated market is worth compared with a fragmented one.

Importance nuance which is worth noting – each MTU of the reporting period is cleared with the bids actually submitted, cross-zonal capacity set to zero and demand unchanged. No behavioral response is modelled. In a truly isolated market balance service providers (BSPs) would bid differently and new capacity would eventually enter, so the figures are an upper-bound estimate of what fragmentation would cost with today's portfolios rather than a forecast of a long-run isolated equilibrium.

Additionally, it is worth nothing that in the local case, pay-as-bid settlement would be used. If such settlement were to be employed, it would result in significantly lower procurement costs, but only if the BSP bidding behavior would remain unchanged. In practice, the bidding strategy would become different, therefore it is difficult to accurately assess the actual cost impact in isolated markets. Nevertheless, the analysis below is performed using the marginal pricing principle. The procurement costs reported should be understood as the upper bound of the local case, as the most expensive assets, which in the local case will be almost always procured, will be setting the marginal price.

In isolated markets, balancing capacity demand would not be fully satisfied: across all products and directions, from their respective BSPs Estonia would cover 74,5%, Latvia – 56%, and Lithuania – 92,4% of all local balancing capacity demand (overall, 20% across the Baltics). Despite new assets and increased liquidity, security of supply would still not be fully maintained, and this naturally then also has a large economic impact, as the most expensive units will be running to ensure balancing needs because of limited supply. Due to market asset maintenance, Lithuania is also unable to fully cover the needed demand.

Table 43 and ***Table 44*** compare the modelled nine-month period procurement cost under current integrated operation with the isolated scenario, split by product and by country. The total cost of procuring balancing reserves would rise from €108.6 million to almost €6.34 billion, roughly 58 times higher (an increase of €6.23 billion). Most of that comes from mFRR, whose cost multiplies about 65 times and aFRR rises by a factor of about 17.

Table 43. Procurement cost impact by product in euros

€/MWh	Current	Isolated Markets	Absolute Change	Δ %
BBCM AFRR	15 347 970,05	275 417 650,79	260 069 680,74	1694%
BBCM MFRR	93 247 464,31	6 066 135 232,52	5 972 887 768,21	6405%
BBCM Total	108 595 434,35	6 341 552 883,30	6 232 957 448,95	5740%

(The "Δ %" column gives the increase as a percentage change of current cost)

By country (***Table 44***), all three states would face large increases, but they are far from equal. Lithuania is the most exposed where its cost rises more than seventy-fold, from €73.7 million to €5.26 billion (+€5.18 billion). Estonia's rises about forty-fold (+€888.6 million). Latvia, the smallest procurement zone of the three, sees the smallest jump at about thirteen-fold (+€162.2 million). The largest balancing capacity supply is in Lithuania, some of which is significantly expensive, and coupling this together with the demand, which is also the largest for Lithuania, the procurement costs thus increase to extreme levels. It is also important to note that the effects of local procurement are also exacerbated by large asset maintenance, which considerably reduces efficient demand coverage. Therefore, the impact of isolated markets was most evident for Lithuania.

Table 44. Procurement cost impact by country in euros

EUR	Current	Isolated Markets	Absolute Change	Δ %
BBCM EE	22 645 443,30	911 214 557,80	888 569 114,50	3924%
BBCM LV	12 282 143,95	174 491 511,69	162 209 367,74	1321%
BBCM LT	73 667 847,12	5 255 846 813,82	5 182 178 966,70	7035%
BBCM Total	108 595 434,36	6 341 552 883,30	6 232 957 448,94	5740%

(The "Δ %" column gives the increase as a percentage change of current cost)

Price Impact

Table 45 to ***Table 48*** carry the same scenario through to clearing prices. For each product and direction they show the monthly average LIVE (actual) price, the modelled Isolated price, and the percent change, by zone. Two things stand out. In most months isolation lifts prices by one to two orders of magnitude. Lithuanian mFRR Up, for example, goes from a period average of €23.94 to €1,565.67 (+6,440%), and Estonian mFRR Down from €17.70 to €919.57 (+5,095%). But the effect is not uniform. A few zone-and-direction combinations actually fall under isolation, most consistently Latvian mFRR Down, down 30.9% on the period average. Fragmentation redistributes as much as it inflates. The worst of it lands on the upward direction, and on mFRR in particular.

Table 45. Monthly average mFRR Down price impact (€/MWh

Month	EE			LV			LT		
	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ
Oct 2025	29,61	647,65	2087,30	26,98	9,52	-64,70	26,98	447,46	1558,50
Nov 2025	15,33	1174,47	7561,30	12,17	4,36	-64,20	12,17	781,46	6321,20
Dec 2025	13,83	913,37	6504,30	12,21	5,62	-54,00	12,21	304,22	2391,60
Jan 2026	17,78	494,71	2682,40	17,77	3,24	-81,80	17,77	21,07	18,60
Feb 2026	17,12	538,02	3042,60	17,12	13,24	-22,70	17,12	83,71	389,00
Mar 2026	17,33	926,23	5244,70	16,79	4,05	-75,90	16,77	221,72	1222,10
Apr 2026	10,03	1133,20	11198,10	10,36	2,64	-74,50	10,37	15,66	51,00
May 2026	12,84	1309,97	10102,30	12,89	29,17	126,30	12,90	178,64	1284,80
Jun 2026	25,25	1123,28	4348,60	25,26	33,23	31,60	25,39	354,90	1297,80
Period avg	**17,70**	**919,57**	**5095,30**	**16,85**	**11,64**	**-30,90**	**16,86**	**268,40**	**1491,90**

The accompanying figures below overlay the two scenarios month by month on a logarithmic axis, since the Isolated prices run 20 to 65 times above the LIVE series, so on a linear axis the actual prices would flatten to the baseline.

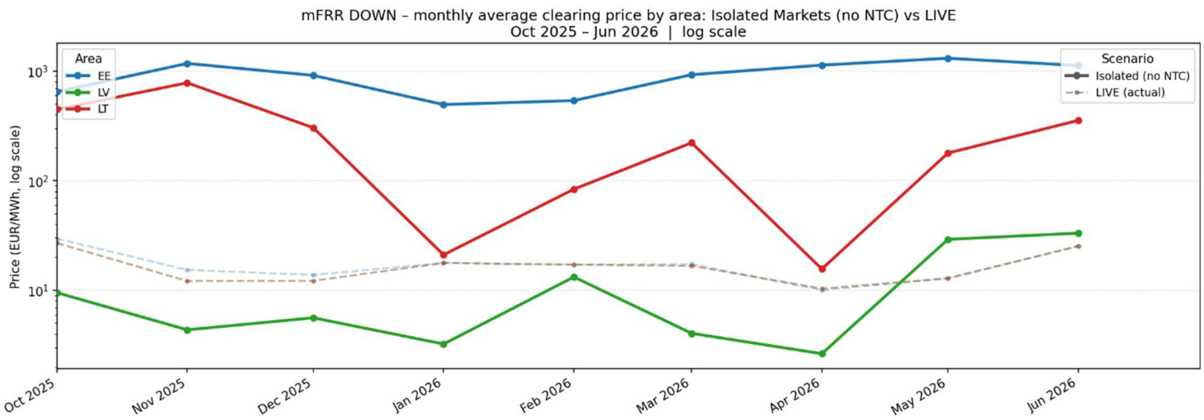

Figure 55. mFRR Down monthly average price comparison

Latvian mFRR Down needs its own note, since it moves in the opposite way in 7 out of 9 months. The pattern is due to the limited available BSP supply and low demand. In the joint market, Latvian downward capacity is procured against Baltic-wide demand and the Latvian price is pulled up to the common clearing level. Cut the borders and that import demand disappears and all of the local supply is used up to cover part of the demand, resulting in a price decrease, by 55 to 82% in most months.

The exceptions are May and June 2026 (+126.3% and +31.6%), which coincide with supply changes in Latvia – due to very limited liquidity, any shift in the offered supply due to entry of new assets can heavily affect market clearing, as such new bids are procured and setting higher prices in order to fulfill the demand as much as possible.

Table 46. Monthly average mFRR UP price impact (€/MWh)

Month	EE			LV			LT		
	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ
Oct 2025	26,28	940,40	3478,40	36,09	131,84	265,30	36,09	667,38	1749,20
Nov 2025	7,53	816,57	10744,20	12,95	127,51	884,60	12,96	627,62	4742,70
Dec 2025	12,74	545,40	4181,00	17,89	74,38	315,80	17,89	1070,13	5881,70
Jan 2026	22,06	526,45	2286,40	22,61	38,71	71,20	22,03	1676,70	7511,00
Feb 2026	33,80	234,43	593,60	33,07	59,85	81,00	33,12	1099,91	3221,00
Mar 2026	11,92	154,38	1195,10	19,16	65,95	244,20	22,84	2268,41	9831,70
Apr 2026	8,47	117,44	1286,50	10,80	68,70	536,10	11,69	2272,11	19336,40
May 2026	8,33	152,62	1732,20	26,12	100,17	283,50	26,18	2292,46	8656,50
Jun 2026	16,52	109,46	562,60	32,75	119,02	263,40	33,04	2081,33	6199,40
Period avg	**16,28**	**402,11**	**2370,00**	**23,44**	**87,46**	**273,10**	**23,94**	**1565,67**	**6440,00**

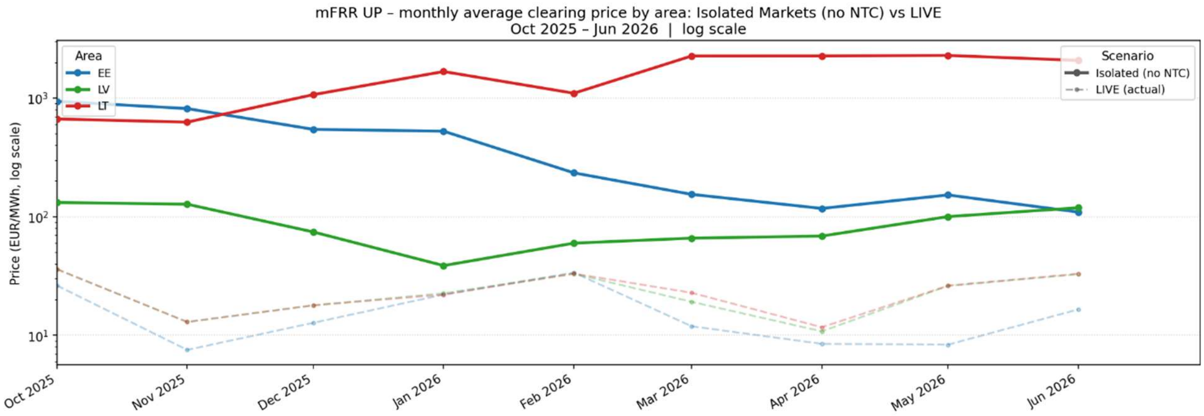

Figure 56. mFRR Up monthly average price comparison

Table 47. Monthly average aFRR DOWN price impact (€/MWh)

Month	EE			LV			LT		
	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ
Oct 2025	16,07	24,18	50,50	13,29	229,01	1623,20	13,29	46,51	250,00
Nov 2025	5,79	21,86	277,50	3,19	14,56	356,40	3,19	12,15	280,90
Dec 2025	5,72	31,82	456,30	3,46	24,66	612,70	3,46	97,95	2730,90
Jan 2026	15,61	20,83	33,40	15,59	145,05	830,40	15,59	111,05	612,30
Feb 2026	12,78	22,01	72,20	12,60	146,73	1064,50	12,60	98,48	681,60
Mar 2026	12,83	37,73	194,10	12,57	86,17	585,50	12,46	272,78	2089,20
Apr 2026	5,28	29,77	463,80	5,57	64,56	1059,10	5,60	303,83	5325,50
May 2026	10,84	30,34	179,90	12,25	68,50	459,20	12,29	268,74	2086,70
Jun 2026	12,87	34,33	166,70	12,87	80,96	529,10	12,88	207,74	1512,90
Period avg	**10,88**	**28,16**	**158,80**	**10,16**	**95,48**	**839,80**	**10,16**	**158,14**	**1456,50**

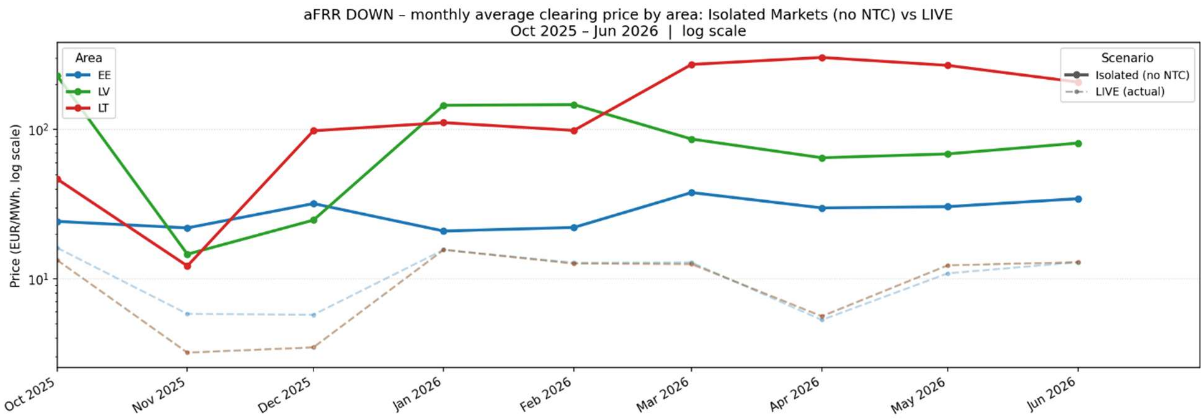

Figure 57. aFRR Down monthly average price comparison

Table 48. Monthly average aFRR UP price impact (€/MWh

Month	EE			LV			LT		
	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ	LIVE	Isolated	% Δ
Oct 2025	23,09	46,45	101,20	56,74	152,61	169,00	56,74	86,05	51,70
Nov 2025	0,02	47,46	237200,00	2,42	87,98	3535,50	2,42	9,14	277,70
Dec 2025	2,44	37,54	1438,50	5,00	56,07	1021,40	5,00	1,97	-60,60
Jan 2026	37,74	25,18	-33,30	52,41	201,94	285,30	51,56	13,49	-73,80
Feb 2026	33,58	22,14	-34,10	38,67	201,17	420,20	38,67	35,40	-8,50
Mar 2026	6,63	31,38	373,30	11,95	341,07	2754,10	11,85	25,08	111,60
Apr 2026	2,90	32,29	1013,40	3,75	381,65	10077,30	3,79	6,04	59,40
May 2026	6,22	33,44	437,60	26,97	368,05	1264,70	26,98	16,61	-38,40
Jun 2026	8,25	36,14	338,10	36,30	296,45	716,70	36,35	48,06	32,20
Period avg	**13,32**	**34,76**	**161,00**	**26,02**	**231,95**	**791,40**	**25,93**	**26,84**	**3,50**

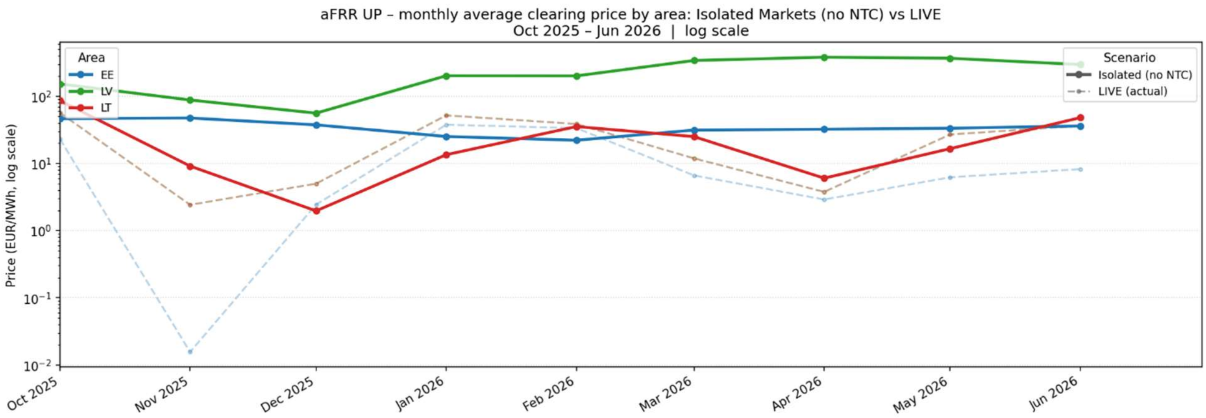

Figure 58. aFRR Up monthly average price comparison

The Isolated markets scenario concludes the effectiveness of BBCM and without it, total procurement cost would rise about 58 times, to €6.34 billion, and clearing prices would climb by 1 to 2 orders of magnitude in nearly every product, direction and zone. All three states gain from common market and this is the strongest numerical case in the report for keeping the joint market and extending it.

As discussed previously, market asset maintenance can have a significant effect on the total costs, and this is even more evident in the local case where scarcity is especially impactful. Reduction of available balancing capacity led to the enormous price and procurement cost increase in Lithuania, as the most expensive assets are procured. Again, a core benefit of a common market is that the effects of maintenance can be alleviated by relying on alternative capacity sources present in other countries, ensuring not only security of the supply, but also economic efficiency.

9. Conclusions

Over the reporting period the Baltic Balancing Capacity Market has continued to mature. It is more stable and more competitive than in its first months, concentration has fallen in every segment, and for most of the time the three bidding zones clear at a single common price. The market nonetheless remains illiquid in places and dependent on cross-zonal sharing and on the reserves the TSOs hold themselves. The findings across the report point consistently to the same few structural features rather than to isolated results, and it is those recurring features, more than any single figure, that carry the main conclusions.

The market performance indicators converge on the upward direction, and on upward mFRR in particular. It is at once the most concentrated segment, with a Herfindahl-Hirschman Index around 3,700 and the two largest providers supplying roughly 80% of accepted volume; the most expensive; the one on which the zones most often clear at different prices, diverging in 29.4% of intervals upward for mFRR and 21.1% for aFRR, against roughly 4% and 3% downward; and the one with the largest day-to-day movement, at €45.1 per MWh of aFRR upward volatility in Latvia and Lithuania. These are not independent observations. The concentration on the upward side is most plausibly part of why upward prices are high and divergent, while the downward direction, which is well supplied, is correspondingly cheap, converged and stable. Upward mFRR is therefore the clearest candidate for continued monitoring, and more competition on that side is the natural corrective.

On the regulatory assessments, a single border explains most of the interaction between the BBCM and the day-ahead market. The Estonia-Latvia border is the main source of forecast error: the forecast was wrong in roughly half of the intervals in the Estonia-to-Latvia direction, against about 5% on the Latvian-Lithuanian border, and, conditional on the forecast actually missing, the average error there reaches €47.65 per MWh against a €25.02 unconditional figure. It is the border on which the higher mark-up ramped to its €5 per MWh ceiling from 2 March 2026, the border on which allocations most often reached the 50% limit in May and June, and the border across which reserving capacity for the BBCM shifts day-ahead prices, lowering the Estonian price by €9.2 per MWh on average while raising the Latvian and Lithuanian prices by €2.45 and €3.23. The associated welfare effect on the single day-ahead coupling is larger than in the February to September 2025 period, estimated at €19.6 million with the Simulation Facility and at €28.8 million with a simpler pessimistic method. The common cause throughout is the persistent day-ahead price differential between Estonia and Latvia, driven by lower Finnish prices and the resulting north-to-south flow.

The scenarios examined in the report reinforce one another and point to the same conclusion that the market still depends heavily on TSO-owned resources and on cross-zonal exchange, and that dependence is non-linear. Reducing TSO-owned resources by a quarter raises total procurement cost by 51%, while halving them raises it by 229%, so the response accelerates rather than scales and the zones only begin to break apart at the deeper cut. Removing TSO-owned resources entirely would add about **€2.02 billion** over the nine months, and a fully isolated market with no cross-zonal capacity would raise total cost from €108.6 million to roughly **€6.34 billion**, some 58 times higher, with Lithuania the most exposed. These figures are upper-bound estimates that hold today's portfolios fixed, but their scale is the strongest evidence in the report of the value of the joint market. As the resources are withdrawn the burden also shifts, falling increasingly on Estonia, whose share of the Baltic cost rises from about 17% today towards 36% once they are removed entirely. And where the live market met reserve demand in full throughout the period, removing the TSO-owned resources leaves about 0,17% of reserve demand uncovered, so at the extreme the effect is not only a cost but a question of security of supply; reserve sufficiency in any case still rests on the participation of a few large assets.

Set against neighboring markets, Baltic balancing capacity prices have converged and stabilized since the launch of the BBCM in 2025, although systematic differences remain. Finnish prices have consistently been the lowest across both mFRR and aFRR, while Baltic prices have generally sat at Polish levels. The year-on-year decline and the seasonal pattern of prices both suggest that the market is continuing to develop and become more competitive.

On the mechanics the methodologies require, the allocation process stayed within its bounds throughout the period. The 50% limit was never breached on any border direction, average allocation ranged between 22.4% and 32.8%, and no case is found for changing the current limits. Three matters are carried into the next reporting cycle.

- The TSOs will examine whether the forecast errors follow an identifiable pattern of day type, time of day or market condition, and will report the impacts and results, together with any new resulting proposals, that have not been discovered yet, to improve forecast accuracy under Article 12(8)(f), in the next Evaluation Report.
- The volume-sensitive adjustment of the forecasted market value will be revisited using the simulation environment and the realized benchmark now available, and its sensitivity parameter will be moved off zero only once a value is shown, with sufficient confidence, to improve forecast quality without a net welfare loss.
- An automatic process for detecting 50%-limit breaches and notifying the Baltic regulatory authorities will also be implemented by the end of 2026.

Taken together, the results describe a young market that is working as intended and improving year on year, while remaining dependent on the arrangements that support it. The joint procurement of balancing capacity and the sharing of reserves continue to deliver benefits that are large relative to any fragmented alternative, and the overall conclusion of this report is that these arrangements should be maintained and, where the market allows, deepened.

10. Appendix

Appendices for Table 12 (Section 2.5)

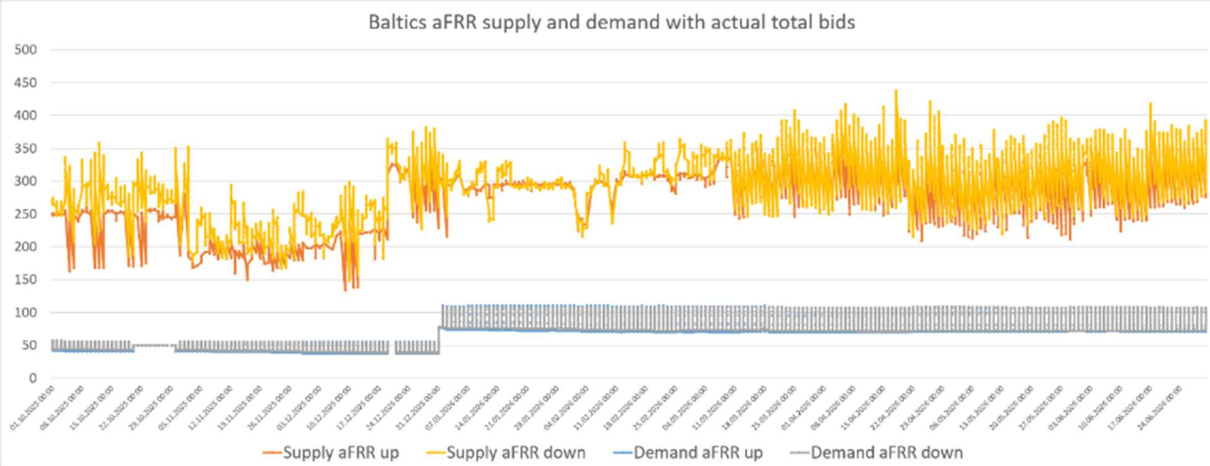

Figure 59. Total aFRR supply and demand in the Baltics for base case scenario (actual total supply)

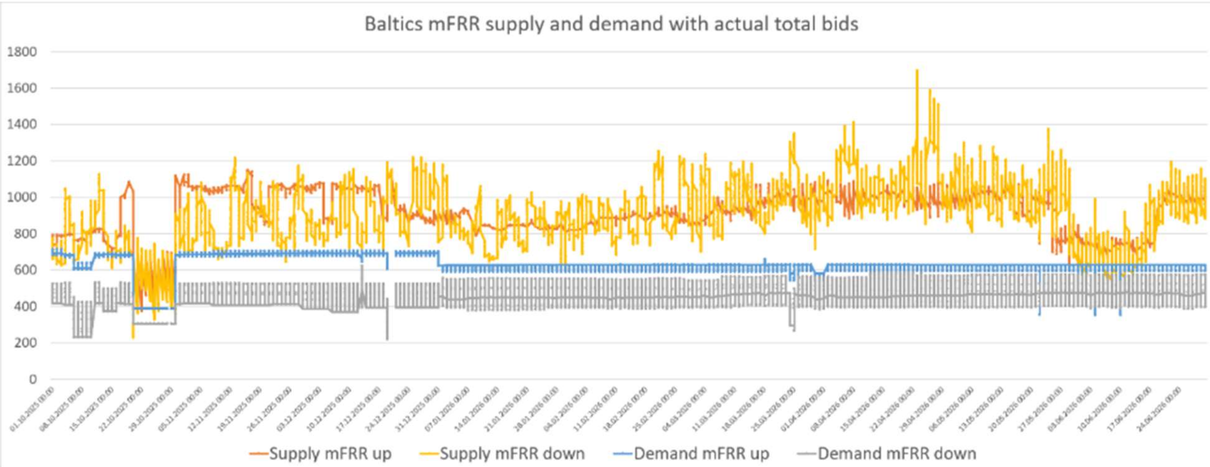

Figure 60. Total mFRR supply and demand in the Baltics for base case scenario (actual total supply)

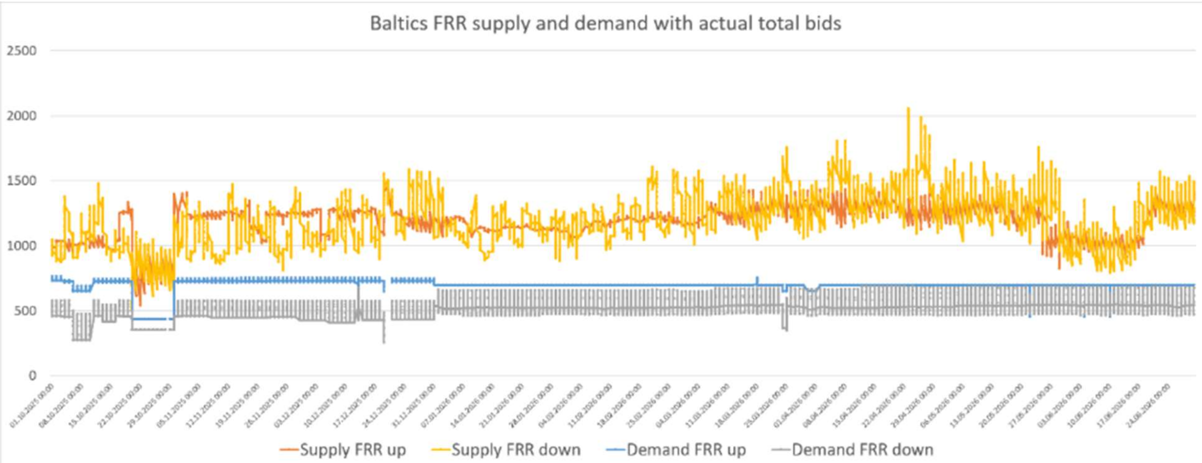

Figure 61. Total FRR supply and demand in the Baltics for base case scenario (actual total supply)

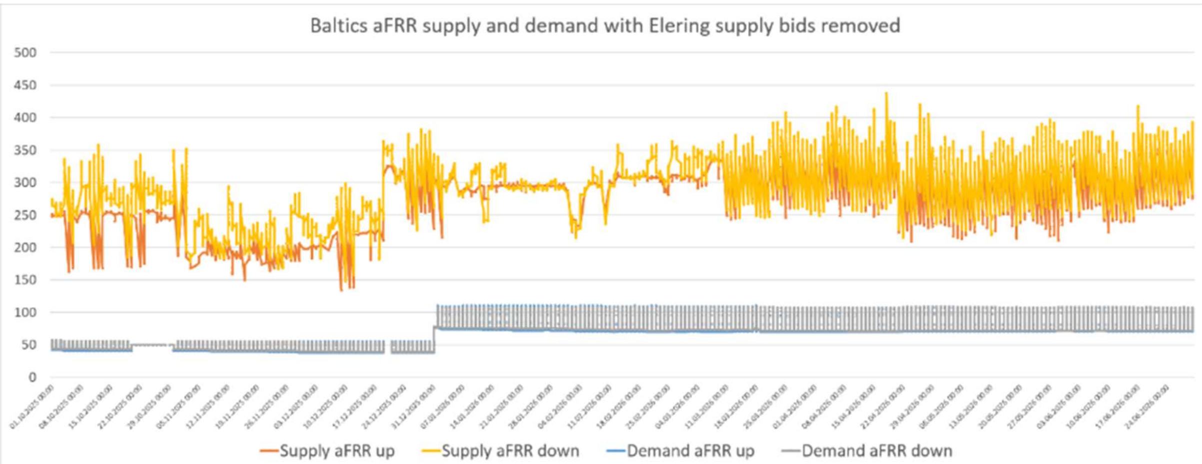

Figure 62. Total aFRR supply and demand in the Baltics for scenario with Elering supply bids removed

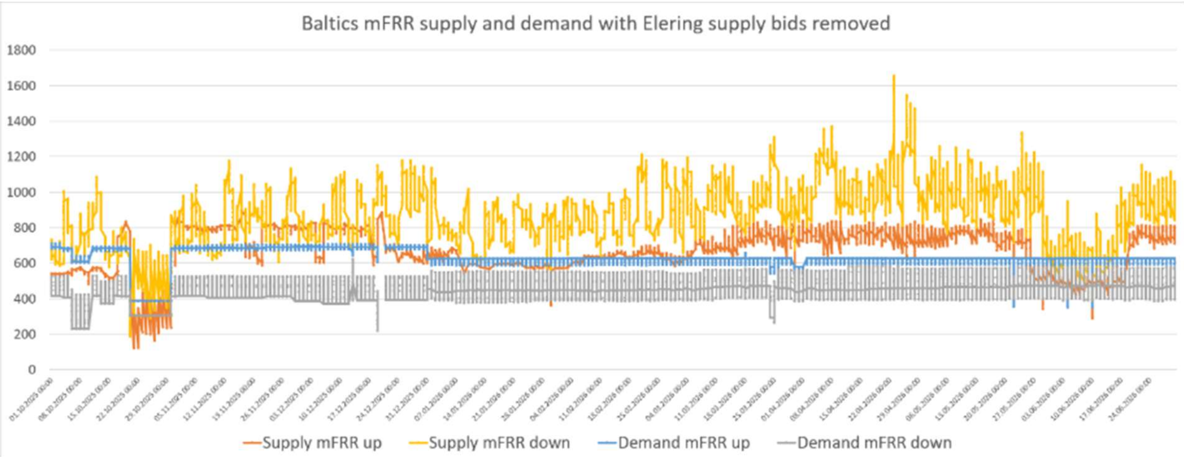

Figure 63. Total aFRR supply and demand in the Baltics for scenario with Elering supply bids removed

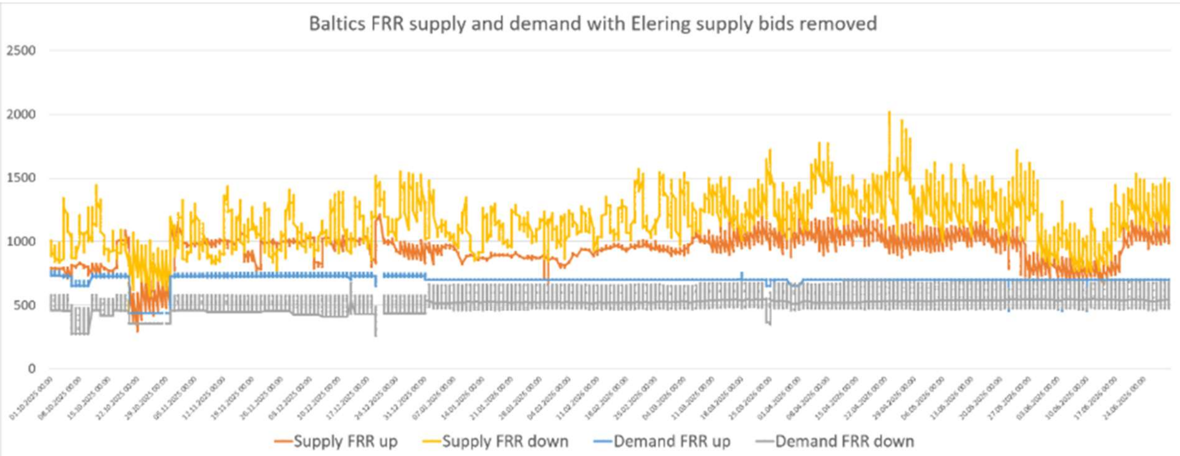

Figure 64. Total FRR supply and demand in the Baltics for scenario with Elering supply bids removed

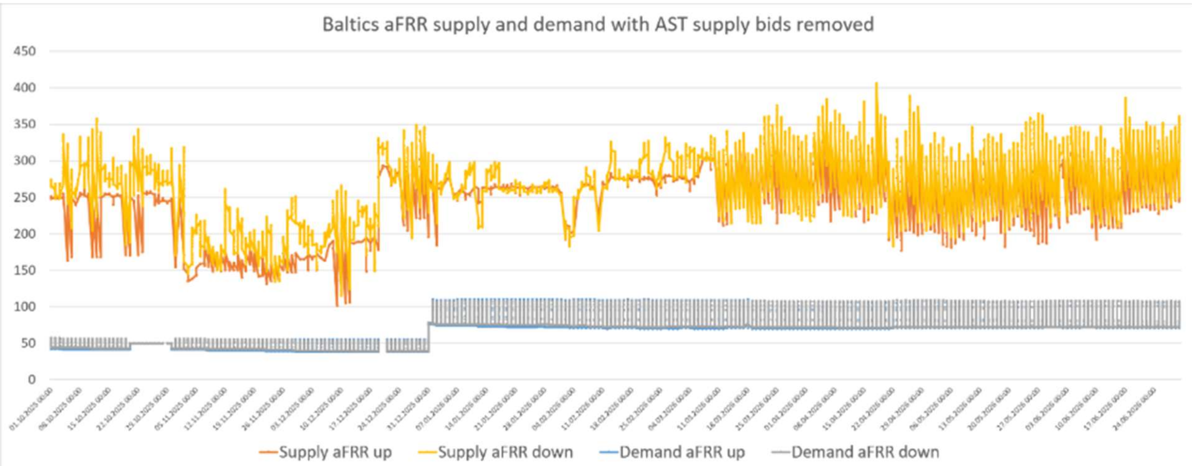

Figure 65. Total aFRR supply and demand in the Baltics for scenario with AST supply bids removed

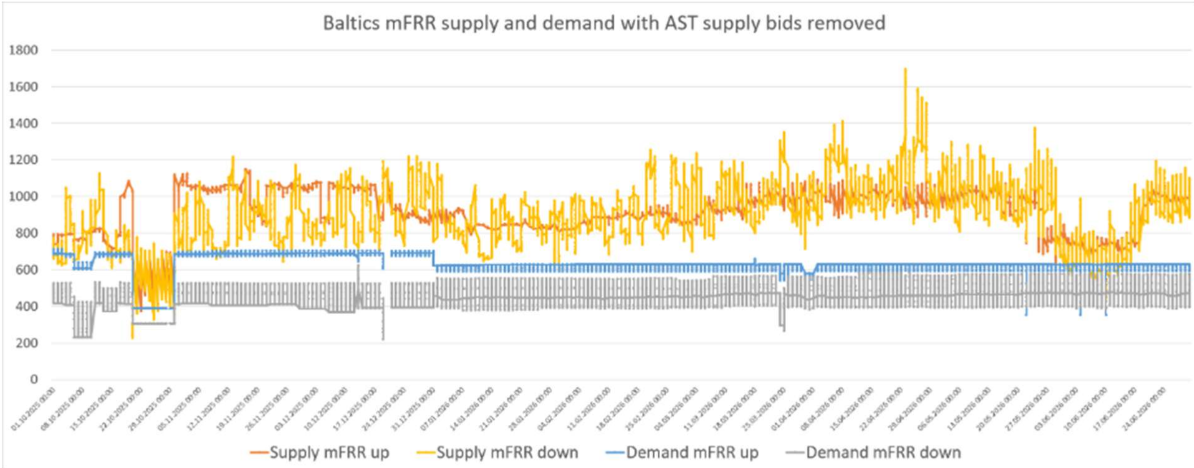

Figure 66. Total mFRR supply and demand in the Baltics for scenario with AST supply bids removed

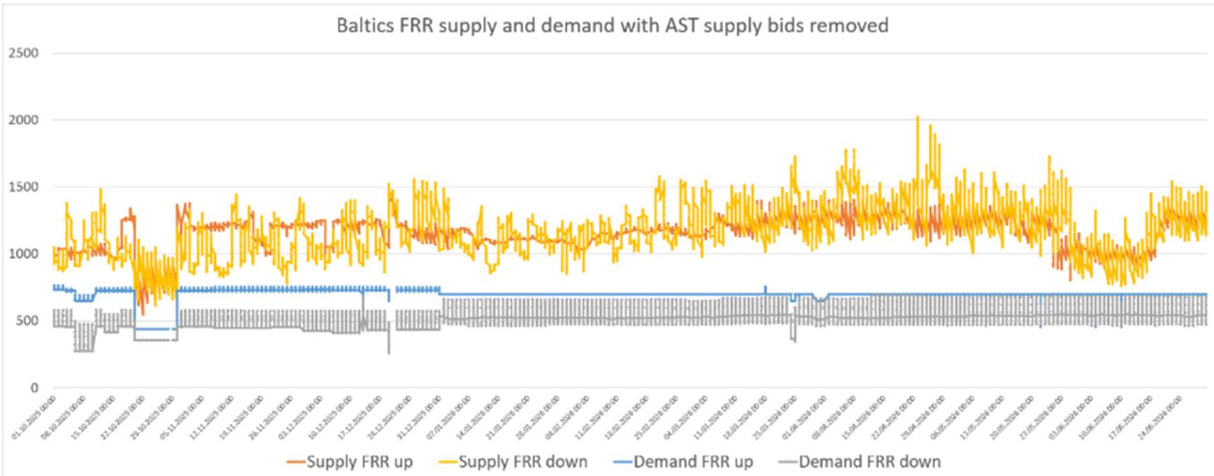

Figure 67. Total FRR supply and demand in the Baltics for scenario with AST supply bids removed

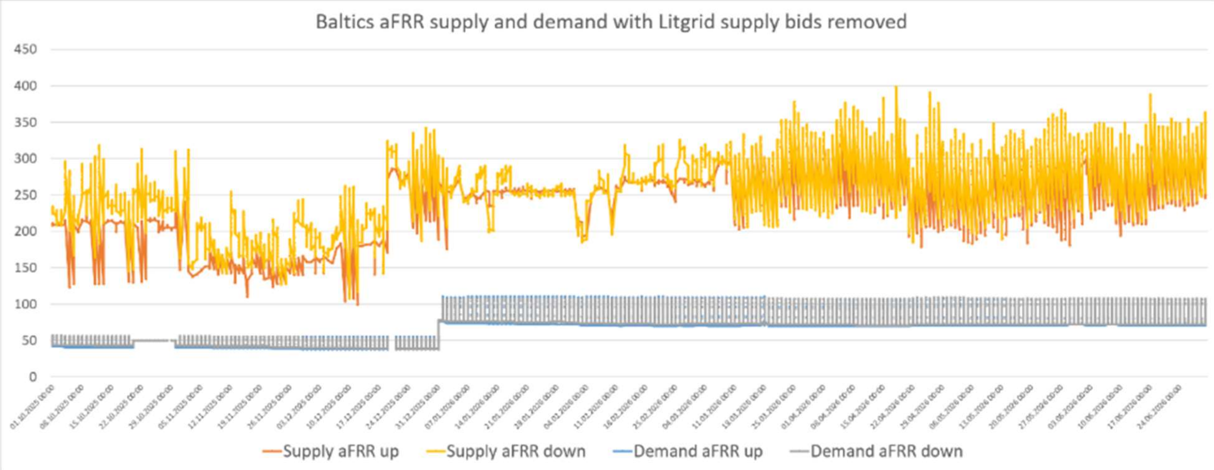

Figure 68. Total aFRR supply and demand in the Baltics for scenario with Litgrid supply bids removed

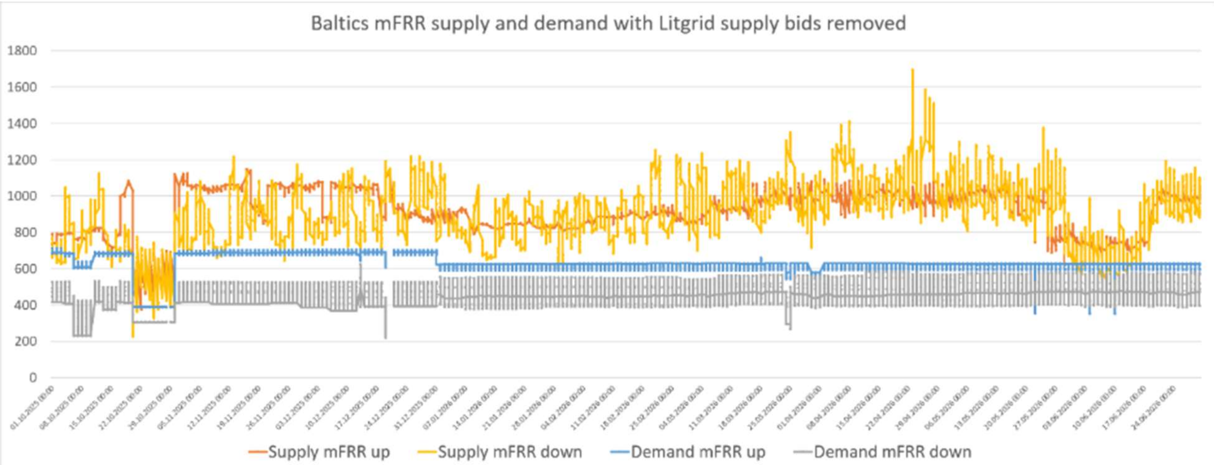

Figure 69. Total mFRR supply and demand in the Baltics for scenario with Litgrid supply bids removed

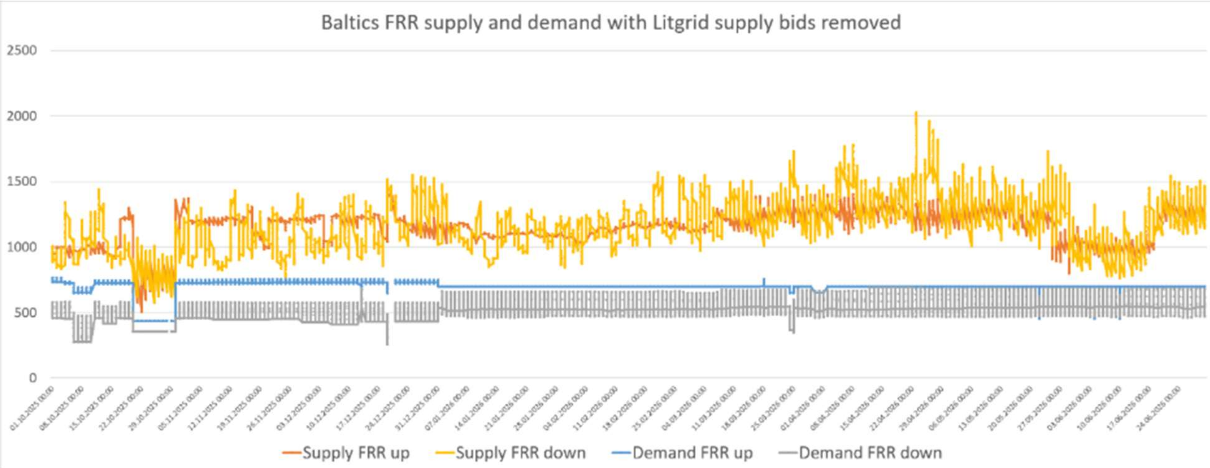

Figure 70. Total FRR supply and demand in the Baltics for scenario with Litgrid supply bids removed

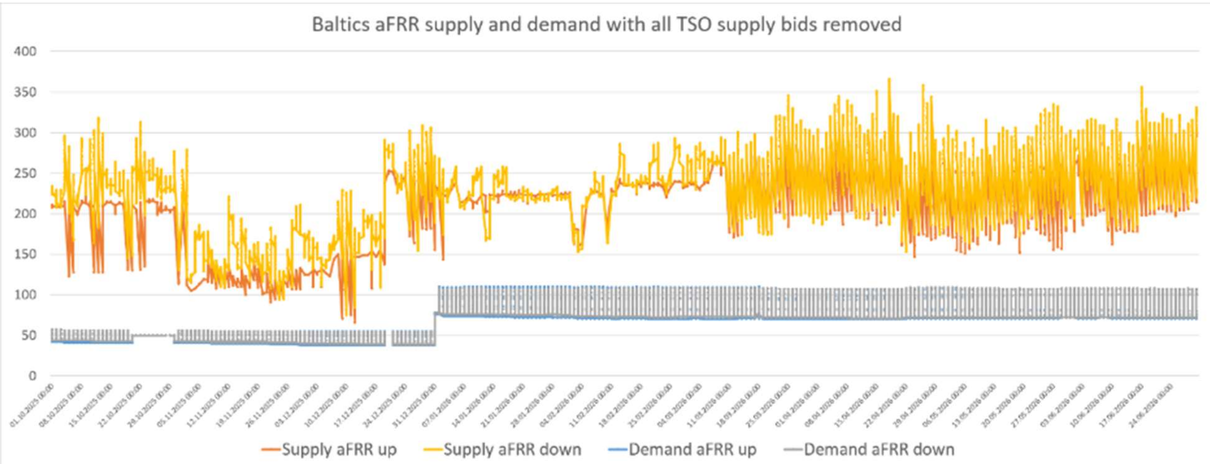

Figure 71. Total aFRR supply and demand in the Baltics for scenario with all TSO supply bids removed

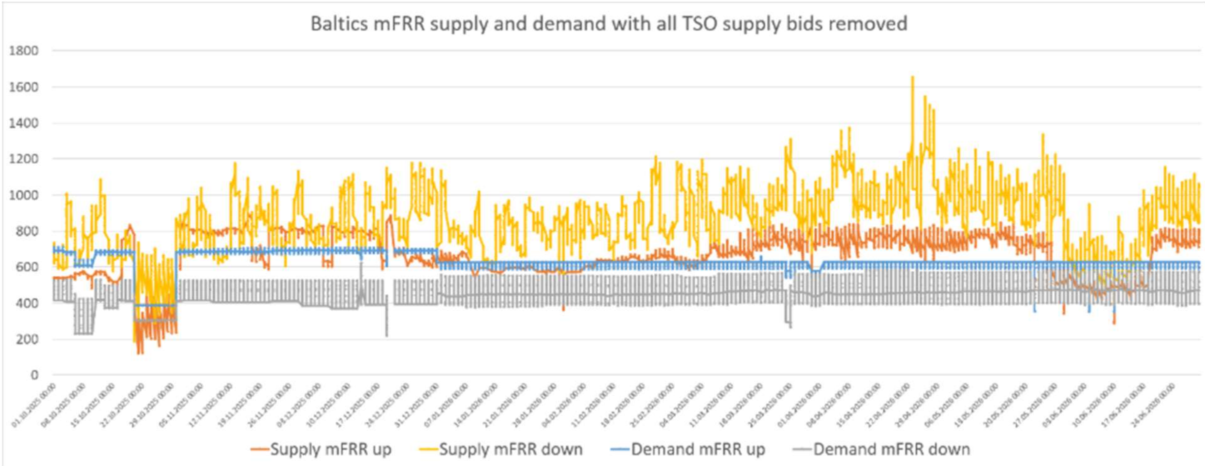

Figure 72. Total mFRR supply and demand in the Baltics for scenario with all TSO supply bids removed

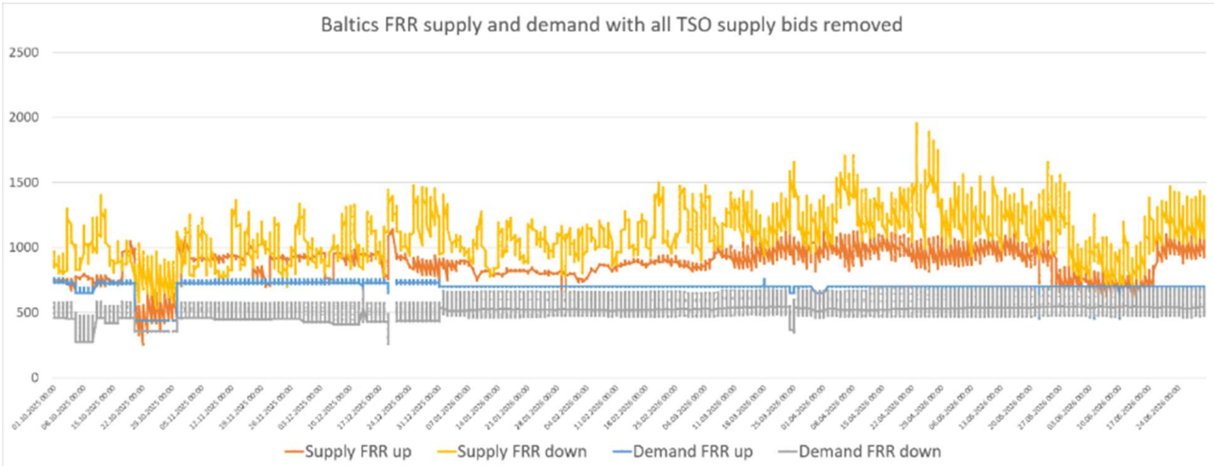

Figure 73. Total FRR supply and demand in the Baltics for scenario with all TSO supply bids removed

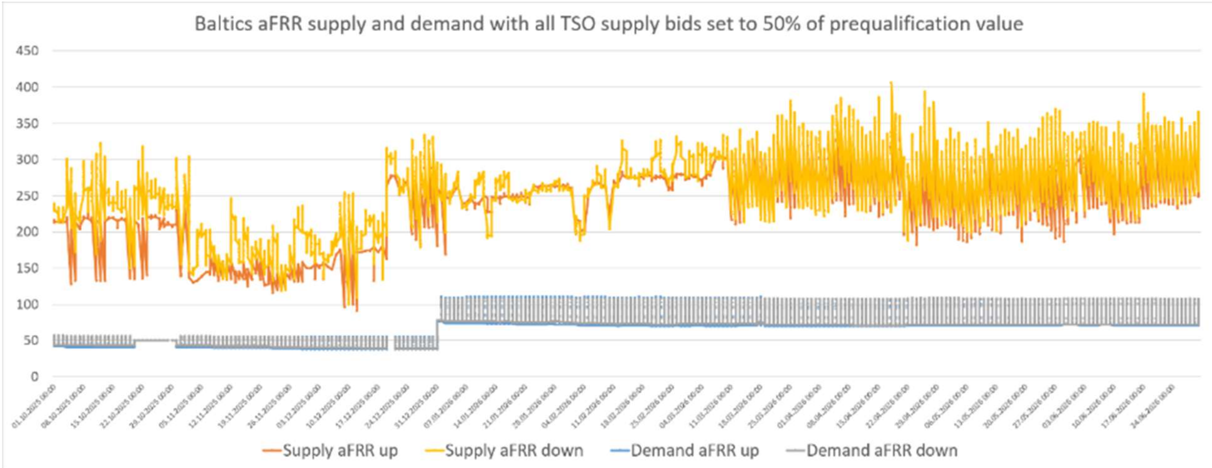

Figure 74. Total aFRR supply and demand in the Baltics for scenario with all TSO supply bids set to 50% of prequalification value

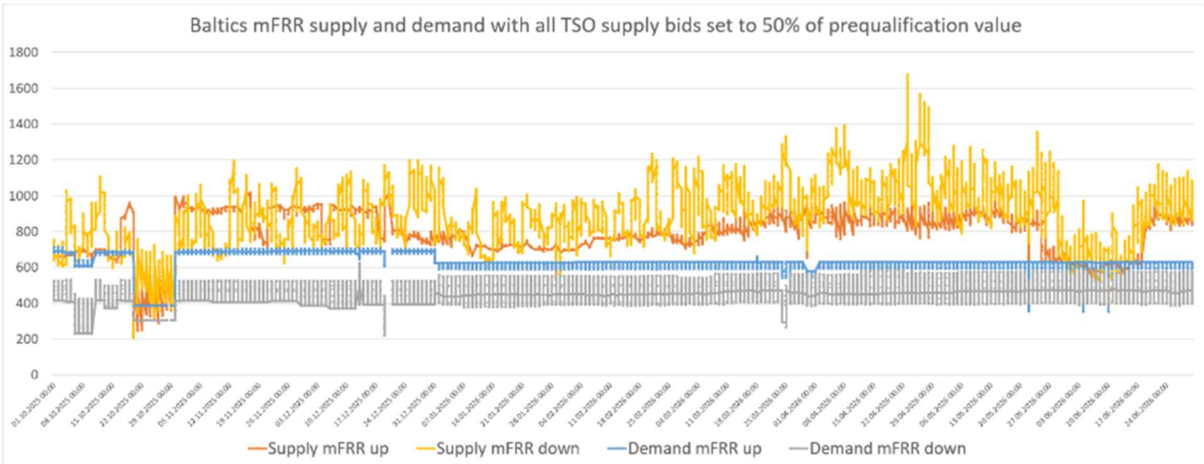

Figure 75. Total mFRR supply and demand in the Baltics for scenario with all TSO supply bids set to 50% of prequalification value

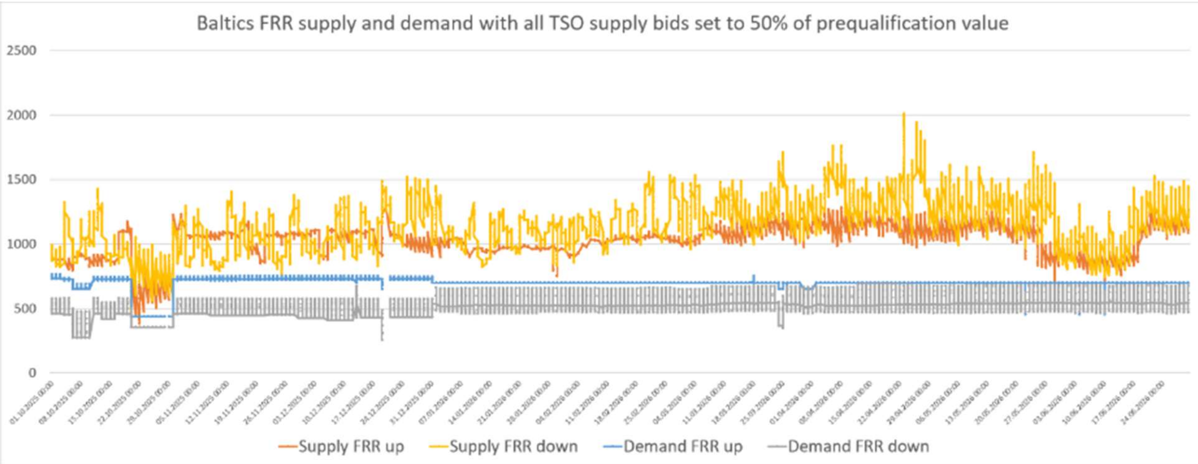

Figure 76. Total FRR supply and demand in the Baltics for scenario with all TSO supply bids set to 50% of prequalification value