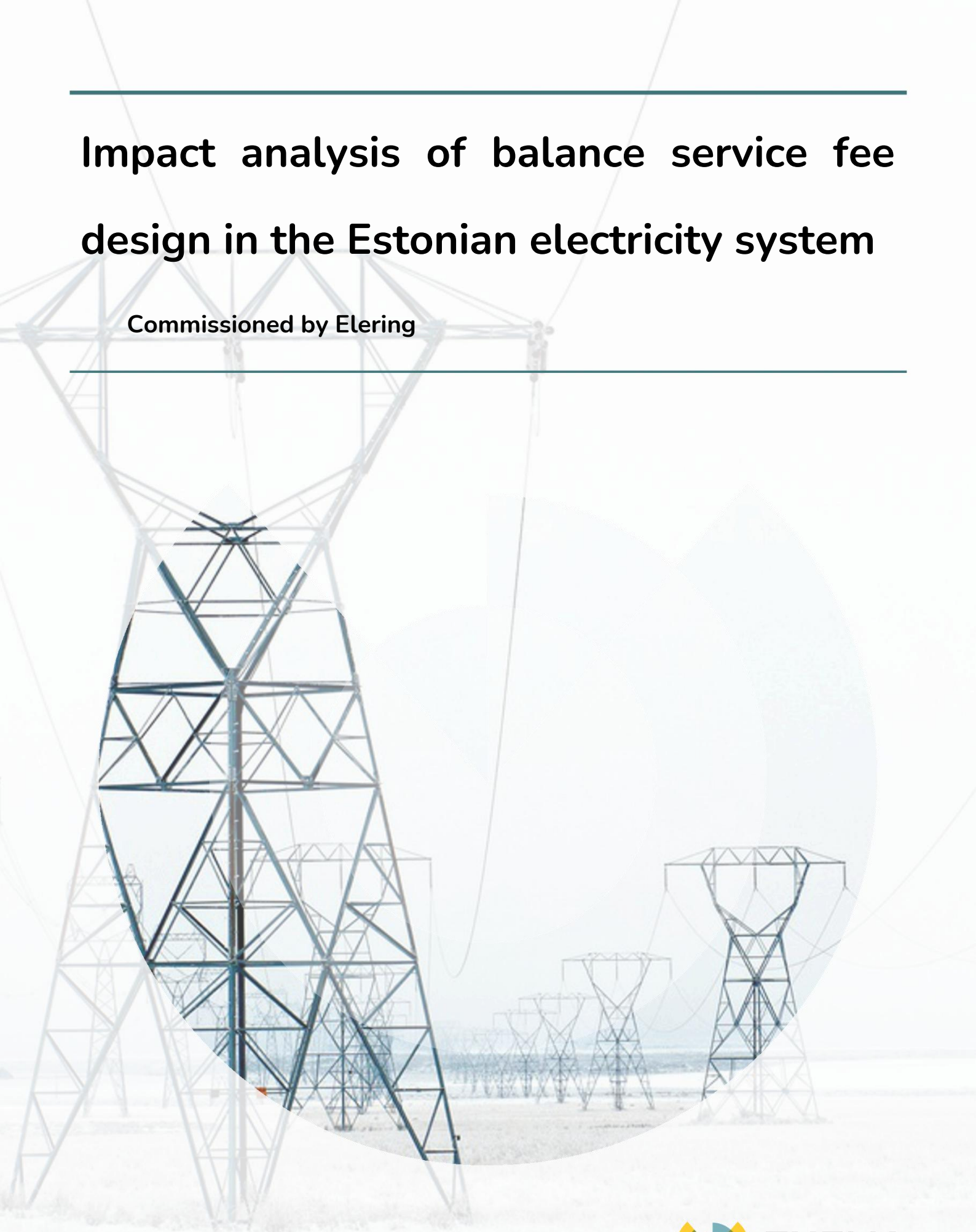
Impact analysis of balance service fee design in the Estonian electricity system

Commissioned by Elering



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Project description

After synchronizing with the Continental European grid in 2025, Estonia must update its balancing fee model to cover increased reserve costs. Four alternatives were assessed based on market impact and feasibility. While the current model benefits consumers, some options risk harming renewable investment or adding uncertainty for market participants. High imbalance fees are difficult to pass on and may distort incentives, particularly for variable generation. In this project we have analysed four alternative models for allocating imbalance costs and their impacts.

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Executive summary

The Baltic electricity system has undergone a significant transition, synchronising with the Continental European frequency area on February 9, 2025. This shift requires a new methodology for balancing service fees, as Estonia now incurs additional costs for procuring frequency reserves. The question is how the costs for buying reserve capacity should be shared between consumers, producers and balancing responsible parties (BRP) in imbalance. We have considered four alternative fee structures:

- Alternative 1 – Equal volume fees on consumption and production, and a small imbalance fee (Current model)
- Alternative 2 – Volume fee for consumption and a small imbalance fee for all BRPs
- Alternative 3 – Volume fee for consumption and a large imbalance fee for all BRPs (Latvian and Lithuanian model)
- Alternative 4 – Differentiated volume fees for consumption and production and a small imbalance fee for all BRPs

We have assessed the Alternatives according to Elering's criteria for impact on retail and wholesale market competitiveness, competitiveness in the Baltic balancing capacity market, and feasibility. Our key findings per criteria are the following:

- **Retail and Wholesale Market Competitiveness:**
    - *For consumers:* Alternative 1 (current model) benefits consumers by imposing the lowest fees on consumption directly. However, a part of the volume fee on production will be passed on to consumers through slightly higher spot prices. Alternative 2 gives the highest direct costs to consumers.
    - *For producers:* Producers prefer Alternative 2, as it exempts them from most fees. Alternative 3 has a large imbalance fee, which negatively impacts renewable energy producers.
- **Balancing Capacity Market Competitiveness**: All alternatives can affect Estonian actors' competitiveness in the Baltic balancing capacity markets. However, the effects are estimated to be small and vary little between the alternatives.
- **Feasibility**: Alternatives 1, 2 and 4 are the most practical under the proposed Electricity Market Act amendments, as BRPs/retailers are able to almost fully forward the fees to customers. Alternative 3 can be challenging for BRPs and retailers to pass on in the short term, creating financial uncertainty.

A first consideration is how much of the imbalance costs that should be recovered through volume fees and imbalance fees respectively. The polluter pays-principle suggests system costs should reflect market participants' contributions, through volume fees for consumption/production and imbalance fees where applicable. However, most of the cost stems from reference incidents and imbalances not clearly attributable to specific actors. This implies that an efficient imbalance fee should be fairly small and that most of the costs should be recovered through a volume fee. Additional arguments for limiting the imbalance fee are that it is hard to pass on to consumers, that it adds risk premiums, and disproportionately affects renewables, undermining Estonia's renewable energy goals. A second consideration is how the volume fees should be distributed between consumers and producers. To promote economic activity, residual costs should be borne by the least price-sensitive market actors (the Ramsey principle). However, this theoretic principle may be difficult to apply, as we do not know the current price elasticities of consumption and demand in the short- and long term. Ultimately, the split of volume fees between consumption and production can depend on policy goals. If attracting industry is key, lower consumption fees are preferable; if boosting domestic renewables is the priority, lower production fees help. A uniform volume fee, coupled with a small imbalance fee, seems to balance the stated policy goals.

1 Introduction

1.1 Background

The Baltic electricity system has historically been connected to the Russian frequency area. Under that system, Elering has not needed to acquire frequency reserves in capacity markets as the balancing was maintained solely on an energy basis. With the Baltic electricity system having synchronised with the Continental European frequency area on February 9, 2025, as part of the integration into the EU internal electricity market, a new methodology for calculating the balance service fees was needed. While only the administrative costs needed to be covered by fees under the previous system, the transition leads to additional costs from procuring frequency reserves.

The Estonian NRA (national regulatory authority) has approved the methodology proposed by Elering as Transmission System Operator (TSO) based on the fee structure used in the Nordic imbalance market. The new fee model follows the same principles as before, consisting of a volume fee on both consumption and production and an imbalance fee on the absolute imbalance volume. The cost associated with procuring reserve capacity has led to a significant increase in the volume fee from 0.08 EUR/MWh to 5.31 EUR/MWh. Market participants are however not exposed to the increased fee yet, as Elering have implemented a transitional arrangement covering balancing service costs using congestion income. The transitional arrangement is set to end July 2025.

Table 1 – Fee structure under the previous and currently approved system, as well as in the Latvian and Lithuanian models

	Previous Baltics	Estonia (current)	Latvia (current)	Lithuania (current)
Consumption fee	0.08	5.31	3	2.69
Production fee	0.08	5.31		
Imbalance fee	0.81	0.81	42.07	26.87

Issues raised by market participants highlight the competitive disadvantage Estonian producers will face from producers in Latvia and Lithuania given the fee structure proposed in both countries. The two countries have proposed a fee structure in which 50 percent of costs are covered through a volume fee on consumption and 50 percent are covered by an imbalance fee. The producers in Latvia and Lithuania do not face a volume fee.

On the other side, large consumers have warned that placing the volume fee burden solely on consumers will place them at a competitive disadvantage and as such production of goods reliant on power will be more expensive.

The Baltic energy ministries have instructed the TSOs to ensure consistency in balancing capacity cost allocation across the Baltics. The deadline for implementing a new fee design, however, is January 1, 2026, meaning that the countries might operate with different structures for some time. A loss of competitiveness, even if only temporary, will therefore be disadvantageous for Estonian market participants.

1.2 Current imbalance settlement

The power market must at all times be in equilibrium, and it is the TSO's responsibility to maintain it. Imbalances occur when actual generation or demand deviate from their expected volumes. In those moments, Elering must activate reserve energy to counteract the imbalance. When the demand is higher than generation, Elering must pay for increased generation or reduced consumption, called up-regulation. The opposite is the case during down-regulation.

Elering recovers the costs associated with balancing the power system through the imbalance settlement process. The primary mechanism for this is the imbalance price, which ensures that market participants causing imbalances are responsible for covering the costs of correcting them. When Elering activates energy to balance the grid, the associated costs are reflected in the imbalance price, meaning that those who deviate from their scheduled production or consumption pay for the corrections required to maintain system stability.

However, the imbalance price covers only the costs of procuring balancing energy, not balancing capacity. The costs associated with securing balancing capacity are recovered through fees, which are analysed in this report. These fees are distributed among market participants to ensure the reliability of the power system while maintaining a transparent cost allocation.

For example, a producer sells 100 MWh in the day-ahead market but only produces 90 MWh, resulting in an imbalance of 10 MWh. All else equal, Elering must then perform an up-regulation to maintain the physical balance. In the imbalance settlement for this hour, this producer must pay the price of Elering's regulation for its 10 MWh of imbalance. In addition, with the current proposed methodology, the producers pay an imbalance fee for its imbalance and a production fee for its production. Assuming the imbalance price, being the regulation price in the dominating direction, was 100 EUR/MWh, Table 2 illustrates the imbalance settlement for this hour under the current fee structure.

Table 2 – Illustrative example of an imbalance settlement

Settlement element	**Volume (MWh)**	**Price (EUR/MWh)**	**Cost (EUR)**
Imbalance price	10	100 (example)	1 000
Volume fee	90	5.31	478
Imbalance fee	10	0.81	8
Total cost			**1 486**

1.3 Scope of analysis

The scope of this report is to conduct an impact analysis of different alternatives for allocating balancing service costs through various fees. The alternatives we consider are:

- Alternative 1 – Equal volume fees on consumption and production, and a small imbalance fee (Current model)
- Alternative 2 – Volume fee for consumption and a small imbalance fee for all BRPs
- Alternative 3 – Volume fee for consumption and a large imbalance fee for all BRPs (Latvian and Lithuanian model)
- Alternative 4 – Differentiated volume fees for consumption and production and a small imbalance fee for all BRPs

For alternatives 1, 2 and 4, the imbalance fee is set to 0.81 EUR/MWh. In alternative 3, the imbalance fee covers 50 percent of costs. The study is to analyse and quantify the impact of these four alternatives, and their effects on the following aspects:

- **Competitiveness of retail and wholesale markets**, including accessibility for smaller market participants, BRPs (Balance Responsible Parties), producers (including the RES group), and consumers.

- **Competitiveness of producers in the joint Baltic reserve capacity procurement market**, assessing whether the methodology would provide Estonian producers with a competitive advantage or disadvantage compared to Latvian and Lithuanian methodologies.
- **Feasibility of the methodology**, including the ability of BRPs and suppliers to pass on the costs and whether the methodology raises any foreseeable legal issues.

Methodology

This analysis builds on economic theory, available literature and different empirical approaches, including THEMA's power market model, which is explained in the appendix. We have also conducted interviews with Estonian market participants to gather local insight as well as to test hypotheses. These interviews are a supplement to the theoretical and empirical analysis.

Report structure

We start the report be analysing the impact on competitiveness in retail markets in chapter 2 and competitiveness in the Baltic balancing capacity market in chapter 3. Next, we investigate the feasibility of each alternative in chapter 4. Finally, we summarise and discuss our findings and give our recommendation in chapter 5. In the appendix, we discuss some specific hypotheses that have been formulated by Elering based on previous stakeholder feedback on different options for the balance fee design. We also provide a summary of the feedback from market participants and a description of the power market model used in separate appendixes.

2 Competitiveness in retail and wholesale markets

This chapter examines how the different alternatives impact the retail and wholesale market. We begin by calculating the fees under each alternative, ensuring they generate the same revenue as the current methodology. Additionally, we analyse how these fees are distributed across various market participants. Next, we assess their potential effects on wholesale markets. Finally, we explore how the retail market structure may be influenced by the different alternatives.

2.1 Methodology and data

To evaluate the alternatives' effect on competitiveness, we analyse how the fee structure affects the market participants in the retail markets. In our analysis, that includes how it affects consumers, producers of solar, wind and other forms of power production, and we discuss if smaller participants are at a disadvantage. In practice, the impact analysis evaluates the effects of the fee structure on the market participants' bidding curves, representing their supply and demand. We also briefly discuss effects on BRPs which we follow up on in the chapter on feasibility.

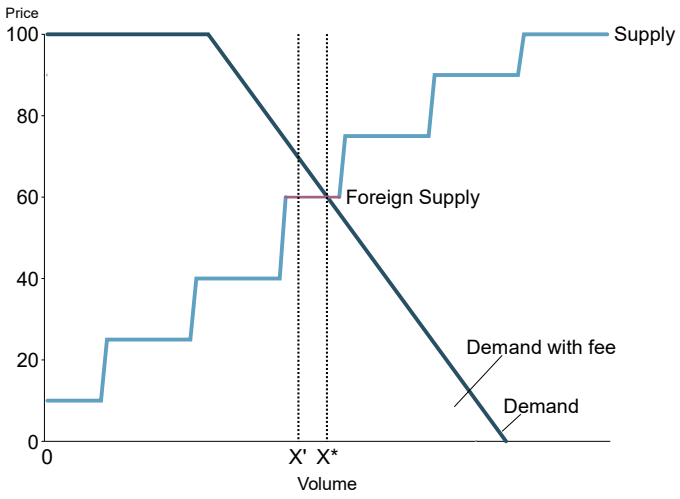
Methodology

To make sure we are evaluating the effect of comparable fee structures, we calculate the fees for alternatives 2, 3 and 4 to bring in the same revenue as alternative 1 where the fees are given by the proposed fee structure. To find the total revenue for alternative 1 we first need to calculate how the consumption and production of electricity will be affected by the introduction of the fee. In our analysis, we disregard the possibility that the choice of fee structure might impact the total costs over time. Considering that balancing capacity procurement is mostly dimensioned by a reference incident, not the imbalance volumes, the impact is unlikely to be significant in the short term. In the long term however, the alternatives might impact the overall balancing costs.

Starting off with consumption, when consumers face an additional fee of 5.31 EUR/MWh, the cost of consuming electricity increases. This in turn leads to a reduction in consumption. In our estimations, we have used a price elasticity of demand for electricity of -0.08 percent (Csereklyei, 2020), meaning a 1 percent increase in spot prices reduce consumption by 0.08 percent.

This is illustrated in a simplified manner in Figure 1. Here we assume that the fee is solely placed on demand. We see that for the same price, consumers will demand less electricity than without the fee. In this example, the fee does not lead to a change in price, but a sufficiently large fee will move the equilibrium to a new price.

Figure 1 – Illustrative example of the effect of fees on the bidding curves in the wholesale market



Production faces the same fee of 5.31 EUR/MWh. The increased cost per unit means that some of the current production may no longer will be profitable such that production will fall. To account for a reduction in production, we do a preliminary simulation of production with these fees to estimate the reduction. With the estimated reduction, we more precisely estimate the effect of the fees and ensure Elering's budget will hold.

Having calculated the new consumption and production levels, we can calculate the revenue for alternative 1. For the imbalance fee of 0.81 EUR/MWh, we have assumed that imbalance volumes are static. As such, the revenue from imbalance fees can be calculated as well.

With the revenue under alternative 1, the fees for the other alternatives can be calculated as well, taking elasticity into account. The calculation is explained in detail in Chapter 2.2.

Since all alternatives have an imbalance fee, the total cost for market participants will depend on their imbalance volumes. As a simplified illustration, we use a solar producer that is also a BRP. Since solar power is weather dependent and difficult to predict, the forecasted production and actual production is likely to differ, creating imbalances. They must pay Elering an imbalance fee for the imbalance generated. Even though this cost does not come directly from produced volume, the cost of the imbalance fees must be covered in order for production to be profitable. This would also be the case if the producers used an external BRP for their forecasting. The BRP would face a fee from Elering that they will transfer to the producer.

The difference in forecasting errors between market participants will lead to the imbalance fee impacting them differently. In our quantification we have distinguished between solar, wind, the rest of production and consumption. Given that their probability of being forecasted incorrectly is higher for renewable production, solar and wind will have a higher realised imbalance cost per MWh of production.

The result from these calculations is the cost per MWh for each group under all alternatives. Using these costs as an input the THEMA model, we can analyse the impact on market participants. The THEMA model simulates how the market will adapt to the new fees based on simulated bidding curves for all producers. The simulation also considers how the reduction in consumption affects the spot price which also affects producers. Using this model allows us to more realistically estimate how different producers are impacted by the alternatives. We use the results from the model in the evaluation of producer competitiveness.

We do the same calculations for the cost per MWh for consumers and different producers in Latvia and Lithuania using their proposals for fee structure. As such, our impact analysis evaluates the effect of the alternatives when competing with Latvian and Lithuanian market participants subject to their own fees.

Data

In our analysis we use production and consumption data for 2025 from the THEMA Market Outlook as well as imbalance volume data for 2024 supplied by Elering from which we have extrapolated the volumes in 2025. We did this by increasing imbalance volumes proportionally to the increase in production and consumption volumes from 2024 to 2025.

The annual absolute forecasting errors for production and consumption are calculated from volumes in 2024 using data from Elering Live (Elering Live, 2025). For consumption, the annual forecasting error was around 5.6 percent, for wind 23 percent and solar 40 percent. For the remaining production, we have used a forecasting error of 1 percent. This way some of the imbalances are generated by the remaining production, but the cost associated for those producers is negligible.

The annual short-run price elasticity of consumption of -0.08 we use is from a paper in which the short run price elasticity of household demand in estimated to be between -0.07 and -0.08 and for industrial demand from -0.08 to -0.1 for European consumption (Csereklyei, 2020). Since Estonia lacks a large power intensive industry, we use an average weighted towards households. The price elasticity of demand is difficult to estimate and will vary between regions, sectors and over time. The consensus is still that the short-run elasticity of demand is low due to electricity being a necessity.

The price elasticity of production was used to correctly calculate the production fee which was used as an input in the model, but its elasticity is handled by THEMA's Market Model

during simulation. To set up the model input, we assumed it to be 0.2, based on an average generation reduction with these fees from a preliminary simulation.

2.2 Calculation of fees for market participants

In our analysis we have calculated the cost per MWh for the market participants under each alternative as described. Alternative 1 is given by Elering as a 50/50 fee split, meaning that production and consumption face the same volume fee.

Under alternative 2, the imbalance fee of 0.81 EUR/MWh covers around one percent of costs, the rest being covered through a consumption fee. We calculate the consumption fee to be 8.46 EUR/MWh in order to bring in the same total revenue as alternative 1 taking into account that consumption volumes will fall due to the increased fee.

Alternative 3 splits the costs 50/50 on consumption and imbalance. Taking imbalance volumes as static, the imbalance fee will be 42.61 EUR/MWh. The consumption fee is calculated to make up the other half of costs, resulting in a 4.25 EUR/MWh fee.

For alternative 4, we apply an approximate 75/25 fee split for consumption and production respectively. With the production fee being one third of the consumption fee, the production fee corresponds to the fee placed on Finnish producers. In Finland, producers are subject to a production fee of 1.73 EUR/MWh and a 0.66 EUR/MWh grid tariff (eSett, 2025). Finnish producers also face a variable tariff based on generation capacity, which we have not included in our estimates. The total production fee is thus 2.39 EUR/MWh. The rationale behind this fee structure is to ensure that producers are not at a disadvantage compared to Finnish producers. The fee faced by producers will be as high as possible while still maintaining a competitive advantage. The imbalance fee again covers around 1 percent of costs. The consumption fee will have to cover the rest of the costs. We calculate the consumption fee to be 7.03 EUR/MWh to bring in the necessary revenue.

The fee structure is presented in Table 3.

Table 3 – Fee structure of the four alternatives, EUR/MWh

	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**
Consumption fee	5.31	8.46	4.25	7.03
Production fee	5.31			2.39
Imbalance fee	0.81	0.81	42.61	0.81

Since all alternatives have an imbalance fee, the actual cost per MWh will differ from the fees presented in Table 3. This comes from the differences in imbalance volumes between market participants. As discussed, this cost comes from the cost of occurring imbalances needing to be recovered by the BRP. For alternatives 1, 2 and 4, the imbalance fee is fairly low meaning that the cost of imbalances is unlikely to differ greatly between sectors. For alternative 3, however, the imbalance fee will lead to large differences in the cost for different market participants.

In order to capture this difference, we have calculated the cost per MWh for consumption, solar, wind and the remaining production using the methodology described in chapter 2.1. The resulting cost per MWh is presented in Table 4.

In our calculations, we have used an average forecasting error of consumption of around 5.6 percent as that was the average in 2024. Given the low imbalance fee of alternative 1, 2 and 4, the cost from imbalance does not increase the cost significantly. For alternative 3 however, the size of the imbalance fee leads to an increase in the cost per MWh of consumers by around 2 EUR. This makes it more expensive for consumers than alternative 1 even with the lower consumption fee.

Solar production has a significant forecast error of 40 percent. Under alternatives 1,2 and 4, that represents an additional cost per MWh of 0.26 EUR on top of the production fee. For alternative 3, the imbalance fee leads to significant costs for solar. The cost per MWh is 13.69 EUR even without a production fee.

Forecasting error for wind is lower than for solar at 23 percent but is still high. The cost per MWh is 0.15 EUR under alternative 1, 2 and 4 and 7.86 EUR under alternative 3, which is higher than the cost for consumers under the same alternative.

We consider thermal production to have a low forecasting error at 1 percent. The resulting additional cost per MWh is low at less than 0.01 EUR/MWh for alternative 1, 2 and 4 and 0.3 EUR in alternative 3.

Table 4 – Estimated total cost from fees per group, EUR/MWh

	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Consumption	5.35	8.49	6.21	7.06
Solar	5.57	0.26	13.69	2.65
Wind	5.46	0.15	7.86	2.54
Rest	5.32	0.01	0.34	2.40
Avg. Prod.	5.38	0.07	3.85	2.46

We see that the cost per MWh is significantly higher for variable renewable energy than for consumption and the remaining production.

2.3 Impact of fees on retail and wholesale market competitiveness

2.3.1 Consumers

Qualitative assessment

For the consumer, the price of electricity is the most important metric. Their competitiveness compared to consumers in neighbouring countries will depend on how much the proposed fee structure affects the price for which they purchase power.

Assuming elastic demand for electricity, an increased fee for consumers leads to the marginal cost for the consumer increasing. This downward shift in the demand curve leads to a lower market price for consumers and producers. If the supply is completely inelastic, the reduction in the spot price will be equal to the fee. If, however, supply is elastic the reduction in the spot price will be lower than the fee since the reduced spot price leads to lower production with a lower marginal cost.

Qualitatively, we expect the reduced competitiveness of consumers to follow linearly from the cost per MWh presented in Table 4 with alternative 1 being the most beneficial for consumers.

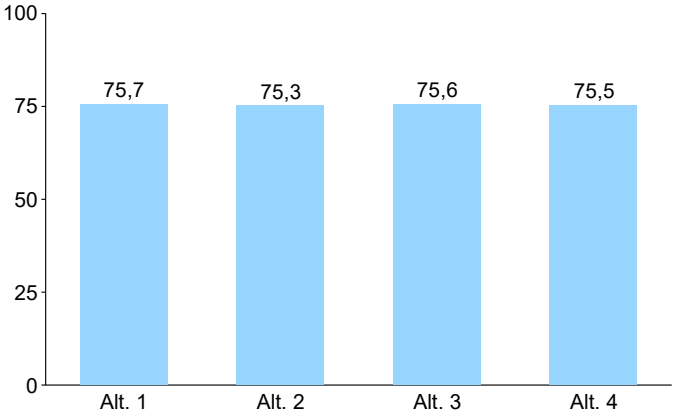
While a high consumption fee could impact economic competitiveness, Estonia lacks a significant power-intensive industry, limiting the potential harm in the current market. Research from Arenguseire Keskus indicates that, on average, electricity costs accounted for just 1.8 percent of Estonian businesses' production value in 2022 (Arenguseire Keskus, 2024). Except for the paper industry, the study found that even during 2022, when energy prices were at record highs, electricity costs had limited impact on investment decisions or business sustainability. The research suggests that a fee below 10 EUR/MWh would have minimal negative effects on existing industry. However, the long-term effects may be different as we discuss in a later in this chapter.

Quantitative assessment

Using a price elasticity of demand for electricity of -0.08, we estimate that alternative 1 leads to the lowest reduction in consumption followed by alternative 3, alternative 4 and finally alternative 2. The ranking follows linearly from the estimated per MWh cost for consumers shown in Table 4.

When it comes to the spot price, our simulations find that the alternatives have a limited impact on the spot price, as can be seen in Figure 2. The difference between the highest price, 75.7 EUR/MWh under alternative 1, and the lowest, 75.3 EUR/MWh under alternative 2, is merely 0.4 EUR/MWh.

Figure 2 – Simulated spot price under each alternative in 2025, EUR/MWh



The modest change in electricity prices can be explained by how prices are determined in a marginal pricing system. In such a market, the spot price is set by the marginal unit of electricity needed to meet demand, whether that electricity is produced domestically or imported.

If Estonia imports a significant share of its electricity, the marginal price is often determined by imported electricity, not local generation. When a fee is introduced on local generation, it may increase the price of domestic generation, but if imported electricity is on the margin, the price would remain unchanged. If a fee is put on consumption, demand will be reduced. The shift in demand does not necessarily lead to a price reduction, as it does not necessarily shift the marginal supplier.

This example is illustrated in Figure 1 and shows how the introduction of a fee might not affect the spot price in the market.

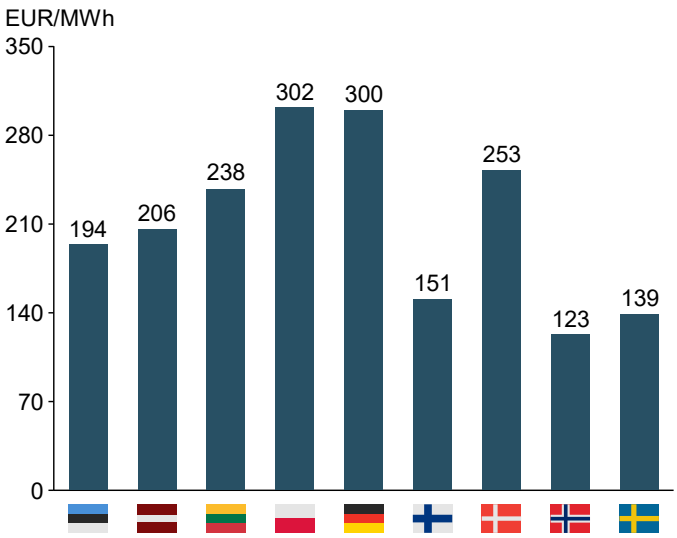
It is worth noting that while the alternatives do have an impact on consumption, the difference between the alternatives is not significantly large. The difference between the most beneficial, alternative 1, and the least beneficial, alternative 2, is 40 GWh.

As described earlier, the price elasticity of demand is difficult to estimate and will not capture all the specific conditions in Estonia and the Baltic region. There is therefore a degree of uncertainty to the size of the effect on consumption. Based on the fact that the fees only make up a small part of the consumers' electricity bill, the effect is unlikely to be economically significant in the short term. We can still conclude that the ranking of the alternatives with regards to the competitiveness of consumers is very likely to stay the same.

In the longer term, a higher electricity consumption fee will increase overall electricity costs and may act as a disincentive for establishing new power-intensive industry in Estonia. However, the consumption fee alone is unlikely to be the deciding factor.

From a pure electricity cost perspective, consumers pay not only the spot price but also grid tariffs, taxes, and any applicable consumption fees. To compare total electricity costs across countries, Figure 3 presents ACER's 2023 data on electricity unit prices for non-household consumers in selected countries (ACER, 2024). This includes all key components: spot prices, grid tariffs, taxes, and VAT. As shown, the unit prices across the Baltic states were similar, with Estonia having a slightly lower cost in 2023.

Figure 3 – Electricity unit price for non-household consumers 2023



Source: ACER (2024)

If a higher consumption fee, such as those analysed in this report, had been in place, Estonia's unit price could have been even closer with Latvia's. Still, it is important to note that the consumption fee represents only a small share of the total electricity cost. For example, if a fee of 8 EUR/MWh were added to the 2023 unit price, it would have accounted for just 4 percent of the total.

Crucially, electricity prices are just one of many factors influencing the location decisions of power-intensive industries. If electricity cost alone were the primary driver, most investments in the region would be directed toward the Nordics. Other elements, such as political and regulatory stability, workforce availability and skills, infrastructure, taxes, and financial incentives, also play a significant role.

The effect of a fee on new industrial establishments in Estonia is uncertain, particularly over the long term. To assess potential impacts, we consider long-term price elasticities, as investment decisions for future electricity consumption are tied to price expectations. Csereklyei (2020) finds that while the EU-wide short-term price elasticity of electricity demand is low (around -0.08), long-term elasticities are substantially higher, ranging from -0.53 to -0.56 for residential consumption and from -0.75 to -1.01 for industrial consumption (Csereklyei, 2020). These figures suggest that although short-term demand may remain stable, long-term consumption, and thus investment decisions, could be significantly affected by higher electricity costs.

Still, given the small difference in the cost for consumers between the alternatives and the relatively small impact of these costs compared to the total electricity costs, we expect limited differences between the alternatives assessed in this report when it comes to the attractiveness of Estonia for new power-intensive industry.

2.3.2 Producers

Qualitative assessment

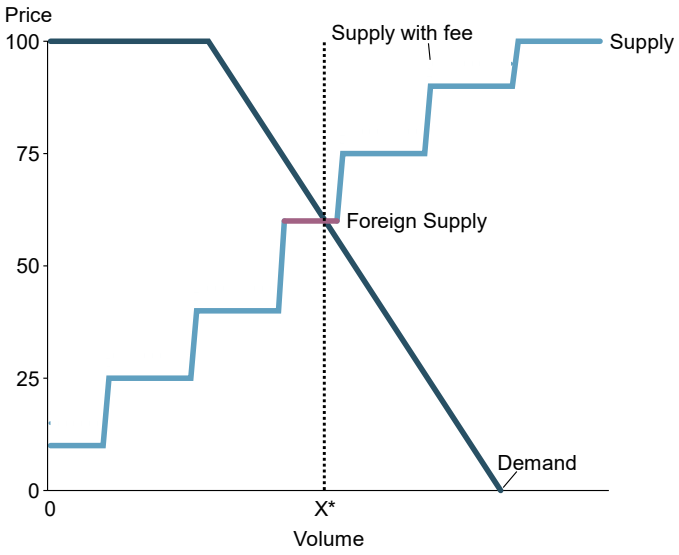
For producers, the fees will need to be included in their bids in the day-ahead market and as such can impact whether or not the bid is below or above the spot market clearing price. If the Estonian power market is isolated from its neighbours and all producers faced the same fee, the entirety of the fee would be absorbed by the spot price such that production and profitability remained the same for producers regardless of whether the fee is paid by producers or consumers. Since the Estonian market is heavily connected with the Baltics and other countries around the Baltic Sea, that is not the case. The import of foreign production that is not subject to the same fees means that the fee will not be fully absorbed. As such, the introduction of a fee on Estonian production has the potential to harm competitiveness.

Producers will include the costs in their bids but since markets are open, but they are unlikely to completely recover the costs through higher prices. A fee on production therefore leads to both a reduction in production volume and a reduction in the profitability of production.

Figure 4 illustrates this with a simplified example. Here the fee is solely placed on domestic production. Given that imported generation is setting the marginal price in equilibrium, a fee on production will increase the cost of domestic generation without increasing the revenue symmetrically. In this example

domestic production levels are unaffected, but profitability is reduced.

Figure 4 – Illustrative example of the effect of fees on bidding curves in the wholesale market



Since Estonia has an electricity deficit, they must import the difference between consumption and production. In order for the markets to clear, the power price in Estonia must be equal or higher than abroad. An Estonian production fee can render some local production uncompetitive leading to an increased need for imports. This mean that more expensive production will be imported, resulting in higher prices. The total price increase, however, will be lower than the increased fee. As such, the Estonian will bear some of the fees through a reduced margin. In the short term, consumers will face a higher cost per MWh and producers must cover some of the increase in costs from their profits.

Moreover, while all Estonian producers face the same nominal fees, the actual cost burden varies depending on forecasting accuracy. Since different technologies have different forecasting errors, the imbalance cost per MWh produced is not uniform. Renewable energy sources, which typically have higher forecasting errors, bear a greater imbalance cost compared to other generation technologies with more predictable output.

Quantitative assessment – Renewable energy producers

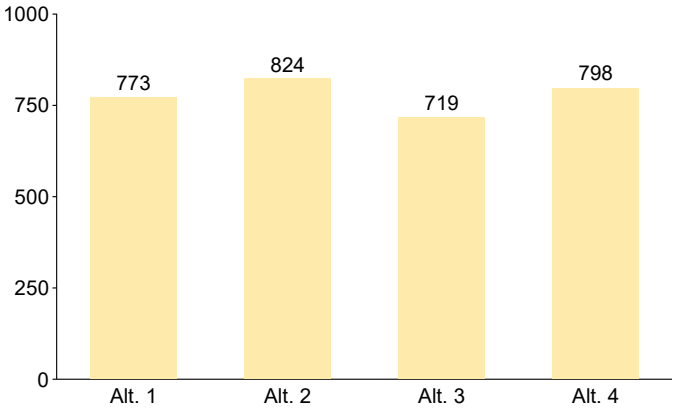
From our simulations for 2025, solar represents around 15 percent of electricity production in Estonia and wind around 20 percent. For comparison, in 2024 the share of solar was 17 percent and the share of wind was 20 percent. For the coming years, both solar and wind power are expected to increase both in terms of volumes and as a share of total production.

As mentioned above, the annual forecasting errors were 40 percent and 23 percent in 2024 for solar and wind power producers respectively. This means there is a significant risk for imbalance that needs to be included in the price. We expect producers to calculate the expected imbalance cost per MWh produced based on the probability of imbalance and include that cost in their bids to make sure the cost is recuperated.

For renewable energy producers, alternative 2 provides the greatest competitiveness, leading to the highest production levels, at 824 GWh and 1024 GWh for solar and wind respectively. This outcome is expected, as alternative 2 does not impose any costs on producers.

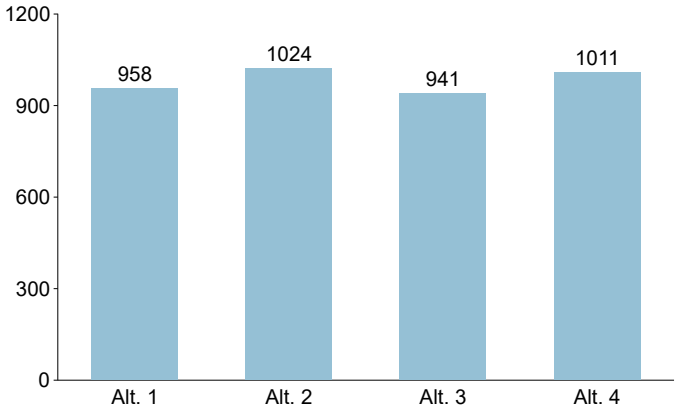
For the competitiveness of solar power production alternative 4, with a low production fee, is the second-best alternative resulting in a production of 798 GWh, followed by alternative 1 giving a similar 773 GWh. Alternative 3, with its high imbalance fee represents a large per MWh cost for solar production resulting in the lowest production of the four at 719 GWh of production.

Figure 5 – Simulated production from solar in 2025, GWh



For wind production, the 2.54 EUR/MWh cost in alternative 4 only reduces production by around 10 GWh compared to alternative 2. The cost under alternative 1 reduces production to 958 GWh and under alternative 3 to 941 GWh. The impact of the fee structure on wind power is significant, but lower than on solar power.

Figure 6 – Simulated production from wind in 2025, GWh

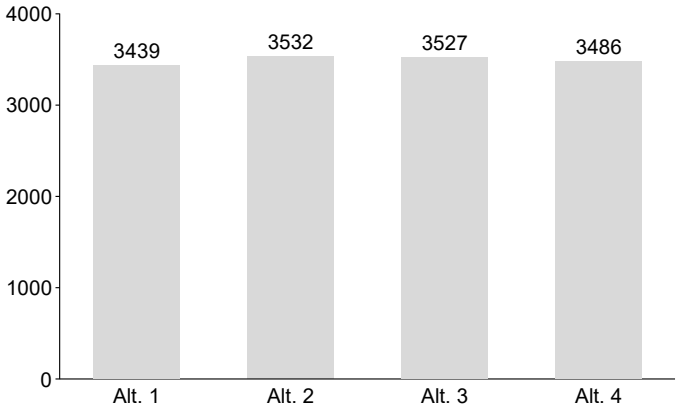


An additional issue with allocating a defined share of costs to the imbalance fee is the necessary inverse relationship between the imbalance fee and the imbalance volume. An argument used for imbalance fees is that it incentivises the BRPs to reduce their imbalance volumes which might reduce the costs for the TSO. When imbalance volumes are reduced, the imbalance fee must be increased to maintain the same revenue due to the balancing service cost structure, shown in chapter 3.1. While the probability for imbalances might be reduced for BRPs, the cost for imbalances is increased, resulting in the same per MWh cost for the BRP. Since the reduction in imbalance volumes is likely to differ between the analysed groups, more of the costs may be allocated to groups with higher imbalances. This effect will likely result in the costs for renewable energy producers increasing above the currently calculated levels and further reduce the competitiveness of solar and wind producers over time.

Quantitative assessment – Thermal power producers

For the remaining production, we have not distinguished between production technology and have assigned a low forecasting error of 1 percent. Under alternative 2 the rest of production totals 3.53 TWh, but like for wind power, the total production does not change much across the alternatives. Alternative 3 leads to a production of 3.53 TWh, practically the same as alternative 2, due to the low risk for imbalance. Alternative 4 gives a production of 3.48 TWh. Alternative 1 leads to the largest reduction in production at 3.44 TWh.

Figure 7 – Simulated production from other sources in 2025, GWh

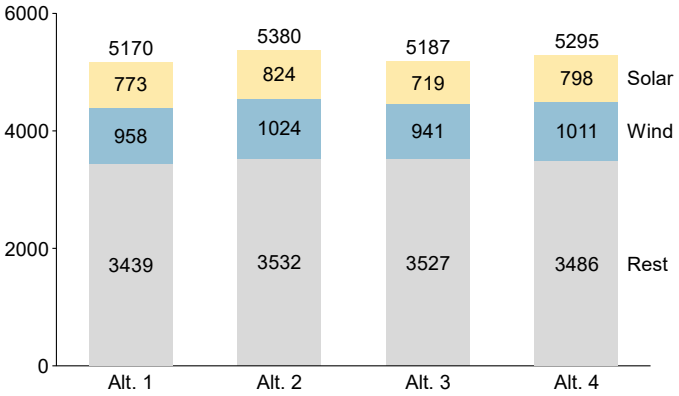


Due to the lower forecasting error for the remaining production, the ranking of the alternatives in terms of the resulting loss of competitiveness is more clear-cut and follows largely from the production fee.

Quantitative assessment – Producers overall

Placing all costs on consumers, alternative 2 is the best for production giving around 200 GWh more total production than the least beneficial, alternative 1, coming mostly from higher solar- and wind power production. When it comes to the other alternatives, there is a trade-off between what is the least harmful to renewable energy production, with higher forecasting errors, and other production technologies. Alternative 4 is less harmful to the competitiveness of renewables at the expense of other production. The opposite is true for alternative 3. Alternative 1, with a high production fee reduces producers' competitiveness the most but is still less harmful to renewable energy production than alternative 3.

Figure 8 – Simulated production by source in 2025, GWh



We note that since our analysis is based on simulated bidding curves, the exact thresholds might not reflect the behaviour of producers directly. Still, the insight that reductions in production can happen in leaps around certain thresholds is important to keep in mind. The ranking of the alternatives compared to one another is likely to remain true.

In the short term the fees will affect the production of existing plants. In the long term the fees can decide whether or not new plants get built, which is difficult to evaluate with certainty. Investment decisions will primarily depend on expected revenue, the capture price, and the costs of investment over its technical lifetime, the LCOE. Public policies can affect either of these to induce investments as well. Based on production data from Elering Live and price data from ENTSO-E, we calculate an average capture price for solar in 2024 of around 65 EUR/MWh (ENTSO-E, 2025). This corresponds to a capture rate of 74 percent given the annual average price in 2024 of 87 EUR/MWh. For wind, the average capture price was 72 EUR/MWh giving a capture rate of 83 percent.

Costs are often represented by the levelised cost of energy, or LCOE, which represent the estimated average cost per MWh over the technical lifetime of the project. The LCOE is difficult to estimate as it depends on a number of project specific factors.

Using the IRENA estimate of the LCOE for solar in 2023 in the Netherlands, the most comparable country in the dataset, at 52 EUR/MWh gives a 13 EUR/MWh margin (IRENA, 2024). The cost on solar from alternative 3 completely removes this margin, making new solar projects unprofitable. The other alternatives leave some margin for the producer.

For wind, IRENA estimates the LCOE to be 40 EUR/MWh in Europe which gives a 22 EUR/MWh margin. All alternatives leave some margin for the producers.

While long-term profitability calculations offer some insight, they do not fully capture the factors influencing investor decisions. We expect capture prices for wind and solar to decline in the coming years, mainly due to increased deployment of renewable projects, which will intensify price cannibalisation. In addition, general LCOE estimates do not always reflect the actual costs faced by individual projects and should be interpreted with caution. Overall, the future profitability of solar and wind in Estonia remains uncertain. Given that profit margins are expected to be relatively thin, assigning significant additional costs to these technologies could render some projects financially unviable.

2.4 Impact on retail market structure

An essential factor in deciding on an optimal fee structure is that its implementation is feasible and does not result in a significant financial burden for the market participants. According to the market participants we interviewed, there was until recently no legal way for BRPs to transfer the proposed fees to their customers. Without assessing the validity of their claims, this would have resulted in them having to bear the costs until the contracts with their customers expired and the fee could be included. The newly proposed amendments to the Electricity Market Act aims to remedy this, stating that: "*Consumers and producers shall pay the supplier a balancing capacity fee … The balancing capacity fee rate … must be displayed as a separate line item on the customer's invoice by the supplier, labeled as 'balancing capacity fee.*". For production and consumption fees, BRPs and retailers can pass through the costs in their entirety to their customers. We

therefore cannot see any impact of volume fees, as we expect the fee to be forwarded to customers in a transparent manner.

On the other hand, we cannot see that the imbalance fee is sufficiently transparent for it to be easily included in the Estonian customer's invoice. This is because imbalances are aggregated by the BRP and correctly allocating imbalances directly to individual customers is unrealistic. Based on insight from interviews with BRPs, we expect that the imbalance fee will be charged to customers based on a historical average for their group. In some cases, where the consumer or producer is sufficiently large, imbalance volumes can be accurately assigned. In most cases, however, this is unlikely. We fail to see that a fee based on aggregated average imbalance volumes fulfills the requirements for transparency.

As the imbalance fee cannot be transparently forwarded to customers regardless of BRP or retailer, we expect BRPs and retailers to carry this cost themselves through their margins. This may have an impact on the retail market structure.

Overall, we expect that imbalance fees harm competitiveness more than an equivalent fee on consumption and production volumes. Additionally, they will disproportionately harm renewable producers and smaller participants. Given the need for more renewable production this effect is counterproductive. These points are explained further below.

Cost of imbalance fee larger than the fee itself

Since imbalance volumes are difficult to assign to individual households or production units in real time, BRPs must charge customers based on expected imbalance costs, relying on historical forecasting errors. If current imbalances exceed past levels, the BRP must cover the difference until the new risk is factored into contracts. This adds uncertainty, especially for new clients without historical data, requiring BRPs to use market averages.

Risk-averse BRPs and retailers are likely to minimise uncertainty by applying a markup to the expected imbalance fee. This additional risk premium means customers may end up paying more than the actual imbalance cost. The additional risk premium on top of the average cost per MWh has not been included in our simulation, but they are likely to be correlated with the size of the imbalance fee and harm competitiveness further.

As an example to illustrate this point, imagine a BRP with a solar producer as a customer. The BRP will charge the producer directly according to the production fee. In addition, the producer will have imbalances due to their forecasting errors, being 40 percent on average in 2024. A risk neutral BRP will charge the producer an additional 40 percent of the imbalance fee per MWh produced on average to make up for this cost. This mark-up will mean that on average the BRPs costs are covered, but they will not be guarded by unforeseen increases in imbalance volumes. If in a single month imbalance volumes are twice as high as expected, the BRP must cover the additional imbalance costs. The risk for this occurring will lead BRPs to include a risk premium in their margins. This risk premium will depend on the BRPs risk appetite and is difficult to estimate, but the result is that the total cost is higher than the direct costs from the fees.

At the other end, producers of thermal power are expected to have fairly low forecasting error rates leading to lower costs per MWh for the BRPs. We therefore expect BRPs to charge a lower mark-up making costs lower per MWh of thermal power generated compared to solar power.

Smaller actors may be at a disadvantage with an imbalance fee

Smaller BRPs and producers face a disadvantage due to imbalance fee uncertainty. Large market participants can spread risk across a broader portfolio, stabilising costs. In contrast, smaller solar and wind producers risk persistent, unpredictable costs, which larger conglomerates can offset with revenues from other sources.

Alternative 3 is particularly challenging for small producers, while alternative 1, 2 and 4 has a milder effect due to their

lower imbalance fee. For BRPs, size provides a clear advantage by reducing income- and cost variability and enabling cross-subsidisation between production and BRP services. Larger BRPs may also charge inelastic consumers more while offering lower fees to large consumers, attracting higher volumes.

In short, the imbalance fee structure favours larger market participants, making market access harder for smaller BRPs and renewable producers.

2.5 Overall impact on retail and wholesale market

Introducing an additional fee to the market participants will increase their costs and change their demand or supply of electricity. Consumers will demand less electricity due to the price they pay increasing while producers will need a higher price to make up for the increased marginal cost. The likely outcome is a reduction in both consumption and generation. Since the Estonian power market is a part of the European electricity market and more locally, the Baltic market, the Estonian power price is not set by the Estonian market participants alone.

The effects on the competitiveness of consumers are expected to be linear. The competitiveness of producers on the other hand depends on how close the margin the producers are.

Based on the methodology described in chapter 2.1 we have calculated the following costs for consumers, solar, wind and remaining producers per MWh in Table 5.

Table 5 – Estimated costs different market participants in the four alternatives, EUR/MWh

	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Consumption	5.35	8.49	6.21	7.06
Solar	5.57	0.26	13.69	2.65
Wind	5.46	0.15	7.86	2.54
Rest	5.32	0.01	0.34	2.40
Avg. Prod.	5.38	0.07	3.85	2.46

Since the costs must be covered by consumption and production, what is beneficial for one side is detrimental to the other. Within production, we also make the distinction between renewable energy and remaining production because renewable energy has a higher forecasting error and thus faces higher costs from the imbalance fee.

Another insight from our analysis is that fees placed on producers are not fully transferred to consumers through the spot price. This is because the power market is open to outside competition who might not face a similar fee. Most of the cost producers face will reduce their margin resulting in lower volumes, as seen above, and reduced profits.

Table 6 present consumption and production volumes simulated with the different alternatives in 2025. The simulations illustrate that renewable energy producers are the most affected regardless of the alternative. Unsurprisingly alternative 2, where no costs are placed on production is the most favourable to producers in general.

Table 6 – Simulated volumes in 2025 under each alternative, GWh

	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Cons.	**8718**	**8688**	**8709**	**8702**
Solar	773	824	719	798
Wind	958	1024	941	1011
Rest	3439	3532	3527	3486
Total Prod.	**5170**	**5380**	**5187**	**5295**

Static analysis – direct impact

Alternative 1 benefits consumers the most, followed by alternatives 4, 3, and 2. For solar, alternative 2 is the best, followed by 4 and 3. Alternative 3 is the least favourable. Wind production sees the greatest benefit under alternative 2, alternative 4 not far behind and alternatives 1 and 3 giving significant reductions in production.

For total production, alternatives 2 and 4 are comparable, while alternative 1 lead to the largest reduction due to its significant production fee. Choosing the best alternative for retail market competitiveness is challenging as market participants have conflicting interests. However, alternatives 2 and 4 are preferable due to predictable volume fees and their support for Estonian production competitiveness. While alternative 1 benefits consumers, it harms production.

For the retail market structure, alternative 3 leads to the most harm. This due to the uncertainty associated with forecasting. Firstly, high imbalance fees can generate great unexpected costs. To make up for this, we expect BRPs to charge a risk premium in addition to the average cost. The total cost is therefore higher than what we have calculated above. In addition, larger BRPs and market participants will be advantaged as the risk can be dispersed over a larger volume.

Another issue is that renewable production, which has a higher forecasting error, will face a higher cost from BRPs than other producers, since they generate the most imbalances.

In the short term, we expect that BRPs are unable to transfer the imbalance fees to their customers meaning that they must bear the cost themselves. This point is explored in Chapter 4.

Dynamic analysis – indirect effects

Costs influence producers' marginal costs and consumers' electricity demand, ultimately impacting the spot price. In this sense, whether a fee is placed on production or consumption is theoretically irrelevant, as the cost is reflected in the spot price and distributed accordingly. However, Estonia's electricity market is not a closed system. With cross-border electricity trade and different elasticities, the allocation of fees between production and consumption affects who ultimately bears the cost.

According to general taxation theory, the efficiency losses related to residual charges may be minimised by applying Ramsey pricing. Ramsey pricing implies that the residual costs for a service are allocated among users according to their price elasticity. The higher the price elasticity, the lower is the share that the user should pay, and vice versa. Allocation of residual costs according to this principle will minimise the distortive effects on the total production and consumption of electricity.

Assigning costs to the least elastic side of the market results in the smallest behavioural distortions. Conversely, placing fees on the most elastic side leads to greater changes in behaviour, causing economically viable activity not to take place and thus a greater loss in socio-economic welfare.

In the short term, demand is expected to be the least elastic. If a fee is placed on consumption, consumption will fall. This results in a loss of socio-economic welfare, as the benefit of this consumption is larger than the marginal cost of production. As the demand reduction is limited, so is the welfare loss.

However, if the costs are assigned to production, which is more elastic, production will have a larger fall. Since production have

a larger reduction, the Estonian socio-economic welfare loss is larger than if the costs were assigned to the more inelastic demand. Economic theory then suggest that costs should primarily be allocated to consumption.

In the longer term, which of consumption and production is more elastic is more uncertain. Power-intensive industries may be price-sensitive and could choose to locate elsewhere if the consumption fee is high. An EU-wide study finds a significantly higher long-term price elasticity, especially for power-intensive industry, Similarly, investment in new generation could be deterred by higher production fees, especially given that profitability is already tight for some projects. With these uncertainties, it is not clear how Ramsey pricing would guide the cost allocation in the long run.

While the imbalance fee harms the retail structure in the short term, some benefits can be envisioned in a dynamic setting. Biggest of all is the potential that a high imbalance fee will lead to a reduction in the imbalance volumes through improved forecasting. It is, however, unclear whether this will reduce the procurement costs for Elering since only parts of the reserved capacity may be dimensioned based on imbalances.

3 Competitiveness in Baltic balancing capacity markets

On the 5th of February 2025, the Baltic TSOs launched the Baltic balancing capacity market. The Baltic capacity markets consist of three products: mFRR (Up/Down), aFRR (Up/Down) and FCR. Each day, suppliers submit bids for delivering the required service for these products on an hourly basis for the following day. Several factors influence these bids, with spot prices and marginal costs being among the most significant.

In this chapter we analyse, both qualitatively and quantitively, how the different fees may impact Estonian competitiveness in these Baltic balancing capacity markets.

3.1 Methodology and data

Methodology

Bids for balancing capacity products respond differently to fluctuations in spot prices and marginal costs. In general, suppliers aim to price their bids based on the alternative value of having their capacity available for regulation. For instance, a bid for upregulation reflects the opportunity cost of withholding capacity from the spot market to be available for upregulation. Instead of offering the capacity for balancing, a supplier could utilise it in the spot market to earn revenue from production. The bid therefore seeks to compensates for the lost profit that the supplier would have otherwise gained from participating in the spot market.

To estimate the impact of different balancing service cost allocation alternatives, we assume that suppliers bid based on the difference between spot prices and marginal costs. Using this approach, we construct a supply curve that represents the expected bidding behaviour of various suppliers. Figure 9 gives a simplified illustration of this relationship, while Figure 10 shows how it may look in practice. Looking at Figure 10, it is important to remember that suppliers place bids in the capacity markets without knowing the spot price, having to estimate this price in their bids.

Figure 9 – Simple illustration of connection between spot price, marginal costs and capacity market bid for up- and down regulation

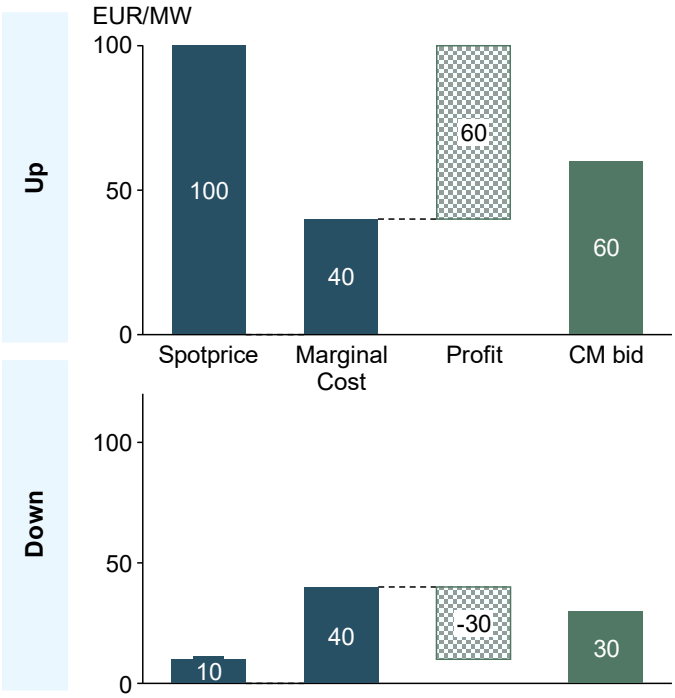
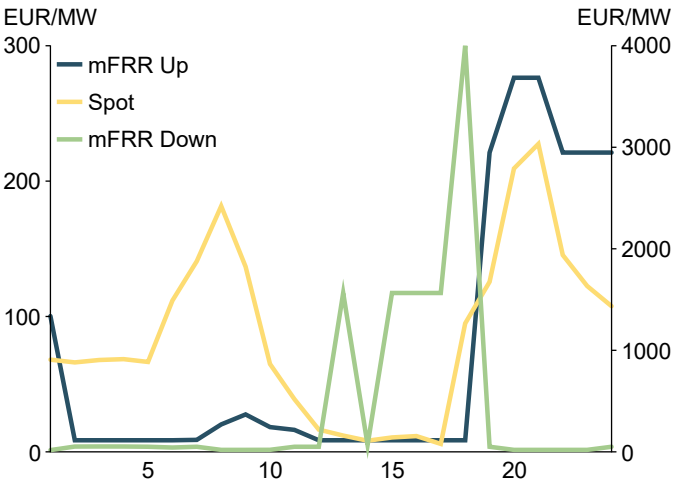


Figure 10 – Spot and mFRR capacity prices 8th of April 2025 (mFRR Down on right axis)



Source: Baltic Transparency Dashboard (2025)

When the supply curve is set, we must determine the demand. For FCR and aFRR, demand is fixed for a year. FCR is dimensioned based on the reference incident in continental

Europe, being 3000 MW and then distributed to each TSO based on their share of the sum of production and consumption (Elering, 2020). FRR is dimensioned to cover imbalances 99 percent of the time and at least covering the reference incident in each direction. Imbalances simulated to happen within 1- and 15-minute period will be dimensioning for aFFR, while mFRR will cover the rest of FRR dimensioning. To set the mFRR demand, we will use the average historic demand for mFRR in each direction.

Once the market outcomes for the different products are established, we assess the effects of alternative fee structures by incorporating the respective fees into the suppliers' cost structures. Specifically, we apply the fees to Estonian suppliers and measure the resulting changes to allocated volumes among the Baltic suppliers. Here, the expected fees for Latvian and Lithuanian suppliers are also taken into account, like described in chapter 2.1.

It is important to note that these estimations rely on simplified market modelling, and the results must be interpreted carefully. There are large uncertainties regarding the mix of suppliers, their marginal costs and their bidding strategies. In addition to the uncertainties, the markets are relatively small, making them sensitive to changes in assumptions. The results do however indicate the direction of the change and their relative impact to the other alternatives.

Data

The supply curve is derived from THEMA's Market Model for the Baltic region, incorporating assumptions about generation capacity, technology types, and marginal costs. Additionally, we estimate what proportion of each generator's capacity is allocated to different capacity markets. Spot prices used to calculate opportunity costs are based on results from THEMA's Baltic Market Outlook on an hourly basis for 2026.

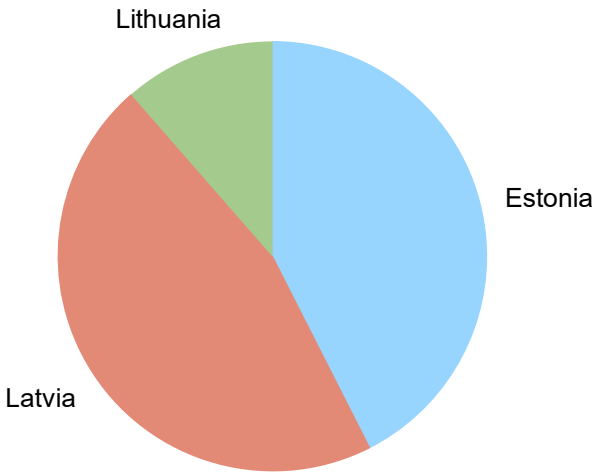
The demand for Baltic capacity markets is determined based on distinct criteria for each product. For FCR and aFRR, demand is set according to 2025 volumes, being 23 MW and 100 MW respectively. For mFRR, volumes are determined based on the average historical demand, being 726 MW for mFRR Up and 483 MW for mFRR Down (Baltic TD, 2025). Then, aFRR was not purchased in this period, which we expect would have reduced the purchase of mFRR. For our analysis, we have reduced the historical average mFRR demand with the aFRR demand of 100 MW.

3.2 FCR market competitiveness

Market overview

The Baltic TSOs require 23 MW of FCR capacity, with Estonian market participants emerging as the primary suppliers. As shown in Figure 11, Lithuania has contributed approximately 10 percent of the procured volumes, while Latvia and Lithuania have each accounted for around 45 percent. Given the small FCR demand, daily procurement tends to be dominated by a single country or even a single supplier.

Figure 11 – Baltic FCR market volume distribution 2025



Source: Baltic Transparency Dashboard (2025)

Qualitative assessment: Effect on FCR competitiveness

For most of the time, a fee will increase balancing capacity suppliers' costs, leaving them less competitive in the Baltic balancing capacity market. However, in some instances, the Estonian suppliers may be more competitive. For energy

storage units, we assume they are subject to production fees, where applicable, but not consumption fees.

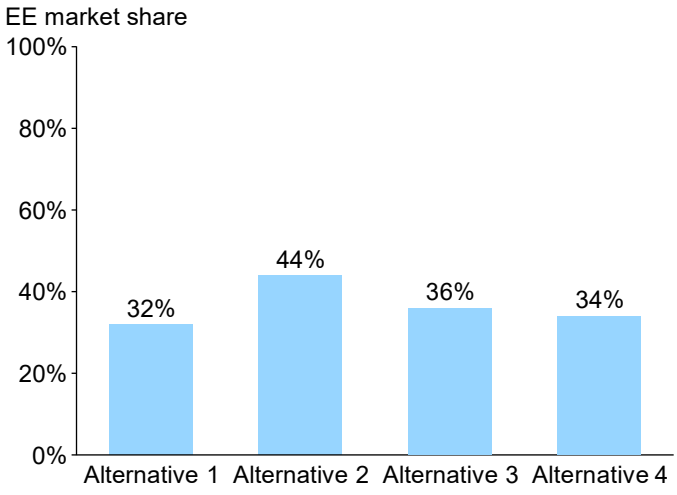
FCR, being symmetrical, may require production units to withhold capacity or operate at a loss to be ready for both up- and downregulation. Energy storage units may be particularly suited for FCR due to their rapid response capability and FCR response expected to incur the least amount of degradation to the unit among the balancing services.

Alternative 1 imposes the highest costs on both energy storage and thermal power plants, likely reducing Estonian competitiveness the most in the FCR market.

Quantitative assessment: Effect on FCR competitiveness

As energy storage adoption increases, fee structures will likely play a more significant role in FCR market dynamics. Latvian and Lithuanian energy storage units benefit from a consumption fee exemption, making Estonian providers less competitive. However, the impact of these alternatives is relatively similar in our estimation. Alternative 1 reduce Estonian volumes the most, having thermal power plants and energy storage units cost increase the most.

Figure 12 – Estimated Estonian FCR market share under the different alternatives

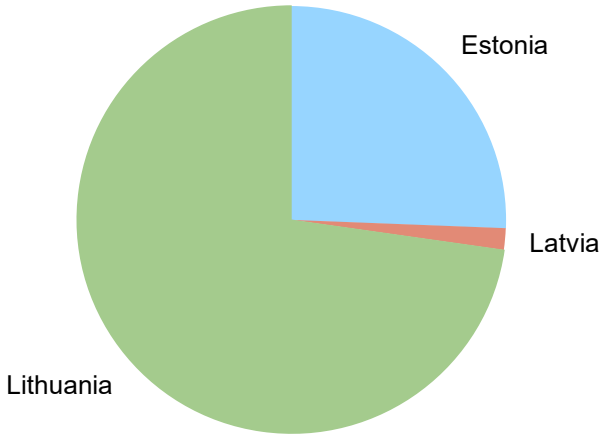


3.3 mFRR market competitiveness

Market overview

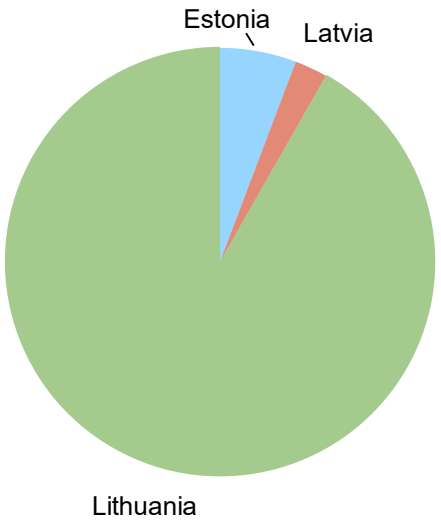
Lithuanian suppliers have predominantly covered both mFRR Up and Down markets. Estonia's participation in the mFRR Up market stands at roughly 25 percent, shown in Figure 13 primarily driven by Elering's Kiisa power plant, which submits zero-cost bids. Consequently, Elering effectively meets most of its own mFRR Up demand. In contrast, mFRR Down has been overwhelmingly supplied by Lithuanian participants, covering over 90 percent of volumes, while Estonian contributions remain marginal, shown in Figure 14.

Figure 13 – Baltic mFRR Up capacity market volume distribution 2025



Source: Baltic Transparency Dashboard (2025)

Figure 14 – Baltic mFRR Down capacity market volume distribution 2025



Source: Baltic Transparency Dashboard (2025)

Qualitative assessment: Effect on mFRR Up

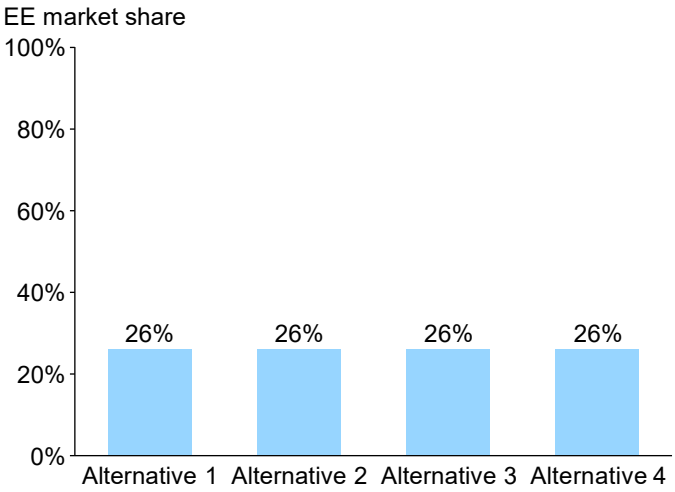
In the mFRR Up market, fees could enhance Estonian competitiveness by lowering opportunity costs. Higher production costs reduce the profitability of selling electricity in the spot market, making it more attractive to reserve capacity for balancing services. Given the 12.5-minute Full Activation Time (FAT) requirement, non-operating power plants are likely able ramp up quickly to participate.

Alternative 1 is expected to provide the largest competitive advantage for Estonian suppliers in mFRR Up by reducing the opportunity cost the most. However, since Elering meets most of Estonia's demand through Kiisa, the potential market impact may be limited. If there is a phase-out of the use of Kiisa, the market impact will be larger but still see Lithuanian suppliers very competitive.

Quantitative assessment: Effect on mFRR Up

In our estimation, the volume distribution between the Baltic states remains stable as we apply the different fees, as seen in chapter 2. The Estonian market share remains constant and equal to what we believe the Kiisa power plant contribute to the market. Other than the Kiisa power plant, we see that Lithuanian hydro power will remain very competitive, continuing to dominate the market.

Figure 15 - Estimated Estonian mFRR Up market share under the different alternatives



Qualitative assessment: Effect on mFRR Down

In the mFRR Down market, suppliers submit bids based on the opportunity cost of being available for downregulation. Producers with ongoing spot market participation typically have minimal opportunity costs, resulting in lower bids. However, producers that are "out-of-the-money" in the spot market may accept short-term losses to offer mFRR Down capacity.

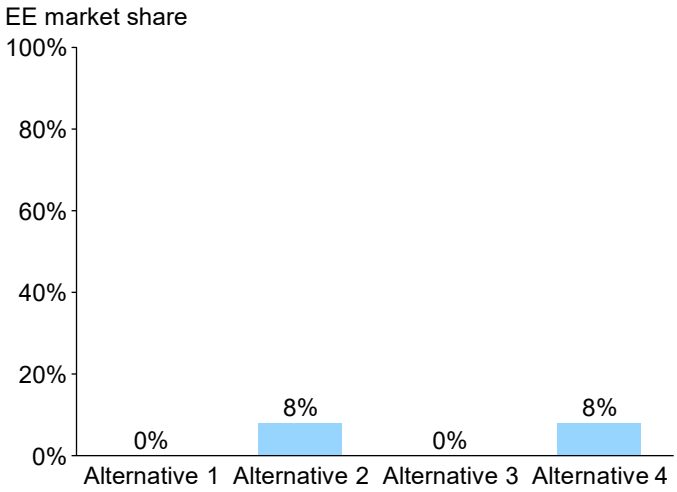
Introducing a production fee is expected to reduce Estonian competitiveness in mFRR Down, as it raises production costs. Alternative 1 imposes the highest production fee and is thus anticipated to have the most negative impact. Alternative 3 introduces an imbalance fee, significantly affecting variable renewable electricity producers. The relative competitiveness of alternatives 1 and 3 depends on the extent to which solar and wind power participate in mFRR Down.

Quantitative assessment: Effect on mFRR Down

For mFRR Down, we see the different fees influence the volume distribution. Before applying the fees, we saw Estonian wind and solar power being competitive. As we apply the fees, they lose competitiveness to Latvian and especially Lithuanian

suppliers. In our calculations, the already modest Estonian mFRR Down share disappears as the fee on producers get too high.

Figure 16 - Estimated Estonian mFRR Down market share



3.4 aFRR market competitiveness

Market overview

The capacity markets for aFRR went live in April. In this market, too, Lithuanian suppliers are dominating. As shown in Figure 17 and Figure 18, Lithuanian suppliers covered about 60 percent of both markets. Estonian suppliers have been more successful in aFRR Down, while in aFRR Up, Estonian and Latvian suppliers have provided about the same volumes.

Figure 17 Baltic aFRR Up capacity market volume distribution 2025

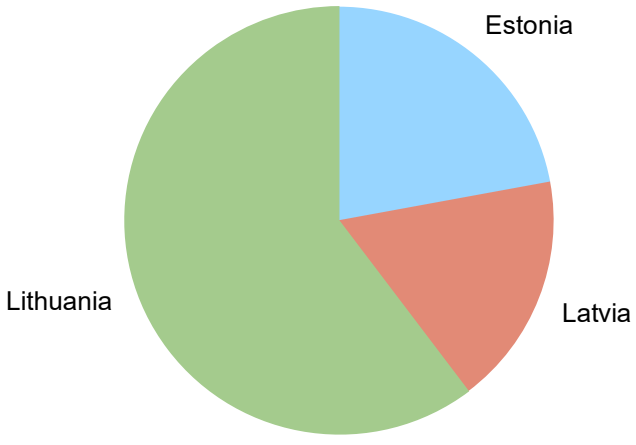
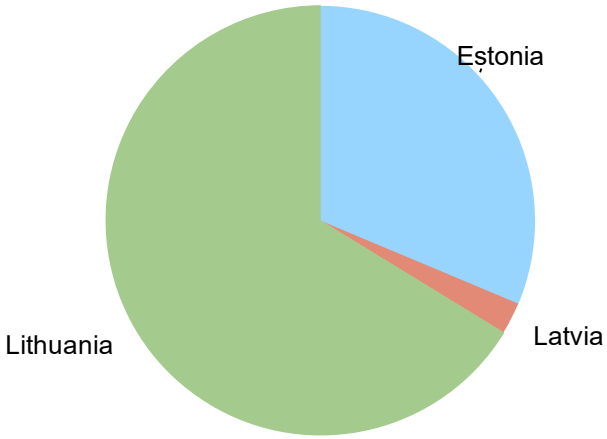


Figure 18 Baltic aFRR Down capacity market volume distribution 2025



Source: Baltic Transparency Dashboard (2025)

Qualitative assessment: Effect on aFRR Down

As for mFRR, aFRR is an asymmetric product with markets for up- and down-regulation. For aFRR down, market dynamics mirror those of mFRR Down. A production fee is expected to reduce competitiveness, and the relative impact of alternatives 1 and 3 depends on solar and wind power participation.

Quantitative assessment: Effect on aFRR Down

For aFRR Down, the effect is similar to the one for mFRR Down. Here, competition from the other Baltic states is high, especially from their hydro power plants. Again, alternative 1 and 3 have the largest negative impact, as they affect wind and solar power plants the most.

Figure 19 - Estimated Estonian aFRR Down market share under the different alternatives

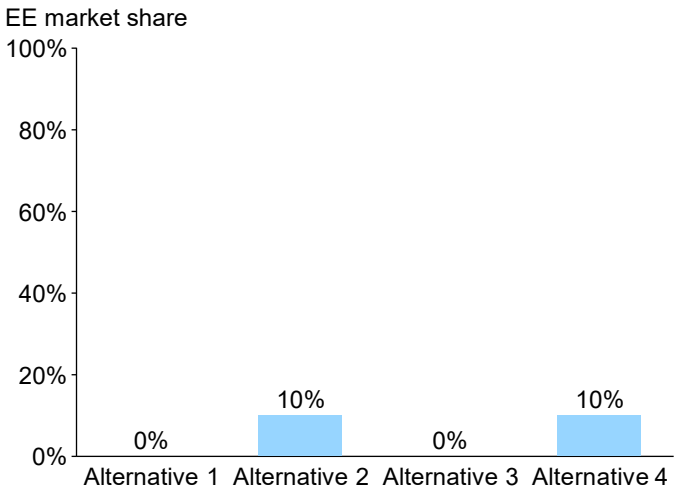
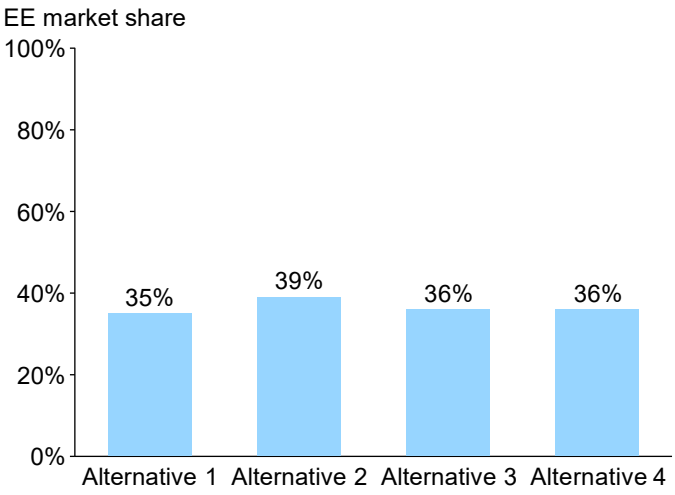


Figure 20 - Estimated Estonian aFRR Up market share under the different alternatives



Qualitative assessment: Effect on aFRR Up

With a shorter FAT of 5 minutes, aFRR Up may require certain power plants to maintain some production to meet ramp-up constraints. If spot prices fall below a plant's marginal cost, it may incur spot market losses to remain available for aFRR Up. Consequently, we expect higher aFRR Up prices not only during peak demand periods but also when spot prices are low.

Fees are expected to negatively impact Estonian competitiveness in aFRR Up, particularly for thermal power plants, which are more frequently "out-of-the-money." Alternative 1 has the most substantial negative impact due to its high cost burden on both thermal plants and energy storage units.

Quantitative assessment: Effect on aFRR Down

Simulations indicate that Alternative 1 reduces the Estonian market share in aFRR Up the most, due to the increased costs for thermal power plants and energy storage. Alternative 3 and 4 also leads to a decline relative to alternative 2, despite the expectation that the imbalance fee is primarily not borne by thermal power plants and energy storage.

3.5 Summary: Impact on Estonian competitiveness in balancing markets

Overall, balance service fees negatively impact Estonian actors' competitiveness in the Baltic balancing capacity markets. While mFRR Up may see some competitive benefits due to reduced opportunity costs, the dominance of Kiisa and high competitiveness of especially Lithuanian pumped hydro power plants limits the overall market effect. Alternative 1 imposes the most substantial burden on Estonian suppliers, particularly affecting thermal power plants and energy storage. Alternative 3 also presents significant challenges, especially for solar and wind power producers in down regulation markets. Alternative 2 is expected to have the least impact, as it does not increase costs for producers or energy storage, which is expected to be the main suppliers of balancing capacity in Estonia.

Table 7 – Summary of estimated Estonian market share in Baltic capacity markets under the different alternatives

Market	Alt. 1	Alt. 2	Alt. 3	Alt. 4
FCR	32 %	44 %	36 %	34 %
aFRR Up	35 %	39 %	26 %	26 %
aFRR Down	0 %	10 %	0 %	10 %
mFRR Up	26 %	26 %	26 %	26%
mFRR Down	0 %	8 %	0 %	8 %
Average	**19 %**	**25 %**	**18 %**	**21 %**

4 Feasibility of alternatives

The third criterion for Estonia's choice of fee structure is the feasibility of each alternative. With feasibility, we investigate the ability of BRPs and retailers to pass on costs to their customers. In our evaluation, we assume that the current iteration of the amendments to the Electricity Market Act, supplied by Elering, will be passed.

4.1 Method and data

Methodology

The feasibility of each alternative will be assessed based on our expectation of BRPs and retailers' ability to forward these fees to their customers. First, we assume the volumes on different types of contracts. Here, we distinguish between three types of contracts:

1. Contracts with a contract period one year and above
2. Contracts with a contract period below one year
3. Contracts directly forwarding BRP fees to customers

These three types have different abilities to pass on BRP cost. For Type 3, the BRPs have it easiest, directly forwarding cost to their customers, being very susceptible to changes in volume fees. However, imbalance fees are more difficult to attribute to a single customer and they are hence not able to pass it on. With Type 2 we assume they are able to pass on the cost throughout the year, but not necessarily directly as the change in fees happen. Here we assume that Elering publish updated fees 3 months in advance of a change and that BRPs and retailers will gradually be able to pass on costs. For Type 1, we assume that the BRP/retailer will have to bear the fees themselves.

The same is done for the production side. Here, our impression is that BRPs are most often also the producers and that the producers not being BRPs have contracts with very short contract periods if any. On the production side, we assume the difficulties arise with Power Purchase Agreements (PPAs). Therefore, we here assume the share of production on a PPA, where the cost of balance service fees may not be forwarded.

With the assumed abilities to forward BRP fees, we estimate how much of the 60 MEUR costs that will not be passed on to customers. Feasibility will be evaluated based on the sum of each alternative we estimate that BRPs/retailers are not able to pass on to customers.

Data

The consumption volumes on each contract type are estimated based on interviews with market participants. There are large uncertainties, and we have therefore chosen to create two scenarios on how the volumes are distributed. These scenarios are shown in Table 8, with the low scenario expecting low ability to pass on BRP fees and the high scenario expecting the opposite. For production, we expect a low rate of PPAs. This is due to relatively small power intensive industry.

Table 8 - Scenarios for share of different contract types

Contract type	Low scenario	High scenario
Consumption		
≥ 1 year	60 %	40 %
< 1 year	30 %	45 %
Directly forward	10 %	15 %
Production		
PPA	20 %	10 %
Non-PPA	80 %	90 %

4.2 BRPs and retailers' ability to forward costs

The currently proposed amendments to the Electricity Market Act clarify that the balancing fees should be collected by the BRPs from consumers and producers. The BRPs are required to display the fee as a separate line labelled "balancing capacity fee" in the client's invoice. This is to ensure transparency and make it easier to identify when changes are made to the fees.

Under this amendment, it is our understanding that BRPs are allowed to re-open fixed price contracts they have with consumers and include the cost in any existing PPA contracts. This would allow BRPs to pass on the entirety of the production and consumption fees to their customers. In essence this means that alternatives 1, 2 and 4 are equally feasible as BRPs and retailers can pass on most of the cost directly to their customers.

Since the imbalance volume for each customer is unknown and varies between and within categories, including it transparently in the balancing capacity fee that BRPs charge customers will be challenging even under the current iteration of the amendment. We then expect that the cost must be borne by the BRPs or retailers until they are able to include it in their contracts and margins.

Alternatives 1, 2 and 4 have an imbalance fee of 0.81 EUR/MWh, where we expect that the cost must be borne by BRPs until all existing contracts lapse. Since the fee only represents one percent of total costs, the effect is unlikely to be economically significant. Alternative 3, with half of costs collected through imbalance fees, creates a significant burden for BRPs and retailers.

The cost to the BRPs will depend on their client portfolio and more specifically the length of their contracts. For BRPs with mostly variable price contracts, the cost can be transferred relatively quickly. For BRPs with mostly fixed price contracts, they must bear the costs until the end of the contract. For contracts with consumers which can last seven years, the accumulated cost for the BRP is significant. This difference in the BRPs ability to pass on imbalance to their customers was clear from the interviews we conducted.

To quantify the cost for BRPs, we distinguish between three types of contracts for consumers: 1) Contracts with a period above one year, 2) with a period below a year, and 3) contracts directly forwarding volume fees. Given the uncertainties regarding the volumes of these contracts, we define one scenario where the ability to pass on cost are low, and one scenario with high ability to pass. The results are displayed in Table 9.

Table 9 Estimated total costs BRPs cannot pass on, million EUR

	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Low scenario	0.2	0.2	13	0.2
High scenario	0.4	0.4	21.6	0.4

With the scenarios we have set up, described in chapter 4.1, we estimate that alternatives 1, 2 and 4 are equally feasible as the BRP bears little cost. We estimate the costs to be between 0.2 and 0.4 million EUR, and we therefore consider it feasible. Under alternative 3, under which half of costs are collected through the imbalance fee, the BRPs incur a significant cost, between 13 and 21.6 million EUR, that cannot be passed onto customers invoices. Based on this, alternative 3 is significantly less feasible than the other alternatives.

5 Comparative analysis

We have analysed four alternatives for allocation of balancing capacity costs based on three criteria. In this chapter we summarise our findings and evaluate the overall impact of the different alternatives. Lastly, we discuss the alternatives in relation to other objectives.

5.1 Summary of findings

The first criterion is competitiveness in retail markets. We calculated the fees for different market participants while considering the simulated spot price effect. The results show varying impacts across alternatives, with a relatively small effect on spot prices. Results are illustrated in Table 10.

For consumers, alternative 1 is the most beneficial, imposing the lowest fees but slightly increasing generation costs and spot prices. Alternative 2 is the least favourable, placing all costs on consumers without significantly lowering spot prices.

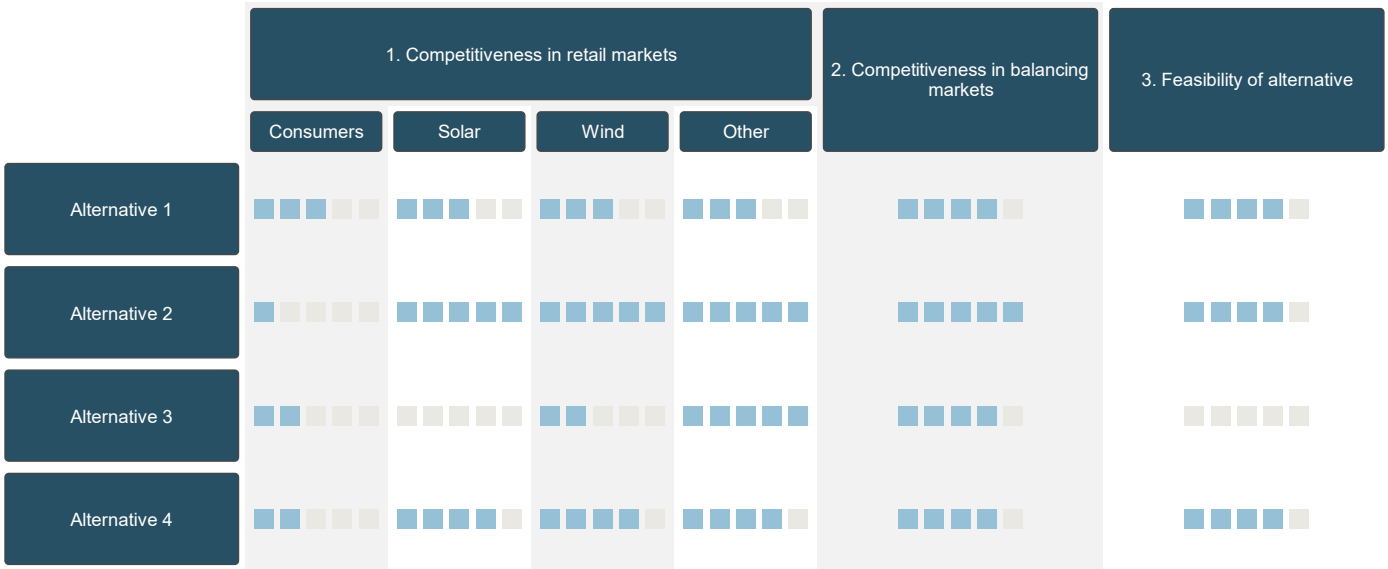
For producers, alternative 2 is preferred as it exempts them from fees without major demand or price reductions. The least favourable option depends on generation type. Solar and wind face high imbalance fees under alternative 3, reducing output by about 10 percent. On average, alternative 1 is the worst for producers, leading to the largest drop in generation and profitability for the producers.

The imbalance fee also creates financial uncertainty, requiring BRPs, retailers, and producers to price in risk, further amplifying its impact. Smaller market participants are more vulnerable due to difficulties in managing larger forecasting errors. Additionally, market participants already face imbalance penalties through the imbalance price.

The second criterion is competitiveness in the Baltic balancing capacity markets. We estimated Estonia's market share across the different Alternatives. All alternatives negatively impact Estonian balancing capacity suppliers, particularly in the mFRR and aFRR Down markets, where higher marginal costs reduce competitiveness. Alternatives 1 and 3 are the most harmful, depending on solar and wind participation in down-regulation capacity markets, but the differences between the alternatives are small

The final criterion is feasibility. Under the proposed amendments to the Electricity Market Act, fees are to be collected via a separate line on invoices for customers or producers. Alternatives 1, 2 and 4 are the most feasible. The imbalance fee is harder to pass on, as customers' contributions to imbalances are unclear from a BRP's perspective. Without a direct pass-through mechanism, BRPs/retailers must raise

Table 10 Summary of alternatives' impact on each criterion (1 – least beneficial, 5 – most beneficial)



margins to cover costs. Alternative 1 has a relatively low imbalance fee and appears manageable, while alternative 3 may impose a significant financial burden on BRPs and retailers.

5.2 Discussion

Polluter pays principle

The polluter pays principle in this context says that the market participants causing the costs should be held responsible for it. As discussed, it is hard to attribute the costs to individual market actors, as the costs of procuring balancing services are largely based on reference incidents. All market participants benefit from procuring balancing capacity, as it increases system security. Maybe the most straightforward option would then be to distribute the cost by having an equally large volume fee, as both consumers and producers benefit from a reliable power system. For some of the products, it is however clear who or what is driving costs.

FCR is dimensioned based on the reference incident, allocated to each TSO based on the production and consumption in their area. This means that, all else equal, a MWh of extra production or consumption will increase balancing capacity costs, as a larger share will be allocated to Elering. With this dimensioning methodology, having a uniform volume fee as in the current methodology, is in line with the polluter pays principle.

For aFRR, imbalances within the 15-minute period will set the demand. As market participants are metered every 15 minutes, it is impossible to observe a single market participants imbalance in this timeframe. Accurately assigning responsibility for aFRR costs is therefore very difficult.

mFRR, on the other hand, may be dimensioned based on observable imbalances. However, mFRR is dimensioned as the largest of simulated imbalances and the reference incident. To be in line with the polluter pays principle, an imbalance fee should cover the costs incurred when imbalances are setting the demand for reserves. When reference incidents are setting the demand, market participants cannot be held accountable for incurred costs.

In sum, to be fully in line with the polluter pays principle, some of the mFRR costs should be covered by an imbalance fee, but not all. FCR costs should be covered by a volume fee, while it is unclear who is responsible for aFRR and partially mFRR costs.

Imbalance vs. volume fee

This report highlights the potential drawbacks of a high imbalance fee, particularly for certain market participants. Solar and wind power would face significant costs per MWh, making new renewable projects less viable, an issue given Estonia's power deficit and 2030 renewable energy targets. A volume fee will distribute the cost more evenly among different types of producers.

However, an imbalance fee also has potential benefits. Higher penalties could incentivise BRPs to improve forecasting, reducing reliance on Elering for system balancing and lowering overall system costs. Since BRPs already cover most balancing costs through imbalance pricing (mFRR or volume-weighted aFRR activation prices), the key question is whether the added incentives of an imbalance fee outweigh its negative effects.

While solar and wind contribute significantly to imbalances and should share balancing costs, imbalances alone do not drive all balancing capacity needs. FFR dimensioning accounts for major outages from power plants, large consumers, or HVDC connections, meaning costs persist even with perfect forecasting (Elering, n.d.). An excessive imbalance fee would therefore contradict the polluter-pays principle.

The Baltic ministries aim to harmonise balancing cost allocation by 2027, with Latvia and Lithuania planning to allocate 50 percent of costs to an imbalance fee. If Elering opts for a different approach, negotiations may be necessary. A potential compromise could be for Elering to adjust their desired model to include an imbalance fee that is in line with the polluter pays principle. That is, all Baltic TSOs implement a methodology

allocating the forecasted balancing capacity costs driven by normal imbalances through an imbalance fee.

5.3 Conclusion

The polluter pays principle suggests that system costs should be distributed in a way that reflects market participants' contribution to those costs. Accordingly, part of the costs could be covered by a volume fee, as FCR is dimensioned based on Estonian volumes, and parts by an imbalance fee, as mFRR for periods may be dimensioned based on imbalances. A large portion of the total costs are however related to reference incidents and short-term imbalances, which will have to be covered by a residual fee if in line with the polluter pays principle.

One option is to recover residual costs through an imbalance fee. However, this approach presents several challenges. First, it is difficult for BRPs to pass imbalance fees on to end customers, since it is not transparent how individual consumers contribute to imbalances. Moreover, large imbalance fees introduce uncertainty for market participants, as they cannot accurately predict the frequency or size of their imbalances despite efforts to stay balanced. To mitigate this risk, BRPs and retailers are likely to include a risk premium into their pricing, potentially raising margins beyond the expected cost of imbalances.

An additional concern is that imbalance fees would disproportionately affect renewable energy producers, whose output is more variable and less predictable. As a result, high imbalance fees could make it more difficult to meet Estonia's renewable energy targets.

Given the lack of feasibility, likely addition of a risk premium, and renewable energy targets, a large imbalance fee, as in alternative 3, appears not to be a suitable method for covering residual costs.

From a Ramsey pricing perspective, residual costs should be placed on the least price-elastic side of the market to minimise welfare loss. Price elasticity vary within production and consumption, but we assume residential consumption to be the least elastic. The first-best solution would involve a differentiated consumption fee, where the most inelastic consumers, likely being the residential consumption, bear a larger share of the cost. However, implementing such differentiation may not be feasible in practice.

When choosing a flat fee, on either consumption, production, or both, we must assess which side is less elastic. In the short term, consumption appears to be less elastic than production. Over the long term, however, it is more uncertain. Power-intensive industries may be price-sensitive and could choose to locate elsewhere if the consumption fee is high. Similarly, investment in new generation could be deterred by higher production fees, especially given that profitability is already tight for some projects. With these uncertainties, it is not clear how Ramsey pricing would guide the cost allocation in the long run.

Therefore, the choice of methodology may ultimately rest on broader policy goals. If Estonia aims to attract new power-intensive industries, a lower consumption fee may be preferable. If the focus is on reducing electricity imports, increasing renewable generation, or limiting subsidy needs, a lower production fee would support those goals.

A pragmatic approach could be to apply a uniform volume fee, striking a balance between economic theory, feasibility, and political priorities.

Appendix A: Hypotheses

In this chapter, we answer the hypotheses posed by Elering in the tender in the order in which they were presented. Our assessments are based on the conducted impact analysis as well as our experience where applicable. Hypothesis 7 consists of five questions which we answer individually before answering hypothesis 7 as a whole.

Hypothesis 1: Adding a balance service tariff to all consumers and producers based on actual volumes is transparent, practical, and ensures full balance responsibility for all market participants

Confirmed. Applying a tariff on actual volumes for both consumption and production is a viable option. Since the market participants pay for actual volumes, there is little risk involved for BRPs and retailers, and the fee can be transparently included in the costs, given the proposed amendments in the Electricity Market Act

Hypothesis 2: Applying a production tariff to cover costs is an appropriate and relevant approach; however, a tariff of approximately 5 €/MWh is too high.

Not confirmed. Our simulations suggest that, in some cases, there is little difference between a 5 EUR /MWh and a lower production fee. However, our simulations also show that fees applied to production do not fully transfer to the spot price. Therefore, producers themselves must bear some of the costs. By not being able to forward the cost into higher spot prices, profitability of electricity generation is reduced, which reduces incentives for investing in new power plants. In the longer term, profit margins are expected to be quite thin, meaning that additional tariffs could hinder investments in new projects. It is difficult to conclude what "too high" means and whether this criterion is met.

Hypothesis 3: Applying only the consumption tariff to cover costs would make the tariff excessively expensive for consumers, harming economic competitiveness.

Partially rejected. While covering all costs through a consumption fee leads to a fee of 8.33 EUR/MWh, it is difficult to say if it will harm economic competitiveness significantly. Demand for electricity is largely inelastic such that consumption does not fall much. Additionally, since Estonia does not have much power-intensive industry, the volume of consumption that would move is limited. Arenguseire Keskus' paper shows that, on average, electricity costs accounted for just 1.8 percent of Estonia's production value in 2022 (Arenguseire Keskus, 2024). An additional fee is therefore unlikely to harm the Estonian economy. This analysis is likely to hold in the short-term, but in the long-term higher electricity costs may hinder the establishment of new industry. However, the levels of consumption fees we are analysing here are relatively small to the total electricity costs, the chosen methodology is not expected to have a large impact on establishment new industries in Estonia.

Hypothesis 4: A tariff based on production and consumption volumes discriminates against energy storage, as storage systems draw energy from the grid for charging (when not charged directly from a production unit) and later feed it back into the grid.

Confirmed. Charging for both consumption and production fees will discriminate energy storage. Only charging it for one side is sensible, but the direction it should be charged for is not intuitively clear as energy storage units may serve different purposes. However, this issue has been addressed in the proposed amendments to the Electricity Market Act.

Hypothesis 5: Allocating significant costs to imbalance volumes is detrimental to the competitiveness of retail markets, lacks transparency, is impractical given the small size of each Baltic electricity system, and ultimately harms large consumers and renewable energy producers

Confirmed. For BRPs, the imbalance fees are a non-transparent cost that is difficult to transfer to the client, especially for long-term fixed price contracts. Additionally, the uncertainty of future imbalances is a risk that the BRPs must cover with a risk premium, increasing the price for clients.

For producers, renewable energy has a much higher forecasting error than remaining production. As such, they face a much higher cost per MWh and are thus at a disadvantage compared to other production.

Hypothesis 6: Estonian renewable energy producers are not at a disadvantage compared to Finnish producers

Partially confirmed. In general, Estonian spot prices are higher than Finnish, increasing Estonian production value relative to the Finnish. Focusing on these fees, only in alternative 1 will Estonian producers be in disadvantage. Even in alternative 4 Estonian producers will be in advantage as Finnish producers also face an imbalance fee. In alternative 3, only solar and wind will be in disadvantage compared to Finnish production.

Hypothesis 7: The imbalance fee component has a significantly negative impact on renewable energy projects and the functioning of the energy market

Confirmed. The imbalance fee disproportionately impacts renewable energy projects. Since renewable energy producers have higher imbalance volumes than other producers, they have a much higher costs per MWh. As a result, they are at a competitive disadvantage compared to other producers.

Subquestions:

7.1: Most contracts are forecasted and signed a year in advance, making it very difficult for all market participants to incorporate such a cost component into their electricity purchase or sales packages.

Partially confirmed. We deem it likely that the cost from imbalance fees must be covered through higher margins for the BRP. For long term contracts, the BRPs must bear the costs until the contract ends. For volume fees, they will easily be forwarded to customers invoices.

7.2: The imbalance cost adds significantly more to the balancing costs of wind and solar parks than the initially proposed production tariff

Confirmed. This is the case in our calculations based on forecasting errors from 2024. The production tariff under alternative 1 is 5.31 EUR but the costs for wind and solar become 5.47 EUR and 5.58 EUR once the imbalance cost is included. Assuming the imbalance cost that is referred to is alternative 3, the cost for wind and solar are 7 EUR and 13 EUR respectively.

7.3: The imbalance fee creates a counterproductive incentive – if everyone makes efforts to reduce imbalances, the same cost is distributed across fewer kilowatt-hours, causing the fee to increase. In other words, it would be better for everyone if the imbalance were as large as possible, so the €/MWh fee would be as low as possible

Confirmed. This is correct as long as the share of costs covered by the imbalance fee is defined as is the case for alternative 3. As an illustrative example, under alternative 3, 50 percent of costs are covered through the imbalance fee. Therefore, if the imbalance volume falls, the imbalance fee must be increased. In practice, the imbalance fee and imbalance volume must be inversely related.

7.4: Allocating costs through the imbalance tariff places a heavier burden on smaller electricity suppliers and may give larger players a competitive advantage. New entrants are particularly impacted, as a high imbalance tariff can create challenges in offering competitive prices, potentially making market entry more difficult.

Confirmed. New market entrants' imbalances are uncertain, will have to price in risk which increases price. Larger players can share the risk over more volume this reducing their aggregate volatility

7.5: The BRP has also highlighted: If such a methodology is implemented, we will need to assess the expected forecast error and imbalance tariff for each customer. Based on 2023 data, the minimum margin would be 14 €/MWh for solar and 10 €/MWh for wind. Additionally, this forces all suppliers into negotiations with consumers, as even if … €/MWh can be transparently invoiced, the additional … €/MWh exceeds the margin of existing contracts. Consequently, the societal cost is not X million but X+Y, as the expected cost is derived from historical data, and suppliers will include their own risk margin in these costs.

Confirmed. Since there is an uncertainty about the imbalance volumes, BRPs will need to include a risk margin in their prices to make sure they remain profitable.

Appendix B: Market participant feedback from interviews

Through the project, several interviews with market participants were conducted. Large-, small-, consumption-heavy- and production-heavy BRPs and a power producer/retailer were interviewed. Based on interviews with market participants, several key insights emerged regarding the implications of proposed fee structures and imbalance cost mechanisms across retail, wholesale, and capacity markets:

Retail and Wholesale Markets

Both BRPs and producers expressed concern over applying fees to electricity production, particularly in the current context where more generation capacity is urgently needed to support the energy transition. Applying such fees could undermine this objective by disincentivising new production.

A major point of contention was the potential introduction of a large imbalance fee, which all noted would disproportionately impact renewable energy projects. Given the variable and less predictable nature of renewable generation, high imbalance costs could significantly increase financial risk and reduce the attractiveness of such investments.

While it was acknowledged that most costs would ultimately be passed on to consumers, both BRPs and producers warned that this could come at the expense of the competitiveness of local production, which may struggle to compete with imported electricity or projects in neighbouring zones with lower fees.

Baltic Capacity Market

When it came to the proposed Baltic capacity market, all interviewees indicated that they did not expect significant impact from the changes discussed. Their main recommendation was to keep the focus on improving the functioning of the wholesale market, which they viewed as more critical to ensuring efficient outcomes and fair competition.

Feasibility

BRPs expressed particular concern about the feasibility of passing imbalance fees on to end customers. They noted that doing so would require allocating a share of imbalance risk to each customer and incorporating it into pricing, a process that adds complexity and could raise the cost of supply, again with a disproportionate impact on variable renewable energy sources.

Among the proposed options, the interviewees generally agreed that alternative 2 appeared to be the most feasible approach.

Other considerations

One BRP highlighted the importance of harmonising methodologies across bidding zones to avoid market distortions. If full harmonisation cannot be achieved in the short term, at minimum, they advocated for coordinated transition periods to prevent cost discrepancies between zones that could harm competition. Other BRPs agreed with this point.

Some BRPs expressed support for the principle of introducing imbalance fees as a way to incentivise better forecasting and reduce imbalance volumes. However, views differed on the appropriate level of the fee: €40/MWh was considered excessively punitive, while €1/MWh was seen as too low to have any real impact. A more moderate level was seen as necessary to strike a balance between effectiveness and investment viability.

Appendix C: Model description

THEMA's proprietary power market model, TheMA, is an advanced, fundamental power market model covering European markets. The model has been used for a variety of purposes including the preparation of price forecasts, scenario analysis and investment evaluations. A wide range of actors within the European power sector license the model for direct use and the model's users include public authorities, energy utilities, portfolio managers and funds. The model is constantly updated, maintained and improved in close collaboration with these licensees.

Overall description

TheMA can be used for both short- and long-term power market analysis. The model matches supply and demand on an hourly basis, with the price determined by the marginal costs of the marginal generator (or equivalently, the willingness to pay of the marginal consumer). In doing so, it accounts for start-up and ramping costs, as well as other intertemporal restrictions relevant to generation costs. The approach for modelling start-up costs and part-load efficiencies is based on Weber, C. (2004): "Uncertainties in the electric power industry: methods and models for decision support". The model has, of course, full sequential hourly time resolution.

The model includes detailed modelling of thermal plants and accounts, among other things, for start-up and shut-down costs, part-load efficiency and minimum-load restrictions. TheMA also incorporates detailed hydropower modelling, based on implicit water values, the simulation of reservoirs, hourly plant availability and inflows, and minimum discharge/generation restrictions, etc. It can also account for cascades and efficiency curves in hydropower.

Variable renewable generation, like wind and solar, is modelled using historically observed hourly volatility; and just like thermal and hydropower plants, large wind farms and PV installations can be individually modelled using their own generation profiles and characteristics.

Demand can be specified at the demand-group level or whatever granularity is needed. Both demand response and load shifting can be modelled. The model can also simulate behind-the-meter optimisation for demand groups where behaviour is influenced by grid tariffs.

Cross-zonal flows can either be optimised (based on the price spread) or be defined by the user (for example to reflect contract-based trade). Interconnector capacities can be set on an hourly basis and the model can be set up to simulate trade using either Net Transfer Capacities (NTCs) or Flow-Based Market Coupling (FBMC).

In this assessment we do not take into account response in investments in new power generation capacity or electricity consumption as a consequence of the reinvestment alternatives.

Methodology

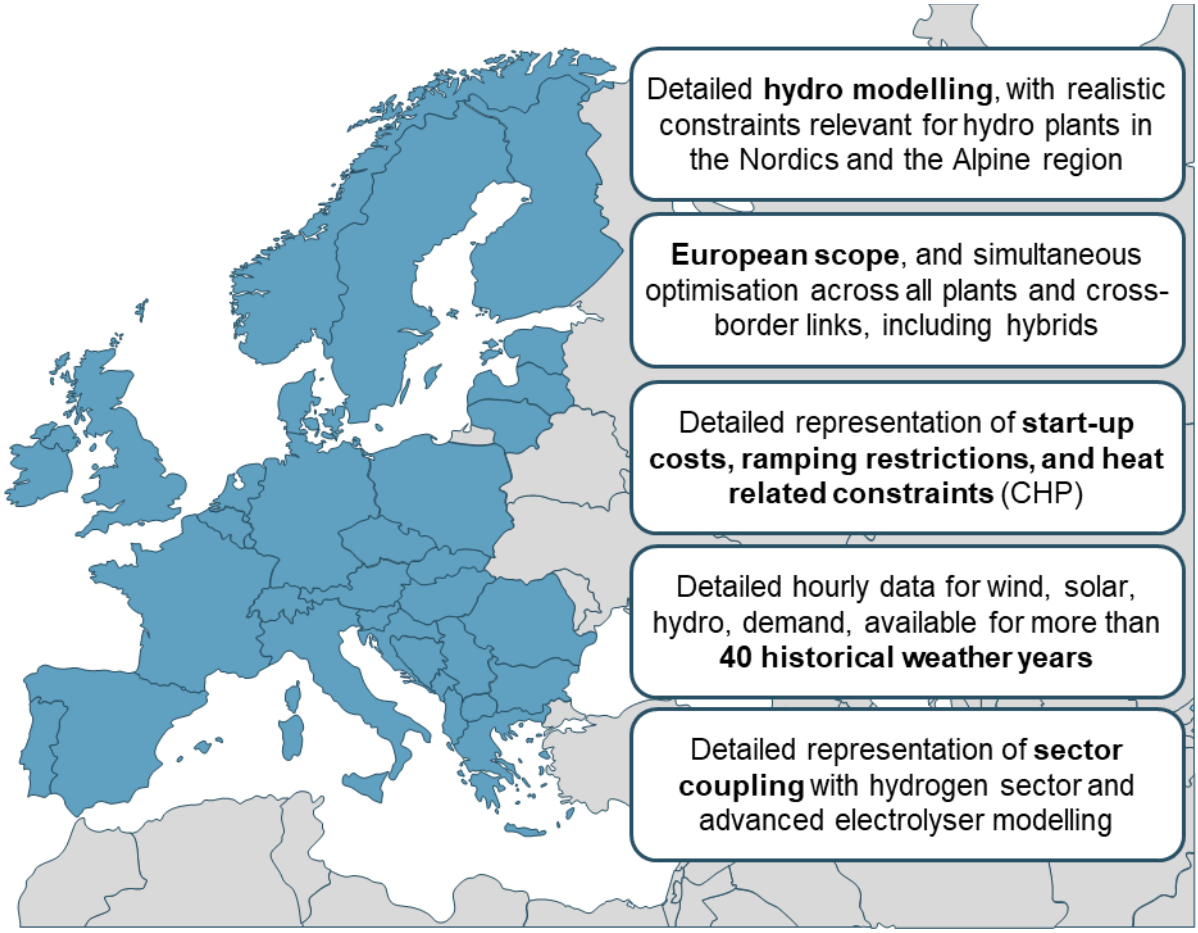
The model is a so-called fundamental power market model. This means essentially that the model finds the intersection of demand and supply. The price is defined as the marginal cost of the marginal plant (or demand component). It should hence be distinguished from models that, for example, model strategic bidding behaviour, market power, or imperfect competition.

To find the intersection, the model uses linear programming (short LP) techniques, as the matching of demand and supply can be formulated as a mathematical cost-minimisation problem under a set of constraints. Equivalently, fundamental models can also be described as a welfare-maximisation problem under a set of constraints.

The constraints include static constraints (for example plant availabilities) and intertemporal constraints (e.g. start-up optimisation constraints). It is the latter constraints, in

particular, that require the model to use an advanced LP solver. The model itself is implemented in GAMS (General Algebraic Modelling System) and is typically run with a commercial solver like CPLEX or GUROBI.

Figure 21 Summary of main model features and coverage.



Model characteristics

The main characteristics of the model are:

- *Benchmarking:* The model's results are continually benchmarked. The model has been backtested in several validation exercises. In addition, since the model is constantly applied in price forecasts, it is also constantly benchmarked against observed forward market prices. As part of the model development process, the model is constantly improved and adjusted to changes in the market and regulatory environment.
- *Full European scope*: As power markets are increasingly integrated, the model simulates the entire European power system. This ensures that cross-border effects are appropriately taken into account.
- *Sector coupling*: Sector coupling with the hydrogen sector is becoming increasingly important. In addition to the power sector, the model co-optimises the source of hydrogen (green, blue, grey etc.), and endogenously models both dispatch from gas-to-power and demand in the form of power-to-gas.
- *New technologies*: Power markets are changing drastically. The technologies we cover in the model include sector coupling (see above), Carbon Capture and Storage (CCS), Direct Air carbon capture, new types of battery and storage (CAES), demand response, and more.
- *Complete database:* The model comes with a complete database covering all major European markets for the period to 2055.

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About THEMA

THEMA Consulting Group is a Norwegian consulting firm focused on Nordic and European energy issues, and specialising in market analysis, market design and business strategy.

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