Capacity calculation methodology within the Baltic Capacity Calculation Region

Among:

AS “Augstsprieguma tīkls”
Elering AS
LITGRID AB
PSE S.A.
Svenska kraftnät
Fingrid Oyj

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CONTENTS

1. GENERAL TERMS

1.1. The Capacity calculation methodology within the Baltic Capacity Calculation Region is required by Article 20(2) of the Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM Regulation).

1.2. Capacity calculation methodology within the Baltic Capacity Calculation (hereinafter referred to as “the Methodology”) are set to define:

1.2.1. Cross-Zonal Capacity calculation, provision and allocation rules between Estonian and Latvian power systems;

1.2.2. Cross-Zonal Capacity calculation, provision and allocation rules between Lithuanian and Latvian power systems;

1.2.3. Cross-Zonal Capacity calculation, provision and allocation rules between Estonian and Finnish power systems;

1.2.4. Cross-Zonal Capacity calculation, provision and allocation rules between Lithuanian and Swedish power systems;

1.2.5. Cross-Zonal Capacity calculation, provision and allocation rules between Lithuanian and Polish power systems;

1.3. Article 9(9) of the CACM Regulation requires that the expected impact of the Proposal on the objectives of the CACM Regulation is described. The impact is presented below in section 1.4 – 1.4.7.

1.4. The Methodology Proposal contributes to and does not in any way hamper the achievement of the objectives of Article 3 of the CACM Regulation. Cross-Zonal Capacities within the Baltic Capacity Calculation Region (hereinafter referred to as “Baltic CCR”) shall be calculated using the coordinated Net Transmission Capacity approach in a way that facilitates and serves the achievement of the following objectives:

1.4.1. promoting effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) by ensuring that maximum Cross-Zonal Capacity (with regards of operational security) is made available to the market in the Baltic CCR;

1.4.2. ensuring optimal use of the transmission infrastructure (Article 3(b) of the CACM Regulation) by applying the net transmission capacity approach, compared to which flow-based approach is not yet more efficient assuming the comparable level of operational security in the Baltic CCR.

The Methodology for the Baltic CCR treats all bidding zone borders within the Baltic CCR equally and provides non-discriminatory access to cross-zonal capacity. Proposed approach aims at providing the maximum available capacity to market participants within the operational security limits. The Methodology for the Baltic CCR is ensuring non-discrimination in calculation of Cross-Zonal Capacities.

1.4.3. ensures operational security (Article 3(c) of the CACM Regulation) as grid constraints are taken into account while providing the maximum available capacity to market participants within the operational security limits;

1.4.4. optimising the calculation and allocation of cross-zonal capacity (Article 3(d) of the CACM Regulation) and ensuring that Cross-Zonal Capacities in day-ahead and Intraday Markets are provided and allocated in a most optimal and reasonable manner by taking into account structure of the Baltic CCR power system, as well as from one side, operational security limits and N-1 situations which are limiting capacities, and from another side – remedial actions which can increase capacities;

1.4.5. ensuring and enhancing the transparency and reliability of information (Article 3(f) of the CACM Regulation), as the CCM determines the main principles and main processes for the day-ahead and intraday timeframes. The Methodology enables Transmission System Operators (hereinafter referred to as "TSOs") to in a transparent way provide Market Coupling Operator (hereinafter referred to as "MCO") with the same reliable information on cross-zonal capacities and allocation constraints for day-ahead and intraday allocation;

1.4.6. contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (Article 3(g) of the CACM Regulation). The Methodology, by taking most important grid constraints into consideration, will support efficient pricing in the market, providing the right signals from a long-term perspective;

1.4.7. respecting the need for a fair and orderly market and fair and orderly price formation (Article 3(h) of the CACM Regulation) as well as providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation) by providing all cross-zonal capacities for allocations to MCO;

1.5. All the data exchange process and timing among TSOs and Coordinated Capacity Calculators (hereinafter referred to as just "Capacity calculator" or "Capacity calculators") is described in respective Coordinated Capacity Calculators Rules.

Until Coordinated Capacity Calculators are established and perform capacity calculation/coordination function, capacity calculation and coordination is performed by TSOs related to respective borders.

1.6. Processes and principles described in this Methodology cover Cross-Zonal Capacity calculation (not for long term transmission rights allocation, for which more detailed methodology is developed according to Regulation 2016/1719 Article 10) for year, month and week ahead time horizons as well as Cross-Zonal Capacity calculation, provision and allocation for day-ahead and intraday time horizons.

1.7. Baltic CCR TSOs have made a feasibility study “Technical Feasibility of Flow-based Capacity Calculation in the Baltic States”, which investigated the effectiveness of implementing the flow-based capacity calculation approach in the Baltic CCR. The study has concluded, that, at current situation, the application of the capacity calculation methodology using the flow-based approach would not yet be more efficient compared to the coordinated net transmission capacity approach and assuming the comparable level of operational security in the Baltic CCR. Baltic CCR TSOs have shared the study with competent regulatory authorities and have jointly requested the competent regulatory authorities to decide on applying the coordinated net transmission capacity approach to the Baltic CCR region following the Article 20(7) of CACM Regulation.

1.8. This Methodology takes into account the Baltic CCR NRAs decisions on Cross-Zonal Risk Hedging Opportunities in accordance with article 30 and on Baltic CCR Regional Design of Long-Term Transmission Rights in accordance with article 31 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation. Meaning, no physical capacity allocation is made before day-ahead allocation and no physical capacity is reserved for long-term capacity on Baltic CCR borders. Therefore the Methodology does not include rules concerning previously allocated cross-zonal capacity for the day-ahead timeframe.

1.9. Equations for day-ahead and intraday capacity calculations included in this Methodology in general represent the same approach for capacity calculation among all borders in order to respect operational security. Nevertheless, equations have some differences based on the fact that in power systems' transmission assets in Baltics have different dependency on temperature. Additional justification of differences in equations is based on:

- existing power system state in the Baltic synchronous area (including generation and consumption patterns);
- power market operation possibilities, which requires adjustments in capacity calculation approach in order to ensure operational security in cases which can result from power market operation. As an example, market trade, which initiates reduction of generation in Latvia and increase of generation by the same amount in Lithuania, would result in overload of Estonia-Latvia bidding-zone border in case if before trade Estonia-Latvia border was already fully loaded.

Taking into account aforementioned reasons, finding of common equation which would suit all cases would give too high level description of calculation process and in such way reducing transparency of calculation process.

1.10. Capacity calculated with 3rd countries shall not reduce cross-zonal capacities on Baltic CCR bidding zone borders.

2. DEFINITIONS

For the purposes of this Methodology, the definitions in Articles 2 of Regulations (EC) No 2015/1222, No 714/2009, No 543/2013, Article 3 of Regulation (EC) No 2017/1485 and Article 2 of Directive 2009/72/EC shall apply. In addition, the following definitions shall apply and shall have the following meaning:

2.1. **3rd Countries** – the Republic of Belarus and Russian Federation excluding Kaliningrad area.

2.2. **AAC** – the Already Allocated Capacity is the total amount of allocated physical transmission rights.

2.3. **AST** – AS “Augstsprieguma tīkls”, Independent Transmission System Operator of the Republic of Latvia.

2.4. **ATC** – the Available Transmission Capacity of the designated Cross-Border Interconnections, which is available to the market after each phase of the transmission capacity allocation procedure.

2.5. **Baltic TSOs** – the transmission system operators for electricity of the Republic of Estonia, the Republic of Latvia and the Republic of Lithuania.

2.6. **Baltic CCR TSOs** – the transmission system operators for electricity of the Republic of Finland, Republic of Estonia, the Republic of Latvia and the Republic of Lithuania, the Republic of Poland, Sweden.

2.7. **Baltic CCR** - Capacity calculation region 9: Baltic. According to ACER decision on the electricity TSOs’ proposal for Capacity Calculation Regions (18.11.2016) Baltic CCR shall include the Bidding Zone borders listed below: a) Estonia - Latvia (EE-LV), Elering AS and AST; b) Latvia - Lithuania (LV-LT), Augstsprieguma tikis and LITGRID AB; and c) Estonia -Finland (EE-Fl), Elering AS and Fingrid Oyj; d) Lithuania — Sweden 4 (LT-SE4), LITGRID AB and Svenska kraftnat; and e) Lithuania - Poland (LT-PL), LITGRID AB and PSE S.A.

2.8. **Instruction for parallel operation in the cross border interconnection (BRELL)** – the document approved among Belarusian, Russian, Estonian, Latvian and Lithuanian system operators that defines parallel power systems operation conditions in the Cross-Border Interconnection. It includes interconnection description, interconnection transfer capacities, interconnection normal and emergency state operations and system protection description.

2.9. **Methodical guidelines for stable operation in BRELL Power Loop** – the document, approved among Belarusian, Russian, Estonian, Latvian and Lithuanian system operators, which defines main system stability requirements to be taken into account by calculation of TTC in all BRELL Loop interconnections.

2.10. **BRELL Loop** – transmission networks of the power systems of the Baltic States, the Republic of Belarus and the Russian Federation (Central and North-Western parts).

2.11. **Cross-Border Interconnection** – is a physical transmission link (e.g. tie-lines) which connects two power systems.

2.12. **CACM** – European Commission Regulation (EU) No 2015/1222 establishing a Guideline on Capacity Allocation and Congestion Management.

2.13. **Common Grid Model** – data set agreed between TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process.

2.14. **D-1** – the day prior to the day on which the energy is delivered.

2.15. **D-2** – the day before the day prior to the day on which the energy is delivered.

2.16. **Elering** – Elering AS, Transmission System Operator of the Republic of Estonia.

2.17. **Fingrid** – Fingrid Oyj, electricity transmission system operator of the Republic of Finland.

2.18. **Litgrid** – LITGRID AB, electricity transmission system operator of the Republic of Lithuania.

2.19. **Market Coupling Operator (MCO)/Nominated electricity Market Operator (NEMO)** – the operator/-s of day-ahead and Intraday Markets in Baltic CCR.

2.20. **NTC** – coordinated Net Transmission Capacity of the designated Cross-Border Interconnections is the maximum Trading Capacity, which is permitted in transmission Cross-Border Interconnections compatible with Operational Security standards and taking into account the technical uncertainties on planned network conditions for each TSO.

2.21. **PSE** - PSE S.A., electricity transmission system operator of the Republic of Poland.

2.22. **Shift Key** – means a method of translating a net position change of a given power system into estimated specific injection increases or decreases in the Common Grid Model. Shift Key is settled as generation, renewable generation and load.

2.23. **SvK –** Svenska kraftnät, electricity transmission system operator in Sweden.

2.24. **SO GL** – European Commission Regulation (EU) No 2017/1485 establishing a Guideline on electricity transmission system operation.

2.25. **TRM** – Transmission Reliability Margin which shall have meaning of "reliability margin" definition of CACM.

2.26. **TTC** – Total Transfer Capacity of the designated Cross-Border Interconnections is the maximum transmission of active power, which is permitted in transmission Cross-Border Interconnections compatible with Operational Security standards applicable for each TSO.

2.27. **Trading Capacity –** the maximum available Cross-Zonal Capacity for trade in Day-Ahead Market and Intraday Market.

2.28. **Baltic synchronous area** – power systems of Lithuanian, Latvian and Estonian which are synchronously interconnected with IPS/UPS power systems.

3. OPERATIONAL SECURITY LIMITS, CONTINGENCIES AND ALLOCATION CONSTRAINTS

3.1. Operational security analyses shall be performed with respect of operational security limits applied in Control Areas of Baltic CCR TSOs. Operational Security Limits are agreed among TSOs of respective synchronous areas. Operational security limits shall be defined and specified according to Article 25 of SO GL. Stability limits are determined according to Article 38 SO GL. Power flow limits are determined according to Article 32 SO GL.

3.2. Contingency Analysis is performed at least for those contingencies which are agreed among Baltic TSOs in the Contingency Lists. Contingency Lists shall be agreed and provided among Baltic TSOs and provided to Capacity calculator for capacity calculation.

3.3. In accordance with the definitions in Article 2 points (6) and (7), Article 23(3)(a) of the CACM Regulation, and respecting the objectives described in Article 3 of the CACM Regulation, besides active power flow limits on Cross-Border Interconnections, other specific limitations may be necessary to maintain the secure grid operation. Under the CACM, allocation constraints constitute measures defined as to the purpose of keeping the transmission system within operational security limits. As the transmission system parameters used for expressing operational security limits (inter alia frequency, voltage, and dynamic stability) depend on production and consumption in a given system, these specific limitations can be related to generation and load. Since such specific limitations cannot be efficiently transformed into operational security limits of individual Cross-Border Interconnections, they are expressed as maximum import and export constraints of bidding zones.

a. If applicable, allocation constraints are determined by Baltic CCR TSOs and taken into account during the single day-ahead coupling in addition to the power flow limits on Cross-Border Interconnections.

b. These allocation constraints shall be modelled as a constraint on the global net position (the sum of all cross border exchanges for a certain bidding zone in the single day-ahead coupling), thus limiting the net position of the respective bidding zone with regards to all CCRs which are part of the single day-ahead coupling.

3.4. Allocation constraints translated into ramping restrictions are described in Section 8).

3.5. A TSO uses allocation constraints in case of a central dispatch model for ensuring a required level of operational reserve for balancing (hereinafter referred to as balancing constraints). The balancing constraints depend on the foreseen balancing situation and are bidirectional, with independent values for each market time unit and separately in the directions of import and export. This is applicable for PSE, for all market time units. The details for the use and the methodology of calculation of allocation constraints as described in this article are set forth in Appendix 1.

3.6. A TSO may discontinue the usage of an allocation constraint as described in Section 3(5). The concerned TSO shall communicate this change to the Baltic regulatory authorities and to the market participants at least one month before its implementation.

3.7. Operational security limits used in capacity calculation are the same as those used in operational security analysis performed according to Articles 74 and 75 of SO GL.

4. GENERATION AND LOAD SHIFT KEYS

4.1. The generation and load shift keys (hereinafter referred to as "GLSK") shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the common grid model. That forecast shall notably take into account the information from the generation and load data provision methodology according to Article 16 of CACM. In Baltic CCR different GLSK strategies are applied. Shift key strategy per power system area shall be the responsibility of each involved TSO, which has to be communicated with other TSOs and Capacity calculator before commencing TTC calculation process in case of deviation from proportional GLSK strategy.

4.2. As a rule, following GLSK strategies are applied in Baltic CCR:

4.2.1. Proportional generation and load shift key strategy if not specified otherwise, is applied in Baltic CCR.

Shift in defined generation/load nodes is proportional to the base case generation/load within an area “a”:

- P_g(n, a) active generation in node n, belonging to area a,
- P_l(n, a) active load in node n, belonging to area a.

The participation of node n in the shift, among generation nodes (GSK) is given by:

$$K_g(n,a) = G(a)\frac{P_g(n,a)}{\sum_i P_g(i,a)}$$

The participation of node n in the shift, among load nodes (LSK) is given by:

$$K_l(n,a) = L(a)\frac{P_l(n,a)}{\sum_i P_l(i,a)}$$

The sum of G(a) and L(a) for each area is to be equal to 1 (i.e. 100%).

4.2.2. For NordBalt and LitPol link from Baltic synchronous area and European Continental side (PSE) side the shifting strategy shall be performed in the way to evaluate most critical impact for system security – therefore Rank GLSK strategy is by default applied for NordBalt and LitPol link. Rank GSK strategy means that if specific dispatchable generating units having significant influence on TTC of a given HVDC link are available then its generation up to available limit is used first during capacity calculation. Such approach means maximization of TTC on a given HVDC link with the use of available internal redispatching and ensures there is no undue discrimination between internal and cross zonal exchanges.

4.2.3. GLSK strategy applied in Nordics is described in details in Nordic CCR Capacity Calculation Methodology.

5. REMEDIAL ACTIONS

5.1. Relevant TSOs shall provide relevant Capacity Calculators with information on available and applicable remedial actions that shall be used in capacity calculation process, e.g. information on available emergency power reserves, available balancing reserves, as well as possibilities to change the power flow on HVDC links.

Not exhaustive list of possible remedial actions in Baltic CCR, which can be used during capacity calculation process:

- Changes of network topology. As an example of such remedial action application in capacity calculation process is "switching in operation" the lines which normally are planned to be "switched off in stand by mode" for hours with low load (voltage increase risk);
- Changes of power system's balance (e.g. by changing generation) – meaning application of redispatching and countertrading activities. As an example of such remedial action application in capacity calculation process, equations (2), (5) and (6) can be given, where amount of assured emergency power reserves is taken into account in order to increase capacities.

Non-costly remedial actions are such actions which don't result in additional costs to TSO in case of planned operational regime for which capacity calculation is performed.

Costly remedial actions are such actions which result in additional costs to TSO even in case of planned operational regime for which capacity calculation is performed.

5.2. Countertrading and redispatching possibilities along with other remedial actions shall be fully exploited before an internal Critical Network Element may affect cross border trade.

6. TOTAL TRANSFER CAPACITY (TTC) CALCULATION METHODOLOGY

6.1. Maximum capacity shall be the default and any temporary deviations from that must be thoroughly justified based on operational security and economic efficiency.

6.2. Each coordinated capacity calculator shall coordinate with the neighbouring coordinated capacity calculators during capacity calculation and validation.

6.3. TSOs and Capacity Calculator shall not limit cross-zonal exchanges due to internal Critical Network Elements unless performed Contingency Analyses determines threat to Operational Security or when operational security analyses show that boundaries of stability limits are exceeded during operation of the transmission system. When cross-zonal exchange is limited, the TSOs shall publish information regarding the event according to Regulation (EC) No 543/2013.

6.4. Total Transfer Capacity (TTC) Calculation for cross-borders with AC interconnectors in Baltic TSOs control area

6.4.1. The Cross-Border Interconnection TTC assessment for AC interconnectors shall follow the methodological principles in the Methodical guidelines for stable operation in BRELL Loop, as well as in national regulations and standards implemented and agreed in the Instruction for parallel operation in the Cross-Border Interconnections between TSOs involved, while taking into account the intra- and intersystem Operational Security.

6.4.2. Methodical guidelines for stable operation in BRELL Loop is used as a basis and reviewed by TSOs, for ensuring the collective secure operation with neighboring interconnected TSOs.

6.4.3. The Cross-Border Interconnection TTC shall be determined by proceeding Contingency Analysis with respect of Operational Security Limits of BRELL Loop and Control Area of Baltic TSOs.

6.4.4. Contingency Analysis is performed for those contingencies which are agreed among Baltic TSOs in the Contingency List. Contingency List shall be agreed and provided among Baltic TSOs and to Capacity calculator.

6.4.5. Critical Network Elements list of Control Area of Baltic TSOs shall be provided among Baltic TSOs and to Capacity calculator.

6.4.6. The cross-border TTC calculation shall be carried out by using as input the following mutually coordinated data and information:

- 6.1.6.1 Base case - Common Grid Model, which includes power transmission equipment model of BRELL Loop and scenario describing net positions for each of Control Area of Baltic TSOs and Russian/Belarusian power systems, valid for given calculation purposes;
- 6.1.6.2 Generation, renewable generation and load Shift Key;
- 6.1.6.3 Critical Network Elements;
- 6.1.6.4 Outage cases;
- 6.1.6.5 Contingency List;
- 6.1.6.6 Remedial Actions;
- 6.1.6.7 Operational Security Limits.

6.4.7. The shifting strategies used in calculations are described in Section 4 of this Methodology.

6.4.8. Determining the TTC values, TSOs and Capacity calculator can take into account ambient temperatures for different seasonal periods within Control Area as well as actual emergency power reserves within Control Area of Baltic TSOs and in Russian/Belarusian power systems to ensure Operational Security.

6.4.9. If during capacity validation process neighbouring TSOs determine different TTC values for the same Cross-Border Interconnection, the lowest value shall be used as a coordinated value.

6.5. Total Transfer Capacity (TTC) Calculation for cross-borders with HVDC interconnectors

6.5.1. TTC for each cross-border that consists solely of HVDC connections is limited by the sum of ratings of HVDC interconnectors that connect the relevant Bidding Zones. In order to define TTC limitation related to adjacent AC networks, Contingency Analyses based on N-1 criterion (i.e. a loss of any single element of power system) shall be performed using Common Grid Models. While performing Contingency Analyses after applying of N-1 criteria following limits shall be not exceed:

- thermal limits, that correspond to the relevant ambient temperature, of network elements, i.e. the maximum amount of electric current that a given network element can conduct without sustaining damage or being in violation of safety requirements
- voltage limits in network nodes, i.e. maximum and minimum voltage levels permitted at given network node in order to prevent equipment damage or voltage collapse respectively;
- rotor angle stability limits related to the ability of the synchronously interconnected system to return to stable state of operation after any disturbance.

6.5.2. Maximum permissible capacity on HVDC interconnector shall be limited when there is lack of available power reserves to replace the failure of the HVDC interconnector.

6.5.3. While relevant party is performing Contingency Analysis according to 6.5.1. it is checked if maximum capacity for each link for each direction could be provided to the market. If Contingency Analysis reveals that network security is not assured when the HVDC interconnectors are fully loaded in any direction, then capacity on the relevant cross-border on relevant direction is reduced until network parameters are within permissible limits during the analysis.

6.5.4. The TTC on relevant HVDC interconnector is the minimum capacity value that is the outcome of the Contingency Analyses that are performed by the relevant parties on each side of the relevant interconnector.

6.5.5. For Baltic CCR TSOs The cross-border TTC calculations shall be carried out by using as input the following data and information:

6.5.5.1 Common Grid Model, which includes:

- power transmission equipment model of BRELL Loop and scenario describing net positions for each of Control Area of Baltic TSOs and Russian/Belarusian power systems, valid for given calculation purposes (For Baltic TSOs);
- Model of Polish power system from European merging function, supplemented with 110kV subtransmission grid and scenario describing PSE net position, valid for given calculation purposes, shall be used for calculations;

- Models of Nordic power systems from European merging function shall be used for calculations.

6.5.5.2 Generation, renewable generation and load Shift Key;

6.5.5.3 Critical Network Elements;

6.5.5.4 Planned Outages;

6.5.5.5 Contingency List;

6.5.5.6 Remedial Actions;

6.5.5.7 Operational Security Limits.

6.5.6. Contingency Analyses are performed for those contingencies which are agreed among respective TSOs in the Baltic CCR in the relevant Contingency List. Contingency List shall be agreed and provided among respective TSOs and to relevant Capacity calculator.

6.5.7. Critical Network Elements list of Control Area of respective TSOs shall be provided among respective TSOs in the Baltic CCR and to relevant Capacity calculator.

6.5.8. The shifting strategy shall be performed in the way to evaluate most critical impact for system security.

6.5.9. TSOs and Capacity calculator shall apply load Shift Key whenever the generation shift shall not be sufficient for determination of TTC.

6.5.10. If HVDC interconnector LitPol Link is connected with entire power system by only one 330 kV tie line Alytus-Gardinas, in this case TTC is defined in coordination with Belarus power system operator.

6.5.11. TTC of cross-border Estonia-Finland is the sum of permissible capacities on HVDC links Estlink 1 and Estlink 2. When there is a need to limit the capacities on the links according to paragraph 6.5.2., the links are limited in minimal possible combination – meaning the maximum possible capacity is given to the market.

7. TRANSMISSION RELIABILITY MARGIN (TRM) CALCULATION METHODOLOGY

7.1. The Transmission Reliability Margin (hereinafter referred to as "TRM") is a capacity margin needed for secure operation of interconnected power systems considering the planning errors, including the errors due to imperfect information from 3rd Countries at the time the transfer capacities have been computed.

7.2. TRM calculation methodology is covering Cross-Border Interconnections between Lithuanian and Latvian power systems as well as between Latvian, Russian and Estonian power systems.

7.3. TRM shall be defined for each individual Cross-Border Interconnections according to the methodology described in this Section 7 of this Methodology.

7.4. For HVDC interconnectors TRM value is 0 MW.

TRM determination

7.5. Statistical data

For determining of the TRM values for each Cross-Border Interconnection, the statistical data of historically planned and factual power flows (historical physical flows) for aforementioned interconnections is used with the time step of 1 minute. If there are no archive data with the time step of 1 minute, then smallest time step, which is available in the archive data, can be used. For intraday, day-ahead, weekly and monthly planning phases TRM calculation uses statistical archive data (both planned and factual power flows are taken from archive – in order to compare historically planned flows with historical physical flows) from last year, but in cases, where topology changes or other network conditions have substantial impact to power flows compared to last year, the data from last month, last week or last day is used.

Deviations shall be calculated as difference between Cross-Border Interconnection actual power flows and planned power flows.

In yearly planning phase, the average TRM value of last 12 months is used.

7.6. TRM determination approach

TRM shall be determined as the arithmetic average value plus standard deviation. Arithmetic average value of the deviation is determined for the above statistical data set and added to the same data set standard deviation:

$$TRM = \frac{\sum_{i=1}^{n} X_i}{n} + \sqrt{\frac{\sum_{i=1}^{n} (X_i - \overline{X})^2}{n-1}} \qquad (1)$$

where:

X_i – data sets of the i-th element, defined as deviation of factual power flow from planned power flow over Cross-Border Interconnections;

$\overline{X}$ – arithmetic average value of Xi $\frac{\sum_{i=1}^{n} X_i}{n}$;

n – number of elements in the data set.

TRM shall be rounded to the nearest integer.

7.7. In case if after evaluation of different network states in previous planning period, as well as historical market outcomes and power systems' balances, and taking into account planned changes in state of power systems can be concluded that actual power flows will be smaller than TTC value, TRM value of 0MW for AC-interconnection can then be used.

7.8. When TRM calculation using time periods that are defined in Article 7.5 of this Methodology does not produce results that are in line with Operational Security, then TRM can be increased until all Operational Security limits are met.

7.9. TRM is being re-calculated once per year or if operational/planning conditions necessitate (e.g. changes in patterns of planned or factual power system regime) before every NTC calculation process. TRM can also be recalculated before ATC calculations in case of major changes in power system.

8. COORDINATED NET TRANSMISSION CAPACITY (NTC) AND AVAILABLE TRANSMISSION CAPACITY (ATC) CALCULATION METHODOLOGY

NTC and ATC calculation methodology for each Baltic CCR border is given below.

Normally, NTC and ATC calculation process is following:

- TSOs and Capacity calculator calculates NTC value calculated for Day-Ahead Market;
- NEMO provide Day-Ahead Market results respecting NTCs and allocation constraints;
- ATC value is calculated for Intraday Market.

In case NEMOs don't provide Day-Ahead Market results in scheduled time, a Day-Ahead fall-back procedure will be initiated. In such a case, according to Article 9.1.2. of this Methodology, ATC capacities shall be reassessed after the fall-back procedure has provided a result. In case if Day-Ahead Market results have not been provided by NEMOs before the intraday cross-zonal gate opening time (defined in the document on "Intraday cross-zonal gate opening and gate closure times in accordance with Article 59 of CACM"), ATC values equal to "0" (zero) shall be provided to the Intraday Market.

If due to time constraints ATC values cannot be calculated by Capacity calculator and validated by TSOs before intraday cross-zonal gate opening time (defined in the document on "Intraday cross-zonal gate opening and gate closure times in accordance with Article 59 of CACM"), TSOs will provide ATC capacities for their respective borders for intraday market timeframe based on the day ahead NTCs and the results of the day ahead market coupling, as well as evaluation of operational security by TSO. In case if neighbouring TSOs come up with different ATC values for provision to the respective border, the lowest value shall be used as a coordinated value and shall be provided to Intraday market for allocations. Updated ATC values shall be provided to Intraday Market as soon as possible after calculation and validation has been successfully finalised.

On HVDC Interconnections, maximum Ramping Rate restrictions are applied during day-ahead and Intraday Market (information on Ramping Rate values available on ENTSO-E Transparency platform). Maximum Ramping Rate restriction indicates the maximum possible rate of active power change for sequential trading periods. The restrictions imply that trade plans on all HVDC connections cannot be changed with no more than the predetermined maximum Ramping Rate restriction from one trading period to the next. Ramping restrictions are taken into account in the Day-Ahead Market in order to reduce risks that might threaten the operational security. Without restricting the maximum exchange of flow per hour (ramping) on interconnections, very large amount of operational reserves would be needed to be able to deal with imbalances within the operational time frame due to change in flows on interconnectors. Capacities available for trading during Intraday Market depend not only on maximum trading capacities provided by TSOs/ Capacity calculators, but also on AACs for consecutive previous and following trading periods.

During intraday trading process ATC values, apart from changes coming from NTC updates, shall be adjusted automatically by respective market operator/market platform after each trade affecting respective border. Value of ATC adjustment (increase or decrease) shall be equal to commercial flow over respective border as the result of trade. The same refers to allocation constraints, which, apart from changes coming from their updates, shall be adjusted automatically by respective market operator/market platform after each trade affecting respective power system. Volume of this adjustment (increase of decrease) shall be equal to the change of net position of a given power system as the result of trade.

In Baltic CCR rules for efficiently sharing the power flow capabilities of Critical Network Elements among different Bidding Zone borders are not needed, as there is no such Critical Network Element/-s in Baltic CCR that would clearly and in majority cases influence power flow capabilities of several borders at once. Therefore, there is no sharing of the power flow capabilities of Critical Network Elements between Bidding Zone borders and this Methodology doesn't contain the rules for efficiently sharing the power flow capabilities of Critical Network Elements among different Bidding Zone borders.

8.1 Trading Capacity Calculation Rules Between Estonian and Latvian Power Systems

Mathematical description of NTC calculation

8.1.1 Estonia-Latvia Cross-Border Interconnection is the Cross-Border Interconnection between Estonian, Russian and Latvian power systems, for which common TTC is calculated. Equation (2) of Section 8.1.2 is used when no capacity is being allocated for trading between Russian and Latvian power systems.

8.1.2 TSOs and Capacity calculator calculate NTC value for Estonia-Latvia Cross-Border Interconnection using following equation:

$$NTC = \min(((TTC_1 + \sum_{i=1}^{n} K_i \cdot P_i) - TRM); TTC_2 - TRM) \quad (2)$$

where:

TTC_1 – Total Transfer Capacity after (N-1) Situation has occurred from actual power system network status according to Instruction for parallel operation in the Cross-Border Interconnection between Estonian, Russian and Latvian power systems. The value of TTC_1 is independent on influence of ambient temperatures – values at 0 (zero) temperature shall be used;

TTC_2 – Total Transfer Capacity value for actual power system network status, according to Instruction for parallel operation in the Cross-Border Interconnection between Estonian, Russian and Latvian power systems. The value of TTC_2 is dependent from the influence of ambient temperature of particular capacity calculation time period to transmission line conductors;

P_i – all available amount of assured emergency power reserves for respective power system *i*(*shall be provided by respective TSO for coming year until 1st of December to the Capacity calculator and to respective TSO's)*;

n – number of power systems;

K_i – reserve power distribution coefficients considering location of the assured emergency power reserve P_i and down regulation according to Table 1 of this Methodology ;

TRM – TRM value calculated according to the methodology described in Article 7 of this Methodology.

8.1.3 In case if during capacity validation process neighbouring TSOs determine different NTC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

Intraday Available Transmission Capacity calculation

8.1.4 Actual D-1 Common Grid Model (hereinafter referred to as "CGM") with day-ahead trading results shall be used and new BRELL Loop power flow calculations shall be performed.

8.1.5 In case if Russia D-1 planning stage data is not available, TSOs and Capacity calculator shall take into account Russia D-2 planning stage data. New intraday ATC values shall be coordinated as soon as Russia D-1 planning stage data are available.

8.1.6 ATC values for Estonia-Latvia Cross-Border Interconnection are calculated as follows:

8.1.6.1 If direction of ATC, for which calculation is performed, corresponds to direction of AAC:

$$ATC = \min(NTC_{coord} - P_{PF};\ NTC_{coord.} - AAC + TRM_{coord.}) \qquad (3)$$

8.1.6.2 If direction of ATC, for which calculation is performed, does not correspond to direction of AAC:

$$ATC = NTC_{coord} - P_{PF} \qquad (4)$$

where:

$NTC_{coord.}$ – coordinated Net Transmission Capacity in the particular Cross-Border Interconnections;

P_{PF} – calculated power flow in the particular Cross-Border Interconnections performed with actual D-1 CGM;

AAC – Already Allocated Capacity in the particular Cross-Border Interconnections after previous capacity allocation phases;

$TRM_{coord.}$ – coordinated TRM value from coordinated TTC and NTC values.

ATC value in formula (4) is calculated considering that the TSOs and Capacity calculator shall, as far as technically possible, net the capacity values of any power flows in opposite directions over congested interconnection line in order to use that line to its maximum capacity.

8.1.7 In case if during capacity validation process neighbouring TSOs determine different ATC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

8.1.8 Reserve power distribution coefficients (see Table 1 of this Methodology) in controlled cross-borders show the impact of power exchange program between two power systems on the loading of controlled Cross-Border Interconnections. Reserve power distribution coefficients in controlled Cross-Border Interconnections of BRELL Loop are determined using BRELL grid model that includes power systems of Belarus, Russia (North-West power system), Estonia, Latvia, Lithuania, Ukraine and Kaliningrad area. In order to determine reserve power distribution coefficients, power flows have been modelled by increasing generation in exporting power system and symmetrical decreasing of generation in consuming power system.

8.1.9 Values of reserve power distribution coefficients used according to availability of appropriate amount of down regulation reserves. Amount of down regulation reserves in percentage is evaluated as proportion of available down regulation reserves on one cross-border side to available amount of assured emergency power reserves from another cross-border side.

Table 1. Reserve power distribution coefficients

Amount of down regulation power (%)	Cross-Border Interconnections	Reserves location			
		Lithuania	Latvia	Belarus	Estonia
100	Estonia-Russia → Latvia	0,62	0,74	0,45	
	Latvia →Russia-Estonia				0,74
50	Estonia-Russia → Latvia	0,48	0,60	0,31	
	Latvia →Russia-Estonia				0,52
0	Estonia-Russia → Latvia	0,34	0,45	0,16	
	Latvia →Russia-Estonia				0,29

8.2 Trading Capacity Calculation Rules Between Lithuanian and Latvian Power Systems

Mathematical description of NTC calculation

8.2.1 TSOs and Capacity calculator calculate NTC values for Lithuania-Latvia Cross-Border Interconnection, taking into account assured emergency power reserves for TSOs to ensure readiness for normal operation after (N-1) Situation has occurred, by using following formula:

$$NTC = (TTC_1 + \sum_{i=1}^{n} K_i \cdot P_i) - TRM \quad (5)$$

where:

$$(TTC1 + \sum_{i=1}^{n} K_i \cdot P_i) \leq TTC \quad (6)$$

where:

TTC_1 – Total Transfer Capacity after (N-1) Situation has occurred from actual power system network status according to Instruction for parallel operation in the Lithuania-Latvia Cross-Border Interconnection;

P_i – all available amount of assured emergency power reserves for respective power system *i(shall be provided by respective TSO for coming year until 1st of December to the Capacity calculator and to respective TSO's)*

K_i – reserve power distribution coefficients considering location of the assured emergency power reserve P_i and down regulation according to Table 2 of this Methodology

n – number of power systems;

TTC – Total Transfer Capacity in actual power system network status according to Instruction for parallel operation in the Lithuania-Latvia Cross-Border Interconnection;

TRM – Transmission Reliability Margin calculated according to the methodology described in Section 7 of this Methodology.

8.2.2 In case if during capacity validation process neighbouring TSOs determine different NTC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

Intraday Available Transmission Capacity calculation

8.2.3 Actual D-1 CGM with day-ahead trading results shall be used and new BRELL Loop power flow calculations shall be performed.

8.2.4 In case if Russia D-1 planning stage data is not available, TSOs and Capacity calculator shall take into account Russia D-2 planning stage data. New intraday ATC values shall be calculated and coordinated as soon as Russia D-1 planning stage data is available.

8.2.5 ATC values for Latvia-Lithuania Cross-Border Interconnection are calculated as follows:

8.2.6 TSOs and Capacity calculator calculate intraday ATC values for Lithuania-Latvia Cross-Border Interconnection as follows:

In direction to Lithuania:

If direction of ATC, for which calculation is performed, corresponds to direction of AAC:

$$ATC = \min(NTC - P_{PF};\ NTC - AAC + TRM) \qquad (7)$$

If direction of ATC, for which calculation is performed, does not correspond to direction of AAC:

$$ATC = NTC - P_{PF} \qquad (8)$$

In direction to Latvia:

ATC in direction to Latvia is calculated taking into account possible worst case of Intraday Market trade that increase Physical Congestion of Cross-Border Interconnections:

$$ATC_{LT\text{->}LV} = \min(NTC - P_{PF};\ NTC - AAC + TRM;\ (NTC_{coord} - P_{PF})_{EE\text{->}LV}) \qquad (9)$$

where:

NTC – coordinated Net Transmission Capacity in the particular Cross-Border Interconnection;

P_{PF} – calculated power flow in the particular Cross-Border Interconnections performed with actual D-1 CGM;

AAC - Already Allocated Capacity in the particular Cross-Border Interconnection after previous capacity allocation phases;

TRM – coordinated TRM value from coordinated TTC and NTC values;

$(NTC_{coord} - P_{PF})_{EE\text{-->}LV}$ – calculated remaining capacity after previous capacity allocation phases by taking into account power flow calculation in Estonia-Latvia Cross-Border Interconnection in direction from Estonia to Latvia.

ATC value in formula (8) of these Rules is calculated considering that the TSOs and Capacity calculator shall, as far as technically possible, net the capacity values of any power flows in opposite directions over congested interconnection line in order to use that line to its maximum capacity.

8.2.7 In case if during capacity validation process neighbouring TSOs determine different ATC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

8.2.8 Reserve power distribution coefficients (see Table 2 of this Methodology) in controlled cross-borders show the impact of power exchange program between two power systems on the loading of controlled Cross-Border Interconnections. Reserve power distribution coefficients in controlled Cross-Border Interconnections of BRELL Loop are determined using BRELL grid model that includes power systems of Belarus, Russia (North-West power system), Estonia, Latvia, Lithuania, Ukraine and Kaliningrad area. In order to determine reserve power distribution coefficients, power flows have been modelled by increasing of generation in exporting power system and symmetrical decreasing of generation in consuming power system.

8.2.9 Values of reserve power distribution coefficients used according to availability of appropriate amount of down regulation reserves. Amount of down regulation reserves in percentage is evaluated as proportion of available down regulation reserves on one cross-border side to available amount of assured emergency power reserves from another cross-border side.

Table 2. Reserve power distribution coefficients

Amount of down regulation power, %	Cross-Border Interconnections	Reserves location			
		Lithuania	Latvia	Belarus	Estonia
100	Latvia→Lithuania	0,88		0,72	
	Lithuania→ Latvia		0,88		0,62
50	Latvia→Lithuania	0,61		0,44	
	Lithuania→ Latvia		0,72		0,46
0	Latvia→Lithuania	0,34		0,16	
	Lithuania→ Latvia		0.55		0,29

8.3 Trading Capacity Calculation Rules Between Estonian and Finnish Power Systems

8.3.1 TTCs on cross-border Estonia-Finland are validated and calculated by respective TSOs and Capacity calculators on both sides of the interconnector using CGMs that represent the AC-networks of observable areas of synchronous areas that each belong to.

8.3.2 Trading Capacity is defined according to formula NTC=TTC-TRM in each side of HVDC link.

8.3.3 NTC between Finland and Estonia that is allocated to the market is calculated according to formula:

$$NTC_{FI\text{-}EE} = \min(FI\ NTC_{FI\text{-}EE};\ EE\ NTC_{FI\text{-}EE}) \tag{10}$$

where:

FI $NTC_{FI\text{-}EE}$ – NTC between FI and EE Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Finland side), EE NTC_{FI-EE} – NTC between FI and EE Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous or technical limitation on HVDC interconnection (from Estonia side).

Intraday capacity allocation procedure

8.3.4 The available capacity after the Day-Ahead Market results is offered to the Intraday Market in line with actual operational conditions. The intraday capacity can be influenced by changed TTC caused by changes in prognosis, topology, and in maintenance plans.

8.3.5 Intraday Trading Capacity on cross-border Estonia-Finland is allocated according formula:

$$ATC_{FI-EE} = NTC_{FI-EE} - AAC_{FI-EE} \tag{11}$$

where:

NTC_{FI-EE} – NTC between FI and EE Bidding Zones,

AAC_{FI-EE} – Already Allocated Capacity in the Finland-Estonia interconnection for relevant time period,

8.4 Trading Capacity Calculation Rules Between Lithuanian and Swedish Power Systems

8.4.1 TTCs on cross-border Lithuania-Sweden are checked and calculated by respective TSOs and Capacity calculators on both sides of the interconnector using CGMs that represent the AC-networks of observable areas of synchronous areas that each belong to.

8.4.2 Trading Capacity is defined according to formula NTC=TTC-TRM in each side of HVDC link.

8.4.3 NTC between Sweden and Lithuania that is allocated to the market is calculated according to formula:

$$NTC_{SE-LT} = \min (SE\ NTC_{SE-LT};\ LT\ NTC_{SE-LT}) \tag{12}$$

where:

SE NTC_{SE-LT} – NTC between SE and LT Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Sweden side);

LT NTC_{SE-LT} – NTC between SE and LT Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Lithuania side).

Intraday capacity allocation procedure

8.4.4 The available capacity is reassessed after the Day-Ahead Market and offered to the Intraday Market in line with actual operational conditions. The intraday capacity can be influenced by changed TTC caused by changes in prognosis, topology, and in maintenance plans.

8.4.5 Matched trading capacity on cross-border Lithuania-Sweden is allocated according formula:

$$ATC_{LT\text{-}SE} = \min (LT\ NTC_{LT\text{-}SE};\ SE\ NTC_{LT\text{-}SE}) - AAC \qquad (13)$$

where:

LT $NTC_{LT\text{-}SE}$ – NTC between LT and SE Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Lithuania side);

SE $NTC_{LT\text{-}SE}$ – NTC between LT and SE Bidding Zones, determined operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Sweden side);

AAC – Already Allocated Capacity in the Lithuania-Sweden interconnection.

8.5 Trading Capacity Calculation Rules Between Lithuanian and Polish Power Systems

8.5.1 TTC on cross-border Lithuania-Poland are checked and calculated by respective TSOs and Capacity calculators on both sides of the interconnector using on Lithuanian side Baltic CGMs that represent the AC-networks of observable area and on Polish side Polish Individual Grid Model supplemented by subtransmission 110 kV grid.

8.5.2 Trading Capacity is defined according formula NTC=TTC-TRM in each side of HVDC link by respective TSO's and Capacity calculator.

8.5.3 The matched NTC are defined according to the following formulas taking into account the losses depending on the direction and number of the circuits of Elk Bis-Alytus 400 kV line in operation:

<u>For direction from Lithuania to Poland (settlement point) in Elk Bis 400 kV):</u>

8.5.4 Two circuits of Elk Bis-Alytus 400 kV line in operation:

$$NTC_{LT\text{-}PL} = \min (PL\ NTC_{LT\text{-}PL};\ LT\ NTC_{LT\text{-}PL};\ 488\ MW) \qquad (14)$$

8.5.5 One circuit of Elk Bis-Alytus 400 kV line in operation:

$$NTC_{LT\text{-}PL} = \min (PL\ NTC_{LT\text{-}PL};\ LT\ NTC_{LT\text{-}PL};\ 485\ MW) \qquad (15)$$

where:

PL $NTC_{LT\text{-}PL}$ – NTC between LT and PL Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Poland side), if calculated NTC between LT and PL Bidding Zones is less than 50 MW, then PL $NTC_{LT\text{-}PL}$ shall be set to 0 MW;

LT $NTC_{LT\text{-}PL}$ – NTC between LT and PL Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas or technical limitation on HVDC interconnection (from Lithuania side), if calculated NTC between LT and PL Bidding Zones is less than 50 MW, then LT $NTC_{LT\text{-}PL}$ shall be set to 0 MW;

488 MW – technical capacity of the Link in Settlement Point ($NTC_{SettlementPoint}$) when both circuits of Elk Bis-Alytus line are in operation (i.e. decreased the 500MW input power of BtB by technical losses of HVDC converter, two circuits of 400kV line and shunt reactors);

485 MW – technical capacity of the Link in Settlement Point ($NTC_{SettlementPoint}$) when one circuit of Elk Bis - Alytus line is in operation (i.e. decreased the 500MW input power of BtB by technical losses of HVDC converter, one circuit of 400kV line and shunt reactors).

<u>For direction from Poland to Lithuania (Settlement Point in Alytus 330kV):</u>

8.5.6 Two circuits or one circuit of Elk Bis-Alytus 400 kV line in operation:

$$NTC_{LT\text{-}PL} = \min(PL\ NTC_{LT\text{-}PL};\ LT\ NTC_{LT\text{-}PL};\ 492\ MW) \tag{16}$$

where:

PL $NTC_{LT\text{-}PL}$ – NTC between LT and PL Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas (from Poland side), if calculated NTC between LT and PL Bidding Zones is less than 50 MW, then PL $NTC_{LT\text{-}PL}$ shall be set to 0 MW;

LT $NTC_{LT\text{-}PL}$ – NTC between LT and PL Bidding Zones, determined by operational security limits in Baltic CCR TSOs' synchronous areas (from Lithuania side) , if calculated NTC between LT and PL Bidding Zones is less than 50 MW, then LT $NTC_{LT\text{-}PL}$ shall be set to 0 MW;

492 MW – technical capacity of the Link in Settlement Point ($NTC_{SettlementPoint}$) when both circuits or one circuit of Elk Bis - Alytus line are in operation (i.e. decreased the 500MW input power of BtB by technical losses of HVDC converter).

Intraday capacity calculation procedure

8.5.7 The available capacity is reassessed after the Day-Ahead Market and offered to the Intraday Market in line with actual operational conditions. The intraday capacity can be influenced by changed TTC caused by changes in prognosis, topology, and in maintenance plans.

8.5.8 The available transfer capacity ATC LT-PL, shall be calculated:

<u>For direction from Lithuania to Poland (Settlement Point in Elk Bis 400 kV):</u>

8.5.9 Two circuits of Elk Bis-Alytus 400 kV line in operation:

$$ATC_{LT\text{-}PL} = \min(PL\ NTC_{LT\text{-}PL};\ LT\ NTC_{LT\text{-}PL};\ 488\ MW) - AAC_{Day\ ahead} \tag{17}$$

8.5.10 One circuit of Elk Bis-Alytus 400 kV line in operation:

$$ATC_{LT\text{-}PL} = \min(PL\ NTC_{LT\text{-}PL};\ LT\ NTC_{LT\text{-}PL};\ 485\ MW) - AAC_{Day\ ahead} \tag{18}$$

<u>For direction from Poland to Lithuania (settlement point in Alytus 330kV):</u>

8.5.11 Two circuits or one circuit of Elk Bis-Alytus 400 kV line in operation:

$$ATC_{LT\text{-}PL} = \min(PL\ NTC_{LT\text{-}PL};\ LT\ NTC_{LT\text{-}PL};\ 492\ MW) - AAC_{Day\ ahead} \tag{19}$$

where:

PL $NTC_{LT\text{-}PL}$ – NTC between LT and PL Bidding Zones for Intraday Market, determined by operational security limits in Baltic CCR TSOs' synchronous areas (from Poland side), if calculated NTC between LT and PL Bidding Zones is less than 50 MW, then PL NTC_{LT-PL} shall be set to 0 MW;

LT NTC_{LT-PL} – NTC between LT and PL Bidding Zones for Intraday Market, determined by operational security limits in Baltic CCR TSOs' synchronous areas (from Lithuania side), if calculated NTC between LT and PL Bidding Zones is less than 50 MW, then LT NTC_{LT-PL} shall be set to 0 MW;

488 MW – technical capacity of the Link in Settlement Point ($NTC_{SettlementPoint}$) when both circuits of Elk Bis-Alytus line are in operation (i.e. decreased the 500MW input power of BtB by technical losses of HVDC converter, two circuits of 400kV line and shunt reactors);

485 MW – technical capacity of the Link in Settlement Point ($NTC_{SettlementPoint}$) when one circuit of Elk Bis - Alytus line is in operation (i.e. decreased the 500MW input power of BtB by technical losses of HVDC converter, one circuit of 400kV line and shunt reactors);

492 MW – technical capacity of the Link in Settlement Point ($NTC_{SettlementPoint}$) when both circuits or one circuit of Elk Bis - Alytus line are in operation (i.e. decreased the 500MW input power of BtB by technical losses of HVDC converter);

$AAC_{Day-ahead}$ – Already Allocated Capacity in the Lithuania-Poland interconnections after day-ahead trading.

9 INTRADAY CAPACITY (ATC) REASSESSMENT FREQUENCY

9.1 Reassessment of Intraday capacity value (ATC) shall be performed every time if any of the following situations occur:

9.1.1 Changes in topology of transmission network - unplanned outages or unplanned (earlier) returning to operation of network elements that affect transmission capacities;

9.1.2 Day-Ahead Market results update, e.g. in case of fall-back procedure applied by NEMO.

9.1.3 Major changes in generation plans as a result of renewable generation forecasts changes;

9.2 Reasons for reassessment - changes in topology of transmission network, as well as update of Day-Ahead Market results affect operational conditions of power systems, therefore ATC reassessment shall be performed in order to ensure operations security of power systems.

10 CROSS-ZONAL CAPACITY VALIDATION METHODOLOGY

10.1 Each TSO shall validate and have the right to correct Cross-Zonal Capacity relevant to the TSO's Bidding Zone borders or Critical Network Elements provided by the Capacity calculators in accordance with Articles 27 to 31 of CACM.

10.2 Each TSO may reduce Cross-Zonal Capacity during the validation of Cross-Zonal Capacity referred to in Article 10.1 for reasons of Operational Security.

10.3 CACM Article 26.2 (rule for splitting the correction of Cross-Zonal Capacity) is not included in this methodology due to the fact that splitting of capacities among borders of Baltic CCR is not performed.

11 CAPACITY CALCULATION FALLBACK PROCEDURE

11.1 If Cross-Zonal Capacities cannot be calculated by Capacity calculator, Capacity calculator informs respective TSOs on inability to calculate capacities. Then respective TSOs calculate and coordinate capacities for respective Cross-Border Interconnections among themselves and provide coordinated capacities to Capacity calculator.

12 PROVISION AND ALLOCATION OF TRADING CAPACITY

12.1 Baltic CCR TSOs provide calculated and validated Trading Capacities and allocation constraints for relevant trading time frames to MCO for subsequent capacity allocation through implicit auctioning carried out by MCO.

Trading Capacities within the Baltic CCR are provided and allocated, subject to allocation constraints, in day-ahead and intraday time frames – Day Ahead Market and Intraday Market. No physical capacity allocation is made before day-ahead implicit allocation and no physical capacity is reserved for long-term capacity on the Baltic CCR borders.

12.2 Trading Capacities for Intraday Market on cross-border Lithuania-Poland are not being provided and allocated until agreement among PSE and Litgrid on operation of Intraday Market on Lithuania-Poland cross-border will be concluded. After starting of Intraday Market on cross-border Lithuania-Poland capacity shall be calculated according rules described in clauses 8.5.7-8.5.11.

Provision and allocation of Trading Capacity between Baltic CCR power systems

12.3 Trading Capacities provided for trade between the Baltic CCR Bidding Zones are equal to the offered capacities calculated according to the Section 8 of this Methodology, and which is subsequently allocated through the implicit auctioning following the trading rules established by the MCO, subject to allocation constraints.

13 FIRMNESS

13.1 After the Day-ahead Firmness Deadline, all Cross-Zonal Capacity and allocation constraints are firm for day-ahead capacity allocation unless in case of Force Majeure or Emergency Situation.

13.2 The Day-ahead Firmness Deadline is 60 minutes before Day-Ahead Gate Closure Time unless there is other deadline included in “All TSOs’ Proposal for the day-ahead firmness deadline (DAFD) in accordance with Article 69 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management”.

13.3 After the Day-ahead Firmness Deadline, Cross-Zonal Capacity which has not been allocated may be adjusted for subsequent allocations, subject to allocation constraints.

13.4 Intraday Cross-Zonal Capacity is firm as soon as it is allocated, subject to allocation constraints, unless in case of Force Majeure or Emergency Situation.

14 RULES FOR AVOIDING UNDUE DISCRIMINATION BETWEEN INTERNAL AND CROSS-ZONAL EXCHANGES

14.1 When defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity. Specifically, TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area, save for the abovementioned reasons and reasons of operational security. If such situation occurs, this shall be described and transparently presented by the TSOs to all the system users. Such situation shall be tolerated only until a long-term solution is found.

14.2 The methodology and projects for achieving the long-term solution shall be described and transparently presented by the TSOs to all the system users.

The methodology and projects for achieving the long-term solution can be implicitly described in existing TSOs' documents:

- TSOs' individual power transmission system development documents;
- TSOs' common power transmission system development documents, e.g. ENTSO-E "Ten year network development plan";

In case if the methodology and projects for achieving the long-term solution is implicitly described in existing TSOs' documents, creation of additional explanatory document(-s) is not required.

15 IMPLEMENTATION OF THE METHODOLOGY

15.1 The TSOs shall implement the Methodology within 3 months after all the following provisions are fulfilled:

a) NRA approval of the Methodology within the Baltic CCR or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(11) and 9(12) of the CACM Regulation,:
b) The implementation of the Coordinated redispatching and countertrading Methodology according to Article 35 of the CACM Regulation;
c) The implementation of the Redispatching and Countertrading Cost Sharing Methodology within the Baltic CCR required by Article 74 of the CACM Regulation.
d) Baltic NRAs' approval and implementation of the document specifying Terms, Conditions and Methodology on Cross-Zonal Capacity Calculation, Provision and Allocation with the 3rd Countries for borders of Baltic States and 3rd Countries (Estonia-Russia, Latvia-Russia, Lithuania-Belarus, Lithuania-Russia(Kaliningrad area)).

15.2 The Methodology shall be published on web pages of Baltic CCR TSO within 7 days after NRA approval of the Methodology within the Baltic CCR or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(11) and 9(12) of the CACM Regulation.

APPENDIX 1: USE OF ALLOCATION CONSTRAINTS AS DESCRIBED IN SECTION 3.5

1. Justification for using allocation constraints in the form of import and export limits

<u>The link between net position and operational security limits</u>

Under CACM, allocation constraints are understood as *constraints needed to keep the transmission system within operational security limits,* which are in turn defined as *acceptable operating boundaries for secure grid operation*. The definition of the latter (Art. 2.7 CACM) lists *inter alia* frequency limits as one of the boundaries to be taken into account.

With regard to constraints used to ensure sufficient operational reserves, if one of interconnected systems suffers from insufficient reserves in case of unexpected outages or unplanned load change (applies to central dispatch systems), there may be a sustained deviation from scheduled exchanges of the TSOs in question. These deviations may lead to an imbalance in the whole synchronous area, causing the system frequency to depart from its nominal level. Even if frequency limits are not violated, as a result, deviation activates frequency containment reserves, which will thus not be available for another contingencies, if required as designed. If another contingency materializes, the frequency may in consequence easily go beyond its secure limits with all related negative consequences. This is why such a situation can lead to a breach of operational security limits and must be prevented by keeping necessary reserves within all bidding zones, so that no TSO deviates from its schedule in a sustained way (i.e. more than 15 minutes, within which frequency restoration reserve shall be fully deployed by given TSO). Finally, the inability to maintain scheduled area balances resulting from insufficient operational reserves will lead to uncontrolled changes in power flows, which may trigger lines overload (i.e. exceeding the thermal limits) and as a consequence can lead to system splitting with different frequencies in each of the subsystems.

<u>Legal interpretation: eligible grounds for applying allocation constraints</u>

Regarding the process of defining what allocation constraints should be applied, it should first be noted that allocation constraints (‘ACs’) are tools defined as to their purpose. CACM does not enumerate ACs in a form of a list which would allow for checking whether specific constraint is allowed by the Regulation. Thus, the application of provision on allocation constraints requires further interpretation.

CACM was issued based on Regulation 714/2009 and complements that Regulation. The general principle in Regulation 714/2009 (Art. 16.3) is that TSOs make available the maximum capacity allowed under secure network operation standards. Operational security is explained in a footnote to annex I *as keeping the transmission system within agreed security limits*. CACM rules on AC and operational security limits (‘OSLs’) seem to regulate the same matter as Article 16.3 in greater detail. The definition of ACs relates to OSLs, so to define what is an allocation constraint, we first need a clear idea of OSLs.

Similarly to the ‘open’ notion of allocation constraints in the CACM, the definition of OSLs (*the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits*) does not include an enumerative catalogue (a closed set), but an open set of system operation characteristics defined as to their purpose – ensuring secure grid operation. The list is indicative (using the words ‘such as’). The open-set character of the definition is also indicated by systemic interpretation, i.e. by the usage of the term in other network codes and guidelines.

In SO GL, the definitions of specific system states involve a role of significant grid users (generating modules and demand facilities). To be in the ‘normal’ state, a transmission system requires sufficient active and reactive power reserves to make up for occurring contingencies (Art. 18) – the possible influence of such issues on cross-zonal trade has been mentioned above. Operational security limits as understood by SO GL are also not defined as a closed set, as Article 25 requires each TSO to *specify the operational security limits for each element of its transmission system, taking into account **at least** the following physical characteristics (…)*. The

CACM definition of contingency (*identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security*) is therefore consistent with the abovementioned SO GL framework, and shows that CACM application should involve circumstances related to generation and load.

Moreover, as regards the way the TSOs procure balancing reserves, it should be noted that the Guideline on Electricity Balancing (EB GL) allows TSOs to apply integrated scheduling process in which energy and reserves are procured simultaneously (inherent feature of central dispatch systems). In such a case, ensuring sufficient reserves requires setting a limit to how much can be imported or exported by the system as a whole (explained in more detail below). If CACM is interpreted as excluding such a solution and mandating that a TSO offers capacity even if it may lead to insufficient reserves, this would make the provisions of EB GL void, and make it impossible or at least much more difficult to comply with SO GL.

In PSE's point of view, systemic interpretation allows for consistent implementation of all network codes. In this specific case, understanding operational security limits under CACM can be complemented by applying SO GL provisions. These, in turn, require the TSOs to apply specific market mechanisms to ensure that generation and load schedules resulting from cross-zonal trade do not endanger secure system operation. In sum, operational security limits cover a broad set of system characteristics to be respected when defining the domain for cross-zonal trade. With regard to generation and load, this is done by applying allocation constraints, in this case balancing constraints, in the form of import/export limits.

The CACM provisions on ACs should also be interpreted systemically. They ensure offering maximum possible trading opportunities while preserving system security. CACM and Regulation 714/2009 should also be interpreted in the light of Union policy on energy as prescribed in Article 194 of the TFEU. The four objectives (to *ensure the functioning of the energy market; ensure security of energy supply in the Union; promote energy efficiency and energy saving and the development of new and renewable forms of energy; and promote the interconnection of energy networks*) are of equal importance and are balanced against each other, as well as applied in the spirit of solidarity between the Member States.

In the context of allocation constraints, these principles can be seen as requiring TSOs in each Member State to use market processes to ensure security of supply as far as possible, only limited by legitimate (non-arbitrary) constraints where not applying them could threaten security of supply in one or more control areas.

CACM provisions on allocation constraints reflect these trade-offs. See e.g. recital (18), which mandates that the Union-wide price coupling process respects transmission capacity and allocation constraints. Therefore, it can be concluded that CACM does not mandate trading opportunities to the point of endangering security of supply. If there is no arbitrary discrimination, CACM, along with other codes, allow a TSO to *ex ante* prevent loss of network stability or occurrence of insufficient reserves.

2. How import and export limits contribute to meeting the CACM objectives?

<u>Contribution to meeting the CACM objectives</u>

Recital 2 of CACM Regulation preamble draws a reciprocal relationship between security of supply and functioning markets. Thanks to grid interconnections and cross-zonal exchange, member states do not have to fully rely on their own assets in order to ensure security of supply. At the same time, however, the internal market cannot function properly if grid security is compromised, as market trade would constantly be interrupted by system failures, and as a result potential social welfare gains would be lost. Recital 18 can be seen as a follow-up, drawing boundaries to ensure a Union-wide price coupling process, namely to respect transmission capacity and allocation constraints.

For the above reasons, one of the aims of the CACM Regulation, as expressed in Article 3, is to ensure operational security. This aim should be fulfilled insofar it does not prejudice other aims. As explained in this methodology, allocation constraints applied by Baltic CCR TSOs are proportional and do not undermine other aims of CACM Regulation.

Compliance of the three reasons for allocation constraints with Article 23

Article 23 requires that allocation constraints are:

1) a) required to maintain the system within operational security limits and b) cannot be transformed efficiently into maximum flows on critical network elements; or

2) intended to increase the economic surplus for single day-ahead or intraday coupling.

As demonstrated under point 1 above, maintaining the transmission system within operational security limits also requires maintaining the necessary reserves to respond to possible contingencies. The inability to efficiently transform these constraints into maximum flows on individual borders is explained below. Therefore, allocation constraints as proposed should be seen as compliant with the CACM regulation.

3. Detailed reasons and method for calculating allocation constraints by PSE

Allocation constraints in Poland are applied as stipulated in Article 8.5 of the CCM methodology. These constraints reflect the ability of Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical characteristics of individual generating units as well as the necessity to maintain minimum generation reserves required in the whole Polish power system to ensure secure operation. This is explained further in subsequent parts of this document.

Rationale behind the implementation of allocation constraints on PSE side

Implementation of allocation constraints as applied by PSE side is related to the fact that under the conditions of integrated scheduling based market model applied in Poland (also called central dispatch system) responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO in so-called self-dispatch market models. The latter is usually defined up to hour-ahead time frame (including real time operations), while for PSE as Polish TSO this is extended to intraday and day-ahead time frames. Thus, PSE bears the responsibility, which in self dispatch markets is allocated to balance responsible parties (BRPs). That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which sometimes leads to implementation of allocation constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation capacity and residual demand[1] (this is why such allocation constraints are called balancing constraints). In self dispatch markets BRPs are themselves supposed to take care about their generating reserves and load following, while TSO ensures them just for dealing with contingencies in the time frame of up to one hour ahead. In a central-dispatch market, in order to provide generation and demand balance, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve requirements. This is realized in an integrated scheduling process as an optimisation problem called security constrained unit commitment and economic dispatch (SCUC/ED). Thus these two approaches ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.

PSE role in system balancing

PSE directly dispatches all major generating units in Poland taking into account their operational characteristics and transmission constraints in order to cover the expected load, which is also

[1] Residual demand is the part of end users' demand not covered by commercial contracts (generation self-schedules).

forecasted by PSE, having in mind adequate reserve requirements. To fulfil this task PSE runs the process of operational planning, which begins three years ahead with relevant overhaul (maintenance) coordination and is continued via yearly, monthly and weekly updates to day-ahead SCUD and ED. The results of this day-ahead market are then updated continuously in intraday time frame up to real time operation.

In a yearly timeframe PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that on average the minimum year ahead reserve margin[2] over forecasted demand including already allocated capacities on interconnections is kept on average in each month. The monthly and weekly updates aim to keep a certain reserve margin on each day[3], if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

The day-ahead SCUC process aims to achieve a set value of spinning reserve[4] (or quickly activated, in current Polish reality only units in pumped storage plants) margin for each hour of the next day, enabling up and down regulation. This includes primary and secondary control power pre-contracted as an ancillary service. The rest of this reserve comes from usage of balancing bids, which are mandatory to be submitted by all centrally dispatched generating units (in practice all units connected to the transmission network and major ones connected to 110 kV, except CHP plants as they operate mainly according to heat demand). The remaining generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is a workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE. Thus, PSE has the right to use any available centrally dispatched generation in normal operation to balance the system. The negative reserve requirements during low load periods (night hours) are also respected and the potential pumping operation of pumped storage plants is taken into account, if feasible.

The further updates of SCUC/ED during the operational day take into account any changes happening in the system (forced outages and any limitations of generating units and network elements, load and wind forecast updates, etc.). It allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW, i.e. potential loss of the largest generating unit, currently 850 MW (subject to change as new units are commissioned) and ca 150 MW of primary control reserve (frequency containment reserve) being PSE's share in RGCE.

Determination of balancing constraints in Poland

When determining the balancing constraints, the Polish TSO takes into account the most recent information on the aforementioned technical characteristics of generation units, forecasted power system load as well as minimum reserve margins required in the whole Polish power system to ensure secure operation and forward import/export contracts that need to be respected from previous capacity allocation time horizons.

Balancing constraints are bidirectional, with independent values for each market time unit, and separately for directions of import to Poland and export from Poland.

For each hour, the constraints are calculated according to the below equations:

$$\mathrm{EXPORT}_{constraint} = \mathrm{P}_{CD} - (\mathrm{P}_{NA} + \mathrm{P}_{ER}) + \mathrm{P}_{NCD} - (\mathrm{P}_{L} + \mathrm{P}_{UPres}) \quad \textbf{(1)}$$

[2] The margin is regulated by the Polish grid code and currently set at 18% (point II.4.3.4.18). It is subject to change depending on the results of the development of operational planning processes.

[3] The margin for monthly and weekly coordination is also regulated by the Polish grid code (point II.4.3.4.18) and currently set at 17% and 14% respectively.

[4] The set values are respectively: 9% over forecasted demand for up regulation and 500 MW for down regulation. These values are regulated by the Polish grid code (point 4.3.4.19) and subject to change – see footnote 2.

$$\mathrm{IMPORT}_{constraint} = \mathrm{P}_L - \mathrm{P}_{DOWNres} - \mathrm{P}_{CD_{min}} - \mathrm{P}_{NCD} \tag{2}$$

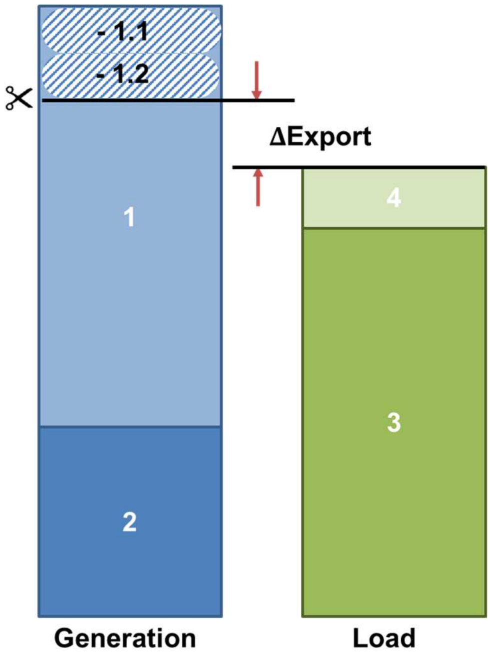
where:

P_{CD}	sum of available generating capacities of centrally dispatched units as declared by generators[5]
$\mathrm{P}_{CD_{min}}$	sum of technical minima of centrally dispatched generating units in operation
P_{NCD}	sum of schedules of not centrally dispatched generating units , as provided by generators (for wind farms: forecasted by PSE)
P_{NA}	generation not available due to grid constraints
P_{ER}	generation unavailabilities adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
P_L	demand forecasted by PSE
P_{UPres}	minimum reserve for up regulation
$\mathrm{P}_{DOWNres}$	minimum reserve for down regulation

For illustrative purposes, the process of practical determination of balancing constraints in the framework of day ahead transfer capacity calculation is illustrated below: figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the next day is developed by TSO day ahead in the morning in order to determine reserves in generating capacities available for potential exports and imports, respectively, for day ahead market. For the intraday market, the same method applies *mutatis mutandis*.

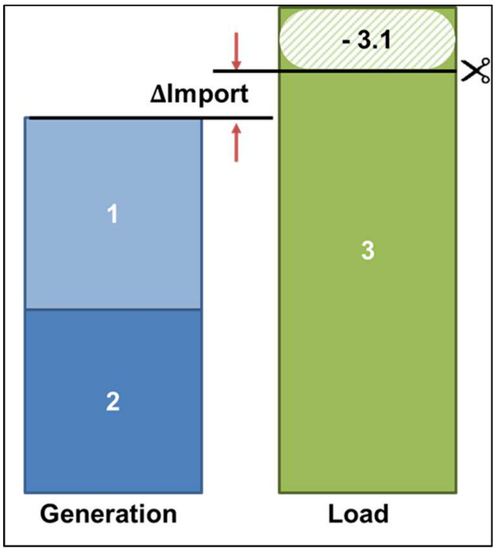
Balancing constraint in export direction is applicable if ∆Export is lower than the sum of transfer capacities on all Polish interconnections in export direction. Balancing constraint in import direction is applicable if ∆Import is lower than the sum of transfer capacities on all Polish interconnections in import direction.

[5] Note that generating units which are kept out of the market on the basis of strategic reserve contracts with the TSO are not taken into account in this calculation.



1. sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
   1.1 generation not available due to grid constraints
   1.2 generation unavailabilities adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
2. sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
3. demand forecasted by PSE
4. minimum necessary reserve for up regulation

Figure 1: Determination of balancing constraints in export direction (generating capacities available for potential exports) in the framework of day ahead transfer capacity calculation.



1 sum of technical minima of centrally dispatched generating units in operation

2 sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)

3 demand forecasted by PSE, reduced by:
   3.1 minimum necessary reserve for down regulation

Figure 2: Determination of balancing constraints in import direction (reserves in generating capacities available for potential imports) in the framework of day ahead transfer capacity calculation.

Frequency of re-assessment

Balancing constraints are determined in a continuous process based on the most recent information, for each capacity allocation time horizon, from forward till day-ahead and intra-day. In case of day-ahead process, these are calculated in the morning od D-1, resulting in independent values for each market time unit, and separately for directions of import to Poland and export from Poland.

Impact of balancing constraints on single day-ahead coupling and single intraday coupling

Allocation constraints in form of balancing constraints as applied by PSE do not diminish the efficiency of day-ahead and intraday market coupling process. Given the need to ensure adequate availability of generation and generation reserves within Polish power system by PSE as TSO acting under central-dispatch market model, and the fact that PSE does not purchase operational reserves ahead of market coupling process, imposing constraints on maximum import and export in market coupling process – if necessary - is the most efficient manner of reconciling system security with trading opportunities. This approach results in at least the same level of generating capacities participating in cross border trade as it is the case in self-dispatch systems, where reserves are bought in advance by BRPs or TSO so they do not participate in cross border trade, either. Moreover, this allows to avoid competition between TSO and market participants for generation resources.

It is to be underlined that balancing constraints applied in Poland will not affect the ability of any Baltic CCR country to exchange energy, since these constraints only affect Polish export and/or import. Hence, transit via Poland will be possible in case of balancing constraints applied.

Impact of balancing constraints on neighbouring CCRs

Balancing constraints are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs, in which PSE has at least it's one border (i.e. Core, Baltic and Hansa).

It is to be underlined that this solution has been proven as the most efficient application of allocation constraints. Considering allocation constraints separately in each CCR would require PSE to split global allocation constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward generation requirements, or when Poland is unable to export any more power due to insufficient generation reserves in upward direction, Polish transmission infrastructure still can be – and indeed is - offered for transit, increasing thereby trading opportunities and social welfare in all concerned CCRs.

Time periods for which balancing constraints are applied

As mentioned above, balancing constraints are determined in a continuous process for each allocation timeframe, so they are applicable for all market time units (hours) of the respective allocation day.

Why these allocation constraints cannot be efficiently translated into capacities of - individual borders offered to the market

Use of capacity allocation constraints aims to ensure economic efficiency of the market coupling mechanism on these interconnectors while meeting the security requirements of electricity supply to customers. If the generation conditions described above were to be reflected in cross-border capacities offered by PSE in form of an appropriate adjustments of border transmission capacities, this would imply that PSE would need to guess most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the NTC approach, this would need to be done in the form of ATC reduction pre border. However, from the point of view of market participants, due to the inherent uncertainties of market results such approach is burdened with the risk of suboptimal splitting of allocation constraints into individual interconnections – overstated on one interconnection and underestimated on the other or vice versa. Consequently, application of allocation constraints to tackle the overall Polish balancing constraints at the allocation phase allows for the most efficient use of transmission infrastructure, i.e. fully in line with price differences in individual markets.