Capacity calculation methodology for the day-ahead and intraday market timeframes within the Baltic Capacity Calculation Region

Among:

AS "Augstsprieguma tikls"
Elering AS
LITGRID AB
PSE S.A.
Svenska kraftnat
Fingrid Oyj

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Vilnius, Riga, Tallinn, Helsinki, Stockholm, Warsaw

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2 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 Region (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 paragraphs 1.4.1 - 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 ensures non-discrimination in calculation of Cross-Zonal Capacities.

1.4.3. ensuring operational security (Article 3(c) of the CACM Regulation) by taking into account grid constraints and 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 this Methodology 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 allocations.

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. Principles described in this Methodology cover Cross-Zonal Capacity calculation, provision and allocation for day-ahead and intraday time horizons.

1.6. This Methodology also takes into account and acts upon the fact that the Baltic States are foreseen to be synchronized with the Continental Europe Synchronous Area by double circuit line connecting Poland and Lithuania. Upon synchronisation, the capacity of this interconnector will be determined considering principles described in whereas (54) of Regulation (EU) 2024/1747.

3 DEFINITIONS

For the purposes of this Methodology, the definitions in Articles 2 of Regulations (EC) No 2015/1222, No 2019/943, No 543/2013, Article 3 of Regulation (EC) No 2017/1485 and Article 2 of Directive No 2019/944 shall apply. In addition, the following definitions shall apply and shall have the following meaning:

AAC - the Already Allocated Capacity is the total amount of allocated physical transmission rights.

AST - AS “Augstsprieguma tikls”, electricity transmission system operator of the Republic of Latvia.

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.

Baltic CCR - Capacity calculation region Baltic. According to ACER decision No 04/2024 on the electricity TSOs’ proposal for Capacity Calculation Regions 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 tikls and LITGRID AB;

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.

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, Kingdom of Sweden.

Baltic LFC Block – region which consist of load-frequency control areas operated by Baltic TSOs -

Litgrid, AST and Elering.

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

BSPS - Baltic State Power Systems (Republic of Estonia, the Republic of Latvia and the Republic of Lithuania)

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

CEP - REGULATION (EU) 2019/943 of the European parliament and of the council of 5 June 2019 on the internal market for electricity

CESA – Continental Europe synchronous area.

CGM – Common grid model.

CGMES – Common grid model exchange standard.

Cross-Border Interconnection - is a physical transmission link (e.g. tie-line or combination of tie-lines) which connects two power systems.

CSA Methodology – methodology developed in accordance with European Commission Regulation (EU) No 2017/1485 establishing a Guideline on electricity transmission system operation Article 75.

D-1 – one day ahead planning timeframe.

D-2 - two days ahead planning timeframe.

EBGL - COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

Elering - Elering AS, Transmission System Operator of the Republic of Estonia.

Fingrid - Fingrid Oyj, electricity transmission system operator of the Republic of Finland.

ID - intraday planning timeframe.

IDA – Capacity auctions in ID timeframe according to CACM Regulation Article 35 where price coupling algorithm and of the continuous trading matching algorithm are applied.

IGM – Individual grid model.

Internal Baltic AC interconnectors – Interconnectors between Baltic TSOs in Baltic area, covering Lithuania – Latvia and Latvia – Estonia cross-borders.

Litgrid - LITGRID AB, electricity transmission system operator of the Republic of Lithuania.

Market Coupling Operator (MCO)/Nominated Electricity Market Operator (NEMO) - the operator/-s of day-ahead and intraday markets in Baltic CCR.

MTU – Market time unit.

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.

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

Regional Models – These models incorporate data on generation, transmission, distribution, and consumption within a Baltic region to facilitate effective planning, capacity calculation, and operational decisions, regional models are essential for optimizing grid operations, ensuring efficient cross-border electricity trade, and maintaining system stability by taking into account the unique characteristics and constrains of each region.

Shift Key – means of method used to translate net position changes within a given bidding zone into estimated changes in the common grid model. This includes both injection increases or decreases due to generation adjustments (Generation Shift Key) and contribution of load adjustments (Load Shift Key).

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

SvK - Svenska kraftnat, electricity transmission system operator in Sweden.

Trading Capacity - The total amount of electricity that can be bought, sold, or exchanged between market participants or regions within a power system. It represents the limit up to which energy transactions can occur without compromising the stability and reliability of the power system.

TRM - Transmission Reliability Margin which shall have meaning of "reliability margin" definition of CACM Regulation.

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.

4 CAPACITY CALCULATION AND VALIDATION PROCESS

4.1. Capacity calculation and validation process involves TSOs and Capacity Calculator and consists of these main steps:

- Input data provision by TSOs for Capacity Calculator (further detailed in Paragraph 4.3).
- Capacity calculation (further detailed in Sections 11 - 21).
- Capacity validation and coordination procedure (further detailed in Section 22).
- Capacity publication to market operator (further detailed in Section 24).

Detailed data exchange processes rules describing input data provision, capacity calculation, coordination, validation and process step timings shall be described in agreements between TSOs and Capacity Calculator.

4.2. TSOs of Baltic CCR shall set up Capacity Calculator according to rules set out in Article 27.2 of the CACM Regulation and Article 37.1.a of CEP Regulation and establish rules governing their operations defined in agreements between TSOs and Capacity Calculator.

4.3. TSOs of the Baltic CCR shall provide to the Capacity Calculator and coordinate between the TSOs and the Capacity Calculator the following inputs for TTC calculation according to Article 29.1 of the CACM Regulation:

- IGM - base case model, which includes power transmission equipment model of Control Area of TSO (according to CACM Article 17 and Section 10).
- Operational Security Limits (according to Section 6).

- Generation and Load Shift Keys (according to Section 8).
- Critical Network Elements (according to Section 4).
- Contingencies (according to Section 4).
- Remedial Actions (according to Section 9).
- TRM values or input data for TRM calculation (according to Section 14).
- Allocation constraints (according to Section 7).

4.4. If input data for capacity calculation process referred in 4.3 is used as static data and is constant in daily capacity calculation processes, such data shall be reviewed and shared between TSOs and Capacity Calculator at least on a yearly basis or upon TSO or Capacity Calculator request.

4.5. In accordance with Article 29 and 30 of the CACM Regulation, capacity calculation shall be performed by the Capacity Calculator whereas the TSOs shall provide required input data and perform validation.

5 CRITICAL NETWORK ELEMENTS AND CONTIGENCIES

5.1. Each Baltic CCR TSO shall define critical network elements (CNEs) of its control area for capacity calculation process.

5.2. The CNEs for capacity calculation shall be defined considering impact computation principles defined in CSA methodology annex 1 and factor determining impact for CNE shall be cross zonal power flow exchange. Internal CNEs which power flow filtering influence factor is less than defined in annex 1 of CSA methodology shall be excluded from capacity calculation process. The TSO shall update the CNE list in case of significant change in grid topology when influence value for CNE element significantly changed from average value. If an internal CNE constitute a structural congestion the TSO shall ensure that cross-border capacities is not impacted by the CNE.

5.3. A contingency analysis is performed for those contingencies which are agreed among Baltic CCR TSOs. Contingencies shall be agreed and provided among Baltic TSOs and provided to Capacity Calculator for Capacity Calculation.

5.4. Each Baltic CCR TSO shall provide Contingencies to be used in capacity calculation process determined in accordance with Article 33 of SO GL and CSA methodology annex 1. Contingencies shall be elements of TSO observability area. Contingency can be the outage of the following elements:

- Line, cable.
- Transformer.
- Generator.
- Load.
- Busbar.
- Multiple elements combined.
- HVDC.

5.5. Each Baltic CCR TSO and Capacity Calculator shall perform regular review of CNEs, Contingencies and other input data and evaluate their relevance in capacity calculation process according to paragraph 5.2. Such evaluation shall be performed at least on a yearly basis.

6 OPERATIONAL SECURITY LIMITS

6.1. Operational security analyses shall be performed with respect of Operational Security limits applied in Control Areas of Baltic CCR TSOs. Operational Security limits shall be determined by taking into account thermal limits, voltage limits, dynamic stability limits (including, rotor angle and voltage stability, frequency stability, small signal stability) in accordance with Article 25 of SO GL.

6.2. Thermal limits shall correspond maximum amount of electric current that a given network element can conduct without sustaining damage or being in violation of safety requirements taking into account ambient conditions (based on TSOs thermal limits assessment procedure). Thermal limits are applied for performing of steady state analysis.

6.3. Voltage limits shall correspond maximum and minimum voltage levels permitted at given network node to prevent equipment damage or voltage collapse (based on TSOs voltage limits assessment procedure). Voltage limits is applied for performing of steady state analysis.

6.4. Dynamic stability limits shall be calculated by evaluating:

6.4.1. Rotor angle stability limits - defined during dynamic stability analysis by applying N-1 disturbances (including three phase symmetrical fault) and analysing behaviour of relative rotor angles among generators, rotor angle stability is maintained if after fault generators relative rotor angles among generators don’t exceed critical relative rotor angles values (remain in synchronous operation).

6.4.2. Voltage stability limits - defined during dynamic stability analysis by applying N-1 disturbances (including three phase symmetrical fault) and analysing network node voltages, voltage stability is maintained if voltage doesn’t exceed critical voltage, which can lead to voltage collapse.

6.4.3. Frequency stability limits - defined by performing frequency stability analysis by evaluating possible biggest imbalance of BSPS from frequency stability point of view after disconnection of Lithuania-Poland cross border interconnection. Frequency stability is maintained if imbalance which occurs after disconnection of Lithuania-Poland does not cause violations of defined boundaries of underfrequency, over frequency and rate of change of frequency.

6.4.4. Small signal stability limits – defined by performing small signal stability analysis to evaluate damping level of oscillations caused by swinging of generators in BSPS against other generators in CESA. Small signal stability limits are maintained if damping of inter area oscillation is not lower, then defined minimum damping level.

6.5. Operational Security limits used in capacity calculation shall be the same as those used in operational security analysis performed according to Articles 74 and 75 of SO GL. Each TSO shall provide thermal and voltage Operational Security limits for electrical system elements within its IGM.

6.6. Baltic CCR TSOs and Capacity Calculator shall perform regular review of Operational Security limits and evaluate their relevance in Capacity Calculation. Such evaluation shall be performed at least on a yearly basis.

6.7. Stability limits referred in paragraph 6.4 evaluation shall be performed according to TSOs stability assessment procedures.

7 ALLOCATION CONSTRAINTS

7.1. In accordance with the definitions in Article 2 points (6) and (7), Article 23(3) 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. Allocation constraints are determined by Baltic CCR TSOs and taken into account during the single day-ahead and intraday coupling in addition to the power flow limits on Cross-Border Interconnections.

7.2. Allocation constraints can be applied as:

a) Constraint on the cross-border and/or on the global net position (the sum of all Cross-Border exchanges for a bidding zone in the single day-ahead and intraday coupling) considered as balancing constraint, thus limiting the net position of the respective bidding zone with regards to all CCRs which are part of the single day-ahead and intraday coupling described in paragraphs 7.3 and 7.4.

b) Constraint translated into ramping restrictions on HVDCs as described in paragraphs 7.5 and 7.6.

c) Implicit loss factor constraint for HVDC interconnector as described in paragraphs 7.7 and 7.8

7.3. A TSO can also use 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. Allocation constraints may be used for an interim period of 2 years following the implementation of this Methodology. If any of the Baltic CCR TSOs still want to use allocation constraints after this period, they shall deliver a proposal for amendments to this Methodology, describing the technical details for calculating the allocation constraints and the justification for the need for them latest two years after the implementation of this Methodology. In case such a proposal has been submitted, the interim period shall be extended until the decision on the proposal is taken by all Baltic CCR NRAs.

7.4. A TSO may discontinue the usage of an allocation constraint as described in paragraph 7.3. The concerned TSO shall communicate this change to the Baltic CCR regulatory authorities and to the market participants at least one month before its implementation.

7.5. On HVDC Interconnections, maximum Ramping Rate restrictions according to SO GL 2017/1485 (Article 137) are applied during D-1 and ID capacity calculation processes. 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 D-1 Market in order to maintain operational security. Capacities available for trading during ID Market depend not only on maximum trading capacities provided by TSOs/ Capacity Calculators, but also on AACs for consecutive previous and following trading periods.

7.6. Ramping restrictions may be used for an interim period of 2 years following the implementation of this Methodology. If any of the Baltic CCR TSOs still want to use ramping restrictions after this period, they shall deliver a proposal for amendments to this Methodology, describing the technical details for calculating the ramping restrictions and the justification for the need for them latest two years after the implementation of this Methodology. In case such a proposal has been submitted, the interim period shall be extended until the decision on the proposal is taken by all Baltic CCR NRAs.

7.7. TSOs may apply implicit loss factors in day-ahead and intraday timeframes in accordance with Article 23(3) of the CACM Regulation. TSOs shall provide these allocation constraints to the Capacity Calculator. The implicit loss factors are calculated as:

*Output quantity = (1 – "Loss Factor") * Input quantity*

The implicit loss factor is a correction mechanism for a negative external effect incentivising the market to respect the cost of electricity losses on HVDC interconnections in the market coupling.

7.8. The implicit loss factor referred in paragraph 7.7 may be applied on an HVDC interconnection if an EU-wide net benefit, i.e. an increase of economic surplus can be demonstrated to the NRAs. If TSOs wish to apply an implicit loss factor, they shall prepare a report demonstrating a net benefit and shall consult stakeholders for at least one month. The report along with the stakeholders' considerations shall be submitted to the Baltic CCR NRAs.

8 GENERATION AND LOAD SHIFT KEYS

8.1. 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 CGM according to Article 24 of the CACM Regulation. That forecast shall notably take into account the information from the generation and load data provision methodology according to Article 16 of CACM Regulation. GLSK strategy per TSO control 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 default GLSK strategy set out in paragraph 8.3 and 8.4.

8.2. Default GLSK strategy shall be based on merit order principle and set up according to paragraphs 8.3 and 8.4. To maintain Operational Security and data accuracy TSOs may determine different GLSK strategy based on best available forecast for generation and load according to Article 24 of the CACM Regulation. If TSOs determine different GLSK strategy, implementation in calculation algorithm shall be coordinated with Capacity Calculator.

8.3. TSOs shall define GLSK strategy to best represent latest specific changes of generation or load in TSO control area according to Article 24 of the CACM Regulation. Following generation and/or load groups merit order shall be used as default:

a. Internal area generation shift.
b. HVDCs setpoint change.
c. Neighbouring system generation shift.
d. Load shifting in specific area.

8.4. GLSK principle depending upon a merit order generation/load shift key method shall be performed according to following rules:

8.4.1. The chosen generation nodes scaled up or down according to the merit order list defined in the GLSK input, provided by TSOs. GLSK data shall contain the generation nodes which performs the total positive or negative shift are provided.

8.4.2. The merit order determines sequence how generation shift is applied to node. The order is defined by the TSOs to best represent latest specific changes of generation or load in TSO control area. If group of generators have the same merit order, then that group of generators will be shifted proportionally.

8.5. GLSK strategy applied in Nordic region is described in detail in Nordic CCR Capacity Calculation Methodology.

9 REMEDIAL ACTIONS

9.1. TSOs shall provide for Capacity Calculator information on available and applicable non-costly and costly remedial actions that shall be used in capacity calculation process.

9.2. 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.

9.3. 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.

9.4. Countertrading and redispatching possibilities along with other remedial actions shall be fully exploited in the DA and ID capacity calculation in accordance with Article 16(4) of the Electricity Market Regulation 2019/943. Thus, the TSOs shall ensure that Article 16(8) of the Electricity Market Regulation 2019/943 is adhered to.

10 IGM AND CGM DATA

10.1. IGM, provided by TSO, shall follow rules referred in methodology of Article 17 of the CACM Regulation and shall consist of valid Operational Security limits, up to date topology data, forecast data. IGM shall consist of input scenario data describing net positions, grid topology and system element data for each market time unit and valid for given calculation purposes.

10.2. Capacity Calculator shall use CGM for capacity calculation processes according to Article 17 of the CACM Regulation. CGM shall consist of IGMs of synchronous area, at least including Baltic TSOs and Polish power system. CGM shall represent base case model, which includes power transmission equipment model of synchronous area and scenario describing net positions for each of Control Area of Baltic TSOs and Polish power system, valid for given TTC calculation purposes.

11 TOTAL TRANSFER CAPACITY (TTC) CALCULATION PRINCIPALS

11.1. TTC shall be calculated by performing Contingency Analyses after applying of N-1 criteria. While calculating TTC Operational Security limits referred in Section 6 shall be not exceeded and determined by selecting the minimum value of:

$$TTC = \min (TTC_{thermal}; TTC_{static\_stab.}; TTC_{dynamic\_stab.}) \quad (1)$$

Where:

$TTC_{thermal}$ - TTC evaluated considering thermal limits according to Section 6.2

$TTC_{static\_stab.}$ - TTC evaluated considering static voltage stability limits according to Section 6.3

$TTC_{dynamic\_stab.}$ - TTC evaluated considering dynamic stability limits according to Section 6.4

11.2. CNEs which are impacted by cross zonal flows according to Article 29.3(b) of CACM Regulation and Section 5 of this Methodology shall be evaluated during TTC calculation.

12 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR INTERNAL AC CROSS-BORDERS INTERCONNECTORS IN BALTIC TSOS CONTROL AREA

12.1. The Cross-Border Interconnection TTC determination for AC interconnectors shall be done by performing Contingency Analyses based on N-1 criterion on a CGM, while taking into account the intra and intersystem Operational Security limits according to Section 6 of synchronous area and Control Area of Baltic TSOs.

12.2. TTC is maximum power flow value on Cross-Border between two bidding zone areas resulted from modelling net position variation and contingency analysis. TTC value is obtained by summing up power flow values of cross-border lines above 110 kV after Operational Security limits reached for any CNE while modelling net position increase in exporting area and decrease in importing area and performing N-1 contingency analysis.

12.3. Contingency analysis is performed for those contingencies which are agreed among Baltic TSOs. Contingencies shall be agreed and provided among Baltic TSOs and to Capacity Calculator according to Section 5.

12.4. The generation and load Shift Keys shifting strategy used in TTC calculations are described in Section 8 of this Methodology.

12.5. If during capacity coordination process according to 22.5 neighbouring TSOs determine different TTC values for the same Cross-Border Interconnection, the lowest value shall be used as a coordinated value.

13 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR CROSS-BORDERS WITH HVDC INTERCONNECTORS

13.1. TTC for each cross-border that consists solely of HVDC connections is limited by the sum of ratings of HVDC interconnectors that connect the 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 CGM, while taking into account the intra and intersystem Operational Security limits according to Section 6.

13.2. Maximum permissible capacity on HVDC interconnector can be limited when there is lack of frequency restoration reserves in Baltic LFC Block to cover dimensioning incident. Contingency analysis is performed according to paragraph 1 and 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 cross-border on one and/or both directions is reduced until network parameters do not exceed permissible limits during the analysis.

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

13.4. The generation and load Shift Keys shifting strategy applied during TTC determination of HVDC interconnector shall be performed in accordance with Section 8.

13.5. 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 13.2 the links are limited in minimal possible combination - meaning the maximum possible capacity is given to the market.

14 TRANSMISSION RELIABILITY MARGIN (TRM) CALCULATION METHODOLOGY OF AC CROSS-BORDERS INTERCONNECTORS IN BALTIC TSO'S CONTROL AREA

14.1. 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 at the time the transfer capacities have been computed and determined according to Article 22 of CACM Regulation.

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

14.3. For HVDC interconnectors TRM value shall be 0 MW.

14.4. For determining of the TRM values for each Cross-Border Interconnection, the statistical data of historically planned and actual power flows (historical physical flows) shall be used for each MTU. TRM shall be determined as the arithmetic average of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time value plus standard deviation based on historical data. TRM shall be rounded to the nearest integer. TRM shall be calculated for each cross-border direction according to formula (2):

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

where:

X_i - data sets of the i-th element, defined as deviation of planned power flow from actual power flow (actual flow subtracted from planned flow) over Cross-Border Interconnection.

$\boldsymbol{\overline{X}}$ arithmetic average value of X_i equal to $\frac{\sum_{i=1}^{n} X_i}{n}$; .

n - number of elements in the data set.

14.5. TRM shall be recalculated every month or more frequently upon TSOs agreement using last 1 year or latest available historical period data. Historical data for TRM evaluation shall be acquired since Baltic TSOs synchronisation with CESA.

14.6. For initial operation period after Baltic TSOs synchronisation with CESA, fixed TRM values shall be applied to LT-LV, LV-EE, and LT-PL Cross-Borders. These values shall be applied during a transitory period of at least 1 month . After this period, the TSOs shall calculate the TRMs according to principles set out in 14.4 and 14.5. Before applying the calculated TRMs, TSOs shall demonstrate to the NRAs that the calculated TRMs do not violate the requirement set in Article 16(8) of the Electricity Market Regulation 2019/943 Fixed values provided in Table 1.

Table 1. Fixed TRM values for initial operation period

Border	EE-LV	LV-EE	LT-LV	LV-LT	LT-PL	PL-LT
TRM value	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW

15 TRADING CAPACITY CALCULATION MATHEMATICAL DESCRIPTION OF NTC CALCULATION FOR DAY AHEAD TIMEFRAME OF INTERNAL BALTIC AC INTERCONNECTORS IN BALTIC TSO'S CONTROL AREA

15.1. Capacity Calculator calculates NTC value for Internal Baltic AC interconnectors_and Available Transmission Capacity (ATC) for both interconnection directions. ATC would represent capacity allocations for day ahead timeframe. Calculation shall be performed using following equations:

$$NTC_{A>B} = TTC_{A>B} - TRM_{A>B}; \quad NTC_{B>A} = TTC_{B>A} - TRM_{B>A} \qquad (3)$$

$$ATC_{DA,\ A>B} = NTC_{A>B} - AABC_{A>B}; \quad ATC_{DA,\ B>A} = NTC_{B>A} - AABC_{B>A} \qquad (4)$$

where:

$TTC_{A>B}$; $TTC_{B>A}$ - Total Transfer Capacity according to actual power system network status, identified during TTC evaluation, defined in Section 12 in direction from areas A>B and B>A.

$TRM_{A>B}$; $TRM_{B>A}$ - transmission reliability margin value calculated according to the methodology described in Section 14 in direction from areas A>B and B>A.

$ATC_{DA,B>A}$; $ATC_{DA,B>A}$ – available transmission capacity given to the Day-Ahead electricity market from areas A>B and B>A.

$AABC_{A>B}$; $AABC_{B>A}$ – Already allocated capacity for balancing market in accordance with Baltic CCR methodology for EBGL Article 38 in direction from areas A>B and B>A.

15.2. If during capacity coordination process according to paragraph 22.5 neighbouring TSOs determine different NTC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

15.3. Final AC Cross-Border ATC value given to Day-ahead market shall be calculated according to formula (4).

15.4. The NTC capacity for AC borders provided by Baltic CCR TSOs for market operations shall be calculated by subtracting transmission reliability margin from the total transfer capacity value for given cross-border and direction. Baltic CCR TSOs ensure that the TRM shall not exceed 30% of the TTC calculated in accordance with Section 11 of this Methodology. Therefore, NTC capacity availability shall comply with CEP Regulation Article 16(8).

16 INTRADAY AVAILABLE TRANSMISSION CAPACITY CALCULATION OF INTERNAL BALTIC AC INTERCONNECTORS IN BALTIC TSO'S CONTROL AREA

16.1. ATC value is directional and 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.

16.2. ATC for ID market shall be calculated for both interconnection directions according to formulas:

$$ATC_{ID\ A>B} = NTC_{ID\ A>B} - AABC_{A>B} - AAC_{A>B} + AAC_{B>A} \qquad (5)$$

$$ATC_{ID\ B>A} = NTC_{ID\ B>A} - AABC_{B>A} - AAC_{B>A} + AAC_{A>B} \qquad (6)$$

where:

$ATC_{ID\ A>B}$; $ATC_{ID\ B>A}$ – available transmission capacity given to the ID electricity market in direction from areas A>B and B>A.

$NTC_{ID\ A>B}$; $NTC_{ID\ B>A}$ – coordinated Net Transmission Capacity for intraday timeframe for the Cross-Border interconnections in direction from areas A>B and B>A.

$AAC_{A>B}$; $AAC_{B>A}$ – Already Allocated Capacity for the Cross-Border Interconnections in direction from areas A>B and B>A after previous capacity allocation phases that includes DA allocations and previous ID allocations for given MTU.

$AABC_{A>B}$; $AABC_{B>A}$ – Already allocated capacity for balancing market in accordance with Baltic CCR methodology for EBGL Article 38 in direction from areas A>B and B>A.

16.2.1. NTC_{ID} value defined in formulas (5) and (6) shall correspond to the latest grid situation in ID timeframe with respect to grid topology, generation and load distribution and Operational Security limits. In general case NTC_{ID} shall be equal to NTC coordinated in DA timeframe. In case of changes in the network which affect NTC value it shall be recalculated in according to Section 15 and re-coordinated according to paragraph 16.3 between parties for ID timeframe.

16.2.2. AABC value defined in formulas (5) and (6) used for ATC calculation shall correspond to chosen ATC calculation direction meaning AABC variable shall always have positive value.

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

16.4. As a fallback ID ATC values equal to “0 MW” (zero MW) shall be provided to the Intraday Market if following conditions occur:

a) In case if DA Market results have not been provided by NEMOs.

b) There are significant changes in the grid that impact cross-zonal capacity value and CGM including DA trading results is not available.

c) There are significant changes in the grid that impact cross-zonal capacity value and there is insufficient time to reassess and re-coordinate cross-zonal capacity values.

16.5. ID ATC values shall be reassessed and re-coordinated by TSOs and Capacity Calculator as soon as technically possible and provided to Intraday Market.

16.6. To ensure operational security of power systems reassessment of Intraday capacity value (ATC) shall be performed every time if any of the following situations occur:

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

16.6.2. Day-Ahead Market results update e.g., in case of fallback procedure applied by NEMO.

16.6.3. Major changes in generation and load plans, renewable generation forecasts changes.

17 TRADING CAPACITY CALCULATION RULES BETWEEN ESTONIAN AND FINNISH POWER SYSTEMS

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

17.2. Trading Capacity shall be defined for both interconnection directions according to formulas (3) and (4) on each side of HVDC link. In case if during capacity validation process different NTC values are proposed for the same Cross-Border Interconnection direction the lowest value shall be used as a coordinated value.

$$ATC_{FI>EE;\ EE>FI} = \min(FI\ ATC_{FI>EE};\ EE\ ATC_{FI>EE});\ \min(FI\ ATC_{EE>FI};\ EE\ ATC_{EE>FI}) \quad (7)$$

where:

$FI\ ATC_{FI>EE}$; $FI\ ATC_{EE>FI}$ – ATC between FI>EE and EE>FI Bidding Zones directions, determined by Operational Security limits in Nordic CCR TSOs’ synchronous area or technical limitation on HVDC interconnection (from Finland side),

EE $ATC_{FI>EE}$; EE $ATC_{EE>FI}$ – ATC between FI>EE and EE>FI Bidding Zones directions, determined by Operational Security limits in Baltic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Estonia side).

17.3. The NTC capacity for EE-FI cross-border shall use TRM equal to zero value in accordance with Article 14.3 of this Methodology. The full TTC capacities shall be provided for market operations and shall comply with CEP Regulation Article 16(8).

17.4. AABC allocation referred in formula (4)) for HVDC shall be defined in the balancing capacity exchange agreements between parties according to EBGL Article 38. In case no capacity exchange agreement is in place, AABC value for HVDC interconnectors shall be 0.

Intraday capacity allocation procedure

17.5. 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.

17.6. Intraday trading Capacity on cross-border Estonia-Finland is allocated according to formulas (5) and (6).

18 TRADING CAPACITY CALCULATION RULES BETWEEN LITHUANIAN AND SWEDISH POWER SYSTEMS

18.1. TTCs on cross-border Lithuania-Sweden are calculated by the Capacity Calculator using CGMs that represent the AC-networks of observable areas of synchronous areas that each belong to and validated by the respective TSO on both sides of the interconnector.

18.2. Trading capacity shall be defined by Capacity Calculator for both interconnection directions according to formula (3) and (4) on each side of HVDC link. In case if during capacity validation process different NTC values are proposed for the same cross-border interconnection direction the lowest value shall be used as a coordinated value.

18.3. Capacities for Lithuania – Sweden interconnection shall be defined according to formula:

$$ATC_{SE>LT,\ LT>SE} = \mathrm{MIN}\ (SE\ ATC_{SE>LT};\ LT\ ATC_{SE>LT});\ \mathrm{MIN}\ (SE\ ATC_{LT>SE};\ LT\ ATC_{LT>SE}) \qquad (8)$$

where:

SE $ATC_{SE>LT}$; SE $ATC_{LT>SE}$ — ATC between SE–LT and LT–SE Bidding Zones directions, determined by Operational Security limits in Nordic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Sweden side);

LT $ATC_{SE>LT}$; LT $ATC_{LT>SE}$ — ATC between SE–LT and LT–SE Bidding Zones directions, determined by Operational Security limits in Baltic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Lithuania side).

18.4. When flow-based capacity calculation with advanced hybrid coupling is utilized within Nordic CCR, operational security limits for CNEs within the Swedish AC grid adjacent to the HVDC interconnection are sufficiently reflected by the flow-based parameters of Nordic CCR. When this is the case, the ATC from the Swedish side shall reflect the technical limitation on HVDC interconnection only. When ATC extraction is utilized within Nordic CCR, such extracted capacities may be used to take operational security limits into account.

18.5. The NTC capacity for SE-LT cross-border shall use TRM equal to zero value in accordance with Article 14.3 of this Methodology. The full TTC capacities shall be provided for market operations and shall comply with CEP Regulation Article 16(8).

18.6. AABC allocation referred in formula (4) for HVDC shall be defined in the balancing capacity exchange agreements between parties according to EBGL Article 38. In case no capacity exchange agreement is in place, AABC value for HVDC interconnectors shall be 0.

Intraday capacity allocation procedure

18.7. 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.

18.8. Intraday trading capacity on cross-border Lithuania-Sweden is allocated according to formulas (5) and (6).

19 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR LITHUANIAN - POLAND AC CROSS-BORDER INTERCONNECTOR

19.1. While calculating TTC, list of considered CNE and contingencies should be determined according to Section 4**.**

19.2. While calculating TTC and performing contingency analyses after applying of N-1 criteria following Operational Security limits according to Article 25, Article 38 and Article 39 of SO GL shall be not exceeded:

19.2.1. Permanently allowed thermal limits, that correspond to the 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.

19.2.2. 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.

19.2.3. Dynamic stability limits including:

i. rotor angle stability and voltage stability.

ii. small signal stability (described in paragraph 19.3).

19.2.4. Frequency stability limit is assessed based on Baltic TSOs rules considering commonly agreed and coordinated availability of frequency support measures between Baltic TSOs. HVDC fast frequency response settings shall be agreed between all Baltic TSOs, Swedish TSO and Finnish TSO. Frequency stability limits are calculated by Lithuanian TSO taking into account the following agreed and coordinated measures/parameters:

i. Forecasted inertia level in BSPS.

ii. Available fast frequency response settings on HVDC links in BSPS.

iii. Forecasted available fast frequency reserves amount provided by Battery Energy Storage Systems (BESS) in BSPS.

iv. Disconnection of AC interconnection with CESA shall not cause rate of change of frequency (ROCOF) greater than 1 Hz/s and activation of load shedding in BSPS.

19.3. TTC values for both directions are calculated considering small signal operational security stability limits (mentioned in 19.2.3.ii) shall be defined by applying following approach:

$$TTC_{SS(PL>LT)} = \min\left(TTC_{1(PL>LT)}; TTC_{2(PL>LT)}\right);\quad TTC_{SS(LT>PL)} = \min\left(TTC_{1(LT>PL)}; TTC_{2(LT>PL)}\right) \qquad (9)$$

where:

$TTC_{SS(PL>LT)}$; $TTC_{SS(LT>PL)}$ – Total Transfer Capacity considering dynamic small signal stability limits.

$TTC_{1(PL>LT)}$; $TTC_{1(LT>PL)}$ – small signal stability limit with N-1 line outages evaluation in directions to PL>LT and LT>PL.

$TTC_{2(PL>LT)}$; $TTC_{2(LT>PL)}$ – security limit based on small signal stability criteria without N-1 line outages evaluation shall be calculated considering security limits based on small signal stability criteria and possible loss of **biggest infeed in Baltic PS** in directions to PL>LT and LT>PL.

$$TTC_{2(PL>LT)} = TTC_{0(PL>LT)} – MaxInf; \quad TTC_{2(LT>PL)} = TTC_{0(LT>PL)} – MaxDem \tag{10}$$

where:

$TTC_{0(PL>LT)}$; **$TTC_{0(LT>PL)}$** – small signal stability limit without N-1 line outages in directions PL>LT and LT>PL.

MaxInf - biggest N-1 infeed disconnection in BSPS.

MaxDem - biggest N-1 demand disconnection in BSPS.

19.4. The hourly values of matched TTC according to Operational Security limits defined in 19.2.1 - 19.2.3 in direction to Lithuania are calculated according to the following formula:

$$TTC_{PL>LT} = \min (PL\ TTC_{SS(PL>LT)}; LT\ TTC_{SS(PL>LT)}; TTC_{(PL>LT)(F)}) \tag{11}$$

where:

PL $TTC_{SS(PL>LT)}$ – TTC between LT and PL bidding areas in direction to Lithuania, determined by PL TSO, considering Operational Security limits defined in 19.2.1 - 19.2.3 and 19.3.

LT $TTC_{SS(PL>LT)}$ – TTC between LT and PL bidding areas in direction to Lithuania, determined by LT TSO, considering Operational Security limits defined in 19.2.1 - 19.2.3 and 19.3.

$TTC_{(PL>LT)(F)}$ – TTC of Lithuania-Poland Cross-Border interconnection in direction to Lithuania calculated by Lithuanian TSO considering frequency stability limits as in 19.2.4.

19.5. The hourly values of matched TTC according to Operational Security limits defined in 19.2.1 - 19.2.3 in directions to Poland are calculated according to the following formula:

$$TTC_{LT>PL} = \min (PL\ TTC_{SS(LT>PL)}; LT\ TTC_{SS(LT>PL)}; TTC_{(LT>PL)(F)}) \tag{12}$$

where:

PL $TTC_{SS(LT>PL)}$ – TTC between LT and PL bidding areas in direction to Poland, determined by PL TSO, considering Operational Security limits defined in 19.2.1 - 19.2.3 and 19.3.

LT $TTC_{SS(LT>PL)}$ – TTC between LT and PL bidding areas in direction to Poland, determined by LT TSO, considering Operational Security limits defined in 19.2.1 - 19.2.3 and 19.3.

$TTC_{(LT>PL)(F)}$ – TTC of Lithuania-Poland Cross-Border interconnection in direction to Poland calculated by Lithuanian TSO considering frequency stability limits as in 19.2.4.

20 TRADING CAPACITY CALCULATION RULES BETWEEN LITHUANIAN AND POLISH POWER SYSTEMS FOR DAY AHEAD TIMEFRAME

20.1. NTC values for Lithuania-Poland Cross-Border Interconnection in direction to Lithuania shall be calculated by using following formula:

$$NTC_{(PL>LT)} = TTC_{(PL>LT)} - TRM_{(PL>LT)} \tag{13}$$

where:

$TTC_{(PL>LT)}$ – TTC of Lithuania-Poland cross border interconnection in direction to Lithuania calculated by Polish and Lithuanian TSOs according to formula (11) as in 19.4.

$TRM_{(PL>LT)}$ – transmission reliability margin due to unintentional deviations in the Lithuania-Poland cross border interconnection. For initial operation period after Baltic TSOs synchronisation with CESA, TRM shall be calculated and applied according to 14.6

20.2. NTC values for Lithuania-Poland Cross-Border Interconnection in direction to Poland shall be calculated by using following formula:

$$NTC_{(LT>PL)} = TTC_{(LT>PL)} – TRM_{(LT>PL)} \quad (14)$$

where:

$TTC_{(LT>PL)}$ – TTC of Lithuania-Poland cross border interconnection in direction to Poland calculated by Polish and Lithuanian TSOs according to formula (12) as in 19.5.

$TRM_{(LT>PL)}$ – transmission reliability margin due to unintentional deviations in the Lithuania-Poland cross border interconnection. For initial operation period after Baltic TSOs synchronisation with CESA, TRM shall be calculated and applied according to 14.6.

20.3. TSOs ensure that the TRM shall not exceed 30% of the TTC calculated in accordance with Section 19 of this Methodology. NTC capacity availability shall comply with CEP Regulation Article 16(8).

21 INTRADAY AVAILABLE TRANSMISSION CAPACITY CALCULATION BETWEEN LITHUANIAN AND POLISH POWER SYSTEMS

21.1. 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.

21.2. Intraday Trading Capacity on cross-border Lithuania-Poland in direction to Lithuania allocated according to formula:

$$ATC_{PL>LT} = NTC_{(PL>LT)} - AAC_{(PL>LT)} + AAC_{(LT>PL)} \quad (15)$$

where:

$NTC_{(PL>LT)}$ - NTC between Lithuanian and Polish power systems calculated in accordance to formula (13) by taking into account actual value of $TTC_{(PL>LT)}$ and $TTC_{(PL>LT)(F)}$ ($TTC_{(PL>LT)}$ and $TTC_{(PL>LT)(F)}$ used in day ahead time frame for NTC calculation can be changed in case of changes in prognosis, topology, and in maintenance plans).

$AAC_{(PL>LT)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Poland to Lithuania for the time period after previous capacity allocation phases.

$AAC_{(LT>PL)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Lithuania to Poland for the time period after previous capacity allocation phases.

21.3. Intraday Trading Capacity on cross-border Lithuania-Poland in direction to Poland allocated according to formula:

$$ATC_{LT>PL} = NTC_{(LT>PL)} - AAC_{(LT>PL)} + AAC_{(PL>LT)} \quad (16)$$

where:

$NTC_{(LT>PL)}$ - NTC between Lithuanian and Polish power systems calculated according to formula (14) by taking into account actual value of $TTC_{(LT>PL)}$ and $TTC_{(LT>PL)(F)}$ ($TTC_{(LT>PL)}$ and $TTC_{(LT>PL)(F)}$ used in day ahead time frame for NTC calculation can be changed in case of changes in prognosis, topology, and in maintenance plans).

$AAC_{(PL>LT)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Poland to Lithuania for the time period after previous capacity allocation phases.

$AAC_{(LT>PL)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Lithuania to Poland for the time period after previous capacity allocation phases.

22 CROSS-ZONAL CAPACITY VALIDATION AND COORDINATION METHODOLOGY

22.1. Each TSO shall validate and have the right to correct Cross-Zonal Capacity of the TSO's Bidding

Zone borders or Critical Network Elements provided by the Capacity Calculator in accordance with Articles 27 to 31 of CACM Regulation.

22.2. Each TSO may reduce Cross-Zonal Capacity during the validation of Cross-Zonal Capacity referred to in this Section for reasons of Operational Security according to Article 26.3 of CACM Regulation.

22.3. Article 26.2 of CACM Regulation (rule for splitting the correction of Cross-Zonal Capacity) is not included in this Methodology because Baltic TSOs network is radial which results in direct flows between areas without any loop flows and splitting of capacities among borders of Baltic CCR is not performed.

22.4. Capacity Calculator shall report cross-zonal capacity reduction in accordance with Article 26.5 of CACM Regulation.

22.5. Capacity coordination process determines final cross-border capacity values to be provided for electricity market. Capacity Calculator shall use TSOs validated cross-border capacity values for coordinating final values. If during capacity coordination process TSOs determine different capacity values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

23 CAPACITY CALCULATION FALLBACK PROCEDURES

23.1. According to Article 21(3) of the CACM Regulation, when the day-ahead capacity calculation for specific DA or ID capacity calculation MTUs cannot be calculated due to a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data, the Baltic TSOs and the Capacity Calculator shall calculate the missing results by applying one of the following capacity calculation fallback procedures:

23.1.1. Capacity Calculator shall use latest data available considering available input data sets listed out in Section 10, CGM replacement procedures according to CGMES if CGM is not available and updated grid topology for calculating cross-zonal capacity.

23.1.2. If CGM is not available or Baltic TSOs IGMs are not included in CGM, Capacity Calculator shall create Regional Model (including Latvian TSO, Lithuanian TSO, Estonian TSO and Polish TSO IGMs, which includes all Baltic TSOs interconnectors and use Regional Model for capacity calculation.

23.2. If Cross-Zonal Capacities cannot be calculated, coordinated or provided to market operator by Capacity Calculator then neighbouring TSOs calculate and coordinate capacities for Cross-Border Interconnections among themselves and publish coordinated capacities to NEMO(s).

24 PROVISION AND ALLOCATION OF TRADING CAPACITY

24.1. Capacity Calculator shall provide calculated and validated Trading Capacities and allocation constraints for all trading time frames to MCO for subsequent capacity allocation through implicit auctioning carried out by MCO.

24.2. Trading Capacities within the Baltic CCR are provided and allocated, subject to allocation constraints, in day-ahead and intraday timeframes - Day Ahead Market and Intraday Market. No physical capacity is reserved for long-term capacity on the Baltic CCR borders.

24.3. Trading Capacities provided for trade between the Baltic CCR Bidding Zones are equal to the offered capacities calculated according to the Sections 11-23 of this Methodology, and which is subsequently allocated through the implicit auctioning following the trading rules established by the MCO, subject to allocation constraints.

25 FIRMNESS

25.1. 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.

25.2. 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”.

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

25.4. 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.

26 RULES FOR AVOIDING UNDUE DISCRIMINATION BETWEEN INTERNAL AND CROSS-ZONAL EXCHANGES. CCR RULES FOR EFFICIENTLY SHARING THE POWER FLOW CAPABILITIES OF CRITICAL NETWORK ELEMENTS AMONG DIFFERENT BIDDING ZONE BORDERS

26.1. 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. To ensure that potential congestions inside a control area do not affect the interconnection capacity the TSO shall exploit all available remedial actions such that cross-border capacities is at least as high as prescribed in Article 16(8) of the Electricity Market Regulation 2019/943.

If cross-border capacities are limited below the level as prescribed in Article 16(8) of the Electricity Market Regulation 2019/943, this shall be described, motivated, communicated, and transparently presented by the TSOs to all the system users without undue delay. The TSOs shall find a long-term solution as soon as possible to correct such a situation and do so in a timely and transparent way. The TSOs shall also inform all system users of actions taken in order to find and execute the long-term solution.

26.2. The methodology, projects, and actions taken for achieving the long-term solution shall be described, motivated, communicated, and transparently presented by the TSOs to all the system users without undue delay.

The methodology, projects, and actions taken for achieving the long-term solution can be described, motivated, communicated, and transparently presented 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 the methodology, projects, and actions taken for achieving the long-term solution is described, motivated, communicated, and transparently presented in existing TSOs' documents, creation of additional explanatory document(-s) or other relevant document(-s) is not required, unless deemed necessary by the NRAs in the Baltic CCR.

26.3. Baltic TSOs network is radial which results in direct flows between areas without any loop flows and there is no such CNEs in Baltic CCR that would clearly and in majority cases influence power flow capabilities of several borders at once, therefore rules for efficiently sharing the power flow capabilities of CNEs among different Bidding Zone borders in Baltic CCR are not applied.

27 IMPLEMENTATION OF THE METHODOLOGY

27.1. The TSOs shall implement the Methodology when 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) Baltic TSOs are synchronised with CESA.

27.2. 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.

27.3. The TSOs shall within 24 months after the implementation of this Methodology perform an evaluation of this Methodology and submit it to the NRAs in the Baltic CCR. If needed, the TSOs shall propose a revised version of the Methodology to the NRAs in the Baltic CCR.

28 LANGUAGE

The reference language for this CCM shall be English. For the avoidance of doubt, where TSOs need to translate this CCM into their national language(s), in the event of inconsistencies between the English version published by TSOs in accordance with Article 9(14) of the CACM Regulation and any version in another language, the relevant TSOs shall, in accordance with national legislation, provide the relevant national regulatory authorities with an updated translation of the CCM.

29 APPENDIX 1: USE OF ALLOCATION CONSTRAINTS

1. Justification for using allocation constraints in the form of import and export limits as described in Section 7.3

The link between net position and operational security limits

Under CACM Regulation, 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 Regulation) 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.

Legal interpretation: eligible grounds for applying allocation constraints

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 Regulation 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 Regulation was issued based on Regulation 714/2009 and complements that Regulation. The general principle in Regulation 714/2009 (Art. 16.3), repeated in Regulation 2019/943 (Art. 16.4), 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 Regulation rules on AC and operational security limits ('OSLs') seem to regulate the same matter as Article 16.4 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 Regulation, 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 Regulation 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 Regulation 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 Regulation 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 Regulation 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 Regulation provisions on ACs should also be interpreted systemically. They ensure offering maximum possible trading opportunities while preserving system security. CACM Regulation and Regulation 2019/943 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 Regulation 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 Regulation does not mandate trading opportunities to the point of endangering security of supply. If there is no arbitrary discrimination, CACM Regulation, 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 Regulation objectives?

<u>Contribution to meeting the CACM Regulation 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 the Article 5 of the 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 SCUC 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 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, which corresponds to the size of the largest unit in the system.

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:

$$EXPORT_{constraint} = P_{CD} - (P_{NA} + P_{ER}) + P_{NCD} - (P_L + P_{UPres}) \quad \textbf{(1)}$$

[2] The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point 10.2.11(3)). It is subject to change depending on the results of the development of operational planning processes.

[3]The generation reserve margin for monthly and weekly coordination is also regulated by the Polish grid code (point 10.2.11(2) and (3)).

[4]These values are regulated by the Polish grid code (point 10.2.11(1)) and subject to change.

$$IMPORT_{constraint} = P_L - P_{DOWNres} + P_{CDmin} - P_{NCD} \quad \textbf{(2)}$$

where:

P_{CD} - sum of available generating capacities of centrally dispatched units as declared by generators[5]

P_{CDmin} - 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

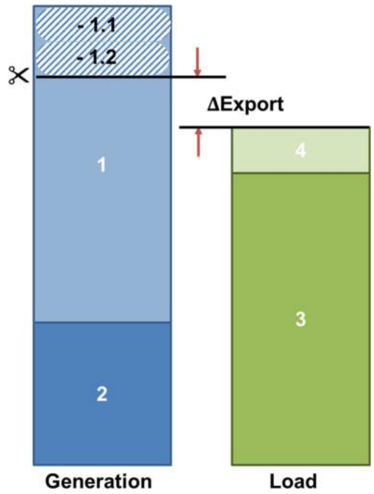
P_{Ures} - minimum reserve for up regulation

$P_{DOWNres}$ - 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 AExport is lower than the sum of transfer capacities on all Polish interconnections in export direction. Balancing constraint in import direction is applicable if AImport 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

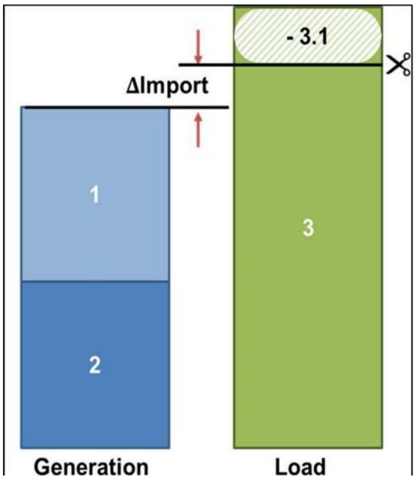
1.2 generation unavailabilities adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)

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 intraday. 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 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 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 per 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.