Baltic CCR TSOs Methodology for calculating cross-zonal capacity within the balancing timeframe

in accordance with Article 37 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

21st November 2023

Whereas

(1) This document describes a common methodology for all Transmission System Operators (hereafter referred to as “TSOs”) of the Baltic Capacity Calculation Region (hereafter referred to as “Baltic CCR”) as defined in accordance with Article 37(3) of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereafter referred to as the “EB Regulation”).

(2) This capacity calculation methodology (hereafter referred to as the “CCM”) takes into account the general principles, goals and other methodologies set in the EB Regulation, Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as the “CACM Regulation”), Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO Regulation") and Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

(3) The goal of this CCM is the coordination and harmonization of capacity calculation in the balancing timeframe.

(4) According to Article 37(3) of the EB Regulation, this CCM shall be consistent with the capacity calculation methodology applied in the intraday timeframe for the Baltic CCR established under the CACM Regulation. Therefore, this CCM will follow the principle established under the CACM Regulation.

(5) The CCM - by building on the intraday CCM fundaments as described in the “Capacity calculation methodology for the day-ahead and intraday market timeframes within the Baltic Capacity Calculation Region” - contributes to the general objectives of the EB Regulation and the CACM Regulation to the benefit of market participants and electricity end consumers.

(6) The CCM makes use of the Baltic capacity calculation process implemented for the intraday timeframe.

(7) Ramping restrictions of the DC interconnected cross-borders shall be considered to ensure grid security for the CZCL values for each MTU and ensure compliance with SO Regulation. Ramping restrictions shall be treated as an allocation constraint in the balancing timeframe and be consistent with approach provided in Baltic CCR Intraday capacity calculation methodology. 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 National Regulatory Authorities (hereafter referred to as “Baltic CCR NRAs”).

TITLE 1
General provisions

Article 1

Subject matter and scope

1. This Proposal shall be considered as the common proposal of the Transmission System Operators AS Augstsprieguma tīkls, Elering AS, Litgrid AB, Fingrid Oyj, Polskie Sieci Elektroenergetyczne S.A. and Svenska kraftnät (hereinafter referred to as “Baltic CCR TSOs”) for the establishment of a methodology for calculating cross-zonal capacity within the balancing timeframe in accordance with Article 37(3) of EB Regulation.
2. This CCM shall define the capability of the interconnected power systems for balancing purposes between Estonian, Latvian, Lithuanian, Finnish, Swedish and Polish power systems.
3. Proposed methodology shall describe cross-zonal capacity calculation principles for balancing timeframe for situation when Baltic countries are synchronously connected to Continental Europe Synchronous Area and principles when Baltic countries are operating in isolated operation mode.
4. Proposed methodology shall describe calculation of cross-zonal capacity within the balancing timeframe and for the operational phase of the balancing market and for the capacity that is published ex post.
5. This CCM shall be used by Baltic CCR TSOs to determine values to be provided to the European balancing platforms MARI and PICASSO in cooperation with Capacity Management Module (CMM).

Article 2

Definitions and interpretation

1. Cross-zonal capacities within the balancing timeframe for the exchange of balancing energy or for operating the imbalance netting process shall be calculated in a way that facilitates the achievement of the following objectives:
   (a) maximizing capacities available to the balancing market while ensuring operational security of the interconnected power systems;
   (b) producing results in a transparent and replicable manner;
   (c) avoiding market distortions.
2. Definitions used in methodology:
   (a) ‘AAC’ already allocated capacity represents the total amount of allocated transmission rights;
   (b) ‘AC’ alternating current;
   (c) ‘aFRR’ frequency restoration reserves with automatic activation;
   (d) ‘ATC’ available transfer capacity;
   (e) ‘Balancing platforms’ term used to refer to MARI and PICASSO platforms;
   (f) ‘Balancing timeframe’ time frame after intraday gate closure time;
   (g) ‘Baltic TSOs’ - AS "Augstsprieguma tīkls", Litgrid AB, Elering AS;
   (h) ‘CC’ Capacity calculation;

(i) ‘CZCA’ cross zonal capacity allocated is capacity allocated for sharing or exchange of balancing capacity between two or more areas for individual process (mFRR, aFRR) and direction;
(j) ‘CZCL’ cross zonal capacity limit is limit for exchange of balancing energy at the balancing border or set of balancing borders (between Areas);
(k) ‘CESA’ Continental Europe Synchronous Area;
(l) ‘DA’ day ahead;
(m) ‘DC’ direct current;
(n) ‘ID’ intraday;
(o) ‘MARI’ Manually Activated Reserves Initiative (MARI) is the European implementation project for the creation of the European mFRR platform;
(p) ‘LT’ long term;
(q) ‘mFRR’ frequency restoration reserves with manual activation;
(r) ‘MTU’ market time unit;
(s) ‘Net position limit’ limitation of total import to area or total export from area. Relevant for scheduling and aggregated areas only;
(t) ‘NTC’ 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;
(u) ‘PICASSO’ The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) is the implementation project to establish the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation (aFRR);
(v) ‘PSE’ Polskie Sieci Elektroenergetyczne S.A.;
(w) ‘TFEU’ Treaty on the Functioning of the European Union;
(x) ‘XB flows’ represents additional planned flows on cross-borders resulting from activations of balancing bids and/or imbalance netting process in the balancing platforms.

3. In this CCM, unless the context requires otherwise:

(a) the singular also includes the plural and vice versa;
(b) the table of contents and headings are inserted for convenience only and do not affect the interpretation of this methodology;
(c) any reference to legislation, regulation, directive, order, instrument, code or any other enactment shall include any modification, extension or re-enactment of it then in force;
(d) any reference to an Article without an indication of the document shall mean a reference to this methodology.

TITLE 2

Cross-zonal capacity calculation within the balancing timeframe

Article 3

Mathematical Description

1. Each TSO shall submit NTC, AAC (long term, day ahead and intraday) and CZCA data to CMM platform.
2. Additionally, when applicable, TSO shall calculate Net position limit values according to this methodology and submit them to CMM platform.
3. The following formulas shall always take into account the calculation perspective of a control area to reflect the capacity direction from which area to which area the capacity is provided. TSOs owning a common border will have opposite direction for import and export to reflect the possible flow direction on the cross-border (e.g. import direction for TSO 1 will reflect the export direction of TSO 2).
4. For all cross-border interconnectors of Baltic area a common CZCL calculation should be used as described in this chapter. CZCL should be calculated for each cross-border separately using corresponding values for each. CZCL should be calculated using:
   (a) sum of already allocated capacity after long term, day ahead and intraday;
   (b) CZCA for each process and direction accordingly (mFRR and aFRR);
   (c) resulting cross border flow of mFRR and aFRR activations in balancing platforms.
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 MTU and separately in the directions of import and export. This is applicable for PSE, for all MTUs. 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.
6. A TSO may discontinue the usage of an allocation constraint as described above. The concerned TSO shall communicate this change to the Baltic CCR NRAs and to the market participants at least one month before its implementation.
7. CZCL for mFRR activations in MARI for import and export directions should be calculated as follows:

$$CZCL_{MARI\_imp,from-to} = NTC_{imp,from-to} - \sum AAC_{(LT+DA+ID)imp,from-to} + \sum AAC_{(LT+DA+ID)exp,from-to} - XBflow_{MARI_{imp,from-to}} + XBflow_{MARI_{exp,from-to}} - CZCA_{PICASSO\_imp,from-to}$$

$$CZCL_{MARI\_exp,from-to} = NTC_{exp,from-to} - \sum AAC_{(LT+DA+ID)exp,from-to} + \sum AAC_{(LT+DA+ID)imp,from-to} - XBflow_{MARI_{exp,from-to}} + XBflow_{MARI_{imp,from-to}} - CZCA_{PICASSO\_exp,from-to}$$

Where:

$NTC_{imp,from-to}$ – net transmission capacity for import direction (latest coordinated between TSOs in ID timeframe);

$NTC_{exp,from-to}$ – net transmission capacity for export direction (latest coordinated between TSOs in ID timeframe);

$\sum AAC_{(LT+DA+ID)imp,from-to}$ – already allocated capacity after latest data of LT, DA and ID markets for import direction;

$\sum AAC_{(LT+DA+ID)exp,from-to}$ – already allocated capacity after latest data of LT, DA and ID markets for export direction;

$XBflows_{MARI_{imp,from-to}}$– resulting import cross border flow of mFRR activations in MARI for import direction;

$XBflows_{MARI_{exp,from-to}}$– resulting export cross border flow of mFRR activations in MARI for export direction;

$CZCA_{PICASSO\_imp,from-to}$ – allocated capacity for aFRR services by import direction;

$CZCA_{PICASSO\_exp,from-to}$ – allocated capacity for aFRR services by export direction.

8. The mFRR CZCL for certain cross-border and direction shall take into account the NTC for given MTU, the previously allocated capacities on LT, DA and ID markets and CZCA in the same direction for aFRR exchange and sharing. The mFRR CZCL shall be updated whenever there is new cross-border activation for mFRR in MARI platform. The additional activations of mFRR for MARI shall reduce or increase the mFRR CZCL depending on the direction. CZCA for mFRR is already included in the NTC as DA and ID processes cannot allocate CZC for mFRR.
9. CZCL for aFRR activations in PICASSO for import and export directions should be calculated as follows:

$$CZCL_{PICASSO\_imp,from-to} = NTC_{imp,from-to} - \sum AAC_{(LT+DA+ID)imp,from-to} + \sum AAC_{(LT+DA+ID)exp,from-to} - XBflow_{MARI_{imp,from-to}} + XBflow_{MARI_{exp,from-to}} - XBflow_{PICASSO_{imp,from-to}} + XBflow_{PICASSO_{exp,from-to}}$$

$$CZCL_{PICASSO\_exp,from-to} = NTC_{exp,from-to} - \sum AAC_{(LT+DA+ID)exp,from-to} + \sum AAC_{(LT+DA+ID)imp,from-to} - XBflow_{MARI_{exp,from-to}} + XBflow_{MARI_{imp,from-to}} - XBflow_{PICASSO_{exp,from-to}} + XBflow_{PICASSO_{imp,from-to}}$$

Where:

$XBflow_{PICASSO_{imp,from-to}}$– resulting import cross border flow of aFRR activations in PICASSO on a specific interconnector in import direction;

$XBflow_{PICASSO_{exp,from-to}}$– resulting export cross border flow of aFRR activations in PICASSO on a specific interconnector in export direction.

10. The aFRR CZCL for certain cross-border and direction shall take into account the NTC for given MTU, the previously allocated capacities on LT, DA and ID markets. The aFRR CZCL shall be updated whenever there is new cross-border activation for mFRR in MARI platform or for aFRR in PICASSO platform. The additional activations of aFRR or mFRR in balancing platforms shall reduce or increase the aFRR CZCL depending on the direction. CZCA for aFRR is made available through the NTC as DA and ID processes cannot allocate CZC for aFRR.

Article 4

Fallback procedures

1. CZCL calculation is done for each cross border by both neighboring TSOs and the minimum of both values should be applied, if not defined differently. If one of TSOs is not able to provide necessary values to CMM and/or balancing platforms the CZCL value that's being applied is determined by rules set in balancing platforms and/or CMM.
2. If respective TSO is not able to determine NTC (for example due to unplanned outage) or AAC for submission to CMM, the TSO should submit zero NTC to CMM.
3. If respective TSO is not able to calculate CZCL value/-s, the TSO should submit zero CZCL to respective balancing platform/-s.
4. In case of Baltic TSOs do not have access to balancing platforms and need to activate mFRR and aFRR then for that purposes should be used capacities calculated according to this methodology.

Article 5

CZCL calculation cycle

1. Based on the requirement of MARI implementation guides the values of CZCL shall be updated after every activation optimization function cycle of MARI and the updated CZCL shall be provided to the balancing platforms and CMM.
2. The Baltic CCR TSOs foresee that cycle of CZCL calculations shall be run after:
   (a) each Intraday Gate Closure Time;
   (b) input values (NTC/AAC) changes;
   (c) every activation optimization function cycle of MARI.

TITLE 3
Final provisions

Article 6

CZCL publication

1. For data publication the CZCL for every cross-border interconnections for every direction and every reserve process is determined as soon as possible after the end of relevant balancing timeframe.
2. Published CZCL for balancing timeframe for relevant direction and process shall be the CZCL calculated before any balancing activations for the respective MTU but after LT, DA and ID markets are cleared. Published CZCL shall correspond to calculated value according to paragraphs 7 and 9 of Article 3 with cross border flow of aFRR activations and mFRR activations equal to "0".

Article 7

Implementation

1. Methodology shall be implemented by the time Baltic TSOs are synchronized with CESA.
2. Methodology will be applicable only for Baltic CCRs TSOs which share common cross borders and at least joined one of the balancing platforms.

Article 8

Language

1. The reference language for this methodology shall be English. For the avoidance of doubt, where the TSOs need to translate this methodology into their national language(s), in the event of inconsistencies between the English version published by the TSOs in accordance with Article 7 of the EB Regulation and any version in another language, the relevant TSOs shall, in accordance with national legislation, provide the relevant Baltic CCR NRAs with an updated translation of this methodology.

Appendix 1
Justification of usage and methodology for calculation of allocation constraints in PSE as described in Article 3 (3.5)

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 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.

<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 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) 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 16.3 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 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 Regulation, 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 Regulation 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 Regulation 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 Regulation) 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 Regulation void, and make it impossible or at least much more difficult to comply with SO Regulation.

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 Regulation 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 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 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.

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.

Detailed reasons and method for calculating allocation constraints by PSE

Allocation constraints in Poland are applied as stipulated in point 3.5 of this CZCBT methodology and described in this Appendix. 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.

<u>Rationale behind the implementation of allocation constraints on PSE side</u>

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.

<u>PSE role in system balancing</u>

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 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

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

[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.

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.

<u>Determination of balancing constraints in Poland</u>

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 MTU, and separately for directions of import to Poland and export from Poland.

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

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

$$\mathrm{IMPORT}_{constraint} = \mathrm{P}_{L} - \mathrm{P}_{DOWNres} - \mathrm{P}_{CD_{min}} - \mathrm{P}_{NCD} \quad \textbf{(2)}$$

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

[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.

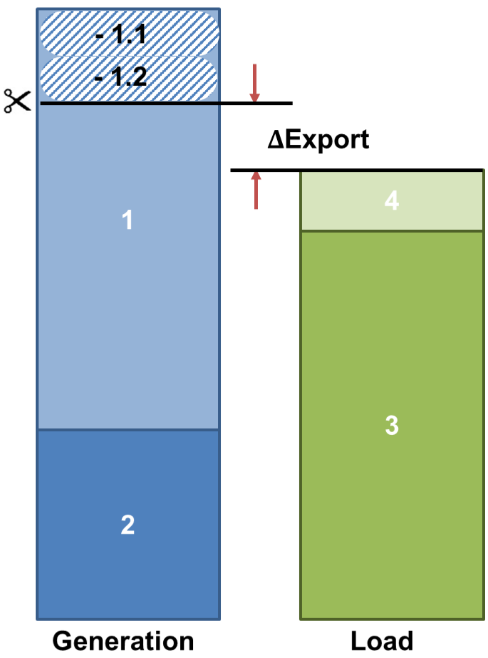
[4] The set values are respectively: 9% over forecasted demand for up regulation and 500 MW for down regulation. These values are regulated by the Polish grid code (point 4.3.4.19) and subject to change – see footnote 2.

[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.

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



sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:

generation not available due to grid constraints

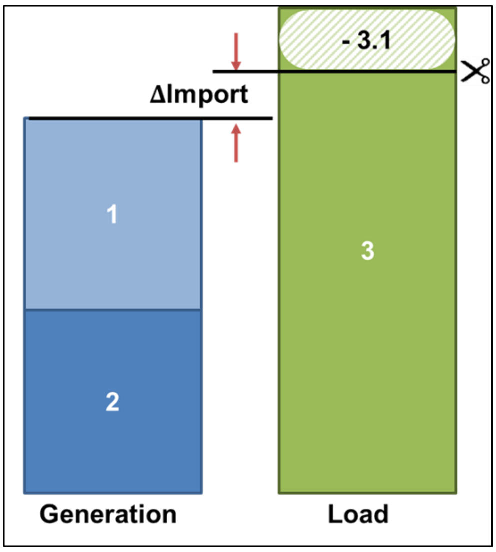
generation unavailabilities adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)

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

demand forecasted by PSE

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.



sum of technical minima of centrally dispatched generating units in operation

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

demand forecasted by PSE, reduced by: 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 MTU, 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 neighboring 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 is 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 MTUs 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.