Explanatory Document to the fifth amendment of the Intraday Capacity Calculation Methodology of the Core Capacity Calculation Region

in accordance with article 20ff. of the Commission Regulation (EU) 2015/1222 of 24th July 2015 establishing a guideline on capacity allocation and congestion management

September 2025

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NRA approval:	☐ outstanding	☐ approved

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1. Introduction

The Commission Regulation (EU) 2015/1222 establishing a guideline on Capacity Calculation and Congestion Management ('CACM') requires the development and implementation of a common Day-Ahead Capacity Calculation Methodology ('DA CCM') and Intraday Capacity Calculation Methodology ('ID CCM') per Capacity Calculation Region ('CCR').

In this explanatory document Core TSOs will explain the changes included in the proposal for a 5th amendment of the Core ID CCM. A track-change version of the Core ID CCM reflecting the proposed changes is shared for informative purpose.

2. Advanced Hybrid Coupling

The Core TSOs are obligated to implement AHC (Advanced Hybrid Coupling) for the Day-Ahead (DA) timeframe as soon as the SDAC algorithm Euphemia is capable of supporting it. The Core TSOs have been ready for this implementation since March 2025. A go-live for AHC in the DA timeframe is currently expected in 2026.

AHC is also intended to be applied in the Intraday (ID) timeframe. While its use in Flow-Based allocation can be directly carried over from the DA timeframe, its application in ATC-based allocation, such as in continuous intraday trading, is currently undefined. Therefore, AHC can only be applied in the ID timeframe if either:

- both intraday auctions and continuous trading are performed using Flow-Based allocation, or
- a method is developed that allows AHC to be applied within the ATC extraction framework.

It is also unclear when SIDC would be ready for a go-live of AHC in the Intraday timeframe.

Despite this uncertainty, the Core TSOs are nonetheless introducing the general framework for AHC into the methodology. However, since a delay in the implementation of Flow-Based allocation in continuous trading is to be expected, the development and analysis of a method for applying AHC under these conditions is proposed. Such an approach will likely require further adjustments to the methodology prior to a potential go-live.

2.1. General Aspects of Advanced Hybrid Coupling

The term hybrid coupling refers to the combined use of Flow-Based ('FB') and Available Transmission Capacity constraints in one single capacity allocation mechanism. There are two forms of the hybrid coupling: Standard Hybrid Coupling ('SHC') and Advanced Hybrid Coupling ('AHC').

The difference between SHC and AHC is how power exchanges over interconnectors between bidding zones ('BZ') within the Core CCR and BZs outside of the Core CCR, where both BZ are part of the Single Intraday Coupling ('SIDC'), are mapped onto Core CNECs. SHC grants access to the scarce CNEC capacity by reserving a capacity on the Core CNECs before capacity calculation, based on the forecasted power exchanges over the respective interconnectors and including a security margin for deviations from this forecast. By contrast, in AHC, the power exchanges over the respective interconnectors are subject to competition for CNEC capacity with all other cross-zonal power exchanges within the Core CCR during market coupling, e.g., in SIDC. The expectation is that by ensuring a non-discriminatory competition for the scarce CNEC capacity, AHC will lead to an increase in socio-economic welfare and improved operational gird security at the same time.

Core TSOs do not intend to conduct a Cost Benefit Analysis ('CBA') regarding the introduction of AHC, as the obligation resulting from the CCM to introduce AHC is independent of economic viability. Therefore, no market analysis is planned for the introduction of the AHC, but only an implementation assessment and impact analysis.

2.2. Concept of AHC for flow-based Capacity Calculation

AHC can be applied to any border to a bidding zone ('BZ') outside the Core CCR which is part of the SIDC.[1] To avoid confusion with the methodology to include virtual hubs of Core internal HVDC lines (often referred to as evolved flow-based or EFB), the virtual hubs for AHC are referred to as 'external virtual hubs.' Whilst the concept of AHC is to a large extent identical to the concept of EFB used to integrate HVDC interconnectors on bidding zone borders inside the Core CCR, a distinction shall be possible in the Core CCM.

The underlying idea of the AHC concept is to treat AHC borders analogously to Core internal borders whenever possible. The Net Position ('NP') of such external virtual hub thus represents the imports and exports from a bidding zone ('BZ') outside of the Core CCR.

For each border where the AHC shall be applied, at least one virtual hub must be defined. TSO propose no legal requirement to introduce only one single external virtual hub per border. However, due to computation complexity and as a simplification to limit the expected challenges with respect to performance that are already foreseeable, Core TSOs foresee only one single external virtual hub per border.[2] However, for future extensions of the AHC concept and if computational performance improves after the AHC is successfully deployed, the Core TSOs intend to expand the concept for parallel HVDC connections in a way that such connections can be included in the single day-ahead market coupling by separate external virtual hubs. Hence, they can be used to further increase capacity, e.g., by optimizing them in the market coupling with different load factors.

[1] This means that the AHC can be implemented for the borders with Norway but not for borders with Switzerland, for example.

[2] In this context, border is interpreted as a connection between two bidding zones where one is outside and one is inside the Core CCR.

For each external virtual hub, the challenge of having to define exactly one GSK border that maps all paths (different DC lines, parallel AC lines, etc.) with a fixed ratio arises. While the PTDFs of the converter station can simply be used for HVDC interconnectors, a detailed GSK must be defined for AC or mixed AC/DC borders. For AC areas outside of Core CCR, a detailed GSK might be unavailable and hence core TSOs must make a best estimate assumption.[3]

2.3. Concept and Study for AHC in ATC based allocation

One key challenge is the application of AHC within ATC-based allocation in continuous trade. The Core TSOs are currently developing a concept and a prototype for ATC extraction that takes these limitations into account. Once this is available, the TSOs will provide analyses on the impact on both Core and non-Core intraday capacities. Based on these results, they will propose corresponding adjustments to the methodology.

Subsequently, PTDFs are required for the external virtual hubs. The existing rules for the computation of PTDFs should be applied. Hence the virtual hubs are included in the PTDF computation, covering both external and internal virtual hubs

The introduction of new PTDFs implicitly leads to an adjusted selection of CNECs. Cross-zonal elements on the AHC borders become CNEs per legal requirement, internal lines may be defined by the TSO. Possible congestions in the grid shall not be considered twice as this could potentially limit capacity unnecessarily. Therefore, in the case of AHC, TSOs may exceptionally decide not to define a cross-border grid element as a CNE (for example, because the respective CNEs have already been considered in the calculation of the NTC of the neighbouring CCR). However, it should also be possible to introduce new CNEs. Thus, the respective TSO at the border takes over a coordinating role between the two CCRs. For HVDC interconnectors, analogous to the consideration of internal HVDC interconnectors, there shall be the possibility to limit the NP of the virtual hubs to the physical installed transmission capacity (e.g., the thermal limits of the cables and the converter) since those assets itself cannot be a CNEC. Since this methodology is only concerning the Core side Core of an interconnection, this limitation shall only cover the limitations on the Core side of the connection.

The objective of equal treatment of flows resulting from exchanges within Core and from exchanges on AHC borders implicitly results in a change in the computation of $\vec{F}_{0,\mathrm{Core}}$.4 Both share the same capacity on the CNECs. Thus, the situation for the computation of $\vec{F}_{0,\mathrm{Core}}$ according will also consider the commercial exchange on the AHC borders as $\overrightarrow{NP}_{\mathrm{ref,Core}}$ will include the net positions of the external virtual hubs. Vice versa, $\vec{F}_{\mathrm{uaf}}$ will not include flows resulting from commercial exchanges on the AHC borders.

2.4. Implementation of AHC

Core TSO will meet the 31st of March 2025 deadline to have developed AHC, updated

[4] The name of the figure is maintained for the sake of simplicity.

the explanatory note and publish an analysis that allows market participants to understand the impact of AHC. However, a "go-live" of AHC by 30th of June 2025 in SDAC will not be feasible due to performance issues identified in EUPHEMIA and the delayed go-live of 15 min MTU.[5] Core TSOs and CCR Core are working closely with SDAC experts to resolve any potential performance issues. Based on the current SDAC planning, the go-live of AHC can be expected between Q4 2025 and Q3 2026, depending on EUPHEMIA performance.

3. Inclusion of Celtic Interconnector and SEM-FR Bidding Zone Border

Pursuant to ACER's Decision No. 04/2024, the Celtic interconnector will create a new bidding zone border assigned to the Core CCR once it becomes operational. Subsequently, the bidding zone border between the Single Electricity Market in Ireland and Northern Ireland ('SEM') and France ('FR'), attributed to EirGrid, System Operator for Northern Ireland (SONI), and Réseau de Transport d'Electricité (RTE), will be included in the flow-based capacity calculation of the Core CCR.

As part of this explanatory document Core TSOs aim at explaining the following proposed changes to the Core DA CCM resulting from the inclusion of the SEM - FR bidding zone border in the Core CCR.

Article 2(1)(b)(b2), the definition of 'external virtual hub (EVH)' is extended to also include exchanges on HVDC interconnectors on the bidding zone borders of the Core CCR when either end of a HVDC interconnector is in a different synchronous area as specified in Article 13 (5)

Article 2(o), the list of Core TSOs in paragraph 13 is amended to include EirGrid and SONI, the TSOs of Ireland and Northen Ireland respectively.

Article 2(w), the definition of '$F_{0,\,all}$' is amended to accommodate a Core CCR bidding zone located outside of the Continental Europe synchronous area. The SEM bidding zone is in a separate synchronous area referred to as the 'island of Ireland' in this proposal.

Article 2(ggg), the definition of 'slack node' is amended to explicitly state that each synchronous area has its own designated slack node. As the SEM bidding zone is part of a separate synchronous area, a different slack node from the one used in continental Europe will be required.

Article 2(xxx), a new paragraph is introduced to define the meaning of the Single Electricity Market (SEM), a bidding zone consisting of both Ireland and Northern Ireland as a single electricity market.

Article 4(4), the paragraph relating to the obligation of 'each Core TSO' in providing capacity calculation inputs to the CCC is amended to include a provision for delegation of this obligation to another Core TSO. EirGrid and SONI, the TSOs of Ireland and Northern Ireland respectively, intend to jointly provide the capacity calculation inputs.

[5] Both NRAs and market participants asked for a stabilization period for 15 min MTU before AHC go-live.

The SEM TSOs share a common scheduling area and local tooling for the Core capacity process.

Article 13(1) is amended to distinguish between Core HVDC interconnectors located within the same synchronous area and those connecting two different synchronous areas, with a corresponding update to Footnote (5) to reflect these changes. Article 13(5), including subparagraphs 5a & 5b, is introduced for the inclusion of Core HVDC interconnectors whose endpoints are situated in different synchronous areas. The evolved flow-based (EFB) approach described in Articles 12(2) to 12(4) continues to apply exclusively for Core HVDC interconnectors within the same synchronous area and cannot be altered as it would undermine the modelling of ALEGrO. Accordingly, the new Article 13(5) establishes provision for inter-synchronous Core HVDC interconnectors such as Celtic, applying an approach similar to AHC at both endpoints of the cable.

Article 17(1), the paragraph concerning the calculation methodology for '$F_{0,\,all}$', and '$NP_{ref,\,all}$', is amended to accommodate a Core CCR bidding zone located outside the Continental Europe synchronous area. Under the proposed amendment, '$F_{0,\,all}$' refer to the flow per CNEC in a situation without any commercial exchange between bidding zones within Continental Europe, between bidding zones within Continental Europe and bidding zones located in other synchronous areas, and between the island of Ireland and bidding zones located in other synchronous areas and '$NP_{ref,\,all}$', refer to the total net positions included in the CGM, of: all bidding zones and VHs of Continentl Europe and the island of Ireland, and connection points of the bidding zones of Continental Europe with the bidding zones of other synchronous areas.

Article 22(2)(c)(iv)is amended to include the reference net position of the SEM bidding zone covering the Island of Ireland synchronous area, as well as the corresponding scheduled exchanges of all HVDC interconnectors between the Island of Ireland synchronous area and other synchronous areas.

Article 26(8), the operationalisation of the SEM-FR bidding zone border is contingent upon the completion and commissioning of the Celtic HVDC interconnector, as well as the fulfilment of the necessary technical conditions required to enable the commencement of commercial operations. The Core ID CCM 5th RfA proposes introduction of a new paragraph, numbered '8', into Article 26, which explicitly links the operation of the SEM - FR bidding zone border within the Core CCR capacity calculation process to the completion of the Celtic HVDC interconnector project.

4. SEM Allocation Constraints

Considering the joint discussions with Core TSOs, EirGrid and SONI intend to use allocation constraints. The general provisions for applying allocation constraints are provided in Article 7 of the Core ID CCM, while Annex I contains the list of Core TSOs approved to use allocation constraints, along with detailed technical and legal reasoning or the need to apply such constraints.

In addition to the intended use of external constraints, defined as constraints on net positions in the currently applicable Core ID CCM and outlined in paragraph 2 of Article 7, EirGrid and SONI would also like to apply ramping constraints on the Celtic HVDC interconnector. As the CCM does not currently provide for this type of allocation constraint, the Core ID CCM 5th RfA proposes the following amendments to accommodate this need.

Article 7(1) is amended to explicitly refer to the specific paragraphs within Article 7 that explain the different types of allocation constraints. Additionally, the Core ID CCM 5th RfA proposes the introduction of a new paragraph, numbered '8', into Article 7, which expressly permits the use of ramping constraints on HVDC interconnectors between synchronous areas as an additional type of allocation constraint, aimed at limiting the maximum flow change from one MTU to the next.

This approach preserves the overall structure of Article 7 while clearly distinguishing between external constraints referred to in paragraph 2 (i.e. constraints on net positions) and ramping constraints on HVDC interconnectors; and exempts the latter from the transitional and reporting obligations outlined in paragraph 3. The application of ramping restrictions on the active power output of HVDC interconnectors between synchronous areas, intended to limit their influence on the fulfilment of the frequency quality target parameters of the synchronous area, is a prescribed measure under Article 137 of the System Operation Guideline (SOGL) regulation. Therefore, it is not considered temporary and does not warrant additional reporting obligations.

4.1. Reasons EirGrid and SONI propose using external constraints

The primary objective of external constraints is to maintain operational security standards while enabling efficient market functioning. The necessity of these constraints for the SEM bidding zone is driven by several factors. As the island of Ireland operates a relatively small power system and electricity market which constitutes a separate synchronous area, dispatching decisions by EirGrid and SONI (SEM TSOs) need to carefully consider system security and real-time balance of supply and demand.

The SEM TSOs are responsible for generation commitment and determining optimal dispatch schedules. In centralized dispatch, balancing reserve procurement and congestion management are performed concurrently, in an integrated process. This differs from self-dispatch systems, where the balance-responsible parties make commitment decisions and determine dispatch positions, based on their own economic criteria, the technical constraints of generating units and the demand elements they are responsible for balancing.

The electricity system of the island of Ireland features a high penetration of renewable energy sources, particularly wind, with the instantaneous System Non-Synchronous Penetration (SNSP) levels reaching up to the safe operational limit of 75%. In the island of Ireland, renewables accounted for 40.0% of the country's electricity generation over the year 2024, with wind energy providing 33% of total electricity demand. Moreover, 41% of the months in the year 2024 had a SNSP of 50% or higher. The large share of wind and solar introduces volatility and unpredictability into the grid, requiring system operators to balance with dispatchable generation and Battery Energy Storage Systems (BESS).

During periods of extremely low wind generation, there can be limited operational flexibility, and managing domestic system reserves becomes crucial to prevent the system from entering an alert, emergency, or blackout state. During these periods of tight system margins, limiting the total export capacity of the SEM bidding zone becomes a key remedial action. This prevents potential market-driven export flows from causing a deficit in reserve margins, thereby ensuring system generation resource adequacy and avoiding potential violations of operational security limits.

In certain situations, conventional generating units identified through system studies are required to operate to support system voltage and provide reactive power in specific parts of the grid, as well as to maintain system inertia above recommended thresholds for frequency stability. These units are treated as priority dispatch (must-run), and system operators may aim to keep them online at or above their minimum generating capability (Pmin). Additionally, during periods of heavy rainfall, run-of-river hydro units are also prioritized to manage water levels and mitigate the risk of upstream flooding. These operational requirements may reduce the system's flexibility to lower domestic generation. To preserve adequate downward regulation capability and avoid over-supply, it may become necessary to limit the total import capacity into the SEM bidding zone. This remedial action ensures must-run units can operate as required while maintaining system balance and protecting operational security limits.

The island of Ireland operates within a synchronous area that comprises the control areas of both Ireland and Northern Ireland. This synchronous area is connected to other synchronous zones exclusively via HVDC subsea cables. While these HVDC links provide essential cross-zonal trading capacity, they offer limited synchronous support and cannot deliver services such as inertia or electromagnetic coupling. The extent of support services available from HVDC links depends on both the technical capabilities and the commercial agreements between interconnector owners and TSOs. Moreover, the relatively small size of the synchronous area restricts the ability to share reserves and balancing capacity across bidding zone borders, placing it at a disadvantage compared to larger systems like Continental Europe. These limitations may necessitate additional measures to ensure sufficient domestic operating reserves are maintained under all operating conditions.

High HVDC import levels can reduce the dispatch of local synchronous generation, which in turn lowers system inertia and increases susceptibility to frequency deviations during disturbances such as interconnector trips or local faults. The sudden loss of an HVDC interconnector also poses transient stability risks, potentially leading to significant power imbalances and rotor angle instability. Moreover, large HVDC power flows can affect local oscillatory modes, raising small-signal stability concerns in a low-inertia environment where damping is limited. When combined with the variability of intermittent renewable sources, these dynamic stability challenges may require operational management, including measures in the form of external constraints to safeguard system security.

4.2. Methodology of calculating external constraints

The methodology outlined here shows how the export and import constraints of the net position of the SEM bidding zone are calculated by evaluating the available generation, demand, and reserve requirements. It considers total dispatchable generation, forecasted wind and solar power, and operational limitations such as energy-limited resources like pumped storage, demand side units (DSU), dynamic stability, and battery energy storage. The process also accounts for reductions due to long-notice plants (long lead-time), generation unavailable because of grid constraints, and unusable hydro capacity.

The difference between net generation and the sum of demand and operating reserves for upward regulation defines the net position constraint in the export direction. On the other hand, the system demand subtracted from the sum of technical minima of dispatchable generation (required to run to maintain system inertia), non-dispatchable generation, and operating reserves for downward regulation defines the net position constraint in the import direction.

$$
\begin{aligned}
\text{Export Constraint} \quad &= \text{Dispatchable generation (DF)} \\
&+ [\text{Solar PV generation} + \text{Wind generation}] \\
&- [\text{Derated generation (Demand Response, Pumped Storage, BESS)}] \\
&- \text{Unusable generation (Long notice, TX constraints, unusable hydro)} \\
&- [\text{Forecasted Demand} + \text{Upward Reserves}]
\end{aligned}
$$

$$
\begin{aligned}
\text{Import Constraint} \quad &= \text{Forecasted demand} \\
&- [\text{Non-dispatchable generation from Solar PV \& Wind}] \\
&- \text{Sum of minima of dispatchable generating units (DF)} \\
&- \text{Downward reserves}
\end{aligned}
$$

Where:

DF - declared on fuel availability

BESS - Battery Energy Storage Systems

TX constraints - unavailable generation due to transmission constraints

4.3. Frequency of re-calculation

External constraints are determined through a continuous process for each capacity allocation time frame, based on the most recent information on the technical offer data of dispatchable generating units, forecasted wind and solar generation, forecasted system demand, and operational limitations such as dynamic stability and system constraints.

4.4. Time periods for which external constraints are applied

External constraints are calculated in the morning of D-1, resulting in bi-directional values (import and export) for each MTU of the respective trading day. However, actual capacity restrictions are applied only to those MTUs where the calculation results indicate a potential violation of system security limits.

4.5. Reasons EirGrid and SONI propose using ramping constraints on Celtic interconnector

With the commissioning of the Celtic interconnector (700 MW), it will become the largest single infeed and outfeed for the all-island system, increasing the total cross-zonal trading capacity of SEM bidding zone to 2200 MW, which accounts for nearly 30% of peak system demand. To maintain system stability, particularly during imbalances caused by flow changes on HVDC interconnections between market time units (MTUs), ramping restrictions are necessary. These restrictions further mitigate the risk of abrupt shifts between (maximum) import and export limits across two MTUs. Thereby, ramping constraints, as a specific type of allocation constraints, ensure that the maximum flow change on the HVDC interconnector between MTUs remains within secure operational limits. It is important to note that the HVDC ramping constraints referred to in this description are applied within the market coupling process as a standard procedure, and do not impact the capacity calculation process.

5. Polish Allocation Constraints

Each European Union country implements its own solutions to ensure secure reserve level. The solutions may differ both in the way the balancing price incentive is created and the timing of the market. PSE is one of the centrally dispatched Transmission System Operators participating in Single Day-Ahead Coupling and Single Intraday Coupling.

Conventional way for centrally dispatched Transmission System Operators is to buy energy and reserves through the Integrated Scheduling Process (ISP), which selects which dispatchable units are to cover demand and determines their output. Procurement of energy and reserves in the ISP is a co-optimized process, ensuring high social welfare.

When ISP is based on market results and unit schedules to determine the most efficient way to realize the schedules and to balance residual demand, export/import, and to secure reserves, then the process is called central dispatch with self-commitment. In that case first ISP run begins after first intraday auction. It’s PSE’s model of balancing.

ISP is run iteratively to include the new trade, load forecast, grid information to correct positions of producers and energy storages in most efficient way.

Producers and consumers are free to trade any volume of power before, during and between iterations of ISP to adjust their positions. The exception is last full ISP which is run after Gate Closure Time of SIDC.

The timing of the trade (before and simultaneous to most runs of ISP) is the reason why central dispatching TSOs need to use Allocation Constraints. In case that every power producer sold all its power on SIDC, it would be impossible to provide sufficient upward reserve. A similar situation would occur with imports and would result in a lack of downward regulation. The reserves are needed for real-time balancing of power system in case of any contingency abruptly changing load or generation of power.

Allocation constraints secure the reserves by constraining trade which could result with overproduction and underproduction of plants which would lead to scarcity of available balancing capacity.

In Poland, the resources available in the ISP are primarily centrally dispatched generating units, i.e. large system power plants. The units have a legal obligation in Poland to be a provider of balancing services, i.e. to offer in the ISP balancing energy in relation to their entire disposable capacities. In their offers they indicate at what price they are willing to increase or decrease the level of electricity generated in a given generating unit in relation to their generation plan and provide information on the technical parameters of these units. Centrally dispatched units are a key regulatory resource in the Polish power system enabling adjustment of the power balance in real time to the needs of consumers. In a situation where the remaining part of producers and recipients do not plan their work meticulously, the TSO is forced to use centrally dispatched units very intensively to balance the system. This leads to exhaustion of the TSO's balance regulation capabilities, disrupting the operation of the national and European power system, and also adversely affects the technical efficiency of the units.

The share of centrally dispatched units in the Polish power system systematically decreasing – currently it amounts to slightly over 40% of the total generation capacity in the country. The non-dispatchable generation segment has grown very dynamically in recent years. The operation of non-dispatchable generation depends on decisions made by their owners, including the reaction to price signals.

To increase the availability of balancing capacity and limit Allocation Constraints impact on market, PSE launched an additional balancing capacity market mechanism which was implemented on 14 June 2024. Balancing capacities on the market are acquired separately for the direction of increasing the power introduced to the system and its reduction. The suppliers of balancing capacities for the TSO may be generating units, energy storage facilities and load. The acquisition of balancing capacities for given day D takes place in the basic process at 8:30 on D-1 and in the supplementary process (the aforementioned ISP) from the afternoon on D-1 until the time of delivery on D. The balancing capacities are acquired in an auction mode, and their valuation is based on the marginal pricing mechanism, i.e. according to a uniform settlement price for a given 15-minute period.

The capacity bought by PSE should not be offered anymore by BSPs on the SDAC and SIDC **leading to significantly less frequently binding (active) ACs**. So far, the market isn't liquid enough to provide sufficient balancing capacity despite that PSE buys all the available capacity on the market. Figure 1 shows how much upward reserve capacity lacks on the market for each time unit. Figure 2 shows the similar information for downward reserve. Figure 3 presents the frequency of scarcity of reserves on the market.

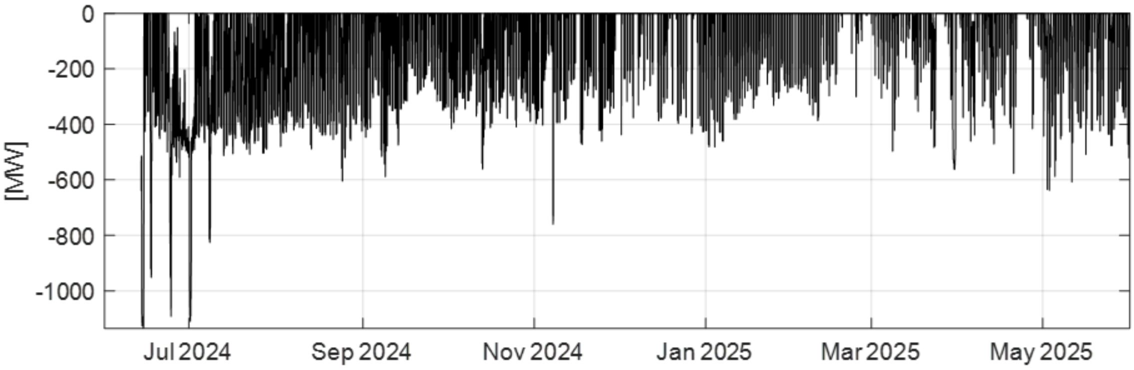

Figure 1. Scarcity of total upward reserve offers in primary procurement (volume procured - volume required). Source: https://raporty.pse.pl/

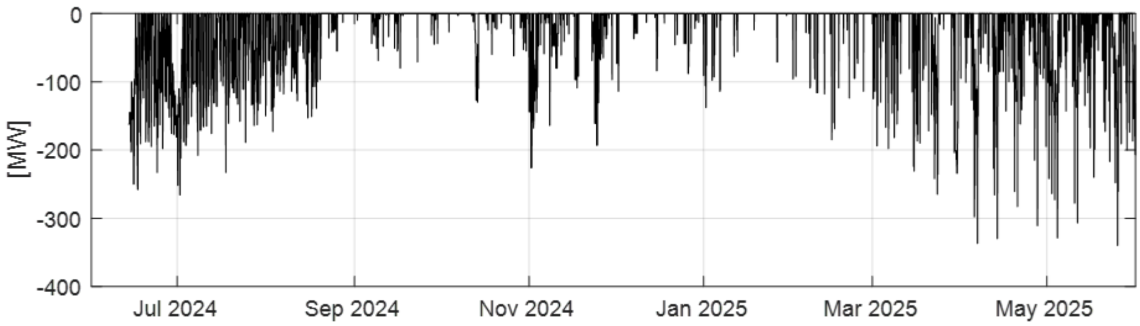

Figure 2. Scarcity of total downward reserve offers in primary procurement (volume procured - volume required). Source: https://raporty.pse.pl/

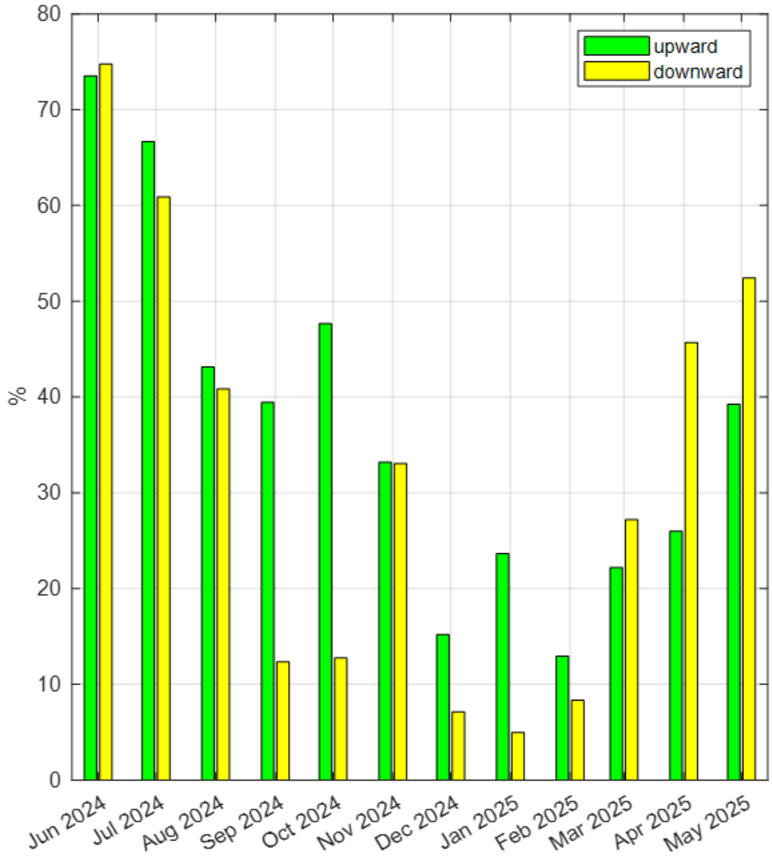

Figure 3. Frequency of reserve scarcity during primary procurement.

Producers unfortunately didn't get used to new market and do not provide enough offers for reserve capacities. What's more we can see seasonal pattern with increasing scarcity of both kinds of reserve in the summer connected with low generation of dispatchable units capable to provide reserve due to large production of renewables. PSE currently works on adding the availability to participate in the market for renewables to increase liquidity.

Despite immaturity of morning balancing capacity market, the impact of retracting procured capacities on frequency of activation of Allocation Constraints is noticeable and can be seen on Figure 4.

PSE quarterly publishes reports analysing the impact of Allocation Constraints on market on JAO site. Reports show that Allocation Constraints removing would lead to net social welfare loss due to intense use of load shedding and increased curtailment of renewable power sources.

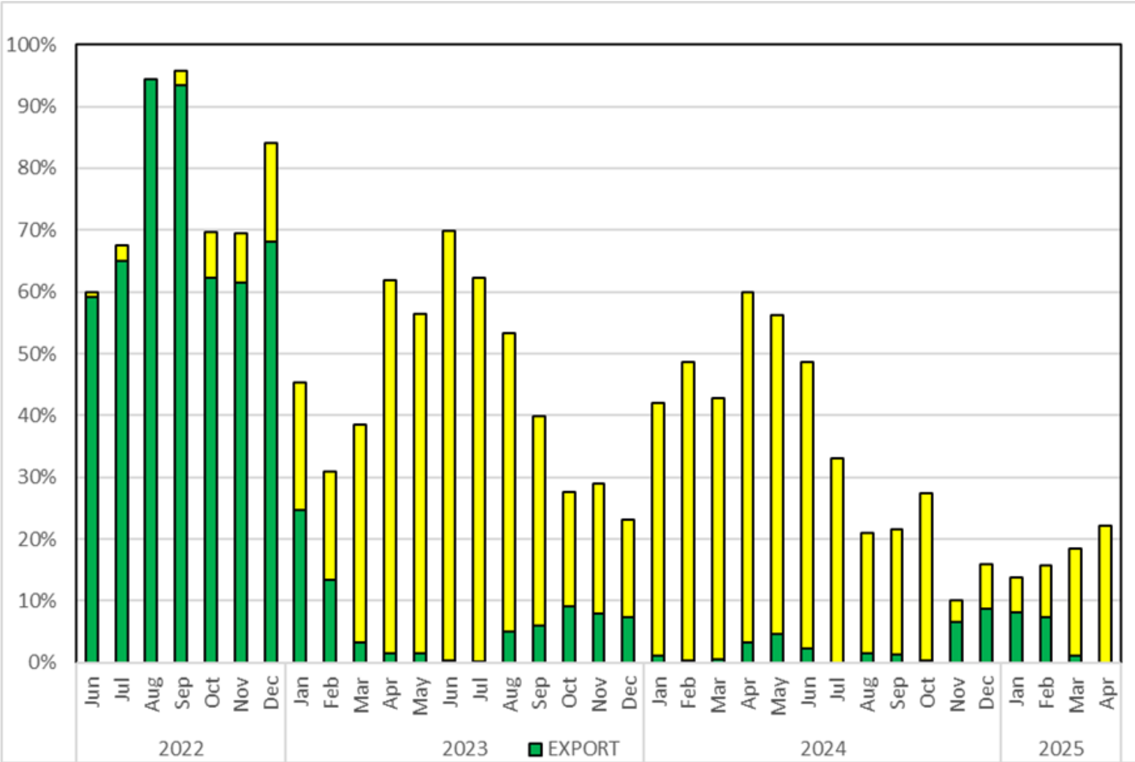

Figure 4. Share of hours in which Allocation Constraints were binding (DA). The launch of new morning balancing capacity market was on 14th June 2024.

The aim of PSE is to minimize the frequency of active Allocation Constraints. PSE expects that decreasing trend of Allocation Constraints binding the market will continue especially with further development of Polish balancing market. Basing on the market results, the current situation of the market makes it impossible to abandon the constraints. They are the only means of ensuring sufficient regulation reserves and secure operation of the power system. They are for now the only effective measure to maintain the frequency stability.

6. FB in IDA

In accordance with Art.3(d) of the CACM Regulation, TSOs and NEMOs should optimize the calculation and allocation of cross-zonal capacity. In this regard, the implementation of FB allocation in IDAs will enable to provide more capacities for trading in ID. The capacity calculation is already in flow-based for the CORE Region, via the IDCC processes. The main improvement lies on the allocation side as the whole flow-based domain will be used during IDA's. Hence, the need for amendment in the IDCC methodology remains limited. An important remark is that ID continuous trading remains in ATC allocation for the moment, meaning that after an IDA in FB allocation, an ATC extraction is needed to open the ID continuous market.

7. Removal of LTA inclusion from IDCC(a) capacities

The implementation of the long-term capacity calculation and the long-term flow-based allocation pursuant to the FCA regulation, can possibly create operational security issues while in parallel the LTA domain is used in DA. For this reason, according to the LT CCM pursuant to the FCA regulation, the LTA domain in DA cannot further be used once LT CC and LT FBA is implemented.

In addition, the IDCC(a) capacity calculation process updates the cross-zonal capacities remaining after the SDAC. Thus, the implementation of LT CC and LT FBA also impacts the IDCC(a) process.

Throughout the ID CCM, for the references to LTA inclusion in the intraday cross-zonal capacities remaining after the SDAC, there is a conditional statement to the application of it only after the implementation of the Core Long Term Capacity Calculation Methodology and LTA allocation pursuant to the FCA regulation, and also after an impact assessment is performed to assess the impact in IDCC(a) capacities without LTA inclusion and LTA domain.

An impact assessment is important to be performed to identify whether IDCC(a) capacities are highly impacted by the removal of the LTA inclusion. The parameter LTA inclusion is one of the parameters used to modify the RAM, according to Article 11(2) of the ID CCM. The parameter determines what the share of LTA will be considered for the IDCC(a) capacity calculation. The individual parameters per TSO are presented below:

50 Hertz	**Amprion**	**APG**	**CEPS**	**ELES**	**ELIA**	**HOPS**	**MAVIR**
20%	20%	0%	100%	100%	100%	100%	20%
PSE	**RTE**	**SEPS**	**TTG**	**TTN**	**TEL**	**TNG**	
100%	100%	20%	20%	20%	20%	20%	

Example: 50 Hertz consider 20% of the LTA for the IDCC(a) capacity calculation.

The higher the share of LTA, the greater the impact on IDCC(a) capacities will be. Precisely six Core TSOs consider 100% of the LTA, whereas the remaining Core TSOs use 20% of the LTA with the exception of APG. Thus, a considerable impact in IDCC(a) capacities is expected without LTA inclusion.

In addition, performing the impact assessment help Core TSOs identifying alternative measures to compensate the loss in capacities.

8. 110kV network elements in final CNEC list

In the Core CCR bidding zones, the 110-132 kV layer is normally built up with a radial topology connecting the high-voltage level towards the distribution levels, thus it serves as a radial interface between the high-voltage grid and the distribution grid. In Hungary the 132 kV network is highly meshed, is a parallel path to the transmission system and plays an important role in system operation as well. Not being able to solve any critical issue at this level would require intervention on higher voltage level.

8.1. Efficiency of IVA application: 110 kV vs. 400 kV

Figure 5 shows that applying IVA on the 400 kV CNEC to solve potential overload on the 110 kV would lead to unnecessary loss of the flow-based domain.

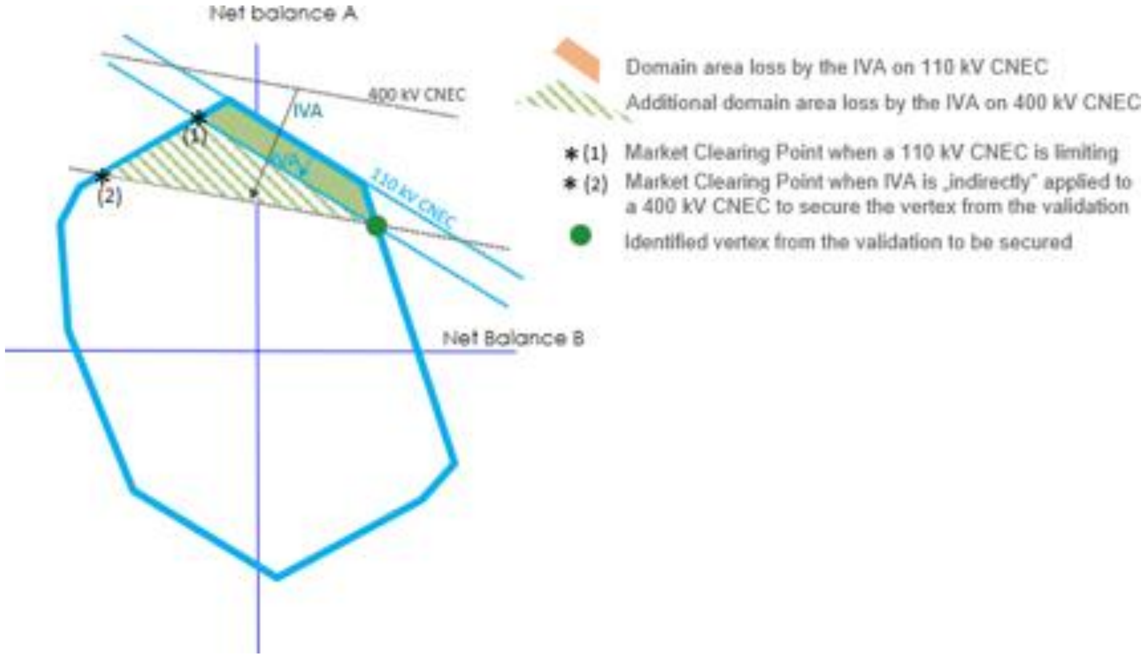

Figure 5. Efficiency of IVA application

9. General updates:

9.1. New deadline for post go-live studies

As per the current amendments of the Core ID CCM, Core TSOs are asked to perform post go-live studies on GLSK, FRM and internal CNECs.

The purpose of such studies would be to develop a proposal for further harmonisation of the generation shift key; to develop a methodology for calculation for FRM per CNEC; and to determine a list of internal network elements combined with the relevant contingencies to be defined as CNECs, such a list would be added to the Core ID CCM as an annex.

In light of the current roadmap and priorities for Core IDCC, including CIS and its subsequent actions, the minRAM study, and the implementation of IDCC(d) and IDCC(e), as well as developments in CE and ROSC, Core TSO proposes postponing the deadline for the GLSK, FRM, and internal CNECs studies. This delay will extend until after the full implementation of the ROSC methodology and after conducting these studies in the day-ahead timeframe. This approach allows for the expected impacts and insights to be incorporated into the ID studies.

9.2. New implementation deadline for IDCC(e)

In the current amendment of the Core ID CCM, the deadline of implementation of IDCC(e) is linked to the implementation of the corresponding intraday CROSA following the ROSC methodology. Taking into account the significant delays in the implementation of the ROSC methodology, the Core TSOs propose to have the go-live of IDCC(e) independent from ROSC.

Core TSOs propose to have IDCC(e) implemented by 36 months after the implementation of calculation of intraday cross-zonal capacities IDCC(b).

9.3. Extension of ATC validation until FB in IDAs

In parallel to IVA validation the Core TSOs may also perform ATC based validation to ensure operational security.

The ATC limitation may be done only in the following situations:

- an occurrence of an unexpected contingency impacting a CNE after the beginning of the related IDCC process;
- as a fallback, in case IVA validation cannot be performed fully in time or if it faces IT issue; or
- a mistake in input data that leads to an overestimation of cross-zonal capacity from an operational system security perspective.

ATC based validation offers the opportunity in case of the above-mentioned situations to limit ID ATCs without having an impact on capacities on other Core borders.

Looking at the benefits offered by ATC validation, Core TSOs propose to extend the deadline of use of ATC based validation until the latest possible time which would be the implementation of flow-based in IDA.

9.4. ID FB computation on shifted CGM

The IDCC-process will add a new step to include additional market results for initial FB computation to allow for a better quality / more accurate grid model rather than using the old D-2 forecasts which influence the Fuaf results. This is done by using an already shifted grid model as a starting point considering previous SDAC/SIDC market results.