Explanatory document to the fourth amendment of the Day-Ahead 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

December 2025

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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') per Capacity Calculation Region ('CCR').

In this explanatory document Core TSOs explain the background to the changes included in the proposal for amendment of the Core DA CCM. A track-change version of the Core DA CCM reflecting the proposed changes is shared for informative purpose.

2. Operational security limits

Article 6 Core DA CCM specifies operational security limits. These are founded on SO GL.

The Core TSOs propose to amend the wording of Article 6 to clarify and resolve an editorial inconsistency. The proposal does not alter the meaning of the stipulations regarding operational security limits.

Article 6(1) Core DA CCM refers to Article 72 SO GL, which in turn refers to Article 25 SO GL. Article 25(1) SO GL allows for all relevant physical characteristics to be considered: "Each TSO shall specify the operational security limits for each element of its transmission system, taking into account *at least* the following physical characteristics […]" (emphasis added).

Article 6(2) Core DA CCM then brings along a certain inconsistency. It first refers to "the thermal limits of CNEs" but then states that these are "the physical limit of a CNE according to the operational security limits in accordance with Article 25 of the SO Regulation". This alleged equivalence is inconsistent with the open definition of security limits in Article 25 SO GL.

The respective proposal for amendment consists of replacing "thermal limits" in Article 6(2) Core DA CCM by "operational security limits" and clarifying in Article 6(2)(a)(iii) that operational security limits relating to physical characteristics other than thermal limits are not dependent on ambient conditions. For example, the maximum admissible current of a CNE might not be based on the thermal rating of the conductors of the overhead line itself as other elements e.g. substation equipment such as a current transformer connected in series, can impose the primary limit.

The proposed amendment to Article 6 is accompanied by a minor adaptation of Whereas (18) to make clear that certain aspects of operational security may, but do not have to be addressed by allocation constraints. This allows, where possible, to continue considering such aspects by operational security limits on CNEs pursuant to Article 6.

3. 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 day-ahead auctions**. It is 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 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 SDAC, 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 SDAC 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 **leading to significantly less frequently binding (active) ACs**. Unfortunately, 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.

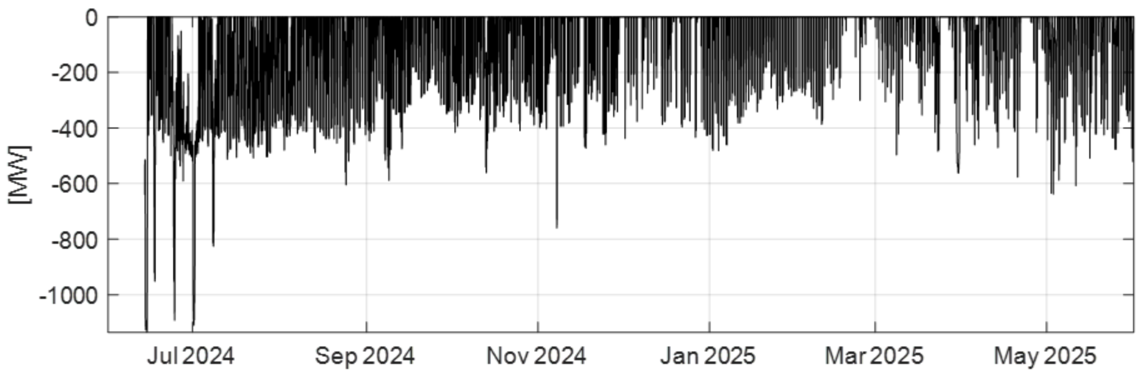


Figure 1. Scarcity of total upward reserve offers in primary procurement (volume procured - volume required). Source: https://raporty.pse.pl/

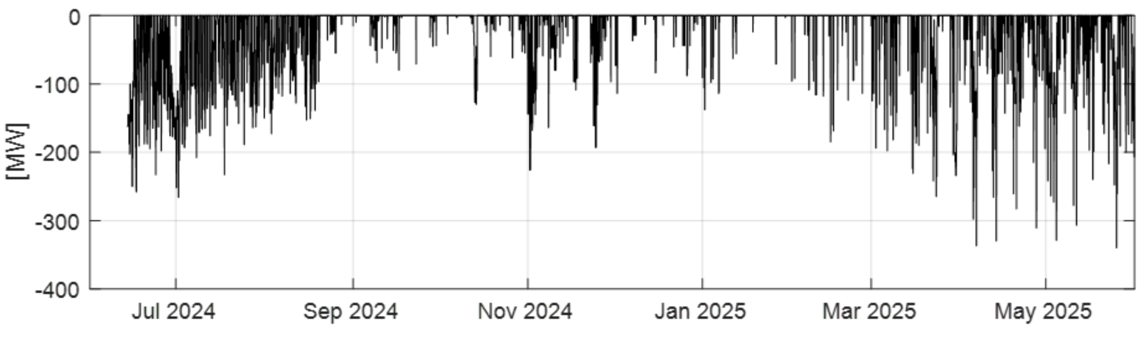


Figure 2. Scarcity of total downward reserve offers in primary procurement (volume procured - volume required). Source: https://raporty.pse.pl/

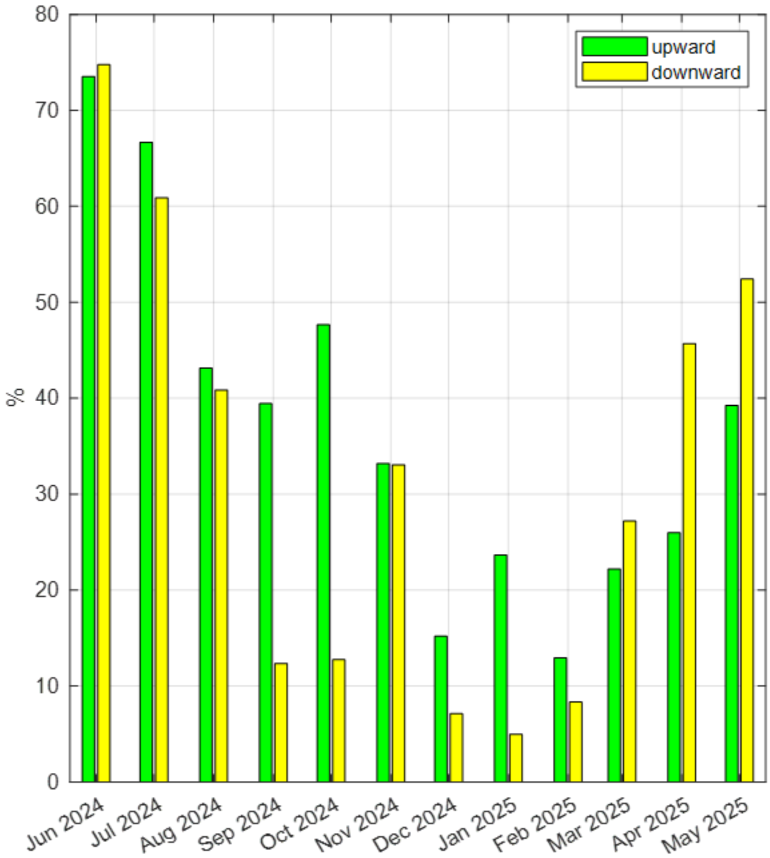


Figure 3. Frequency of reserve scarcity during primary procurement.

Generators 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 the market on the 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.

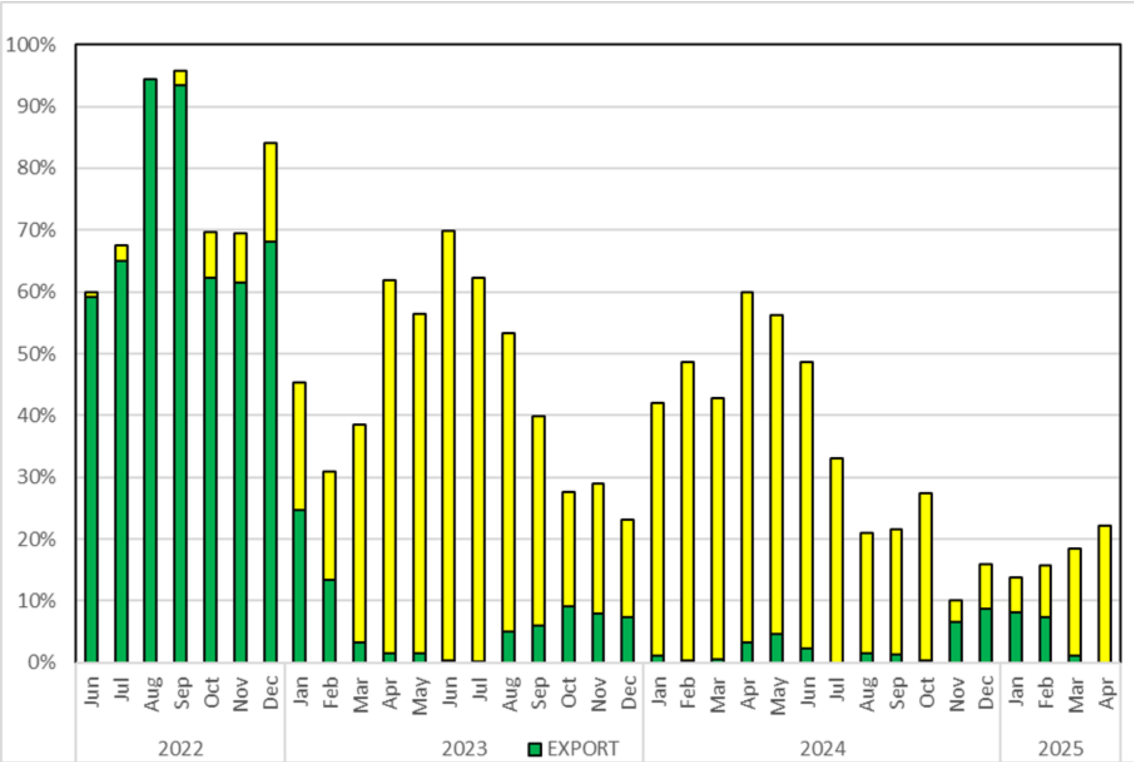


Figure 4. Share of hours in which Allocation Constraints were binding (DA). The launch of new morning balancing capacity market was on 14th June 2024.

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.

4. 110 kV 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.

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.

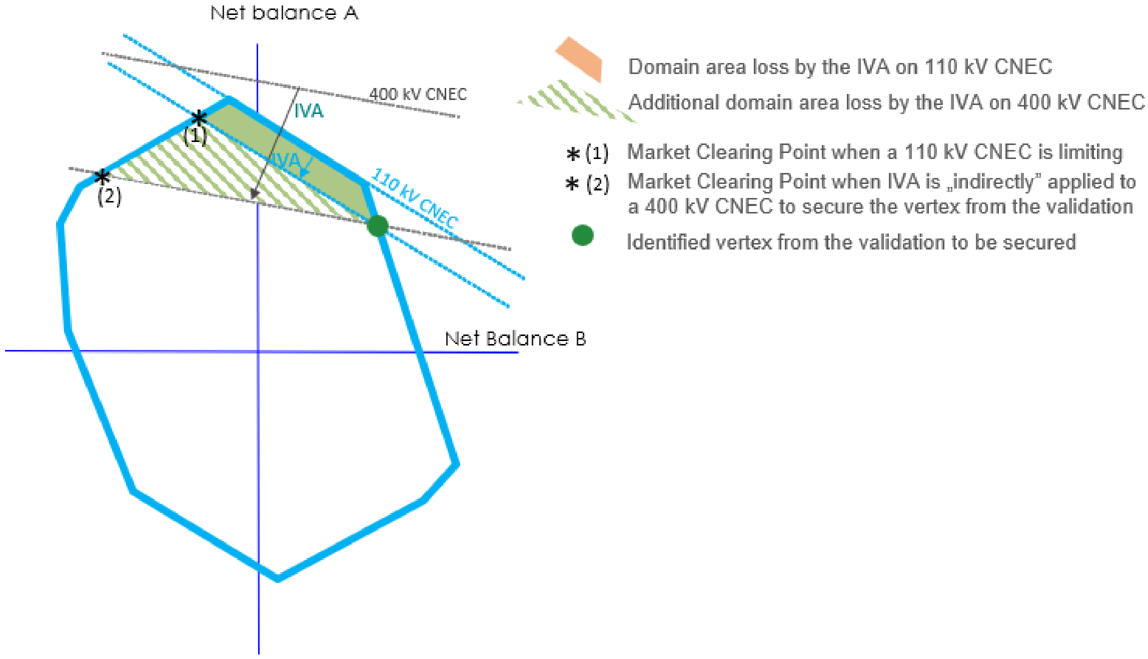
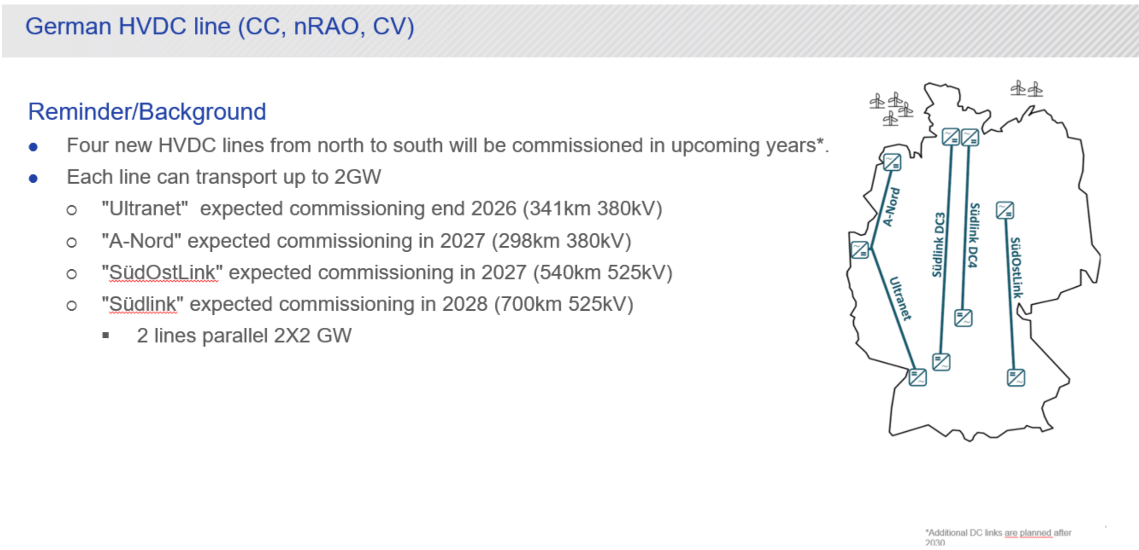


Figure 5. Efficiency of IVA application

5. Integration of new inner-German HVDC lines



The German Transmission System Operators (TSOs) are developing high-voltage direct current (HVDC) lines within Germany in the upcoming years, which will serve as a corrective measure for the NRAO and Coordinated Validation. The first line's commission is planned end of 2026. The following Article were extended.

In Article 10(7) changing the set point of a bidding zone internal HVDC line has been added to reflect that the initial setpoint change of the HVDCs can be used as a remedial action.

For Article 16(3)(b), the range of setpoints of bidding zone internal HVDC lines was added in the iterative optimisation process of the NRAO and in Article 24(4) for the regular review of the common list of RAs taken into account in the day-ahead capacity calculation the bidding zone internal HVDC setpoints were added as well.

6. 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(13), 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(20a), 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 12 (5)

Article 2(22), the definition of 'F0, 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(60), 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(78), a new paragraph numbered '78' 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(3), 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. The SEM TSOs share a common scheduling area and local tooling for the Core capacity process.

Article 12(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 12(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 12(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(3), the paragraph concerning the calculation methodology for 'F0, all', is amended to accommodate a Core CCR bidding zone located outside the Continental Europe synchronous area. Under the proposed amendment, 'F0, 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.

Article 25(2)(d)(xiii), the last bullet point of subparagraph 2(d)(xiii) 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 28(8), the operationalization 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 DA CCM 4th RfA proposes introduction of a new paragraph, numbered '8', into Article 28, 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.

7. 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 DA 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 DA 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 DA CCM 4th RfA proposes the following amendments to accommodate this need.

Whereas (18) is extended to include a reference to ramping constraints on HVDC interconnectors between synchronous areas, identifying them as a specific type of allocation constraint separate from external constraints.

The Core DA CCM 4th RfA proposes the introduction of a new sub-paragraph, numbered '7(2)(c)', 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. The references to the allocation constraints on net position defined in 7(2)(a) & (b) are also updated throughout Article 7. This approach preserves the overall structure of the article on allocation constraints and exempts the introduced ramping constraints on HVDC interconnector from the transitional and reporting obligations outlined in Article 7(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.

7.1. Reasons EirGrid and SONI propose using net position constraints

The primary objective of allocation 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 allocation constraints to the net position to safeguard system security.

7.2. Methodology of calculating allocation constraints on net position

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.

$$\textbf{\textit{Export}}_{Constraint} = P_{CD} - P_{UG} - P_{DER} + P_{NCD} - (P_L + P_{UPres})$$

$$\textbf{\textit{Import}}_{Constraint} = P_L - P_{DOWNres} - P_{CDmin} - P_{NCD}$$

Where:

P_{CD} : Sum of operating generating capacities of centrally dispatched units as declared on fuel availability by generators

P_{CDmin} : Sum of technical minima of centrally dispatched generating units in operation

P_{UG} : Unavailable generation due to Transmission Constraints, Long-Notice Units, Unusable Hydro

P_{DER} : Derated generation (Demand Response Units, Pumped Storage, Battery Energy Storage Systems)

P_{NCD} : Sum of schedules of generating units that are not centrally dispatched, as provided by generators

P_L : Forecasted Load

P_{UPres} : Minimum reserve for upward regulation

$P_{DOWNres}$: Minimum reserve for downward regulation

7.3. Frequency of re-calculation

Allocation constraints on net position 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.

7.4. Time periods for which allocation constraints on net position are applied

In the case of the day-ahead process, allocation constraints on net position are calculated on the morning of D-1, resulting in bi-directional values (import and export) for each DA CC 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.

7.5. 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.

The ramping constraint is required due to the nature of the generation stack in the SEM bidding zone rather than any technical constraints on the Celtic interconnector itself, although the constraint will appear on the interconnector since it is the only one available for cross-border flows in Core CCR. To calculate the ramping constraint, EirGrid and SONI will carry out market and system modelling analysis for all hours of the year 2028 to coincide with forecasted Celtic Interconnector go-live. This analysis will assess the ramping characteristics of the system against a range of possible ramping rates on the Celtic interconnector. These system ramps are constrained by the typical ramp characteristics of renewable generators such as wind and solar PV, and the technically feasible ramping characteristics of the conventional dispatchable generating units in the SEM. The range of acceptable ramp rates is defined by calculating the number of system frequency events that breach system security high and low frequency standards. Based on these study results and overall EirGrid and SONI system frequency control standards, the acceptable Celtic interconnector ramp rates will be defined in due course before Celtic interconnector go-live.

8. Formula for Computing the maximum zone-to-zone PTDF (Equation 5 of the Core DA CCM)

The current formula for computing the maximum zone-to-zone Power Transfer Distribution Factors ($PTDF_{z2zmax}$) has some limitations which will only be confounded when additional HVDC interconnectors (similar to ALEGrO) are introduced in the Core CCR. The proposed correction to the $PTDF_{z2zmax}$ formula aims to remove these limitations and, importantly, to account for a potential future scenario in which there is more than one HVDC interconnector with both ends in the same synchronous area in the Core CCR. Figure 6 below shows the version of Equation 5 in the Core DA CCM before it was adapted (the $PTDF_{z2zmax}$ formula). With the current changes, the aim is to correct the RHS of the $PTDF_{z2zmax}$ formula, i.e. the part that accounts for the maximum influence of exchanges via the Internal Virtual Hubs (IVH) on a given CNEC.

$$PTDF_{z2zmax,l} = max\Big(\underbrace{\max_{X\in\{BZ\cup EVH\}}(PTDF_{X,l}) - \min_{X\in\{BZ\cup EVH\}}(PTDF_{X,l})}_{\text{Maximum influence of exchanges between Core bidding zones (and/or External Virtual Hubs) on a given CNEC l}}, \max_{H_1,H_2\in IVH}\underbrace{\big(|(PTDF_{A,l} - PTDF_{H_1,l}) - (PTDF_{B,l} - PTDF_{H_2,l})|, |PTDF_{H_1,l} - PTDF_{H_2,l}|\big)}_{\text{Maximum influence of exchanges via the Internal Virtual Hubs on a given CNEC l}}\Big)$$

Figure 6. Previous version of Equation 5 in the Core DA CCM.

To highlight the first shortfall of the previous $PTDF_{z2zmax}$ formula, consider a scenario in which there is no HVDC interconnectors in the Core CCR and the circular flow from France to Belgium via Germany has the maximum influence on CNEC l as illustrated in Figure 7 below. The maximum zone-to-zone PTDF for this hypothetical scenario is defined by only the LHS of the $PTDF_{z2zmax}$ formula, i.e. the part that accounts for the maximum influence of exchanges between Core bidding zones (and/or External Virtual Hubs (EVH)) on a given CNEC l.

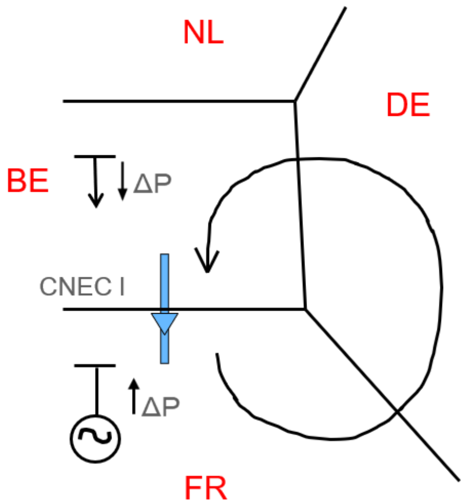


Figure 7. Scenario 1: No HVDC interconnector in the Core CCR. The circular flow from France to Belgium via Germany has the maximum influence on CNEC l

The maximum zone-to-zone PTDF for this hypothetical scenario can be expressed as follows:

$$PTDF_{z2zmax,l} = PTDF_{BE,\,l} - PTDF_{FR,\,l}$$

Equation 1

with

$PTDF_{BE,l}$	zone-to-slack $PTDF$ of Belgium on a CNEC l
$PTDF_{FR,l}$	zone-to-slack $PTDF$ of France on a CNEC l

Considering the scenario that the circular flow with the maximum influence on CNEC l is now via ALEGrO (or HVDC I) as illustrated in Figure 8 below, such a flow (or exchange) should ideally be captured by both the LHS and RHS of the $PTDF_{z2zmax}$ formula. However, the definitions of bidding zones A and B in the previous $PTDF_{z2zmax}$ formula did not allow for an exchange between France and Belgium via HVDC I to be considered. This is because A and B were defined as the two bidding zones connected by the HVDC interconnector, i.e. Belgium and Germany in the case of ALEGrO. In essence, the RHS of the previous $PTDF_{z2zmax}$ formula only accounted for the influence of an exchange between Belgium and Germany via ALEGrO (or HVDC I) on a given CNEC l. The restriction introduced by the definitions of bidding zones A and B in the $PTDF_{z2zmax}$ formula must therefore be removed.

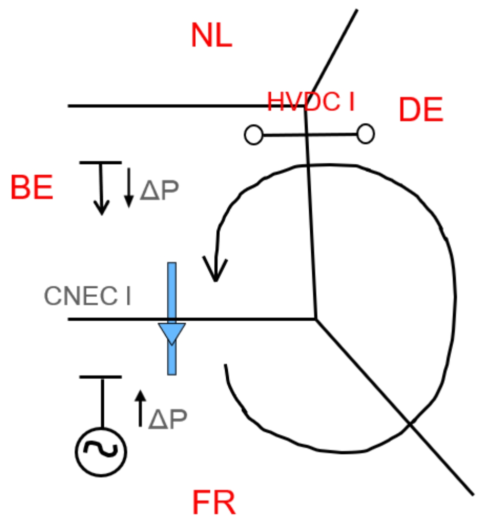


Figure 8. Scenario 2: One HVDC interconnector in the Core CCR. The circular flow from France to Belgium via the HVDC interconnector has the maximum influence on CNEC l

After effecting this change and zeroing in on the highlighted part of the $PTDF_{z2zmax}$ formula (see Figure 9 below), it can be observed that the highlighted part of Figure 9 also contains the LHS of the $PTDF_{z2zmax}$ formula, i.e. the part that accounts for the maximum influence of exchanges between Core bidding zones (and/or EVH) on a given CNEC l. This will be proven shortly.

$$PTDF_{z2zmax,l} = max\Bigg(\underbrace{\max_{X\in\{BZ\cup EVH\}}(PTDF_{X,l}) - \min_{X\in\{BZ\cup EVH\}}(PTDF_{X,l})}_{\text{Maximum influence of exchanges between Core bidding zones (and/or External Virtual Hubs) on a given CNEC l}}, \max_{H_1,H_2\in IVH}\underbrace{\left(|(PTDF_{A,l} - PTDF_{H_1,l}) - (PTDF_{B,l} - PTDF_{H_2,l})|, |PTDF_{H_1,l} - PTDF_{H_2,l}|\right)}_{\text{Maximum influence of exchanges via the Internal Virtual Hubs on a given CNEC l}}\Bigg)$$

Figure 9. Previous version of Equation 5 in the Core DA CCM.

For Scenario 2, the highlighted part in Figure 9 above can be expressed as shown below (assuming that HVDC I is ALEGrO):

$$(PTDF_{BE,\,l} - PTDF_{ALBE,\,l}) - (PTDF_{FR,\,l} - PTDF_{ALDE,\,l})$$

Equation 2

with

$PTDF_{BE,l}$	zone-to-slack $PTDF$ of Belgium on a CNEC l
$PTDF_{FR,l}$	zone-to-slack $PTDF$ of France on a CNEC l
$PTDF_{ALBE,l}$	zone-to-slack PTDF of the converter station of ALEGrO (HVDC I) in Belgium
$PTDF_{ALDE,l}$	zone-to-slack PTDF of the converter station of ALEGrO (HVDC I) in Germany

Regrouping terms in Equation 2 above results in Equation 3 below:

$$(PTDF_{BE,\,l} - PTDF_{FR,\,l}) + (PTDF_{ALDE,\,l} - PTDF_{ALBE,\,l})$$

Equation 3

Comparing Equation 3 with Equation 1, it becomes apparent that the HVDC interconnector serves as an „additional contributor" to the maximum zone-to-zone PTDF, i.e. the HVDC interconnector introduces the term $(PTDF_{ALDE,\,l} - PTDF_{ALBE,l})$. Consequently, the first part of Equation 3 above can be ignored since it is already accounted for in Equation 1 and hence the first part of the $PTDF_{z2zmax}$ formula, i.e. the part that accounts for the maximum influence of exchanges between Core bidding zones (and/or EVH) on a given CNEC l.

Another limitation of the $PTDF_{z2zmax}$ formula is that it does not account for a situation in which there is more than one HVDC interconnector in the Core CCR as shown in Figure 10 below.

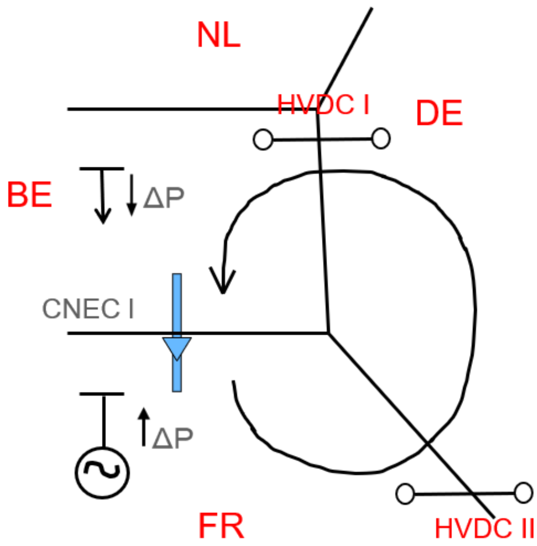


Figure 10. Scenario 3: Two HVDC interconnectors in the Core CCR.

The formula is therefore further adapted as shown in Equation 4 below:

$$PTDF_{\mathrm{z2zmax},l} = \underbrace{\max_{X\in\{\mathrm{BZ}\cup\mathrm{EVH}\}} PTDF_{X,l} - \min_{X\in\{\mathrm{BZ}\cup\mathrm{EVH}\}} PTDF_{X,l}}_{\text{Maximum influence of exchanges between Core bidding zones (and/or EVHs) on a given CNEC l}} + \underbrace{\sum_{\substack{k\in K \\ H_{1k},H_{2k}\in\, IVHs}} \left|PTDF_{H_{1k},l} - PTDF_{H_{2k},l}\right|}_{\text{Total influence of exchanges via IVHs on a given CNEC l}}$$

Equation 4

9. Harmonised GSK Methodology

Note: This section deals with the amendment of the Generation Shift Key (GSK) stipulations, mainly in Article 9. For the sake of clarity, the following explanations refer to Generation and Load Shift Key (GSLK) to emphasise that the GSK can contain both nodes of injection to and withdrawal from the CGM.

For the purpose of DACC, the main focus of the Generation-Load Shift Key (GLSK) is to achieve modelling accuracy for shifts from the IGM's Original Net Position (ONP) towards the net-position at the Market Clearing Point (MCP). This ensures the most accurate calculations of capacities available to the DA market.

However, GLSKs are also applied for shifts towards other net positions than the MCP. For example, in DACC GLSK is also used for shifts to zero balance when computing the Adjustment for MinRAM (AMR). Therefore, GLSK modelling has an impact on virtual capacities, capacity validation results but also on other operational processes that use GLSKs as an input (e.g. CGM balance adjustment, Cost Sharing, IGM creation for some TSOs).

Given this broader application, it is understandable that a single GLSK cannot achieve equal accuracy across very different target net positions. For instance, a GLSK optimized to model shift from German NPF of 9 GW toward an MCP of 10 GW would differ significantly from a GLSK intended to model a shift toward zero balance. This reflects an inherent trade-off: optimizing GLSKs for accurate shift to MCP may come at the expense of flexibility across a wider range of net positions, including highly unlikely ones such as zero balance.

9.1. The Core GLSK Studies

For the purpose of the Core GLSK Study, the focus is placed on optimizing GLSKs for accurate shifts toward the MCP.

The motivation behind the Core GLSK Study is the ACER decision on the Day-ahead Capacity Calculation Methodology of the Core Capacity Calculation Region (CCR) which stipulates in Article 9(6) that:

> Within eighteen months after the implementation of this methodology in accordance with Article 28(3), all Core TSOs shall develop a proposal for further harmonisation of the generation shift key methodology and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. The proposal shall at least include:
>
> a) the criteria and metrics for defining the efficiency and performance of GLSKs and allowing for quantitative comparison of different GLSKs; and
> b) a harmonised generation shift key methodology combined with, where necessary, rules and criteria for TSOs to deviate from the harmonised generation shift key methodology.

The results of the CWE GSK Study that was previously conducted for the CWE CCR influenced the requirements that have been defined in this Article. The Core GLSK study was carried out in two parts, performed sequentially, to fulfil each requirement.

The first part of the Core GLSK Study leveraged on the findings of the CWE GSK Study to derive criteria and metrics for a quantitative assessment of the performance of various GLSK approaches employed by Core TSOs. In the second part of the Core GLSK Study various candidate GLSK strategies as well as the status quo GLSK strategies employed by Core TSOs were evaluated based on the KPIs from the first part of the Core GLSK study. Based on this evaluation, a concrete harmonised GLSK methodology is proposed to be included in the Core CCM.

9.2. Summary of Core GLSK Study Part 1

The first part of the GLSK addressed the following requirement in the Article 9(6) of the Core DA CCM: "[…] define **criteria and metrics** for defining the efficiency and performance of GLSKs and allowing for **quantitative comparison of different GLSKs**". To achieve this, various KPIs were defined to evaluate existing GLSK approaches among

Core TSOs. The following criteria were considered in the selection of the finally chosen KPIs:

- **Prioritize KPIs which address the objective of a GLSK as defined in the Core DA CCM,** to accurately model generation and load at nodal level following a net position change**:** For this reason, the focus was set on KPIs quantifying primarily the nodal forecasting error between the DACF and the D2CF common grid models shifted to the MCP. Other aspects like shifts to zero balance, the violation of Pmin/Pmax limits, and flow-based indicators were included as supplementary, secondary information.
- **Build on KPIs that have proven useful in the CWE GSK Study or other works:** For this reason, the benchmark based KPI based on an ex-post computed "perfect GLSK" was evaluated.
- **Focus on KPIs that evaluate the performance of currently applied GLSKs.**
- **Make KPIs comparable across various TSOs with very different system sizes, generation portfolios etc:** For this most KPIs are normalized, e.g. to installed capacities or a quantile of a bidding zone's net positions.
- **Prioritize KPIs which allow to derive conclusions on the GLSK modelling itself and do not mix the impacts of various other processes:** For this reason, the focus was set on KPIs analysing nodal powers based on D2CF/DACF IGMs. However, due to the high interdependency between IGM creation and GLSK modelling quantitative effects can often not be traced back to GLSK modelling solely but usually quantify the joint effect of IGM creation and GLSK modelling.
- As a result of the preceding considerations one primary KPI was *selected* - the nodal forecasting error (NFE) - which measures the deviations between nodal injections and withdrawals in the DACF and those in D2CF IGMs shifted to the MCP.

To have a broader perspective and gain additional insights, four different groups of supplementary KPIs were selected:

- **Pmin/Pmax violations** in the original IGM and after shifts to the MCP and to zero balance.
- **Net position accuracy** of the D2CF IGM.
- **Benchmarking based KPIs**, evaluating a "perfect GLSK" as a reference.
- **A load-flow based KPI,** translating the nodal forecasting error to load flow impacts.

Based on the findings of Core GLSK Study Part 1, the "Nodal Forecasting Error" KPI was defined as the primary KPI for the second part of the Core GLSK Study, as it directly addresses the key objective of a GLSK as defined in the Core CCM: accurately modelling generation and load at nodal level following a net position change. In addition, the "perfect GLSK" and "equally distributed GLSK" are defined as useful reference strategies for the "Benchmarking based KPIs".

Load flow based KPIs that are analysed in the Core GLSK Study Part 1 are not considered as suitable KPIs for GLSK quality. The target of the load-flow based KPI would be to obtain a flow delta that is ideally solely the result of GLSKs. A load flow based KPI as a quality metric in GLSK creation of an individual TSO would aim to reduce flow deltas also causes by nodal forecast error in neighbouring network areas, thus creating implausible load/generation patterns.

The first part of the Core GLSK Study also highlights the dependency of GLSK and IGM quality. Ideally, a D2CF shifted to MCP using a GLSK is very close to the first DACF IGM. Practically, there are significant differences between D2CF and DACF that cannot be compensated by an GLSK shift, e.g. D-2 power plant schedules and unavailabilities, large forecast errors in net-position or nodal forecasting accuracy. An ex-post calculated “perfect GLSK” shows how large the potential improvements of GLSKs are as well as how significant the underlying IGM quality issues are.

9.3. Summary of the Core GLSK Study Part 2

The second part of the Core GLSK Study addressed the following requirement in Article 9(6) of the Core DA CCM: “[…] a **harmonised generation shift key methodology** combined with, where necessary, **rules and criteria for TSOs to deviate** from the harmonised GLSK”. To achieve this, 9 GLSK strategies as well as the status-quo GLSK for each Core TSO were assessed based on the NFE KPI to investigate if there are candidate GLSK strategies for a harmonised GLSK and to define rules for Core TSOs to deviate from the harmonised GLSK as well as how this will be monitored. The assessment was performed using historical data from the year 2023. The performance of a given GLSK strategy was quantified and ranked based on its contribution to NFE after a shift to the MCP. In other words, the lower the NFE after the shift to the MCP, the better the GLSK strategy.

GLSK strategies can be defined along 3 main design choices: How are GLSK factors calculated for each node, which nodes are considered and if and how an LSK component is included in the GLSK.

Note on GSK and LSK factors: A GSK, as defined in the Core CCM, refers to nodal factors for all or a subset on nodes within a bidding zone that maps zonal net position changes into nodal injections or withdrawals. Therefore, a positive net position change can be interpreted as an increase in generation or a decrease in load. The distinction between GSK and LSK components is not relevant for the general purpose of the GSK, however it is significant in the determination of GLSK factors, as it includes an assumption of how sensitive load or renewable infeed is to net position changes. For all GLSK, i.e. GSK methodologies that include a LSK component, GSK and LSK components are combined using a weighted sum.

Based on these criteria the candidates below were assessed alongside the status quo GLSKs of Core TSOs. Status Quo GLSKs applied by Core TSOs are often one or combinations of the candidates below.

Control range approach: GSK factors are calculated based on available generation capabilities (Pmax – Pmin) for each node. No LSK components are considered.

Auto G(L)SK: GSK factors are calculated proportional to nodal active power generation in the IGM. GLSK variant derives LSK factors based on active load in the IGM. Nodes are selected based on a statistical approach, e.g. by analysing the correlation of a node's power in the past (30 days) with the net-position delta and select all nodes beyond a certain correlation threshold (e.g. 0.2). LSK and GSK are combined proportionally weighted by total load and generation.

Country G(L)SK: GSK factors are calculated proportional to nodal active power generation in the IGM. GLSK variant derives LSK factors based on active load in the IGM. All nodes are considered.

For each node k the GSK factors are derived by the relative active power generation P at node k divided by total active power in the TSOs control area, here defined as the sum over all nodes j in the set J of nodes that have active generation in the TSOs IGM. The LSK factors are derived analogously for all nodes with active load or negative active generation. LSK and GSK are combined as the proportionally weighted sum by total load and generation.

$$GSK_k = \frac{P_k^{activePowerGeneration}}{\sum_j P_j^{activePowerGeneration}} \; \forall \, j \; activePowerGeneration < 0$$

Equation 5

$$LSK_k = \frac{P_k^{activeLoad}}{\sum_j P_j^{activeLoad}} \; \forall \; j \; activeLoad > 0 \wedge activePowerGeneration \geq \; 0$$

Equation 6

Based on discussions in deep dives with TSOs after Phase 2 this change was implemented to e.g. incorporate renewable infeed better as a **refined Country GLSK approach**.

$$GLSK_i = \frac{|p_i^{GEN}| + |p_i^{LOAD}|}{\sum_{k \; in \; nodes \; of \; TSOarea} \left(|p_k^{GEN}|| + p_k^{LOAD}| \right)}$$

Equation 7

Dynamic optimised GLSK: The approach consists of the following two steps: 1) Ex-post calculation of optimized GLSK factors: Optimized GLSK factors are computed retrospectively based on historical data that is grouped in suitable scenarios based on criteria like renewable infeed, generation/load or net-position. 2) Matching a BD to a scenario: A BD is assigned to a specific scenario in 1) and the corresponding optimized GLSK factors are applied. See Figure 1-All nodes can be considered.

The relative benchmark is obtained by comparing the NFE of each GLSK Strategy against an “equally distributed GLSK” as well as the “perfect GLSK”.

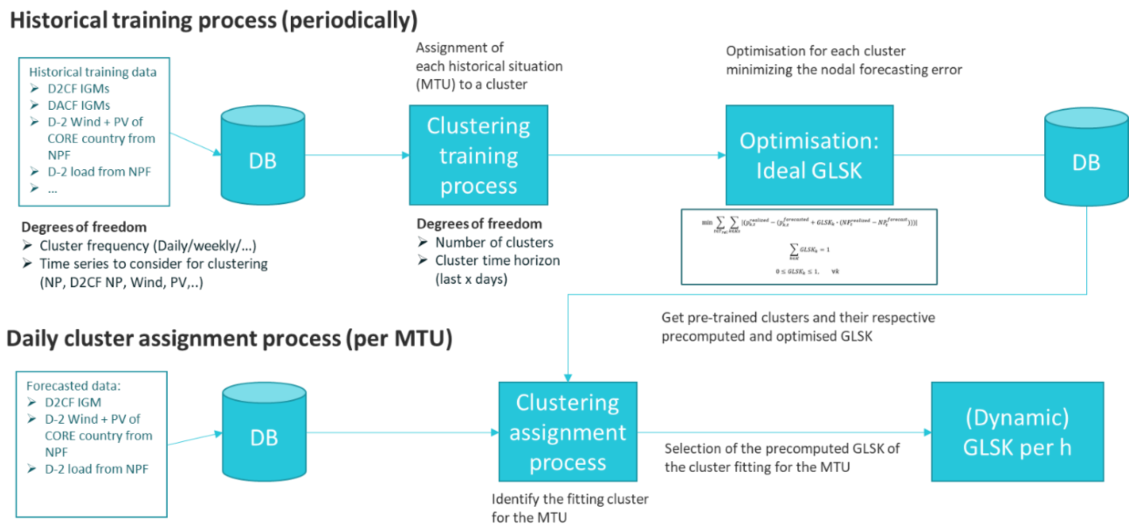


Figure 11. Optimised Dynamic GLSK Methodology

The “Optimized Dynamic GLSK” can be configured by varying the number of clusters, time range of cluster input data and the cluster training periods. The TSO specific selection of input timeseries can be done on a broad set of timeseries (e.g. D-2 net position data, RES forecasts per country, weather data, peak/off-peak, day of the week, …) based on ML-based analysis on the feature importance.

Equally Distributed GLSK: GLSK factors are 1/N for all N nodes in a bidding zone.

Ideal GLSK: GLSK Factors are calculated ex-post for all nodes based on the NFE KPI in order to derive the ideal GLSK values. All nodes are considered.

Figure 11 provides an overview of the performance ranking of the various GLSK strategies for each Core TSO. StatusQuoF226 are the applied GLSKs for each Core TSO.

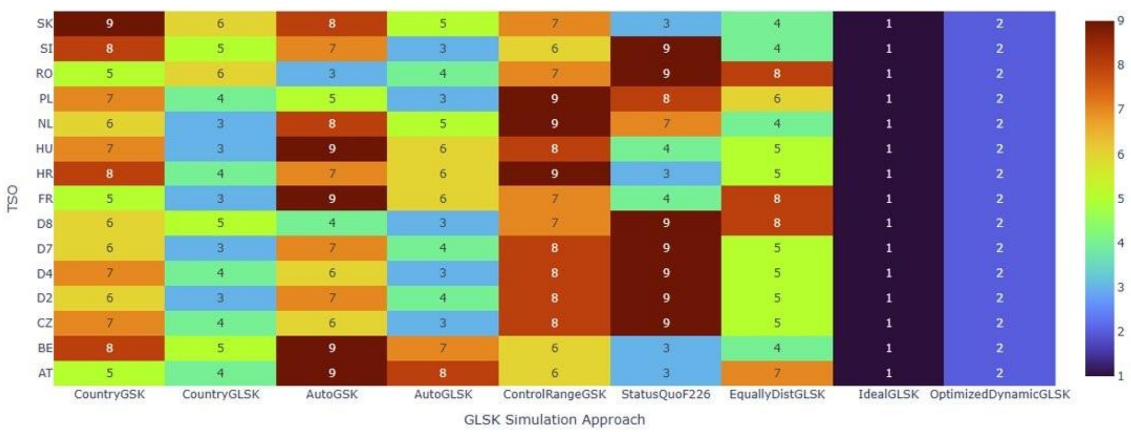


Figure 12. Performance ranking of GLSK strategies for each Core TSO

The two main findings from the second part of the Core GLSK Study are: first, that the dynamically optimised GLSK delivers the best performance and second, that the Country GLSK is the next best option, outperforming the status quo approach in 11 out of 15 cases.

9.4. Notes on the new Article 9 of the Core CCM

Considering, on the one hand, the varying level of assessed benefits per TSO and the complexity and time required to agree on, procure, develop, implement and operate an algorithmically complex and data-intensive IT solution for dynamic optimised GLSK, and, on the other hand, the simplicity and ease of implementing the Country GLSK — which already delivers significant improvements 2 — the Core TSOs have decided to propose the Country GLSK as the baseline for the harmonised GLSK methodology. It is therefore referred to as the **"harmonised GSK"** methodology in the following and the CCM itself. In order to fulfil the obligations set out in Article 9(6) of the Core DA CCM — which requires the definition of rules and criteria under which TSOs may deviate from the proposed harmonised Generation Shift Key methodology — and to reflect additional findings from the GLSK studies, which indicate, for example, that statistical node selection can improve GLSK quality in some cases or that using only generation nodes may be beneficial in specific situations or that some TSO already have well performing second best GLSK approach, the Core TSOs have agreed to establish such rules and criteria. Specifically, Core TSOs may apply a custom GLSK approach, provided it outperforms the harmonised GSK methodology based on the NFE KPI.

To ensure quality control and a level playing field among Core TSOs, regular monitoring and reporting on the GLSK quality of Core TSOs is foreseen, using the Country GLSK as a benchmark. In case of any significant negative deviation in comparison with quality of the Country GLSK, the concerned Core TSO will be required to implement, at a minimum, the harmonised GSK approach or any other better performing GLSK approach.

As the definition of Dynamically Optimised GLSK is more abstract and depends on many TSOs specific inputs and parametrization, a definition within the CCM needs the requirement that any TSO specific implementation of this method outperforms the harmonised GSK methodology based on the NFE KPI. Thereby making the inclusion redundant against the Article itself, that states that TSOs shall implement the harmonised GSK methodology or any other method that outperforms it – therefore even being best performing GLSK approach, it is not explicitly noted in amendment.

9.5. Limitations and Insights Gained from the Core GLSK Study

One of the key insights from the Core GLSK Study was the identification of critical flaws in the traditional interpretation of a GLSK. Traditionally, GLSK factors are assigned only to so-called "market-sensitive" nodes - typically those connected to conventional power plants such as gas, hydro, pumped-storage, and hard coal. This approach creates a dichotomy between market-sensitive and non-market-sensitive nodes, with GLSK factors intended to quantify the contribution of the market-sensitive nodes to a net position change (ΔNP) within a given bidding zone. However, the Core GLSK Study revealed that this traditional interpretation is prone to significant nodal forecasting errors. Two main issues contribute to this:

1. The inherent difficulty in accurately identifying, in advance, which nodes will contribute to a given ΔNP.

2. The ongoing phase-out of conventional generation in many bidding zones, which reduces the relevance of historically market-sensitive nodes.

The example below illustrates these shortcomings:

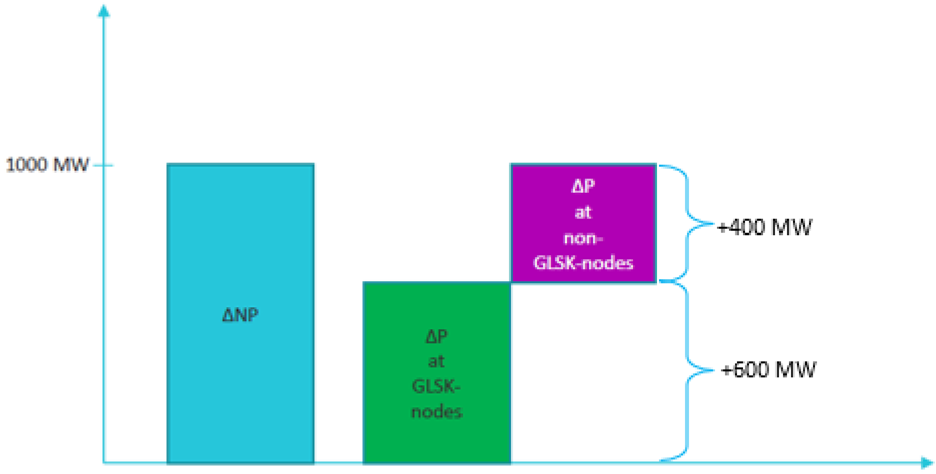


Figure 13: Ex-post analysis of the nodal contribution to ΔNP of 1000MW

In Figure 13, an ex-post analysis of a ΔNP of +1000 MW shows that +600 MW came from GLSK (market-sensitive) nodes, while +400 MW came from non-GLSK (non-market-sensitive) nodes. Despite this, the traditional GLSK approach would allocate the entire 1000 MW shift only across the GLSK nodes. This leads to an inherent forecasting error of 400 MW, misattributed across the GLSK nodes. As the number of conventional, market-sensitive nodes continue to decline, such errors are likely to grow. The study therefore emphasizes a need to rethink the interpretation of a GLSK. Rather than limiting GLSK factors to a predefined subset of nodes, they should be assigned to as many nodes as could realistically contribute to a ΔNP. Nodes should only be excluded if their injections can be confidently forecasted. This broader approach better accounts for actual system behaviour and reduces nodal forecasting errors.

Furthermore, the results of the Core GLSK Study shows that, for several TSOs, shifting from the D2CF to the Day-Ahead MCP requires adjustments of several gigawatts. Providing suitable linear GLSKs for such large ranges presents a significant challenge. A similar challenge arises when shifting to a zero-balance position or in future CC GLSKs application in ROSC&Cost Sharing.

10. Removal of LTA inclusion

The Core TSOs aim to make maintaining operational security, which is a crucial condition of DA CCM, independent from the amount of long-term allocated capacities (LTA). This will allow LTA pursuant to Core LT CCM and more generally, pursuant to FCA GL, to be set without a direct link to operational security.

To reach this aim, the LTA inclusion must end at the latest for the first delivery period of the long-term capacities calculated according to the LT CCM pursuant to FCA GL. It is an option to do this even earlier. This is introduced in Art. 18(1)(b)-(d) and Art. 28(9).

Throughout the DA CCM, wherever LTAs are used, this now becomes conditional to the application of the rules pursuant to Article 18(1)(a). This ensures that any link to LTAs is removed synchronously and based on a single decision. Article 28(8) clarifies this decision and obliges Core TSOs to announce it with a lead time of at least one month.

After the removal of LTA inclusion, cross-zonal capacity (CZC) will only consist of flow-based parameters. The extended LTA inclusion (ELI) to combine flow-based parameters with bilateral exchange restrictions will no longer be necessary. This does, however, not mean that the removal of LTA inclusion must be synchronised with a removal of ELI in SDAC. For a transitional period, it is possible to set the bilateral exchange restrictions to zero such that formally ELI input is provided though actual capacity is only represented by the flow-based parameters.

In addition to the inclusion of LTA as such, LTA have been used in the DA CCM for several further purposes. Therefore, substitute solutions are foreseen for all of these:

- LTAs have been the basis of the default flow-based parameters (DFP) pursuant to Article 22(b), which are part of the capacity calculation fallbacks (the other one being spanning). Consequently, Article 22 is substantially modified in the request for amendment. After removal of LTA inclusion, DFP will have the form of a flow-based domain with CNECs, PTDF and RAM. The DFP will be determined from historical flow-based domains of one year by applying a statistical approach with the following steps, cf. Article 22(4):
  1. In the historical flow-based domains, CNECs will be grouped by CNE. Each CNE which is part of pre-solved CNECs in more than a predefined percentage of the historical flow-based domains will be the basis for one “representative constraint” in the DFP.
  2. All pre-solved CNECs containing a given CNE from step 1 are normalised. This means that all their PTDFs and the RAM are scaled such that the “length” of the PTDF vector is 1. The purpose of the normalisation is to make the RAM of all these CNECs comparable in terms of their impact on limiting the cross-zonal exchanges. For example, there could be two CNECs C1 and C2 such that C2 has twice the RAM of C1 but also all PTDFs are twice as high as those of C1. Looking only at the RAM, one might think that C2 has a higher “capacity” than C1. But in fact, C1 and C2 are equivalent. Normalisation will thus make sure that the RAMs become comparable and interpretable for the next steps of the DFP determination process. To determine the “length” of the PTDF vectors, the Euclidian norm is used, cf. Article 2(1), point 80.
  3. The RAM of each representative constraint is computed as a fixed quantile of the normalised (and thus comparable) historical RAMs across the CNECs with the given CNE.
  4. To determine the PTDF of the representative constraint, the mean of the normalised historical PTDF from all CNECs with the given CNE is computed. The reasoning behind this approach for the PTDFs is based on the fact that the PTDF vector is a normal vector to the hyperplane that a CNEC effectively

constitutes. Hence the PTDFs denote the direction in which the CNEC limits cross-zonal exchanges. The direction (i.e. the orientation in the hyperspace formed by the Core bidding zones) of the representative CNEC is thus the mean (i.e. average) direction of the set of CNECs that it represents. As a matter of fact, this mean may have a length other than 1. Therefore, to make sure that the that the RAM is still consistent with the amount of the PTDFs, the mean PTDFs are normalised again.

5. The union of the representative CNECs from steps 1 to 4 contains redundant CNECs, which are removed by pre-solving (analogous to regular flow-based parameters).

The DFP are updated at least on a monthly basis. They are computed upfront such that they will be readily available when needed, because the need to use DFP usually goes along with tight timing of the operational capacity calculation process.

If there have been structural changes of the Core bidding zones, internal virtual hubs (IVHs) or external virtual hubs (EVHs) within the time period of the historical flow-based parameters or there will be such change between this time period and the period for which the initial default parameters will be applied, using 12 months of historical domains would not be possible. For example, a newly introduced external virtual hub for a new AHC border would be missing in the historical data but needed in the DFP. To avoid such inconsistency, the CCC may, in coordination with all Core TSOs, use a more suitable data basis, including but not limited to using data from a parallel run and shortening the time period of the historical data.

It is possible that in the upcoming validity period (up to one month) planned outages are expected to reduce transmission capacity and that such reduction is not contained in the data base of historical flow-based domains used for computing the DFP. To cover such cases, Article 22(4)(e) allows the affected TSOs to apply an Individual Validation Adjustment (IVA) on the representative CNECs stemming from CNEs in their control area. Any such reduction shall be communicated and justified to market participants and to all Core regulatory authorities.

Article 22(5) makes sure that the rules for setting the parameters of the statistical approach are in line with those for Coordinated Validation, cf. Article 20(4b).

The DFP pursuant to this new approach – Article 22(4)-(6) – must be used at the latest when LTA inclusion is abolished. It is optional to apply them even earlier, hence a reference in Article 22(7) – containing the legacy DFP approach – to Article 18(1)(a).

The publication of DFP is covered by two elements. When DFP are applied in the operational process, their publication (PTDF, RAM, Fmax and, if applicable, IVA) is covered by the regular publication requirements pursuant to Art. 25(2)(d). In addition, Article 22(4)(g) ensures that intermediate DFPs are published ex ante regardless of DFP application, to be consistent with the current practice where LTAs (being the basis of current DFP) are known ex ante.

- The ATCs for SDAC fallback (also called shadow auction ATCs) are currently based on LTA pursuant to Article 23(5a). With the removal of LTA inclusion this will be substituted by extracting ATCs from a flow-based domain. This approach is already in the DA CCM in Article 23(5),but was so far only foreseen for the case when the LTAmargin approach would have been applied instead of ELI.

  When the capacity calculation works fine, the shadow auction ATCs are extracted from the regular flow-based domain.

  When DFP are applied, the shadow auction ATCs are extracted from the DFP (which will be a flow-based domain, too) using the same algorithm.

  Compared to the version submitted to public consultation, Article 23(3) and (5) have been streamlined by making use of the RAM from final computation, which firstly makes sure that the RAM floor level from the final computation is respected in the shadow auction ATCs, and secondly implicitly covers the DFP case.Article 23(6) covers the rare case when both the capacity calculation fails (leading to the use of DFP) and later on shadow auction ATCs are required due to a failure of SDAC leading to day-ahead explicit auctions being run via JAO (see Core Fallback methodology[1]). In this case the shadow auction ATCs will be taken from a previous separate computation, based on DFP. The allocation constraints, which are used as external constraints in the DFP, are outdated in this case. This could lead to operational security issues if the outdated allocation constraints are less restrictive than those of the current business day. Therefore, proportional capping of ATCs for relevant BZs is applied based on the external constraints of the current business day. Compared to the version submitted to public consultation, the wording has been made more precise to clarify that the shadow auction ATCs will be based on DFP in this case.

- So far, even if the application of IVA led to the RAM of CNECs becoming low, LTA inclusion would ensure a certain minimum level of CZC. With the proposal for amendment, such minimum level of CZC will be guaranteed on the level of RAM in the flow-based domain, by introducing a mandatory 20% floor.
  - In regular operations, 20% of Fmax are always included in the flow-based parameters before validation, via the adjustment for minimum RAM, AMR. This remains unchanged. However, the 20% might be undercut by IVA and/or the accounting of flows due to long-term nominations (LTN). Therefore, the amendment foresees in Article 21(3) that a 20% of Fmax floor will be applied during the final computation. This implements a minimum CZC floor. The fact that it is applied after LTN shift protects against small or zero CZC due to LTAs that are still allocated as physical transmission rights (PTRs). Core TSOs may deviate from the RAM floor level of 20 percent of the

1 https://eepublicdownloads.entsoe.eu/clean-documents/nc-tasks/20240321_44CACM_Shadow%20Allocation%20Rules_CLEAN.pdf

maximum admissible power flow on their own CNECs if operational security cannot be maintained otherwise. The concerned Core TSO(s) shall communicate such deviations immediately to market participants via an Urgent Market Message (UMM) broadcasted on the JAO website[2]. The concerned Core TSO(s) shall provide to the CCC a report with a justification why the application of the RAM floor level of 20 percent would have led to the inability to maintain operational security and an action plan describing how such situations will be avoided in the future. This report will become an annex to the quarterly report. Note that compared to the version submitted to public consultation the exceptional deviation from the RAM floor level of 20 percent has been made more flexible. Instead of applying no floor at all, it will now be possible to still keep an, albeit lower, floor level and hence keep all RAMs greater than zero.

- In the capacity calculation fallback case, when DFP are applied, the initial DFP fulfil the 20% rule as in regular operations, because all historical final RAMs used to compute the DFP fulfil the rule. However, the 20% of Fmax can again be undercut by IVA (here: pursuant to Article 22(4)(e)) and/or LTN. Therefore, the 20% floor is applied for the final DFP by making a link from Article 22(6), where the LTN shift for DFP is described, to Article 21, where the regular LTN shift is described. This ensures full consistency between regular computations and the fallback case.

Originally, the LTAmargin approach was foreseen as a potential alternative to ELI and for optional use during individual validation. None of these options are applied today. To reduce clutter in the DA CCM, the more so in the light of the additions for the conditional removal of LTA inclusion, the LTAmargin approach is removed from the DA CCM.

[2] https://www.jao.eu/news?roles_target_id_group=tso