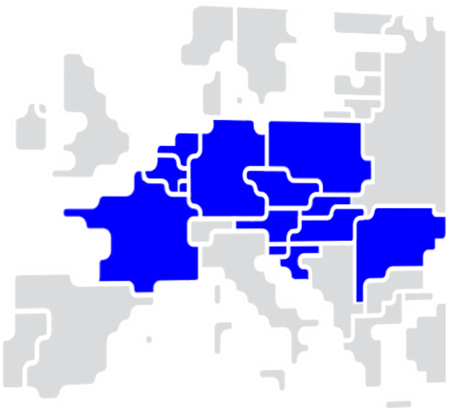
Explanatory document to the Core CCR TSOs proposal for a common coordinated long-term capacity calculation methodology in accordance with Article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

June 2019



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1. INTRODUCTION

Sixteen TSOs follow a decision of the Agency for the Cooperation of Energy Regulators (ACER) to combine the existing regional initiatives of former Central Eastern Europe and Central Western Europe to the enlarged European Core capacity calculation region (Decision 06/2016 of November 17, 2016). The countries within the Core CCR are located in the center of Europe which is why the Core CCR Project has a substantial importance for the further European market integration.

In accordance with article 10 of the FCA Regulation, the Core TSOs are working on the implementation of the common coordinated long-term capacity calculation methodology Proposal (hereafter LT CCM or Proposal).

The aim of this explanatory note is to provide a detailed description of the LT CCM and relevant processes. This paper considers the main elements of the relevant legal framework (i.e. FCA and CACM Regulation, 714/2009, 543/2013). Chapter 2 of this document covers the input aspects, Chapter 3 the validation methodology, while Chapter 4 details the Core LTCCM process; Chapter 5 deals with updates and publication and Chapter 6 mentions the implementation timeline.

1.1 Approach for finalization of the Core LT CCM

Although the Core TSOs started the development of the required Core LT CCM in an early stage, it is highly challenging for the 16 TSOs (13 countries) in the Core CCR to deliver a final CCM within 6 months after the ACER approval of the day-ahead flow-based capacity calculation methodology Proposal.

Therefore, the Core TSOs follow the approach for finalization of the Core LT CCM mentioned hereafter:

Publication of the first draft of the Approval Package accompanying the public consultation from 10 June to 11 July 2019. This first draft contains the Core LT CCM Proposal and its accompanying explanatory note, including a high level description of all the steps mentioned in the High level Business process on how to determine the final values and methods for e.g. scenario's, CNEC selection, Generation Shift Key methodology and the treatment of Remedial Actions and Scenario's (including outages).

1. Submission of the final Approval Package for Core NRA approval of the Core LT CCM Proposal ultimately 26 August 2019 (the ACER approval of the DA CCM proposal ultimately on 26 February 2019). This final package contains:
   - Core LT CCM Proposal, including updates based upon Core NRAs' and stakeholders' comments, if any;
   - explanatory note, including a description of all the steps mentioned in the High level Business process on how to determine the final values and methods for e.g. CNEC selection, Generation Shift Key methodology and the treatment of Remedial Actions and Scenario's (including outages), including updates based upon Core NRAs' and stakeholders' comments, if any;
   - the Robust Experimentation calculation results, including updates based upon Core NRAs' and stakeholders' comments, if any;
   - overview of implementation of the LT CCM.

Main reasons for Core TSOs to propose this approach:

- to be able to develop a Core LT CCM that meets stakeholders' and Core NRAs' expectations as reflected in feedback, if any, received after public consultation;
- to secure the development of a solid LT CCM, supported by experimentation results and feasibility studies, being able to provide an acceptable level of capacity to the market while ensuring security of supply.

1.2 Core TSO Deliverable Report

Currently no deliverable reports are foreseen.

It should be considered that this Explanatory Note describes the current status of the Core LT CCM (May 2019) but will be amended according to the further development of the Core LT CCM driven by the public consultation results and by the Robust Experimentation results.

1.3 High Level Business Process

See below *Figure* 1 depicting the Core LTCC High Level Business Process (HLBP):

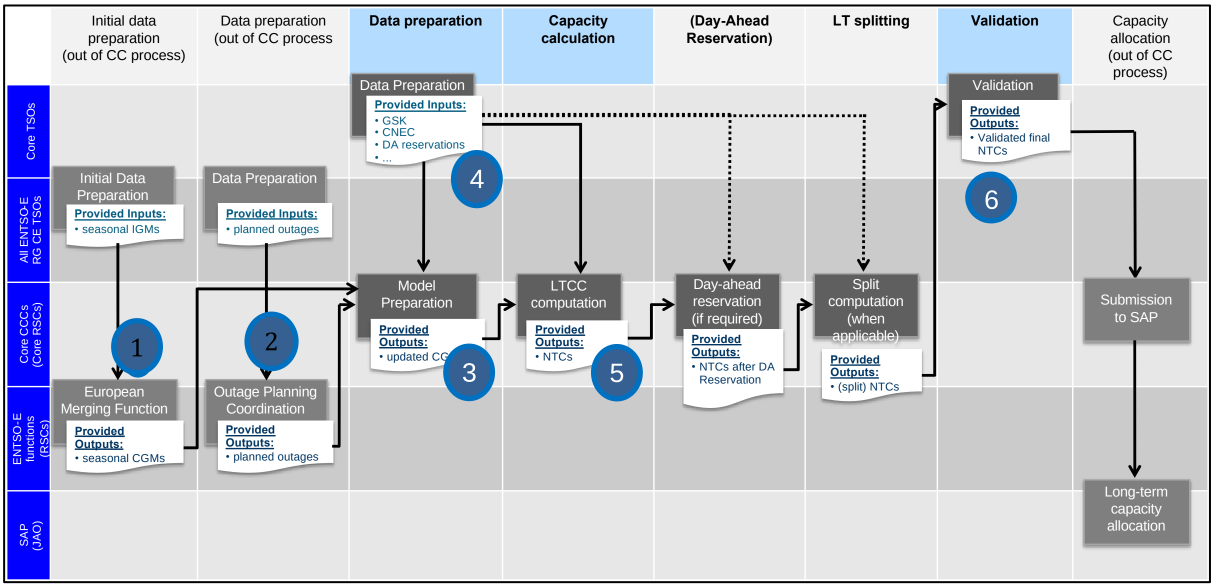


Figure 1: High Level Business Process

6 Steps are shown (numbered); the steps dedicated to the Core LTCC process are shown in the three columns, marked light blue (Data preparation, Capacity calculation and Validation). The rows indicate which role is responsible for the process.
Data preparation for Core LTCC relies on all TSOs' ENTSO-E processes. These all TSOs' data preparation steps are shown in the first two columns.

Herewith follows a description of the 6 steps:

1. This step is related to an all TSOs' ENTSO-E process (article 67 of the SO GL Regulation and the FCA-CGMM). Each Core TSO provides an IGM for each seasonal CGM. IGMs are merged into seasonal default CGMs by the Core CCC each year for the next calendar year.

2. Also this step is related to an all TSOs´ ENTSO-E process (Title 3 of the SO GL Regulation). Availability plans (outage plans) are provided by each Core TSO to a common database. This

database and the communication between the database and the Core TSOs are managed by the Core CCC. Preliminary outage plans of ENTSO-E TSOs are available in the OPC database from 1 November for the next calendar year (article 97 of the SO GL Regulation).

Planned Core processes:

3. Based on default CGMs (see step 1) and the preliminary outage plans of all Core TSOs for the whole year (see step 2), the Core CCC can create the forecasted network models for any of the selected time stamps; this is achieved by incorporating the relevant outages (see Article 10 on Scenarios) in the CGMs.

4. In this step, each Core TSO provides to the Core CCC the necessary input data. These are e.g. GSK and CNEC files (see Article 8 GSK and Article 7 on CNEC Selection).

5. During this step, the Core CCC performs the actual capacity calculation based on the Core LT CCM. This step represents all necessary calculations performed by the Core CCC and is described in Article 14. Note: The capacity calculation outcomes will be subject to LT Splitting Rules Methodology pursuant to article 16 of FCA Regulation. Before the LT Splitting, the capacity may be subject to DA reservation pursuant to the 714/2009 Regulation. For further details, please see the LT Splitting Rules Methodology.

6. During the sixth and last step, the Core TSOs validate the capacity calculation results (see Article 13 on Validation) upon which the cNTCs are submitted to the SAP. Note: The validation of LT splitting rules is also done in this step together with the result of the capacity calculation outcomes.

These briefly described relevant steps and related methodologies are explained more in detail in the next sections.

2 TREATMENT OF INPUT

2.1 Reliability margin methodology

This section refers to Article 5 of the LT CCM.

Article 11 of the FCA Regulation requires a methodology for reliability margin (hereafter referred to as "RM"), meeting the requirements set out in article 22 of the CACM Regulation.

In article 2 (14) of the CACM Regulation the following definition is given:

"Reliability Margin means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation".

FRM means the margin reserved on the permissible loading of a critical network element or cross zonal capacity to cover uncertainties of power flows in the period between the capacity calculation and real time, taking into account the availability of RA.

The uncertainties covered by the RM values are among others:

a. Core external transactions (out of Core CCR control: both between Core region and other CCRs as well as among TSOs outside the Core CCR);

b. generation pattern including specific wind and solar generation forecast;
c. GSK;
d. load forecast;
e. topology forecast;
f. unintentional flow deviation due to the operation of load frequency controls.

Core TSOs consider that the additional uncertainties between de long-term timeframes and DA timeframe are covered by the selected scenarios, therefore they use the same FRM as in the current DA timeframe.

In accordance with article 22 of the CACM Regulation the methodology to determine the RM shall consist of a probability distribution of deviations between the expected power flows at the time of the capacity calculation and realized power flows in real time, and a RM calculation based on this probability distribution.

For LT cross-zonal capacity calculations the annually created ENTSO-E year-ahead reference scenarios are used (those scenarios are created in accordance to article 65 of the SO GL Regulation, see the paragraph on scenarios).

The LT cross-zonal capacity calculation methodology for the Core CCR considers that the additional uncertainties between de LT timeframes and DA timeframe are covered by the selected scenarios, therefore LT timeframe capacity calculations will use the same FRM applied in the DA timeframe. These FRMs shall be transferred into TRMs on all Core BZBs per direction, using:

TRM on bidding zone border = NTC (with FRM equal to zero) – NTC (with FRM equal to X %).

The TRM is used only for publication purposes. The technical calculation valuable value are the FRMs but because article 22.5 of the CACM Regulation dictates a TRM, the Core TSOs must publish this TRM.

The methodology shall be reviewed and if necessary, updated in order to keep full consistency with the methodology and its evolution in the Core CCR.

Due to the controllability of the power flow over DC interconnections, the determination of a reliability margin does not need to be applied on bidding zone borders only connected by DC interconnections.

2.2 Methodologies for operational security limits

This section refers to Article 6 of the LT CCM.

According to article 12 of the FCA Regulation the proposal for a LT CCM shall include methodologies for operational security limits and contingencies and it shall meet the requirements set out in articles 23(1) and 23(2) of the CACM Regulation. This methodology for operational security limits is in accordance with article 25 on operational security limits of the SO GL Regulation and with article 72 on Operational security analysis in operational planning of the SO GL Regulation.

According to Article 6, the maximum admissible current ($I_{\max}$) is the physical limit of a CNE determined by each Core TSO in line with its operational security policy. The physical limit reflects the capability of a transmission element (e.g. line, circuit-breaker, current transformer or disconnector). This $I_{\max}$ is the same for all the CNECs referring to the same CNE. $I_{\max}$ is defined as a permanent or temporary physical (thermal) current limit of the CNE in kA.

A temporary current limit represents a loading that is allowed for a certain finite duration only (e.g. 115% of permanent physical limit can be accepted during 15 minutes). Each individual Core TSO is responsible for deciding, in line with their operational security policy, if a temporary limit can be used. All Core TSOs will use seasonal limits or constant limits depending on the assets for LT capacity calculations.The calculation of yearly capacities is carried out using 4 (winter, spring, summer, autumn) seasonal CGMs. In function of the selected timestamp the seasonal criteria will be applied conform per each Core TSO policy. No Dynamic Rating will be used in Core CCR for LT capacity calculations due to absence of the required forecast parameter.

In addition, Core TSOs may use operational security limits for capacity calculation. It must be stated that these are not the same as those used in operational security analysis, but are meant to take into account the needs of operational security analysis that deal with uncertainties of generation and load. Such operational security limits shall be modelled as a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone), thus limiting the net position of the respective bidding zone.

It is forseen that in long-term capacity calculation constraints on the bidding zone export/import limits may be used by TenneT TSO B.V. and PSE. Those Core TSOs need to take in a consideration such constrains for following reasons:

PSE
In central dispatch systems PSE bears the responsibility, which in self dispatch markets is allocated to balance responsible parties. That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which sometimes leads to necessity of implementation constraints on the global net position if this is needed to ensure operational security of Polish power system in terms of available generating capacities for upward regulation. When determining constraints on bidding zone export/import limits, the Polish TSO takes into account the most recent information on technical characteristics of generation units, forecasted power system load as well as minimum reserve margins required in the whole Polish power system to ensure secure operation and forward import/export contracts that need to be respected from previous capacity allocation time frames if any.

TenneT TSO B.V
The combination of voltage constraints and limitations following from using a linearised GSK make it necessary for TenneT TSO B.V. to apply constraints on the bidding zone export/import limits. TenneT TSO B.V. determines the constraints on the bidding zone export/import limits for the Netherlands based on studies, which combine a voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the (linear) GSK during different extreme import and export situations in accordance to article 38 of the SO GL Regulation.

Constraints on bidding zone export/import limits will be provided by TenneT B.V. and PSE to the Core CCC as an input data for respective LTCC process.

Other Core TSOs may also use contraints on bidding zone export/import limits in future if needed.

The legal base is article 12 of the FCA Regulation in connection with article 23(1) and 23(2) of the CACM Regulation. Article 12 of the FCA Regulation foresees that: “The proposal for a common capacity calculation methodology shall include a reliability margin methodology for operational security limits and contingencies which shall meet the requirements set out in Article 23(1) and (2) of Regulation (EU) 2015/1222.”

This means that the reliability margin methodology for long-term included in the proposal for a common capacity calculation methodology shall:

- meet the requirement of respecting the operational security limits used in operational security analysis (as foreseen in article 23.1 of the CACM Regulation);
- shall describe the particular method and criteria that are used to determine the operational security limits used for capacity calculation (in case the operational security limits used in capacity calculation are not the same as those used in operational security analysis), as foreseen in article 23.2 of the CACM Regulation.

In light of the above, it may be argued that when the operational security limits and contingencies used in operational security analysis differ from the ones used in capacity calculation the particular method and criteria shall be put in place in the proposal for a common capacity calculation methodology to serve needs of operational security analysis.

Article 75 of the SO GL Regulation foresees development of a proposal for a methodology for coordinating operational security analysis that is applicable by Core TSO when performing a coordinated operational security analysis (article 72 of the 2 SO GL Regulation). This methodology shall aim at the standardization of operational security analysis at least per synchronous area and shall include in the light of article 75.1 of the SO GL Regulation at least (inter alia):

- principles for common risk assessment, covering at least, for the contingencies referred to in Article 33 of the SO GL Regulation: (i) associated probability; (ii) transitory admissible overloads; and (iii) impact of contingencies,
- principles for assessing and dealing with uncertainties of generation and load, taking into account a reliability margin in line with article 22 of the CACM Regulation.

Bearing this in mind, when preparing the proposal for the common capacity calculation methodology, the Core TSOs can describe the particular method and criteria for the capacity calculation taking into account needs of operational security analysis that deal with (for example) uncertainties of generation and load (which result in a limit on import or export capacity).

2.3 Critical Network Elements and Contingencies

This section refers to Article 7 of the LT CCM.

CNEs were formerly known as Critical Branches (CBs), while contingencies were called Critical Outages (COs). The combination of a CB and a CO (formerly CBCO) is referred to as a CNEC.

The list of CNEs is determined by the Core TSO for his own bidding zone/ control area and the respective scenarios used in LT CCM. A CNE is a network element, significantly impacted by Core cross-zonal trades, which are supervised under certain operational conditions, the so-called contingencies (see below). A CNE can be a cross-zonal or internal network element. Those elements can be an overhead line, an underground cable, or a transformer.

For each CNE within a certain scenario, Core TSOs provide a list of contingencies limited to their relevance for the respective CNE. A contingency can be a trip of a line, a cable, or a transformer; a busbar; a generating unit; a load; or a set of the aforementioned contingencies.

The cross-zonal sensitivity is the criterion for selecting the CNECs that are significantly impacted by cross-zonal trade. Cross-zonal network elements are by definition considered to be significantly impacted. The other CNECs shall have a maximum zone-to-zone $PTDF$ that exceeds the threshold of x %.

Zone to zone PTDFs				
CNEC	A→B	A→C	B→C	Max z2z
CNEC 1	0,1 %	8,8 %	8,7 %	**8,8 %**
CNEC 2	28,7 %	15,8 %	-12,9 %	**28,7 %**
CNEC 3	17,3 %	24,6 %	7,3 %	**24,6 %**
CNEC 4	2,7 %	1,7 %	-1,0 %	**2,7 %**

Figure 2: CNEC Selection Threshold Example

The last column of Figure 2 selects the maximum zone-to-zone PTDF per CNEC. Investigating CNEC 1 for instance, out of three cross-border exchanges, exchange A->C holds the maximum zone-to-zone PTDF of 8.8%, indicating that 1 MW of A->C exchange imposes 0.088 MW on this CNEC. When considering the maximum zone-to-zone PTDF of CNEC 4, it is clear that this CNEC does not meet the 5% threshold criterion. This implies that the branch will not be considered for the calculation.

The impact of this CNEC selection threshold can only be assessed in conjunction with the notion of RAM, according to Article 14 of the LT CCM. This is clarified in the following example.

A CNEC 1 with a maximum zone-to-zone $PTDF$ of 5% and a RAM of 200 MW (being 20% of an F_{max} = 1000 MW), is able to allow for a commercial exchange of at least 200/0.05 = 4000 MW. The wording “at least” refers to the exchange for which the maximum zone-to-zone $PTDF$ holds, i.e. for other exchanges even higher exchanges would be feasible.

A CNEC 2 with a maximum zone-to-zone $PTDF$ of 10% and an identical RAM of 200 MW (being 20% of an F_{max} = 1000 MW), is able to allow for a commercial exchange of at least 200/0.10 = 2000 MW.

Assuming that we are referring to the same pair of bidding zones for the two CNECs, the example shows that CNEC 2 is more restrictive for the potential exchange between those two bidding zones. Or in other words: CNEC 1 cannot be limiting for the exchange between the two bidding zones in the presence of CNEC 2.

Increasing the maximum zone-to-zone $PTDF$ threshold value would essentially imply setting the RAM of those CNECs, which then fall below the threshold, to an infinite value.

The Core TSOs shall decide on the exact CNEC selection before formal submission to Core NRAs on 26th of August.

2.4 Generation Shift Keys

This section refers to Article 8 of the LT CCM Proposal.

The GSK defines how a change in net position is mapped to the generating units in a bidding zone. Therefore, it contains the relation between the change in net position of the bidding zone and the change in output of every generating unit inside the same bidding zone.

The GSK-methodology in the Core CCR used for LTCC is harmonised as follows:

a. all Core TSOs use the proportional method.
b. all Core TSO respects the following common rules:
    i. use all expected generating and consumption units in the IGM;
    ii. Core TSOs who are facing specific situations in their grid (for example: having hardly any hydro power due to an extraordinary dry season) shall apply dedicated features and update their GSK accordingly. These features ensures more realistic flow patterns as a consequence of the specific grid situation;
    iii. the consideration of dispersed units connected to a lower voltage level in the GSK files.

It must be explicitly stated that since the generation pattern (locations) is unique for each Core TSO and the range of the NP shift is also different, there is no unique formula for all Core TSOs for the creation of the GSK: the GSKs in the Core CCR are determined by each Core TSO individually on the basis of the latest available information about the generating units and loads; to be calculated for each scenario seperately.

Each TSO assesses a GSK for its control area taking into account the characteristics of its system. Individual GSKs can be merged if a bidding zone contains several control areas.

The GSK created by each Core TSO can be different for each scenario or can be same for all scenarios. If only reference GSK file is provided, it is used for all scenarios. If no GSK file is provided, a proportional shift is impliciltelly applied to all generating nodes (load nodes will not be included).

The GSK values are given in dimensionless units. For instance, a value of 0.05 for one unit means that 5 % of the change of the NP of the bidding zone will be realized by this unit. Technically, the GSK values are allocated to units in the CGM. In cases where a generation unit contained in the GSK is not directly connected to a node of the CGM (e.g. because it is connected to a voltage level not contained in the CGM), its share of the GSK will be allocated to one or more nodes of the CGM in order to appropriately model its technical impact on the transmission system.

Appendix 1 describes thoroughly the GSK-creation per Core TSO.

2.5 Methodology for remedial actions in capacity calculation

This section refers to Article 9 of the LT CCM Proposal.

After first capacity calculation results are available, Core TSOs may draw a conclusion that the capacity values are not in line with Core TSO's best practice and experience. In order to improve calculation results, the Core TSOs will create a common set of coordinated remedial actions to be applied in accordance with predefined criteria. The list will be validated and approved by each Core TSO based on coordinated capacity calculation results. The Core TSOs can initiate updates of the list.

Each Core TSO assesses the impact of RAs proposed by other Core TSOs on its grid. In case of significant negative influence to capacity or the (n-1) criteria is violated, then a Core TSO may refuse the proposed RA.

During the calculation process the Core CCC will apply the RAs based on the predefined criteria and deliver results to the Core TSOs. Both the application of remedial actions and the final capacity calculation during the validation phase has to be confirmed by all Core TSOs.

For the LTCC within the Core CCR, only the following RAs are considered:

- opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s) or;
- switching of one or more network element(s) from one bus bar to another, or;
- transformer and PST tap adjustment.

Appendix 2 lists the Core TSOs who foresee to use this option; however, all Core TSOs not listed in appendix 2 may also use coordinated RAs based on first capacity calculation results if needed.

2.6 Scenarios

This section refers to Article 10 of the LT CCM Proposal.

In accordance with article 19 of the FCA Regulation, the Core TSOs shall jointly develop a common set of scenarios to be used in the CGM for each long-term capacity calculation time frame; this applies for the situation where security analysis based on multiple scenarios pursuant to article 10 of the FCA Regulation is applied, which is the case for the Core CCR.

For the LTCC for both timeframes, the Core TSOs shall use the annually created ENTSO-E year-ahead reference scenarios (i.e. default scenarios), in accordance with article 3.1 of CGMM for FCA in conjunction with article 65 of the SO GL Regulation. This Pan-European process is based on the common grid methodology as developed in accordance with article 18 of the FCA Regulation[1]. The description of these scenarios is available ultimately 15 July each year; the accompanying CGMs are available ultimately 15 September each year[2].

The current CGMM differentiates the four seasons; for each season a scenario is created for peak and valley, hence resulting in 8 final scenarios for each year. This is based on the assumption that ENTSO-E provides 8 CGMs. Please remind that ENTSO-E on an annual basis decided how many CGMs are created. The ENTSO-E Outage Planning Coordination (OPC) process also uses these scenarios (CGMs) as starting points for security assessments. Therefore, the main quality issues in the CGMs are solved by the CCC, on request of the Core TSOs. The main issues of preliminary year-ahead availability plans provided by all TSOs before 1st November (pursuant to article 97 of the SO GL Regulation) are solved ENTSO-E Core TSOs and CCC early November each year (4-5 November).

The Core TSOs use these pieces of information and the accompanied updated CGMs for the long-term capacity calculation process for the yearly cNTCs.

The related year-ahead seasonal scenarios used for yearly cNTC calculation may be updated for monthly cNTC calculation. Core TSOs may initiate a scenario update for any predictable change, compared to the year-ahead seasonal scenarios, associated with a specific measure concerning the grid topology or generation pattern.

[1] The Common Grid Model Methodology ("CGMM") of article 18 of the FCA Regulation has been approved by all NRAs on 04.07.2018 (*All TSOs' proposal for a common grid model methodology in accordance with Article 18 of Commission Regulation EU 2016/1719 of 26 September 2016 establishing a Guideline on forward capacity allocation*).

[2] Article 22(1)g CGMM SO GL Regulation: 1 September + 10 business days.

If this is the case, the Core TSOs may update:

- the generation pattern; and/or
- the topology due to grid element commissioning or decommissioning

in its own IGM, and may provide one updated IGM for each default seasonal scenario for the referred calculation time-frame, while the net positions in the IGMs shall remain the same as given in the year ahead CGMs.

Accordingly, the Core CCC updates the CGM by replacing the initial IGM with the newly updated single Core TSOs' IGM: the Core CCC does this when a Core TSO provides a new monthly IGM that respects the net position of the respective default seasonal scenario; all in accordance with the agreed upon timing.

The Core CCC applies the planned outages for the monthly cNTC calculations for the selected timestamps on the above mentioned updated CGM. Also for the monthly capacity calculations the Core TSOs will work coordinated with the OPC process.

2.6.1 Outage selection and resulting capacity products

The LT CCM shall be performed taking into account a security analysis based on multiple scenarios. The scenarios are defined in the CGMM – the latter required in accordance with article 18 of the FCA Regulation - containing: forecast situation(s) comprising grid topology, structural data, operational limits, forecasted situation for generation, forecasted situation for load (see above).

All ENTSO-E RG CE TSOs’ planned outages and the associated topological switches are stored and regularly updated in the OPC database (later Operational Data Environment [OPDE]). The Core CCC will use this database for downloading the most actual set of planned outages not only for the Core CCR but for the whole synchronous area. According to the SO GL Regulation, preliminary year-ahead availability plans, i.e. planned outages of all TSOs' are available in OPC database as from 1st November for the next year, and final year-ahead availability plans as from 1st December.

According to the OPC process time schedule, the quality check of preliminary availability plans regarding tie-line inconsistencies is first performed by the Core CCC, upon which the availability plans are corrected by the Core TSOs ultimately 4 November of each year. The year-ahead capacity calculation shall be performed using these outage data amended in OPC data base.

Month-ahead capacity calculation shall be performed using the latest outage data updated by Core TSOs in the OPC database.

Theoretically, any timestamp with the planned outages can be selected for LTCC. In order to keep the regular workload of Core TSOs and Core CCC within a reasonable boundary the selection of planned outages for scenarios of year-ahead and month-ahead capacity calculation is determined as follows:

Year-ahead:
For each month of the year two timestamps are selected: one valley timestamp and one peak timestamp, resulting in 24 timestamps. The following selection criterion is applied on these timestamps: the largest number of simultaneously planned outages in Core CCR in the respective valley and peak periods of the month. Then all planned outages available in the OPC database for the selected timestamps of the synchronous area of Continental Europe are applied for the related default seasonal scenarios: the

outages of the valley timestamp for the default valley scenario and the outages of the peak timestamp for the default peak scenario.

Based on the 24 timestamps (i.e. the network models including the planned outages), capacity caculations are performed (as described in following sections), upon which the lowest capacity of the two capacity calculations of each month are selected, resulting in 12 values per month (per bidding zone border and per direction). This is the calculated year-ahed capacity for the related monthly subperiod as the grey columns in Figure 3 below.

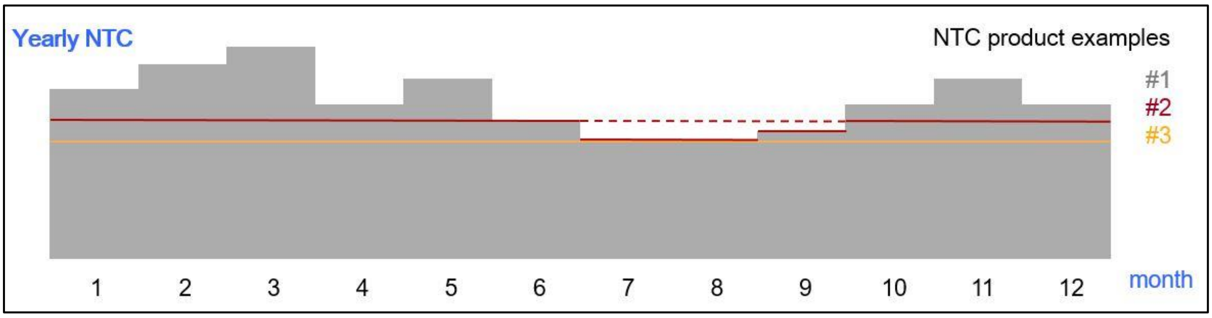


Figure 3

Based on this so-called profile different year-ahead capacity products (e.g. year-ahead capacity with 12 monthly subperiods or a stable bound year-ahead capacity adjusted to the lowest calculated capacity) can be defined upon which reduction periods could be applied.

Month-ahead:
Analogue to the monthly granularity approach for year-ahead outage selection and capacity product possibility, a weekly granularity is applied for the month-ahead process, resulting in 4 or 5 times 2 timestamps (valley and peak). Hence, 8-10 timestamps are selected, and 8-10 calculations are performed using the most actual planned outages information available in the OPC database. Resulting calculated capacities look like the grey columns in Figure 4 below.

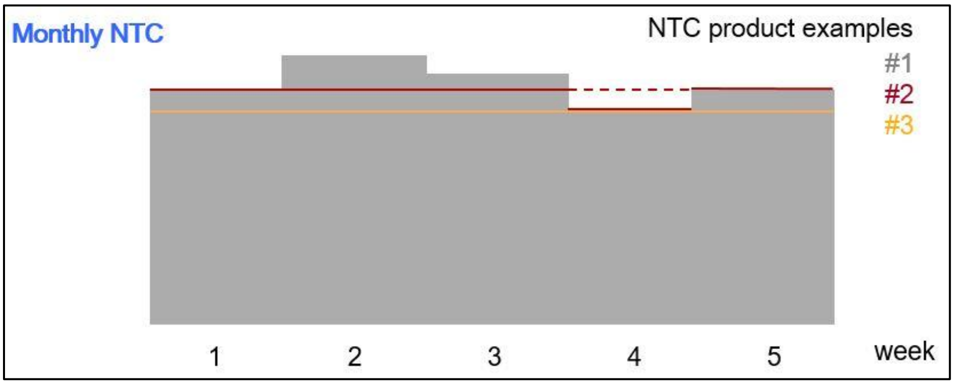


Figure 4

Also for this profile different month-ahead capacity products (e.g. month-ahead capacity with 4-5 weekly subperiods or a stable bound month-ahead capacity adjusted to the lowest calculated capacity) can be defined.

Based on later experiences, Core TSOs in coordination with Core CCC may modify the above selection approach.

2.6.2 Base case quality

This section describes the additional quality check of CGMs used for the purpose of LT capacity calculations and describes the way how the quality of base case model can be reached.

Upon receiving the yearly CGMs and before the actual capacity calculation process, the LT CCM foresees two additional process steps yielding the necessity to check the base case quality:

1. Mapping of the planned outages

For each timestamp for which the capacity will be calculated, the planned outages of grid elements will be added (see previous paragraph). The outage of the grid element combined with the eventual topological changes will lead to different loading of the elements compared to the loading of those elements in seasonal CGMs.

2. Congestion Check in CGMs with zero balance net position in the Core CCR.

While it can be expected that overloading of the grid elements will be avoided in the year-ahead reference scenarios, it is still possible that certain grid elements after planned outages mapping and transition of CGM net position to zero balance, will be loaded to such an extent (e.g. 99,9%) that the coordinated NTCs will result in zero(s).

The Core CCC shall calculate for each timestamp the RAMs for each CNEC with the Core zero balance position. This RAM will be compared to a predefined threshold.

In case the predefined threshold is exceeded on one or more CNECs, the Core TSOs will strive to meet an agreed threshold by one or a combination of the following measures which are still subject to further evaluation:

1. Topological measures such as:
    - opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s) or;
    - switching of one or more network element(s) from one bus bar to another, or;
    - transformer and PST tap adjustment.

2. Application of other coordinated measures:
    - minRAM;
    - other RAs (such as implicit RA or to use of phase shifter to relieve congestions in a different control area.

The actions to obtain base case quality are shared among all Core TSOs in advance of the capacity calculation.
The Core CCC prepares a report listing added planned outages, the RAMs per CNEC after the application of zero balance and the accompanying measures (provided by Core TSOs) to solve them.

Figure 5 shows the steps clearly:

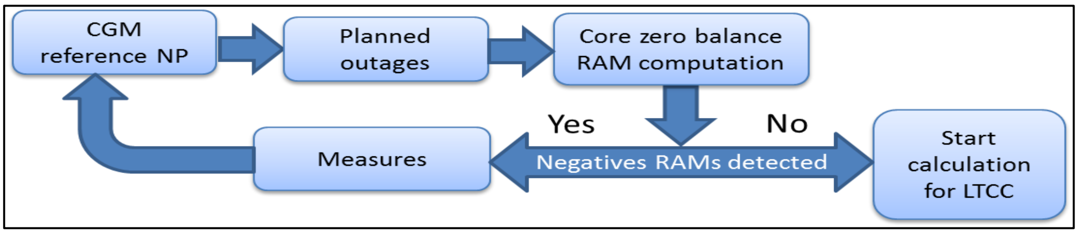


Figure 5

The decision on the action that will be considered in order to obtain a congestion free CGM for each timestamp, in base case situation with net position to zero balance in Core CCR, will be taken after Robust Experimentation will be finalized.

2.7 Integration of cross-border HVDC interconnectors located within the Core CCR

This section refers to Article 11 of the LT CCM Proposal.

This document details the methodology for the integration of the HVDC interconnector HVDC in the Core LT CCM. In fact, this document describes the general integration of a HVDC grid element.

2.7.1 Introduction

The integration of a HVDC grid element in an AC meshed grid is very particular as its flow is constant and independent of the situation on the surrounding AC meshed grid, contrasting AC elements that are directly impacted by the situation on the surrounding HVDC grid element(s). Nevertheless the goal is to integrate the HVDC grid elements in such a way that they are compatible with the existing calculation methodologies for an AC grid. The case of Alegro is also particular because the DE <> BE border will be the only one in Core CCR to be fully DC.

2.7.2 Philosophy

In the LT CCM for the Core region, an AC-line is characterized by its zone-2-zone PTDFs and its RAM. An AC-line can be a CNEC. The idea is to give the same parameters to a HVDC element so it can be integrated in the calculation tool.

RAM

The available margin on an HVDC element is defined in the same way as on an AC-line, being the difference between the Fmax – Fref. The Fmax of the HVDC will be equal to the MPTC (Maximum Permanent Transfer Capability).

PTDF

An HVDC element has no zone-to-zone PTDF except between the two virtual hubs to which it is connected. Paragraph 2.7.3 in this document gives the definition of the virtual hubs.

CO

An HVDC element is a CO, this means that the impact on other AC elements on the loss of an HVDC element has to be taken into account.

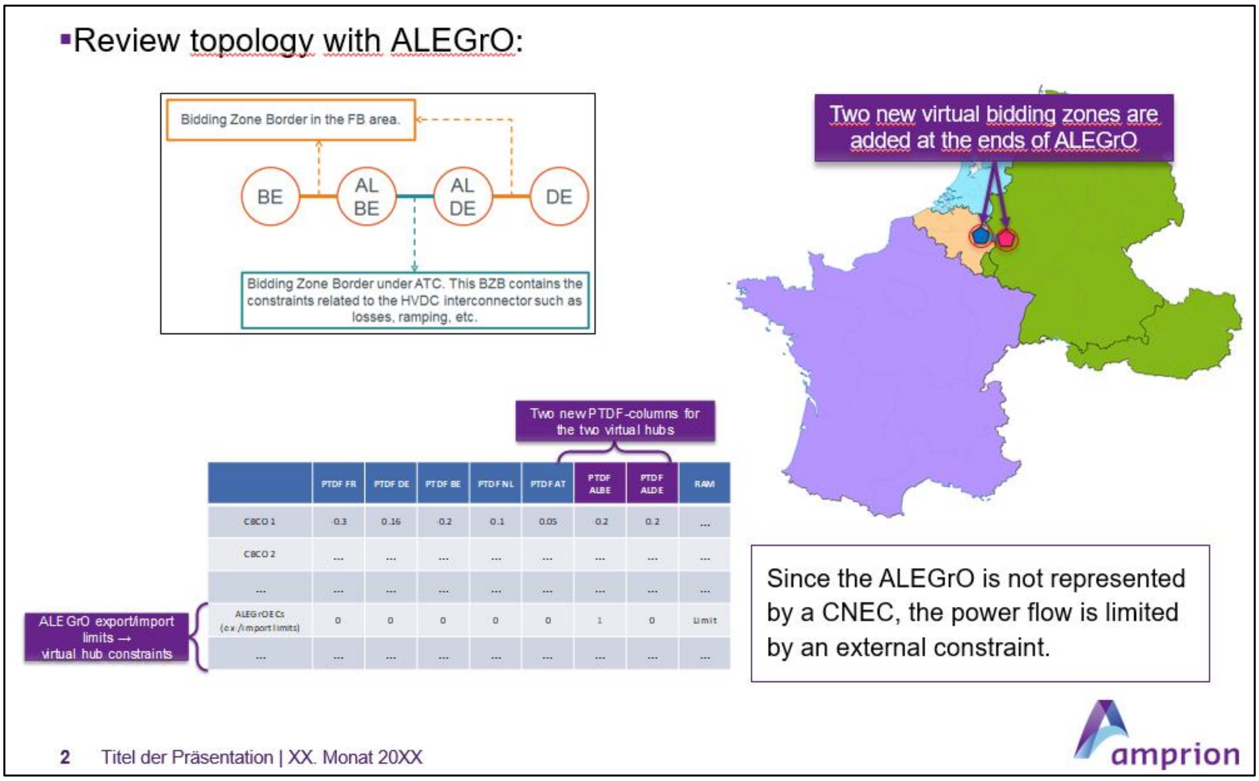
CB
An HVDC element is not a critical branch because the flow on an HVDC is not influenced by the surrounding grid situation (e.g. exchanges on other BZBs). Consequently, Alegro will not have any FRM (see Reliability Margins section).

Operation of the HVDC
The HVDC will be operated with fixed flows (Set Point), which would be equal to the commercial flows. The adjustment of the flow as a remedial action or topologic adaptation for the base case improvement will not be consider.

2.7.3 Methodology

Amprion and Elia foresee to integrate the HVDC interconnector Alegro by adding two virtual hubs in order to represent the exchange over the DC link. Each virtual hub is modelled as one load/generation node. The PTDFs of the CNECs concerning the virtual hubs can be calculated and integrated in the Core LT CCM, independently of the respective approach (Bottom-Up or Top-Down).

The HVDC interconnector Alegro will be considered in the inputs of Core TSOs as a CO, but not as a CB according to the particularities of the HVDC technology (fixed flows so no change in flow due to exchanges on other BZB, no overload possible). In addition, the MPTC (Maximum Permanent Technical Capacity), for which the BE <> DE NTC will be capped in any case, will be an input provided by Core TSOs for the computation. This method is general and could also be applied for any other future HVDC interconnector within the Core CCR.



	PTDF FR	PTDF DE	PTDF BE	PTDF NL	PTDF AT	PTDF ALBE	PTDF ALDE	RAM
CBCO 1	0.3	0.16	0.2	0.1	0.05	0.2	0.2	…
CBCO 2	…	…	…	…	…	…	…	…
…	…	…	…	…	…	…	…	…
ALEGrOECs (ex-/import limits)	0	0	0	0	0	1	0	Limit
…	…	…	…	…	…	…	…	…

Figure 6

Some consequences:

- the NTC on the BE <> DE border will be limited by the Alegro MPTC or by a limiting AC CNEC;
- the NTC on AC BZB will never been limited due to an overload on an HVDC;
- the NTC on AC BZB will not be computed with the use of the controllability of the HVDC flow as a remedial action.

2.8 Statistical analysis of likely corners

This section refers to Article 12 of the LT CCM Proposal.

This document details the methodology for the selection of likely corners that will be used for the determination of the Core LT cNTC values.

2.8.1 Introduction

A corner represents a combination of bilateral exchanges. For a system with Nb borders, the number of possible corners is 2^{Nb}. Figure 7 illustrates this concept for a system with 4 borders.

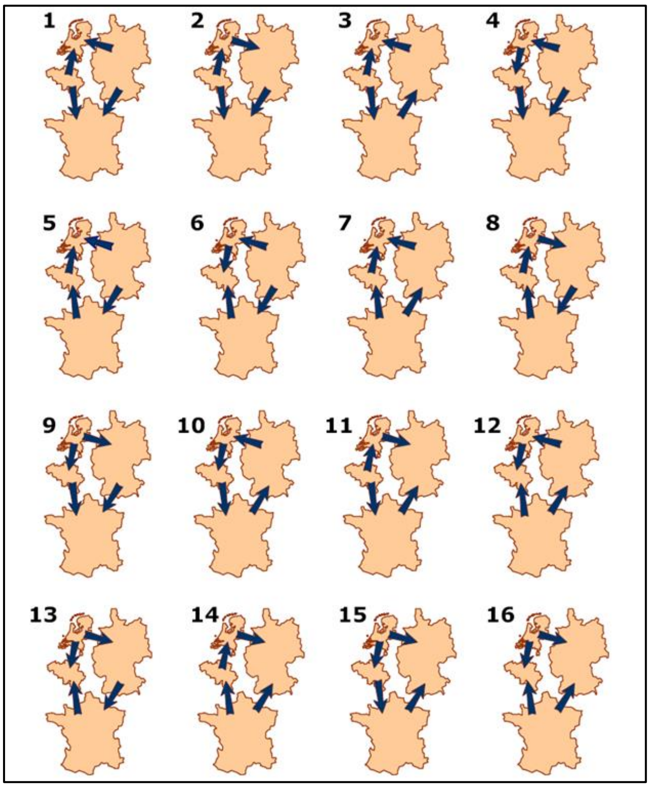


Figure 7: Example of possible corners on a 4-hub system with 4 BZBs

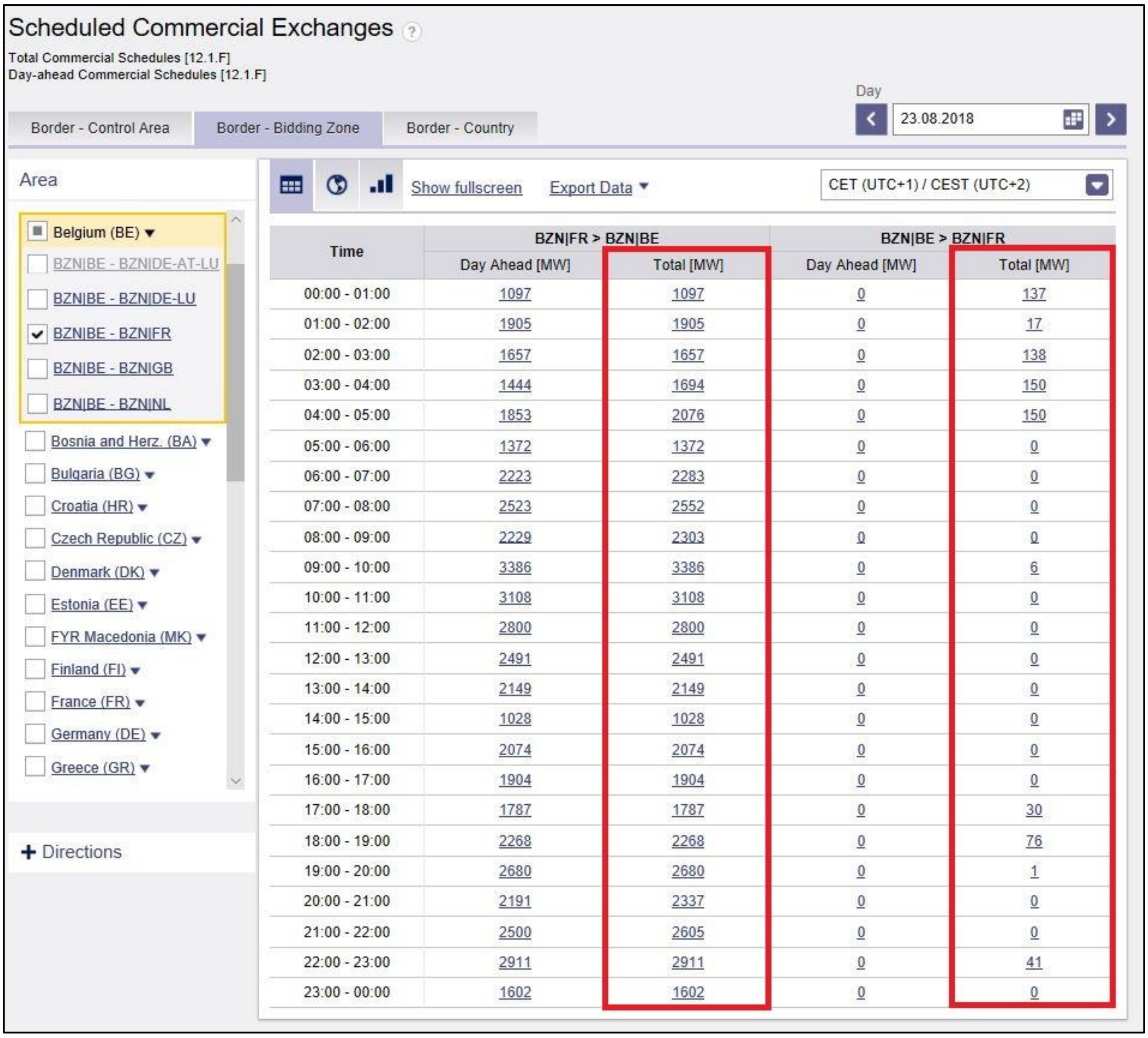
The Core CCR consists of 17 bidding zone borders, leading to 131.072 possible corners. This means that in the existing Core CCR there are 131.072 ways of combining the NTCs. As such a large number represents quite a challenge for any cNTC calculation methodology, it has been decided to perform a statistical analysis on a rolling one-year dataset to identify, out of this total number of possible corners, how many of them occurred as a result of market coupling during this time period. The results of this analysis mitigates the computational tractability by performing a simultaneous feasibility assessment for a more limited set of corners.

Once a year, before the Year-Ahead capacity calculations, the set of likely corners for each season of the upcoming year are determined based on historical data of the corresponding season from the previous year through the statistical method as explained in this section.
The subsequent Month-Ahead capacity calculations will use the associated seasonal likely corners as determined for the Year-Ahead capacity calculations.

2.8.2 Methodology

Gather Input Data

In the context of long-term capacity calculation, a corner is deemed to be likely if this corner matches the market coupling results of the Intraday capacity timeframe[3].
In order to perform this analysis, the utilization of total scheduled commercial exchanges per border (including intraday), for which it was possible to retrieve all the necessary information per Core border from the ENTSO-E transparency platform[4], has been chosen. An example of such data is shown in Figure 8.



Time	BZN|FR > BZN|BE Day Ahead [MW]	BZN|FR > BZN|BE Total [MW]	BZN|BE > BZN|FR Day Ahead [MW]	BZN|BE > BZN|FR Total [MW]
00:00 - 01:00	1097	1097	0	137
01:00 - 02:00	1905	1905	0	17
02:00 - 03:00	1657	1657	0	138
03:00 - 04:00	1444	1694	0	150
04:00 - 05:00	1853	2076	0	150
05:00 - 06:00	1372	1372	0	0
06:00 - 07:00	2223	2283	0	0
07:00 - 08:00	2523	2552	0	0
08:00 - 09:00	2229	2303	0	0
09:00 - 10:00	3386	3386	0	6
10:00 - 11:00	3108	3108	0	0
11:00 - 12:00	2800	2800	0	0
12:00 - 13:00	2491	2491	0	0
13:00 - 14:00	2149	2149	0	0
14:00 - 15:00	1028	1028	0	0
15:00 - 16:00	2074	2074	0	0
16:00 - 17:00	1904	1904	0	0
17:00 - 18:00	1787	1787	0	30
18:00 - 19:00	2268	2268	0	76
19:00 - 20:00	2680	2680	0	1
20:00 - 21:00	2191	2337	0	0
21:00 - 22:00	2500	2605	0	0
22:00 - 23:00	2911	2911	0	41
23:00 - 00:00	1602	1602	0	0

Figure 8: Scheduled commercial exchanges retrieved from ENTSO-E transparency platform

[3] Looking at physical cross-border flows includes loop-flows and hence the former are not useable.

This input data has been gathered in this example for the one-year period 1/10/2017-30/09/2018. This example contains 15 BZBs in which DE-AT is not taken into account. In case of a new BZB there is no historical data available for the upcoming season of the first year. In this case both directions on this new BZBs are automatically considered as likely.

2.8.3 Data preprocessing

Once the total scheduled commercial exchanges per border and direction have been retrieved from the ENTSO-E transparency platform, for every hour of the considered period and every Core border, the difference between the total LT capacities and the total scheduled commercial exchanges on both directions has been calculated. Three cases are possible:

- the net total scheduled commercial exchange is in the direction A→B, i.e. $\boldsymbol{TSCE}_{A\to B} - \boldsymbol{TSCE}_{B\to A} > 0$
- the net total scheduled commercial exchange is in the direction B→A, i.e. $\boldsymbol{TSCE}_{A\to B} - \boldsymbol{TSCE}_{B\to A} < 0$
- the net total scheduled commercial exchange is zero, i.e. $\boldsymbol{TSCE}_{A\to B} - \boldsymbol{TSCE}_{B\to A} = 0$

This is summarized in Table 1.

Case	A→B
$\boldsymbol{TSCE_{A\to B} - TSCE_{B\to A} > 0}$	1
$\boldsymbol{TSCE_{A\to B} - TSCE_{B\to A} < 0}$	-1
$\boldsymbol{TSCE_{A\to B} - TSCE_{B\to A} = 0}$	0

Table 1: From total scheduled commercial exchanges to defining border directions

For each of the first two cases the border is defined in either direction, for the third case the border is undefined. As a corner presupposes a specified direction per border, for each undefined border both directions have to be considered as likely. This leads to the creation of associated corners, as described in the next paragraph.

2.8.4 Creation of associated corners

When all borders are defined, i.e. their values are either 1 or -1, one unique corner per hour is obtained. For each undefined border, two derived corners are associated to it; consequently, for every hour, the total number of corners is 2^{NUb}, where NUb is the number of undefined borders. This procedure ensures that the dimension of the problem remains constant, no matter the number of undefined borders.
An example of this approach is described in Figure 9.

Hour	BE→FR [MW]	BE→NL [MW]	DE→FR [MW]	DE→NL [MW]	DE→PL [MW]
10:00-11:00	-600	0	0	900	1200

Hour	BE→FR	BE→NL	DE→FR	DE→NL	DE→PL
10:00-11:00	-1	**0**	**0**	1	1

Hour	BE→FR	BE→NL	DE→FR	DE→NL	DE→PL
10:00-11:00	-1	**1**	**1**	1	1
	-1	**1**	**-1**	1	1
	-1	**-1**	**1**	1	1
	-1	**-1**	**-1**	1	1

Figure 9: Creation of associated corners

2.8.5 Results

Summary

The analysis revealed that seven undefined borders ($\boldsymbol{TSCE_{A\to B} - TSCE_{B\to A} = 0}$) per timestamp have been experienced during the considered period (1/10/2017-30/09/2018). Nevertheless, in 97% of the cases, four undefined borders exist, as shown in Figure 10.

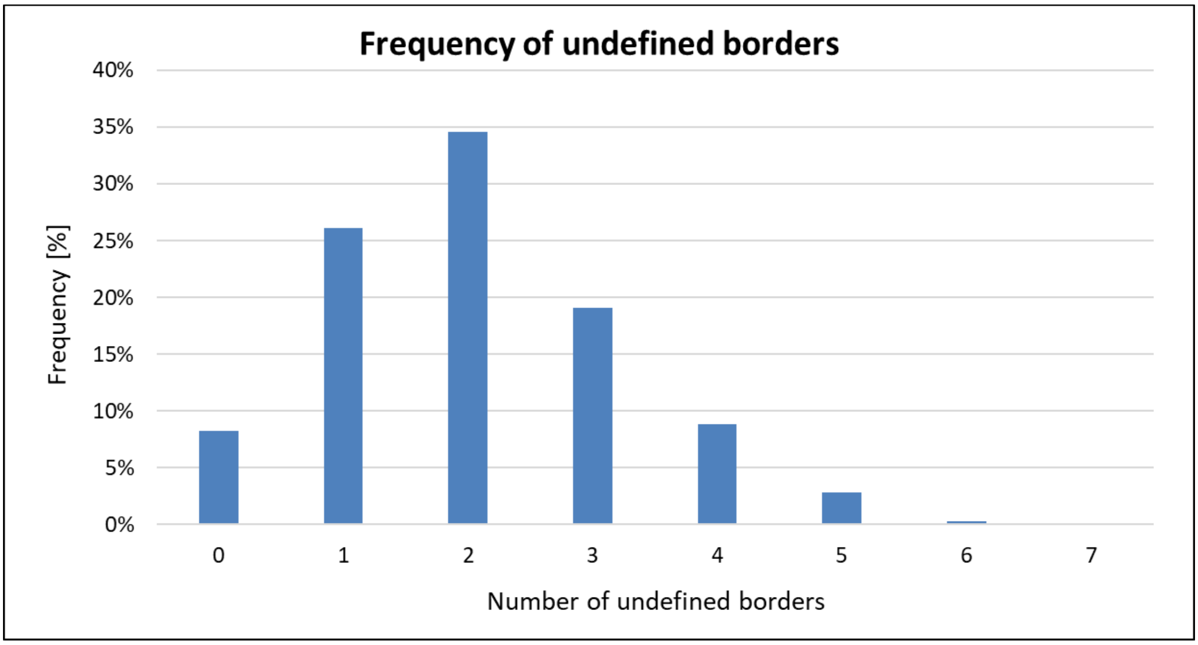


Figure 10: Frequency of undefined borders

Furthermore, out of 2^{15} (32.768) possible corners, only 2304 unique corners have been observed, 7% of the total. Significantly, 63% of those unique corners occurs less than 10 hours or, in other words, just 3% (861) of the possible corners are needed to cover 90% of the cases. The needed corners to cover progressive % of time is shown in Figure 11.

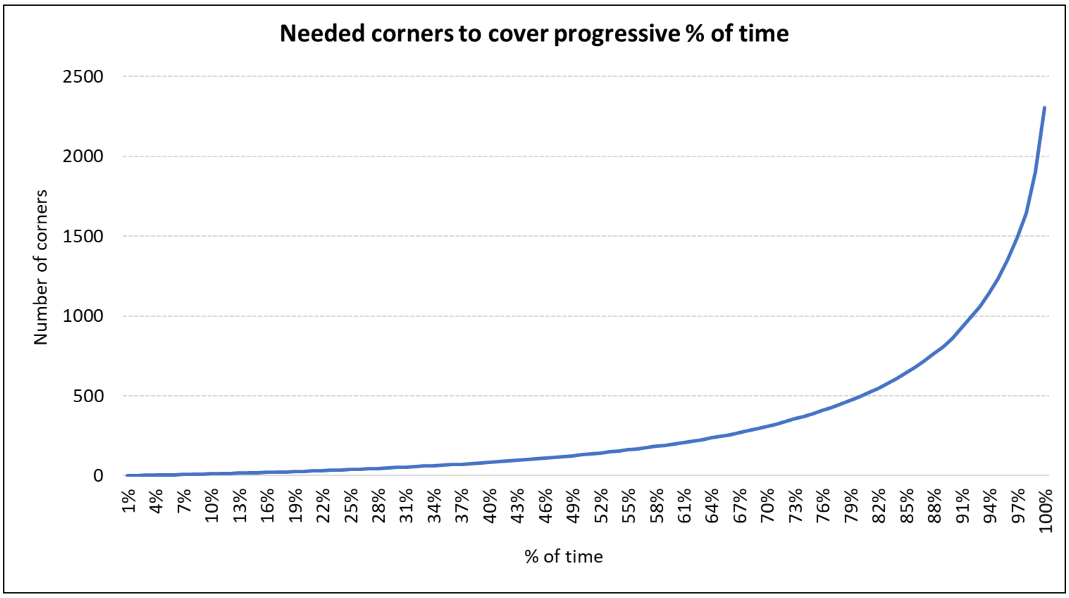


Figure 11: Needed corners to cover progressive % of time

Table 2 includes some key percentages with their respective values of needed corners.

% of time	Needed corners
50%	131
90%	861
95%	1233
99%	1904
100%	2304

Table 2: Key values of needed corners for different coverages

In order to have all NTCs present in at least one Likely Corner the first **81** most frequent occurred corners would need to be selected (covering 40% of the occurrences).

Furthermore, the top 10 most frequent corners with their respective frequency of occurrence over the considered period are reported in Figure 12.

BE-FR	BE-NL	CZ-DEAT	CZ-PL	CZ-SK	DEAT-HU	DEAT-NL	DEAT-PL	DEAT-SI	FR-DEAT	HR-HU	HR-SI	HU-RO	HU-SK	PL-SK	Frequency
1	1	-1	1	1	1	1	1	1	-1	1	1	-1	-1	1	692
1	-1	-1	-1	-1	1	1	-1	1	-1	1	1	-1	-1	-1	590
-1	1	-1	1	1	1	1	1	1	-1	-1	-1	-1	-1	1	511
-1	1	-1	1	1	1	1	1	1	1	1	-1	-1	-1	1	510
-1	1	-1	1	1	1	1	1	1	1	1	-1	1	-1	1	490
1	1	-1	1	1	1	1	1	1	-1	-1	-1	1	-1	1	419
-1	1	-1	1	1	1	1	1	1	1	-1	-1	-1	-1	1	419
-1	1	-1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	413
1	-1	-1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	409
-1	1	1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	374

The columns represent the BZB and the sign the direction (+ is from left to right, - is from right to left)

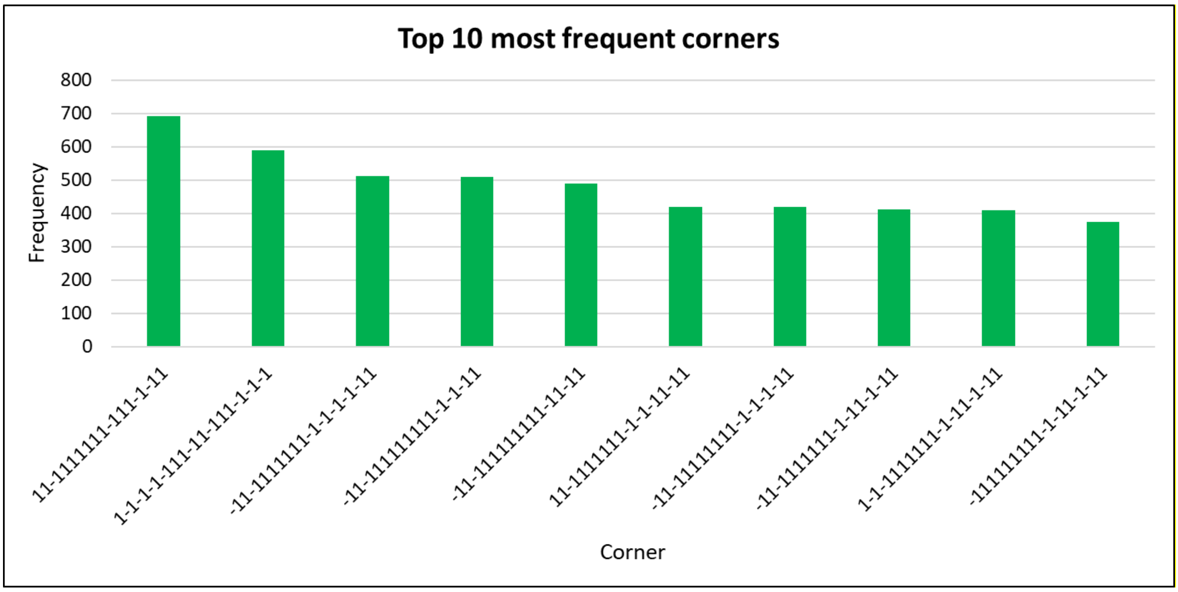


Figure 12: Top 10 most frequent corners

Moreover Figure 13 shows the relative percentages of time in which either of the two border directions has been observed.

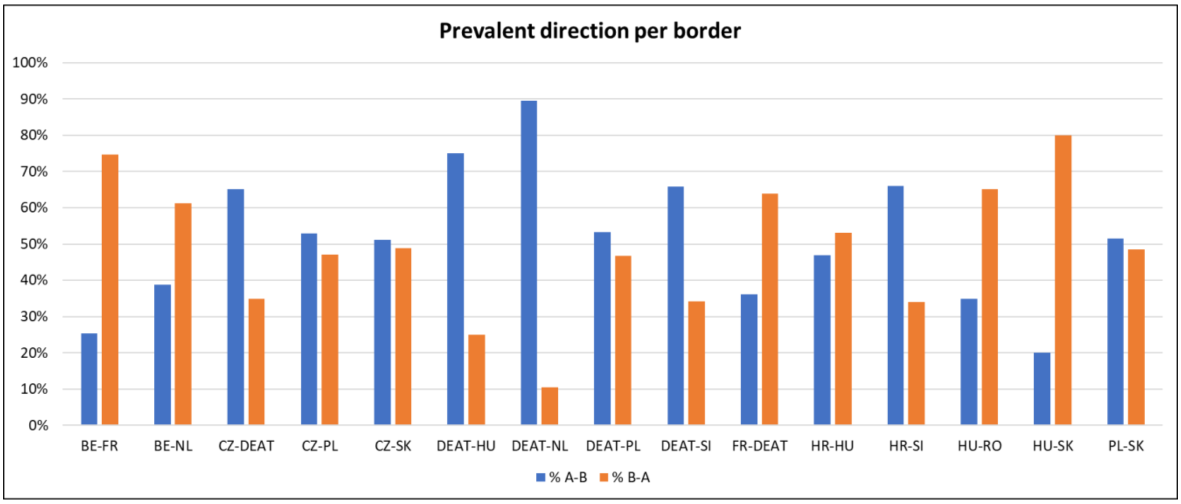


Figure 13: Prevalent direction per border

It can be observed that most Core borders have a clear predominant direction (for example DEAT-NL) and some borders do not have a clear predominant direction (for example PL-SK).

2.8.5.1 Seasonal effect

A per-season analysis has also been performed in order to identify a potential seasonal effect on the observed corners.

The seasonal partition of the top 10 most frequent corners is depicted in Figure 14.

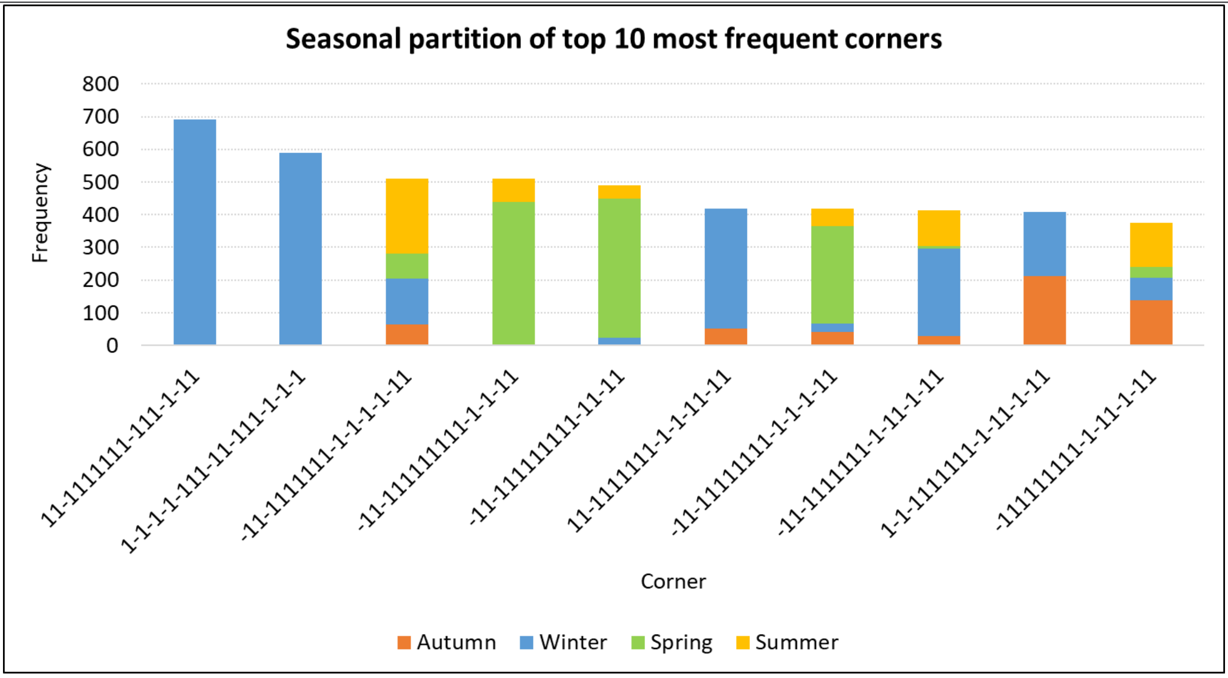


Figure 14: Seasonal partition of top 10 most frequent corners

This assessment reveals that the two most frequent corners appear during the winter season and, more generally, the less frequent corners occur in the summer period.

Therefore, the long-term capacity calculation will determine the likely corners per season and not per year. The definition of the season conforms the section on Scenarios in this Explanatory Note. The seasonal analysis on this example gives the following results:

Autumn

Considered timeframe: 01.10.2017 – 20.12.2017 + 21.09.2018 – 30.09.2018

BE-FR	BE-NL	CZ-DEAT	CZ-PL	CZ-SK	DEAT-HU	DEAT-NL	DEAT-PL	DEAT-SI	FR-DEAT	HR-HU	HR-SI	HU-RO	HU-SK	PL-SK	Frequency
1	-1	-1	1	1	1	1	1	1	-1	-1	-1	-1	-1	1	284
1	-1	-1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	213
1	-1	1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	193
1	-1	1	1	1	1	1	1	1	-1	-1	-1	-1	-1	1	180
1	-1	-1	-1	1	1	1	-1	1	-1	-1	-1	-1	-1	-1	169
1	-1	1	-1	1	1	1	-1	1	-1	-1	1	-1	-1	1	159
-1	1	-1	1	1	1	1	1	1	-1	-1	1	1	-1	1	142
-1	1	1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	138
1	-1	-1	1	1	1	1	1	1	-1	-1	-1	1	-1	1	133
1	-1	1	-1	1	1	1	-1	1	-1	-1	-1	-1	-1	1	118

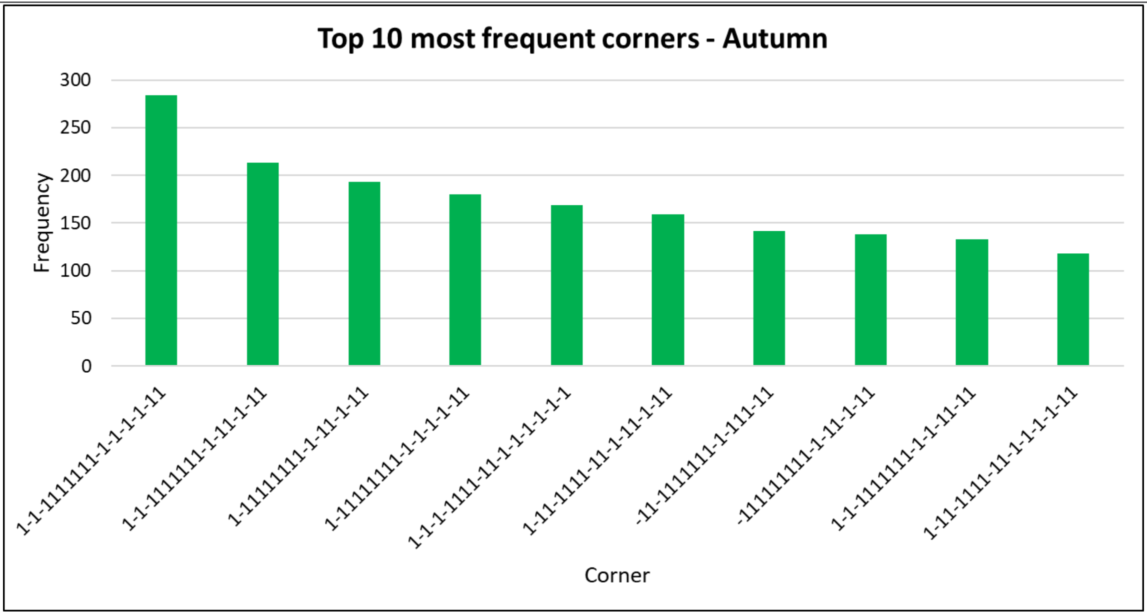


Figure 15: Top 10 most frequent corners – Autumn

In order to have all NTCs present in at least one likely corner the **106** most frequent occurred corners would need to be selected (covering 76% of the occurrences).

Winter

Considered timeframe: 21.12.2017 – 20.03.2018

BE-FR	BE-NL	CZ-DEAT	CZ-PL	CZ-SK	DEAT-HU	DEAT-NL	DEAT-PL	DEAT-SI	FR-DEAT	HR-HU	HR-SI	HU-RO	HU-SK	PL-SK	Frequency
1	1	-1	1	1	1	1	1	1	-1	1	1	-1	-1	1	692
1	-1	-1	-1	-1	1	1	-1	1	-1	1	1	-1	-1	-1	590
1	1	-1	1	1	1	1	1	1	-1	-1	-1	1	-1	1	368
-1	-1	-1	-1	-1	1	1	-1	1	-1	1	1	-1	-1	-1	344
-1	-1	-1	-1	-1	1	1	-1	1	-1	-1	1	-1	-1	-1	340
1	-1	-1	1	1	1	1	1	1	-1	1	1	-1	-1	1	310
-1	-1	-1	-1	-1	1	1	-1	1	-1	1	1	1	-1	-1	308
1	-1	-1	-1	-1	1	1	-1	1	-1	-1	1	-1	-1	-1	284
1	1	-1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	280
-1	-1	1	-1	-1	1	1	-1	1	-1	1	1	-1	-1	-1	270

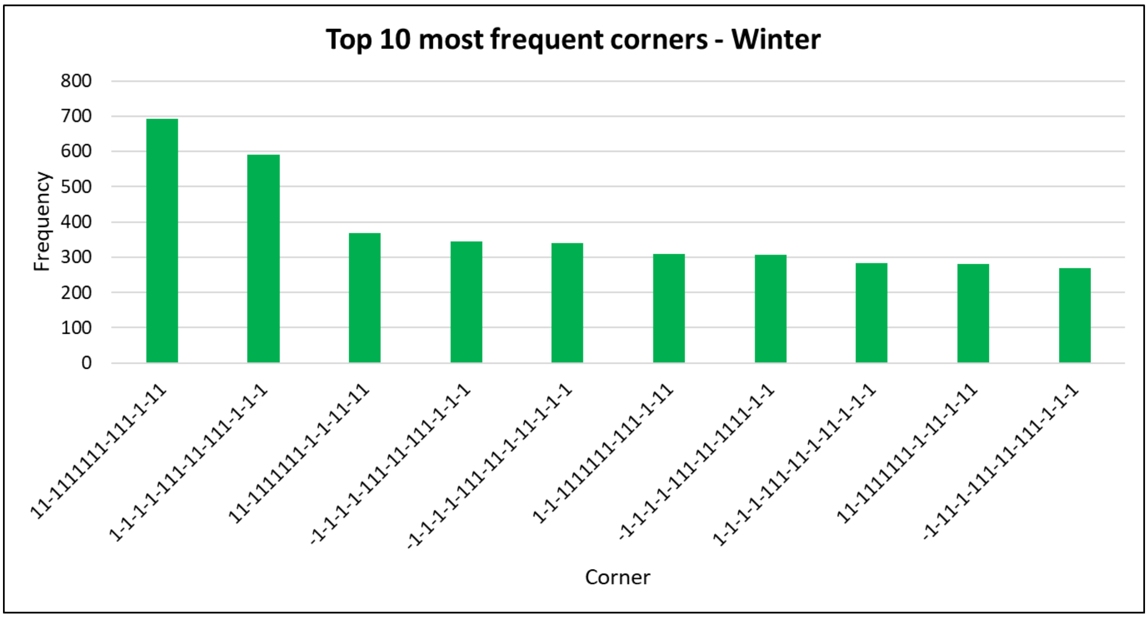


Figure 16: Top 10 most frequent corners – Winter

In order to have all NTCs present in at least one Likely Corner the **80** most frequent occurred corners would need to be selected (covering 56% of the occurrences).

Spring

Considered timeframe: 21.03.2018 – 20.06.2018

BE-FR	BE-NL	CZ-DEAT	CZ-PL	CZ-SK	DEAT-HU	DEAT-NL	DEAT-PL	DEAT-SI	FR-DEAT	HR-HU	HR-SI	HU-RO	HU-SK	PL-SK	Frequency
-1	1	-1	1	1	1	1	1	1	1	1	-1	-1	-1	1	438
-1	1	-1	1	1	1	1	1	1	1	1	-1	1	-1	1	424
-1	1	-1	1	1	1	1	1	1	1	-1	-1	-1	-1	1	296
-1	1	1	1	1	1	1	1	1	1	1	-1	1	-1	1	266
-1	-1	-1	1	-1	1	1	1	1	-1	1	-1	-1	-1	-1	230
-1	1	-1	1	1	1	1	1	1	1	-1	-1	1	-1	1	205
-1	1	1	1	1	1	1	1	1	1	-1	1	1	-1	1	194
-1	1	1	1	1	1	1	1	1	1	-1	-1	-1	-1	1	163
-1	-1	-1	1	-1	1	1	1	1	1	1	-1	-1	-1	-1	160
-1	1	1	1	1	-1	1	1	-1	-1	1	1	-1	1	1	150

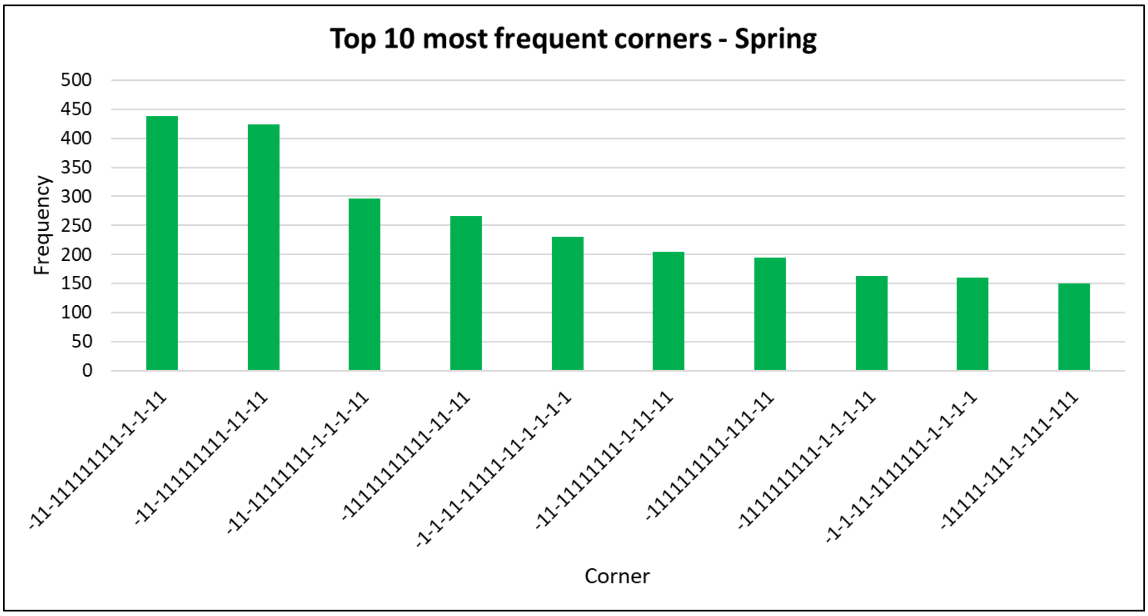


Figure 17: Top 10 most frequent corners – Spring

In order to have all NTCs present in at least one Likely Corner the **40** most frequent occurred corners would need to be selected (covering 38% of the occurrences).

Summer

Considered timeframe: 21.06.2018 – 20.09.2018:

BE-FR	BE-NL	CZ-DEAT	CZ-PL	CZ-SK	DEAT-HU	DEAT-NL	DEAT-PL	DEAT-SI	FR-DEAT	HR-HU	HR-SI	HU-RO	HU-SK	PL-SK	Frequency
-1	1	-1	1	1	1	1	1	1	-1	-1	-1	-1	-1	1	231
-1	-1	-1	1	-1	1	1	1	1	-1	-1	-1	-1	-1	-1	218
-1	1	1	1	1	1	1	1	1	-1	-1	-1	-1	-1	1	212
-1	-1	-1	1	-1	1	1	1	1	-1	-1	1	-1	-1	-1	207
-1	-1	1	1	-1	1	1	1	1	-1	-1	1	-1	-1	-1	166
-1	1	-1	1	1	1	1	1	1	-1	1	-1	-1	-1	1	157
-1	-1	1	1	1	1	1	1	1	1	-1	1	-1	-1	1	147
-1	1	1	1	1	1	1	1	1	1	-1	1	-1	-1	1	146
-1	1	-1	1	1	1	1	1	1	1	-1	1	-1	-1	1	142
-1	-1	-1	1	1	1	1	1	1	-1	-1	1	-1	-1	1	135

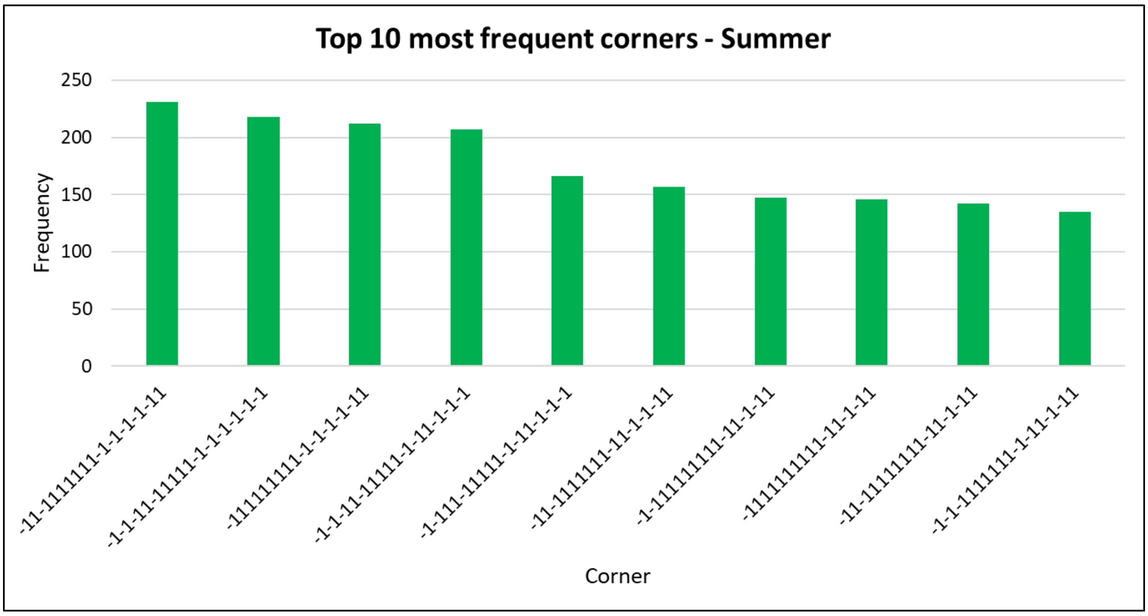


Figure 18: Top 10 most frequent corners – Summer

In order to have all NTCs present in at least one Likely Corner the **115** most frequent occurred corners would need to be selected (covering 63% of the occurrences).

As a starting point, the long-term capacity calculation methodology will consider that the set of likely corners needs to cover 90% of the occurrences. This threshold will be subject to further analysis and subsequent adaptation regularly in the forthcoming years. Core TSOs will further analyze if there is a need to add an ad-hoc corner selection due to exceptional grid situations.

Note: The information on likely corners presented in this example is not the input data that is used for the robust experimentation. For the robust experimentation only one likely corner is considered as shown in Figure 19.

BE-FR	BE-NL	CZ-DE	CZ-AT	CZ-PL	CZ-SK	AT-HU	DE-NL	DE-PL	AT-SI	FR-DE	HR-HU	HR-SI	HU-RO	HU-SK	PL-SK	DE-AT
1	1	-1	-1	1	1	1	1	1	1	-1	1	1	-1	-1	1	1

Figure 19

3 VALIDATION

3.1 Validation methodology

This section refers to Article 13 of the LTCCM Proposal

The Core TSOs are legally responsible for the cross-zonal capacities and therefore have to validate the calculated values, in accordance with article 15 of the FCA Regulation, before the coordinated capacity calculator can send them for allocation. Each Core TSO shall have the right to correct cross-zonal capacity relevant to the Core TSO's bidding zone borders provided by the Core CCC.

After the calculation a re-assessment might be necessary to respect operational security requirements (e.g. forced outage) of a grid element, error in input data like: changes in availability or technical characteristics of generator or load units, possible unforseen changes in the grid situation which has occured during the computation phase and imply changes in provided IGMs for the CGM used in calculation for that timeframe). Each Core TSO may reduce cross-zonal capacity for reasons of operational security. This reduction of the capacity has to be monitored with at least an identification of the limiting CNEC and the explanation of the unforseen event.

Article 15 of the FCA Regulation refers to article 26 of CACM Regulation, where it is stipulated that any reduction during the validation stage shall be reported to the Core NRAs every three months. If a Core TSO expects an increase of capacity, then the entire coordinated capacity calculation needs to be performed for the particular timestamp, in order to fulfill the correction for splittling rules as stipulated in article 26.2 of the CACM Regulation.

It must be clarified that the iterations on the results are not part of the final validation process, but they are part of the calculation process.

4 DETAILED DESCRIPTION OF THE CAPACITY CALCULATION PROCESS

4.1 Technical description of the Capacity Calculation method

This section refers to Article 14 of the LT CCM Proposal.

In order to calculate the cross-zonal cNTCs respecting the system security, the following parameters are to be calculated for each critical network element for each timestamp:

- PTDFs for each bilateral exchange direction;
- RAMs.

In accordance with article 29(3)(a) of the CACM Regulation, the Core CCC shall calculate the impact of a change in the bidding zones net position on the power flow on each CNEC (determined in accordance with the rules defined in Article 7 on CNEC). This influence is called the zone-to-slack $PTDF$. This calculation is performed from the CGM and the GSK defined in accordance with Article 8 on GSK.

The zone-to-slack $PTDFs$ are calculated by first calculating the node-to-slack $PTDFs$ for each node defined in the GSK. These nodal PTDFs are derived by varying the injection of a relevant node in the CGM and recording the difference in power flow on every CNEC (expressed as a percentage of the change in injection). These node-to-slack $PTDFs$ are translated into zone-to-slack $PTDFs$ by multiplying the share of each node in the GSK with the corresponding nodal PTDF and summing up these products. This calculation is mathematically described as follows:

$$\mathbf{PTDF}_{\mathrm{zone-to-slack}} = \mathbf{PTDF}_{\mathrm{node-to-slack}}\,\mathbf{GSK}_{\mathrm{node-to-zone}}$$

Equation 1

with

$\mathbf{PTDF}_{zone-to-slack}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones; rows: CNECs)
$\mathbf{PTDF}_{node-to-slack}$	matrix of node-to-slack $PTDFs$ (columns: nodes; rows: CNECs)
$\mathbf{GSK}_{node-to-zone}$	matrix containing the $GSKs$ of all bidding zones (columns: bidding zones; rows: nodes; sum of each column equal to one)

The zone-to-slack $PTDFs$ as calculated above can also be expressed as zone-to-zone $PTDFs$. A zone-to-slack $PTDF_{A,l}$ represents the influence of a variation of a net position of bidding zone A on a CNEC l and assumes a commercial exchange between a bidding zone and a slack node. A zone-to-zone $PTDF_{A\to B,l}$ represents the influence of a variation of a commercial exchange from bidding zone A to bidding zone B on CNEC l. The zone-to-zone $PTDF_{A\to B,l}$ can be derived from the zone-to-slack $PTDFs$ as follows:

$$PTDF_{A\to B,l} = PTDF_{A,l} - PTDF_{B,l}$$

Equation 2

In order to determine the flow in the situation without commercial exchanges within the Core CCR for all Core bidding zones, leading to the following equation:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \mathbf{PTDF}_f \ \overrightarrow{NP}_{ref,Core}$$

Equation 3

with

$\vec{F}_{0,Core}$	flow per CNEC in the situation without commercial exchanges within the Core CCR
$\vec{F}_{ref}$	flow per CNEC in the CGM
$\mathbf{PTDF}_f$	power transfer distribution factor matrix for the Core CCR
$\overrightarrow{NP}_{ref,Core}$	Core net position per bidding zone included in the CGM

Based on the definition of PTDF described above, the RAM is calculated in accordance with the definition of Fmax in Article 6 Operational Security Limits and in accordance with the definition of FRM in Article 5 on Reliability Margins as follows:

$$RAM = F_{max} - FRM - F_{0,Core}$$

Please remind that the non-Core BZB exchanges are maintained in accordance with the ENTSO-E Year-Ahead scenarios.

In the above paragraphs, the general process applicable for both approaches have been explained.

Before the Core TSOs explain the two approaches in more technical detail, the ultimate cNTC calculation algorithm can take into account several options concerning the following points:

- application of Core TSOs experiences: Core TSOs can define a special sub-set of CNECs or a threshold to indicate insensitive elements for NTC calculation (Right No.1 and Rule No.1 respectively);
- the “Bottom-Up” approach only considers positive contributors, while the “Top-Down” approach considers both negative and positive contributors (i.e. the approach allows to take into account NTCs that reduces the load on a CNEC while checking the grid security);
- in the “Bottom-Up” approach, the RAM of CNEC is shared without border prioritization between positive contributors, while in the “Top-Down” approach the RAM of a CNEC is distributed using the PTDF share. As a consequence, in the “Bottom-Up” approach even bidding-zone-borders that are electrically further to the CNEC obtain the equal share of available RAM for capacity allocation, whereas in the “Top-Down” approach the biggest portion of the available RAM is allocated to the bidding-zone-borders that are electrically closer to the CNEC;
- NTCs for directions outside of likely corners: conservative value or bilateral value can be used for such directions.

Now follows the description of each of the two approaches, the Bottom-Up approach and the Top-Down approach. A decision to use one of these approaches or a combination thereof, will be made during the public consultation based on more experience and on more results from robust experimentations.

4.1.1 Top-Down Approach

Introduction

Core TSOs have specified the LTCC requirements for the Core coordinated NTC (cNTC) calculation methodology in line with the high-level principles agreed by the Core LTCC Team on 10.06.2018 and approved by the Core Sterring Group on 20.06.2018. Two approaches based on PTDF are currently under discussion: “Bottom-Up” and “Top-Down”. This chapter provides a detailed explanation the Top-Down approach.

The principles under which the Top-Down approach has been developed are the following:

- full compliance with FCA Regulation and Core Steering Group decision – The approach offers a clear, transparent and 100% cNTC scenario-based methodology. It has been developed with the objective to benefit from Core TSOs’ experiences in both LT and DA capacity calculations;
- network security – The calculated figures must allow Core TSOs to effectively limit cross-border power exchanges in such a way that the relevant network security criteria are fulfilled. Therefore, this top-down approach entirely respects the CNEC-selection methodology and loading criterion in a transparent manner;
- coordination and maximization of trade opportunities – This Top-Down approach inherently starts with finding the maximum cross-border capacities followed by a correction in case it would be required to cover the grid security in the likely corners;
- transparency – The procedure shall be highly transparent, i.e. with a comprehensive methodology as well as clear information on the input and the output side:
    - input: The provided data and assumptions made by each Core TSO shall be transparent to all other Core TSOs;
    - output: The procedure shall allow for the identification of bottlenecks limiting the cNTC values.
- non-discriminatory and common - The NTC calculations for each BZB are done by the Core CCC considering the same grid model, the same scenario and applying the same calculation method. The sequence of NTC calculations and corrections does not influence the final results;
- overall feasibility and compatibility between the long and short-term capacity calculation methodologies and processes.

Top-Down Approach

The different steps to achieve a complete assessment of the cNTC with the Top-Down approach are the following:

1. maximum bilateral NTC assessment;
2. simultaneous feasibility assessment of the bilateral NTCs;
3. NTCs correction to achieve simultaneously feasible results;
4. validation of the NTCs simultaneous feasibility.

While step 1 and step 4 are applied only once in the methodology, steps 2 and 3 have to be repeated for each corner selected in the analysis.

In order to ease the understanding of each step in this calculation approach, a simplified pedagogic example with 3 CNECs, 4 BZBs and one likely corner will be used throughout the rest of the chapter.

Therefore, Figure 20 contains the fixed input parameters for each CNEC: RAM, zone-2-zone PTDF, likely corner and the Fmax. The determination of those input parameters is independent of this Top-Down approach, in other words they are determined based on their own methodologies.

Coordinated Bilateral Power Shits (Top Down) Approach Pedagogic Example										
	Inputs									
Input CNECs	PTDF (A>B)	PTDF (B>A)	PTDF (A>C)	PTDF (C>A)	PTDF (D>B)	PTDF (B>D)	PTDF (D>C)	PTDF (C>D)	RAM	Fmax
CNEC1	-0,5	0,5	0,18	-0,18	-0,06	0,06	0,09	-0,09	1200	2000
CNEC2	0,27	-0,27	0,05	-0,05	0,13	-0,13	-0,1	0,1	600	1200
CNEC3	0,12	-0,12	0,27	-0,27	-0,12	0,12	0,05	-0,05	2000	3000
Corner	1	0	1	0	1	0	1	0		

Figure 20

4.1.1.1 Maximum bilateral NTC assessment

Inputs

- CBCO files for each Core TSO;
- GSK files for each Core TSO;
- CGM in UCT format;
- RefProg of the CGM (Commercial Schedules).

Description

The CBCO files are merged for the Core CCR and, for each CNEC of the given BZB, the following quantities are calculated via a load flow tool:

- the RAM;
- the PTDF per BZB.

Based on this data for each CNEC, the top-down approach will first calculate the bilateral NTCs for each BZB and direction respecting the constraint following the formula (1) with the example of the border direction A→B:

$$PTDF_{CNEC,AB} * NTC_{AB} \leq RAM_{CNEC} \quad \forall\, CNEC \in \{A, B\} \qquad (1)$$

In other words, for each BZB the NTC that could be given by each CNEC with its entire RAM goes to one border at the same time. The lowest NTC, determined by the most limiting CNEC, is withhold as the initial bilateral NTC.

Pedagogic example

In the pedagogic example, this is done in Figure 21:

Maximum Bilateral NTC Assessment

CNECs	Bilateral NTCs NTC (A>B)	NTC (B>A)	NTC (A>C)	NTC (C>A)	NTC (D>B)	NTC (B>D)	NTC (D>C)	NTC (C>D)
CNEC1	99999	2400	6666,667	99999	99999	20000	13333,33	99999
CNEC2	2222,222	99999	12000	99999	4615,385	99999	99999	6000
CNEC3	16666,67	99999	7407,407	99999	99999	16666,67	40000	99999
Bilateral NTC	**2222,222**	**2400**	**6666,667**	**99999**	**4615,385**	**16666,67**	**13333,33**	**6000**

Bilateral NTCs for the selected corner	
NTC (A>B)	2222,222
NTC (A>C)	6666,667
NTC (D>B)	4615,385
NTC (D>C)	13333,33

Figure 21

In this table you can see that for each CNEC (see each row) the NTC of each BZB (see each column) is calculated based on the above formula (1), i.e.:

$$NTC_{AB} = \frac{RAM_{CNEC}}{PTDF_{CNEC,AB}}$$

In this example we can see that CNEC 1 would be able to offer 2400MW as NTC B>A, 6667MW as NTC A>C, 20000MW as NTC B>D and 13333MW as NTC D>C. The directions for which the CNEC have a negative ptdf (i.e. they increase the RAM, or in other words they offload the line), the NTCs are set by default to 99999.

In this example we can see that CNEC 2 is the limiting CNEC for the NTCs A>B, D>B and C>D leading to the respectively bilateral NTCs of 2222MW, 4615MW and 6000MW.

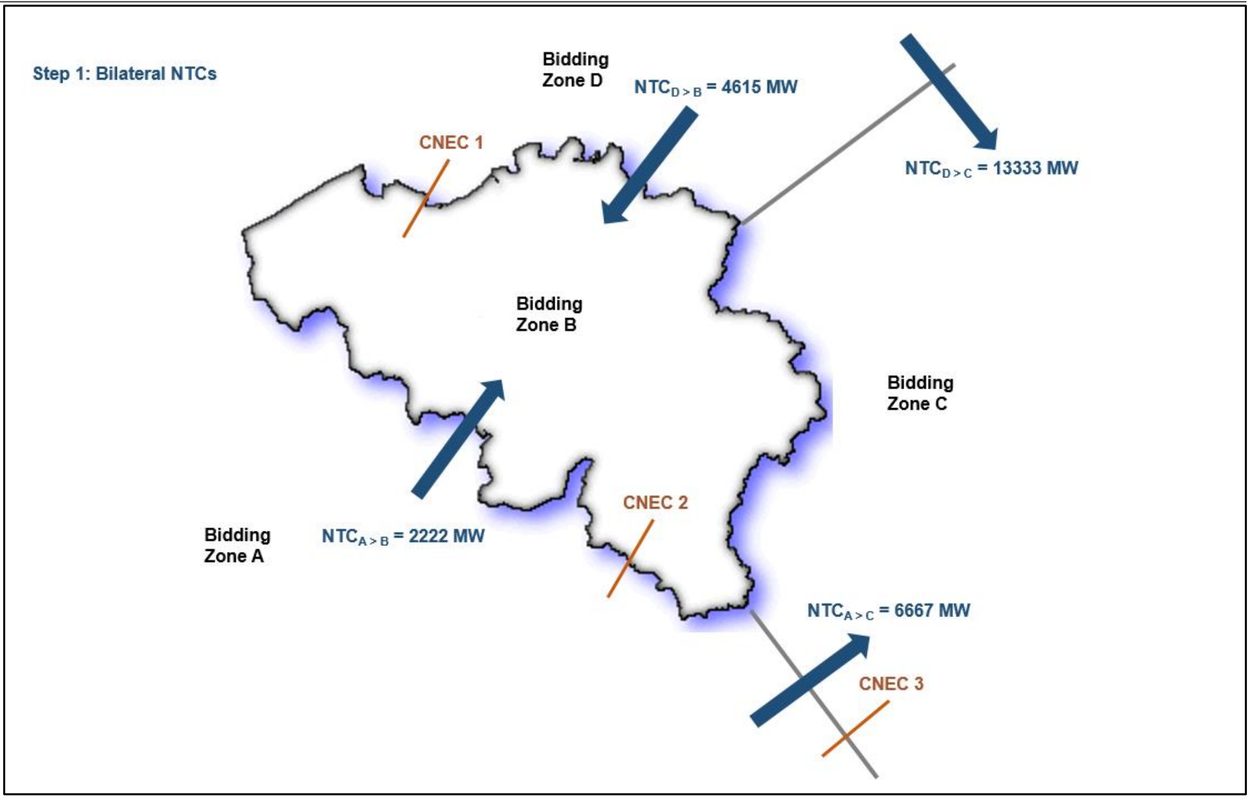


Figure 22: Calculation of initial bilateral NTCs (blue)

4.1.1.2 Simultaneous feasibility assessment of the bilateral NTCs

Inputs

- set of selected corners;
- each Core CNEC with a BZB PTDF and RAM;
- bilateral NTCs per border and direction.

Description

The step above delivers the bilateral NTCs considering that the RAM of each CNEC goes only to one NTC at the same time. As a consequence there is a great likelihood that some of these NTCs are not simultaneously feasible when combined nevertheless the fact that NTCs can also offload CNEC (i.e. each BZB has an NTC in one directions that loads the CNEC and an NTC in the other direction that offloads the CNEC, mathematically this is reflected by the same ptdf but opposite in sign).
One certain combination of NTC directions is called a corner.

The bilateral NTCs calculated in the previous step will now be assessed for all the selected corners. The corner selection is done by means of an ad-hoc statistical analysis based on historical market data and is explained in a dedicated chapter.

For each corner (i.e. the selected set of NTC direction combinations), the simultaneous feasibility of NTCs for all the Core CNECs is checked according to (2):

$$\sum_{\{i,j\} \in \ borders} PTDF_{CNEC,ij} * NTC_{ij} * Corner\ direction_{ij} = \ RAM^{*}_{CNEC} \ \leq RAM_{CNEC} \qquad (2)$$

In other words we will check if the combinations of those bilateral NTCs doesn't require a RAM (RAM^*_{CNEC}) on the CNECs that is higher than the available RAM (RAM_{CNEC}).

Pedagogic example

In the pedagogic example, this is visible in Figure 23:

Security Check and Determination of the most severely violated CNEC

	Simultaneous Feasibility for the Selected Corner										
CNECs	RAM* (A>B)	RAM* (B>A)	RAM* (A>C)	RAM* (C>A)	RAM* (D>B)	RAM* (B>D)	RAM* (D>C)	RAM* (C>D)	netto required RAM for this corner	Available RAM	Remaining RAM (Initial RAM - DeltaRAM*)
CNEC1	-1111,11111	0	1200	0	-276,92308	0	1200	0	1012	1200	188
CNEC2	600	0	333,333333	0	600	0	-1333,33	0	200	600	400
CNEC3	266,6666667	0	1800	0	-553,84615	0	666,6667	0	2179	2000	-179

=> Negative RAM of the most severely violated CNEC (To be brought to zero with the correction)

Figure 23

For each CNEC (row) the netto required RAM is calculated that is necessary to combine the initial bilateral NTCs (column) conform the selected corner:

$$RAM^*_{CNEC,corner} = (NTC_{AB} * PTDF_{AB}) + (NTC_{AC} * PTDF_{AC}) + (NTC_{DB} * PTDF_{DB}) + (NTC_{DB} * PTDF_{DC})$$

Subsequent, the last column shows the difference of this total netto RAM, required on the CNEC due to this NTC combinations, and the available RAM on the CNEC and thus the eventual overload.

$$\Delta RAMcorner = RAM_{CNEC} - RAM^*_{CNEC,corner}$$

→ (over) load of the CNEC in the corner which is shown in the last column in the table above.

If one look at CNEC 3 in this example, you see that:

- the NTC A>B (2222MW) requires a RAM on CNEC 3 of 267MW;
- the NTC A>C (6667MW) requires a RAM on CNEC 3 of 1800MW;
- the NTC D>B (4615MW) requires a RAM on CNEC 3 of -554MW (/!\ i.e. it offloads CNEC 3 /!\);
- the NTC D>C (1333MW) requires a RAM on CNEC 3 of 667MW.

The combination of the bilateral NTCs A>B, A>C, D>B and D>C requires a netto RAM on CNEC 3 of 2179MW. But the available RAM on CNEC 3 is only 2000MW. As a result, the combination of those 4 initial bilateral NTCs lead to an overload of 179MW on CNEC 3.

Note: It is important to note that NTCs can also offload CNEC (reflected mathematically via a negative ptdf). This offloading effect is taken into account in this top-down approach as is visible in this example (NTC D>B offloads CNEC 1, NTC D>C offloads CNEC 2, …).

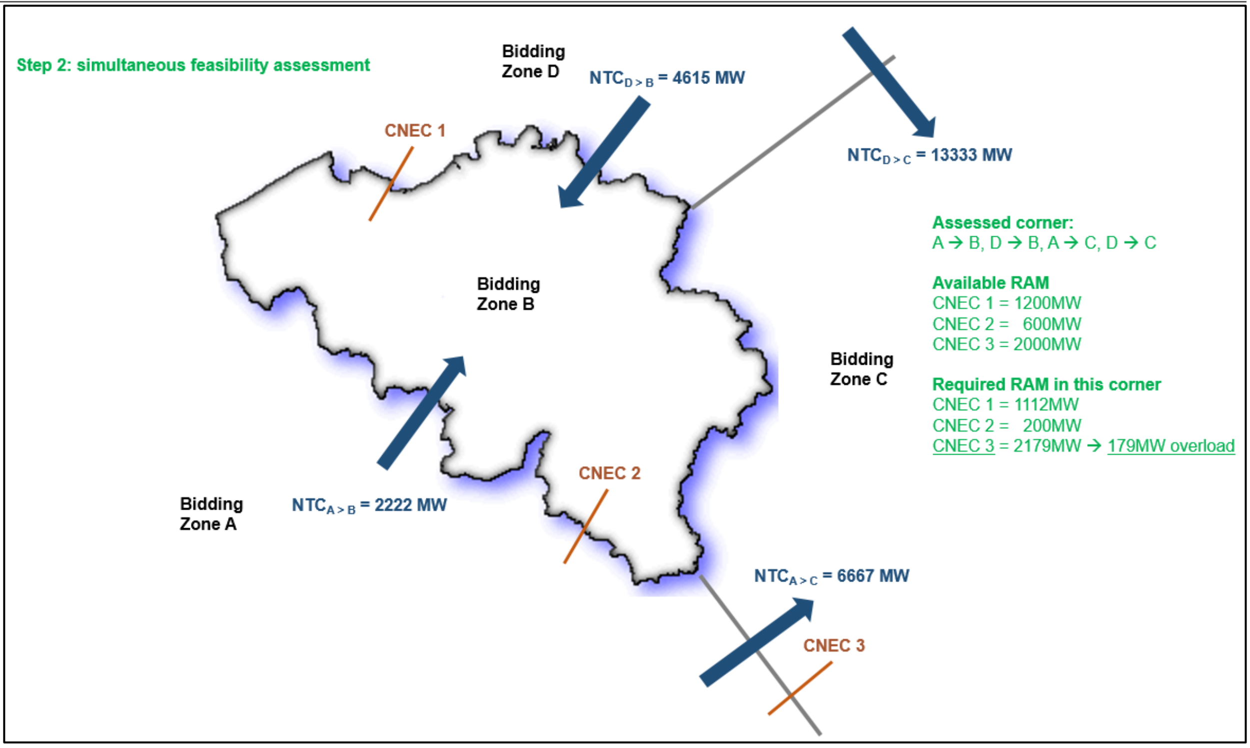


Figure 24: Simultaneous feasibility assessment of the corner (green)

4.1.1.3 NTCs correction to achieve simultaneously feasible results

Inputs

- set of selected corners;
- bilateral NTCs per border and direction;
- each Core CNEC with a BZB PTDF and RAM.

Description

If the previous step detects overloaded CNECs than this step will correct the bilateral values, starting with the most overloaded CNEC, until no CNEC is overloaded anymore. So, the bilateral values will now be corrected until their combination in all the selected corners leads to RAM on the CNECs that is equal or less than the available RAM.

If this corrected set of NTCs, based on the most overloaded CNEC, satisfies the RAM constraints for this corner than no further NTCs reduction is needed. Otherwise, a new NTCs reduction will have to be performed, starting by identifying the new most severely violated CNEC.

In other words, in case more than one CNEC would be overloaded with the initial bilateral NTCs, than we would start with calculating the corrections required to alleviate the overload on the most overloaded CNEC. Once new NTCs that secures the most overloaded CNEC are found, we check again if any other CNEC still have overloads with those new NTCs. If not than we have our final secure values for this corner. If yes, then the correction step is repeated but starting from the already corrected NTCs and using the remaining overload on the new most overloaded CNEC.

The most severely violated CNEC (CNEC$^{\alpha}$) is identified as expressed in (3):

$$CNEC^{\alpha} = min(RAM_{CNEC} - RAM^{*}_{CNEC}) = \Delta RAM_{Corner} \quad (3)$$

The correction key to correct the bilateral values is purely PTDF based in order to reflect the idea of correcting NTCs closer to the overloaded CNEC more than NTCs further away from the overloaded CNEC. The correction key is formed by the following set of equations (4):

$$\begin{cases} \sum_{\{i,j\} \in \ borders} PTDF_{CNEC_{ij}^{\alpha}} * \Delta NTC'_{ij} * Corner\ direction_{ij} = \ \Delta RAM_{Corner} \\ \frac{\Delta NTC'_{AB}}{PTDF_{CNEC^*,AB}} = \frac{\Delta NTC'_{AC}}{PTDF_{CNEC^*,AC}} \ldots \{A,B,C\} \in \ borders \end{cases} \quad (4)$$

where $\Delta NTC'$ is the reduction of NTC that should be calculated and forms the only unkown parameter in this set of equations (ΔRAM is the overload on the CNEC which you want to alleviate).

At this stage only positive PTDFs are taken into account to avoid that the corrections of the NTCs for this corner needs higher NTCs then the initial bilateral values due to its offloading effects. Thus only NTCs adding additional loading to the line will be reduced and NTCs offloading the line will not be increased. Note: This is not to be confused with verifying overloaded CNECs performed in the previous step during which the negative ptdf (thus offloading NTCs) are taken into account.

Consequently, the new NTC^*_{ij} would then be calculated as per (5):

$$NTC^*_{ij} = Bilateral\ NTC_{ij} - \Delta NTC'_{ij} \quad (5)$$

Pedagogic example

In the pedagogic example this is visible in Figure 25:

As the situation is not secured for the corner by using the values of the Bilateral NTCs, a NTC reduction proportional to the PTDFs should be performed focussed on the most severely violated CNEC.

	PTDFs for the different corners and CNECs filtering out negative values to not increase initial NTCs							
CNECs	**PTDF (A>B)**	**PTDF (B>A)**	**PTDF (A>C)**	**PTDF (C>A)**	**PTDF (D>B)**	**PTDF (B>D)**	**PTDF (D>C)**	**PTDF (C>D)**
CNEC1	0	0	0,18	0	0	0	0,09	0
CNEC2	0,27	0	0,05	0	0,13	0	0	0
CNEC3	0,12	0	0,27	0	0	0	0,05	0
NTC Reduction	**239,8492376**	**0**	**539,660785**	**0**	**0**	**0**	**99,9371823**	**0**

NTCs after Corners Selection	
NTC (A>B)	1982,372985
NTC (A>C)	6127,005882
NTC (D>B)	4615,384615
NTC (D>C)	13233,39615

Figure 25

The green row in this figure shows the corrections needed on the initial bilateral NTCs. For example the initial bilateral NTC A>B (which is 2222MW) needs to be reduced with 240MW.

The correction in this pedagogic example needs to work out the following equations for CNEC 3:

$$\begin{cases} \Delta RAM = (\Delta NTC_{AB} * PTDF_{AB}) + (\Delta NTC_{AC} * PTDF_{AC}) + (\cancel{\Delta NTC_{DB} * PTDF_{DB}} = 0) + (\Delta NTC_{DB} * PTDF_{DC}) \\ \dfrac{\Delta NTC_{AB}}{PTDF_{AB}} = \dfrac{\Delta NTC_{AC}}{PTDF_{AC}} \quad => \quad \Delta NTC_{AB} = \dfrac{\Delta NTC_{AC}}{PTDF_{AC}} * PTDF_{AB} \quad \rightarrow \mathbf{240}\boldsymbol{MW} \\ \dfrac{\Delta NTC_{DC}}{PTDF_{DC}} = \dfrac{\Delta NTC_{AC}}{PTDF_{AC}} \quad => \quad \Delta NTC_{DC} = \dfrac{\Delta NTC_{AC}}{PTDF_{AC}} * PTDF_{DC} \quad \rightarrow \mathbf{100}\boldsymbol{MW} \end{cases}$$

Substituting those ΔNTC_{AB} and ΔNTC_{DC} in the first equation gives:

$$\rightarrow \Delta RAM = (\frac{\Delta NTC_{AC}}{PTDF_{AC}} * PTDF_{AB} * PTDF_{AB}) + (\Delta NTC_{AC} * PTDF_{AC}) + (\frac{\Delta NTC_{AC}}{PTDF_{AC}} * PTDF_{DC} * PTDF_{DC})$$

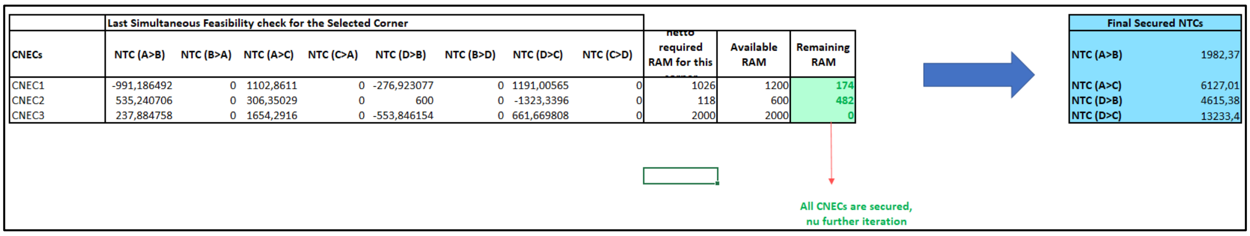
$$\rightarrow \Delta RAM = \Delta NTC_{AC} * (\frac{PTDF_{AB}^2}{PTDF_{AC}} + PTDF_{AC} + \frac{PTDF_{DC}^2}{PTDF_{AC}})$$

$$\rightarrow \Delta RAM = \frac{\Delta NTC_{AC}}{PTDF_{AC}} * (PTDF^2{}_{AB} + PTDF^2{}_{AC} + PTDF^2{}_{DC})$$

$$\rightarrow \Delta NTC_{AC} = \frac{\Delta RAM}{(PTDF^2{}_{AB} + PTDF^2{}_{AC} + PTDF^2{}_{DC})} * PTDF_{AC} \quad \rightarrow \mathbf{540}\boldsymbol{MW}$$

Having those required reductions on the initial bilateral NTCs, we obtain the new NTCs that will remove the overload on CNEC3. For example NTC A>B = 2222MW – 240MW = 1982MW.

After the new NTCs are obtained the combination of those new corrected NTCs is checked again if it would lead to overloads on CNEC based on formula (2) as visible in Figure 26 below:



	Last Simultaneous Feasibility check for the Selected Corner										
CNECs	NTC (A>B)	NTC (B>A)	NTC (A>C)	NTC (C>A)	NTC (D>B)	NTC (B>D)	NTC (D>C)	NTC (C>D)	netto required RAM for this corner	Available RAM	Remaining RAM
CNEC1	-991,186492	0	1102,8611	0	-276,923077	0	1191,00565	0	1026	1200	174
CNEC2	535,240706	0	306,35029	0	600	0	-1323,3396	0	118	600	482
CNEC3	237,884758	0	1654,2916	0	-553,846154	0	661,669808	0	2000	2000	0

Final Secured NTCs	
NTC (A>B)	1982,37
NTC (A>C)	6127,01
NTC (D>B)	4615,38
NTC (D>C)	13233,4

Figure 26

We see in this example that the new NTCs, after applying the correction key, does not lead any longer to an overload on CNEC 3 (as this was the only overloaded CNEC with the initial bilateral NTCs). Because there are no other CNEC overloaded, the correction step stops here in this pedagogic example.

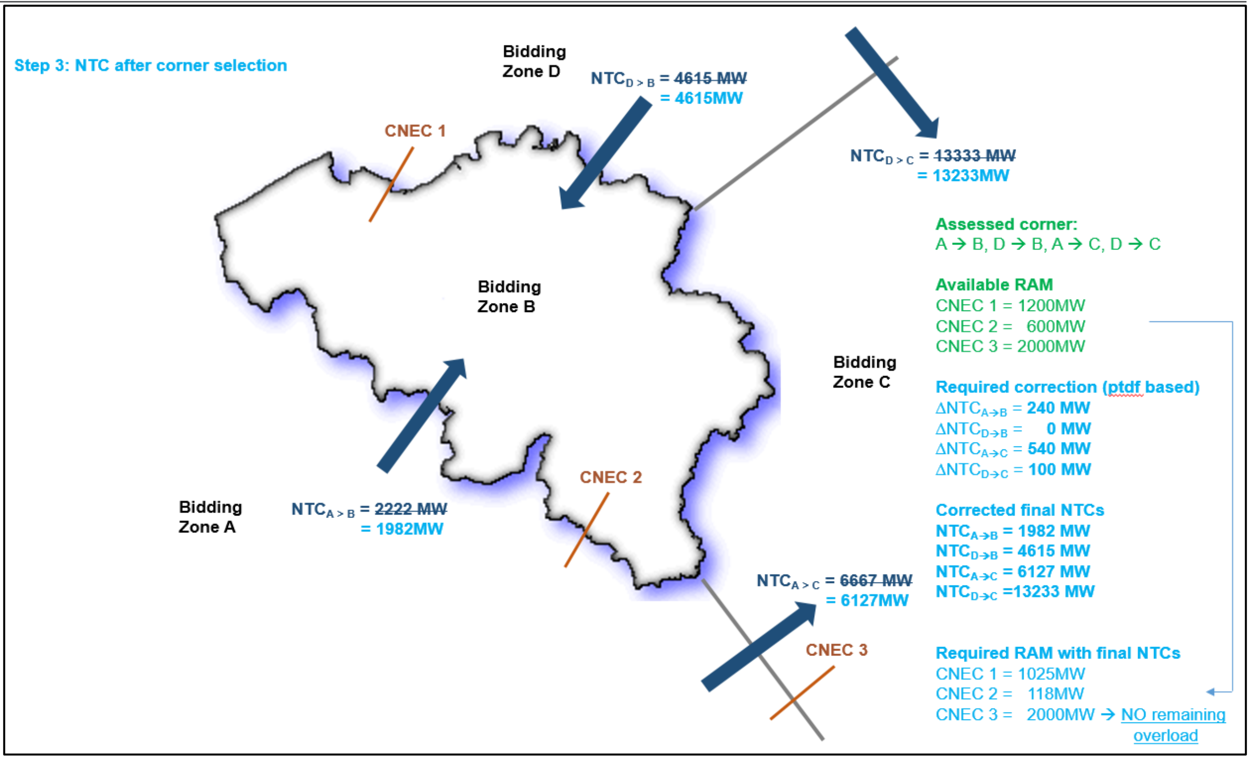


Figure 27: NTCs after corner selection (blue)

4.1.1.4 Validation of the NTCs simultaneous feasibility

Inputs

- set of NTCs per corner.

Description

Once the NTCs are calculated for all the selected corners, the lowest NTCs should be selected according to (6) :

$$NTC_{ij,final} = min_{ij}(NTC_{ij}^{*}) \qquad (6)$$

Note: In the exceptional case that an NTC is not part of one of the selected corners, the initial bilateral value will be given (i.e. it was considered unlikely to occur simultaneous with other NTCs as it was never part of a selected corner).

Pedagogic example

The simplified pedagogic example considered only one corner and therefore offering immediately the final values.

4.1.2 Bottom-Up Approach

The *scenario-based* capacity model proposed for the cNTC calculation in Core CCR for the LTCC is the so-called Bottom-Up approach. It is based on the consideration of the maximum allowed power flow on individual network elements that represent the network constraints to be fulfilled when calculating cNTC for the allocation of transmission capacities.

The principles by which the concept has been developed are:

- network security – The calculated figures must allow the Core TSOs to effectively limit cross-border power exchange such that the relevant network security criteria are fulfilled. Since the Core

TSOs are individually responsible for system security in their control areas, each Core TSO must have full control of the flow limits concerning its area;

- maximization of trade opportunities – Within the limits of network security and taking into consideration of Core TSOs experience and best practice in internal capacity calculation risks policies and chosen cNTC approach, the procedure shall allow for a high utilization of the grid infrastructure by the network users;
- transparency – The procedure shall be highly transparent both on methodology itself as well as on the input and the output side;
    - input: The data provided, and assumptions made by each Core TSO shall be transparent to all other Core TSOs;
    - output: The procedure shall allow identifying the bottlenecks limiting the cNTC values.

The concept allows for defining any network element, i.e. transmission line or transformer, as a potential CNE. From the viewpoint of a single Core TSO it is possible to consider both internal network elements – as long as they are contained in the underlying load flow model of sub-scenario – as well as interconnectors. In addition to that, the concept takes into account any set of pre- defined potential contingencies related to each considered CNE. The MF possible are then calculated for each critical network element in required N-X situations. Each single MF represents one network constraint to be fulfilled within coordination of NTC in Core CCR. However, Core TSOs are expected to be pragmatic and realistic in determination of CNECs valid for LTCC scenario(s) in order to avoid over-constraining of the problem.

Namely, if comparable capacity level (or even higher) is expected after introduction of the new Core cNTC as it is nowadays where each Core TSOs in principle individually calculate NTC on their borders, then the same/very similar level of risk in definition of CNECs for each LTCC scenario and the LTCC scenarios themselves, is necessary. Otherwise, the Core cNTC might be over-constrained, resulting with significantly lower resulting capacity level in comparison to the current process which is an indicationthat different risk is applied by the Core TSOs when NTCs are individually calculated nowadays.

This document assumes that definition of sub-scenarios i.e. LTCC scenario(s), list of relevant CNECs and GSK, is regulated to necessary extent and properly defined by the Core TSOs. Details of the Core TSOs' regulations in definition of the LTCC scenarios are out of scope of this document (for the time being) and are valid per-se for each methodology for cNTC calculation i.e. Bottom-Up approach as well.

The main features of the Bottom-Up approach are:

- objective and straightforward representation of grid constraints considering required security level defined in required N-X situations defined in LTCC scenarios and CNEC lists– due to the consideration of individual limits of network elements;
- independence of base case exchange assumptions in the underlying base case load flow model provided in the reference scenario i.e. all TSOs' seasonal scenario, because the approach is capable to consider that the most critical contingency related to a specific critical network element depends on the respective exchange scenario. This is achieved by taking into account all potential contingencies per critical network element. Thus, the actually most critical contigency is a result of the Bottom-Up approach;
- the results of MF-cNTC transparently indicate the network constraints limiting the amount of offered transmission capacities (critical network elements and respective contingencies);
- resulting coordinated cNTCa for each border between neighboring bidding zones are by default simultaneously feasible, respecting not the "worst case", but rather Core TSOs' best internal

operational practice and risk considerations in capacity calculation built in transparent Core cNTC CNEC selection rights and rules (see relevant chapter). Core cNTC CNEC selection rights and rules are jointly defined and applied in transparent way, assuring equal and non-discriminatory treatment of all TSOs in cNTC process.

RAM vector calculations start by determining the maximum flow. The RAM is obtained from the thermal limits of the CNECs by consideration of the base flow which is a flow in case of extracted exchanges existing in the reference CGM, the already allocated flow (valid for monthly computation run since there are already allocated capacity from the annual allocation process) and the flow uncertainties.

4.1.2.1 Core TSOs' experience and best practice in the Bottom-Up Approach

Core TSOs requested the following:

- Right No.1: Core TSOs are allowed, on a per-TSO basis, to define a (sub)set of their own CNECs within (sub)set of LTCC scenarios which are not to be considered relevant for calculation of MF-cNTC for particular exchange direction;
- Rule No.1: CNECs electrically "enough far away" (low sensitivity to particular exchange direction) from particular bidding zone border must not limit MF-cNTC for that exchange direction. This is a general rule applicable for all Core TSOs.

The Right No.1 is modelled with the following adaptation of RAM and PTDFs:

- for each CNEC provided by the TSO_i in the $LTCC - scenario_j$, PTDF values corresponding to particular $ExchangeDirection_{X\to Y}$ are to be set to zero making requested exchange direction insensitive to RAM value of that CNEC i.e.

$$PTDF^{X\to Y}_{CNEC_{TSO_i}, LTCC-scenario_{TSO_i,j}} \rightarrow 0$$

- setting the PTDF values to zero is not the only necessary adaption. RAM values for the CNECs provided by the TSO_i in the $LTCC - scenario_j$ are to be adjusted (i.e. increased) for the share of flows coming from the exchanges they are to be insensitive to.

$$RAM^{+/-}_{CNEC_{TSO_i}LTCC-,scenario_{TSO_i,j}} = \max(RAM^{+/-}_{CNEC,min}; ARS \cdot RAM_{CNEC,ini})$$

$$ARS = \frac{Remaining\ number\ of\ exchange\ directions\ with\ positive\ PTDF\ (after\ step\ 1)}{Initial\ number\ of\ exchange\ directions\ with\ positive\ PTDF}$$

Where

RAM_{ini}	Initial RAM on the CNEC of the LTCC scenario.
RAM_{min}	Minimum guaranteed capacity on each CNEC for particular cNTC LTCC round. This value is normally provided as relative value referent to the *MaximumFlow* (e.g. 20% of *MaximumFlow*)

ARS	Share of RAM on the CNEC(s) of the LTCC scenario(s) available for the rest of the contributing exchange directions after assurance of the RAM share for the *ExchangeDirections* of interest for the *TSOi*.
$RAM^{+/-}_{CNEC_{TSO_i,LTCC-scenario_{TSO_i},j}}$	Final value of the RAM for the CNEC(s) of the LTCC scenario(s) provided by the TSOi willing to exercise the Right No 1.

It is to be emphasized that equal treatment and no discrimination of any exchange direction as well as any of the CNECs in Core CCR is the key principle around which the bottom-up approach is built. Namely at the time of capacity calculation there is no information on the value of exchange direction hence each exchange direction has the same right to use network capacity. This in principle means that the only way how the share of the remaining available capacity per network element across the different contributing exchange direction can be defined is to assign equal shares i.e. if three exchange directions require the capacity of a CNEC (PTDFs are positive), then all three have equal rights to use the capacity of the CNEC, this approach is applied in right No.1[5].

The Right No.1 could be described mathematically as follows:

$$\left(\exists CNEC_{TSO_i,LTCC-scenario_{TSO_i},j} \wedge \exists\ ExchangeDirection_{X\to Y}\right)\Big|_{ExchangeDirection_{X\to Y}\neq f\left(CNEC_{TSO_i,LTCC-\ scenario_{TSO_i},j}\right)}$$

$$\Rightarrow (PTDF^{X\to Y}_{CNEC_{TSO_i,LTCC-scenario_{TSO_i},j}} \rightarrow 0 \wedge RAM^{+/-}_{CNEC_{TSO_i LTCC-,scenario_{TSO_i},j}}$$

$$= \max(RAM^{+/-}_{CNEC,min}; ARS \cdot RAM_{CNEC,ini})$$

In order to allow for better understanding of the Right No.1, the following example will help.

Let us assume there is CNEC1 and CNEC2 in LTCC scenario 1 of the Core TSO A willing to exercise the Right no 1 for the exchange directions A>B and A>D and not for other existing directions B>D, B>C and D>C. Initial RAMs on CNEC1 is 25 and CNEC2 +100MW, respectively. Beside these two CNECs there is also third CNEC, CNEC3, provided by the Core TSO B. Core TSO B does not want to exercise its Right No.1. (only positive RAMs are considered for simplification purposes, without decrease of generality of the example).

[5] One could define different waiting factor for each exchange direction each/group of CNECs, but that would require agreement on the approach which could be subject to further discussions and analyses. From the perspective of the methodology – that is just a parametrization.

	RAM+	A>B	A>D	B>D	B>C	D>C
S1,TSO A						
CNEC1	25	0,45	0,75	-0,12	-0,20	0,07
CNEC2	100	0,35	0,60	-0,15	0,09	0,06
S2,TSO B						
CNEC3	+45	0,25	0,11	0,56	0,35	0,67

Figure 28

After the step 1 of annulling the sensitivities the table of the constraints looks as follows:

	RAM+	A>B	A>D	B>D	B>C	D>C
S1,TSO A						
CNEC1	25	**0**	**0**	-0,12	-0,20	0,07
CNEC2	100	**0**	**0**	-0,15	0,09	0,06
S2,TSO B						
CNEC3	+45	0,25	0,11	0,56	0,35	0,67

Figure 29

In order to fully model application of the Right No1 Core TSO 1 exercises, the RAMs are to be adopted. Assuming that the minimum guaranteed capacity level of a CNEC is set to 35MW (just for the purpose of simplified computations), RAMs on the CNECs are as follows:

$$RAM_{CNEC1} = \max(25MW, 35MW) = 35MW$$
$$RAM_{CNEC2} = \max(100MW, 35MW) = 100MW$$
$$RAM_{CNEC3} = \max(45MW, 35MW) = 45MW$$

Relevant capacity level on the CNEC1 is 35MW (guaranteed min RAM value).

The ARS for the remaining relevant exchange directions, i.e. the exchange directions with positive PTDFs, on CNECs 1 and 2 are as follows:

$$ARS^{RAM+}_{CNEC1,TSO_A,rn1} = \frac{1}{3} = 0{,}667$$
$$ARS^{RAM+}_{CNEC2,TSO_A,rn1} = \frac{2}{4} = 0{,}5$$

Considering the minimum guaranteed capacity rule[6], the final RAMs on those two CNECs are as follows:

$$RAM^{+}_{CNEC1_{TSO_A,LTCC-scenario_{TSO_A,1}}} = \max(35MW; 0{,}667 \cdot 35MW) = 35MW$$
$$RAM^{+}_{CNEC2_{TSO_A,LTCC-scenario_{TSO_A,1}}} = \max(35MW; 0{,}5 \cdot 100MW) = 50MW$$

Set of security constraints, after consideration of the Right No 1 of the Core TSO A, finally looks like this:

	RAM+	A>B	A>D	B>D	B>C	D>C
S1,TSO A						
CNEC1	**25**	**0**	**0**	-0,12	-0,20	0,07
CNEC2	**50**	**0**	**0**	-0,15	0,09	0,06
S2,TSO B						
CNEC3	+45	0,25	0,11	0,56	0,35	0,67

Figure 30

CNEC1 and CNEC 2 provided in LTCC scenario 1 of Core TSO A will not affect exchange directions A>B and A>D as requested by the Core TSO A. However, we know that in practice, A>B, A>D really impact the CNEC1 and CNEC2 (see the first table) therefore RAM has to be adopted such that the new value indeed present available flow for the rest of the exchange direction assuming equal treatment of all directions and no discrimination in rights to use the share of RAM on each CNEC.

Important to note is that Core TSO A cannot request that CNECs of other TSOs should be insensitive on exchange direction A>B nor A>D. One can see that CNEC3, for instance, remains under impact of A>B therefore even though Core TSO A is saying “maximize A>B regardless of my CNEC” by exercising right no 1, A>B will still be constrained by other CNECs of other Core TSOs which are impacted by that exchange direction.

Also one could see that remaining available flow is calculated in very transparent way clearly elaborating on shares of capacity coming from different exchange directions, risks coming from calling for Right No 1.

Right No 1 is perfectly modelled and supported by the methodology transparently and non-discriminatory.

The second requirement, the Rule No 1, could be described mathematically as follows:

$$\left(\forall\exists\ CNEC_{LTCC_{-scenario_j}}\right)\ \left(\exists\ ExchangeDirection_{X\to Y}\rceil_{PTDF^{X\to Y}_{CNEC\ scenario_j}\le PTDF_{threshold}\approx 0}\right)$$
$$\Rightarrow PTDF^{X\to Y}_{CNEC\ scenario_j} \rightarrow 0$$

[6] The Bottom-Up Approach does consider this, but a value is not defined yet.

For each CNEC in each $LTCC\_scenario_j$, that are not really affected by particular exchange direction, i.e. CNEC is "enough electrically far away" form the exchange direction, PTDF values corresponding to particular $ExchangeDirection_{X \to Y}$ are to be set to zero. Benchmark for measuring fulfilment of the condition "enough electrically far away" is a PTDF threshold i.e.:

$$PTDF^{X \to Y}_{CNEC\,scenario_j} \leq PTDF_{threshold} \to PTDF^{X \to Y}_{CNEC\,scenario_j} \Rightarrow 0$$

Let us assume there is PTDF threshold 0,10. Starting from the initial situation as given in already known table, we have the following situation:

	RAM+	A>B	A>D	B>D	B>C	D>C
S1,TSO A						
CNEC1	25	0,45	0,75	-0,12	-0,20	0,07
CNEC2	100	0,35	0,60	-0,15	0,09	0,06
S2,TSO B						
CNEC3	+45	0,25	0,11	0,56	0,35	0,67

Figure 31

Set of security constraints, after consideration of the Rule No 1, finally looks like this:

	RAM+	A>B	A>D	B>D	B>C	D>C
S1,TSO A						
CNEC1	25	0,45	0,75	-0,12	-0,20	**0**
CNEC2	100	0,35	0,60	-0,15	**0**	**0**
S2,TSO B						
CNEC3	+45	0,25	0,11	0,56	0,35	0,67

Figure 32

Of course, both Right No. 1 and Rule No.1 can be simultaneously applied and in that case, the final set of constraints would look as follows:

	RAM+	A>B	A>D	B>D	B>C	D>C
S1,TSO A						
CNEC1	**35**	**0**	**0**	-0,12	-0,20	**0**
CNEC2	**50**	**0**	**0**	-0,15	**0**	**0**
S2,TSO B						
CNEC3	+45	0,25	0,11	0,56	0,35	0,67

Figure 33

4.1.2.2 Bottom-up approach calculation of cNTCs

The Bottom-Up approach is completed with calculation of NTCs taking into consideration the set of security constraints provided for each CNEC and each LTCC scenario taking into consideration the following steps:

- based on the remaining available margins and PTDFs calculated for all Core TSOs' CNEC for all LTCC scenarios considering above given filters, the cNTCs for all Core borders are calculated using the following approach:
    1. for each CNEC and each LTCC scenario, the remaining margin is equally shared between the Core internal borders that are positively influenced ➔ $\mathrm{MaxBEFactor}_i = \frac{RAM_{CNEC,scenario}}{N_{\mathrm{shares}}}$
    2. from those shares of margin, maximum bilateral exchanges are computed by dividing each share by the positive neighbouring bidding zone'as zone-to-zone PTDF ➔ $\mathrm{incrementalMaxBE_i} = \frac{\mathrm{MaxBE}Factor_i}{pPTDF_{z2z}}$
    3. the bilateral exchanges are updated by adding the minimum values obtained over all CNECs of all LTCC scenarios. ➔ $\mathrm{MaxBE} = \min(MaxBE = MaxBE + incrementalMaxBE)$
- this iteration continues until the maximum value over all CNECs considering all scenarios of the absolute difference between the margin obtained in two subsequent iterations is smaller than a stop criterion. The resulting values represent coordinated maximum bilateral NTC values for all Core internal bidding zone border – Core cNTC for LTCC.

Note: The Bottom-Up approach fully supports every other share of remaining margin. However, in order to change from equal share of RAM between the Core borders to some other share reflecting market value of direction, appropriate experimentation is needed. The Bottom-Ap approach starting point is an equal share of remaining RAM.

Calculation of final NTCs for all desired corners is described in corresponding chapter about likely corners. As additional information, the algorithm will provide the CNE(C)s with no remaining available margin left which are the limiting elements for particular computation round (yearly or monthly computations).

The computation of the cNTC in the Bottom-Up approach can be precisely described with the following pseudo-code:

While max(abs(margin(i+1) - margin(i))) >StopCriterioncNTC

For each CNEC

For each non-zero entry in pPTDF_z2z Matrix

$$\mathrm{MaxBEFactor}_i = \frac{RAM_{CNEC,scenario}}{N_{shares}}$$

$$\mathrm{incrementalMaxBE_i} = \frac{\mathrm{MaxBE}Factor_i}{pPTDF_{z2z}}$$

$$\mathrm{MaxBE} = \min(MaxBE = MaxBE + incrementalMaxBE)$$

End for

End for

For each BilateralExchange

MaxBE = min(MaxBE)

End for

For each CNEC

*RAM(i+1) = RAM(i) – pPTDF_z2z * MaxBE*

End for

End While
cNTCs = Integer(MaxBE)

Configurable parameters:

- StopCriterioncNTC (stop criterion); recommended value is 1.E-3;
- N_{Shares} (number of Core internal commercial borders).

In principle, the whole process could be summarized as follows: firstly, in the LTCC MF-cNTC process, similarly to the other CC processes, for each CNEC one is able to obtain RAM that is subsequently used for determining LT capacities. This RAM is known for each CNEC and therefore also for each LTCC scenario. After RAM for each CNEC is calculated, this RAM is equally divided over all contributing BZB, so when calculating the LTCC capacities for a particular BZB, one is able to use all CNEC but only to that extent allowed by the share of RAM assigned to that BZB. Utilization of RAM assigned to each BZB (for example, from RAM of 100MW, 10MW is assigned for the use of particular BZB) is assessed by the respective PTDF (for example, 10MW used with PTDF of 50% allows on particular border to exchange 20MW).

Due to the equal sharing of RAM over all BZB, it is quite likely that some BZB will not be able to fully use the RAM assigned for their disposal in all CNECs due to the fact, that the capacity of particular BZB will be constrained by other CNECs (generally, capacity will be determined by one particular CNEC, most likely the one with the highest PTDF-RAM impact). Hence, after the initial iteration where simultaneously feasible exchanges are determined, certain amount of RAM will remain unused. This unused RAM could be re-assigned for all BZB in next iteration starting from the point 2 so that the process of increasing all BZB could continue. The above will be an iterative process, until calculated RAM is less than the agreed threshold.

Result of this process is the set of simultaneously feasible cNTC (or cTTC, depending whether FRM on CNEC is considered or not) for each bilateral exchange directions between neighbouring bidding zone borders belonging to the particular market corner. In case the Core TSOs select n different market corners, the calculation steps are to be repeated for each of the market corner.

4.1.2.3 Bottom-up calculation of cNTCs – the final cNTC values

After obtaining a set of simultaneously feasible cNTC values for each of the selected market corners, determination of the final set of NTC values can be done by applying the lowest obtained value for the bilateral border exchange direction according all the values obtained for the exchange direction in all the market corner vectors. The example is given in Figure 34.

	cNTC(A>B)	cNTC(C>B)	cNTC(D>B)	cNTC(E>B)	cNTC(B>A)	cNTC(B>C)	cNTC(B>D)	cNTC(B>E)	Selected Likely Corners
simoultaneously feasible bilateral capacity	713	1347	478	478	∞	∞	∞	∞	←
simoultaneously feasible bilateral capacity	534	1326	886	∞	∞	∞	∞	605	←
simoultaneously feasible bilateral capacity	1069	1874	∞	728	∞	∞	501	∞	←
simoultaneously feasible bilateral capacity	1069	∞	478	478	∞	5782	∞	∞	
simoultaneously feasible bilateral capacity	∞	1010	478	364	633	∞	∞	∞	←
simoultaneously feasible bilateral capacity	713	1769	∞	∞	∞	∞	251	605	
simoultaneously feasible bilateral capacity	∞	∞	478	478	828	5109	∞	∞	
simoultaneously feasible bilateral capacity	2138	∞	∞	955	∞	5193	501	∞	
simoultaneously feasible bilateral capacity	∞	1347	591	∞	552	∞	∞	404	
simoultaneously feasible bilateral capacity	713	∞	886	∞	∞	5109	∞	605	
. . .									
simoultaneously feasible bilateral capacity	∞	∞	591	∞	552	3406	∞	404	
simoultaneously feasible bilateral capacity	∞	∞	∞	728	828	3895	251	∞	
simoultaneously feasible bilateral capacity	∞	∞	∞	∞	552	3406	167	404	
	min	min	min	min	…			min	
All corners	534	1010	478	364	552	3406	167	404	
Selected corners	534	1010	478	364	633	∞	501	605	←

All possible Corners

Figure 34: Selection of final NTC values

In the example provided in figure 34, out of all possible market corners only the four marked with the red arrows are selected as relevant for computation of the Final LTCC cNTC values: market corner 1 as full import to BZ B, market corner 2 as import to BZ B from BZs A, C and D but export from BZ B to BZ E etc. cNTCs obtained for each of the market corner are by definition simultaneously feasible.

All other vectors of simultaneously feasible combination of cNTCs obtained for other market corners even though presented in the table would not be obtained since they are not requested by the Core TSOs.

The final set of cNTC would be obtained by selecting the lowest value for each bordering bidding zone exchange direction taking into consideration only requested market corners – in this case the four red ones.

The values obtained in this case are surely not lower than the most conservative case where all cNTCs obtained for all bilateral bordering exchange direction are simultaneously feasible. The most conservative case can be used as a sort of reference case for the risk Core TSOs are taking when selecting subset of possible market corners for obtaining the final cNTCs.

Last but not least, in case where one or more bordering bilateral exchange directions are not members of any of selected market corners, Core TSOs could consider a default value to be offered to LT auctions. The default value could be any value but also the one obtained from the most conservative reference case allowing for minimization of the operational risks for the Core TSOs.

4.1.3 Reduction Periods

In accordance with article 31 of the FCA Regulation, the Core TSOs developed a proposal for the regional design of long-term transmission rights to be issued on each bidding zone border within the capacity calculation region. Article 7 of this long-term capacity calculation proposal foresees the application of Reduction Periods, which is defined as: *a period of time, i.e. specific calendar days and/or hours within the product period, in which Cross Zonal Capacities with a reduced amount of MW are offered, taking into account a foreseen specific network situation (e.g. planned maintenance, long-term* outages).

Where the product to be auctioned includes reduction periods, the auction specification shall include for each reduction period information on the duration of the reduction period and the amount of offered capacities.

Harmonised allocation rules (HAR) for long-term transmission rights developed in accordance with article 51 of the FCA Regulation also supports the use of reduction periods.

In accordance with article 48 of the FCA Regulation, all TSOs established Single Allocation Platform (SAP). The SAP requires that the SAP Operator shall receive the amount of long-term cross-zonal capacity to be offered in the respective auction directly from the TSOs or the coordinated capacity calculator where relevant. The SAP Operator shall publish the Offered Capacity including Reduction Periods (if applicable) in accordance with the HAR.

Other relevant HAR articles related to Reduction Periods, are:

- the standard form of the Auction product shall be a base product by which a fixed amount of MW throughout the Product Period is allocated subject to announced Reduction Periods;
- the Allocation Platform may announce one or more Reduction Periods in the Auction Specification. In this case, the Auction Specification shall include for each Reduction Period information on the duration of the Reduction Period and the amount of Offered Capacities;
- for the avoidance of doubt, Reduction Periods do not apply to already allocated Long Term Transmission Rights and shall not be considered for any purpose including compensation as a curtailment.

The application of reduction periods is legally possible for each individual hour, which ensures that a minimum amount of capacity will be reduced. However, from a LTCC perspective, this level of detail is very challenging indeed, because in that case all timestamps representing outages causing reduction need to be considered (see Article 10 of Scenarios).

In order for the Core TSOs to facilitate the long-term capacity calculation process, reduction hours are considered in default timestamps as follows:

- for the yearly NTC calculations, a weekly timestamp is chosen;
- for the monthly NTC calculation, a hourly timestamp is chosen.

As a result of this approach, capacities would be reduced for the whole respective period represented by timestamp. The results of the yearly calculation in monthly timestamps, is shown in Figure 35 below:

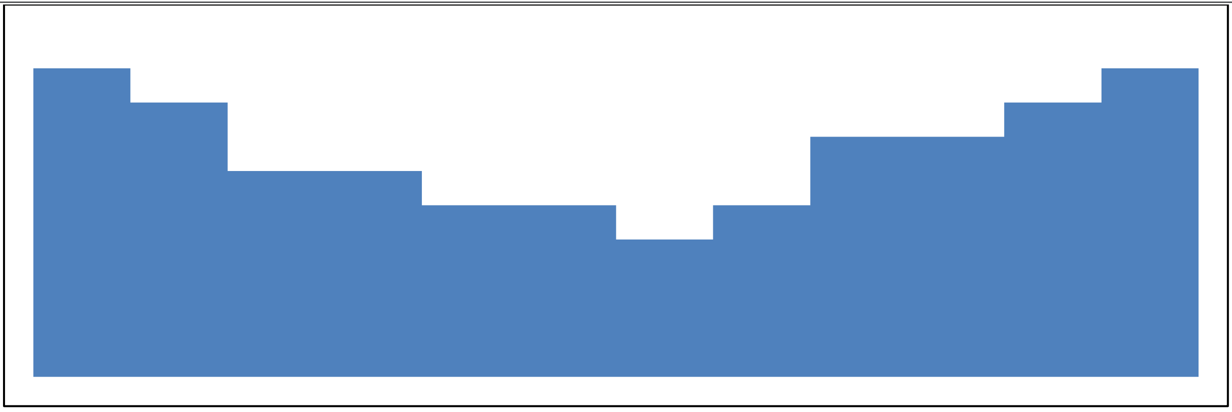


Figure 35

Analogue results can be imagined for monthly calculation, using weekly timestamps. Based on these results as a next step the coordinated NTCs for the respective yearly and monthly products need to be determined.

Given that the article 28 of the HAR states that base load with a *fixed amount* of MW is the basic form of any product, the Core TSOs need to determine fixed amount of NTC represented by the red line in Figure 36:

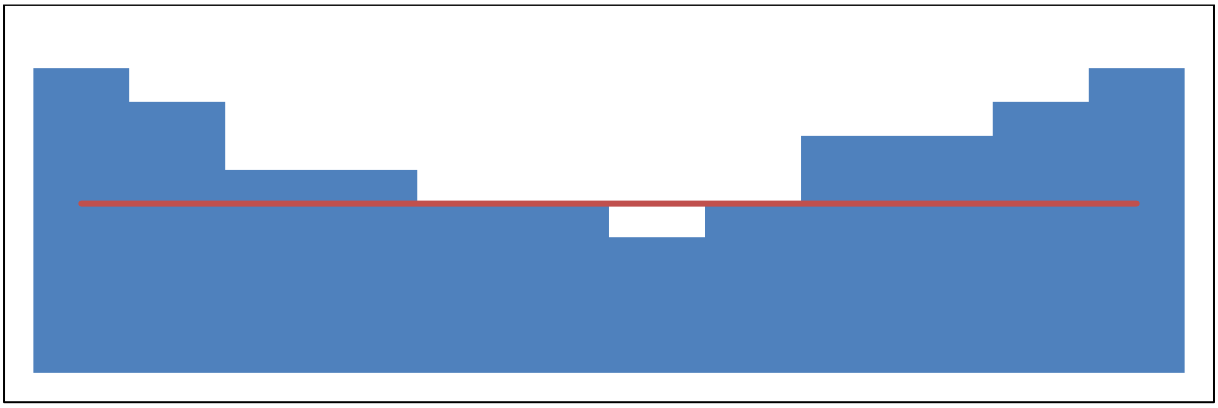


Figure 36

Core TSOs will finalize calculation results to meet the form of product regulated in the Regional LTTR design which includes possibility of introducing reduction periods. Core TSOs can apply reduction periods per BZB per direction in case the long-term capacity will be unduly reduced as can be seen in the figure above.

The final determination of reduction periods is dependent on the implementation of the split according to the LT Splitting Rules Methodology. This is illustrated by the following example:

Assuming the red line above is 100MW and the lowest capacity is 80MW. If apply splitting rule of 50%/ 50% yearly part would be 50MW for the whole month hence it is not necessary to apply a reduction period in this case.

4.2 Consideration of non-Core bidding zone borders

This section refers to Article 15 of the LT CCM Proposal.

Capacity calculation on non-Core borders is out of the scope of LT CCM. Based on approved methodologies from the relevant capacity calculation regions, JAO auctions the provided NTC capacities on Core to non-Core borders.

However, the impact of exchanges between CCRs physically exists and needs to be taken into account to ensure viable secure grid assessments, and this is done implicitly as is explained in the following lines.

As a basis or starting point for LTCC, the prepared scenarios (CGMs) include assumptions on the exchanges on non-Core bidding zone borders. During the capacity calculation process, these exchanges are untouched and remain fixed. This is done as this is in line and compatible with the DA CCM. The expected exchanges with the Core CCR are captured implicitly (in the RAM over all CNECs). The resulting uncertainties to the aforementioned assumptions are implicitly integrated within the reliability margin (see section 2.1 in this document). As such, these assumptions will impact the available margins of Core CNECs, and consequently NTCs. It must be noted that it is called implicit. An explicit integration would mean incorporating exchanges between Core and non-Core bidding zones in a dedicated, seperated calculation step, which is not the case.

At this stage, during the calculation step, relevant CNECs between Core and non-Core zones will be included in LTCC for the purpose of Core TSOs security of the NTC domain (exchanges within the Core CCR).

The Core TSOs work on a target solution, in close cooperation with the adjacent involved CCRs, that fully takes into account the influences of the adjecent CCR during the NTC calcuation process and therefore less reliance on Core TSOs assumptions on non-Core exchanges. The base for non-Core approach in LT CCM will be article 21.1.b) vii) of the CACM Regulation.

The proposal is that the Core LT CCM can update its method when the Core DA CCM fulfill article 13.4. of the DA CCM. It should be noted that the final DA CCM method is considered to be the target solution to explicitly model the exchange situations of adjacent CCRs within the Core flow-based domain which will be discussed with adjacent involved CCRs, according to article 17(4) of the DA CCM. How this would impact the LT CCM must be explored and decided upon when the DA target solition is finalized.

4.3 Fallback procedures

This section refers to Article 16 of the LT CCM Proposal.

In accordance with article 10(7) of the FCA Regulation, referring to article 21(3) of CACM Regulation, a fallback procedure needs to be in place in case the initial capacity calculation does not lead to any results. First of all the Core TSOs would like to emphasise that the long-term capacity calculation process is not under such time pressure as the day-ahead capacity calculation process. This means that the Core TSOs have some leeway to deal with any issue that could delay the calculation process. Hence, the fallback procedure will only be applied in case of force majeur situations. It must be mentioned that the Core TSOs implemented measures to avoid force majeur situations:

- redundant input data process, including replacement strategies in case input data is missing because of IT-problems of any party;
- back up IT-systems at the Core CCC and Core TSOs' side;
- back up between Core CCC’s IT-facilities.

In case of force majeur situations, the Core TSOs will firstly, together with JAO, to the extend possible for JAO, postpone the relevant yearly or monthly auction for which the Core TSOs can not provide coordinated NTCs. In this situation, the Core TSOs and JAO will agree on a new deadline for the submission of the coordinated NTCs.

Secondly, in case the postponement of the auction is not possible, or the new deadline has been reached, the Core TSOs foresees the following fallback process:

For the yearly process

The Core TSOs will use the coordinated yearly values of the previous year as a starting point. Then the Core TSOs will first bilaterally validate these NTC values (this could imply that a cNTC will be lower due to different foreseen topology situations); in a second step these values will be discussed and agreed upon in a Core TSOs coordination meeting (this also qualifies as validation according to article 15 of the FCA Regulation) the latter ensures that also the fallback NTCs are coordinated, even in a force majeure situation.

For the montly process

The first step for the monthly calculations, is that the Core TSOs will use and bilaterally agree on the remaining capacity of the yearly process for that month (meaning the remaining capacity above the red line of a particular month). The red line is explained in the section of scenarios.
In case that the first step will result in low capacity or zero, then Core TSOs will use the coordinated monthly values of the previous year of that month, as a starting point for a bilateral discussion. This is the same process as described in the yearly process. Low capacity is described as capacity lower then the coordinated monthly values of the previous year of that month.

5 UPDATES AND PUBLICATION

5.1 Review and Updates

This section refers to Article 17 of the LT CCM.

The Core TSOs foresee to review and update the necessary parameters in conjunction with the same process as for the DA CCM.

5.2 Publication of Data

This section refers to Article 18 of the LT CCM.

The Core TSOs foresee to publish the information as described in Article 18(2). This enhances transparency for market parties and also facilitates the Core NRAs need for monitoring compliance.

5.3 Monitoring and Information to Regulatory Authorities

This section refers to Article 19 of the LT CCM.

The Core TSOs consider that the transparency framework as provided in this section on reporting in general to the Core NRAs, provides all necessary information to the Core NRAs enabling them to monitor compliance with this LT CCM and other relevant legislation.

The Core TSOs foresee to send the information regarding the names of CNECs, the CNE EIC codes and Contingency EIC codes, the import/export limits and the final TRM value per BZB per direction to the Core NRAs for the purpose of monitoring compliance.

6 IMPLEMENTATION

6.1 Timescale for implementation of the Core Long term capacity calculation methodology

This section refers to Article 20 of the LT CCM Proposal.

In accordance with article 10ff. of the FCA Regulation, the Core TSOs are working on the implementation of the LT CCM.

The Core TSOs propose to finalize the implementation of the LT CCM ultimately 18 months after approval by either the Core NRAs or by ACER.

The implementation phase covers:

- finalising the hardware at the Core CCC:
  i. to facilate IT-tools;
  ii. to create redundancy within the Core CCC;
  iii. to create redundancy at the Core CCC (fall-back).
- finalising the software at the Core CCC:
  i. to create interface with the ENTSO-E OPC Database;
  ii. to create redundancy within the Core CCC;
  iii. to create redundancy at the Core CCC (fallback).

APPENDIX 1 - Methods for GSKs per bidding zone

The following section depicts in detail the method currently used by each Core TSO to design and implement GSKs.

Austria:
APG's method only considers market driven power plants in the GSK file which was done with statistical analysis of the market behaviour of the power plants. This means that only pump storages and thermal units are considered. Power plants which generate base load (river power plants) are not considered. Only river plants with daily water storage are also taken into account in the GSK file. The list of relevant power plants is updated regularly in order to consider maintenance or outages.

Belgium:

Elia will use in its GSK flexible and controllable production units which are available inside the Elia grid (they can be running or not). Units unavailable due to outage or maintenance are not included.

The GSK is tuned in such a way that for high levels of import into the Belgian bidding zone all units are, at the same time, either at 0 MW or at Pmin (including a margin for reserves) depending on whether the units have to run or not (specifically for instance for delivery of primary or secondary reserves). For high levels of export from the Belgian bidding zone all units are at Pmax (including a margin for reserves) at the same time.
After producing the GSK, Elia will adjust production levels in all datasets to match the linearised level of production to the exchange programs of the reference day

Croatia:
HOPS will use in its GSK all flexible and controllable production units which are available inside the HOPS' grid (mostly hydro units). Units unavailable due to outage and maintenance are not included, but units that aren't currently running are included in GSK. In addition also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). All mentioned nodes are considered in shifting the net position in a proportional way.

Czech Republic:
The Czech GSK considers all production units which are available inside CEPS´s grid and were foreseen to be in operation. Units planned for the maintenance and nuclear units are not included in the GSK file. The units inside the GSK will follow the change of the Czech net position proportionally to the share of their production. In other words, if one unit represents n% of the total generation on the Czech bidding zone, n% of the shift of the Czech net position will be attributed to this unit.
The current approach of creation GSKs is regularly analysed and can be adapted to reflect situation in CEPS´s grid.

France:
The French GSK is composed of all the flexible and controllable production units connected to RTE's network in the D-2 CGM.
The variation of the generation pattern inside the GSK is the following: all the units which are in operation in the D-2 CGM will follow the change of the French net position based on the share of their productions

in the D-2 CGM. In other words, if one unit represents n% of the total generation on the French bidding zone in the D-2 CGM, n% of the shift of the French net position will be attributed to this unit.

Germany:
The four German TSOs provide one single GSK for the whole German bidding zone. Since the structure of the generation differs for each German TSO, an approach has been developed, which allows the single TSO to provide GSKs that respect the specific character of the generation in their own grid while ultimately yielding a comprehensive single German GSK.

In a first step, each German TSO creates a TSO-specific GSK with respect to its own control area based on its local expertise. The TSO-specific GSK denotes how a change of the net position in the forecasted market clearing point of the respective TSO's control area is distributed among the nodes of this area. This means that the nodal factors of each TSO-specific GSK sum up to 1. Details of the creation of the TSO-specific GSKs are given below per TSO.

In a second step, the four TSO-specific GSK are combined into a single German GSK by assigning relative weights to each TSO-specific GSK. These weights reflect the distribution of the total market driven generation among German TSOs. The weights sums up to 1 as well.

With this method, the knowledge and experience of each German TSO can be brought into the process to obtain a representative GSK. As a result, the nodes in the GSK are distributed over whole Germany in a realistic way, and the individual factors per node are relatively small.

Both the TSO-specific GSKs and the TSOs' weights are time variant and updated on a regular basis. Clustering of time periods (e.g. peak hours, off-peak hours, week days, weekend days) may be applied for transparency and efficiency reasons.

Individual distribution per German TSO:

50Hertz:
The GSK for the control area of 50Hertz is based on a regular statistical assessment of the behaviour of the generation park for various market clearing points. In addition to the information on generator availability, the interdependence with fundamental data such as date and time, season, wind infeed etc. is taken into account. Based on these, the GSK for every MTU is created.

Amprion:
Amprion established a regular process in order to keep the GSK as close as possible to the reality. In this process Amprion checks for example whether there are new power plants in the grid or whether there is a block out of service. According to these monthly changes in the grid Amprion updates its GSK.
If needed Amprion adapts the GSK in meantime during the month.

In general Amprion only considers middle and peak load power plants as GSK relevant. With other words base load power plants like nuclear and lignite power plants are excluded to be a GSK relevant node.
From this it follows that Amprion only takes the following types of power plants: hard coal, gas and hydro power plants. In the view of Amprion only these types of power plants are taking part of changes in the production.

TenneT Germany:
Similar to Amprion, TTG considers middle and peak load power plants as potential candidates for the GSK. This includes the following type of production units: coal, gas, oil and hydro. Nuclear power plants are excluded upfront.

In order to determine the TTG GSK, a statistical analysis on the behaviour of the non-nuclear power plants in the TTG control area has been made with the target to characterize the units. Only those power plants, which are characterized as market-driven, are put in the GSK. This list is updated regularly.

TransnetBW:
To determine relevant generation units, TransnetBW takes into account the power plant availability and the most recent available information from the independent power producer at the time when the individual GSK-file needs to be created.

The GSK for every considered generation node i is determined as:

$$\mathrm{GSKi} = \frac{\mathrm{Pmax,i - Pmin,i}}{\sum_{i=1}^{n} \quad (\mathrm{Pmax,i - Pmin,i})}$$

Where n is the number of power plants, which are considered for the generation shift within TransnetBW's control area.
Only those power plants which are characterized to be market-driven, are used in the GSK if their availability for the MTU is known.

Hungary:
MAVIR uses general GSK file listing all possible nodes to be considered in shifting the net position in a proportional way, i.e. in the ratio of the actual generation at the respective nodes. All dispatchable units, including actually not running ones connected to the transmission grid are represented in the list. Furthermore, as the Hungarian power system has generally considerable import, not only big generation units directly connected to the transmission grid are represented, but small, dispersed ones connected to lower voltage levels as well. Therefore, all 120 kV nodes being modelled in the IGM are also listed representing this kind of generation in a proportional way, too. Ratio of generation connected to the transmission grid and to lower voltage levels is set to 50-50% at present.

Netherlands:
TenneT TSO B.V. will dispatch controllable generators in such a way as to avoid extensive and not realistic under- and overloading of the units for foreseen extreme import or export scenarios. Unavailability due to outages are considered in the GSK. Also the GSK is directly adjusted in case of new power plants.
All GSK units (including available GSK units with no production in de D2CF file) are redispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit in order to prevent unfeasible production levels.

The maximum production level is the contribution of the unit in a foreseen extreme maximum production scenario. The minimum production level is the contribution of the unit in a foreseen extreme minimum production scenario. Base-load units will have a smaller difference between their maximum and minimum production levels than start-stop units.
TenneT TSO B.V. will continue fine-tuning their GSK within the methodology shown above.

Poland:

PSE present in GSK file all dispatchable units which are foreseen to be in operation in day of operation. Units planned for the maintenance are not included on the list. The list is created for each hour. The units inside the GSK will follow the change of the Polish net position proportionally to the share of their production in the D-2 CGM. In other words, if one unit represents n% of the dispatchable generation on the Polish bidding zone in the D-2 CGM, n% of the shift of the Polish net position will be attributed to this unit.

Romania:
The Transelectrica GSK file contains flexible and controllable units which are available in the scenario. The units planned for maintenance and nuclear units are not included in the list. The fixed participation factors of GSK are impacted by the generation present in the IGM.

Slovak Republic:
In GSK file of SEPS are given all dispatchable units which are in operation in respective time frame which the list is created for. The units planned for maintenance and nuclear units are not included in the list. In addition also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). All mentioned nodes to be considered in shifting the net position in a proportional way.

Slovenia:
GSK file of ELES consists of all the generation nodes specifying those generators that are likely to contribute to the shift. Nuclear units are not included in the list. In addition also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). At the moment GSK file is designed according to the participation factors, which are the result of statistical assessment of the behaviour of the generation units infeeds.

APPENDIX 2 - Methods for Remedial Actions per bidding zone

For the time being, the following Core TSOs foresee to use the aforementioned remedial actions in order to optimise the calculation and allocation of long-term cross-zonal capacity in accordance with article 3.b of the FCA Regulation: APG, ELES, Elia, RTE, TTG and TTN.