Explanatory note for Channel TSOs proposal of common capacity calculation methodology for the long-term market timeframe in accordance with Article 10 of Commission Regulation (EU) 2019/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

January 21st, 2020

Disclaimer

This explanatory document is submitted by all TSOs of the Channel Region to all NRAs of the Channel Region for information and clarification purposes only accompanying the proposal for common capacity calculation methodology for the long-term market timeframe in accordance with Article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016.

Contents

1 Introduction

1.1 Purpose of the document

Article 10 (1) of the FCA Regulation requires the LT CC Methodology to be submitted within six months following the approval of the common coordinated capacity calculation methodology in the Channel CCR referred to in Article 9 (7) of the CACM Regulation (hereinafter referred to as the “Channel Day-Ahead and Intraday Capacity Calculation Methodology”). The TSOs of the Channel CCR being unable to reach consensus on the LT CC Methodology by the due date, they informed the national regulatory authorities of the Channel CCR and the Agency for the Cooperation of Energy Regulators (hereinafter referred to as “the Agency”) on 23 May 2019 and provided the relevant documentation and information in compliance with Article 4 (4) of the FCA Regulation. Following information to the European Commission by the Agency, the former provided some guidance which resulted in the TSOs of the Channel CCR being able to reach an agreement on the main principles of the LT CC Methodology. The TSOs of the Channel CCR were requested by the European Commission to draft the LT CC Methodology based on these main principles under an agreed timetable. This document provides further explanation on the concepts and different inputs used for long term (LT) capacity calculation for the Channel CCR. Where deemed necessary, the document explains differences in the proposed LT CC Methodology between the different TSOs of the Channel CCR.

The following topics are out of scope of this document:

- Channel Day-Ahead and Intraday Capacity Calculation Methodology.
- Splitting rules of LT cross-zonal capacity.
- Allocation of cross-zonal capacity in LT timeframe.
- Any compensation payable to an interconnector in the event that its capacity is restricted. Bilateral agreement will be put in place between System Operators (“SO”) and Interconnectors (“IC”).

1.2 Explanation of the main choices of the proposed methodology

The Channel Capacity Calculation Region consists of the following bidding zone borders:

- France – Great Britain (FR-GB);
- Netherlands – Great Britain (NL-GB); and
- Belgium – Great Britain (BE-GB).

Figure 1 provides the lay-out of the Channel CCR bidding zone borders:

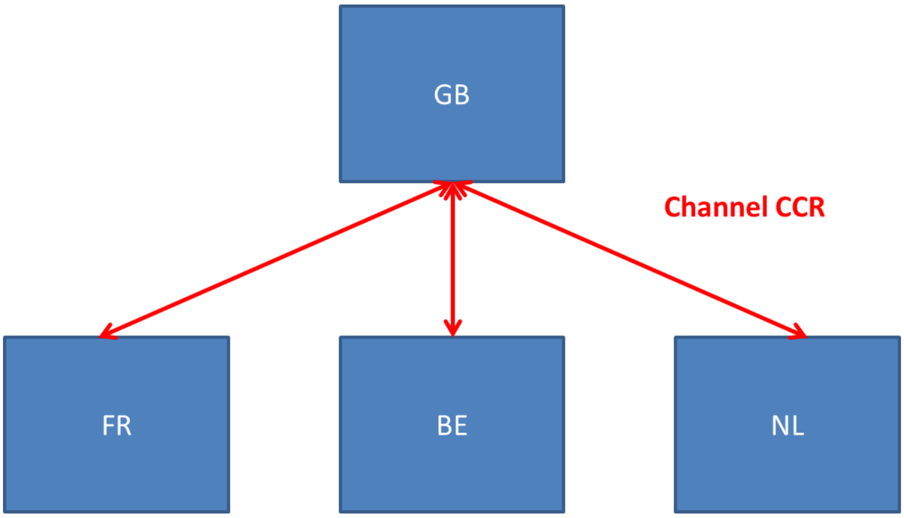

Figure 1: Lay-out of the Channel CCR bidding zone borders

The LT CC Methodology needs to define cross-zonal capacities for the different HVDC interconnectors between Great-Britain and the continent. The Long-Term capacity calculation for the BE-FR and BE-NL bidding zones borders is to take place in the Core CCR, as decided by ACER in its decision 06/2016.

The Great-Britain and Continental European grids belong to different synchronous areas (i.e. having different frequencies). All bidding zone borders in the Channel CCR consist of controllable HVDC interconnectors. From technical point of view each of the HVDC interconnectors in the Channel CCR can be controlled in an independent way.

According to Article 2 of the FCA Regulation, forward capacity allocation means "*the attribution of long-term cross-zonal capacity through an auction before the day-ahead time frame*". Also, Article 9 of the FCA Regulation states that "*all TSOs in each capacity calculation region shall ensure that long-term cross-zonal capacity is calculated for each forward capacity allocation and at least on annual and monthly time frames*". The proposed LT CC Methodology in the Channel CCR will perform calculations for the annual and monthly timeframes for the associated cross-zonal capacities allocations. Capacity allocation for eventual other long-term timeframes will use the results of the most recent available calculations. For example the allocation of seasonal and quarterly products is based on the results of the annual capacity calculation and the allocation of weekly and weekend products is based on the results of the monthly capacity calculation.

According to Article 10.4 of the FCA Regulation, the LT CC Methodology shall be based whether on a security analysis using multiple scenarios or on a statistical analysis of historical data in which the former is the default approach and the latter only allowed under certain conditions. Furthermore, in accordance with Article 10.2 and 10.5 of the FCA Regulation, the LT CC Methodology shall apply a Coordinated Net Transmission Capacity (CNTC) approach or a flow-based approach in which the former is the default approach and the latter only allowed under certain strict conditions.

Taking into account the above default approaches, the nature of the Channel CCR (where cross-zonal capacity is less interdependent) and the requirement set out in Article 10.3 of the FCA Regulation to be compatible with the Channel Day-Ahead and Intraday Capacity Calculation Methodology, the proposed LT CC Methodology will be a CNTC approach based on security analysis of different scenarios with the exception of the first calculation that will take place in February before the delivery year and will be performed under a statistical-based approach instead.

The Channel CCR consists of HVDC interconnectors that can be operated in an independent way. The proposed LT CC Methodology provides that ultimately the maximum permanent technical capacity (MPTC) of the interconnectors is given to the market, except during the periods with a planned outage on the interconnector cables or in case of a planned outage of a critical network element with significant impact on the interconnector in one of the bidding zones to which that interconnector is connected.

The reason for this is that, under normal operating conditions and without planned outages of a critical network element with significant impact on the interconnector, the grid is considered sufficiently strong to accommodate the full MPTC of the interconnectors. The MPTC is the maximum permanent technical capacity which is the maximum continuous active power which a cross-zonal network element (interconnector/HVDC system) is capable of transmitting.

1.3 Planning for implementation

The implementation will be prepared by interactions with TSOs and coordinated capacity calculator(s) ("CCCs").

The first step will aim at defining the IT requirements based on the high level business process and requirements resulting from the proposed methodologies and developed by the TSOs. This shall cover identification of formats, AS IS model, TO BE model, performance... IT development shall then follow.

In parallel with the IT development, TSOs shall organize trial runs, where possible failure can be detected and feedback from end-user will lead to improvements. The trial run is expected to start not sooner than Q1-2021 and will continue until the go-live.

The capacity calculation process is expected to go-live no later than 12 months after the go-live of Channel Day-Ahead and Intraday Capacity Calculation.

This schedule is based on the following assumptions:

a. Channel TSOs submission of the LT CC Methodology by 21st January 2020;

b. Channel NRA approval of the LT CC Methodology by 21 July 2020;

2 LT CC Methodology under a statistical based approach

The first year-ahead cross-zonal capacities are to be made available before the end of February of the preceding year. Following the unavailability of the input data for a scenario based CNTC approach following SO GL Regulation before this deadline, the first year-ahead cross-zonal capacities are subject to a statistical capacity calculation and associated validation conditions capped at 35% of the IC transmission capacity (MPTC).

FCA Art.10(4)(b) demonstration

As outlined in Art.3 of the proposal, the LT CC Methodology for the Channel CCR is composed partly of a statistical calculation. Following Article 10(4)(b) of the FCA Regulation the usage of a statistical capacity calculation in the methodology needs to be justified. Channel TSOs believe that the requirements stipulated under Article 10(4)(b) are demonstrated as follows:

<u>FCA Article 10(4)(b)(i) “increase the efficiency of the capacity calculation methodology”</u>

The LT CC Methodology wants to release a first part of the annual cross-zonal capacity (to be allocated to the market in the form of long term auctions, subject to Article 16 of the FCA Regulation) by the end of February of the preceding year. The input data required for a scenario based approach, such as the definitions of the seasonal scenarios in accordance with Article 19 of the FCA regulation and the associated common grid models in accordance with Article 18 of the FCA regulation, are not available before the end of February of the preceding year following the deadlines stipulated in the SO GL Regulation in conjunction with the Common Grid Model Methodology 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*). Following the unavailability of the input data for a scenario based approach the Channel TSOs believe that it is more efficient to apply a statistical capacity calculation for the first year-ahead cross-zonal capacities.

<u>FCA Article 10(4)(b)(ii) “better take into account the uncertainties in long-term cross-zonal capacity calculation than the security analysis in accordance with paragraph 4(a) [a security analysis based on multiple scenarios]”</u>

As mentioned above, computing cross-zonal capacity before the end of February of the preceding year has no access to coordinated and common scenarios and hence to the load and generation patterns (of TSOs out of the Channel CCR). Aside the uncertainty of the load and generation patterns, many onshore TSOs have no knowledge yet concerning the unavailability plans of grid elements (according to Articles 97 and 99 of the SO GL Regulation, preliminary year-ahead availability plans are available as from 1 November and final year-ahead availability plans as from 1 December). Therefore Channel TSOs believe that a statistical calculation takes into account better the uncertainties for this part of the LT CC Methodology.

<u>FCA Article 10(4)(b)(iii) “increase economic efficiency with the same level of system security.”</u>

By releasing a first part of the annual cross-zonal capacity by the end of February of the preceding year, way earlier than possible under a scenario based approach, Channel TSOs believe that this promotes long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants. Following a maximum setting of 35% of the interconnectors MPTC under the statistical part of the methodology as outlined under Article 5 of the Proposal in conjunction with the possibility to perform individual grid security analysis as outlined under Article 6 of the Proposal, Channel TSOs believe that the same level of system security is maintained.

STATISTICAL ASSESSMENT

This methodology recognises the implicit agreement between onshore and interconnector TSOs that 35% of Channel interconnector capacity will be released for Long Term capacity products in February of the year before delivery, except for identified exceptional circumstances. The emphasis in this methodology therefore minimises the required effort of a more complex statistical methodology, as the desired output is already understood, and the purpose is to expose those times when a 35% allocation may not be appropriate, based on historical data.

Therefore the CCC shall calculate the cross-zonal capacity for each interconnector and direction on a bidding zone border as follow:

1. Obtain the last 2 years' worth of Day Ahead NTC data per interconnector and per direction (including zero values and times of interconnector outage)
2. Take the average of those NTC values
3. Apply a 50% threshold to this average value
4. Where the resulting number is above 35% of the interconnector MPTC, a cap at 35% of the interconnector capacity is applied. Where the resulting number is below 35% of the interconnector MPTC, the relevant <35% is applied.
5. The value calculated in step 4 is subject to validation.

The main advantage of this methodology is that it is very simple to apply, and takes into account the raw historical data, which needs no further manipulation such as:

- Removing LTA inclusion
- Removing the impact of Intraday as a remedial Action (NGESO)
- Removing the impact of counter-trading

The broad assumption in this methodology is the application of a 50% threshold generically takes account of the above without the necessity of complex manipulation of the historical data set. In addition, it takes into account the margin reflecting the difference between historical cross-zonal capacity values and forecasted long-term cross-zonal capacity values as required by Article 23(1)(c) of the FCA Regulation.

VALIDATION

1. Channel TSOs have the responsibility to validate the capacities proposed by the CCC and may locally re-assess the computed NTCs per bidding zone or interconnector.
2. If the result of the calculation gives a lower value than 35 percent of the MPTC, Channel Onshore TSOs have the right to increase the outcome of the calculation up to 35 percent of the MPTC.

3. Channel Onshore TSOs may reduce the 35 percent value or the value coming from Article 5 due to planned outages. The reduction shall be incorporated in the yearly product as reduction periods. The level of reduction shall be duly justified thanks to a scenario-based analysis and presented to the concerned TSOs.

4. If several interconnectors influence similar CNECs in the same control area, any reductions on these interconnectors shall be done proportionally to their influence on the limiting CNECs.

3 LT CC Methodology under a scenario-based approach

3.1 High level process

On a high level the Long-Term cross-zonal capacity calculation process can be described by the following flow chart:

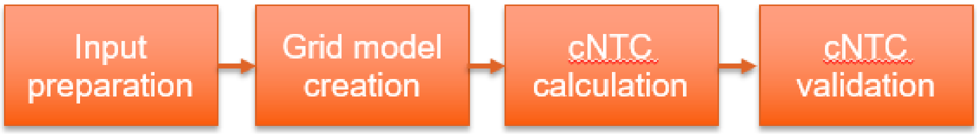

Figure 2: high level long-term cross-zonal capacity calculation process

The Coordinated Capacity Calculator (CCC) shall calculate the cross-zonal capacity for each interconnector on a bidding zone border for each selected timestamp of the annual or monthly timeframe using the coordinated net transmission capacity approach. This calculation process is composed of the following 4 steps: input gathering, grid model creation, calculation and validation. After validation of the resulting capacities by TSOs for each timestamp, the final NTCs are submitted to the TSOs for allocations.

3.2 Timestamp selection

The LT CC Methodology for the Channel CCR considers that under normal operating conditions and without planned outages of a Critical Network Element with significant impact on the interconnector, the grid is sufficiently strong to accommodate the full MPTC of the interconnectors. Therefore the long-term cross-zonal capacities will be computed only in respect of the periods with a planned outage of a Critical Network Element with significant impact on the interconnector. The outage planning of the Critical Network Elements listed before is available through the Outage Planning Coordination (OPC) database (see further in $2.3.5 *Scenarios and planned outages*). Based on this database, the timestamp selection will use the outage planning of the Critical Network Elements of the Channel CCR (see further in $2.3.1 *Definition of a Critical Network Element and a Contingency*) as follows:

i. One timestamp will be selected per granularity of the concerned period. This granularity is fixed in advance and is the following:

   a. 1 month for the annual cNTC calculation

   b. 1 week for the monthly cNTC calculation

ii. The selected timestamp is the day with the largest simultaneous number of planned outages within the granularity.

iii. In case two or more timestamps take place within the same scenario and contain the same planned outages, those redundant timestamps will be ignored. In case the granularity does not contain any planned outages, no timestamp will be selected. Instead, a second timestamp within another granularity can be selected.

iv. As the timestamp selection is mainly driven by the number of simultaneous planned outages and not by the impact of the outages, the TSO may request ad hoc extra timestamps.

v. Particularity for the annual timestamps selection:

a. for the first annual scenario based calculation:

As some months of the year may have no planned outages (i.e. no planned outages within the granularity), no timestamps will be selected for those months. Therefore an alternative timestamp (i.e. second or more) within another month with more than one planned outage can be selected. The maximum number of timestamps to be selected is 12 at this stage as the delivery of the results is time sensitive (before end of September Y-1).

b. For the second annual scenario based (re)calculation (which is optional):

The aim is to reuse the calculation results of the 1st scenario based calculation. Planned outages within the granularity for which no timestamp was selected, the value of the other outage within the granularity (for which the timestamp was selected) is used. If this value is deemed to be unrepresentative for this outage, the value of a representative outage that is already calculated for another granularity is taken (e.g. outage of a parallel line during the month before,….). Only when deemed necessary and in exceptional cases a new timestamp and calculation on this new timestamp will be performed.

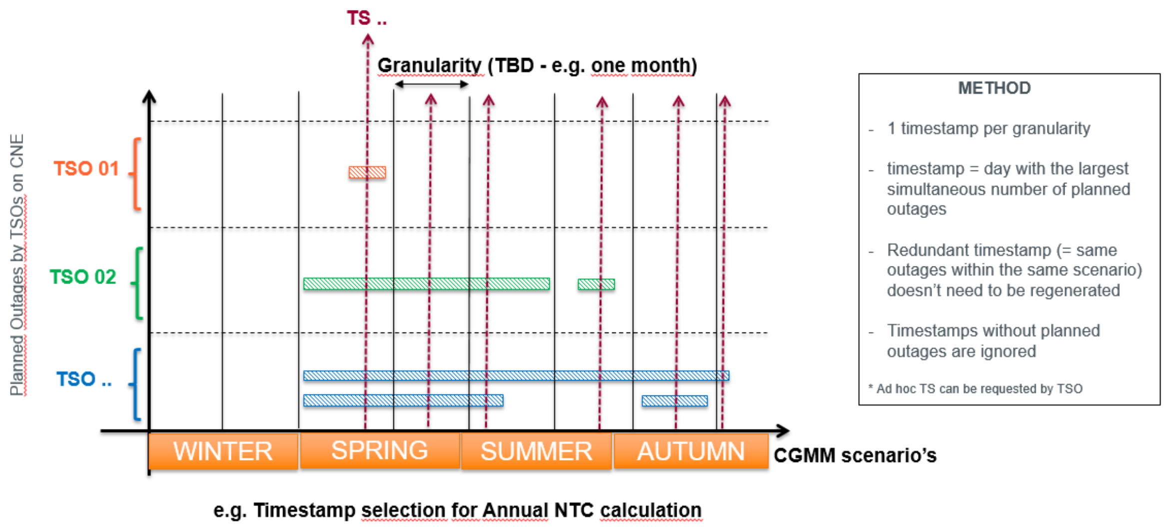

Figure 3: selection of timestamps

Timing & validation

The timestamp selection, which is based on the outage planning of the CNE in the Channel CCR, is proposed by the CCC to the TSOs sufficiently in advance of the relevant calculation, i.e. on D-10 for the first annual calculation and D-5 for the monthly calculation (with "D" being the starting day of the calculation by the CCC). The individual TSOs can send their request for ad-hoc timestamps at the latest on D-5 for the first annual calculation and on D-2 for the monthly calculation.

The timings mentioned are a starting assumption and need to be validated during a parallel run.

3.3 Step 1: Inputs gathering phase

The following input data is required to generate the grid models for each timestamp selected:

- Critical Network Elements (CNEs) and Contingency (Cs);
- Flow Reliability Margin (FRM);
- Maximum admissible current on a Critical Network Element (Imax) / Maximum allowable power flow (Fmax);
- Remedial Actions (RAs);
- Generation Shift Key (GSK);
- Maximum Permanent Technical Capacity of the HVDC interconnectors (MPTC); and
- Ad hoc timestamp.

3.3.1 Definition of a Critical Network Element and a Contingency (CNEC)

A Critical Network Element (CNE) is a network element, significantly impacted by Channel cross-zonal flows, which can be monitored under certain operational conditions, the so-called Contingencies. The CNECs (Critical Network Element and Contingencies) are determined by each onshore TSO of the Channel CCR for its own network according to agreed rules, described below.

The CNECs are defined by:

- A CNE: a line or a transformer that is significantly impacted by cross-zonal flows;
- An “operational situation”: normal (N) or contingency cases (N-1, N-2, busbar faults; depending on the TSO risk policies).

A contingency can be:

- Trip of a line, interconnector or transformer;
- Trip of a busbar;
- Trip of a generating unit;
- Trip of a (significant) load;
- Trip of several elements.

The combination of a CNE and a C is referred to as a CNEC.

Given that all interconnectors in the Channel CCR are HVDC links, considering their ability to control the flow to a fixed value, these interconnectors shall not be monitored as Critical Network Elements, but are considered as Contingencies.

The CNEC selection criteria will be based on cross-zonal flow sensitivity thresholds. These cross-zonal flow sensitivity thresholds determine the maximum CNEC list, but TSOs have the possibility to discard elements from the list, based on operational studies or operational experience.

Explanation of the cross-zonal sensitivity thresholds:

The cross-zonal flow sensitivity is a crucial criterion for selecting relevant CNECs. The significantly influenced CNECs shall be defined on the basis of a minimum sensitivity from any cross zonal flow in the Channel CCR above a certain threshold.

This sensitivity criterion corresponds to the maximum of the following bidding zone to bidding zone power transfer distribution factor (PTDF) absolute value:

i. Great Britain to France;

ii. Great Britain to Belgium;

iii. Great Britain to The Netherlands.

TSOs want to point out the fact that the identification of this threshold is driven by three objectives:

- Need for an objective and quantifiable notion of “significant impact”;
- Guaranteeing security of supply by allowing as much exchange as possible, in compliance with TSOs’ risks policies, which are binding and have to be respected. In other words, this value is a direct consequence of Channel TSOs’ risk policies standards; and
- Striving for consistency with the other calculation timeframes (i.e. day-ahead and intraday timeframes in the Channel CCR).

The TSOs of the Channel CCR will implement the CNEC selection principles as defined in the Channel Day-Ahead and Intraday Capacity Calculation Methodology.

For the Channel CCR the cross-zonal flow sensitivity of a CNE to an exchange over one of the bidding zone borders of the Channel CCR expresses the MW flow impact of such exchange over the CNE;

- E.g. a sensitivity of X% on a CNE for exchanges over the IFA interconnector implies that an exchange of 100 MW over IFA will result in an additional flow of X MW on the CNE.

This is equivalent to saying that the maximum “zone to zone” PTDF of a given grid element should be at least equal to X% for it to be considered objectively “critical”.

For each CNEC the following sensitivity value is calculated:

Sensitivity = max(Zone to slack PTDFs) - min(Zone to slack PTDFs)

If the sensitivity is above the threshold value of X%, then the CNEC is said to be significantly impacted by Channel trades.

For the Channel CCR, the cross-zonal sensitivity relates to exchanges over the Channel CCR bidding zone borders.

Thus, to find the influence on any grid constraint from any cross border exchange, we may trace the route between the two bidding zones by PTDFs. For example if we would like to find the influence on a Critical Network Element "n" by a cross-zonal trade from zone "A" to zone "B", we can calculate:

The influence of cross border trade from zone "A=Great Britain" to zone "B=Continental Europe” (the Netherlands, Belgium or France) on constraint "n".

PTDF A-B (n) = PTDF A(n) – PTDF B(n).

The PTDF of zone "A" on constraint "n"

The PTDF of zone "B" on constraint "n"

Generally, we would like to find the largest between any bidding zones (A,B) on each grid constraint "n" and evaluate if this is above chosen threshold. This might be found directly by calculating:

Max PTDF A-B (n) = Max PTDF A,B (n) – Min PTDF A,B (n).

If this value is below the threshold X%, the CNEC is considered as not significantly influenced by the changes in bidding zone net positions.

3.3.2 Flow Reliability Margin

Article 11 of the FCA Regulation requires a methodology for reliability margin (hereafter referred to as "RM") to be included in the LT CC Methodology. This RM methodology shall meet the requirements set out in Article 22 of the CACM Regulation.

Article 2 (14) of the CACM Regulation defines the reliability margin as the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation.

Flow Reliability Margin (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 Remedial Actions.

The uncertainties covered by the FRM values are among others:

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

b) Generation pattern including specific wind and solar generation forecast;

c) Generation Shift Key;

d) Load forecast;

e) Topology forecast;

f) Unintentional flow deviation due to the operation of load frequency controls.

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 realised power flows in real time, and a RM calculation based on this probability distribution.

For Long-Term 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).

The LT CC Methodology considers that the additional uncertainties between Long-Term and Day-Ahead timeframes are covered by the selected scenarios, therefore Long-Term capacity calculations will use the same FRM as the one applied in the Day-Ahead timeframe.

The RM methodology shall remain consistent with the RM methodology developed in the Channel Day-Ahead and Intraday Capacity Calculation Methodology.

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.

2.2.4 Operational security limits on the Critical Network Elements

According to article 12 of the FCA Regulation the proposal for a common LT CC Methodology 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.

Maximum admissible current on a Critical Network Element (I_{max})

The maximum admissible current (I_{max}) is the physical limit of a CNE determined by each TSO in line with its operational security policy. I_{max} is defined as a permanent physical (thermal) current limit of the CNE. As the thermal limit and protection setting can vary in function of weather conditions, I_{max} is usually fixed (at least) per season. Each individual TSO is responsible for deciding which value should be used. No dynamic rating will be used in Channel for Long-Term capacity calculations due to absence of the required forecast parameters.

Maximum allowable power flow (F_{max})

The value F_{max} describes the maximum allowable power flow on a CNEC in MW. F_{max} will be calculated using reference voltages.

F_{max} is calculated from I_{max} by the given formula:

$$F_{max} = \sqrt{3} \cdot I_{max} \cdot U \cdot \cos(\varphi)$$

where I_{max} is the maximum permanent allowable current in kA of a Critical Network Element(CNE). The values for cos(ϕ) and the reference voltage U (in kV) are fixed values for all CNE of one synchronous area. For continental Europe TSOs, in line with current practises, the cos(ϕ) will be 1 and reference voltage U will be 225 kV and 400 kV.

Specificities of TSOs

National electricity transmission system of Great Britain operational security limits

The operational security limits for the national electricity transmission system of Great Britain are outlined within the NETS Security and Quality of Supply Standard (SQSS). This document outlines the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits.

These operational security limits are the same as those used in operational security analysis.

Since NGESO is applying a zero FRM, any monitored CNEC in GB can be monitored using operational security limits in I_{max}, therefore NGESO shall not be required to provide corresponding F_{max} limits. Hence NGESO shall not define a conversion formula to convert I_{max} to F_{max}

RTE, TTN and ELIA as TSOs of the CE synchronous area

The LT CC Methodology should maintain consistency with the neighbouring CCRs in this respect and these TSOs who are also active in neighbouring CCRs shall apply the operational security limits identical to those in the neighbouring CCRs. Therefore,

3.3.3 Generation shift keys

The Generation Shift Key (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.

In case generating units are injecting electricity in lower voltage layer which are not contained in the CGM, TSOs can attribute factors on consumption.

Every 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.

A GSK aims to deliver the best forecast of the impact on Critical Network Elements of a net position change, taking into account the operational feasibility of the reference production program, projected market impact on generation units and market/system risk assessment.

In general, the GSK includes power plants that are market driven and that are flexible in changing the electrical power output. TSOs can also use fewer flexible units, e.g. nuclear units, if they do not have sufficient flexible generation for matching maximum import or export program or if they want to moderate impact of flexible units. Since the generation pattern (locations) is unique for each TSO and the range of the shift in net position is also different, there is no unique formula for all TSOs of the Channel CCR for creation of the GSK. Finally, the resulted change of bidding zone balance should reflect the appropriate power flow change on CNECs and should be relevant to the real situation.

The GSK values can vary and are given in dimensionless units. For instance, a value of 0.05 for one unit means that 5 % of the change of the net position of the bidding zone will be realized by this unit. Technically, the GSK values are allocated to units in the Common Grid Model. 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 can be allocated to one or more aggregated generation units of the CGM in order to model its technical impact on the transmission system.

Justification on why GSKs can be different for different TSOs

Each bidding zone has its specificities in terms of market and systems: the pattern and type of market players are not the same in each market area and the design of the network is also not the same. As GSKs intend to represent at best the market behaviour in a specific area, it is of importance to take into consideration these specificities of each area. As a consequence, it is hard to impose the same principles and rules everywhere.

Additionally, technical limitation on the tools need to be taken into account too when designing the GSKs in an area. And as, for a question of transparency, the TSOs of the Channel CCR intend to use the same GSK definition for an area which may be involved in different regions, these technical limitations have to consider the tools used not only in the Channel CCR, but also in other CCRs like CORE. The real Pmin/Pmax of the units cannot be taken into account when adjusting the net position of an area using the GSKs. Moreover, in order to ensure convexity, GSKs need to be linear and the same for an increase or a decrease of the net position. Both technical limitations have a strong influence on the way the design/definition of the GSKs may impact the loading of the system, especially in bidding zone where the number of market driven units is low.

Then, for each area, considering these technical limitations, there is a need to find the best compromise between representing at best the expected market behaviour while respecting the limits and specificities of the network. We can notice that the Belgian and Dutch TSOs, which have similar size of grid and number of market driven units, have similar approach in their definition of the GSKs, aiming at avoiding unrealistic loading of grid equipment that would be the case with a pure pro-rata approach while for the French TSO, considering the higher size of system and number of market driven units, a pure pro-rata approach is sufficient.

Specificities of the TSOs

Great Britain GSK:

For the Long-Term timeframes, the Britain GSK shall represent the best forecast of the relation of a change in net position of the bidding zone to a specific change of generation or load in the Common Grid Model.

French GSK:

The French GSK is composed of all the units connected to RTE’s network. The variation of the generation pattern inside the GSK is the following: all the units which are in operations in the base case will follow the change of the French net position on a pro-rata basis. That means, if for instance one unit is representing n% of the total generation on the French grid, n% of the shift of the French net position will be attributed to this unit. This choice of the proportional GSK is mainly related to the fact that generation in France is composed at 75% by nuclear power that does not vary following a merit order. Indeed the French electricity market being a portfolio market, the merit order is not geographically relevant. Thus a proportional representation of the generation variation, based on RTE's best estimate of the initial generation profile, ensure the best modelling of the French market.

Belgian GSK:

The Belgian TSO will use in its GSK a fixed list of nodes based on the locations where most relevant flexible and controllable production units (market oriented generating units) are connected. This list will be determined in order to limit as much as possible the impact of model limitations on the loading of the CNEs. The variation of the generation pattern inside the GSK is the following: the variation of the generation pattern inside the GSK shall be such that the sum of the generation which are in operations on each of these nodes in the CGM will follow the change of the Belgian net position in such a way that the generation at the node will reach its maximum when the maximum generation capability of the Belgian bidding zone is reached and will reach its minimum when the minimum generation capability of the Belgian bidding zone is reached.

Dutch GSK:

The Dutch GSK will dispatch the main generators in a manner which avoids extensive and unrealistic under- and overloading of the units for extreme import or export scenarios. The GSK is directly adjusted in case of new power plants. Also unavailability of generators due to outages are considered in the GSK.

All GSK units are re-dispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit. The total production level remains the same.

The maximum production level is the contribution of the unit in a predefined extreme maximum production scenario. The minimum production level is the contribution of the unit in a predefined extreme minimum production scenario. Base-load units will have a smaller difference between their maximum and minimum production levels than start-stop units.

3.3.4 Remedial Actions

Article 14 of the FCA Regulation provides to the TSOs of the Channel CCR the possibility to use Remedial Actions (RA) in the LT CC Methodology.

During Coordinated Capacity Calculation, TSOs take Remedial Actions into account to maximize as much as possible the allowed exchanges over the bidding zone borders of the CCR while ensuring a secure power system operation, i.e. N-1/N-k criterion fulfilment.

Remedial Actions used in capacity calculation embrace the following measures:

- changing the tap position of a phase shifter transformer (PST)
- topology measure: opening or closing of a line, interconnector, transformer, bus bar coupler.

The effect of these RAs on the CNEs is directly determined in the calculation process to monitor the shift of load flow in the synchronous area.

There are several types of RAs, differentiated by the way they are used in the capacity calculation.

- Preventive (pre-fault) and curative (post-fault) RAs: Preventive RAs are applied before any fault occurs, and thus to all CNECs of the domain, curative RAs are only used after a fault occurred. As such the latter RAs are only applied to those CNECs associated with this contingency. Curative RAs allow for a temporary overload of grid elements and reduce the load below the permanent threshold.

• Shared and non-shared RAs: Each TSO can define whether he wants to share the RA provided for capacity calculation or not. In case a RA is shared, it can be applied to increase the remaining available margin on all relevant CNECs. If it is non-shared a TSO can determine the CNECs for which the RA can be applied in the capacity calculation.

Each TSO defines the available RAs in its responsibility area according to his operational principles and ensures the availability of the measure until real-time.

Each TSO shall ensure all relevant available non costly Remedial Actions are made available to the coordinated capacity calculator. Each TSO of the Channel CCR may decide to make available costly Remedial Actions.

In accordance to Article 25(6) of the CACM Regulation, the Long-Term capacity calculation will consider the same RAs used for the DA capacity calculation, taking into account their technical availability.

At the end of the calculation of cross zonal capacity, where a Remedial Action is assumed to be used to increase the cross zonal capacity, the coordinated capacity calculator shall inform the respective TSO. The decision to instruct any Remedial Action remains with each TSO.

In case a RA made available for the capacity calculation is also a RA which may be used during capacity calculation in another CCR, the TSO owning the RA shall take care when defining the RA to ensure consistent, non-contradicting, use in his potential application in both CCR to ensure a secure power system operation.

Specificities of the TSOs Belgian RA:

For ELIA, the application of BE PSTs shall be considered as RA in both Core and Channel CCRs. In order to ensure consistent use in both CCRs, ELIA may restrict the range of application of each PST depending on the loading of the Belgian CNEs in the base cases.

3.3.5 Scenarios and planned outages

Scenarios

In accordance with Article 19 of the FCA Regulation, the TSOs of the Channel CCR shall jointly develop a common set of scenarios to be used in the Common Grid Model for each long-term capacity calculation timeframe. This applies for the situation where security analysis based on multiple scenarios pursuant to Article 10 of the FCA Regulation is applied, which is also the case for the Channel CCR.

Article 2.4 of the CACM Regulation defines scenario as t*he forecasted status of the power system for a given time-frame* and hence reflects a specific representative predicted grid state (expected grid topology, generation and load pattern, net position. etc …) for a certain period of time.

The definition of the scenarios and the methodology to determine its key values are part of the Common Grid Model Methodology ("CGMM"). The CGMM developed in accordance with 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*).

As a security analysis based on multiple scenarios is applied in the Channel region for the long-term capacity calculation, the common grid model ("CGM") for long-term capacity calculation time frames shall be established on the basis of this CGMM pursuant Article 18(2) of the FCA regulation. As there is no reason to change the key values, the LT CC Methodology for the Channel CCR proposes to take over the scenarios and associated grid models containing the key values as established by the CGMM without any modifications. Following the CGMM, the description of these scenarios is available ultimately on 15 July each year; the accompanying CGMs are available ultimately on 15 September each year.

The scenarios for each year have the following structure:

Figure 4: seasonal Entso-E scenarios

As the figure shows, the current CGMM proposal defines the key values for the creation of 4 scenarios of non-overlapping time periods: WINTER, SPRING, SUMMER and AUTUMN. For each season a scenario is created for peak and valley, hence resulting in 8 final scenarios for each year.

The related year-ahead seasonal scenarios used for annual cNTC calculation may be updated for monthly cNTC calculation by incorporating the latest available information regarding the generation pattern. TSOs should require a scenario update for any predictable change compared to the year-ahead seasonal scenarios in accordance with Articles 3(2) and 3(3) of CGMM as part of the FCA Regulation, which is associated with a specific measure concerning the grid topology respectively generation pattern. If this is the case, the TSOs may update:

- the generation pattern,
- the topology due to grid element commissioning or decommissioning,

in its own Individual Grid Model (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 CCC updates the merged CGM by replacing the initial IGM with the newly updated single TSOs' IGM in accordance with the agreed timing.

Outages

As described above, the key values of the scenarios as part of the CGMM are among others the expected grid topology, load, net position, generation pattern, PST tap position but NOT the planned outages. The LT CC Methodology for the Channel CCR proposes to take into account the planned outages of the onshore TSOs (and not of the interconnector TSOs) in Article 14.

All ENTSO-E RG CE TSOs’ planned outages are stored and regularly updated in Outage Planning Coordination (OPC) database. According to SO GL, preliminary year-ahead availability plans, i.e. planned outages of TSOs, are available in OPC database as from 1 November for the next year, and final year-ahead availability plans as from 1 December.

According to the OPC process time schedule, first quality check of preliminary availability plans regarding tie-line inconsistencies is performed by RSCs and accordingly, availability plans are corrected by TSOs by 4 November.

3.4 Step 2: Grid Models

For each selected timestamp, the LT CC Methodology for the Channel CCR proposes to generate a common grid model pursuant to Article 18 of the FCA Regulation using the scenarios and associated grid models as established by the CGMM without any modifications of the key values but adding the planned outages of the onshore TSOs on the relevant CNEs foreseen for these timestamps as available in the OPC database. This process is done by the CCC.

The grid models delivered by the CGMM have the aim to be congestion free but this is not guaranteed. The outage of the Critical Network Element combined with the eventual topological changes will lead to different loading of the elements compared to the loading of those elements in seasonal grid models. Therefore a quality check will take place to verify that the selected timestamps do not contain overloaded CNECs. In case the timestamp is not congestion free the TSO will take appropriate actions to ensure that the grid models become congestion free.

Timing & validation

The description of the scenarios is available by the CGMM ultimately on 15 July each year; the accompanying CGMs are available ultimately on 15 September each year. The individual TSOs do not need to confirm their agreement on the key values of these scenarios as the use of the CGMM for the determination of the key values of the scenarios is the main concept of this LT CC Methodology for the Channel CCR.

By D-5 for the annual calculation & D-2 for the monthly calculation, the CCC has received all required input and can start the creation of the CGM for each timestamp based on the seasonal grid models from the CGMM (with “D” being the start day of the calculation by the CCC).

The timings mentioned are a starting assumption and need to be validated during a parallel run.

3.5 Step 3: Calculation methodology

For each selected timestamp a Common Grid Model is available containing the seasonal scenario and the planned outages of the relevant CNEs. For each timestamp the cross-zonal capacities in the Channel CCR will be assessed using a coordinated NTC approach.

3.5.1 Mathematical description

In theory the coordinated NTC approach should aim at assessing the maximum transfer of power in each direction of each of the bidding zone borders of the CCR that will be possible to reach simultaneously without endangering the security of the system.

This maximum power transfer is called Total Transfer Capacity. When each of the bidding zone border is composed of HVDC links, no Transfer Reliability Margin needs to be considered for these links and the Net Transfer Capacity is equal to the Total Transfer Capacity.

For the Channel CCR, the assessment will consider the maximum secure value of simultaneous import and export of the synchronous grid of Continental over all the interconnectors of the Channel CCR bidding zone borders for each timestamp that has been selected (further called ‘market direction’).

Practically, in the Channel CCR, the assessment of this maximum secure value of the interconnector capacity will be done through a calculation, using the common grid model as reference and considering the MPTC of each interconnector (in the direction of the synchronous grid of Continental Europe towards Great-Britain and vice versa) as a starting position.

This approach will evaluate at each step of the assessment the ability to cope with the operational security limits expressed by the Imax/Fmax on each CNEC taking into account an optimal use of the available Remedial Actions in the defined market direction. A Remedial Action Optimizer (RAO) will be used which has as objective function to increase margins until a positive value is reached on all CNECs.

If case of no negative margin on a CNE in a bidding zone at this timestamp, the maximum secure value of the interconnector capacity will be made available for both market directions for that timestamp.

If case of no negative margin on a CNE in all the bidding zones at this timestamp, the maximum secure value of the interconnector capacity will be made available on all interconnectors and no calculation will be needed for that timestamp.

If no available Remedial Actions can be found to fulfil the operational security limit of a CNEC in one market direction in one bidding zone, the assessment will be repeated with a reduced maximum secure value of the interconnector capacity (in respect of the interconnectors linked to this bidding zone) until a level of the maximum secure value of the interconnector capacity has been identified for which no CNE violations occur.

The assessment will be stopped when operational security limits are respected on all CNECs.

3.5.2 Remedial Action optimization

Article 14 of the FCA Regulation provides the TSOs of the Channel CCR with the possibility to use Remedial Actions in the LT CC Methodology.

In accordance to Article 25(6) of the CACM Regulation, the Long-Term capacity calculation will consider the same RAs as used for the DA capacity calculation, taking into account their technical availability, to deal with both internal and cross-zonal congestion in order to facilitate more efficient capacity allocation and to avoid unnecessary curtailments of cross-zonal capacities.

The coordinated capacity calculator shall maximise cross-zonal capacity using the list of available Remedial Actions given by the TSOs within the capacity calculation process.

To achieve this optimization in the calculation process, the coordinated capacity calculator will use a Remedial Action Optimizer (RAO).

RAO tool:

The Remedial Action Optimizer (RAO) tool determines the optimal Remedial Actions (RAs) from a defined objective function. More precisely, the goals of the optimizer are twofold:

- Secure the reference network situations; and
- Determine the optimal Remedial Actions from a defined objective function.

In particular, the objective function of RAO tool for the Channel CCR is to increase margins of all CNEC until a positive value is reached for all CNECs.

High level process flow of optimisation process is as followed:

Figure 5. High level process flow of optimisation process.

Depending on the base case (Common Grid Model) and contingencies, different preventive Remedial Actions can be used during the capacity calculation: it could be a change of taps of a PST on a given range, or a change of state (open / close) of a circuit breaker.

In addition, the remedial actions optimizer (RAO) will take into account 'remedial action usage rules' in the process, i.e. in which case a remedial action can be used.

The 'remedial action usage rules' will be defined upfront by TSOs. Concretely, for each Remedial Action (RA) within its grid, each TSO indicates in its input data for which kind of cases this RA can be used. For instance:

- to solve congestion only on a specific Critical Network Element;
- to solve congestion on any Critical Network Elements being part of its Control Area.

Determining the preventive and curative RAs

The inputs of the RA optimisation process are the following data:

- Common grid model: containing the seasonal scenario with the planned outages for this timestamp;

- List of Critical Network elements and Contingencies;

- List of Remedial Actions available per TSO.

The outputs of the optimisation process are the optimal Remedial Actions set for the considered timestamp and the computed cross-zonal capacity:

- Preventive Remedial Actions;

- If relevant, Curative Remedial Actions after each Contingency ("C");

- Cross-zonal capacity on the HVDC interconnectors before LTA or AAC inclusion.

The RAO algorithm explores solutions through a sequential approach made of the following subproblems: 1. Preventive problem for all CNECs; 2. Curative problem for every Contingency.

On both preventive and curative steps, the available Remedial Actions are tested. The objective function selects the most efficient ones, which are then implemented. RAs are tested and implemented through iterations within a search tree by simulating all the implemented contingencies for preventive RAs. Once the preventive optimization is finished, the set of preventive actions is fixed and implemented as starting point for all curative optimizations. For curative RAs, approach is different, and is made contingency per contingency.

Algorithm keeps applying RA until one of the following conditions is fulfilled:

In preventive:

- All preventive Remedial Actions have been tested;

- At a certain step of optimization, no preventive Remedial Actions improve the objective function.
In curative:

- The maximum number of curative actions have been reached;

- At a certain step of optimization, no curative actions improve the objective function.

The output of the RAO is a coordinated set of preventive RAs linked to each Contingency.

3.5.3 Implementation of reduction of the interconnector capacity

In case of a negative margin on CNECs which cannot be solved with available Remedial actions, the maximum secure value of the interconnector capacity will have to be reduced.

The reduction of the maximum secure value of the interconnector capacity will only concern the bidding zone where the limiting CNECs are located.

In case several interconnectors are located in the concerned bidding zone, the reduction shall be applied only to the interconnectors which have an influence on the limiting CNE above the thresholds defined in Article 8 of the LT CC Methodology and proportionally to their influence.

This is illustrated by the below example, where the capacity over the interconnectors must be reduced in order to resolve an overload on CNEC X. In this particular case the capacity reduction over HVDC1 will be twice the reduction of capacity on HVDC2 since the impact of an exchange of HVDC1 on CNEC X is twice the impact of an exchange of HVDC2 over CNEC X.

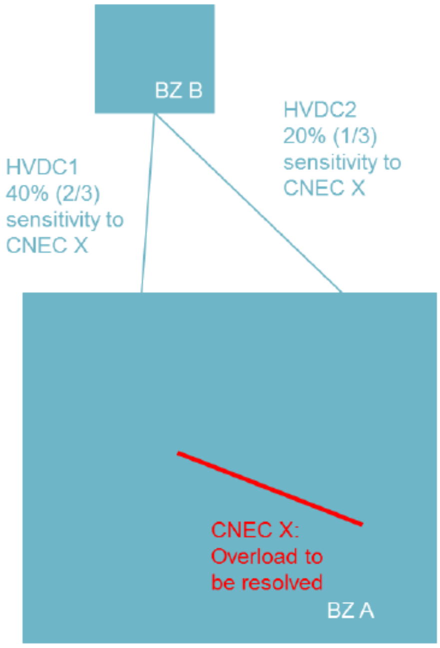

Figure 6 reduction of interconnector capacity in case of multiple interconnectors connected to a bidding zone

Specificities of LT time Horizon

The LT capacity for the computed timestamp can differ from the maximum permanent technical capacity only in case of a specific planned outage of a Critical Network Element with significant impact on the interconnector exists in one of the bidding zones to which that interconnector is connected. Each HVDC link will be associated with a set of CNECs that will be monitored in order to implement reductions of the maximum secure value of the interconnectors capacity.

The NTC values will be computed per interconnector in each bidding zone border per selected timestamps. In case of a negative margin on the CNECs which cannot be solved with available Remedial Actions, the congestion is solved by reducing only the maximum secure value of the interconnector capacity on the interconnectors in the bidding zone border where the limiting CNE is located. As each interconnector is associated with a set of potential CNECs, the maximum secure value of the interconnector capacity will be reduced on the interconnectors associated with the limiting CNECs.

How to implement a shift of import/export

Any shift of the power transfer between two bidding zones shall be realized by adjusting the generation in each of the bidding zone in line with the GSK of the bidding zone.

Timing & validation

The annual capacity calculation using a Minimum Guaranteed Value must be carried out before the end of September Y-1 whereas the annual capacity calculation releasing the interconnector MPTC while using reduction periods must be performed in December Y-1. In respect of the monthly capacity calculations using reduction periods, they shall be done before the end of the Month M-2.

The calculations start on D-0 and ends on D+5 for the annual capacity calculation using a Minimum Guaranteed Value and ends on D+3 for the Monthly capacity calculation. The exact timing of day “D-0” are the following:

Annual computations: “D-0” = September 15th

Final annual computations: “D-0” = December 1st

Monthly computations: “D-0” = 10th of Month-2

The timings mentioned are a starting assumption and need to be validated during a parallel run.

Mitigating actions

In case no values could be generated during the monthly calculations then the results of the annual calculation are used.

In case no values could be generated during the annual calculations then the results of the previous year are used.

3.5.4 NTC calculation process for each timestamp

i. Select and load the representative CGM base case for each selected timestamp;

ii. Apply Generation Shift Keys to each base case in order to reflect each interconnector operating at

   a. Interconnector MPTC in the direction of the synchronous grid of Continental Europe towards Great Britain and vice versa;

   b. Or alternative lower figures used in place of (a) above if an established longer term restriction is identified based on technical limitations or as the result of a contract or agreement.

iii. Run contingency analysis on the CGM using the CNEC list provided by the TSOs;

iv. Evaluate results to identify base cases

   a. allowing Interconnector MPTC without further actions

   b. indicating a potential Interconnector import or export limitation as a result of a negative margin on a Critical Network Element or operational security standard violation.

v. For each negative margin on a CNE identified in step iv(b), deploy the list of Remedial Actions to alleviate this margin of the Critical Network Element.

vi. Evaluate the impact of Remedial Actions. If Remedial Actions can mitigate the negative margin of the CNE or the operational security standard violation, the interconnector MPTC can be made available for that scenario timestamp.

vii. If the Remedial Actions used cannot alleviate the CNE violation, the maximum secure value of the interconnector capacity of the bidding zone where the limiting CNEC(s) is/are located should be progressively reduced in steps from the starting points set out in Article 18. In case several interconnectors are located in the concerned bidding zone, the reduction shall be applied only to the interconnectors which have an influence on the limiting CNE above the CNE thresholds and proportionally to their influence.

Following each capacity reduction, the contingency analysis should be repeated with the Remedial Actions already deployed until a level of the maximum secure value of the interconnector capacity has been identified for which no CNE violations occur. This establishes the maximum secure value of the interconnector capacity for these scenario timestamps.

3.6 Long-term cross-zonal capacity process

During the previous step the cNTC is calculated for each selected timestamp delivering a technical profile that represents the maximum capacity allowed on each HVDC-cable to comply with safety standards of the network for the concerned time window. With the objective to maximize the capacity available for the market this technical profile will be given by using the principle of reduction periods with the exception of the annual capacity calculation using a Minimum Guaranteed Value.

3.6.1 Annual cross-zonal capacity

Annual capacity

The long-term capacity calculation takes into account planned outages of the relevant CNEs, but under the SO GL the finalization of the outage planning occurs between 31 October and 30 November of the preceding year. As this is too late to start the allocation of the long-term products under a scenario-based approach, the first annual NTC-calculation will take place based on a provisional outage planning before the end of September Y-1 and a second annual NTC calculation will take place later (in December Y-1) based on the final outage planning. The former generates a preliminary technical profile and the latter a final technical profile.

Step 1: Minimum Guaranteed Value (MGV)

Following the annual capacity calculation before the end of September Y-1 based on a provisional outage planning (a high-level knowledge of outage requests for the upcoming year is needed), a preliminary technical profile will be calculated based on the selected timestamps. The NTC (Net Transfer Capacity) given will equal the minimum value of the technical profile (Cfr. Figure 7) with the exception of the planned outage of the HVDC-interconnector itself (which could potentially lead to 0MW capacity for LT allocation depending on the technical construction of the HVDC).

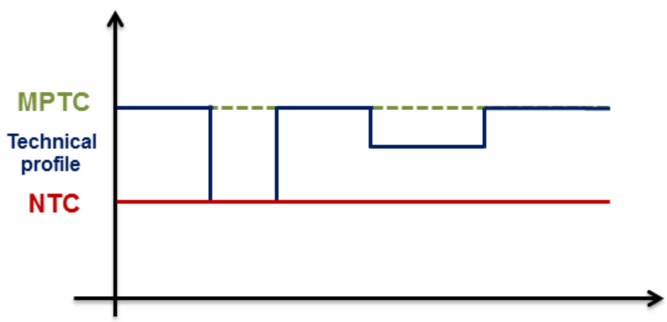

Figure 7. Example of Minimum Guaranteed Value

This Minimum Guaranteed Value approach offers margins towards changes in onshore TSOs outage planning (the outage can be shifted in time without the need for curtailment).

The MGV approach allows to allocate capacity prior to the finalization of the outage planning while taking into account safety standards. The planned outage of the HVDC-interconnector itself will be immediately considered as reduction period and will not part of the MGV approach.

Step 2: Reduction Period

After finalization of the outage planning on the CNEs under SO GL (at the latest before 1 December of the preceding year) a final technical profile is defined based on the selected timestamps as outages are considered as firm. Based on the preliminary profile additional calculations are performed if required. The NTC given will be equal to the technical profile calculated by using the principle of reduction periods (Cfr. Figure 8). The exact start and end dates of the reduction period must be provided before the allocation stage.

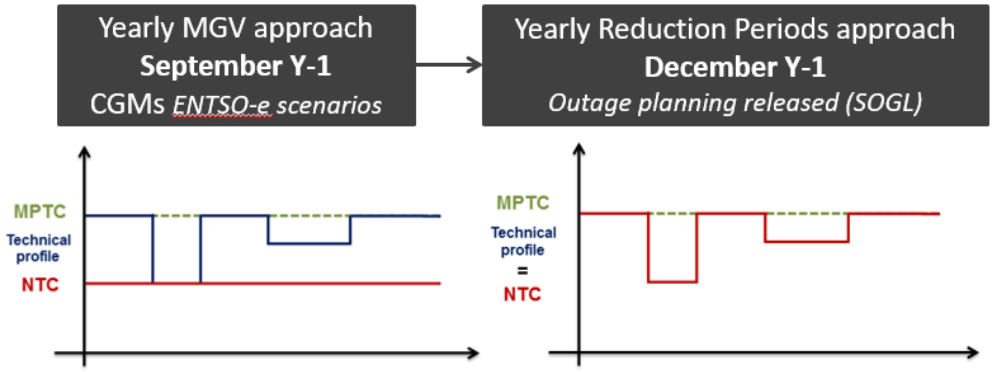

Figure 8. Example of reduction periods in LT products

This approach releases the remaining capacity available during periods with no planned outages. In case the planned outage on a CNE is reduced or cancelled, the updated reduction period has to be communicated as soon as possible.

3.6.2 Monthly cross-zonal capacity

Based on the latest information on the outages planned of the Critical Network elements, available in the OPC database, an updated technical profile will be calculated based on the selected timestamps. The NTC given to the market will be equal to the updated technical profile calculated by using the principle of reduction periods (Cfr. Figure 8) taking into account LTA. In case the planned outage on a CNE is reduced or cancelled, the updated reduction period has to be communicated as soon as possible.

3.6.3 Other long-term cross-zonal capacity

No updated technical profile will be calculated, instead the most recent available technical profile is used. For products with a duration greater than one month, the capacity will be derived from annual capacity calculations. For products with a duration equal to or less than one month, the capacity will be derived from monthly capacity calculations.

Timing & validation:

Preliminary scenario based annual cross-zonal capacity using a Minimum Guaranteed Value

With D+0 fixed on September 15th of the preceding year, or the first Monday after in case of a weekend, the preliminary annual calculations start on D+0 and are finished by D+5 expressed in working days. The validation of the preliminary technical profile ends by D+10 giving a period of 5 working days for initial calculations and 5 working days for iterations and validation. The resulting MGV is published on D+10.

Final scenario based annual cross-zonal capacity using reduction periods

With D+0 fixed on December 1st of the preceding year (immediately after the finalization of the outage planning according SO GL), or the first Monday after in case of a weekend, each TSO indicates the latest on D+2 to the CCC if new NTC calculation is required. The CCC recomputes the requested timestamps before D+5. On D+5 the final technical profile is validated by the TSOs and the remaining capacity is released.

Monthly cross-zonal capacity

With D+0 fixed on the 10th of Month-2, or the first Monday after in case of a weekend, the monthly calculations start on D+0 and are finished by D+3. The validation of the updated technical profile ends by D+8 giving a period of 5 working days for iterations on the cNTC calculation and validations. The resulting NTCs are released on D+8.

The timings mentioned are a starting assumption and need to be validated during a parallel run.

<u>Mitigating Actions</u>

In case no values could be generated during the monthly calculations then the results of the annual calculation are used.

In case no values could be generated during the annual calculations then the results of the previous year are used.

3.7 Step 4: cross-zonal validation

As mentioned in the paragraph of the long-term cross-zonal capacity process, all TSOs have the responsibility to validate the capacities proposed by the CCC and may locally re-assess the computed NTCs on the interconnector. This re-assessment may be necessary to prevent any risk due to possible unforeseen changes in grid situations which have occurred during the qualification phase such as

a. Forced outage on one interconnector or one element defined as CNE or Contingency;

b. A mistake in input data, that leads to an incorrect cross-zonal capacity;

c. Any other criteria that the TSO shall have previously defined, let agreed by its NRA and published in its website before its application.

In the case of such unforeseen changes and if a TSO is detecting a constraint, the TSO may reduce the proposed NTCs.

The reduction of the proposed NTCs shall be monitored, based at minimum on an identification of the limiting CNEC and the explanation of the unforeseen event causing the NTC reduction. The output of this process is the amended NTC which is considered as the final NTC.

3.8 Fallback procedure

In accordance with Article 42 of the FCA Regulation, in the event that the coordinated capacity calculator is unable to produce results, the default fallback procedure shall be the postponement of the forward capacity allocation.

In case the postponement of the forward capacity allocation is not possible, or the new deadline has been reached and no results are available, the TSOs of the Channel CCR foresees the following fallback process:

- For the annual capacity allocation, the TSOs will use as a starting point cross-zonal long-term capacity calculated by the CCC for the equivalent planned outages for the previous year. The TSOs of the Channel CCR will bilaterally validate these NTC values and then these values will be validated in a coordination meeting of the TSOs of the Channel CCR.
- For the monthly allocation, the TSOs of the Channel CCR will use as a starting point cross-zonal long-term capacity calculated by the coordinated capacity calculator during the annual process for this month. The TSOs of the Channel CCR will bilaterally validate these NTC values and then these values will be validated in a coordination meeting of the TSOs of the Channel CCR.

4 Criteria for an operational process

Performance of the N-1 security assessment of the maximum import/export

NTCs computation is based on an N-1 security assessment of both import and export market directions for the Channel CCR for each timestamp. The capacity calculation process for the Channel CCR is based on an AC loadflow computation using several input data from TSOs to be processed by the CCC. Following the defined methodology, 4 grid situations (import/ export cases on UK side and on continental Europe side) have to be computed for each timestamp. In addition, the computation time will be mostly influenced by, on one hand, the content of input data and in particular the number of outages, amount and kind of Remedial Actions and also the base case situation of the grid which could vary from non-congested cases to highly congested cases that will have to be managed by the CCC operator, and on the other hand by the IT infrastructure (machine speed and memory) will also influence the possibilities to run parallel computations in a dedicated short period of time. Moreover, the use of the new CGMES format containing much more information in the grid models will have an impact on the memory of the used machine. For the Channel project, real simulations of the calculation process with industrialized solution, which have not been started yet, will give a better view on the possibilities to optimize the computation time. Considering the time available for LT CC process the feasible number of assessed TS will be confirmed.

Taking into account the abilities of the tools and their foreseen development, the CCC shall maximize the number of assessed representative timestamps.
During the implementation phase and especially during internal parallel run, TSOs and CCC will consider the maximum number of assessed representative timestamps. Considering the time available to perform the process in the annual and monthly time horizon, the number of assessed timestamps may be different in each case.