WB6 Energy Community

Energy Community

Explanatory Note of the coordinated NTC calculation methodology for Shadow CCR 10

Electricity Coordinating Center Ltd.

December 2018

This report is a deliverable under the **Technical Assistance to Connectivity in the Western Balkans, Component 2: Regional Energy Market**.

www.energy-community.com

This project is supported by the European Union. The contents of this publication are the sole responsibility of the Energy Community Secretariat and can in no way be taken to reflect the views of the European Union.

Electricity Coordinating Center Ltd.
Vojvode Stepe 412, PO Box 50
11040 Belgrade 33, Serbia

Explanatory Note of the Coordinated NTC calculation methodology for Shadow CCR 10

Belgrade

December 2018

Table of Contents:

1. INTRODUCTION 3

2. COORDINATED NTC CALCULATION METHODOLOGY 5

2.1 EXCHANGE OF IGMS AND CGMS 5
2.1.1 Creation of IGMs 5
2.1.2 Balanced net positions and flows on DC lines 5
2.1.3 Creation of CGMs 7
2.2 OPERATIONAL SECURITY LIMITS, CONTINGENCIES AND ALLOCATION CONSTRAINTS 7
2.3 REMEDIAL ACTIONS 9
2.4 TRANSMISSION RELIABILITY MARGIN (TRM) 9
2.4.1 Objectives and methodological approach 10
2.4.2 TRM calculation concept 12
2.4.2.1 Realisation data 12
2.4.2.2 Forecast data 13
2.4.2.3 Analysis of flow differences: obtaining border-wise FRM 15
2.4.2.4 Conversion flow-based to transaction based values: obtaining TRM 16
2.4.3 Application steps 17
2.5 BASE CASE EXCHANGES VALUES 18
2.5.1 Calculation of BCE based on NTF 18
2.5.2 BCE from CGMA process 19
2.6 GENERATION/LOAD SHIFT KEYS 19
2.7 COMPOSITE NTC 20
2.7.1 Static coefficient approach 21
2.7.2 Dynamic coefficient approach 22
2.7.3 Fixed ratio approach 22

3. BUSINESS PROCESS 23

3.1 SHADOW CCR 10 BUSINESS PROCESS 23
3.2 COORDINATED CAPACITY CALCULATION PROCESS 25

4. ANNEX 26

4.1 BIDDING ZONES AND BORDERS 26
4.1.1 Bidding Zones 27
4.1.2 Coordinated Capacity Calculators per borders 28

1. INTRODUCTION

Based on ''Decision of the Agency for the Cooperation of Energy Regulators No 06/2016 of 17 November 2016 on the electricity transmission system operators' proposal for the determination of capacity calculation regions'' CCR 10 is official SEE capacity calculation region, consisted of EU TSOs: ADMIE, TRANSELECTRICA and ESO EAD. In order to include Non-EU TSOs from SEE region in coordinated capacity calculation process, Shadow CCR 10 region is proposed[1]. Shadow CCR 10 includes the WB6 TSOs (CGES, EMS, KOSTT, MEPSO, NOS BiH and OST) and CCR 10 TSOs, as well as borders to neighbouring TSOs – MAVIR, HOPS and TERNA. Figure 1 describes Shadow CCR 10.

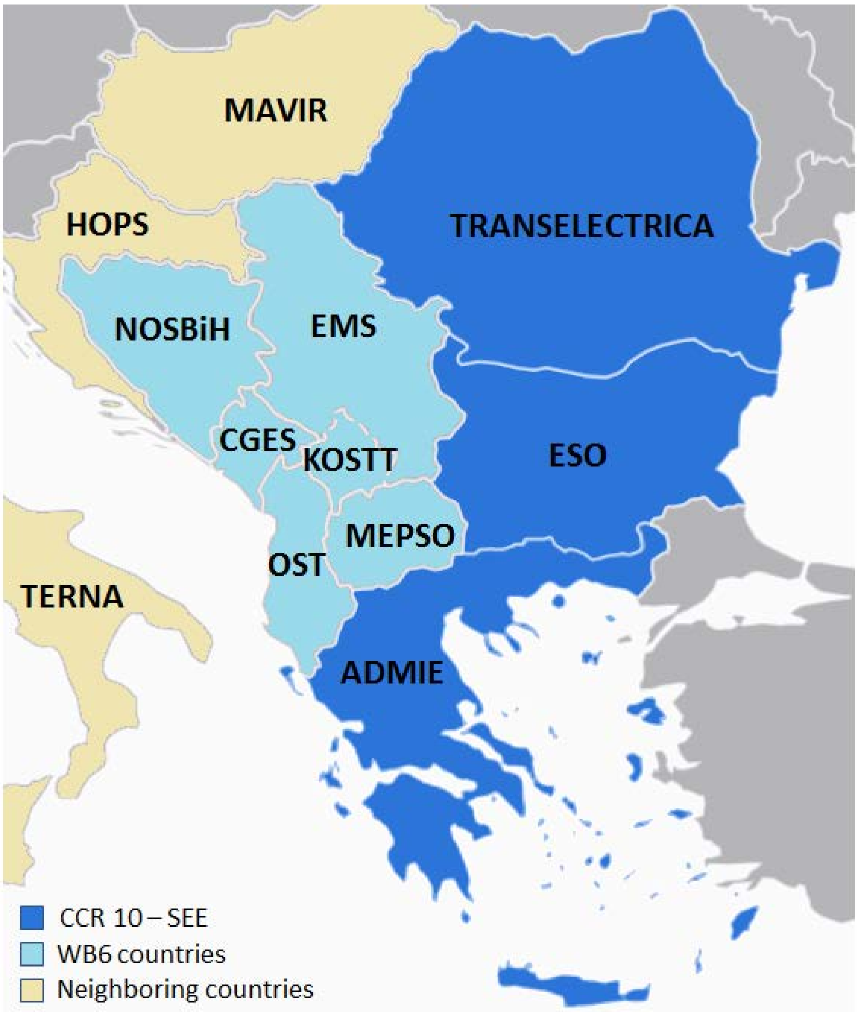


Figure 1 Shadow CCR 10 - SEE (Recreated)

[1] According to ToR, Shadow CCR 10 is based on: ACER's decision on CCRs, Explanatory document to all TSOs' proposal for CCR, WB6 initiative, The MoU signed by the stakeholders of EU MSs in the perimeter of the WB6 and Ongoing TSOs' activities in this region.

This document sets out the main principles for the Coordinated Capacity Calculation methodology (CCCm) for the day-ahead market timeframe applied in the Shadow CCR 10. It contains a description of both the methodology and the business process in compliance with the CACM Regulation[2]. CCCm includes all borders contained in Table 1.

Table 1 Bidding zones and scenario of Coordinated Capacity Calculators on particular borders

No.	Bidding Zone 1	Bidding Zone 2
1	EMS&KOSTT	ESO
2	EMS&KOSTT	MEPSO
3	EMS&KOSTT	OST
4	EMS&KOSTT	CGES
5	EMS&KOSTT	NOS BIH
6	MEPSO	ESO
7	CGES	NOS BIH
8	CGES	OST
9	ESO	ADMIE
10	ADMIE	OST
11	MEPSO	ADMIE
12	EMS&KOSTT	Transelectrica
13	EMS&KOSTT	HOPS
14	EMS&KOSTT	MAVIR
15	NOS BIH	HOPS
16	Transelectrica	ESO
17	CGES	TERNA

[2] Commission regulation (EU) 2015/1222 – guideline on capacity allocation and congestion management

2. COORDINATED NTC CALCULATION METHODOLOGY

According to the current practice in SEE region, the methodology based on NTC[3] is used by all SEE TSOs. Therefore, a day-ahead CCCm for Shadow CCR 10 will be based on NTC methodology, as well.

In order to define CCCm for Shadow CCR 10, following main aspects will be specified:

- Exchange of IGMs and CGMs;
- Operational security limits, contingencies and allocation constraints;
- Remedial Actions;
- Transmission Reliability Margins;
- Base Case Exchange values;
- Generation/Load Shift Keys;
- Composite NTC.

2.1 Exchange of IGMs and CGMs

(D-2) Individual Grid Models (IGMs) will be the main input for a day-ahead coordinated capacity calculation. These models describe the state of the individual TSOs networks for two days-ahead timeframe (D-2). Based on these IGMs, Common Grid Models (CGMs) will be created for D-2 timeframe. Creation of IGMs, as well as CGMs, should be in line with Common Grid Model Methodology (CGMM) that is common for entire ENTSO-E area.

2.1.1 Creation of IGMs

All TSOs of Shadow CCR 10 shall create hourly IGMs for D-2 timeframe, for the purpose of a day ahead coordinated capacity calculation. The IGMs shall be created using:

- The best available load forecast;
- The best available generation forecast:
    - the latest available forecast of intermittent generation;
    - the latest information of scheduled dispatchable generation;
- Forecast situation for grid topology;
- Balanced net positions and flows on DC lines, as output from CGMA process;
- Operational security limits for each network element.

2.1.2 Balanced net positions and flows on DC lines

Establishing balanced net positions is, in principle, straightforward for those timeframes for which schedule data are available (i.e. day-ahead and intraday). However, for timeframes for

[3] RG CE OH– Policy 4: Coordinated Operational Planning

which schedules are not available (from two-days ahead up to year ahead), balanced net positions have to be established via a process known as Common Grid Model Alignment (CGMA). The CGMA process consists of a set of procedures by which the initial (preliminary) estimates of net positions are revised such that the resulting set of net positions is balanced. In other words, CGMA is a process used for alignment of net positions and HVDC flows on the pan-European level. The process will be centrally carried out on Operational Planning Data Environment (OPDE) platform using developed algorithms and CGMA software tools. The process is divided into three phases, as shown on Figure 2:

- Pre-processing phase;
- Processing phase;
- Post-processing phase.

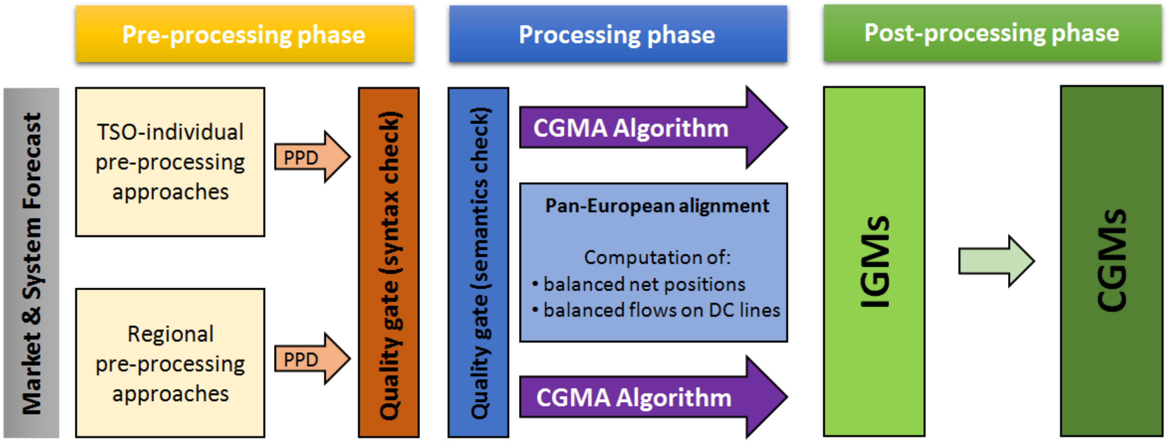


Figure 2 Common Grid Model Alignment Process

During pre-processing phase, each TSO shall provide its Pre-Processing Data (PPD) to the CGMA IT platform operated by Alignment Agents (AAs). The role of AA is assigned to Regional Security Coordinators (RSCs), and they are responsible for completing a number of tasks related to the CGMA process on behalf of the TSO. Pre-Processing Data consist of following:

- Preliminary Net Position (PNP);
- Feasibility Range (FR) for the adjustment of PNP;
- Preliminary flows on DC lines (PFlow);
- Maximum import and maximum export flows on DC lines.

The PPD should correspond to the TSO's best forecast. It is rather intuitive that by estimating the PPD on a regional basis, in a coordinated manner, the precision of the estimates should increase. The more precise estimates are, the smaller adjustments are required in order to obtain balanced net positions. A number of parties are therefore developing methods for estimating PPD on a regional basis, through so-called coordinated pre-processing approaches. Obligation of each TSO is to provide PPDs such that these meet the quality standards. However, TSOs can delegate this task to their AAs if they want to join a coordinated approach.

During the processing phase, the CGMA algorithm redistribute the PNPs across all bidding zones, until they sum to zero. In this phase PPD is used for computation of variables of interest, namely:

- balanced net positions (BNP);
- balanced flows on DC lines (BFlow).

During the post-processing phase, BNPs and the BFlows will be used to adjust each TSO's IGMs. TSOs will receive BNPs and BFlows from OPDE/CGMA platform and shall use them as input data for creation of D-2 IGMs. Also, these files are necessary input in process of CGM creation that will be done by RSCs.

2.1.3 Creation of CGMs

RSC shall be responsible for creation of hourly CGMs for D-2 timeframe, for the purpose of day-ahead capacity calculation. This role shall include:

- Validation of IGMs delivered by CE TSOs;
- Solving tie-line inconsistencies between SEE TSOs (if any);
- Creation of CE CGMs by merging IGMs, using BNP and BFlow from CGMA process;
- Delivery of CGMs to TSOs and Coordinated Capacity Calculator.

RSC has an obligation to merge IGMs from whole Continental Europe area in single CGM for each hour. If provision of D-2 IGMs is not possible for some specific date by some TSOs (as a result of unexpected failure of business process), the latest available day ahead (D-1) IGMs will be used instead.

Corresponding RSC[4] responsible for coordinated capacity calculation for particular border will use self-created CGMs, until unique CGM is established on Continental European level.

2.2 Operational security limits, contingencies and allocation constraints

Critical Network Element (CNE) is a network element either within a bidding zone or between bidding zones impacted by cross-border trades. CNEs are elements selected/defined by TSOs to be monitored during security calculations, because it is considered that overload of these elements will most likely jeopardize the grid and limit energy exchanges.

Critical Network Element and Contingency (CNEC) represents a set of CNE and specific operational situation for which CNE shall be monitored during capacity calculation. Operational situation can be "N" state, or contingency case (N-1, N-2, N-X). Contingency can contain tripping of one network element (N-1 security analysis) or multiple network elements (N-X security analysis).

[4] Referring to the list of borders and RSCs in Table 4.

For each specified CNE, TSO should assign one or more contingency in order to create specific CNEC pair in accordance with Article 75 of SO GL[5]. Based on TSO's needs and operational experience, the CNEC list should be periodically updated.

Operational security limits that will be observed during NTC calculation include acceptable operating boundaries for secure grid operation such as thermal limits and voltage limits. Additional allocation constrains described in Article 2 of CACM Regulation will not be applied in Shadow CCR 10.

Overload occurs when the amount of current flowing through the network element exceeds the maximum admissible current (I_{max}) of that element, which is usually determined based on thermal limits. When overload happens during NTC calculation, operational security limits are breached and capacity calculation should be stopped (if specified RA cannot solve network element overload), meaning that NTC value should be determined in such manner, that overload does not occur (i.e. to ensure that loading on CNE is lower than 100%).

For IGMs described through UCTE Data Exchange Format maximum admissible current of CNE could be represented by:

- Line rating – Permanent Admissible Transmission Loading (PATL) or
- Transformer rating, described with equation:

$$I_{max} = \frac{S_{nom}}{\sqrt{3} \cdot V_1},$$

where S_{nom} represents nominal power while V_1 represents rated voltage on non-regulated winding.

Maximum admissible current for each network element, as a part of IGMs, is determined by TSOs in line with Article 25 of the SO GL. Since thermal current limits are dependent on weather conditions, I_{max} is changed at least on the seasonal level. However, if weather forecasts show that conditions are going to be different from usual for a certain period of time, current limits can be changed more often. Also, the maximum admissible current can be defined with fixed limits for all market time units in the case of transformers and certain types of conductors which are not sensitive to ambient conditions or in case of specific situations where the limit reflects the capability of substation equipment (such as circuit-breaker, current transformer, or disconnector).

For IGMs described through CGMES format, PATL and TATL (Temporary Admissible Transmission Loading) can be defined.

Regarding the voltage constraints, maximum admissible voltage deviation on certain element has to be determined by TSOs in line with their operational security policies. This data shall be available within CNEC set. During the security analyses, if certain contingency causes voltage

[5] Commission regulation (EU) 2017/1485 – guideline on electricity transmission system operation

drop/increase that is out of predefined limits, and if there is no suitable RA that can solve it, calculation should be stopped.

2.3 Remedial Actions

Remedial Actions (RAs) refer to all measures applied in due time by TSO (individually within their bidding zone or in a coordinated way if they affect multiple grids) in order to relieve overloads on certain CNEs, i.e. to keep system in secure state and to maximize cross-border capacities. In particular, RA serves to fulfil security criteria (regarding power flows) and to maintain voltage constraints. CCCm include usage of only non-costly RAs, such as:

- topology changes in the network including opening or closing of one or more line(s), cable(s), transformer(s), busbar coupler(s), or switching of one or more network element(s) from one busbar system to another;
- adjustment of flows by using phase shifting transformers and other flow controlling devices;
- switching of reactive power devices (tap-changers, reactors, capacitor banks, SVC, etc.) or changing the set-point level of their controllers.

Based on the time of application, RAs could be classified as:

- Preventive RAs – used normally in operational planning or scheduling stage to maintain system in Normal State in the coming operational situation and to prevent propagation of disturbance outside the TSO's Responsibility Area;
- Curative RAs – implemented immediately after an occurrence of a contingency or with delay compatible with the Temporary Admissible Transmission Loading, which leads to a state differing from Normal State.

TSOs should create a list of available RAs that will be applied when each specific CNEC occurs. Also, TSOs shall agree on the list of remedial actions that can be shared between them in capacity calculation. This means that a shared remedial action of one TSO is used to solve the contingency in the grid of another TSO.

2.4 Transmission Reliability Margin (TRM)

Transmission Reliability Margin (TRM) represents the necessary margin in the NTC calculation related to Total Transfer Capacity (TTC), which is required to cover uncertainties and unintended deviations of power flows in the period between the capacity calculation and real time.

Within the CACM Regulation (Article 22(5)), the Reliability Margin should consider both:

- Transmission Reliability Margin (TRM): transaction based category, related to NTC calculation assigned to border/direction;

- Flow Reliability Margin (FRM): related to Flow-based (RAM) calculation assigned to respective Critical Branch/Critical Outage (CB/CO).

Both Reliability Margins, according to CACM Regulation, are to be based on the analysis of the following data:

- Unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between bidding zones, to maintain a constant frequency;
- Uncertainties which could affect capacity calculation and which could occur between the capacity calculation timeframe and real time, for the market time unit being considered.

2.4.1 Objectives and methodological approach

The origin of the uncertainty involved in the capacity calculation process for the day-ahead market comes from phenomena like external exchanges, approximations within the Coordinated NTC methodology and differences between forecasted and realized programs. This uncertainty must be quantified and discounted in the allocation process, in order to prevent that on delivery day TSOs will be confronted with flows that exceed the maximum allowed flows of their grid elements. This has direct link to the firmness of day-ahead capacity allocation results.

Therefore, TRM has to be defined for each border, which quantifies at least how the aforementioned uncertainty impacts the flows, i.e. cross-border schedules. Inevitably, the TRM reduces TTC on the electrical border since a part of this free space provided to the market to be used for cross-border trading must be reserved to cope with these uncertainties.

The basic idea behind the TRM determination is to quantify the uncertainty by comparing the Forecasted (D-2) model, partially adjusted (with realised net positions, topology, PST tap positions) to the observation of the corresponding timestamp in real time. More precisely, the base case, which is the basis of the NTC computation at D-2, is compared with a "snapshot[6]" of the transmission system on day D. This basic idea is illustrated in the Figure 3.

[6] SN CGM dataset, or Real time recordings; options explained later

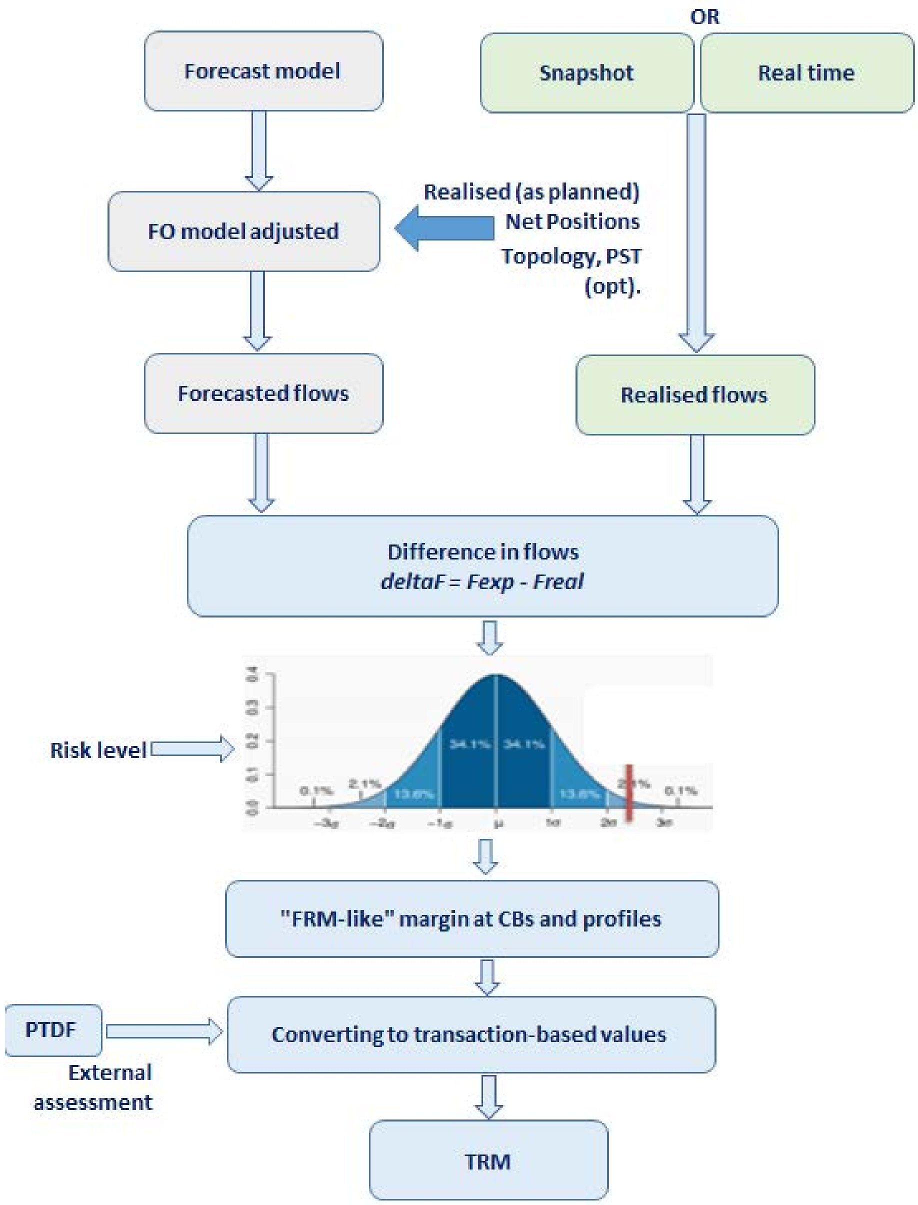


Figure 3 TRM assessment concept

In order to be able to properly compare the observed flows from the snapshot with the predicted flows in a coherent way, the D-2 Forecast model should be adjusted with the realized schedules corresponding to the time to which the snapshot was related. In this way, the same commercial exchanges are taken into account when comparing the forecast flows with the observed ones (e.g. intraday trade is reflected in the observed flows and need to be reflected in the predicted flows as well for fair comparison).

The differences between the observations and predictions are stored in order to build up a database that allows the TSOs[7] to make a statistical analysis on a significant amount of data. Based on a predefined risk level, the border-wise FRM values are computed from the distribution of flow differences between forecast and observation, while TRM values can be computed by converting physical cross-border flow values to the corresponding transaction-based values.

By following this approach, the subsequent effects are covered by the TRM analysis:

- Uncertainties component of TRM: will be ensured by comparing forecasted and realised situations
    - External trade
    - Internal trade in each bidding zone
    - Uncertainty in Generation pattern
    - Uncertainty in RES generation forecast
    - Uncertainty in Load forecast
    - Assumptions inherent in the generation shift
- Deviations component of TRM: Inclusion of unintentional flow deviations due to operation of load-frequency control will be ensured by applying scheduled exchanges (as planned close to real time) in forecast data, instead of exact real time exchanges.

2.4.2 TRM calculation concept

2.4.2.1 Realisation data

Realized data are required to:

- record the realised flows/exchanges at the observed elements/borders: Realised flow, Freal,cb (per Critical Branch (CB)) is the main output of this sub-process
- provide realised countries' net positions, in order to align the forecasted data to realised level of exchanges
- provide the information on the realised topology, including PST tap positions

The main option for determining the realised situation is merged Snapshot CGM of Continental Europe.

In **Snapshot-based approach**:

- A number of historical SN CGMs is used as an input (corresponding to multiple timestamps, e.g. hh:30:00 of different hours and dates within one period)

[7] TRM assessment is seen as periodical common activity among TSOs and CCCs. CCC can be the coordinator of this process, and it can collect necessary input data.

- List of Critical Branches (CB) is used as an input, defining the tie lines of observed TTC calculation profile (bilateral, or composite).
- AC LF is run on the Snapshot CGMs.

The requirements for usage of SN CGMs are:

- area resolution of merged SN CGM model to correspond to the D-2 Forecast CGM used for TTC calculation, at least for the area of interest (region)
- the snapshot data (IGM) for the aforementioned systems need to be simultaneous and instantaneous (representing e.g. the hh:30:00 real time situations); without SN based on average hourly data; consequently, no SN replacement is desirable
- the modelling approach for snapshot models needs to correspond fully to the D2CF models used for TTC calculation, in sense of topology (area names, nodes, branches, element IDs), so the information on net positions, elements flows, topology statuses and tap positions would be automatically transferrable to the Forecast (D2CF) datasets.

Current state of Snapshot data exchange in SEE is such that not all required SN IGMs are available or simultaneous. In addition, the correspondence (topology, element IDs) to the D2CF models is not fulfilled.
Knowing the current obstacles in data availability of Snapshot-based approach, an alternative approach is proposed, based on direct application of real-time recordings.
In **Real Time Recordings-based approach**:

- No SN models are used, but the direct real time data provided by the TSOs (corresponding to multiple time stamps, e.g. hh:30:00 of different hours and dates within one period)
- List of Critical Branches (CB) is used as an input, determining tie lines that will be monitored. For the TRM calculation, the tie lines of observed TTC calculation profile (bilateral or composite) are included.

2.4.2.2 Forecast data

The set of D2CF CGMs for the same timestamps that were used in D-2 TTC calculation is required. They are altered with certain portion of real time data (from SN-based, or RTR-based approach, as defined previously), to provide the reference load flows. These reference load flows are to be compared with realised flows, providing the Δflow, as the main input to the reliability margin assessment.
Topology adjustment:
The two categories exempted from inclusion into the Reliability Margin are:

- Unplanned topology changes (trippings) copied from day D, back to D-2 Forecast model, since their possibility to happen is covered with n-1 analysis

- PST adjustments/Remedial Actions: if they are included in TTC calculation (during n-1 analysis), they are copied back to D-2 Forecast model

The category which influence is included into the Reliability Margin is:

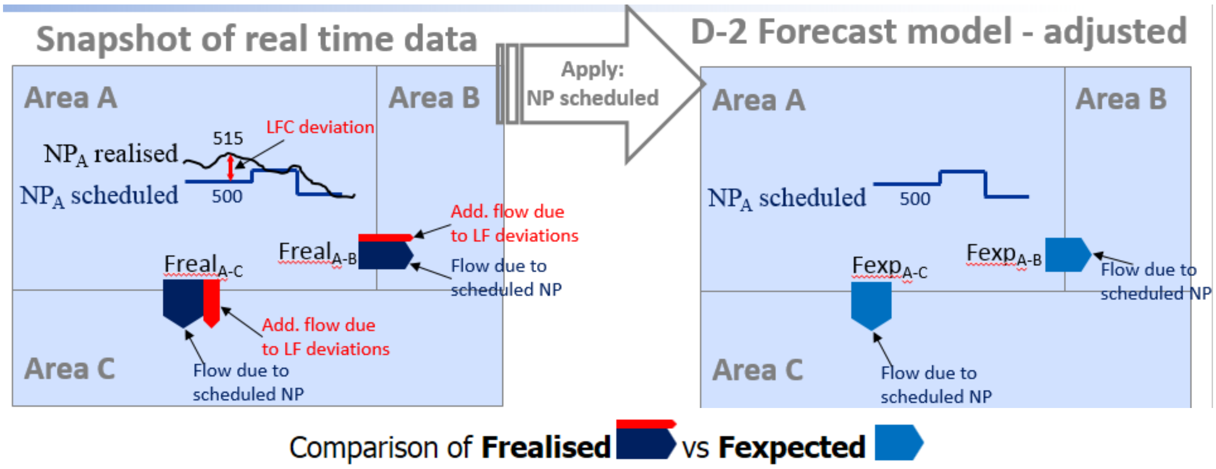
- Eventual planned topology changes from date D (late intentional changes of topology) are not copied back to D-2 Forecast Model, since they represent the "part of forecasting error"

Net positions adjustment:

Realised Net Positions of modelled areas are applied to the D-2 Forecast models. Here it is important to note, that if load-frequency deviations component of TRM should be embedded into TRM calculation, planned net positions of countries (close-to-real-time areas' aggregated schedules)[8] should be used instead of realized ones.

By applying scheduled and not realised Net Position from D to D-2, intentionally the difference among resulting cross-border flows is increased for the influence of LFC deviation.

Thus, cross-border flow component by deviations due to LF control exists in Snapshot data and does not exist in adjusted D-2 Forecast data; this approach provides perfect correlation of "deviations" and "uncertainties" of reliability margin.



[8] If country A has close-to-real time planned Net Position of 500 MW, for the moment hh:30, and its realised Net Position in hh:30 was 515 MW, this 15 MW difference is due to the operation of load-frequency control. Real time recorded CB flows (Freal) actually correspond to the "515 MW" situation. Therefore, if adjustment of D2CF model would be done to exact 515 MW, then the comparison of CB flows realised (Freal) vs. expected (Fexp), would include only modelling/forecast uncertainties component. On the other hand, if intentionally the figure of 500 MW would be used to obtain Fexp, the 15 MW net position difference would influence the "planned" CB flow. Thus the component of Reliability Margin dealing with load-frequency control deviations would be implicitly included in the calculation. This is done in a manner that provides natural cross-correlation of "uncertainties" and "deviations" effects; in some timestamps these two would be summed up, in some they would compensate each other, etc.

If one would like to calculate the "uncertainties" component solely, then it can use the input set of Net Positions purely as realised.

Figure 4 Applying realised Net Positions to the Forecast data

GLSK approach: in order to apply the realised NPs to the D2CF model (but without applying the exact power plants or loads to the D2CF, which would be their equalising - and thus "unfair" to the TRM assessment), the GLSK approach to alter the Net Positions needs to be defined.

Calculating reference load flows:

At preselected CBs, the flows at the original D2CF models are calculated, as well as the flows at the adjusted D2CF models.
Expected flow, physical Fexp,cb (per CB), is the main output of this sub-process.

2.4.2.3 Analysis of flow differences: obtaining border-wise FRM

The sub-processes "Realised data" and "Forecasted data" have the **Freal,cb** and **Fexp,cb** as the main outputs. By summarising them for the tie lines at certain calculation profile, the values of **Freal,profile** and **Fexp,profile** are obtained.

The process is as follows:

- *For the profile the Freal and Fexp are calculated for all available timestamps*
- Selected are only those timestamps for which Freal ≥ 0 and ΔF=Freal-Fexp ≥ 0
- The selected ΔF values are sorted in ascending order
- The 95% of the selected and sorted ΔF values is taken into account; This means that the TSOs apply a common risk level of 5% i.e. the RM values cover 95% of the historical errors
- Thus border-wise FRM is calculated

Example:

- *Observing expected and realised flows over some border/direction; can be composite profile as well*
- *E.g. there are 40 timestamps, with realised flow in “forward“ direction*
- *Out of those 40, the 23 have non-negative flow deviation (contributing to cross-border flow, thus potentially endangering security)*
- *They are sorted in ascending order*
- *95% of percentiles is to be taken into account, which reaches 21st value in the ordered list*
- *Resulting border-wise FRM value would be 82 MW*

Area 1->Area 2				
time-stamp	Pexp Expected flow	Preal Realised flow	Δflow	Δflow (≥0)
t1	598	610	12	**12**
t2	611	621	10	**10**
t3	596	614	18	**18**
t4	603	528	-75	
t5	598	518	-80	
t6	651	651	0	**0**
t7	646	626	-20	
t8	653	683	30	**30**
t9	648	697	49	**49**
t10	651	666	15	**15**
t11	628	613	-15	
t12	631	622	-9	
t13	596	701	105	**105**
t14	603	725	122	**122**
t15	598	531	-67	
t16	648	676	28	**28**
t17	651	679	28	**28**
t18	636	676	40	**40**
t19	653	669	16	**16**
t20	598	663	65	**65**
t21	611	595	-16	
t22	616	694	78	**78**
t23	613	695	82	**82**
t24	608	611	3	**3**
t25	611	633	22	**22**
t26	656	629	-27	
t27	663	616	-47	
t28	661	649	-12	
t29	658	675	17	**17**
t30	661	673	12	**12**
t31	591	568	-23	
t32	593	552	-41	
t33	596	665	69	**69**
t34	591	566	-25	
t35	593	567	-26	
t36	576	539	-37	
t37	571	557	-14	
t38	543	481	-62	
t39	543	561	18	**18**
t40	546	549	3	**3**

	No.	timestamp	Δflow (≥0) ascending
	n1	t6	**0**
	n2	t24	**3**
	n3	t40	**3**
	n4	t2	**10**
	n5	t1	**12**
	n6	t30	**12**
	n7	t10	**15**
	n8	t19	**16**
	n9	t29	**17**
	n10	t3	**18**
	n11	t39	**18**
	n12	t25	**22**
	n13	t16	**28**
	n14	t17	**28**
	n15	t8	**30**
	n16	t18	**40**
	n17	t9	**49**
	n18	t20	**65**
	n19	t33	**69**
90%	n20	t22	**78**
95%	**n21**	**t23**	**82**
	n22	t13	**105**
100%	n23	t14	**122**

Figure 5 Border-wise FRM calculation example

2.4.2.4 Conversion flow-based to transaction based values: obtaining TRM

Since TRM is commercial (transaction-based) value, related to network profile (border/direction) the conversion from physical flows related to tie lines, to commercial flows related to borders, needs to be done. Following necessary aspects need to be taken into consideration:

- network profile needs to be defined (e.g. ROBG-RS)
- for the particular tie lines at that profile, physical flows are aggregated (e.g. flows at Portile De Fier-Djerdap and Sofia-Nis); this is Freal,cb and Fexp,cb at the observed profile

For the conversion of physical values to commercial values single, unique PTDF value can be applied upon all timestamps; ΔFt as the subject to the statistical analyses; then FRM (border-wise) determination; afterwards converting FRM (border-wise) to TRM, as:

$$TRM=FRM/PTDF$$

Offline determination of average PTDF value is required for each profile, potentially excluding loop flows effect.

Example:

- *If border-wise FRM between A and B is 82 MW*
- *If PTDF on lines A-B for transaction A-B is 75% ("sensitivity")*
- *TRM = FRM/PTDF = 82/0.75 = 109.3 MW*
- *To decrease the flow A-B for 82 MW, it is required to decrease the A-B transaction (i.e. TTC) for 109.3 MW*

2.4.3 Application steps

TRM values shall be reviewed at least once per year for all borders, according to the described methodology.

TSOs and RSCs/CCCs will endeavour to ensure the correspondence of CGM Snapshots to the requirements of TRM assessment methodology.

While the CGM snapshots are not suitable for TRM assessment, real time recordings will be used for the realised data.

Before the first operational calculation of the TRM values, shadow SEE CCR TSOs shall use the TRM values already in operation in the existing capacity calculation initiatives. Based on the data acquired from questionnaire, these values are displayed in Table 2:

Table 2 Actual TRM values

No.	Bidding Zone 1	Bidding Zone 2	TRM
1	EMS&KOSTT	ESO	100
2	EMS&KOSTT	MEPSO	100
3	EMS&KOSTT	OST	50
4	EMS&KOSTT	CGES	100
5	EMS&KOSTT	NOS BIH	100
6	MEPSO	ESO	100
7	CGES	NOS BIH	100
8	CGES	OST	100
9	ESO	ADMIE	100
10	ADMIE	OST	100
11	MEPSO	ADMIE	100
12	EMS&KOSTT	TRANSELECTRICA	100
13	EMS&KOSTT	HOPS	100

No.	Bidding Zone 1	Bidding Zone 2	TRM
14	EMS&KOSTT	MAVIR	100
15	NOS BIH	HOPS	150
16	Transelectrica	ESO	100
17	CGES	TERNA	to be defined

A possible third step is to undertake an operational adjustment on the values derived previously, which can be applied to adjust the computed TRM values to a value within the range between 1% and 20% of the TTC calculated.
For the day-ahead common capacity calculation, the RMs for the shadow SEE CCR borders shall be implemented 3 months after collecting 1 year of data since the day-ahead capacity calculation go-live.
During the first year upon the start of day-ahead coordinated capacity calculation, Shadow CCR 10 TSOs will collect all data necessary for the common TRM methodology. Based on collected data, in the next 3 months Shadow CCR 10 TSOs will provide to the NRAs the initially calculated TRM values, as well as a report with the final proposal of TRM methodology, adjusted on the basis of the results and findings obtained during the previous year. Six months after the approval of the TRM methodology by NRAs, Shadow CCR 10 TSOs have the obligation to implement common TRM methodology.

2.5 Base Case Exchanges values

Base Case Exchange (BCE) values are related to the best forecast of commercial exchanges at the timeframe considered.
In order to standardize NTC calculation, one of the main tasks should be numerical assessment of BCE values. This methodology proposes two approaches for determination of BCE values. BCE approach shall be agreed among all TSOs.

2.5.1 Calculation of BCE based on NTF

Notified Transmission Flow (NTF) is physical flow between two areas in base case through interconnected lines prior to any generation shift between areas. It results from the flow originated by the BCE and from the parallel flows.
It is difficult to identify different origins of parallel flows that lead to the NTF value and separate them to distinguished terms (such as loop flows, natural flows), meaning that the simplest way to define BCE is through equation:

$$BCE \equiv NTF$$

2.5.2 BCE from CGMA process

Base Case Exchange values can be derived from CGMA process as well. As part of CGMA output results, Indicative AC flows per border will be delivered. These values are intended to be used as BCE values for NTC calculation. By default, the CGMA algorithm computes AC flows in such a way that these flows are minimized and balanced net positions are respected.

2.6 Generation/Load Shift Keys

According to CACM regulation a methodology for common generation shift key, considering a method of translating net position change of a given bidding zone into estimated specific injection increases or decreases, should be defined. Generation/Load Shift Keys (GLSKs) are used to handle these changes in generation or load profile by computing the new generation injections or load profile at the electrical nodes to comply with the change of generation as well as load.

According to the current NTC calculation practice in SEE region, the most common GLSK methods are:

- Proportional to reserve;
- Proportional to engagement.

However, generation shift proportional to engagement without respecting power limits of generators almost always leads to breaching generators power limits, which could easily trigger unrealistic overloads (usually overloads of elements close to big power plants). Because of this occurrence, it is suggested that primary method for coordinated NTC calculation should be generation/load shift proportional to reserve, while shifting proportional to engagement would not be used regularly.

Additionally, it is suggested to TSOs, if it is possible, to define the priority list of the production/consumption units in form of:

- Generation shift key (GSK) list specifying those generators and their available amount of MWs that shall contribute to the shift;
- Load shift key (LSK) list specifying those consumption nodes and their available amount of MWs that shall contribute to the shift in order to take into account the contribution of generators connected to lower voltage levels.

If during the NTC calculation generators reserve limits are reached (on export or import side) without any overloads, additional power plants from other areas that does not increase loop flows significantly, may be considered. For instance, in case of NTC calculation on border BA → ME where additional power plants from AL can be added on import (ME) side and from HR on export (BA) side.

The default generation shift methodology for all concerned bidding zones is *proportional to the remaining available capacity of generation* in the D-2 CGM for each market time unit, until the exploitation of all available reserve. After that, in case of need for further shifting

(transmission limit is not reached), additional shift is done proportionally to the actual generation from the previous calculation step.
The default generation shift principle considers *all generation units*.
Exact generation shift, with the participating units needs to be defined for each bidding zone.

2.7 Composite NTC

NTC methodology is primarily defined to calculate cross-border capacities in bilateral way – power flow is forced from one export area to one import area. However, in highly meshed grids bilateral approach evokes loop flows that reduce calculation quality. The strong interdependence between some of the borders within the highly meshed grid can seriously compromise the usage of classical bilateral approach. In order to eliminate this by-product of bilateral NTC calculation, composite approach can be used – several bidding zones are considered as one import/export area.
For each border and direction, depending of its network interdependence with other borders, it has to be defined whether composite or bilateral calculation is going to be performed. According to the CCR 10 methodology proposal and SEE TSOs’ current practices, composite NTC will be performed on some predefined borders, described in Table 3.

The list of composite NTC profiles is as follows:

Table 3 Composite borders

<table>
<tr><th>No.</th><th colspan="2">Area 1</th><th colspan="5">Area 2</th></tr>
<tr><td>1*</td><td colspan="2">EMS&KOSTT</td><td colspan="2">NOS BiH</td><td colspan="3">HOPS</td></tr>
<tr><td>2*</td><td>TRANSELECTRICA</td><td>ESO</td><td colspan="5">EMS&KOSTT</td></tr>
<tr><td>3*</td><td colspan="2">EMS&KOSTT</td><td>CGES</td><td colspan="2">MEPSO</td><td colspan="2">OST</td></tr>
<tr><td>4**</td><td colspan="2">ADMIE</td><td>OST</td><td colspan="2">MEPSO</td><td>ESO</td><td>TEIAS</td></tr>
<tr><td>5**</td><td colspan="2">TRANSELECTRICA</td><td colspan="2">ESO</td><td colspan="3">EMS&KOSTT</td></tr>
</table>

* Based on current TSOs practices.
** Based on information for the RO-BG-GR borders was taken from the relevant SEE CC methodology which was under public consultation.

Recognition of composite borders/directions needs to be further elaborated and verified by TSOs, as well as the possibility for different shape of composite/bilateral calculation at different directions, where reasonable. E.g. NTC can be calculated as composite in one direction and bilateral in another.

Example: NTC can be calculated,

- as composite at the direction EMS&KOSTT $\rightarrow$ CGES + MEPSO + OST, due to predominant exchange flow towards south
- as bilateral in opposite direction e.g. for CGES $\rightarrow$ EMS&KOSTT

Three approaches for the distribution of composite NTC values per border are available:

- Static coefficient approach – proportionally to maximum current limits;
- Dynamic coefficient approach – proportionally to border flow increment;
- Fixed ratio based on operational experience and agreed among concerned TSOs.

Approach for the distribution of composite NTC values shall be agreed among all TSOs that share certain calculation profile.

This includes the recognition of need for duplicated calculations (e.g. fractions of different composite NTCs, or combining composite and bilateral) and the adoption of final NTC value at certain borders.

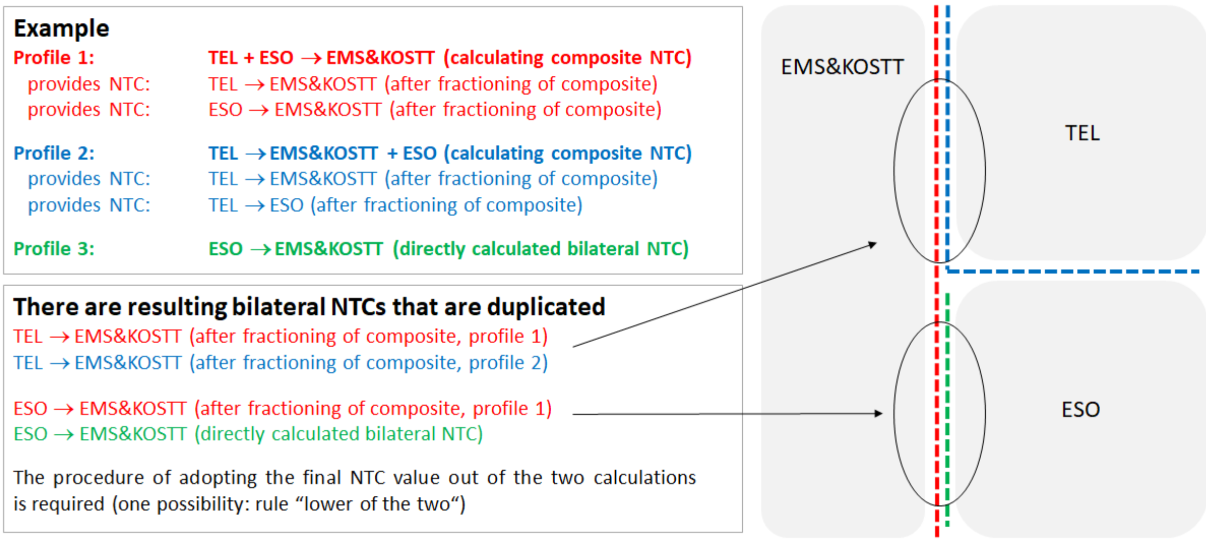


Figure 6 Combining composite and bilateral calculation profiles

2.7.1 Static coefficient approach

Static coefficient approach describes the distribution of composite NTC values per border proportionally to sum of maximum current limits on all tie lines between two bidding zones participating in composite NTC calculation. If composite NTC is calculated between exporting area A and importing areas B and C, the following equation represent static coefficient approach:

$$NTC_{A\to B} = \frac{Imax_{A\to B}}{Imax_{A\to B} + Imax_{A\to C}} \cdot NTC_{A\to B+C}$$

$$NTC_{A\to C} = \frac{Imax_{A\to C}}{Imax_{A\to B} + Imax_{A\to C}} \cdot NTC_{A\to B+C}$$

where:

$NTC_{A\to B+C}$ – total calculated NTC value;

$NTC_{A\to B}$ – NTC value assigned to border between bidding zones A and B;

$NTC_{A\to C}$ – NTC value assigned to border between bidding zones A and C;

$Imax_{A\to B}$ – sum of maximum current limits for all tie-lines between bidding zones A and B;

$Imax_{A\to C}$ – sum of maximum current limits for all tie-lines between bidding zones A and C.

2.7.2 Dynamic coefficient approach

Dynamic coefficient approach describes the distribution of composite NTC values per border proportionally to difference between sum of load flows on all tie lines in base case and in calculation step where NTC value is accepted. If composite NTC is calculated between exporting area A and importing areas B and C, the following equation represent dynamic coefficient approach:

$$NTC_{A\to B} = \frac{\Delta F_{A\to B}}{\Delta F_{A\to B} + \Delta F_{A\to C}} \cdot NTC_{A\to B+C}$$

$$NTC_{A\to C} = \frac{\Delta F_{A\to C}}{\Delta F_{A\to B} + \Delta F_{A\to C}} \cdot NTC_{A\to B+C}$$

where:

$\Delta F_{A\to B}$ – sum of load flow increment between base case and step where NTC value is accepted for all tie-lines between bidding zones A and B;

$\Delta F_{A\to C}$ – sum of load flow increment between base case and step where NTC value is accepted for all tie-lines between bidding zones A and C.

2.7.3 Fixed ratio approach

Fixed ratio approach is based on operational experience and the analysis of historical results of capacity calculation, allocation and load flows. It requires mutual agreement among the concerned TSOs of a certain profile.
Similar solution is applied among the TSOs at Northern borders of Italy.

$$NTC_{A\to B} = \frac{k_{A\to B}}{k_{A\to B} + k_{A\to C}} \cdot NTC_{A\to B+C}$$

where:

$NTC_{A\to B+C}$ – total calculated NTC value;

$NTC_{A\to B}$ – NTC value assigned to border between bidding zones A and B;

$NTC_{A\to C}$ – NTC value assigned to border between bidding zones A and C;

$k_{A\to B}$ – fixed ratio for border between bidding zones A and B;

$k_{A\to C}$ – fixed ratio for border between bidding zones A and C.

3. BUSINESS PROCESS

In order to implement coordinated capacity calculation methodology for Shadow CCR 10, it is highly important to develop a business process that will be applicable to all TSOs and RSCs in this region. Business process should consist of the following steps:

- Shadow CCR 10 TSOs create hourly D-2 IGMs using balanced net positions from CGMA process;
- RSC uses these models for creation of D-2 Common Grid Models (CGMs) and uploads validation reports to the QAS portal;
- Coordinated Capacity Calculator uses CGMs to calculate preliminary cross-border capacity values;
- TSOs finish the process by adopting/modifying (with an explanation) the cross-border capacity values.

3.1 Shadow CCR 10 business process

Business process is one of the main parts of the methodology and it will determine future tasks of TSOs and RSCs. The initial proposal of business process can be seen in Figure 7. It is high-level description, where different blocks describe:

- blue blocks – responsibility of TSOs;
- red blocks – tasks that are assigned to RSCs;
- green blocks – processes performed by European entities.

Business process starts at TSOs side by beginning forecast activities necessary to determine estimated values of load, generation and net positions. TSOs upload PPD to CGMA platform and wait for BNP as response. Using forecasted load and generation, BNP and topology plan, TSOs create D-2 IGMs and upload them to the OPDE (or send them to RSCs in some other way).

RSCs validate IGMs based on syntax, semantics and load flow checks, and upload validation reports of IGMs to Quality Assessment Service (QAS) portal. If IGMs do not have satisfactory quality, new version of IGMs should be sent to RSCs again. Using valid IGMs and BNPs, RSCs create CGMs. Validation reports of CGMs should be also uploaded to QAS portal so TSOs can see quality of CGMs.

Coordinated Capacity Calculators for Shadow CCR 10 use CGMs and input data to calculate preliminary NTC values. This business process finishes by approval or modification (with an explanation) of NTC values by each TSO from the region.

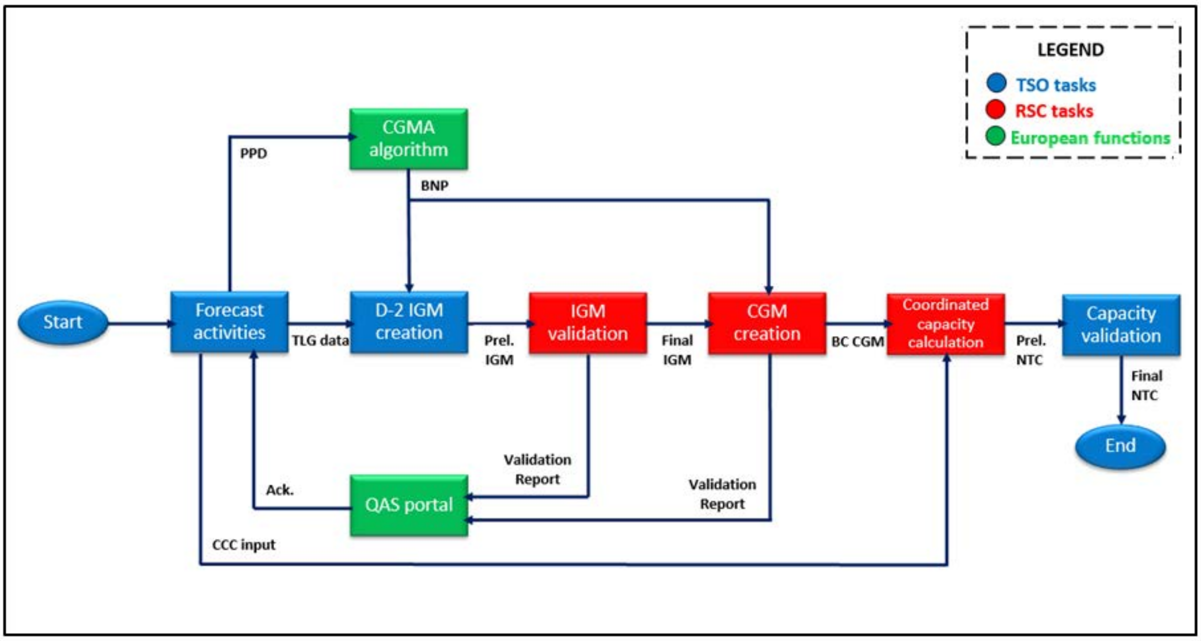


Figure 7 Business process diagram

Figure 8 gives the initial proposal of timeline for business process. Some of the timings are fixed by other processes, such as Delivery of PPD, Active Quality Management Process (AQMP) and Delivery of BNP, while others are given as proposal.

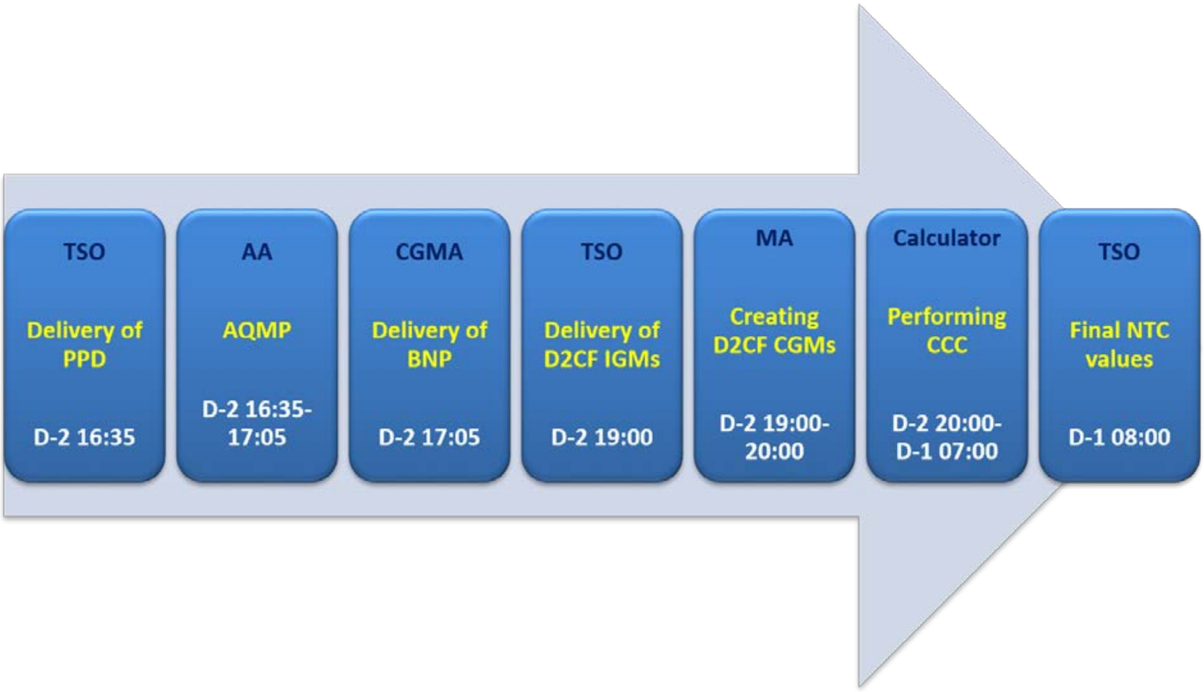


Figure 8 Proposed timeline of business process

3.2 Coordinated Capacity Calculation process

NTC calculation in Shadow CCR 10 shall be performed by corresponding Coordinated Capacity Calculator (CCC). CCC shall receive two basic sets of data:

- CGMs from RSCs (stated as Base Case CGMs);
- Capacity calculation (CC) input data from TSOs (operational security limits, GLSKs, CNECs, adequate RAs, transmission reliability margins and previously allocated cross-zonal capacity values).

Coordinated Capacity calculation process is shown on the Figure 9. First step in this process represents base case security analysis. If system cannot be declared as secure in base case, additional considerations should be performed in coordination with TSOs. On the other hand, if system is secure in Base case, capacity calculation can start by updating BC CGMs using provided GLSKs. It means that generation in export area should be increased and generation in import area should be decreased by the same amount of power (ΔE). After ensuring base case secure state, security analysis is performed on these updated CGMs. Every CNEC (from i=1 to N) is simulated and if there are no constraints detected, ΔE value is increased and CGMs updated again. Otherwise, if some contingency provokes an overload on certain CNE, adequate RA is considered. If detected constraint cannot be relieved by applying any specified RA, preliminary NTC value is determined; otherwise new CNEC is checked.
Coordinated Capacity calculation is a centralized calculation based on AC load flow, which delivers the main parameter needed for the definition of NTC domain: Total Transmission Capacity (TTC). The TTC represent the maximum power exchange on a bidding zone border, if future network conditions were perfectly known in advance and calculation is performed from relevant CGM and the GSK, taking into account operational security limits and remedial actions.
In order to calculate final secure ATC (Available Transfer Capacity) values, CCC shall take into account the rest of input data from TSOs, regarding technical uncertainties and unintended deviations of future network conditions in form of TRMs and previously allocated/nominated capacities. The final available cross-zonal transfer capacity shall be calculated by subtracting TRM and already allocated/nominated capacities from calculated TTC value:

Two calculations of ATC value will be done in two different timeframes of D-2 calculation process:

- In the evening of D-2, when only the information of already allocated capacity (AAC) from forward allocation timeframes is available, the preliminary check is done, in a way:

$$ATC_{A-B} = NTC_{A-B} - AAC_{A-B}$$

This check should provide the awareness to the CCCs and TSOs, in case that ATC appears as negative. AAC of different directions at the same borders is not netted, due to the optionality of its realisation.

- In the morning of D-1, after the nominations of already allocated capacities, the information about Already Nominated Capacity (ANC) from forward allocation timeframes is available, the preliminary check is done, in a way:

$$ATC_{A-B} = NTC_{A-B} - ANC$$

This check provides the final information on the size of ATC available for the D-1 allocation processes, and the trigger of eventual curtailment of long-term transmission rights, in case that ATC appears as negative. ANC is netted value based on nominations at different directions at the same border.

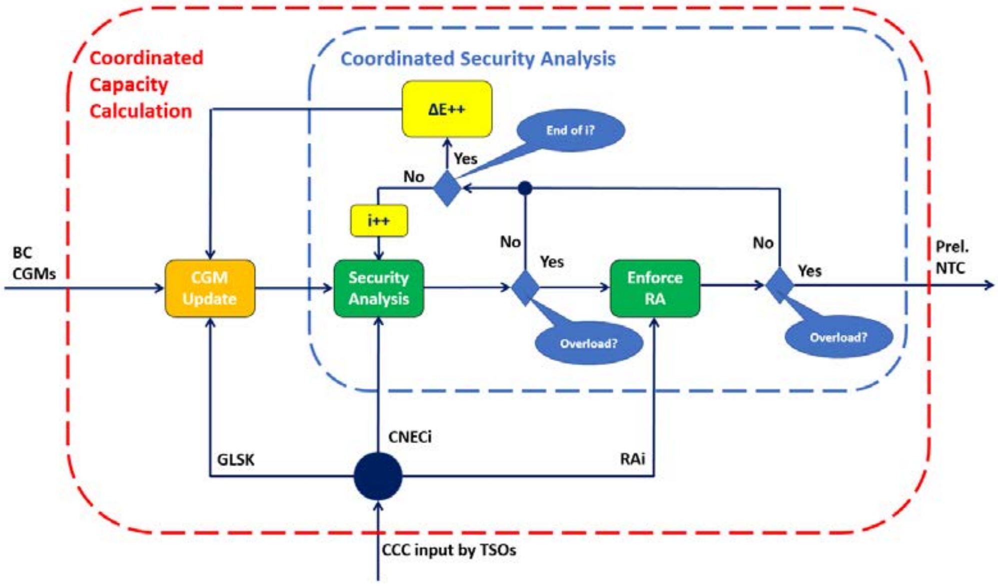


Figure 9 Detailed overview of Coordinated Capacity Calculation block

4. ANNEX

4.1 Bidding zones and borders

Knowing the pending status of Shadow CCR 10 with regard to the European legislation, an important aspect of the project is to properly recognize the scope of involved TSOs, bidding zones and borders. There are also some open questions, for which the consultant will provide some proposals during the Project execution. For example, there are some TSOs whose borders belong to different CCRs, and at the same time these CCRs are under the coordination of different RSCs (example: border EMS - Transelectrica, which is included in Shadow CCR 10 and at the same time is a service user of RSCs SCC and TSCNET, respectively).

4.1.1 Bidding Zones

Bidding zones in Europe are currently defined according to different criteria. The majority of bidding zones are defined by national borders (e.g. France or the Netherlands). However, some bidding zones are larger than national borders (e.g. Germany and Luxembourg [9] or the Single Electricity Market for the Island of Ireland) while some are smaller within individual countries (e.g. Italy, Norway or Sweden).

An optimal delineation of bidding zones should promote robust price signals for efficient short-term utilization and long-term development of the power system, whilst at the same time limiting system costs, including balancing costs and re-dispatch actions undertaken by TSOs.

The CACM Regulation envisages the definition of bidding zones not necessarily according to the boundaries of states/TSOs, but according to the position of real network congestion:

- A single country may contain several market zones (e.g. Scandinavia);
- Several countries can be merged into one market zone (e.g. DE + LU, and currently DE + LU + AT);
- The configuration of the market zones should be regularly updated according to the situation in the transmission network and market effects.

Examples of the bidding zones in the Europe are shown on the Figure 10Figure 10.

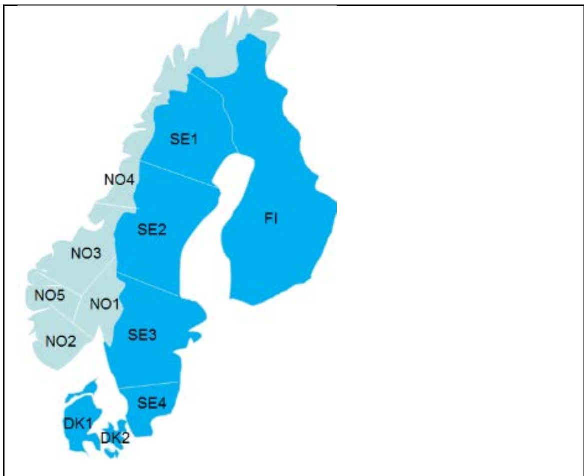


Figure 10 Example of the bidding zones in Europe

"ENTSO-E draft proposal for Capacity Calculation Regions (CCRs)" (29 October 2015) outlines potential composition of the SEE region including the non-EU bidding zones borders from the WB6. Annex 1 of that document outlines the interdependencies between EU and non-EU bidding zones borders as well as cooperation between some non-EU and EU TSOs.

[9] Before October 2018, also Austria was the part of DE-LU-AT Bidding Zone. After that, Austria is a separate Bidding Zone.

It establishes the basis for the future (early) implementation of the CACM Regulation by non-EU TSOs and creates the so-called “shadow region” or” Shadow CCR 10” (including OST). It represents the current resolution of the bidding zones (Figure 11).

Figure 11 Shadow CCR 10

It is important to note:

- TEIAS (Turkey) is not yet in the list of the Shadow CCR 10, and its status seems pending. Working assumption is that this project would by default continue on the level of Shadow CCR10 region as currently defined, while it is opened for the accession of Turkey, if defined so on the ENTSO-E level; such change is put of the scope of consultants' mission.
- EMS&KOSTT are single bidding zone, with capacity calculation and allocation operated by EMS; there are ongoing discussions regarding the future resolution which may keep or alter the existing solution; working assumption for this project is to continue with present bidding zone resolution, and to integrate any possible change if would be agreed in outer processes, during the time duration of the project.

4.1.2 Coordinated Capacity Calculators per borders

One of the important issues that must be determined by TSOs is selection of Coordinated Capacity Calculator. This is supposed to be agreed among SEE TSOs. Different entities may be selected to perform this role for different borders.

The definition of "Coordinated Capacity Calculator" is important for the future managing of the whole process of the coordinated capacity calculation and is defined in Article 2 (11) of the CACM Regulation as: "the entity or entities with the task of calculating transmission capacity, at regional level or above".

Due to the specificities of the Shadow CCR 10, TSOs of Shadow CCR 10 will use coordinated NTC approach to determine the cross-border capacities for each border of the Shadow CCR 10.

So, one of the issues is who will be the capacity calculator for the particular borders between TSOs belonging to different RSCs. The following proposal, stated in the Table 4, is based on current RSCs responsibility areas.

Table 4 Bidding zones and scenario of Coordinated Capacity Calculators on particular borders

No.	Bidding Zone 1	RSC service provider	Bidding Zone 2	RSC service provider	Possible Capacity Calculator
1	EMS&KOSTT	SCC	ESO	SCC	SCC
2	EMS&KOSTT	SCC	MEPSO	SCC	SCC
3	EMS&KOSTT	SCC	OST	SCC	SCC
4	EMS&KOSTT	SCC	CGES	SCC	SCC
5	EMS&KOSTT	SCC	NOS BIH	SCC	SCC
6	MEPSO	SCC	ESO	SCC	SCC
7	CGES	SCC	NOS BIH	SCC	SCC
8	CGES	SCC	OST	SCC	SCC
9	ESO	SCC	ADMIE	SCC	SCC
10	ADMIE	SCC	OST	SCC	SCC
11	MEPSO	SCC	ADMIE	SCC	SCC
12	EMS&KOSTT	SCC	Transelectrica	TSCNET	SCC/TSCNET?
13	EMS&KOSTT	SCC	HOPS	TSCNET	SCC/TSCNET?
14	EMS&KOSTT	SCC	MAVIR	TSCNET	SCC/TSCNET?
15	NOS BIH	SCC	HOPS	TSCNET	SCC/TSCNET?
16	Transelectrica	TSCNET	ESO	SCC	SCC/TSCNET?
17	CGES	SCC	TERNA	CORESO	SCC/CORESO?

While there are borders where TSOs from both sides already designated RSC/CCC and there no issue on the selection of CCC is expected, there are borders between TSOs belonging to different RSCs/CCCs, and the question of calculation and harmonization of NTC values remains pending.

For instance, coordinated capacity calculator for such borders, as listed in the table, possible solutions can be:

- One RSC calculates, while another RSC monitors/provides fallback;
- Both RSCs can periodically (e.g. on monthly basis) switch the roles of main and fallback CCC;

- Two RSCs (in coordination with two TSOs), can calculate separate NTC values and then harmonize them.
    - Such solution could especially be logical and applicable for perspective HVDC connection Montenegro - Italy, where the capacity of HVDC itself is clear, but two RSCs could separately assess the transfer capabilities of surrounding related AC networks (CORESO for Italy, SCC for Montenegro & SEE).

In each of mentioned cases, a proper harmonization and results selection process needs to be established.