Explanatory Document to all TSOs' proposal for the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered in accordance with Article 14(5) of Regulation (EU) 2019/943 of the European parliament and of the Council of 5th June 2019 on the internal market for electricity

1 October 2019

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1. Definitions and Interpretations

For the purposes of this document, the terms used shall have the meaning given to them in Article 2 of the IME Regulation and in Article 2 of the CACM Regulation. In case of inconsistencies, the definitions of Article 2 of the IME Regulation shall prevail.

In addition, in this document the terms used have the meaning given to them in Article 2 of the common proposal developed by all Transmission System Operators regarding the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered pursuant to Article 14(5) of the Regulation (EU) 2019/943 of the European Parliament and Council of 5th June 2019 on the internal market for electricity (recast), which is hereinafter referred to as the "BZR Methodology".

2. Introduction

ACER initiated the first edition of the bidding zone review process under Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as the "CACM Regulation") on 21st December 2016, specifying Central Europe as the relevant region. The process lasted 15 months and ended on 21st March 2018. The review concluded that the evaluation presented for the Bidding Zones (BZs) did not provide sufficient evidence for a modification of or for maintaining of the current BZ configuration, hence, the participating TSOs recommended that the current BZ delimitation shall be maintained.

The Regulation (EC) 2019/943 on the internal market for electricity (recast) (hereinafter referred to as the "IME Regulation") entered into force on 5th June 2019 and requires in its article 14 (5) all relevant TSOs to deliver a proposal for the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered (hereinafter referred to as "BZR Methodology") by 5th of October 2019.

Upon guidance received from EU Commission, ACER and the NRAs, the "relevant TSOs" for the elaboration of the BZR Methodology shall be understood as all TSOs. The BZR Methodology will therefore be a pan-European one and shall be approved by all NRAs.

The IME Regulation foresees the following timeline for the BZ Review:

- Proposal for a BZR Methodology to be submitted by all TSOs to all NRAs for approval by 5th of October 2019;
- Decision to be taken by all NRAs within 3 months of submission of the BZR Methodology by5th January 2020;
- In case NRAs cannot reach a consensus, ACER decision on the BZR Methodology by5th April 2020;
- Proposal of the participating TSOs to amend or maintain the BZ configuration to the member states or the designated competent authorities no later than 12 months after approval of the BZR Methodology.

This explanatory document provides additional background information and explains the rationale behind the choices made in the proposal for the BZR Methodology. It will be handed over to the NRAs together with the BZR Methodology in order to support their understanding of the BZR Methodology and facilitate its approval.

The following elements are elaborated upon in this explanatory note:

- Section 3: Bidding Zone Configurations. This section provides background information on how TSOs have come up with proposals for the bidding zone configurations to be analysed in the BZR methodology and includes argumentation per configuration.
- Section 4: Scenarios and Assumptions. This section provides more information about the scenarios used to analyse the different bidding zone configurations, what data is used for the assessment and what assumptions are made for conducting the assessment.
- Section 5: Bidding Zone Review Modelling Chain. This section provides an overview of the full modelling chain used to assess the different bidding zone configurations, and provides some more detailed information of individual parts of this modelling chain
- Section 6: Evaluation. In this section background information is provided per individual criterion which will be used to evaluate the different bidding zone configurations.

3. Bidding Zone Configurations

3.1. Division by Bidding Zone Review Regions (BZRR)

A two-step concept has been adopted for the delivery of the BZR Methodology (including methodology, assumptions and configurations) in order to enable the needed regional flexibility:

1. *All-TSO approach for the delivery of the methodology and assumptions:* a common proposal of all TSOs.
2. *Regional approach for the delivery of configurations:* the proposals on alternative and/or status quo configurations are delivered on a regional level by the BZ Review Regions (BZRRs), as presented in Article 4(2) of the BZ Review Methodology.

The justifications on the choice of alternative configurations, their combinations in BZRRs as well as status quo configurations are provided in Annexes of this explanatory document.

4. Scenarios and assumptions

4.1. Introduction and overview

The bidding zone review will assess the merits of alternative bidding zone configurations as compared to the status quo configuration. Each of these configurations (including the status quo configuration) will be compared on the basis of the same scenarios and assumptions. Each BZRR that is proposing alternative configurations will perform at least one model run for the Base Year for each selected BZ configuration. Optionally, the TSOs of a BZRR can choose to run the model on selected alternative scenarios based on other target years than the Base Year for each configuration as well.

4.2. Target year

The bidding zone review aims at investigating the impact of alternative bidding zone configurations for the Base Year of 2025, both for the status quo configurations and for the alternative configurations.

The year 2025 is chosen for the analysis of the Base Year for the following reasons. Firstly, by 2025 there will be more certainty concerning the applicability of the 70% criterion as intended in article 16(8) of the IEM regulation since the actions plans and derogations will come to an end at the end of 2025. Secondly, important grid infrastructure developments are expected to be completed in 2025 which gives to 2025 as Base Year a more robust picture of the actual situation than the relatively dynamic years before. The third reason to include an analysis for 2025 is that the actual implementation of bidding zone amendments require time to achieve both political agreement and to take the necessary technical measures and are therefore not likely to be performed before that year. Finally, 2025 grid models and market data are readily gathered, verified and agreed upon in the TYNDP process and therefore provide a reliable and robust basis for this BZR.

The option to study alternative scenarios or performing additional sensitivity analysis is left open to the BZRRs. A sensitivity analysis can take the form of checking for the robustness by studying alternative assumptions on grid investments or market variables. Complete alternative scenarios can be run for alternative target years or weather years for all configurations, in which target year is understood as a complete scenario with consistent assumptions for a specific year in the future . The results for complete alternative scenarios are combined with the results for the scenario for the Base Year as presented in chapter 6. The options for sensitivity analysis are discussed in chapter 4.10.

4.3. Weather years

The bidding zone review will make use of data out of the Pan-European Market Modelling Data Base (PEMMDB) or other weather data sources of equal or higher quality. This database contains historical time series data for all relevant countries considering weather years ranging from 1982 to 2016 that are necessary for modelling the infeed of weather-dependent generation (such as wind and solar) and for the load. The PEMMDB further contains a 2025 'National Trends' scenario for all data types, i.e. the expected load and generation time series projections for 2025, considering representative weather years.

The selected weather years will be based on the conditions that it should be close enough to be able to represent 2025 conditions considering the effects of climate change and that it should be representative for weather conditions in other years without many outliers and extremes. A possible method for the selection of weather years is given by the TYNDP methodology, based on a clustering method that ensures the representativeness of the selected year. If multiple weather years are considered, the final recommendation will take into account all modelled weather years as presented in chapter 6.

4.4. Grid model

For the base year, the TYNDP 2025 reference grid will be used. The reference grid model takes into consideration all high voltage network elements that are expected to be available by the end of 2025. For the purposes of the bidding zone review at least all network elements that are operated at a voltage level of 220 kV and higher are considered. The BZ Review Methodology allows TSOs to represent the 220 kV grid of its grid only partially or to take it out of the grid model for its control area only in the situation where the representation of the 220 kV grid has a negative effect on the reliability of the results. The main reason for this choice is explained by the fact that overloads at this voltage level in some grids are normally solved by topological actions. Including these congestions in this case would lead to an overestimation of congestions and redispatch costs to solve them.

Considering that a simulation of topological action is not available at this point, a simplification of the network model provides the opportunity to effectively represent such topological measures. As an alternative, TSOs can make manual changes in the grid model to represent topological measures as remedial action.

TSOs are also able to include lower voltage levels if they consider that this improves the simulations.

4.5. Load data

Zonal load data will be based on the demand data from the Pan-European Market Modelling Database (PEMMDB) 'National Trends' scenario for 2025 for the base year. If alternative target years will be assessed by the TSOs of a BZRR, PEMMDB data will be used for that target year. Load data will be disaggregated to nodal level as described in chapter 4.9. The elasticity of load wil be represented through demand side response as is listed in the PEMMDB. A Value of Lost Load (VOLL) parameter will be considered in case not all load can be served generator resources or the available demand side response. The working assumption is to utilize the VOLL in accordance with the Mid-Term Adequacy Forecast (MAF) methodology. This value respects the constraint of being more expensive than the most costly generation, such as to ensure it will be the last option to be selected in the market modelling.

4.6. Generation data

Generation data will be based on the generation data from the PEMMDB 'National Trends' scenario for relevant target year, which in case of the Base Year is 2025. Generation data with known locational information will be mapped to the appropriate nodes of the grid model. Zonal generation data, such as solar and wind capacity, will be disaggregated to nodal level as defined below in chapter 4.9

The electricity production of weather dependent generation technologies will be based on the weather-related data as generated for the PEMMDB in the Pan-European Climate Database (PECD) or a database of equivalent quality. The choice of weather year(s) or years is explained above in chapter 4.3. Wind and solar generation technologies are represented in PECD as load-factor time series. These indicate for each hour at which percentage of the total installed capacity that generation type is able to produce in a bidding zone.

Weather independent technologies are modelled based on their fundamental costs, as explained in chapter 5.2. The amount of production by the thermal generation fleet is therefore dependent on its prices, the load, the amount of variable renewable energy production and the market coupling process. Moreover, changes in the original dispatch according to the market coupling algorithm may be made according to the redispatch algorithm if it is necessary to solve congestions.

4.7. Consideration of neighbouring regions

As a result of the regional approach of the BZR, simulations carried out by TSOs of a BZRR should be focused on the geographical extent of that BZRR. A trade-off has to be found regarding the geographical scope considered in the simulations:

- On the one hand, considering only the geographical scope of the considered BZRR (i.e. completely removing neighbouring regions from the simulations) would mean that interactions between the grids and markets of neighbouring regions are completely left out;
- On the other hand, performing a full pan-European simulation for each BZRR would mean a high complexity and computational burden for TSOs of all BZRRs. The opportunity of simplification brought by the regional approach would be lost.

The proposed approach consists in applying different degrees of simplification to neighbouring regions depending on how they are connected to the considered BZRR. For simulations of a given BZRR, the table below explains how a BZ outside this BZRR (noted BZoutside) will be taken into account:

Is $Bz_{outside}$ …	**Directly connected by a tie-line to the BZRR**	**Not directly connected by a tie-line**
Part of the same synchronous area as the considered BZRR	$BZ_{outside}$ should have a grid and market modelling	Simplifications can be applied in the grid and market modelling of $BZ_{outside}$. If $Bz_{outside}$ has a negligible impact on the BZRR, it does not need to be modelled.
Part of another synchronous area than the considered BZRR	$BZ_{outside}$ should have a suitable market modelling but the grid does not need to be modelled	$BZ_{outside}$ does not need to be modelled

4.8. Other assumptions

The bidding zone review will use as an assumption fuel and CO2 prices based on the data collected for the TYNDP 2020 process for the relevant target year. For the analysis of the Base Year, the TYNDP 2025 National Trends reference prices will be used.

4.9. Disaggregation to nodal level

To allow for the analysis of alternative zones and for the optional case of an analysis of locational prices, zonal generation and load data will need to be disaggregated to nodal level in their representation in the grid model. Zonal generation and load data from PEMMDB will be disaggregated to nodal level by the TSO operating those nodes. Generation and load data from zones outside of the BZRR will not be mapped to a nodal level but be considered on a zonal level. Nodal level is understood as the level of substations of the represented voltage levels as described in chapter 4.4. Substations at lower voltage levels than those represented in the grid model will be aggregated to the most relevant substations represented in the models. This could be done on the basis of their Power Transfer Distribution Factors (PTDF). When increasing the production or consumption at a certain grid node, the most relevant substation will show the highest change in flow and therefore have the highest PTDF.

The disaggregation to nodal level can be based on a number of different sources. E.g. population density figures can be considered to reflect the division of total load over the represented grid nodes. The disaggregation of e.g. zonal installed PV capacity can be done according to land use data, such that the generated electricity is divided over the represented grid nodes according to the types of land a technology are normally built on. Land use refers to the purpose the land serves e.g settlements, recreational areas or agriculture. Each TSO can use its own methods to arrive at a nodal representation of zonal data, but these methods should be adequately explained in the bidding zone review documentation.

4.10. Sensitivity analysis

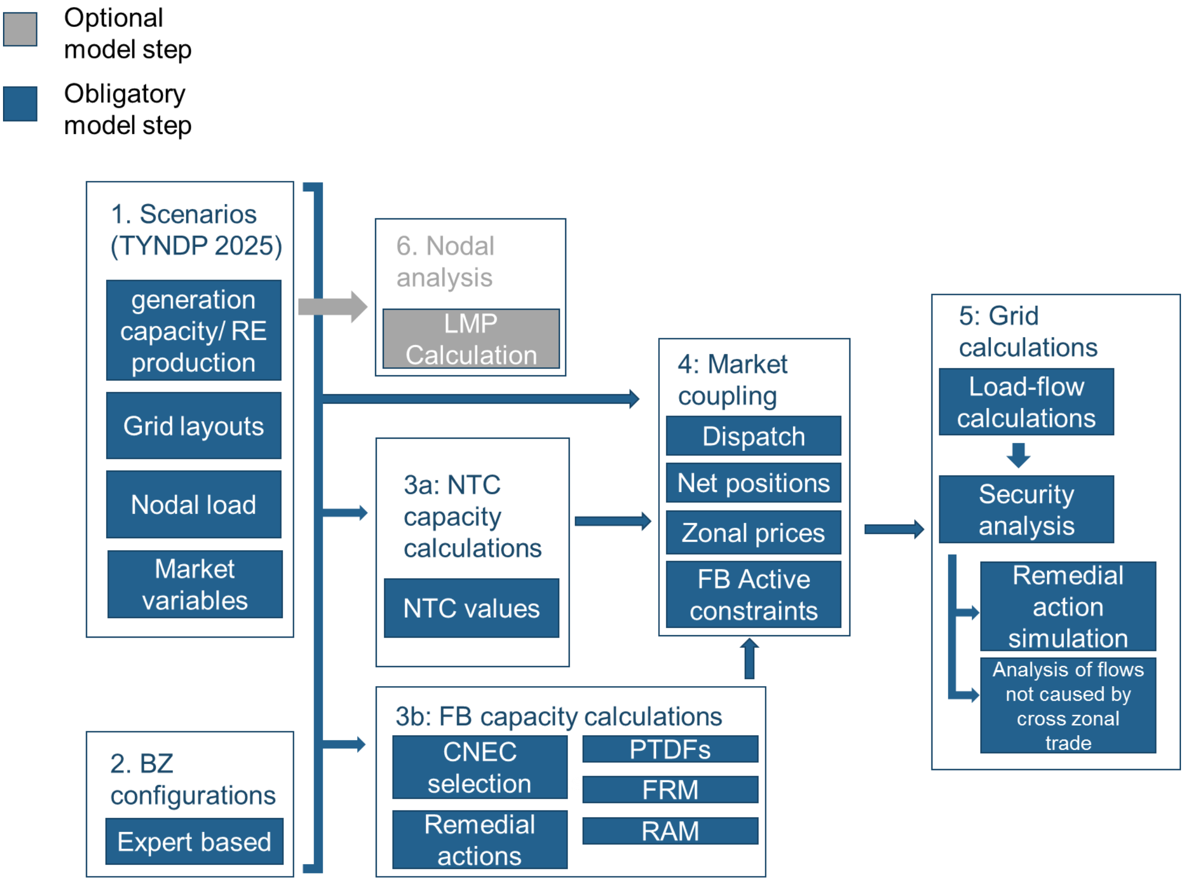
Optionally, the TSOs of a BZRR may decide to perform additional sensitivity analyses by variation of any of the input data including grid infrastructures. When modelling future scenarios, sensitivity analysis is an important tool to capture the impact of uncertainty regarding input data and to test the robustness of results. Since the BZR will focus on the year 2025, there is uncertainty with respect to input parameters such as CO_2 and fuel prices. Additionally, demand and RES infeed variability can differ depending on the weather year that is considered. Furthermore, sensitivity analysis could be used to investigate the robustness of the results to expected grid developments in order to investigate under which conditions the expected benefits remain, e.g. how bidding zone configurations are affected by future grid expansion options. Such analysis will be taken into account in the analysis of uncertainty of the final calculations and to test the 'robustness of price signals' criterion and the 'stability and robustness of bidding zones' as described in chapter 6. If variations have a strong impact on the figures calculated by the model, the uncertainty of the outcome will be higher. If little variation shows, the outcome is robust.

4.11. Configurations

TSOs of each BZRR that have provided alternative configurations will run the model for all the bidding zone configurations as listed in annexes of the BZ Review Methodology including the status quo configuration as well as alternative configurations to be compared to the status quo configuration. The final evaluation of the alternative BZ will be based on the criteria presented in chapter6.

5. Bidding zone review modelling chain

An overview of the modelling chain that will be used for the analysis of the alternative bidding zone configurations is shown in the figure below. The overview shows all obligatory and optional modelling steps as set in the articles 6 to 12 of the BZR Methodology. Additional information on these modelling steps is given in the paragraphs below. The content of the scnenarios and configurations (block 1 and 2) is explained in article 4.



5.1. Capacity calculation

Additional explanations on article 7.5.a of the BZR Methodology: NTC approach based on process-specific computations

This approach of NTC computation aims at enabling TSOs to utilize as closely as possible the practices used in the approved or foreseen capacity calculation methodologies. For example, this would enable the TSOs to simulate processes based on dichotomy, on the same principle as the current capacity calculation in SWE CCR area or in Italy North CCR. The principle of dichotomy allows, through an iterative approach, to test different levels of commercial exchanges between bidding zones and to determine *via* a security analysis which ones are secure or not from an operational point of view. The highest commercial exchange considered secure serves to determine a TTC (total transmission capacity) from which an NTC can be derived.

Additional explanations on 70% requirement in capacity calculation

The BZR shall respect the requirements of Article 16(8) of the IEM Regulation stating the minimum levels of available capacity for cross-zonal trade. For the implementation of these requirements, Recommendation of the ACER of 8 August 2019 on the implementation of the minimum MACZT pursuant to Article 16(8) of the IEM Regulation shall be taken as a reference or any other indications or guidelines provided by the NRAs about how to calculate this percentage, as long as they are available sufficiently in advance allowing their consideration in the modelling.

The ACER recommendation describes a methodology based on CNECs for both NTC and flow-based approaches.

The capacity available for cross-zonal trade on a CNEC depends on the maximum admissible power flow of the considered capacity calculation market time unit (CC MTU) which is defined as $F_{\max}$.

$F_{\max}$ should be determined in accordance with the implemented CCM and, if relevant, could be implemented as a time-varying value in order to reflect varying ambient conditions.

TSOs may apply allocation constraints according to the requirements set in Article 23(3) of the CACM Regulation, including the possibility to limit the combined import or export from one bidding zone to another to a threshold value.

The margin available for cross-zonal trade (MACZT) for a given market time unit (MTU) is defined as

$$MACZT(MTU) = MCCC(MTU) + MNCC(MTU) \geq MACZT_{\min}(MTU),$$

where $MCCC$ entails the portion of capacity available for cross-zonal trade on bidding zone borders within the considered coordination area and $MNCC$ describes the portion of capacity available for cross-zonal trade outside the considered coordination area. $MACZT_{\min}$ is the minimum margin available for cross-zonal trade.

a. The standard value for $MACZT_{\min}$ is defined as 70 % of $F_{\max}$. However, $MACZT_{\min}$ may differ depending on the simulated year due to derogations and national action plans.

b. The computation of MCCC is described in Recommendation of the ACER of 08 August 2019 on the implementation of the minimum MACZT pursuant to Article 16(8) of Regulation (EU) 2019/943.

c. For the calculation of MNCC in the BZR it is suggested to simplify the approach described in Recommendation of the ACER of 08 August 2019 on the implementation of the minimum MACZT pursuant to Article 16(8) of Regulation (EU) 2019/943 in order to reduce the complexity of the model chain. It is further suggested to assume electricity exchange from trade outside of CCR reaches the maximum NTC volume. In cases where MNCC(MTU) is positive it reduces the minimum MCCC(MTU) and will be included in the MACZT(MTU) calculation. Otherwise it is assumed to be zero. Furthermore, if it is expected that the variations of MNCC do not impact the MACZT significantly, MNCC values could be computed on one timestamps and assumed to be constant on the entire simulated timespan.

In order to consider (n-1) security, MACZT calculations have to take into account contingencies. This is ensured by the use of CNECs.

5.2. Market coupling

The market coupling algorithm combines the information from capacity calculations, generation and load data, and assumptions from the scenarios to determine the unit commitment of generators and their costs. The algorithm performs a cost-minimizing optimization, providing the least costly solution for all market participants for the considered time stamps in the respective target year. Considering that evaluation of all time-stamps of the considered target year would strongly impact the computing time, the bidding zone review will assess at least each third hour.

The market coupling model will generally assume perfect competition. Perfect competition creates a situation in which pricing of market participants is purely based on fundamental costs, representing that power plants operate in a way that leads to overall cost minimization. Results of this assumptions are generally considered to be representative for the resulting prices and unit commitment in the day ahead market process.

Representation of grid constraints

The market coupling algorithm takes into consideration the network constraints as determined in the capacity calculation chapter 5.1. Some bidding zone borders are subject to NTC based capacity calculations, while others make use of the flow-based methodology as current practice in the CWE region. As it is not yet known, which of the capacity calculation methodologies will be used for which bidding zone border, this choice will be determined by the BZRR.

- Where NTC based capacity calculations are performed NTC based constraints will be taken into account in the market coupling calculations.
- For capacity calculation making use of the flow-based methodology, the market-coupling methodology will make use of the zonal PTDFs, GSKs, and FRMs to calculate the constraints for the market coupling algorithm for the CNECs taken into account for capacity calculation. The CNECs selection is described in article 7.8 of the BZR Methodology.

For these constraints the model will take due account of the 70% provision of the IME regulation as described in chapter 5.1. These constraints together determine the domain in which the market can be operated in terms of net positions of the bidding zones. The market coupling algorithm will select the least costly solution within this domain to cover the load.

Representation of generation

The method and data available to represent electricity generation differs per technology. As presented in chapter 4.6, this data is sourced from the PEMMDB.

Thermal generation is considered to bid according to their short-run marginal cost, including fuel costs, CO_2 costs, variable operation and maintenance costs and relevant start-up costs. The fuel costs are a combination of the fuel prices and the efficiency of the power plant, as defined in the database. The fuel and CO_2 emission prices will be consistent with those used for the TYNDP process. Each of these generators will be coupled to a specific node represented in the grid model. In case the power plants have must-run constraints due to e.g. combined heat and power production, industrial process connection or other reasons, the simulation ensures that must-run obligation is always followed. The model will also take into account maintenance and outage frequencies of power plants.

This method of representation in the market model is used for all dispatchable thermal capacities, including CCGTs, gas turbines, internal combustion engine, coal and lignite power plants, nuclear power plants, oil power plants, and biomass-fired power plants. Power plant is considered dispatchable if its production volume is fully or partially dependent on the day-ahead electricity price.

Renewable generation technologies other than dispatchable biomass have different methodologies. The amount of produced Wind, Solar PV and Solar thermal electricity are considered to be weather dependent only. The load factors, i.e. the amount of production with respect to the installed capacity, for wind and solar power has been calculated for the PEMMDB for each of the ENTSO-E countries for the weather years 1982 to 2016. The total installed capacities are available for each current bidding zones but will be disaggregated to a nodal level according to chapter 4.9,'disaggregation to nodal level'. These technologies are considered to produce energy as long as resources are available, and it is required to serve the load. Only if production in combination with the must-run power plants would exceed the load, these technologies are curtailed. In principle all wind and solar resources are assumed to bid at the marginal price of €0,00 per MWh, since these technologies have negligible short-term marginal costs.

Hydroelectricity is considered as a separate category because they are both resource dependent and, with the exception of run-of-river power plants, are able to have a controllable production. The resource dependency is indicated by the inflow profiles for hydro power plants, which is dependent on the weather year under consideration. Hydroelectric power plants may include reservoir and pumping facilities, while constraints on their utilization/optimization may be applied.

Renewable power plants, other than hydro, wind, solar and dispatchable biomass are categorized as other renewables and will be represented by a price-independent infeed time series.

Non-renewable power plants, other than dispatchable thermal power plants, are represented with infeed time series with an associated marginal cost.

Representation of load

The power demand is considered to be inflexible except the share that is defined to be available for Demand Side Response (DSR). Variations of load are available for all ENTSO-E countries for the weather years 1982 to 2016 and target year 2025 in the PEMMDB. The market coupling algorithm will meet the requested load for the relevant weather year by combining the generation technologies discussed above by a cost minimization, while respecting the identified grid constraints for each considered hour. The load in PEMMD is zonally defined and will be disaggregated into nodes as described in chapter 4.9 'disaggregation to nodal level'. Load flexibility is represented by an amount available for DSR and its activation cost. There may be several categories of DSR with different activation costs and availability data in each zone In case inflexible load is shed because the available production does not suffice to meet the demand after all available DSR has been activated, the value of lost load (VOLL) is be assumed as the cost of the shedding of the inflexible part of the load.

The market coupling algorithm will determine for each timestamp the unit commitment for all power plants, which sets the power infeed or consumption at each grid node. Secondly, it determines the electricity price in each of the bidding zone. Thirdly, the market coupling calculates the Net Positions of all bidding zones. Fourthly, it determines the Commercial exchanges between bidding zones. Finally, the market coupling algorithm records for each timestamp whether the constraints were actively limiting exchanges. The expected outcomes of the model is as follows:

Output	**Unit**	**Resolution**
Amount of production	MW	Per timestamp, per node
Electricity prices	€ per MWh	Per timestamp, per zone
Net positions	MW	Per timestamp, per zone
Commercial exchanges	MW	Per timestamp, per combination

Active constraints	# of timestamps	Per Year per CBCO

5.3. Operational security analysis

This step consists in computing the flows on the grid resulting from the market coupling and detecting congestions.

Load flows are computed in N-situation and in (N-1) situations taking into account the results of the market simulation in terms of generation and load. The considered (N-1) simulations correspond to the list of contingencies defined according to article 9.2 of the BZR Methodology. The recommended approach for the load flow is to compute a DC load flow, but AC load flow can be used upon agreement of TSOs of a BZRR. In each computed situation (N- or N-1), security limit violations are detected. The list of violations (name of the affected grid element, corresponding contingency, quantitative description of the violation) forms the output of the operational security analysis. The expected outcomes of the model is as follows:

Output	Unit	Resolution
List of Violations	MW, element name	Per identified violated Branch and contingency

5.4. Remedial action simulation

In the remedial actions simulation, difficulties often arise when trying to make an automated simulation of remedial actions whose effect cannot be linearised. In particular, simulation of topological actions (such as opening / closing of circuit breakers and busbar couplers) are a major challenge when large geographical areas and large amounts of timestamps are simulated. If these topological actions are not correctly taken into account, many simulation results can be affected (e.g. operational security, redispatching costs, market coupling results…), especially for TSOs where topological actions are frequently used.
TSOs should strive towards a full consideration of all types of remedial actions. However, in case it is not feasible to fully integrate topological remedial actions into the BZR modelling chain, several options to take into account at least partially their effect can be applied in accordance with the BZR Methodology. These options should be applied only for TSOs where they are estimated to be relevant. Some of them focus on the 220 kV level because the previous Bidding Zone Review has shown that difficulties in modelling topological remedial actions can lead to results that are misleading when studying bidding zone configurations (cf. model-based approach in the First Bidding Zone Review). The considered option are presented hereunder in ascending order of complexity:

- Removing all 220 kV lines from the grid model in the entire simulation chain. This would require aggregating the loads and generations of the removed voltage level to the 400 kV substations. This possibility is granted in article 9.2 of BZR Methodology.
- Adapting the topology of the grid model by implementing some topological actions in order to avoid appearance of constraints that otherwise would require a full optimisation of these remedial actions. This possibility is granted in article 9.2 of BZR Methodology.

  Example: in some TSOs, there are frequent cases of contingencies on a 400 kV line that systematically overloads the underlying 220 kV line, and where the usual remedial actions is to open the overloaded 220 kV line curatively. In an incomplete model without optimisation of topological remedial actions, this constraint would be solved with redispatching. However, by opening the 220 kV line from the start in the grid model, the constraint is avoided without leading to an overestimations of redispatching costs.

- Removing 220 kV lines from the list of elements in the redispatching module. Ideally, removing only those lines for which known remedial actions systematically allow to solve congestions would lead to better results. This possibility is granted in article 10.3 of BZR Methodology.
- Limited assessment of non-costly remedial actions: the TSO performs a full optimisation of non-costly remedial on a representative subset of timestamps after market coupling and security analysis. This optimisation can be performed manually or with any suited software outside the BZR simulation chain. By running the redispatching calculation with and without implementation of these non-costly remedial actions, the impact of non-costly remedial actions on redispatching costs and other relevant results is assessed. This possibility is granted in article 10.3 of BZR Methodology.

The second step is to apply an optimization of the Phase Shifting Transformers (PSTs). This optimization will minimize the amount of overloads in the grid based by changing the tap positions of the PSTs. It is both feasible and realistic that such optimization takes place on a transnational level, which is current practice of the TSOs.

When, after the non-costly remedial action optimization, N-1 overloads are still present in the network, costly remedial actions are normally applied to solve these. The most important method used as a costly remedial action is redispatch. The redispatch analysis will take as input the unit commitment from the market coupling algorithm, the relevant network model and the N-1 overloads as calculated by the load-flow and security analysis. Moreover, it will take as an input the units available for redispatch and the prices for redispatching these units in the downward and upward direction. The available units for redispatch will be based on a survey among TSOs, as circumstances, the legal environment and redispatch mechanisms differ significantly per TSO. The TSOs of a BZRR can decide to add a mark up to the fundamental costs that determines the redispatch prices. Based on these inputs, the redispatch algorithm will solve all overloads by redispatching the available units at the least possible costs. In consideration of the System Operations Guideline (SO GL) article 76 and the IME regulation article 13, the redispatch simulation will be done irrespective of bidding zones, or TSO control areas. Since according to regulation it is required to perform such optimization including units in other bidding zones, a transnational optimization is close to the expected reality in the base year. The expected outcomes of the model is as follows:

Output	Unit	Resolution
Amount of production	MW	Per timestamp, per node
Redispatch costs	€	Per timestamp, total
Redispatch volume	MWh	Per timestamp, total
Redispatch volume (zonal)	MWh	Per timestam, per zone

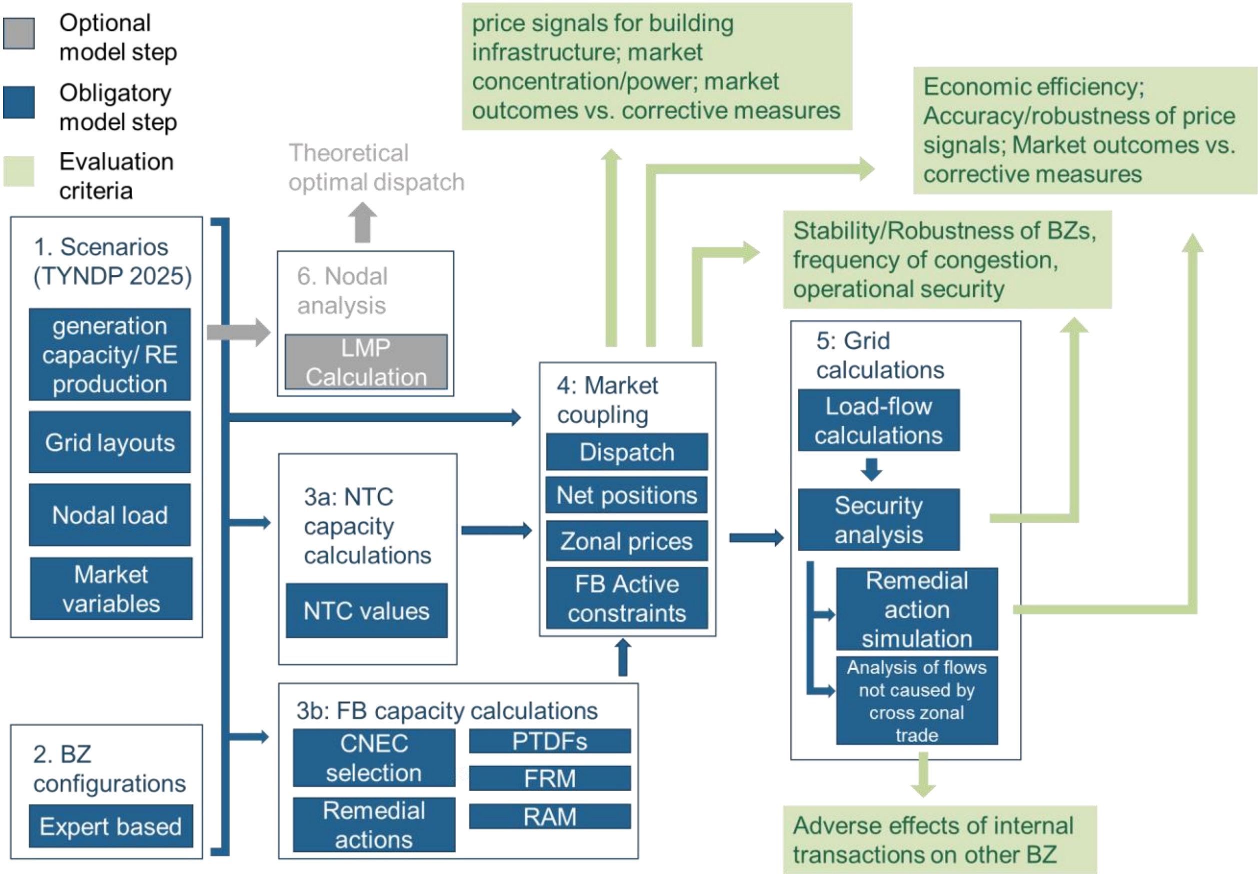
5.5. Analysis of flows not induced by cross-zonal trade

The proposed approach for the analysis of flows not induced by cross border flows comes from the Core capacity calculation methodology. It consists in computing the flows on all grid elements in a situation where the net positions of all bidding zones are shifted to 0 MW (situation with no commercial exchanges). This method has been chosen since it is included in the approved CORE capacity calculation methodology. However, alternative methods for the calculation of flows not induced by cross-zonal trade are currently under investigation in some CCR for other methodologies under development. They may be be considered additionally if agreed by the TSOs of a BZRR. The expected outcomes of the model is as follows:

Output	Unit	Resolution

Flows not induced by cross-zonal trade.	MW	Per cross-border grid element

6. Evaluation



The model chain above represents an indication from where the calculations for certain indicators are obtained. Different parts of the model chain are the source of results for different indicators. Market coupling calculations provide results for price signals for building infrastructure, and market concentration and market power. Together with the remedial action simulation it also assesses economic efficiency, accuracy and robustness of price signals and market outcomes in comparison to corrective measures. Together with the security analysis, the market coupling has impact on the criteria of robustness of bidding zones, frequency of congestions and operational security. The analysis of flows not induced by cross-zonal trade assesses the adverse effects of internal transactions on other BZ. The nodal analysis does not influence the assessment of bidding zone configurations but serves as an additional analysis that is able to show the theoretical optimal dispatch, which can serve as additional information.

Depending on the geographical scope on which the criteria are computed, a BZRR could give results about a neighbouring BZRR. Contradictory results could undermine the studies' credibility. Therefore, three categories are defined into which all criteria have to be classified since some criteria cannot be restricted to the BZRR's geographical scope.

In order to have a better understanding on the evaluation approaches chosen for each criterion further explanation is provided below.

The general principle applied for the evaluation is to monetize as many criteria as possible. However, for the evaluation of most criteria only indicators are available that do not deliver monetized outcomes. Further extensive research is needed to develop evaluation approaches that can deliver monetized results. As such, the methodology may be improved at a later stage in terms of having more criteria monetized.

(1) CACM criterion "Operational security"

The Article 3 (2) of the guidelines on electricity transmission system operation (Commission regulation (EU) 2017 / 1485) defines 'operational security' as 'the transmission system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterised by operational security limits'. Hereby, 'normal state' means 'a situation in which the system is within operational security limits in the N-situation and after the occurrence of any contingency, taking into account the effect of the available remedial actions'.

(2) CACM criterion "Security of supply"

The criterion is limited to generation adequacy as other elements are considered under the criterion "Operational Security". Generation adequacy refers to sufficient conventional and renewable installed generation capacity to supply the electrical load. While TSOs are responsible for grid security, ensuring security of supply is not a TSO task. Yet, both are interlinked, i.e. grid security cannot be ensured in cases where generation adequacy is at risk. Estimating security of supply is a complex task and can be done by assessing different indicators. For the BZR, the two basic approaches Remaining Capacity Margin (RCM: difference between the maximum available generation capacity and the maximum hourly load per hour) and Energy Not Served (ENS: missing MWh to reach generation per year) must be followed. The more complex approaches Loss of Load Expectation (LOLE: predicted hours of no supply per year) and Expected Energy Not Served (EENS: expected missing MWh to reach generation per year) can be analysed if possible. In order to implement the more complex approaches and monetise the security of supply indicator, it would be required that additional data collection and modelling is carried out. This would mean that the modelling chain is expanded to include a step which is similar to the MAF studies carried out by ENTSO-E on a yearly basis. The additional data to be collected is distribution of outage durations and outage probability. This could, with the already foreseen data to be collected, be used in a probabilistic model in order to determine LOLE and EENS which then could be translated to a monetised value by applying an agreed value of lost load (VOLL).

(3) CACM criterion "Degree of uncertainty in CZC calculation"

The degree of uncertainty in CZC calculation is generally understood as the deviation between the capacity calculation and real-time scenario. For estimating the uncertainties in the computed load flows used for the capacity calculation the "capacity calculation reliability margins" (FRMs/RMs) is used. Uncertainty in CZC calculation is inevitable due to several sources of uncertainty such as inaccuracy of zonal PTDFs, generator outages compensated by frequency containment reserve / frequency restoration reserve (FCR/FRR) and changes in RES or forecast generation and load. At least these sources of uncertainty shall be used to evaluate the degree of uncertainty in CZC calculation.

(4) CACM criterion "economic efficiency"

Economic efficiency is a well-known economic concept, also known as the welfare concept. In energy economics, the market efficiency (indicator of economic efficiency) is derived from market models and is defined as the change in the total system costs (variable production costs in the day-ahead market model including total redispatch costs). Generally, the economic efficiency represents the situation where consumers and producers can maximize their surpluses and therefore improve social welfare. Thereby, only the marginal costs of redispatch are included as mark-ups are only a redistribution from consumers to producers and therefore do not have an effect on overall welfare.

(5) CACM criterion "firmness cost"

CACM Article 2 (44) defines 'firmness' as 'a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed'. In the following, firmness costs will be understood as the related costs to ensure the cross-zonal capacity rights.

In addition, Article 61 of the Forward Capacity Allocation (FCA) Guidelines clarifies that the cost of ensuring firmness shall include costs incurred from compensation mechanisms associated with ensuring firmness of cross-zonal capacities as well as the cost of redispatching, countertrading and imbalances associated with compensating market participants, and must be borne by TSOs, to the extent possible in accordance with Article 16(6)(a) of Regulation (EC) No 714/2009.

(6) CACM criterion "market liquidity"

Under market liquidity it is generally understood how quickly any market participant is able to buy or sell any volume of energy (implicit) or capacity (explicit) without greatly affecting the market price. If the market is highly liquid, it is the sign of efficient distribution of relevant supply and demand information which leads to an efficient market dispatch. Also, there is a strong relation to the risk exposure. In liquid markets, open trading positions are closed more quickly which facilitates the trading and hedging process. Illiquid markets are connected to a lot of uncertainties which traders must face when they want to trade their assets and this high-risk exposure leads to higher costs. Liquid markets minimise risks and increase total market efficiency.

For the purpose of the quantitative analysis, the market-depth analysis seems to be the best approach for assessment. The analysis will focus on the price change between the respective orders taking into account possible cross-zonal exchanges. It needs to be noted that in the fundamental market model the only possibility is to simulate a single ("aggregated") timeframe i.e. without distinction between long-term, day-ahead or intraday timeframe. In case TSOs find out that the model results are accompanied by a lot of uncertainties during the calculations, analysis of historical data shall be performed.

(7) CACM criterion "Market concentration and market power"

Market concentration describes the number of players with a relevant market share at the demand and supply sides. Market power is a different concept and is related to the capability of certain parties to profitably manipulate market prices.

For the evaluation of "market concentration" two indicators shall be calculated, the HHI (Herfindal-Hirschman-Index) and the RSI (Residual Supply Index), also known as PSI (Pivotal Supplier Indicator).

The HHI is an indicator of economic theory to measure market concentration and is defined as the sum of the squared market shares

$$HHI = \sum_{i=1}^{N} s_i^2$$

where s_i is the market share of company i in the market and N is the total number of companies in the market. The HHI ranges from 1/N to 1.

A small HHI indicates a highly competitive (unconcentrated) market, while a high HHI indicates a high market concentration.

Another well-known indicator to measure market concentration is the RSI, also known as the Pivotal Supplier Indicator, which also considers potential imports. The RSI measures how much capacity remains in the market, when one provider retains its capacity:

$$RSI = \frac{Total\ Supply - Largest\ Seller's\ Supply}{Total\ Demand}$$

where s_i is the market share of company I in the market and N is the total number of companies in the market.

Cross-zonal contributions can in general be considered as follows:

$$Total\ supply = Total\ domestic\ supply\ capacity + Total\ net\ import$$

An RSI above 100% indicates that sufficient capacity remains in the market to meet the demand. An RSI below 100% indicates that the remaining capacity does not meet the demand.

Intermittency of variable renewable generation will be considered when calculation the supply. Since it is not possible to derive meaningful assumptions regarding the net import or export that could be considered for new bidding zone borders for which no historical import and export values are available, the quantitative analysis will neglect these. Yet, consideration of net imports would lead to decreased domestic market concentration, while consideration of net exports would lead to increased domestic market concentration.

Market power is a different concept and is related to the capability of certain parties to profitably manipulate market prices. The measurement of market power is more difficult since it requires competition modules to be incorporated in the modelling. Thus, it shall be assessed qualitatively.

(8) CACM criterion "facilitation of effective competition"

Effective competition is the situation in which there are enough companies in the market able to compete to produce the same product and there does not exist a single company that is able to raise prices significantly above the system marginal cost for a given time period.

The facilitation of effective competition represents the combination of the four criteria - market liquidity, market concentration, market power and robustness of price signals which are strongly interlinked. High market liquidity, low market concentration and low market power in combination with robust price signals are preconditions for effective market competition.

(9) CACM criterion "price signals for building infrastructure"

The CACM Article does not clarify whether the term "infrastructure" refers to investments in generation/demand only or investments in network infrastructure and due to the fact, that "price signals" are mentioned twice in the CACM Article for the purpose of this evaluation the term "infrastructure" is interpreted as transmission grid infrastructure.

There are two different types of lines creating the transmission grid infrastructure – the internal lines and the cross-zonal lines. The internal lines' price signals should be based on actual market results which show the efficiency of the grid and the need for their expansion but in reality, these investments are widely regulated and hence they do not depend on the market price signals. Due to this fact the investments in cross-zonal lines seem more relevant. Price signals for building of cross-zonal lines are represented by price differences between neighbouring zones. Additionally, the correlation between market congestion and physical congestion may be considered for the bidding zone borders under investigation. This would be reflected by measuring whether price differentials between bidding zones and physical congestion in the cross-sections between those bidding zones bidding zones occur simultaneously.

(10) CACM criterion "Accuracy and robustness of price signals"

Accuracy of price signals is understood as the ability of prices to reflect all relevant market and grid conditions. The more accurately prices reflect market conditions and the restrictions of the underlying grid, the better prices will be able to guide market participants in efficiently utilising the power system in the short term and developing the power system in the long term. With this view, it is considered relevant that day-ahead zonal prices lead to:

- Dispatching conditions compatibile with the system security: paying higher prices to power plants of which their infeed relieves congestions and lower prices to power plants of which their infeed increases congestions, and/or
- Higher revenues for generators located in bidding zones which are facing potential scarcity situations in terms of adequacy margins.

Hence, the two indexes identified for measuring price signals accuracy are aimed at measuring the ability of different bidding zone configurations to cope with the two goals mentioned above.

Robustness of price signals is understood as the continuity of price signals with regard to external conditions. Therefore, the more robust a price signal, the less it depends on alternative assumptions with regard to e.g. grid infrastructure, investments in generation and demand and economic variables. Since the robustness of prices makes use of the differences in prices signals for different assumptions it can be quantitatively assessed only if alternative scenarios are simulated, or sensitivity analyses are performed.

(11) CACM criterion "transition and transaction cost"

Transition and transaction costs follow an adjustment of a bidding zone configuration. Transition costs are understood as the 'one-time' costs directly related to a configuration change.

Transaction costs generally refer to the costs of participating in the market. They are permanent costs for search and information, bargaining, policing and enforcement. Transaction costs are, to some extent, specific to a given bidding zone configuration.

The type of such costs as well as their level varies largely among different actors affected by a reconfiguration as well as by the reconfiguration itself (e.g. whether BZ border is along TSO border, whether the BZ configuration has been adapted before, whether the grid is highly meshed or not).

(12) CACM criterion "infrastructure cost"

The ENTSO-E Guidelines for Cost Benefit Analysis of Grid Development Projects provides a definition for project costs and states that 'total project expenditures are based on prices used within each TSO and rough estimates on project consistency (e.g. km of lines)". Environmental costs can vary significantly between TSOs. More details on the Cost Benefit Analysis, which is e.g. applied in the TYNDP, can be found in the Guidelines themselves (e.g. project costs are pre-tax).

The grid scenarios considered in the Bidding Zone Review are based on the investments considered in the TYNDP. Due to its broader focus, the TYNDP refers mainly to cross-zonal projects and considers the current bidding zone configuration as an exogenous assumption. Since the Bidding Zone Review has a more detailed focus and aims for the assessment of alternative bidding zone configurations, national grid investment projects (located within the current bidding zones) will be added to the list of TYNDP grid investments for the purpose of this Bidding Zone Review.

Grid investments included in the TYNDP address the major system bottlenecks and structural congestions. Addressing those structural congestions by an adaptation of bidding zones would not remove them but rather disclose those congestions transparently to the market and restrict trading accordingly. This would not, per se, change the need for grid investments. Since, in comparative terms, grid investments would not change in the different configurations, a detailed assessment of the costs of building new grid infrastructure to the full extent is not relevant for the Bidding Zone Review. The absolute level would correspond to the costs of investments reported in the TYNDP.

The impact of alternative bidding zone configurations on the infrastructure costs will not be considered explicitly in the Bidding Zone Review. Instead, we refer here to the TYNDP 2025. In addition, costs for national investment projects can be found in the national grid development plans.

(13) CACM criterion "Market outcomes in comparison to corrective measures"

For this criterion, the market outcome respectively market dispatch and the corrective measures respectively redispatch shall be compared. The question is whether economically inefficient remedial actions are applied. In order to answer this question, in a first step, redispatch costs and possibly volumes are compared between the benchmark and the alternative configuration under investigation. In a second step, market dispatch costs are compared between the benchmark and the alternative configuration under investigation. Finally, the changes from the first two steps are compared so that the change in the overall system costs between the two configurations is given. Since the system costs are also tackled within the criterion "economic efficiency", the outcome of the criterion "market outcomes in comparison to corrective measures" is only used for comparison and validation purposes and not for the final assessment.

(14) CACM criterion "Adverse effects of internal transactions on other BZs"

Adverse effects of internal transactions on other BZs are understood to be flows not induced by cross-zonal trade. Flows not induced by cross-zonal trade is defined as all flows that are still present in case no cross zonal trades are performed in the market coupling..

(15) CACM criterion "Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes"

The adjustment of a bidding zone configuration will most likely impact the operation and the efficiency of the balancing mechanisms of the concerned TSOs and the imbalance settlement process.

The type of impacts as well as their level might vary largely among the different TSOs involved in the specific bidding zone reconfiguration. For the evaluation of impacts on balancing mechanisms and imbalance settlement processes. It is important to evaluate the capability of the new LFC blocks associated to the new bidding zones to balance the system taking into account both the new availability of balancing resources and the foreseen level of congestion with the new bidding zones in terms of delivery of balancing power and different market incentives for providers. This is important in new BZs with high RES share where higher balancing needs will exist.

(16) CACM criterion "stability and robustness of bidding zones over time"

This criterion is strongly linked to other CACM criterion "location and frequency of congestion" and in order to ensure stability and robustness of bidding zones over time, bidding zone borders need to reflect structural congestion as well as ensure that it occurs within the same grid area.

(17) CACM criterion "Consistency across capacity calculation time frames"

The question as to whether an alternative bidding zone configuration leads to a higher or lower level of consistency across capacity calculation timeframes is not a technical one but related to the market design. From a technical / economical point of view, the same bidding zones shall be considered across all timeframes. If not, a different structure of bidding zones (e. g. bidding zones in day-ahead markets look different than in the intraday market segments) might lead to inconsistent price signals and might create undesirable arbitrage possibilities (between the different markets). Hence, whether the consistency across all capacity calculation time frames shall be ensured or not is a question of the desired market design. It is, therefore, more a decision than an evaluation criterion.

(18) CACM criterion "Assignment of generation and load units to BZs"

It is in the nature of things that the assignment of units and loads in a new bidding zone configuration cannot become easier or 'better' compared to the current one, because the current bidding zone configuration already considers a clear assignment of every generation and load unit. In general, the geographical location of a generation or load unit should clearly indicate to which bidding zone the unit would be assigned in case of an adaptation of bidding zones. Yet, specific contractual requirements can lead to an assignment which does not correspond to its geographical location. Additionally, it is not unusual that large thermal generation units are connected to more than one substation. If such a generation unit is close to the new bidding zone border, one has to decide to which bidding zone both substations shall be assigned. The analysis for this criterion shall be made through expert discussions and shall compare the level of difficulty of assigning generation and load units to bidding zones between the different configurations under investigation.

(19) CACM criterion "Location and frequency of congestion (market and grid)"

This criterion is strongly linked to the CACM requirement for bidding zones to be 'sufficiently stable and robust over time'. Hereby, the assessment of the location and frequency of congestion forms the basis for the evaluation of whether reconfigured bidding zones can be considered as sufficiently stable and robust over time.

In order to examine whether the congestion remains sufficiently stable and robust over time, congestion has to be compared for the configuration under investigation over different sensitivity analyses or years. Market congestion could thereby be represented by the active market constraints resulting from the market coupling, while grid congestion could be represented by overloads resulting from the grid calculations. Additionally, future investment which may relieve existing congestion shall be taken into account. For this purpose, the ENTSO-E TYNDP could be used.

(20) Criterion "RES integration"

This criterion is not specifically mentioned in CACM Article 33. However, in light of the CEP target to provide clean energy for all Europeans, the integrated amount of energy from RES is an important indicator to be analysed.

Annexes:

Annex 1 – Considerations on Bidding zone review region "Central Europe" bidding zone configurations;

Annex 2 – Justification of alternative configurations of the Bidding zone review region "Nordics" which are to be considered in the bidding zone review process;

Annex 3 – Justification of alternative configurations of the Bidding zone review region "South East Europe" which are to be considered in the bidding zone review process;

Annex 4 – Justification of configurations of the Bidding zone review region "Central Southern Italy" which are to be considered in the bidding zone review process;

Annex 5 – Justification of configurations of the Bidding zone review region "Baltic" which are to be considered in the bidding zone review process;

Annex 6 – Justification of configurations of the Bidding zone review region "Iberian Peninsula" which are to be considered in the bidding zone review process;

Annex 7 – Justification of configurations of the Bidding zone review region "Single Electricity Market Ireland" which are to be considered in the bidding zone review process;

Annex 8 – Justification of configurations of the Bidding zone review region "United Kingdom" which are to be considered in the bidding zone review process.