Bidding Zone Review

Bidding Zone Review Region (BZRR)

Central Europe

**Background**

This document serves – along with the provided overview Excel file *“20221111\_BZR\_Input Data and Assumptions Overview\_CE.xlsx”* - to satisfy the requirements of Article 17.2 pursuant to Article 16 of the *ACER Decision of 24 November 2020 on the Methodology and assumptions that are to be used in the bidding zone review process (hereafter the “Bidding Zone Review methodology”) in accordance with Article 14(5) of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.* As per Article 16.2, the list of the minimum set of data to be published is outlined in Appendix Ia of the Bidding Zone Review methodology.

This document provides additional information, supplementary to what is in the overview Excel file. The structure and contents follows from Part A of Appendix Ia (e.g. Chapter 1 – Scenario, Chapter 2 – Generation etc.). For some items the response or data is addressed sufficiently in the Excel, and not repeated here. For these sections, the comment *‘See Excel’* is given. For other aspects more detailed data or explanations are provided.

30 November 2022

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**Changelog**

List of important changes in this document in comparison to version 16 November 2022.

* 30 November 2022
  + Table 2: List of additional grid projects expected by the year 2028 included in the sensitivity analysis, the following changes have been applied for Romania:
    - Added Overhead Line 400kV Resita – Timisoara – Sacalaz (it will be commissioned in 2026)
    - Added Overhead Line LEA 400 kV Timisoara – Arad (it will be commissioned in 2027)
    - Added Overhead Line 400 kV Constanta Nord – Medgidia (it will be commissioned in 2028)
    - Removed the upgrade of existing 220kV double circuit OHL Timisoara-Sacalaz-Arad to 400kV (will be commissioned in 2029)
  + Table 7: Overview of the capacity calculation method applied per border modelled in BZRR CE
    - Typo corrected where the border ITN1 – ITCN was erroneously labelled to be part of the Hansa CCR whereas it is part of the Greece-Italy CCR
  + In section 1.2, a fourth dimension is introduced for the sensitivity analysis: the demand, based on expectations for the year 2028

List of important changes in this document in comparison to version 8 October 2022.

* 16 November 2022
  + Table 2: List of additional grid projects expected by the year 2028 included in the sensitivity analysis
    - Project “Brabo III: capacity increase between Doel and Mercator” was removed from the list of project to be included in the grid model for the sensitivity analysis, as this project is already active in the 2025 base case scenario.
    - Additional grid projects for the Czech Republic have been added to the table
  + Updated the grid model information included in section 1.3.
  + Hydro redispatch mark-up adjusted in Table 6 (in the absence of sufficient data, values from the category “Gas CCGT old 2” are assumed)
  + In section 2.9, for the cost for ensuring availability of redispatching units two historical values are needed; for both values data sources have been added in footnotes. The value of the hourly peak upward dispatch change over the year has been corrected.
  + Updated reserves capacities for CZ, DE and NL in Table 7.
  + Romanian action plan added to Table 8

## List of all climate years used as a basis for the study.

*See Excel.*

## Description of the sensitivities used to complement the scenario of the ‘main study’.

In order to assess the stability and robustness of bidding zones over time criteria without leading to infeasible simulation times, BZRR Central Europe will consider a single sensitivity analysis in which several dimensions are varied together:

* Higher fuel and carbon prices (aligned with the Nordics)
* Additional grid expansion projects, based on expectations for the year 2028
* Additional capacity of renewable energy resources (RES), based on expectations for the year 2028
* Demand adjustments, based on expectations for the year 2028

The alternative fuel and carbon prices are aligned with the assumptions used in the European Resource Adequacy Assessment (ERAA) 2022, which are representative of forecasts for the period 2025-2028. The underlying fuel prices are based on the assumptions in *Commission staff working document implementing the REPowerEU action plan*, published in May 2022.[[1]](#footnote-2) The carbon price is based on an interpolation between recent high prices and IEA WEO2021 2030 Announced Pledges scenario[[2]](#footnote-3). These fuel and carbon price assumptions applied in the CE sensitivity shown in Table 2 are fully aligned with the assumptions applied in the Nordic sensitivity.

The additional grid expansion projects are considered based on expectations from CE TSOs on which additional internal and cross-border lines are expected to be commissioned by the end of 2028. The additional projects considered with respect to the main scenario (which considered only projects expected to be commissioned up to 30 June 2025) are listed in Table 1.

The additional RES capacities (solar PV, onshore and offshore wind) in the sensitivity are largely aligned with the National Estimates scenario in the European Resource Adequacy Assessment (ERAA) 2022, for target year 2028 (Table 3).

The 2028 demand time series in the sensitivity are based on the European Resource Adequacy Assessment (ERAA) 2022[[3]](#footnote-4). As the ERAA 2022 demand series cover 2027 and 2030, the year 2028 has been obtained from a linear interpolation.

Table 1 – Description of fuel and carbon price assumptions in the sensitivity analysis

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Unit | Fuel/  Commodity | Main scenario | Sensitivity | Source |
| €/GJnet | Nuclear | 0.47 | 0.47 | No change |
| Lignite | 1.8 | 1.8 | No change |
| Hard Coal | 2.3 | 3.02 | REPower EU (2028) |
| Gas | 5.57 | 12.5 | REPower EU (2028), adjusted for gas blend |
| Light oil | 12.87 | 19.25 | REPower EU (2028) |
| Heavy oil | 10.56 | 15.79 | REPower EU (2028) |
| Oil shale | 1.56 | 1.74 | same as TYNDP (2028) |
| €/t | CO2 | 40 | 103.5 | Interpolation between recent high prices and IEA WEO2021 2030 Announced Pledges scenario[[4]](#footnote-5) |

Table 2 – List of additional grid projects expected by the year 2028 included in the sensitivity analysis

|  |  |
| --- | --- |
| Project | Country |
| PSTs Westtirol | AT |
| second 380/220 kV transformer Westtirol | AT |
| Seyring new switch gear | AT |
| Interconnector DE-LUX - Aach(DE) - Bofferdange (LU) | DE / LU |
| Harmony link | PL |
| Decommissioning lines: KRA-GOR, ZRC-SLK, DUN-SLK, ZDK-SLK (1 tor), ZDK-GDA, ZDK-PKW (220 kV), PKW-PLE (220 kV), PKW-BYD (2 tory 220 kV), PKW-BYD (2 tory 220 kV), BYD-JAS (220 kV), JAS-GRU (220 kV), DBN-PAS, DBN-TRE, PAS-OSR, TRE-JOA, JOA-WIE, GBL-OLM | PL |
| New line commissioning: KRA-BCS, BCS-GOR, GDP-GDA (110 kV), ZCB-SLK, ZCB-ZRC, DUN-KZE, KZE-SLK, KZE-ZDK, ZDK-GDP, ZDK-PKW, PKW-PLE (400 kV), PKW-BYD (400 kV), BYD-JAS (400 kV), JAS-GRU (400 kV), DBN-PAS, DBN-OSR, TRE-ROK, WIE-ROK, ROK-JOA, ZCB-GDP, PBO-CZT, PBO-BIR, PBO-KOM, PBO-BUJ, MOS-PBO, KOP-PBO, PBO-XLI\_PD21, PBO\_XLI\_PD22, DBN-PBO, WIE-PBO, PBO-XDT\_PD11, PBO-XNO\_PD11, GBL-OLM, GBL-OLM | PL |
| New trafo commissioning: BCS, GDP, WIE, ZDK, PKW, BYD, JAS, PBO | PL |
| HTLS Mercator-Bruegel: upgrade existing corridor | BE |
| Ventilus: new internal corridor from coast to Izegem/Avelgem | BE |
| Boucle du Hainaut: new internal corridor from Avelgem to Courcelles | BE |
| Rüthi | CH |
| 380kV Beznau-Mettlen | CH |
| Increase the capacity of existing 400 kV Double OHL V445/446 Hradec - Rohrsdorf from 1393 MW to 1694 MW | CZ |
| New network element commissioning - OHL V429 Kočín - Přeštice | CZ |
| New network element commissioning - OHL V803 Nošovice - Prosenice | CZ |
| New network element commissioning - OHL V406 Kočín - Mírovka | CZ |
| New network element commissioning - OHL V407 Kočín - Mírovka | CZ |
| New network element commissioning - OHL V811 Hradec Západ - Výškov | CZ |
| New network element commissioning - OHL V495 Chodov - Čechy Střed | CZ |
| New network element commissioning - OHL V479 Chotějovice - Výškov | CZ |
| Existing network element de-commissioning - OHL V210 Chotějovice – Bezděčín | CZ |
| Existing network element de-commissioning - OHL V211 Chotějovice – Výškov | CZ |
| Existing network element reinforcement/upgrade - OHL V423 Čebín – Sokolnice | CZ |
| Existing network element de-commissioning - OHL V209 Čechy Střed - Bezděčín | CZ |
| Existing network element reinforcement/upgrade - OHL V409 Praha Sever - Čechy Střed | CZ |
| Existing network element reinforcement/upgrade - OHL V419 Praha Sever – Výškov | CZ |
| Existing network element reinforcement/upgrade - OHL V245X1N Lískovec - Xnode (Podborze) | CZ |
| Existing network element reinforcement/upgrade - OHL V246X1N Lískovec - Xnode (Podborze) | CZ |
| Existing network element reinforcement/upgrade - OHL V443X1N Dětmarovice - Xnode (Podborze) | CZ |
| Existing network element reinforcement/upgrade - OHL V444X1N Nošovice - Xnode (Podborze) | CZ |
| Existing network element reinforcement/upgrade - OHL V453 Neznášov – Krasíkov | CZ |
| Existing network element reinforcement/upgrade - OHL V416 Mírovka – Prosenice | CZ |
| New network element commissioning - New 420 kV substation Praha Sever | CZ |
| Italy – Montenegro 2nd pole | IT |
| Italy – Tunisia | IT |
| Italy-Slovenia | IT |
| Lienz (AT) - Veneto region (IT) 220 kV | IT |
| Tyrrhenian Link | IT |
| New HVDC Centro Sud / Centro Nord | IT |
| New cable Bolano-Paradiso | IT |
| New 380kV Substation and new OHLs 380 kV “Montecorvino – Avellino N - Benevento II” | IT |
| New OHL 380 kV “Laino – Altomonte” | IT |
| New OHL 380 kV "Chiaramonte Gulfi – Ciminna" | IT |
| Internal grid reinforcements in Pordenone Area | IT |
| Internal grid reinforcements in Veneto Area | IT |
| Capacity increase for 380 kV OHL "Parma - S.Rocco" | IT |
| 50HzT-P221/M460a/DC-Kabel Hansa PowerBridge (HPB) | DE |
| 50HzT-P357/M566/Querregeltransformatoren inkl. Anlagenumstrukturierung UW Güstrow | DE |
| 50HzT-P358/M567/Netzkuppeltransformatoren Lauchstädt und Weida | DE |
| P37/M25a/Vieselbach – Landesgrenze Thüringen/Hessen | DE |
| P37/M25b/Landesgrenze Thüringen/Hessen – Mecklar | DE |
| P72/M351/Abzweig Göhl | DE |
| P124/M209a/Wolmirstedt – Klostermansfeld | DE |
| P124/M209b/Klostermansfeld - Schraplau/Obhausen - Lauchstädt | DE |
| P150/M352a/Schraplau/Obhausen - Wolkramshausen | DE |
| P150/M463/Wolkramshausen – Vieselbach | DE |
| P161/M91/Großkrotzenburg - Urberach | DE |
| P200/M425/Punkt Blatzheim - Oberzier | DE |
| P406/M606/Aach - Bofferdange | DE |
| P410/M624/Querregeltransformatoren (PST) in Enniger | DE |
| AMP-P21/M51b2/Regelzonengrenze TTG/AMP - Merzen | DE |
| AMP-P47/M60/Urberach - Pfungstadt - Weinheim | DE |
| AMP-P47a/M64/Punkt Kriftel - Farbwerke Höchst-Süd | DE |
| TTG-P21/M51a/Conneforde - Garrel/Ost - Cappeln/West | DE |
| TTG-P21/M51b1/Cappeln/West - Regelzonengrenze TTG/AMP | DE |
| TTG-P24/M71b/Dollern - Sottrum | DE |
| TTG-P24/M72/Sottrum - Mehringen (Grafschaft Hoya) | DE |
| TTG-P24/M73/Mehringen (Grafschaft Hoya) - Landesbergen | DE |
| TTG-P151/M353/Borken - Twistetal | DE |
| DC4/DC4/Wilster/West - Bergrheinfeld/West (SuedLink) | DE |
| DC5/DC5/Wolmirstedt - Isar | DE |
| P314/M489/Querregeltransformatoren (PST) im Saarland | DE |
| DC5/DC5/Wolmirstedt - Isar | DE |
| P176/M387/Eichstetten - Bundesgrenze [FR] | DE |
| TNG-P47/M31/Weinheim - Daxlanden | DE |
| TNG-P47/M32/Weinheim - Mannheim (G380) | DE |
| TNG-P47/M33/Mannheim (G380) - Altlußheim | DE |
| TNG-P47/M34/Altlußheim - Daxlanden | DE |
| TNG-P49/M41a/Daxlanden - Bühl/Kuppenheim - Weier - Eichstetten | DE |
| DC3/DC3/Brunsbüttel – Großgartach (SuedLink) | DE |
| P53/M350/Ludersheim - Sittling - Suchraum Stadt Rottenburg/Gemeinde Neufahrn - Altheim | DE |
| P112/M201/Pleinting - Bundesgrenze DE/AT | DE |
| P112/M212/Abzweig Pirach | DE |
| P222/M461/Oberbachern - Ottenhofen | DE |
| TYNDP Project n° 228 | FR |
| OHL 400kV Resita – Timisoara – Sacalaz | RO |
| OHL LEA 400 kV Timisoara – Arad | RO |
| OHL 400 kV Constanta Nord – Medgidia | RO |

Table 3 - Comparison between RES capacities assumed in the main scenario and sensitivity

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | Solar PV | | Onshore Wind | | Offshore wind | |
| Zone | Main scenario | Sensitivity  (ERAA 2028) | Main  scenario | Sensitivity  (ERAA 2028) | Main  scenario | Sensitivity  (ERAA 2028)) |
| AT00 | 5.0 | 9.2 | 5.5 | 6.5 | 0.0 | 0.0 |
| BE00 | 7.5 | 9.4 | 3.6 | 4.4 | 2.3 | 3.0 |
| CH00 | 4.0 | 8.5 | 0.2 | 0.3 | 0.0 | 0.0 |
| CZ00 | 2.6 | 7.3 | 0.6 | 0.7 | 0.0 | 0.0 |
| DE00 | 74.5 | 157.8 | 63.9 | 92.8 | 11.1 | 14.6 |
| DEKF | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 0.3 |
| DKKF | 0.0 | 0.0 | 0.0 | 0.0 | 0.6 | 0.6 |
| DKW1 | 1.8 | 4.7 | 4.4 | 4.5 | 1.7 | 2.6 |
| FR00 | 23.1 | 33.4 | 25.9 | 31.3 | 3.0 | 3.5 |
| HR00 | 0.3 | 1.0 | 1.2 | 2.6 | 0.0 | 0.0 |
| HU00 | 3.8 | 8.6 | 0.3 | 0.3 | 0.0 | 0.0 |
| ITN1 | 12.1 | 29.0 | 0.3 | 0.3 | 0.0 | 0.2 |
| LUG1 | 0.3 | 0.5 | 0.4 | 0.4 | 0.0 | 0.0 |
| NL00 | 11.9 | 28.3 | 6.0 | 8.6 | 5.9 | 8.7 |
| PL00 | 4.9 | 10.9 | 9.6 | 10.5 | 0.7 | 5.9 |
| RO00 | 3.4 | 4.3 | 4.3 | 4.9 | 0.0 | 0.0 |
| SI00 | 0.9 | 1.5 | 0.0 | 0.1 | 0.0 | 0.0 |
| SK00 | 0.9 | 1.0 | 0.2 | 0.4 | 0.0 | 0.0 |

## Network model for the scenario and sensitivities

### Main scenario

While the LMP study made use of a PSSE format model, the tool chain developed for the main study in CE has been developed to use a CGMES format model. This model has been provided to ACER in Annex B. The CGMES model was developed in parallel with the PSSE model, such as to ensure consistency between both models. However, since the end of the LMP study, some minor changes have been made in the CGMES model. These changes are listed below.

* Some rdf:IDs had to be changed from the original rdf:IDs in the LMP grid model as they were not corresponding to the UUID format which is required by the CGMES standard, which can cause problems during the import process for some modelling tools (e.g. TNA).
* Zero branch reactances were set to a very low value (0.001) to ensure load flow numerical stability.
* 14 German grid reserve generators were added to the model for the RAO modelling, which were previously missing from the LMP model.
* Numerous syntax changes were made to correct the delivered model (e.g. transformers referring to the same node at both ends, SynchronousMachine.qPercent values exceeding the 100%, missing attributes).
* The network structure of the Belgian grid was adjusted to correctly represent the Brabo III project in the CGMES model. This was not correctly represented in the PSSE model.

Note that where syntactical or identifier model parameters have been changed, this should not have an effect on the grid topology and should not alter any power flow calculation results.

### Sensitivity

An additional grid model is currently being built to be used for the sensitivity analysis including (i) the additional infrastructure projects considered in CE for target year 2028 (Table 2) and (ii) the additional RES capacities considered for target year 2028 (Table 3).

## List of additional infrastructure projects for the target year compared to the year when the BZR starts.

The grid projects considered in the main scenario are unchanged from those considered in the LMP study, which are based on their expected realization by June 2025.

## Assumptions on how different voltage levels were considered or not, per bidding zone.

*See Excel.*

# Generation

## Generation time series for weather dependent generation units

*See Excel.*

## Minimum and maximum generating capacities

*See Excel.*

## Must run constraints

Must-run constraints are considered in all steps of the modelling chain (NTC, Flow-based, RAO).

## Ramping capabilities

Inclusion of ramping limits depends on the simulation step:

* EU-wide NTC Considered, in a simplified way
* CE-Flow based Considered, in a simplified way
* RAO: Not considered

## Minimum run time

Inclusion of minimum run times depends on the simulation step:

* EU-wide NTC Not considered
* CE-Flow based Considered
* RAO: Not considered

## Start-up and shut-down times

Inclusion of start-up and shut-down times depends on the simulation step:

* EU-wide NTC Not considered
* CE-Flow based Considered
* RAO: Considered, in a simplified way (Art 9.8.b)

## Start-up costs

Inclusion of start-up costs depends on the simulation step:

* EU-wide NTC Considered
* CE-Flow based Considered
* RAO: Considered, based on post-processing

## Breakdown of short-run marginal costs used for market dispatch

Table 4 gives a breakdown of the typical short-run marginal cost (SRMC) of the different generator types considered in the market simulations, for both the main scenario and sensitivity analysis fuel and carbon prices.

Table 4 – Breakdown of short-run marginal cost elements per generator type in the main scenario and sensitivity

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Plant category | Indicative efficiency  (% LHV) | Main scenario | | | | Sensitivity | | | |
| Total SRMC (€/MWh) | *- of which fuel* | *- of which CO2* | *- of which VOM* | Total SRMC (€/MWh) | *- of which fuel* | *- of which CO2* | *- of which VOM* |
| Nuclear/- | 33% | 14.1 | 5.1 | 0.0 | 9.0 | 14.1 | 5.1 | 0.0 | 9.0 |
| Hard coal/old 1 | 35% | 65.6 | 23.7 | 38.7 | 3.3 | 134.4 | 31.1 | 100.1 | 3.3 |
| Hard coal/old 2 | 40% | 57.8 | 20.7 | 33.8 | 3.3 | 118.0 | 27.2 | 87.6 | 3.3 |
| Hard coal/new | 46% | 50.7 | 18.0 | 29.4 | 3.3 | 103.1 | 23.6 | 76.1 | 3.3 |
| Lignite/old 1 | 35% | 63.4 | 18.5 | 41.6 | 3.3 | 129.3 | 18.5 | 107.5 | 3.3 |
| Lignite/old 2 | 40% | 55.9 | 16.2 | 36.4 | 3.3 | 113.6 | 16.2 | 94.1 | 3.3 |
| Lignite/new | 46% | 49.0 | 14.1 | 31.6 | 3.3 | 99.2 | 14.1 | 81.8 | 3.3 |
| Gas/conventional old 1 | 36% | 79.6 | 55.7 | 22.8 | 1.1 | 185.1 | 125.0 | 59.0 | 1.1 |
| Gas/conventional old 2 | 41% | 70.0 | 48.9 | 20.0 | 1.1 | 162.7 | 109.8 | 51.8 | 1.1 |
| Gas/CCGT old 1 | 40% | 72.3 | 50.1 | 20.5 | 1.6 | 167.2 | 112.5 | 53.1 | 1.6 |
| Gas/CCGT old 2 | 48% | 60.5 | 41.8 | 17.1 | 1.6 | 139.6 | 93.8 | 44.2 | 1.6 |
| Gas/CCGT present 1 | 56% | 52.1 | 35.8 | 14.7 | 1.6 | 119.9 | 80.4 | 37.9 | 1.6 |
| Gas/CCGT present 2 | 58% | 50.3 | 34.6 | 14.2 | 1.6 | 115.8 | 77.6 | 36.6 | 1.6 |
| Gas/CCGT new | 60% | 48.7 | 33.4 | 13.7 | 1.6 | 112.0 | 75.0 | 35.4 | 1.6 |
| Gas/OCGT old | 35% | 82.3 | 57.3 | 23.5 | 1.6 | 190.9 | 128.6 | 60.7 | 1.6 |
| Gas/OCGT new | 42% | 68.9 | 47.7 | 19.5 | 1.6 | 159.3 | 107.1 | 50.6 | 1.6 |
| Light oil/- | 35% | 165.6 | 132.4 | 32.1 | 1.1 | 282.1 | 198.0 | 83.0 | 1.1 |
| Heavy oil/old 1 | 35% | 144.0 | 108.6 | 32.1 | 3.3 | 248.7 | 162.4 | 83.0 | 3.3 |
| Heavy oil/old 2 | 40% | 126.4 | 95.0 | 28.1 | 3.3 | 218.1 | 142.1 | 72.7 | 3.3 |
| Oil shale/old | 29% | 72.3 | 19.4 | 49.7 | 3.3 | 153.4 | 21.6 | 128.5 | 3.3 |
| Oil shale/new | 39% | 54.6 | 14.4 | 36.9 | 3.3 | 114.9 | 16.1 | 95.5 | 3.3 |

## Additional costs used for the redispatching mechanism including specific opportunity costs, readiness costs and any other cost related to the participation to redispatching

Table 5 shows the assumptions for the additional costs (i.e. ‘markups’) to be considered on top of short-run marginal cost for the redispatch timeframe. In line with BZR methodology articles 9.4.d, these are provided per generation technology, as unit-based markups could not be computed.

After assessing the available data on redispatch costs across Europe together with the requirements of the BZR methodology, the BZ taskforce concluded that it was not possible to provide separate costs for countries relying on market-based redispatch, and non-market based (i.e. regulated) redispatching of sufficient quality in a way that was consistent with the methodology. Thus, following the provision allowed in BZR Article 9.4.b.iii, redispatch costs have been provided based on the average of countries with non-market-based redispatching, assuming this is the best proxy for the incremental short-run marginal costs of the units (without considering additional markups related to local market power and/or scarcity conditions). However, ultimately markups were only provided by the German TSOs. Thus, the redispatch markups presented below in Table 5 are based on data provided by the German TSOs, calculated according to the German industry guideline ("Branchenleitfaden") for the remuneration of redispatch measures dated 18/04/2018. The additional costs consist of two elements: opportunity costs and depreciation costs. Readiness costs are zero. If no or too little data is available for a generator category, the value of the next best-fitting category is taken (proxies are shown in italics). Note that the redispatch markups are independent of the short-run marginal cost of the generation units, thus they are the same in the sensitivity as in the main scenario.

Note that redispatch markups for renewable energy sources and renewables are assumed to be 0 €/MWh, reflecting the opportunity costs in the DAM framework which is cleared in the previous step in the modelling chain.

Table 5 – Additional costs (on top of marginal cost) considered for redispatching

|  |  |  |  |
| --- | --- | --- | --- |
|  |  | Redispatch markup (€/MWh) | |
| Plant main type | **Plant sub type** | **Upward** | **Downward** |
| Nuclear |  | *1.44* | 1.44 |
| Lignite | old 1 | 3.85 | 3.42 |
| Lignite | old 2 | 4.41 | 2.96 |
| Lignite | new | *4.41* | *2.96* |
| Hard coal | old 1 | 2.44 | 3.01 |
| Hard coal | old 2 | 10.46 | 3.25 |
| Hard coal | new | *10.46* | *3.25* |
| Gas | conventional old 1 | *15.31* | *-* |
| Gas | conventional old 2 | *15.31* | *-* |
| Gas | CCGT old 1 | 5.13 | 3.50 |
| Gas | CCGT old 2 | 4.79 | 4.18 |
| Gas | CCGT new | *4.79* | *4.18* |
| Gas | OCGT old | *15.31* | *-* |
| Gas | OCGT new | *15.31* | *-* |
| Gas | present 1 | 15.31 | - |
| Gas | present 2 | *15.31* | *-* |
| Oil plants (all) |  | *15.31*[[5]](#footnote-6) | *-* |
| Run of River and pondage |  | *0* | *0* |
| Reservoir |  | *0* | *0* |
| Pump Storage[[6]](#footnote-7) | Open Loop | *4.79* | *4.18* |
| Pump Storage | Closed Loop | *4.79* | *4.18* |
| Wind Onshore |  | *0* | *0* |
| Wind Offshore |  | *0* | *0* |
| Solar Photovoltaic |  | *0* | *0* |

Regarding coordination of remedial actions outlined in Art 9.10, full coordination on remedial actions is assumed for target year 2025, as this is the expectation according to ROSC timelines[[7]](#footnote-8).

Regarding the cost for ensuring availability of redispatching units, this is considered only for Germany. In this case, the approach outlined in Art 9.15 is chosen for Germany in line with current and expected operational practices and the TYNDP cost benefit analysis. Following Art 9.15, to compute the cost for ensuring availability of redispatching units two historical values are needed:

* the cost for ensuring availability of redispatching units: e.g. 197 million € for 2019[[8]](#footnote-9)
* the hourly peak upward dispatch change over the year: e.g. 7.7 GW for 2019[[9]](#footnote-10)

The data shown above for the year 2019 is given as an example. The data collection for 2020 is still ongoing. There is no data for 2021 available yet. It was not yet possible to assess whether these historical values lead to a sensible model output. Therefore, the given values should not be seen as final.

# Load

## Load time series

*See Excel.*

## Day-ahead demand elasticity

*See Excel.*

## DSR: Maximum power [MW] which may respond

*See Excel.*

## DSR: Minimum price [€/MWh] at which the response is triggered

*See Excel.*

## DSR: Maximum activation duration [h]

*See Excel.*

## DSR: Maximum activated energy per day [MWh]

*See Excel.*

## DSR: Average amount of DSR [MW] available for the market dispatch

*See Excel.*

## DSR: Average amount of explicit DSR [MW] not available for redispatching after considering market dispatch and technical constraints

*See Excel.*

## Average amount of DSR [MW] available for neither of them

*See Excel.*

# Reserves

## FCR requirement [MW]

Due to the use of different tools and modelling simplifications, reserves are modelled somewhat different in the main study than in the LMP simulations. In the LMP simulations, a detailed modelling of reserve capacity was used where FCR, FRR and RR were considered separately, and in both the upward and downward direction and allowing for time varying reserve capacities. In the main study for CE, a simplified approach is applied where all reserve categories are lumped into one symmetrical, static reserve category.

Table 6 shows the total reserve capacity that is used in the base scenario for the status quo configuration, as the sum of the FCR and FRR+RR capacities. In case time-varying reserves were used in the LMP study, the yearly average was calculated. Also, where distinct upward and downward reserves were used in the LMP study, the average value between the two is used. For a new bidding zone configuration, the reserves in an existing bidding zone will be split over the newly created bidding zones. Or, if the TSO considers it necessary to do so, the reserves may be dimensioned for the new zones. As the TSOs are still investigating the reserve requirements in case of a bidding zone split, the reserve requirements in alternative configurations are not yet defined.

The impact of a bidding zone split in terms of reserve requirements is not trivial to assess. In fact, while a change in bidding zone configuration is not altering the physical reality of the power system, it could imply the introduction of a zonal reserve requirement in each of them (e.g. trip of the biggest generator in each zone) according to current operational practices. In addition, reserve procurement processes are not fully harmonized among different EU countries (e.g. in terms of auction design and sharing possibility) and, for this reason, changing the BZ configuration could imply an impact in terms of reserve procurement volumes in some countries. In addition, specific rules as defined by article 153, 157 and 160 of the System Operation Regulation are in place in order to identify the minimum reserve requirements. Therefore, it is still under investigation whether there is the need to newly dimension the required reserve capacity for each bidding zone configuration individually in certain zones, particularly as no reserve sharing (i.e. transmission capacity reservation for balancing energy) is foreseen in the modelling chain.

Table 6 – Reserve capacities considered in the base scenario.

|  |  |  |  |
| --- | --- | --- | --- |
| Zone | FCR (MW) | FRR + RR(MW) | Total Reserve  requirement (MW) |
| AT00 | 71 | 465 | 536 |
| BE00 | 0 | 1039 | 1039 |
| BG00 | 50 | 275 | 325 |
| CH00 | 65 | 725 | 790 |
| CZ00 | 76 | 962 | 1038 |
| DE00 | 573 | 2460 | 3033 |
| DKW1 | 20 | 374 | 394 |
| FR00 | 540 | 2100 | 2640 |
| HR00 | 100 | 350 | 450 |
| HU00 | 41 | 671 | 712 |
| ITN1 | 276 | 1793 | 2069 |
| NL00 | 116 | 1305 | 1421 |
| PL00 | 200 | 1000 | 1200 |
| RO00 | 62 | 580 | 642 |
| SI00 | 16 | 250 | 266 |
| SK00 | 27 | 539 | 566 |

## FRR requirement

See section 4.1.

## RR requirement

See section 4.1.

# Capacity Calculation

## Capacity calculation method per border

Table 7 shows an overview of the capacity calculation method applied per border. For borders within the CORE capacity calculation region (CCR) the flow-based (FB) approach is applied. For NTC borders, according to BZR Article 6.17 there are three approaches for calculation of NTC transmission capacities:

1. Approach based on **thermal ratings** – for already existing DC borders only (tNTC)
2. Approach based on **CNECs and GSKs** i.e. a coordinated NTC (cNTC) approach
3. Approach based on **TYNDP values** – for other borders not impacted by BZ re-configuration and borders with Third countries (NTC)

The different types of NTC borders are shown in Table 7 and Figure 1.

Note that all the new borders created as a result of splits in the alternative configurations in the CORE region are modelled as flow-based, while the split of ITN1 is modelled as cNTC.

Table 7 – Overview of the capacity calculation method applied per border modelled in BZRR CE

|  |  |  |  |
| --- | --- | --- | --- |
| BZ  from | BZ  to | CCR | Border type |
| AT00 | CH00 | - | cNTC |
| AT00 | CZ00 | Core | FB |
| AT00 | DE00 | Core | FB |
| AT00 | HU00 | Core | FB |
| AT00 | ITN1 | Italy North | cNTC |
| AT00 | SI00 | Core | FB |
| BA00 | HR00 | - | NTC |
| BE00 | FR00 | Core | FB |
| BE00 | NL00 | Core | FB |
| BE00 | UK00 | 3rd | NTC |
| BG00 | RO00 | SEE | NTC |
| CH00 | AT00 | - | cNTC |
| CH00 | DE00 | - | cNTC |
| CH00 | FR00 | - | cNTC |
| CH00 | ITN1 | - | cNTC |
| CZ00 | AT00 | Core | FB |
| CZ00 | DE00 | Core | FB |
| CZ00 | PL00 | Core | FB |
| CZ00 | SK00 | Core | FB |
| DE00 | AT00 | Core | FB |
| DE00 | CH00 | - | cNTC |
| DE00 | CZ00 | Core | FB |
| DE00 | DKW1 | Hansa | cNTC |
| DE00 | FR00 | Core | FB |
| DE00 | NL00 | Core | FB |
| DE00 | PL00 | Core | FB |
| DE00 | DEKF | - | NTC |
| DE00 | DKE1 | Hansa | NTC |
| DE00 | NOS0 | - | NTC |
| DE00 | SE04 | Hansa | tNTC |
| DE00 | UK00 | - | NTC |
| DEKF | DE00 | - | NTC |
| DKE1 | DE00 | - | tNTC |
| DKE1 | DKW1 | - | tNTC |
| DKW1 | DE00 | Hansa | cNTC |
| DKW1 | DKE1 | Nordic | NTC |
| DKW1 | NOS0 | - | NTC |
| DKW1 | SE03 | Nordic | NTC |
| DKW1 | UK00 | - | NTC |
| ES00 | FR00 | SWE | cNTC |
| FR00 | BE00 | Core | FB |
| FR00 | CH00 | - | cNTC |
| FR00 | ITN1 | Italy North | cNTC |
| FR00 | ES00 | SWE | cNTC |
| FR00 | UK00 | - | NTC |
| HR00 | HU00 | Core | FB |
| HR00 | SI00 | Core | FB |
| HR00 | BA00 | - | NTC |
| HR00 | RS00 | - | NTC |
| HU00 | AT00 | Core | FB |
| HU00 | HR00 | Core | FB |
| HU00 | RO00 | Core | FB |
| HU00 | SI00 | Core | FB |
| HU00 | SK00 | Core | FB |
| HU00 | RS00 | - | NTC |
| HU00 | UA01 | - | NTC |
| ITCN | ITN1 | Greece-Italy | NTC |
| ITN1 | AT00 | Italy North | cNTC |
| ITN1 | CH00 | - | cNTC |
| ITN1 | FR00 | Italy North | cNTC |
| ITN1 | SI00 | Italy North | cNTC |
| ITN1 | ITCN | Greece-Italy | NTC |
| LT00 | PL00 | Baltic | tNTC |
| NL00 | BE00 | Core | FB |
| NL00 | DE00 | Core | FB |
| NL00 | DKW1 | Hansa | tNTC |
| NL00 | NOS0 | - | NTC |
| NL00 | UK00 | - | NTC |
| NOS0 | DE00 | - | NTC |
| NOS0 | DKW1 | - | NTC |
| NOS0 | NL00 | - | NTC |
| PL00 | CZ00 | Core | FB |
| PL00 | DE00 | Core | FB |
| PL00 | LT00 | Baltic | tNTC |
| PL00 | SE04 | Hansa | tNTC |
| RO00 | HU00 | Core | FB |
| RO00 | BG00 | SEE | NTC |
| RO00 | RS00 | - | NTC |
| RO00 | UA01 | - | NTC |
| RS00 | HR00 | - | NTC |
| RS00 | HU00 | - | NTC |
| RS00 | RO00 | - | NTC |
| SE03 | DKW1 | - | NTC |
| SE04 | DE00 | Hansa | tNTC |
| SE04 | PL00 | Hansa | tNTC |
| SI00 | AT00 | Core | FB |
| SI00 | HR00 | Core | FB |
| SI00 | HU00 | Core | FB |
| SI00 | ITN1 | Italy North | cNTC |
| SK00 | CZ00 | Core | FB |
| SK00 | HU00 | Core | FB |
| SK00 | UA01 | - | NTC |
| UA01 | HU00 | - | NTC |
| UA01 | RO00 | - | NTC |
| UA01 | SK00 | - | NTC |
| UK00 | BE00 | - | NTC |
| UK00 | DE00 | - | NTC |
| UK00 | DKW1 | - | NTC |
| UK00 | FR00 | - | NTC |
| UK00 | NL00 | - | NTC |

Figure - Overview of NTC borders



## List of action plans and derogations for the target year considered pursuant to IEM regulation

Several countries (AT, DE, HU, NL, PL, SK) have action plans or derogations for target year 2025 in order to achieve the 70% minRAM target mandated by the Clean Energy Package. Some countries have country-wide derogations, while others are for specific critical network elements (CNEs). These are shown in Table 8.

Table 8 – Overview of derogations per CNE or member state, applied in the main scenario (and sensitivities) for all alternative configurations

|  |  |  |  |
| --- | --- | --- | --- |
| Country | CNE | CNE type | minRAM target for 2025 |
| AT | *\*All\** | *\*All\** | 59.7% |
| DE | *\*All\** | *\*All\** | 60.3% |
| NL | BKK-DIM380 | internal | 62% |
| NL | BMR-DOD380 | internal | 62% |
| NL | BSL-GT380 | internal | 63% |
| NL | BSL-RLL380 | internal | 62% |
| NL | CST-KIJ380 | internal | 62% |
| NL | DIM-LLS380 | internal | 62% |
| NL | DOD-DTC380 | internal | 62% |
| NL | DTC-HGL380 | internal | 62% |
| NL | DTC-NDR380 | cross-border | 68% |
| NL | EEM-EOS380 | internal | 62% |
| NL | EEM-EHH380 / EEM-MEE380 / EEH-MEE380 / EHH-MEE380[[10]](#footnote-11) | internal | 62% |
| NL | ENS-ZL380 | internal | 62% |
| NL | GNA-HGL380 | cross-border | 65% |
| NL | GT-EHV380 | internal | 63% |
| NL | KIJ-BKK380 | internal | 62% |
| NL | KIJ-BWK380 | internal | 62% |
| NL | KIJ-GT380 | internal | 62% |
| NL | KIJ-OZN380 | internal | 62% |
| NL | LLS-ENS380 | internal | 62% |
| NL | MBT-BMR380 | internal | 62% |
| NL | MBT-DOD380 | internal | 70% |
| NL | MBT-EHV380 | internal | 63% |
| NL | MBT-OBZ380 | cross-border | 63% |
| NL | MBT-SDF380 | cross-border | 65% |
| NL | MBT-VYK380 | cross-border | 63% |
| NL | MEE-DIL380 | cross-border | 62% |
| NL | OZN-DIM380 | internal | 62% |
| NL | RLL-GT380 | internal | 63% |
| NL | RLL-ZVL380 | cross-border | 62% |
| NL | VHZ-BWK380 | internal | 62% |
| NL | ZL-HGL380 | internal | 62% |
| NL | ZL-MEE380 | internal | 62% |
| PL | *\*All\** | *\*All\** | 60% |
| SK | *\*All\** | *\*All\** | 62.5% |
| HU | Oroszlány–Dunamenti | internal | 58.75% |
| HU | Oroszlány–Gy?r | internal | 58.75% |
| HU | Gy?r-Neusiedl | internal | 58.75% |
| HU | Gy?r-Bécs | internal | 58.75% |
| HU | Paks–Sándorfalva | internal | 60.75% |
| RO | *\*All\** | *\*All\** | 63% |

## Average FRM over all CNECs, per BZ.

A fixed FRM of 10% of the Fmax is assumed for all CNECs, as per methodology Art 6.10(b).

## PTDF threshold used by each TSO and, if different from default value, why the adopted threshold better reflects an economic efficiency analysis.

A PTDF threshold of 10% is assumed for all TSOs/zones, as per methodology Art. 6.8 .

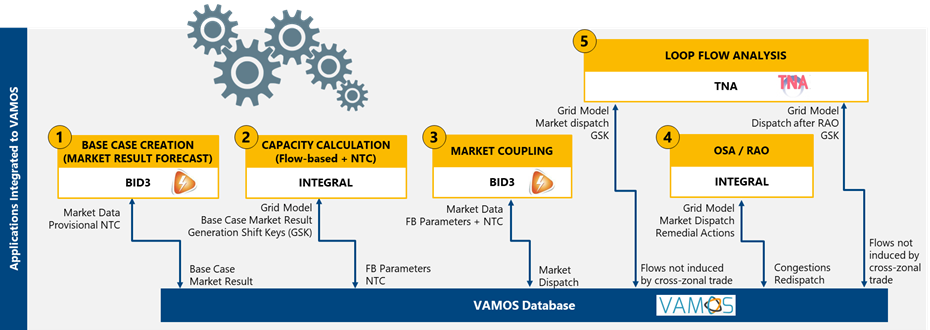
## Allocation constraint per border/BZ.

Allocation constraints are not applied as part of the BZR.

# Miscellaneous

## List and brief description of the main characteristics of the modelling tools used for the analysis

Modelling Chain consists of five calculation modules that are simulated using three different software applications. An overview of the Modelling Chain and a short description of the different calculation modules is given below:



|  |  |  |
| --- | --- | --- |
| Module | SoftwareApp | Short Description |
| Base Case Creation | BID3 | The purpose of this module is to obtain a market result forecast to be used for Capacity Calculation. Hence market simulation is performed for the Full EU using fundamental market data (generation, load, RES, fuel prices) and NTC values from TYNDP. Base Case Market Dispatch is used as a basis to perform Capacity Calculation. |
| Capacity Calculation | Integral | Capacity Calculation is performed using Flow-based and NTC approach as described in Section 5.1. It consists of several steps such as calculation of GSKs, zonal PTDFs and RAMs, CNEC selection and Presolve. FB parameters and NTC values obtained in the Capacity Calculation are used as an input to Market Coupling |
| Market Coupling | BID3 | Market Coupling is performed using calculated FB parameters and NTCs for the CE region, as well as the fundamental market data. Flows to CE-external regions are taken from the base case creation results.The resulting market dispatch is used as an input for Loop Flow Analysis and OSA/RAO modules. |
| Operational Security Analysis (OSA) and Remedial Actions Optimization (RAO) | Integral | Besides the market dispatch, one of the main inputs for the OSA and RAO are the available remedial actions (redispatch potential, available PST and HVDC range). DC Load Flow is used to identify congestions and a linear optimization problem is solved to derive the cost-optimal solution for alleviating congestions. Final dispatch after RAO (incl. redispatching) is used as an input for Loop Flow Analysis. |
| Loop Flow Analysis | TNA | Loop Flow Analysis is performed two times – first one is based on the market dispatch and the second one is based on the final dispatch after RAO. Loop flow analysis is performed in line with the methodology applicable to RDCT cost sharing, as per Article 74 of CACM regulation.  Main result of the Loop Flow Analysis is share of the flows not induced by cross-zonal trade. |

All calculations modules are executed in an online simulation environment (VAMOS). VAMOS enables automated execution of individual calculation modules by providing a centralized data storage, interface between the application as well as a web-based User Interface. Each of the modelling tools is briefly described in the following sections.

### BID3

BID3 is a hydro-thermal power market simulation software developed by AFRY. It combines state-of-the-art simulation of thermal-dominated markets, reservoir hydro dispatch under uncertainty, demand-side response and scenario-building tools. BID3 is predominantly an economic dispatch model that simulates the hourly generation of all power stations on the system, taking into account fuel and emission costs, operational constraints, and system constrains. It models thermal, hydro (reflecting the option value of water), and intermittent renewable sources of generation.

### INTEGRAL

INTEGRAL (INTEraktives GRAfisches netzpLanungswerkzeug) is a network analysis tool developed since 1974 together with the member companies of FGH. This tool is used by all TSOs in Germany and Austria, as well as distribution system operators, engineering offices, universities and operators of industrial networks. FGH continually develops the tool according to the needs of the customers and continues to expand the range of functionalities. New functionalities were added to INTEGRAL in order to meet the requirements of the BZR methodology, including the ability to model DSR and time-coupled daily optimisation in RAO. Integral is used to perform both the capacity calculation and Operational Security Analysis (OSA) and Remedial Actions Optimisation (RAO) or redispatch steps.

### TNA

Transmission Network Analyzer (TNA) is a software tool developed by EKC which provides analytic and network planning functions for different types of static analysis of transmission network including models building and merging, NTC and flow-based capacity calculation, and coordinated security assessment. One of the functions supported by TNA is Power Flow Colouring, based on the method developed by EKC within the Future Flow Horizon project and later adopted by ACER as a part of the methodology for redispatching and countertrading cost sharing in the CORE region. Power Flow Colouring is used within the Bidding Zone Review Study to determine loop flows.

### VAMOS

VAMOS (Varied Market-Model Operating System) serves as a modelling environment platform for the Bidding Zone Review in Central Europe. In this role, VAMOS is used to collect all input data in a single dataset, to adapt this dataset for alternative BZ-configurations, sensitivities etc., to visualize results in different formats and to run the simulations in an automated manner. For the latter, VAMOS works on pre-defined calculation chains and handles all tasks with an integrated scheduler. It is accessible for all CE TSOs trough a web interface. The tool is provided by Austrian Power Grid (APG) along with the hardware used for the simulations.

## All other assumptions and parameters set at pan-European or BZRR level with an impact on the results of the BZR

Several other key assumptions are made for CE. These are summarised in the following sections.

### Planned outages

To maximise consistency with the LMP study assumptions, the same planned outages patterns generated by the LMP study are used in the main study in most cases. However, it was observed that the availability of French nuclear capacity was too high in the LMPs, leading to excessive exports from plants. Thus, an extended list of outages for France nuclear power plants is applied in the main study in line with PEMMDB, to limit overgeneration. The overall planned outage rate of French nuclear plants taken from PEMMDB is 26.17%.

### MinRAM CCR

A MinRAM\_CCR of 20% is used in the Core CCR, in accordance with operational practice.

### Clustering approach for RAO (and CC)

To decrease runtime of the toolchain, the assessment is performed on a selected subset of 50 days and a weighting of importance is applied to each assessed day. In order to ensure comparability between the different BZ configurations, all BZ configurations and all steps ex-post NTC calculation are assessed for the same 50 days. However, a different set of 50 days might be selected for every climate year.

The 50 days that shall maximally represent and capture the behaviour of each climate year are identified through K-medoids clustering across various features. The figure below lists the key features that are taken into account as well as the overall process to perform the clustering:

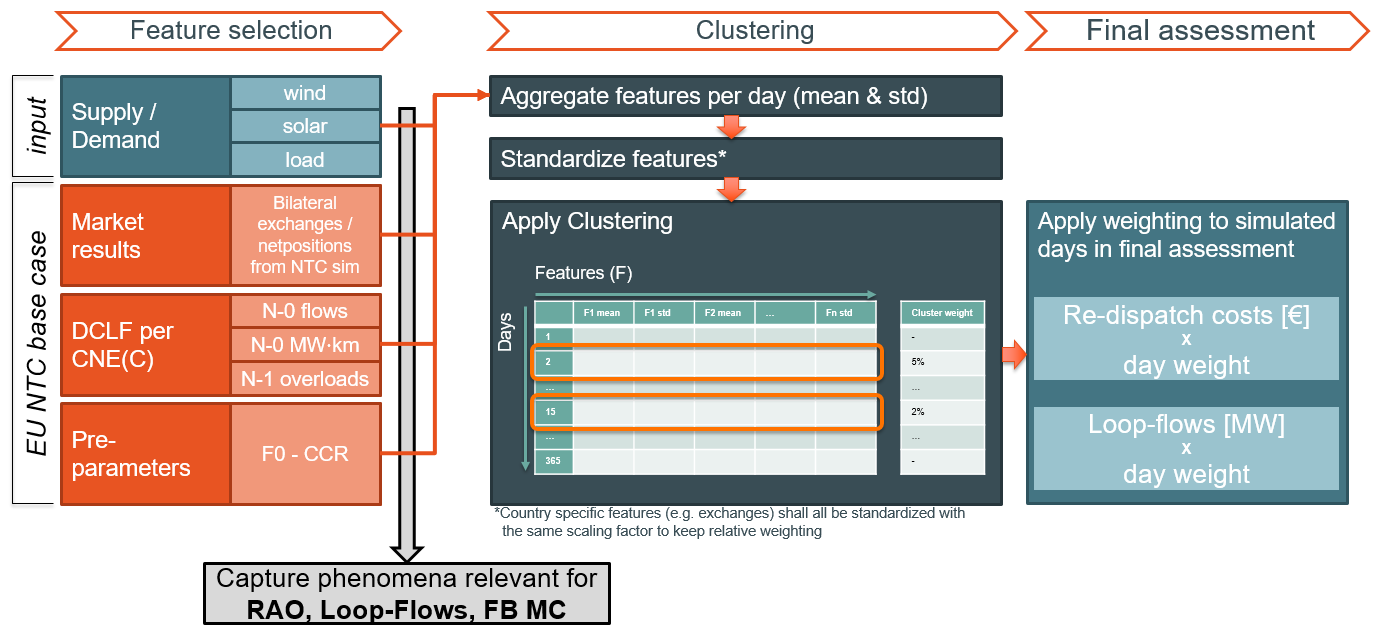


Figure 2 – Overview of the clustering approach

### CNEC list

It was initially planned to use the CNEC list from the LMP Study. However, it was noticed that the list contains many redundant elements that lead to a deteriorated performance of the Modelling Chain (increased computation times and memory requirements). This was especially due to a large number of Contingencies (N-1 situations) that were considered for each Critical Network Element (CNE).

Hence, a CNEC list reduction approach was applied with the aim to eliminate those Contingencies that are “redundant” for each CNE. The results of Capacity Calculation and OSA/RAO should remain unchanged when these CNECs are removed from the list.

The approach is based on the Reference Flows which are determined in Capacity Calculation (Figure 3). For each CNE in each MTU, reference flows in different Contingency states are compared. It is then counted how often a specific Contingency leads to maximum loading on the given CNE (“critical” N-1 state). Contingencies that are not “critical” in any MTU are considered as redundant for the given CNE - hence the corresponding CNECs are removed from the list. Note that the Basecase (N-0 state) CNECs are not considered in the reduction, e.g. they are kept on the CNEC list although they may be redundant.

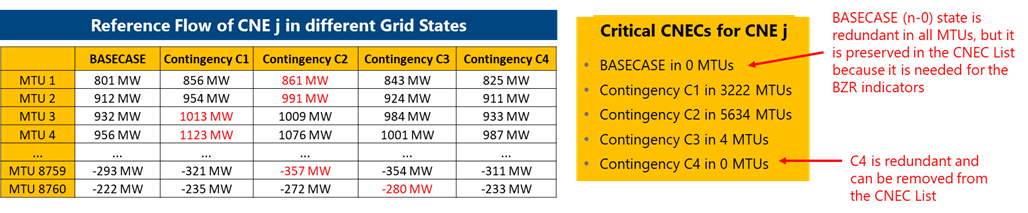


Figure 3 – Overview of the CNEC reduction approach

Note that the reduced CNEC list as a result of this reduction approach is applied directly in the RAO, and the CNECs considered in the Capacity Calculation are a subset of this list, in line with BZR methodology Art 6.7. All cross-border lines are also retained as CNEs as per the methodology requirement.

### GSK Strategies

Table 9 shows the Generation Shift Key (GSK) strategies applied per zone in INTEGRAL, according to expected operational practice based on TSO feedback. For countries which apply quite complex GSKs which cannot be modelled in INTEGRAL, the closest matching GSK strategy is considered. If no detailed data was provided or none of the available GSK strategies in the tools were sufficiently representative, a strategy proportional to the basecase (P0) is applied.

Table 9 – Overview of GSK strategies applied in the main study for the main scenario and sensitivity

|  |  |
| --- | --- |
| Zone | GSK Strategy |
| AT00 | Proportional to Pmax |
| BE00 | Proportional to (Pmax- P0) |
| CH00 | Proportional to P0 |
| CZ00 | Proportional to P0 |
| DE00 | Proportional to (Pmax- Pmin) |
| DKW1 | Proportional to (Pmax- P0) |
| FR00 | Proportional to P0 |
| HR00 | Proportional to P0 |
| HU00 | Proportional to P0 |
| ITN1 | Proportional to P0 |
| NL00 | Proportional to (Pmax- P0) |
| PL00 | Proportional to P0 |
| RO00 | Proportional to P0 |
| SI00 | Proportional to P0 |
| SK00 | Flat participation factor |

Note that in the case of alternative bidding zone configurations, TSOs may need to adapt the GSK strategy based on national specifics.

### Dynamic line rating (DLR)

DLR will be applied in the main study using the same hourly rating factors applied in the LMPs.

### Topological remedial actions (TRAs)

In the LMP simulations, topological remedial actions (TRA) were applied to only 3 weeks using an explicit and ex-post method in PLEXOS. In this approach TSOs were able to propose ex-post TRAs to relieve certain congestions by proposing a topological action (open or close breakers, change substation topology and dynamically change lines from busbars) for a determined substation. TSOs had the opportunity to check the final congestions and provide the actions for the concerned lines.

For the main BZR study another approach is considered. Due to the high number of configurations and time stamps to be simulated, an automated approach implemented within the modeling chain was developed. Inside the RAO module, INTEGRAL was modified to allow TSOs to propose TRAs as non-costly remedial actions after the Operational Security Analysis (OSA). The selected method is the Fmax approach, which does not optimize topological actions or directly modify the network topology to apply a TRA. Instead, the approach only considers the relieving impact of a TRA on congested lines, which decreases the overload. TSOs should then provide a list of actions based on conditions to apply (utilization rates greater than X%, for example) and new value of Fmax to be imported for specific lines.

1. <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=SWD:2022:230:FIN&from=EN>. The values underlying Figure 2 in Annex 7 were provided to ENTSO-E as part of ERAA2022. [↑](#footnote-ref-2)
2. [Macro drivers – World Energy Model – Analysis - IEA](https://www.iea.org/reports/world-energy-model/macro-drivers) [↑](#footnote-ref-3)
3. <https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/ERAA/2022/data-for-publication/ERAA_2022_Demand_TimeSeries_post_consultation.7z> [↑](#footnote-ref-4)
4. [Macro drivers – World Energy Model – Analysis - IEA](https://www.iea.org/reports/world-energy-model/macro-drivers) [↑](#footnote-ref-5)
5. No data available for oil, using gas costs as a best estimate [↑](#footnote-ref-6)
6. In the absence of sufficient data, values from the category Gas CCGT old 2 are assumed. [↑](#footnote-ref-7)
7. ROSC will coordinate on Core level the security analysis and RDCT activations for the 380kV & 220kV grids. The first wave of ROSC (focusing on DA) should be implemented by 2025 (legal deadline Apr 2024). The second wave of ROSC (adding ID) is planned for 2025. [↑](#footnote-ref-8)
8. <https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2021.pdf?__blob=publicationFile&v=2> [↑](#footnote-ref-9)
9. <https://www.netztransparenz.de/EnWG/Redispatch> [↑](#footnote-ref-10)
10. In December 2020, the CNE of EEM-MEE380 was split into 2 when a transformer was looped into the high voltage line at substation Eemshaven het Hogeland. This substation was initially abbreviated as EEH, and per 26/12/20 as EHH. [↑](#footnote-ref-11)