Bidding Zone Review

Bidding Zone Review Region (BZRR)

Central Europe

Background

This document serves – along with the provided overview Excel file *"CE_BZR_Input Data and Assumptions Overview.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 follow 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.

20 February 2024

Contents

Changelog

List of important changes in this document in comparison to version 22 December 2022.

- 20 February 2024
    - Table 7: font colour changed, as a part of the numbers was not visible
- 30 January 2024
    - Table 8 header adjusted
- 20 December 2023
    - Section 1.2 and 1.3.2: Update of the sensitivity analysis with possible simplifications.
    - Table 2: List of additional grid projects expected by the year 2028 included in the sensitivity analysis: The German HVDC "A-Nord" was added (planned commissioning date 2027).
    - Table 4 has been added: Comparison between total annual total load (TWh/y) per climate year assumed in the main scenario for 2025, and as sensitivity for 2028 (based on interpolation between ERAA22 profiles for target years 2027 and 2030)
    - Section 2.9: Redispatch markups calculated for the year 2021 were added. These markups serve as a reference for the redispatch markups in the sensitivity analysis where increased fuel and CO2 prices are considered.
    - Table 6 has been added: Additional costs (on top of marginal cost) considered for redispatching in the sensitivity analysis
    - Section 4.1: It was clarified that reserve requirements are held constant for all configurations.
    - Section 6.2.5: it was clarified that for the split scenarios the same GSK strategy is applied as for the original BZ.

List of important changes in this document in comparison to version 30 November 2022.

- 22 December 2022
    - Table 7: Overview of the capacity calculation method applied per border modelled in BZRR CE
        - The PL-SK border was missing and has been added.
    - Croatian action plan added to Table 8
    - Table 2: Improved description of Polish grid projects.
    - Added remark about Swiss hydro correction to section 2.1.
    - Added remark about French load correction to section 3.1.
    - Added section 6.2.8 about Input data corrections with respect to LMP study.

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

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

1) Scenario

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

See Excel.

1.2 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" criterion without leading to infeasible simulation times, BZRR Central Europe will consider consecutive sensitivity analyses on the following dimensions if possible:

- Higher fuel and carbon prices (aligned with the Nordics) and adapted redispatch markups to reflect the increased fuel and carbon prices
- 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
- Additional load based on the expectations for the year 2028

BZRR CE TSOs are aiming to deliver the final BZR report, including the recommendation to amend (or not) the current bidding zone configuration, by the end of 2024. TSOs will strive to perform sensitivity analyses to include the 'stability and robustness of BZs over time' criterion as part of the final evaluation. However, this will require simplifications to the sensitivity analyses which may include:

(i) applying an incremental approach by changing one dimension at a time;

(ii) simplifying various modelling steps in the sensitivity runs to speed up the most time-consuming steps;

(iii) performing sensitivity analysis only for a reduced number (e.g. 3-5) of the most promising alternative configurations, e.g. based on a ranking of the monetized benefits;

(iv) performing sensitivity analysis for a reduced number of climate years.

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] The carbon price is based on an interpolation between recent high prices and IEA WEO2021 2030 Announced Pledges scenario[2]. 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.

[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.

[2] Macro drivers – World Energy Model – Analysis - IEA

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 (Table 3) and annual total load (Table 4) for the sensitivity are based on the National Estimates scenario from the European Resource Adequacy Assessment (ERAA) 2022, for target year 2028. As 2028 was not a target year for ERAA 2022, load for 2028 is an interpolation between 2027 and 2030. The underlying ERAA 2022 datasets can be downloaded from the ENTSO-E website.[3]

[3] https://www.entsoe.eu/outlooks/eraa/2022/eraa-downloads/

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

Unit	Fuel/ Commodity	Main scenario	Sensitivity	Source
€/GJ_{net}	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	CO_2	40	103.5	Interpolation between recent high prices and IEA WEO2021 2030 Announced Pledges scenario[4]

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
Commissioning of HVDC connection between Poland and Lithuania (Harmony Link)	PL
Switching the 220 kV Krajnik – Gorzów to 400 kV (create connection 400 kV Krajnik – Baczyna and 220 kV Baczyna – Górzów). Installation of new transformer 400/220 kV in Baczyna	PL
Installation of new transformer 400/110 kV in Gdańsk Przyjaźń and connection to Gdańsk I on 110 kV	PL
Construction of Choczewo 400 kV substation	PL
Construction of Choczewo – Żarnowiec double circuit 400 kV line	PL
Construction of Choczewo – Gdańsk Przyjaźń double circuit 400 kV line	PL
Construction of Krzemienica 400 kV substation together with Dunowo – Słupsk Wierzbięcino 400 kV line entry and single circuit of Słupsk Wierzbięcino – Żydowo Kierzkowo 400 kV line entry	PL
Switching the 220 kV Żydowo Kierzkowo – Gdańsk I, Piła Krzewina– Żydowo Kierzkowo, Plewiska – Piła Krzewina, Piła Krzewina – Bydgoszcz Zachód – Jasiniec, Jasiniec – Grudziądz lines to 400 kV. Replacement of the 220/110 kV transformers in Żydowo Kierzkowo, Piła Krzewina, Bydgoszcz Zachód substations with 400/110 kV transformers	PL
[5]Reconstruction of existing single circuit Gdańsk Błonia – Olsztyn Mątki 400 kV to double circuit 400 kV	PL
Entry of Joachimów – Wielopole 400 kV line to Rokitnica. Construction of double circuit Trębaczew – Rokitnica 400 kV line together with capacity increase of line from Trębaczew to Joachimów – Dobrzeń line tap. Construction of double circuit 400 kV line from Dobrzeń to Pasikurowice-Ostrów line tap. Decommissioning of Pasikurowice – Dobrzeń – Trębaczew – Joachimów 400 kV lines	PL
Construction of Podborze 400/220 kV substation together with Dobrzeń – Detmarovice and Wielopole – Nosovice 400 kV lines entry, Kopanina – Liskovec,	PL

[4] [Macro drivers – World Energy Model – Analysis - IEA]

[5] Based on the best knowledge at the time of a BZ Review data collection i.e. before formulation of the newest PL transmission network development plan. The newest PL transmission network development plan provides for the creation of a triple circuit connection between Gdańsk Błonia and Olsztyn Mątki.

Bujaków – Liskovec, Bieruń – Komorowice, Moszczenica – (Czeczott) Poręba 220 kV lines entry. Installation of new transformer 400/220 kV in Podborze	
Installation of second transformer 400/220 kV in Wielopole	PL
Capacity increase of existing Rzeszów – Krosno Iskrzynia 400 kV line	PL
Capacity increase of existing Krajnik – Baczyna 400 kV line	PL
Capacity increase of existing Jamki – Łagisza 220 kV line	PL
Capacity increase of existing Świebodzice – Ząbkowice 220 kV line	PL
[6]Capacity increase of existing Miłosna – Wyszków – Ostrołęka 220 kV line	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

[6] Based on the best knowledge at the time of a BZ Review data collection i.e. before formulation of the newest PL transmission network development plan. The newest PL transmission network development plan provides for the switching of this line to 400 kV (connection Stanisławów – Wyszków – Ostrołęka).

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
DC1/DC1/Emden-Ost – Osterath (A-Nord)	DE
DC4/DC4/Wilster/West - Bergrheinfeld/West (SuedLink)	DE
DC5/DC5/Wolmirstedt - Isar	DE
P314/M489/Querregeltransformatoren (PST) im Saarland	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[7]	RO
OHL LEA 400 kV Timisoara – Arad[7]	RO
OHL 400 kV Constanta Nord – Medgidia[7]	RO

[7] These three Romanian lines were (wrongly) part of the grid model that was used in the LMP study. However, because they will not be commissioned until after 2025, they have been removed from the base case grid model for the BZRR CE main study. They are however included in the grid model for the sensitivity analysis.

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

Table 4 - Comparison between total annual total load (TWh/y) per climate year assumed in the main scenario for 2025, and as sensitivity for 2028 (based on interpolation between ERAA22 profiles for target years 2027 and 2030)

	Main scenario (2025)			**Sensitivity (2028)**		
Zone	**CY 1989**	**CY 1995**	**CY 2009**	**CY 1989**	**CY 1995**	**CY 2009**
AT00	75.9	76.5	75.9	83.1	84.2	84.1
BE00	89.1	89.4	89.4	96.1	96.8	97.1
BG00	35.3	35.8	35.3	37.0	37.7	37.4
CH00	61.5	61.9	62.0	61.9	63.2	64.0
CZ00	70.7	71.1	70.6	73.3	74.0	73.9
DE00	555.6	559.7	557.6	608.7	620.0	621.7
DKE1	13.9	14.3	14.1	19.1	19.8	19.7
DKW1	24.9	25.1	25.0	34.4	34.9	34.8
FR00	482.1	483.9	486.3	500.1	502.7	510.3
HR00	17.1	17.2	17.4	17.8	17.9	18.1
HU00	42.1	42.4	42.3	50.6	51.2	51.0
ITN1	176.7	178.5	180.7	185.4	185.9	189.5
LUB1	0.5	0.5	0.5	0.5	0.5	0.5
LUF1	0.9	0.9	0.9	0.9	0.9	0.9
LUG1	6.5	6.5	6.5	7.5	7.5	7.5
NL00	119.1	119.0	118.7	140.7	141.3	141.2
PL00	169.7	171.8	170.9	176.0	178.4	177.8

RO00	60.9	61.6	61.0	63.4	64.3	63.8
SK00	33.5	33.5	33.4	30.5	30.7	30.6

1.3 Network model for the scenario and sensitivities

1.3.1 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.

1.3.2 Sensitivity

An additional grid model is currently being built to be used for one of the sensitivity analyses.

1.4 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.

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

See Excel.

2) Generation

2.1 Generation time series for weather dependent generation units

It had come to light that Swiss hydro inflow data for Open Loop pumped storage plants was (wrongly) assigned to hydro reservoir plants. This has been corrected for the BZRR CE main study. Otherwise, see Excel.

2.2 Minimum and maximum generating capacities

See Excel.

2.3 Must run constraints

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

2.4 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

2.5 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

2.6 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)

2.7 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

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

Table 5 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 5 – 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 CO_2*	*- of which VOM*	Total SRMC (€/MWh)	*- of which fuel*	*- of which CO_2*	*- 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

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

Table 6 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 6 are based on 2019 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 as they have not been claimed by power plant operators (at least in the considered year). 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 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 6 – Additional costs (on top of marginal cost) considered for redispatching in the main scenario

		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*[8]	-
Run of River and pondage		*0*	*0*
Reservoir		*0*	*0*
Pump Storage[9]	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*

For the sensitivity analysis where increased fuel and CO_2 prices are considered, 2021 data is used to calculate the redispatch markups in order to reflect the increased fuel and CO_2 prices also in the redispatch markups. For the 2021 data, no distinction between plant sub types could be made.

Table 7 – Additional costs (on top of marginal cost) considered for redispatching in the sensitivity analysis

		Redispatch markup (€/MWh)	
Plant main type	**Plant sub type**	**Upward**	**Downward**
Nuclear		*1.06*	1.06
Lignite	old 1	5.57	5.64
Lignite	old 2	5.57	5.64
Lignite	new	5.57	5.64
Hard coal	old 1	6.18	5.91
Hard coal	old 2	6.18	5.91
Hard coal	new	6.18	5.91
Gas	conventional old 1	7.78	-
Gas	conventional old 2	7.78	-
Gas	CCGT old 1	7.78	6.92
Gas	CCGT old 2	7.78	6.92
Gas	CCGT new	7.78	6.92
Gas	OCGT old	7.78	-
Gas	OCGT new	7.78	-
Gas	present 1	7.78	-
Gas	present 2	7.78	-
Oil plants (all)		5.04	-
Run of River and pondage		0	0
Reservoir		0	0
Pump Storage[10]	Open Loop	*7.78*	*6.92*
Pump Storage	Closed Loop	*7.78*	*6.92*
Wind Onshore		0	0
Wind Offshore		0	0
Solar Photovoltaic		0	0

[8] No data available for oil, using gas costs as a best estimate
[9] In the absence of sufficient data, values from the category Gas CCGT old 2 are assumed.
[10] In the absence of sufficient data, values from the category Gas CCGT old 2 are assumed.

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[11].

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[12]
- the hourly peak upward dispatch change over the year: e.g. 7.7 GW for 2019[13]

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.

[11] 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.

[12] https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2021.pdf?__blob=publicationFile&v=2

[13] https://www.netztransparenz.de/EnWG/Redispatch

3) Load

3.1 Load time series

It had come to light that the load time series for France were two days out of sync with the other bidding zones in the LMP study, resulting in the situation that for example weekdays and weekend days were not aligned. This has been corrected for the BZRR CE main study. Otherwise, see Excel.

3.2 Day-ahead demand elasticity

See Excel.

3.3 DSR: Maximum power [MW] which may respond

See Excel.

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

See Excel.

3.5 DSR: Maximum activation duration [h]

See Excel.

3.6 DSR: Maximum activated energy per day [MWh]

See Excel.

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

See Excel.

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

See Excel.

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

See Excel.

4) Reserves

4.1 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 8 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 are split over the newly created bidding zones.

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.

For the purpose of the BZR, constant reserve requirements are assumed for all configurations. However, in case a split of the bidding zone Germany/Luxemburg would be implemented in the future, the impact on balancing capacity, operational processes and in particular the volume changes would have to be re-evaluated. Furthermore, an operational balancing concept including transmission capacity reservations would have to be developed, assessed, and implemented. The question of how much transmission capacity could be reserved for balancing purposes and would not be available for the wholesale market would become relevant in this context. More detailed information on this topic is available in the "All TSOs Participating in Bidding Zone Review Response to the ACER's and the National Regulatory Authorities' Feedback on input data, scenario, sensitivity analyses and assumptions to be used in the Bidding Zone Review of 3 May 2023"[14].

Table 8 – Reserve capacities considered in the base scenario and for all alternative configurations.

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

[14] https://www.entsoe.eu/documents/nc/NC%20CACM/BZR/231130_TSOs_formal_answer_to_ACER-NRAs_feedback_vF_PUBLIC.pdf

DE00	573	2460	3033[15]
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

4.2 FRR requirement

See section 4.1.

4.3 RR requirement

See section 4.1.

[15] German reserves were (wrongly) excluded in the LMP study, but are now included in the BZRR CE main study.

5) Capacity Calculation

5.1 Capacity calculation method per border

Table 9 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 9 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 9 – 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	SK00	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	PL00	Core	FB
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

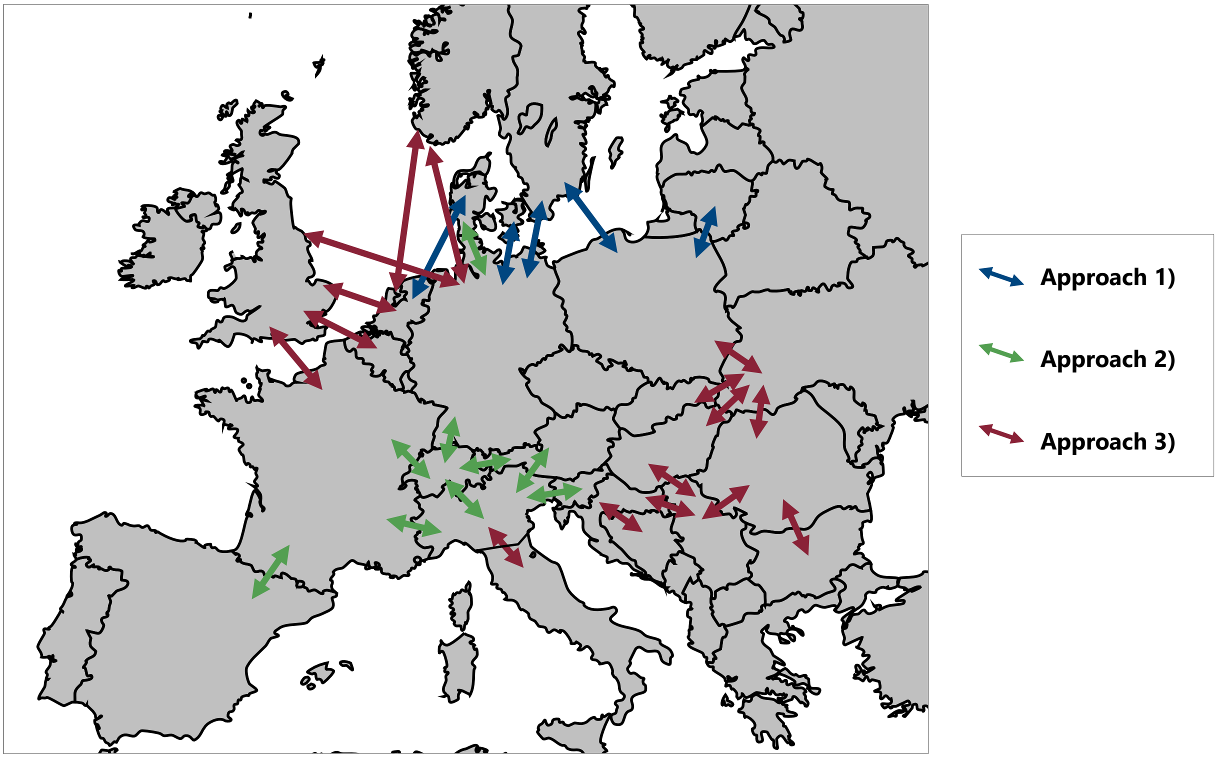


Figure 1 - Overview of NTC borders

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

Several countries (AT, DE, HU, NL, PL, SK, RO, HR) 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 10.

Table 10 – 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[16]	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%

[16] 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.

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%
HR	[HR-HR] 220kV Brinje - VE Padene [OPP] BASECASE	internal	60,7%
HR	[HR-HR] 220kV Brinje - VE Padene [OPP] N-1 Konjsko - Velebit	internal	60,7%
HR	[HR-HR] 220kV Brinje - VE Padene [OPP] N-1 Melina – Velebit	internal	60,7%
HR	[HR-SI] 220kV Pehlin - Divaca [DIR] BASECASE	cross-border	60,7%
HR	[HR-SI] 220kV Pehlin - Divaca [DIR] N-1 Melina - Divaca	cross-border	60,7%
HR	[HR-HR] 220kV Zakucac - Konjsko [OPP] BASECASE	internal	60,7%
HR	[HR-BA] 220kV Zakucac - Mostar [DIR] BASECASE	cross-border	60,7%
HR	[HR-SI] 220kV Zerjavinec - Podlog [DIR] BASECASE	cross-border	66%
HR	[HR-SI] 220kV Zerjavinec - Podlog [DIR] N-1 Tumbri - Krsko 1	cross-border	66%
HR	[HR-SI] 220kV Zerjavinec - Podlog [DIR] N-1 Tumbri - Krsko 2	cross-border	66%
HR	[HR-HR] 400kV Konjsko - Velebit [DIR] BASECASE	internal	62%
HR	[HR-HR] 400kV Konjsko - Velebit [DIR] N-1 Zakucac - Mostar	internal	60,7%
HR	[HR-SI] 400kV Melina - Divaca [DIR] BASECASE	cross-border	60,7%
HR	[HR-SI] 400kV Melina - Divaca [DIR] N-1 Pehlin - Divaca	cross-border	60,7%
HR	[HR-SI] 400kV Melina - Divaca [DIR] N-1 Tumbri - Krsko 1	cross-border	60,7%
HR	[HR-SI] 400kV Melina - Divaca [DIR] N-1 Tumbri - Krsko 2	cross-border	60,7%

HR	[HR-SI] 400kV Melina - Divaca [DIR] N-1 Zerjavinec - Tumbri	cross-border	60,7%
HR	[HR-SI] 400kV Tumbri - Krsko 1 [OPP] N-1 Tumbri - Krsko 2	cross-border	60,7%
HR	[HR-SI] 400kV Tumbri - Krsko 2 [OPP] N-1 Tumbri - Krsko 1	cross-border	60,7%
HR	[HR-SI] 400kV Zerjavinec - Cirkovce [OPP] N-1 Zerjavinec - Heviz	cross-border	60,7%
HR	[HR-HU] 400kV Zerjavinec - Heviz [OPP] N-1 Zerjavinec - Cirkovce	cross-border	60,7%

5.3 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).

5.4 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 .

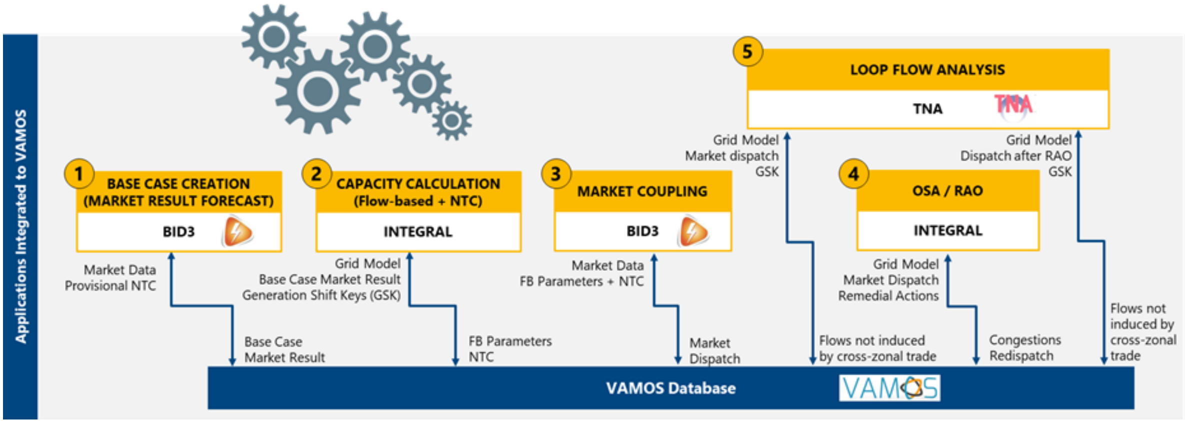
5.5 Allocation constraint per border/BZ.

Allocation constraints are not applied as part of the BZR.

6) Miscellaneous

6.1 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.

6.1.1 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.

6.1.2 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.

6.1.3 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.

6.1.4 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.

6.2 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.

6.2.1 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 26.2%.

6.2.2 MinRAM CCR

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

6.2.3 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:

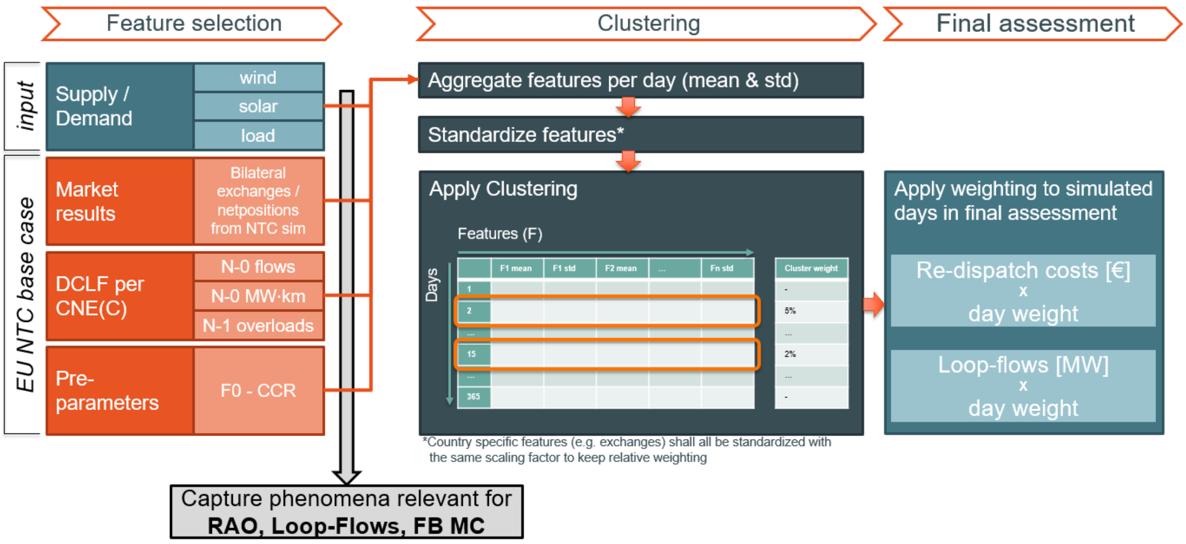


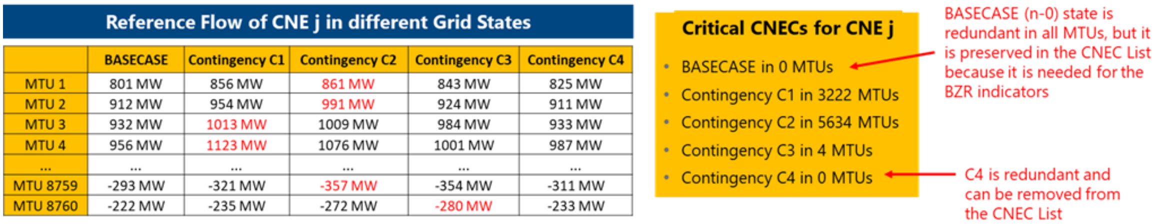
Figure 2 – Overview of the clustering approach

6.2.4 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.


Reference Flow of CNE j in different Grid States

	BASECASE	Contingency C1	Contingency C2	Contingency C3	Contingency C4
MTU 1	801 MW	856 MW	861 MW	843 MW	825 MW
MTU 2	912 MW	954 MW	991 MW	924 MW	911 MW
MTU 3	932 MW	1013 MW	1009 MW	984 MW	933 MW
MTU 4	956 MW	1123 MW	1076 MW	1001 MW	987 MW
...	...	...	...	...	...
MTU 8759	-293 MW	-321 MW	-357 MW	-354 MW	-311 MW
MTU 8760	-222 MW	-235 MW	-272 MW	-280 MW	-233 MW

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.

6.2.5 GSK Strategies

Table 11 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 (P_0) is applied.

Table 11 – Overview of GSK strategies applied in the main study for the main scenario and sensitivity

Zone	GSK Strategy
AT00	Proportional to P_{max}
BE00	Proportional to (P_{max}- P_0)
CH00	Proportional to P_0
CZ00	Proportional to P_0
DE00	Proportional to (P_{max}- P_{min})
DKW1	Proportional to (P_{max}- P_0)
FR00	Proportional to P_0
HR00	Proportional to P_0

HU00	Proportional to P_0
ITN1	Proportional to P_0
NL00	Proportional to $(P_{max} - P_0)$
PL00	Proportional to P_0
RO00	Proportional to P_0
SI00	Proportional to P_0
SK00	Flat participation factor

For the split scenarios the same GSK strategy is applied as for the original BZ.

6.2.6 Dynamic line rating (DLR)

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

6.2.7 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.

6.2.8 Input data corrections with respect to LMP study

Since the finalization of the LMP study, the following corrections were made to the input data that will be used in the BZRR CE main study. (Most were already mentioned in this document, but are included here to provide an overview.) As some indicators of the main study are based on the LMP study results, it will have to be carefully assessed how they are impacted by these corrections.

- German reserves were not included in the LMP study. This has been corrected in the main study. See also Table 8.
- French load profiles were shifted by 2 days in the LMP study. This has been corrected in the main study. See also section 3.1.
- Four Romanian transmission lines (three grid projects) were included in the grid model of the LMP study, but will not be commissioned until after 2025. They have been removed from the grid model for the base case in the main study. They are however still included in the sensitivity analysis. See also Table 2.
- Availability of French nuclear plants was assumed too high in LMP study. An extended list of planned outages in line with the PEMMDB will be used in main study. See also section 6.2.1.

- Swiss hydro inflow data for Open Loop Pumped Storage plants was assigned to hydro Reservoir plants. This has been corrected in the main study. See also section 2.1.