ACER Decision on ERAA 2023: Annex I.c

To be read together with the updated results set out in Annex IV

European Resource Adequacy Assessment

2023 Edition

Annex 2: Methodology

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1 Introduction to the European resource adequacy assessment methodology

Adequacy studies aim to evaluate a power system's available resources and projected electricity demand to identify supply/demand mismatch risks under a variety of scenarios. In an interconnected power system such as the European system, this scope should be extended by considering the supply and demand balance under a defined network infrastructure, which can have a considerable impact on adequacy results. In this context, the focus of a pan-European adequacy forecast – as presented in the current report by ENTSO-E – is to assess the adequacy of supply to meet demand on the mid-term time horizon while considering interconnections between different power systems across the European perimeter, as illustrated in Figure 1.

Figure 1: The interconnected European power system modelled in the ERAA 2023

The present European Resource Adequacy Assessment (ERAA) probabilistic methodology is considered a reference within Europe.

To optimise and forecast a power system's operation, a large amount of detailed information is required. However, even with the best available data, the results are subject to considerable uncertainty and, therefore, result in a difficult decision-making process for market players.

Figure 2 illustrates the main elements of the ERAA 2023 methodology and their impact on adequacy. The adequacy assessment considers, among others, generation, demand, demand-side response (DSR), storage and network infrastructure.

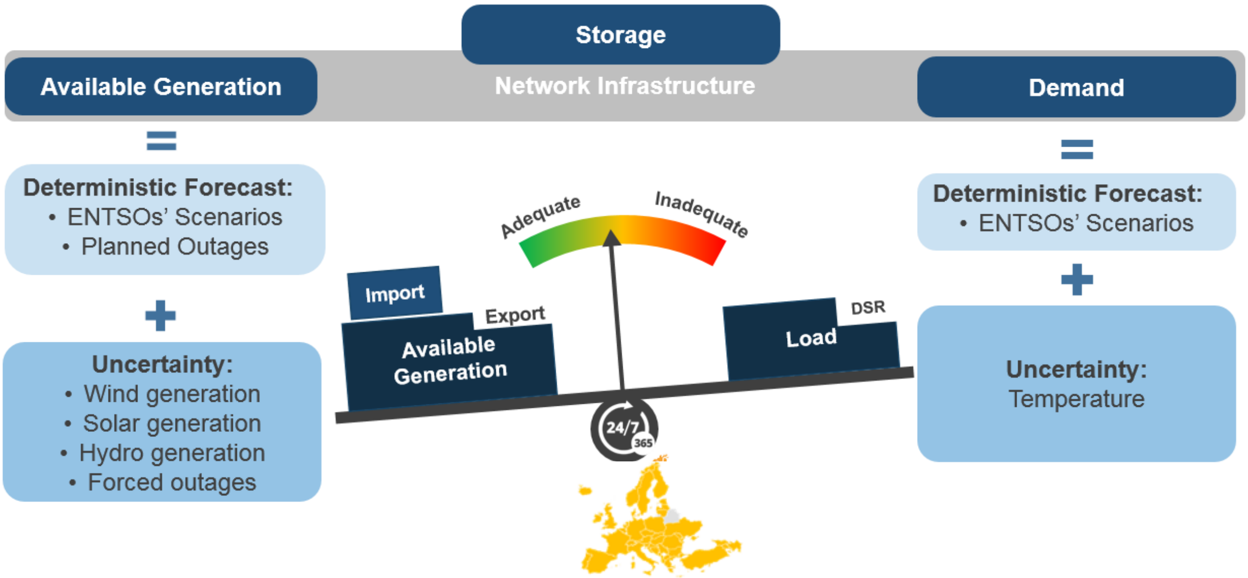

Figure 2: Overview of the ERAA 2023 methodological approach

1.1 Geographical scope & granularity

The present study focuses on the pan-European perimeter and neighbouring zones connected to the European power system. Zones are modelled either **explicitly** or **non-explicitly**. Explicitly modelled zones are represented by market nodes that consider complete information using the finest available resolution of input data (e.g. information regarding generating units and demand) and for which the unit commitment & economic dispatch (UCED) problem is solved. More details can be found in Section 11.5. Non-explicitly modelled zones are market nodes for which detailed power system information is not available to ENTSO-E. For these zones, exogenous fixed energy exchanges with explicitly modelled zones are applied.

In total, 59 bidding zones (study zones) in 36 countries are modelled explicitly in the ERAA 2023. The ERAA accounts for interconnections between study zones and intrazonal grid topologies. Some countries are divided into multiple study zones according to the market setting in those countries (e.g. Greece, Denmark and Italy). Complementing Table 1, Table 2 and Table 3 provide a list of explicitly modelled, non-explicitly modelled and non-modelled zones. Most recently, four Energy Island bidding zones have been added (DKNS, DKBH, BEOF and NLLL)

Table 1: Explicitly modelled countries / study zones

Explicitly modelled member countries/regions and study zones			
Albania (AL00)	Estonia (EE00)	Lithuania (LT00)	Romania (RO00)
Austria (AT00)	Finland (FI00)	Luxembourg (LUG1, LUB1, LUV1, LUF1)	Serbia (RS00)
Belgium (BE00, BEOF)	France (FR00)	Republic of North Macedonia (MK00)	Slovakia (SK00)
Bosnia and Herzegovina (BA00)	Germany (DE00, DEKF)	Malta (MT00)	Slovenia (SI00)
Bulgaria (BG00)	Greece (GR00, GR03)	Montenegro (ME00)	Spain (ES00)
Croatia (HR00)	Hungary (HU00)	Netherlands (NL00, NLLL)	Sweden (SE01, SE02, SE03, SE04)
Cyprus (CY00)	Ireland (IE00)	Norway (NON1, NOM1, NOS0)	Switzerland (CH00)
Czech Republic (CZ00)	Italy (ITN1, ITCN, ITCS, ITS1, ITCA, ITSA, ITSI)	Poland (PL00)	United Kingdom (UK00, UKNI)
Denmark (DKW1, DKE1, DKKF, DKNS, DKBH)	Latvia (LV00)	Portugal (PT00)	

Table 2: Non-modelled countries/study zones

Non-modelled member countries/study zones	
Iceland (IS00)	Türkiye (TR00)

Table 3: Non-explicitly modelled countries/study zones

Non-explicitly modelled neighbouring countries/regions	
Morocco (MA00) - connected to ES00	Tunisia (TN00) - connected to ITSI
Moldova (MD00) – connected to RO00	Ukraine (UA00) – connected to SK00

1.2 Time horizon and resolution

The ERAA target methodology aims to identify adequacy risks up to 10-year ahead and thus assists stakeholders in making well-informed investment decisions. The ERAA 2023 considers an increased number of targets years (TYs) compared to the ERAA 2022, i.e. four TYs: 2025, 2028, 2030 and 2033. The choice of these four TYs is motivated by techno-economic trends and policy decisions relevant for the assessed TYs (e.g. the phase-out of certain generation technologies).

An hourly simulation resolution, also referred to as an hourly market time unit (MTU), has been adopted for all TYs and scenarios for the assessment. More information on the time resolution of each step can be found in the following sections 10.7 and 11.1. All input time series data for the UCED model (e.g. renewable energy source [RES] generation, demand profiles and net transfer capacities [NTCs]) are consequently expressed in hourly intervals. Data provided in a seasonal format by Transmission System Operators (TSOs) are transformed into hourly time series before being fed into the UCED model.

1.3 Modelling assumptions

The ERAA model is a simplified representation of the pan-European power system that – like any model – is based on a set of assumptions. Below is a non-exhaustive list of the main assumptions:

1) **Cost driven dispatch decision:** The modelling tool dispatches available resources for specified time horizons. minimising the overall system costs.
2) **Perfect foresight**: Available RES energy, available thermal capacities (accounting for planned maintenance and forced outages [FOs]); DSR capacities; grid capacities (accounting for FOs); and demand are assumed to be known in advance with perfect accuracy; there are no deviations between forecast and realisation. This also implies a perfect allocation of storage capacities (e.g. Hydro storages) within the year.
3) **Demand is aggregated by study zone:** Individual end-users or end-user groups are not modelled.
4) **Demand elasticity regarding climate and price:** Demand levels are partly correlated to the weather. For example, temperature variations will affect demand levels due to adaptations in the use of electrical heating/cooling devices. Part of the demand is modelled as explicit or implicit DSR, in which load can be reduced or shifted if energy prices are high (see more details in Section 2.3.2). The remaining portion of energy demand is regarded as inelastic to price and will thus hold, regardless of the energy price.
5) **Focus on energy markets only:** Only resources available to the market are accounted for in the ERAA 2023. Non-market resources are not considered in the scenarios apart from strategic reserves, which are considered in the framework of Capacity Mechanism (CM), when applicable. Adequacy is evaluated from a day-ahead/intraday market perspective. Lack of adequacy, the primary focus of the ERAA, should reflect the expectation that the system is not structurally balanced, at least in some hours and/or days. In addition, forward/futures markets or forward/futures contracts between market players are not modelled. As such, these do not influence modelled resource capacities.
6) **RES production depends on climate:** Solar, wind and hydro power generation directly depend on climate conditions.
7) **FOs only affect thermal generation and grid assets:** Power plants and grid assets are subject to Fos, which implies that their net generating capacity (NGC) is not continuously guaranteed.
8) **Planned maintenance of thermal units is optimised:** Planned maintenance of thermal units is scheduled in the least critical periods of the planning horizon, assuming perfect foresight of the demand and intermittent renewable infeed (i.e. periods with likely supply surplus rather than supply deficit). The maintenance optimisation methodology further aims to reflect the impact of different climate conditions.
9) **Some technical parameters of thermal generators are modelled in a simplified manner:** Technical parameters considered to have a low impact on adequacy are modelled in a simplified manner or are neglected (e.g. minimum uptime/downtime). Details on this are given in Section 2.1.
10) **Flow-Based (FB) modelling for the CORE area:** In the adequacy model, grid limitations within the CORE area (AT, BE, HR, CZ, FR, DE, HU, LU, NL, PL, RO, SK and SI) are modelled using the FB approach, which mimics multilateral im-/export restrictions. The remaining part of Europe is modelled via bilateral NTC exchange limitations. In the Economic Viability Assessment (EVA) model, the NTC approach is used for all Europe.
11) **'Copper plate model':** The ERAA matches supply and demand, in addition to exchanges between study zones, without considering grid constraints within study zones.

2 Model Components & Granularity

The following chapter gives an overview of the different elements that are part of the power system model in the ERAA 2023 their granularity as well as their characteristics.

2.1 Generation/Resource side

Table 4 presents the categorisation and spatial granularity of considered resource technologies.

Table 4: Classification of Resource units

Category	Technology	Aggregation
RES	Wind	Aggregated in Pan-European Climate Database (PECD) zones; onshore and offshore wind capacities are collected and modelled separately
	Solar	Aggregated in PECD zones; solar photovoltaic (PV), rooftop solar PV, concentrated solar (thermal) with storage and concentrated solar (thermal) without storage are collected and modelled separately
	Other RES	aggregated in PECD zones
	Hydro without reservoir: RoR and Pondage	aggregated in market nodes
	Hydro with reservoir: Reservoir, Open-Loop Pump Storage Plants (PSP), Closed-Loop PSP	aggregated in market nodes
Non-RES	Coal	unit-by-unit
	Gas	unit-by-unit
	Nuclear	unit-by-unit
	Other Non-RES	aggregated in technology bands
Storage	Batteries	aggregated in market nodes
DSR	DSR	unit-by-unit

Generation data are provided by TSOs through the Pan-European Market Modelling Data Base (PEMMDB). Climate-dependent data such as hydro inflows, solar and wind generation time-series are included in the PECD. Section 0 gives more information about the PEMMDB and PECD. Additional standard parameters are also collected by ENTSO-E, known as the Common Data (e.g. FO rates per technology).

2.1.1 RES

As for Wind, Solar and Other RES technologies, the total capacity installed at PECD zone level is specified and corresponds to the sum of all plant-by-plant and aggregated capacities. In addition, hourly generation curves can be assigned to individual units and/or aggregated capacity provided by TSOs. Solar and wind generation are climate dependent and result from solar irradiance and wind conditions, respectively (see Sections 12.3.2). Planned and forced outages for RES technologies are already included in the hourly time series and are therefore not explicitly modelled.

The available power of RES technologies is injected into the grid at no cost or curtailed following the optimisation model’s decision.

The characteristics of Hydro technologies, namely run-of-river (RoR), Pondage, Hydro with traditional reservoir, Open-Loop PSP and Closed-Loop PSP, are described in a separate Section 2.1.4 and Section 6.1.1.

2.1.2 Non-RES

Only units available in the market are accounted for. Thermal units are dispatched according to their marginal production costs and other plant parameters, including associated costs for CO_2 emissions. No CO_2 emissions are considered for biofuel units. In addition, start-up costs are considered when a unit must be started. Table 5 describes the consideration of unit-specific technical parameters as modelled, non-modelled or simplified modelling as applied in the ERAA 2023. Technical parameters assumed to have a significant impact on resource adequacy are modelled explicitly or simplified. Parameters that are less relevant or have no impact on resource adequacy are neglected in the simulation.

Table 5: Summary of various parameters in the models

Parameter	Description	Accounted in EVA and/or adequacy step
Heat rate [GJ/MWh]	The amount of energy used by a power plant to generate one MWh of electricity	Modelled in both steps
FO Rate	Likelihood of an unplanned outage.	Modelled in both steps
Must-run [MW]	Hourly constraint for single or group of units to produce at least a certain amount of MW.	Modelled in both steps
Min Stable Level [MW]	Minimal operation level of a unit.	Not modelled
Derating [MW]	Hourly constraint for single or group of units to reduce the capacity offered to the market.	Modelled in both steps
CHP revenue profiles [€/MWh_el/h]	An hourly profile by which the Variable Operations and Maintenance (VOM) costs of the CHP unit is reduced	Modelled in both steps
Start-up Time [h]	Time interval required to start a unit from 0 to Min Stable Level.	Simplified in adequacy step only
Ramp Rates [MW/h]	Limitation on the increase / decrease of the generation level within one hour for a unit that is already dispatched.	Not Modelled
Min Up / Down Time [h]	Minimum time interval that a unit should be in operation / out of operation. Frequently related to economic reasons.	Not Modelled

The impact of Ramp Rates and Min Up / Down Times on adequacy indices are negligible due to the perfect foresight assumption in the simulations. Scarcity situations are anticipated in advance, and units are ramped sufficiently early to cope with any adequacy risk and the associated high cost. Start-up Times are modelled in a simplified manner, only immediately after the occurrence of a FO of a unit. In these times, Start-up Time limitations can have an impact on adequacy as the outage withholds the unit from starting in advance.

In addition to unit-by-unit thermal generators, the technology Other Non-RES comprises multiple bands of aggregated Non-RES technologies for each market node. Similar smaller plants are grouped together by technology, price and efficiency, and can be given a must-run status. TSOs are free to provide time series of aggregated capacity with an hourly derating profile if relevant. Available capacity profiles can also be provided for different climate years (CYs) and will as such be attached to the different PECD CYs 1982 – 2016. Available capacity profiles enable a reduction in computational difficulty by simplifying unit dispatch for smaller plants, while still considering decreased power output from planned maintenance or FOs.

Other Non-RES usually aggregates small combined heat and power (CHP) units, waste incineration plants, non-dispatchable thermal generation and any other plants that cannot be provided in a unit-by-unit resolution.

2.1.3 Batteries

Battery storages are increasingly adopted as a means to introduce flexibility into the grid. This flexibility can either participate in the market (e.g. 'in-the-market' batteries) or not (e.g. 'out-of-market' batteries). All the 'in-the-market' battery capacity is 'price-elastic' and is explicitly modelled. Their dispatch is optimised within the probabilistic modelling and the main parameters considered for this technology type are as follows:

- Installed output capacity (MW);
- Storage capacity (MWh);
- Efficiency (92% per cycle, or values provided by TSOs); and
- Initial state of charge (default: 50%).

'Out-of-market' batteries are accounted as implicit DSR as described in Section 2.3.2 (together with electri vehicles [EVs] and heat pumps [HPs]) and can further be classified in either 'price-elastic' or 'price-inelastic'. The former are explicitly modelled while the latter is exogenously accounted for in the demand profiles based on information provided by TSOs. The storage technologies Open-Loop PSP and Closed-Loop PSP are described in the following section.

2.1.4 Hydro

Hydro capacities are aggregated by study zone and technology type. The availability of hydro energy inflows and additional hydro constraints in addition to the criteria for the capacity aggregation are available and defined in the pan-European Hydropower Modelling Database complementing the PECD[1] (also referred to as the 'PECD Hydro database'). A key improvement in the hydropower modelling methodology for the ERAA 2023 arises from the update of the PECD Hydro database, within which the RoR & Pondage was split into two distinct categories that now allow distinguishing between pure RoR and RoR with pondage capabilities, as well as small storages, as explained below.

Hydropower plants are now aggregated into five distinct technology categories:

1. RoR;
2. Pondage;
3. Reservoir (hereafter referred to as 'traditional reservoir');
4. Open-loop PSP reservoir; and
5. Closed-loop PSP reservoir.

The RoR category aggregates non-dispatchable hydropower (river) plants whose generation profile follows the contingent availability of natural water inflows with negligible modulation capabilities.

The new pondage category, now separated from the pure RoR, instead collects fluvial or swell power plants with pondage capabilities, i.e. the possibility to leverage a dam or storage system ahead of the turbine inlet and thus leverage a certain degree of generation flexibility with respect to the natural water inflows. The pondage category also accounts for small daily storages, i.e. small reservoirs without pumping capabilities and with a ratio of reservoir size [MWh] to net generation capacity [MW] smaller than 24 hours.

[1] Hydropower modelling - New database complementing PECD

Major hydro storage plants without pumping capabilities are merged instead into the traditional reservoir category. PSPs are differentiated between basins with natural inflows, i.e. the open-loop PSP reservoir, and PSPs without natural inflows, i.e. the closed-loop PSP reservoir.

The hydropower generation is ruled by a set of constraints and parameters that define the maximum and minimum power available for turbining (or pumping) operations. These include hydro natural inflows, minimum and maximum generation and reservoir level constraints. Due to the level of aggregation, i.e. aggregated capacity per technology type, FOs and maintenance requirements are implicitly reflected in the time series which define the maximum generation constraints. The data availability varies depending on the set of input data provided by TSOs for the peculiar generation mix of the market nodes within their control areas. It follows that the data in Table 6 are not fully available for all market nodes but are, rather, an indication of the template and structure of the database itself.

Table 6: Key hydropower data and constraints aggregated per technology type

MW / GWh	ROR	Pondage	Trad. Reservoir	Open-Loop PSP	Closed-Loop PSP
Hydro inflows	D	D	W	W	-
Max. power output	D	D	W	W	W
Min. power output	D	D	W	W	W
Max. generated energy	-	-	W	W	W
Min. generated energy	-	-	W	W	W
Max. pumping power	-	-	-	W	W
Min. pumping power	-	-	-	W	W
Max pumped energy	-	-	-	W	W
Min. pumped energy	-	-	-	W	W
Deterministic res. level	-	D	W	W	-
Max. reservoir level	-	D	W	W	-
Min. reservoir level	-	D	W	W	-
Reservoir size	-	Y	Y	Y	Y
Turbine capacity	Y	Y	Y	Y	Y
Pump capacity	-	-	-	Y	Y
Size/Capacity ratio [h]	-	≤ 24	>24	any	any
	D: Daily	W: Weekly	Y: Yearly	-: Not applicable	■: Not modelled

In what follows, a detailed description is given of the modelling assumptions and the hierarchy of the constraints collected in the table above.

Hydro Inflows – available as cumulated daily or weekly energy lots – are equally distributed over 24 or 168 hours respectively, given the hourly resolution of the UCED simulation. Depending on the hydropower category, inflows are immediately dispatched (e.g. pure RoR generation) or stored within the hydro reservoirs and released according to the optimised reservoir management performed by the modelling tool. If available hourly inflows exceed the dispatch needs or the maximum reservoir level trajectories, the modelling tools can decide to spill (i.e. dump) the inflow surplus.

Minimum and Maximum Generation power constraints regulate the hourly hydropower dispatch. If not explicitly provided, minimum power is assumed to be equal to zero and maximum generation is set to be equal to total installed capacity, derated by the frequency containment reserve (FCR) and frequency restoration reserve (FRR) hydro reserve requirements if applicable. RoR generation is assumed to be non-dispatchable by definition; thus, the daily inflows are turbined at a constant hourly output during the day. If a non-zero reservoir size is provided for the pondage category, such dispatch flexibility is granted according to minimum and maximum generation profiles, which can reflect both the non-dispatchable RoR and the dispatchable swell or pondage share of the aggregated capacity, respectively.

Minimum and maximum generated energy constraints represent weekly limitations to the energy output that are enforced in an intertemporal manner, i.e. the total generation over the whole week has to be lower (or higher) than the maximum (or minimum) energy constraint for the respective week. These types of constraints can be retrieved from a detailed analysis of historical generation profiles, in addition to reflecting the combination of a wide range of restrictions, including minimum or maximum water flows from/to reservoirs or river damns due to environmental regulations; regulated levels of river or hydro storage flows due to regulated water use for navigation, agriculture or others; technical operational constraints of cascade reservoir systems and PSP plants; and any other peculiar constraint relevant for a specific study zone.

Reservoir Level Constraints are treated as discrete constraints to be enforced by the modelling tool at the beginning of each week, i.e. on the first hour of the week. Nevertheless, the intrinsic complexity of optimising hydropower generation from hydro reservoirs characterised by climate-dependent and/or seasonal constraints and inflow patterns may sometimes lead to punctual infeasibilities in the UCED solution. Such infeasibilities frequently arise from the solver attempting to enforce the initial reservoir level (or minimum/maximum level) as hard constraints at the beginning of each week without sufficient flexibility. Therefore, two sets of minimum and maximum reservoir level constraints are collected, labelled as ‘technical’ and ‘historical’. As the naming suggests, historical constraints include the minimum and maximum measured (weekly or daily) levels, while the technical constraints report operational limits of the reservoir that are independent from climatic conditions, e.g. safety operational levels, minimum water reserves for potable and agriculture uses, and others, which can never be violated. When infeasibilities or adequacy issues are detected, the solution adopted is to treat historical level trajectories as soft constraints, thus allowing the solver to violate them at a high penalty cost. Setting the penalty cost sufficiently high but still lower than the value of lost load (VoLL) ensures that the solver prioritises the dispatch of hydro resources and inflows during hours of generation scarcity to avoid energy not served (ENS) if potentially in conflict with historical reservoir trajectories. Technical constraints are instead treated as hard constraints regardless of the contingent dispatch or system status.

Minimum and Maximum Pumping are treated analogously to minimum and maximum power output constraints. Only limitations to the maximum pumping power are applied in the model. The other pumping constraints – marked in blue in Table 6 – are neglected and excluded from the hydropower modelling methodology. In particular, minimum power as well as minimum and maximum (weekly) energy constraints for pumping operations are deemed as too restrictive and unsuitable for the nature of the MC adequacy simulations, in which PSP plant operations shall be left as a flexible decision variable to be optimised by the solver according to the contingent availability of resources and endogenous marginal prices.

2.1.5 Balancing Reserves

Balancing reserves (or ancillary services) are power reserves contracted by TSOs that help stabilise or restore the grid’s frequency following minor or major disruptions due to unforeseen factors such as outages or rapid changes in load. Although they are fundamental to a power system’s stability, only replacement reserves (RR) are considered available in the energy-only market (EOM) for adequacy purposes in the ERAA. Indeed, the ERAA measures structural inadequacies that manifest in time steps of an hour or longer and does not analyse what occurs within each hour. Due to the time resolution of the UCED and, as mentioned in Section 1.3 the fact that the ERAA model utilises perfect foresight of available generation and demand, FCR and FRR balancing reserves are not considered in the ERAA models. Table 7 below summarises the different balancing reserves and how they are treated in the model.

Table 7: Consideration of Balancing Reserves in the ERAA 2023

Balancing Reserve type	Availability in the EOM
FCR	Unavailable
FRR	Unavailable
RR	Available

For the ERAA 2023, TSOs could choose to account for balancing reserve requirements either by thermal, renewable (wind and solar) and/or by hydro units. For thermal units, known contracted capacities for reserves were already deducted from the data reported by the TSOs. TSOs were also able to report FCR and FRR requirements that must be explicitly modelled and covered by the remaining available thermal and/or renewable fleet. These requirements are not already accounted for in the reported net generation capacities. More details on how this modelling is done can be found in Section 0.

Finally, TSOs were able to report reserve requirements that must be covered by hydro units. More specifically, FCR and FRR requirements may also be covered by reservoir, open-loop PSP and closed-loop PSP units. The full requirement may be covered either by one technology or a collection of them, depending on TSO reporting. Section 0 gives further insights on how reserve requirements provided by hydro are accounted for in the adequacy models.

2.2 Grid side

Like thermal capacities, TSOs provide forecasted available NTCs with an hourly resolution. The TSOs provide data divided into the categories high voltage alternating current (HVAC) and high voltage direct current (HVDC), and NTCs are aggregated per border. Planned maintenance for transmission lines was not centrally optimised in the ERAA 2023 but was considered integrated into the NTC hourly availability, as provided by TSOs. Transmission levels depend on deterministic planned outages and random FOs, which are modelled in the same manner as for dispatchable generation resources. TSOs can report specific FOR per interconnector. Standard assumptions of 0% for HVAC and 6% for HVDC are applied if TSOs do not provide specific FOR values. Interconnectors between market zones can consist of multiple poles, which are also explicitly modelled in the ERAA. The default assumptions for calculating the number of poles, in the event TSOs did not provide any information, is 1 pole per 400 MW of capacity, with a minimum of two poles per line for HVAC interconnections and 1 pole per cable for HVDC ones.

Apart from bilateral interconnector constraints, the following constraints are also considered in the ERAA 2023:

- Gross export/import limits, constraining the sum of exports/imports from the considered market area; and
- Country position net import/export limit, setting a lower and upper bound for the net balance of the market area. This is typically related to the minimum amount of inertia that a country needs to maintain, i.e. the minimum number of units spinning in their system to be operationally stable and running within operationally safe levels.

Due to the complexity of power systems, the consideration of multi-lateral interconnection restrictions, such as flow-based market coupling (FBMC), become more important. FBMC is therefore implemented for the CORE.

2.3 Demand & flexibility

The majority of the demand is inflexible, i.e. is fixed and not dependant on market conditions (prices or other), but some quantity is flexible and modelled as either explicit DSR or implicit DSR. Implicit DSR is further broken down in two categorises, i.e. 'price sensitive' and 'price-insensitive'. Table 8 summarises the above:

Table 8 Modelling of explicit and implicit DSR

	Examples	In the market?	Price sensitive?	Modelling choice
Explicit DSR	Large scale batteries	Yes	Yes	Explicitly modelled
Price-sensitive implicit DSR	EVs, HPs, Household batteries (out-of-market)	No	Yes	Explicitly modelled
Price-insensitive Implicit DSR	EVs, HPs, Household batteries (out-of-market)	No	No	Accounted for in the demand profiles

Constraints on the maximum daily operating hours for DSR and the activation time of iDSR are included in the EVA and UCED.

2.3.1 Base Demand

The base demand is composed of any fixed load and includes the price insensitive parts of EVs, HPs and batteries.

TSOs can choose to either have ENTSO-E calculate the base demand time series on their behalf based on data provided by the TSOs or provide the time series themselves. ENTSO-E generates demand time series using a dedicated tool, i.e. the Demand Forecasting Tool (DFT).

2.3.2 Price sensitive demand Side Flexibility

The categories belonging to 'price sensitive' DSR are Explicit DSR and price sensitive implicit DSR.

Explicit DSR capacity differs between study zones and between hours of the day. The dataset provided by the TSOs includes:

- the maximum DSR capacity [MW];
- the day ahead activation price [EUR/MWh];
- the actual availability [MW] for all hours of the year; and
- the maximum number of hours the DSR source can be used per day (default: 24 hours).

Each of the above parameters can be specified for different activation price bands, either as a market resource or as strategic reserves (the latter is not considered in the ERAA adequacy simulations). From a modelling perspective, DSR is similar to any other generation asset but with an activation price usually higher than the marginal cost of most other generation categories and with an availability rating that limits activated DSR capacity for a given hour.

The approach for the implicit Demand Side Response (iDSR) implemented in the ERAA 2023 aims to include explicitly in the market models (with due simplifications) the flexibility – with respect to endogenous market prices – expected from EVs, HPs and out-of-market Batteries (oomB). An important input for this modelling approach is the share of price sensitive consumers $\boldsymbol{R}$ among those consumer types. Those vary between countries and are collected from each TSO as a best estimate. Based on this parameter, we can compute the amount of 'price sensitive EVs, HPs and oomBs'.

The price-sensitive share of oomB is modelled as a battery characterised by **installed charge/discharge capacity** and **storage size** (as directly reported in the data collected for oomB capacity) multiplied by the corresponding price sensitive ratio $\boldsymbol{R_{oomB}}$. The example below illustrates the application of $\boldsymbol{R_{oomB}}$.

Assuming for a given study zone and TY
- An oomB installed capacity of 350 MW;
- A storage capacity of 1100 MW; and
- A $\boldsymbol{R_{oomB}}$ of 5%

The following would be explicitly modelled:

- **Charge/Discharge capacity** = Capacity x R_{oomB} = 350 MW x 5% = 17.5 MW.
- **Storage size** = Size x R_{oomB} = 1100 MWh X 5% = 55 MWh.

In addition, the following assumptions are made:

- **State of Charge (SoC)** initial and final level of the year = set to 50% by default.
- **Cycle efficiency** = set to 92% default value.

As for EVs and HPs, the methodology leverages primarily on the demand forecasts generated by the dedicated tool, as described in section 2.3.2, which includes a base consumption for EVs and HPs. In the modelling tool, the price sensitive share of EV and HP consumers ($\boldsymbol{R_{EV}}$ and $\boldsymbol{R_{HP}}$) can shift their demand within time windows to gain arbitrage and improve resource adequacy in times of scarcity. The energy within each time window must be balanced, i.e. energy cannot be shifted outside a time window.

The time windows applied for EVs in addition to HPs depending on the respective time zone are presented in Table 9. The detailed mathematical formulation of the modelling of flexible EVs and HPs can be found in Appendix 2.

Table 9: EV and HP Time Windows

Time Zone	Start Window 1	Start Window 2	Start Window 3	Start Window 4
STANDARD (UTC)	3am	9am	3pm	9pm
UTC+1	2am	8am	2pm	8pm
UTC+2	1am	7am	1pm	7pm
UTC-1	4am	10am	4pm	10pm

2.4 Flow-based domains

2.4.1 Main input used

Table 10 summarises the main characteristics of the input used to compute the ERAA 2022 FB domain for TY 2025 and were reused for ERAA 2023. NTCs submitted by TSOs were used for the FB domain enlargement.

Table 10: Main input characteristics used to compute the FB domain for TY 2025.

Parameter	Assumption
Time horizon	2025
Market	DA
Time resolution of market data	1 h
CCR	CORE[2]
Market model	ERAA 2021
Grid model	TYNDP 2020 National Trends TY 2025
Initial DA market simulation	ERAA 2021 study with Flow-Based – Base Case A
Optimization of PST and DC settings	Alegro DC links by market simulation with AHC; PSTs with SHC through the calculation of reference flows
CNECs	All cross-border lines communicated by TSOs
PST tap range	1/3
minMACZT	minMACZT = 70% or minRAM = 20%; depending on which criterion is more constraining
FRM	Based on individual TSO feedback
MACZT	MACZT=max(minMACZT, Fmax - FRM - F0) or MACZT=max(minRAM, Fmax - FRM - F0); depending on which criterion is more constraining
Number of representative domains	4

2.4.2 CNEC selection

The definition of the critical network elements and contingencies (CNECs) in cross-border capacity calculation has a considerable influence on the resulting FB domains. Additional CNECs imply additional constraints to account for and thus potentially more restrictive FB domains allowing fewer cross-border exchanges.

Only cross-border CNECs with a rated voltage level of 220 kV or higher in combination with relevant contingencies were considered and provided by the TSOs. This choice was performed to respect the Core capacity calculation methodology, which specifies that most of the CNECs provided by TSOs should be cross-border CNECs.

The same list of provided CNECs was considered for each timestamp on which FB domains were calculated.

[2] The CORE region is composed of Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxemburg, the Netherlands, Poland, Romania, Slovakia and Slovenia

2.4.3 Representative domain selection

As a result of the representative domain selection described in the FB methodology description, four representative timestamps were identified from the results of the initial market model and used as a basis for setting the production and load in the nodes of the grid model, and consequently calculating the four representative domains.

3 Overview of scenarios and calculations steps

This Section provides an overview of the ERAA adequacy assessment process. The process starts with the collection of a large amount of raw input data. The latter is processed to serve as input for the scenario computations. The preparation of input data for all TYs and uncertain variables (e.g. CYs) is a major task for the ERAA. Figure 3 presents the following elements:

- The data are stored/generated in three databases/tools, namely the PEMMDB, PECD and TRAPUNTA and constitute the ‘National Trend’ scenario. For more information, see Annex 1;
- Some data are defined by TY, whereas other data are by CY (*N* CYs) or both TY and CY;
- A single modelling tool is used to optimise planned maintenance profiles for the thermal generation assets of each modelled market node (for unplanned maintenance, see Section 11.4). Planned maintenance of grid assets is already included in the NTCs provided by the TSOs;
- Thermal capacity can be dispatched at will, whereas wind and PV capacities depend on climate conditions during their operation. As such, the available wind and PV (power) generation can be injected at no cost (or curtailed following the optimisation model’s decision); and
- The datasets are fed into the reference market modelling tool.

National Trends Input calculation process

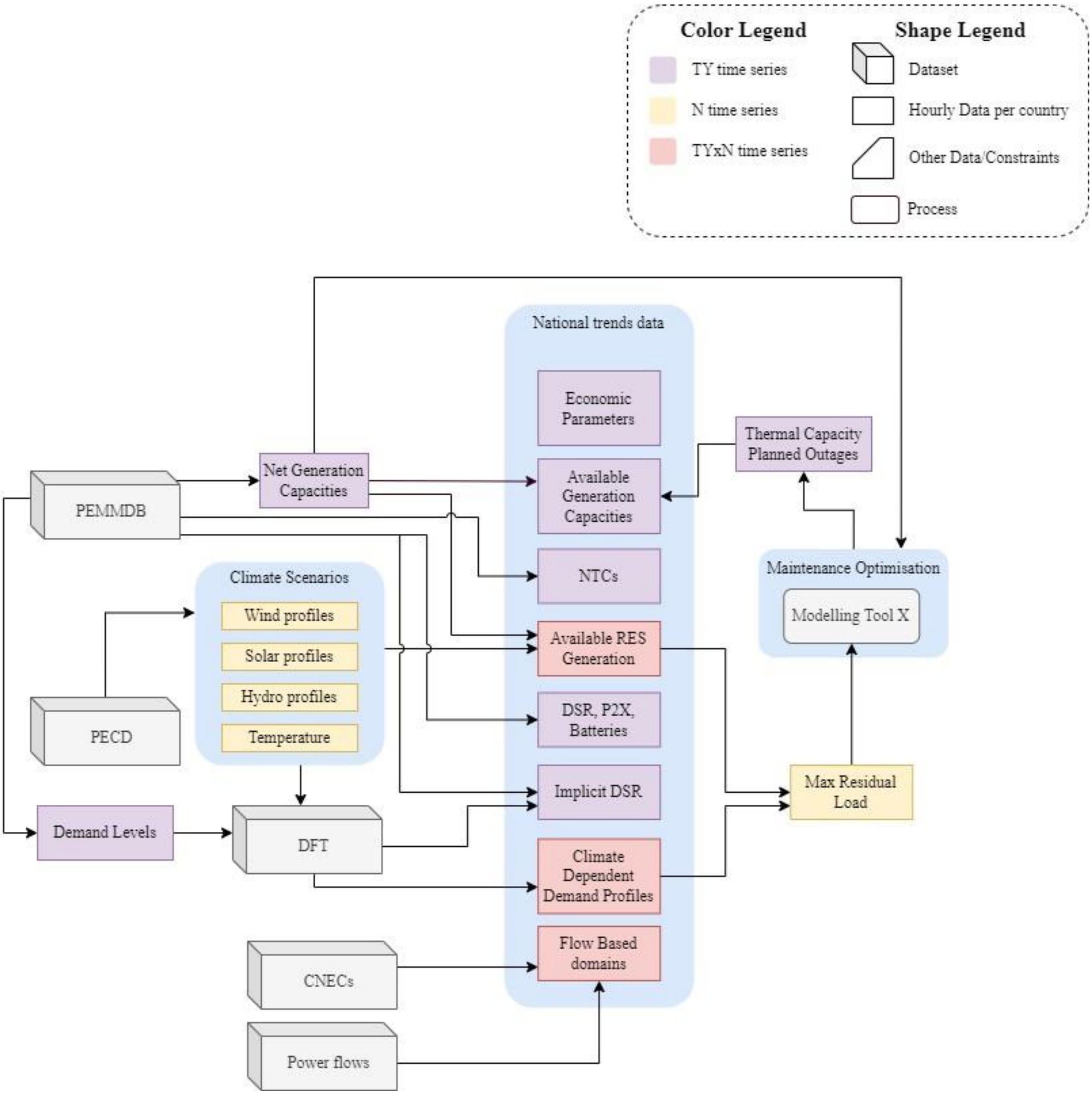

Figure 3: Overview of the initial input data processing

4 Flow-Based Domains Calculation methodology

The ERAA target Methodology requires the implementation, where applicable, of a FB capacity calculation methodology (CCM) for cross-zonal trade. In the European day-ahead (DA) market for electricity, energy is traded within and across study zones. The market assumes no grid restrictions within a study zone, but there are limitations to the amount of energy that can be traded across study zones. One approach to account for those limitations is market coupling by NTC, in which the trades across any given border and market time unit do not affect exchange capacities on other borders in the market clearing process. The FBMC approach, in contrast, considers interdependencies in the power system by allowing export from or imports to the study zones as long as monitored network elements are not overloaded. Therefore, it better represents the physical reality of the grid. The market coupling approach is currently defined by so-called capacity calculation regions (CCRs)[3].

The map below (Figure 4) shows the perimeter of the Core region, on which FB domains were calculated. The map also shows the countries which were considered in the advance hybrid coupling (AHC) calculation.

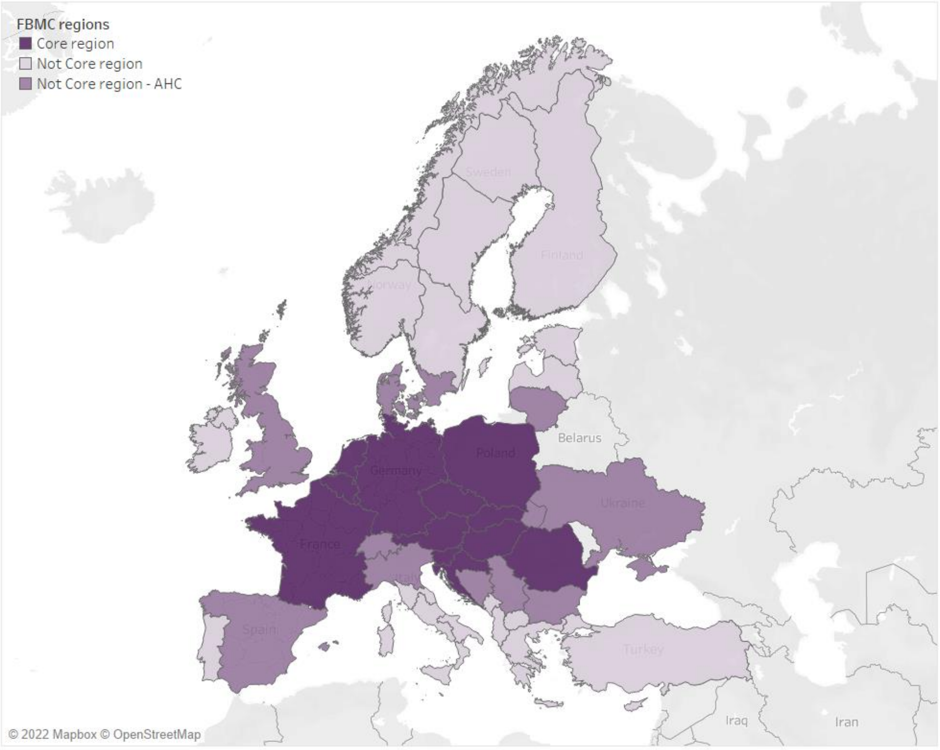

Figure 4: Core Capacity Calculation Region

The present section describes the methodology for computing FB domains and allocating them to each hour of each TY. The ERAA 2023 uses individual FB domains for each TY. The Core FB domains for TY 2025

[3] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222 , https://www.entsoe.eu/network_codes/ccr-regions/

used were those of ERAA 2022. The domains for the remaining TYs were derived from the TY 2025 domains after applying an expansion method (see section 4.3). Figure 5 illustrates this expansion for one timestamp.

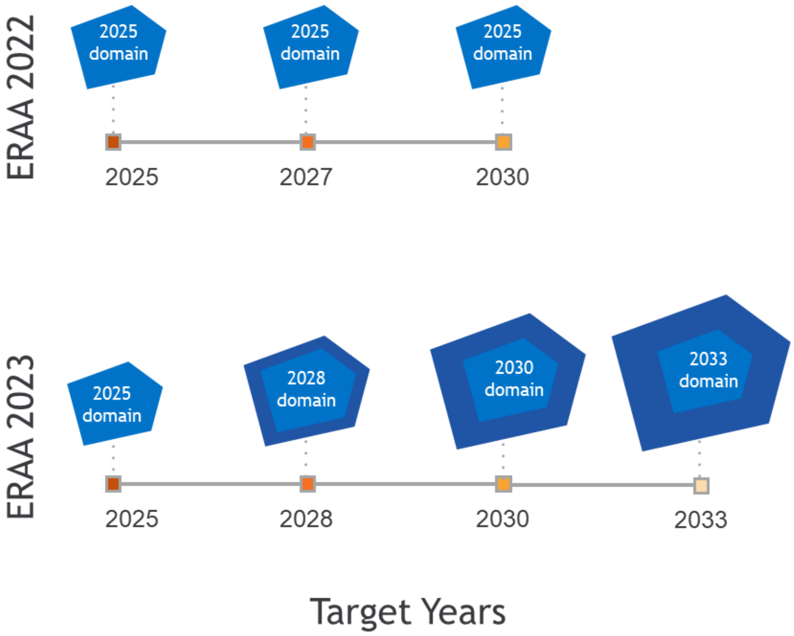

Figure 5: Illustrative comparison of the FB domains used in ERAA 2022 and ERAA 2023

4.1 FB domain concept description

In broad terms, a FB domain describes the solution space for the net positions of individual study zones in a given CCR such as CORE for a given market time unit (currently one hour). In other words, it defines the limitation for exchanges between study zones in that CCR. External flows (to neighbouring countries) or internal DC line flows can also be accounted for.

A FB domain is defined by a set of linear constraints derived from linearised equations in the network models (analysing active power flow) across monitored network elements. A change in study zone net position directly translates into the change of power flow on the respective network element. This relation is represented by power transfer distribution factors (PTDF).

Monitored network elements considered as critical network elements (CNEs)[4] in the capacity calculation can be both within and across study zones. Specific requirements apply for the consideration of internal network elements. By including relevant contingencies, the N-1 security constraints of the grid can be represented. This results in a list of CNECs, i.e. a list of CNEs combined with relevant contingencies under which particular CNEs are monitored. For each CNEC, a margin available for cross-zonal trade (MACZT) is defined that restricts the power flow on the CNEC, which in turn will be the limiting factor for net positions of study zones in the form of FB domains.

As explained above, the constraints of an FB domain are given by the CNEC power flow definition on the left-hand side and their respective capacity margin on the right-hand side. Thus, an FB domain consists of linear constraints in the form of inequalities. In the conceptual FB domain given in Table 11 there is a linear

[4] ACER Decision on tge Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies

constraint in which *A*, *B* and *C* corresponds to the net positions of study zones or flows and/or set points of selected external flows to the CCR, internal HVDCs and selected phase-shifting transformers (PST) within the CCR:

$$-0.3A + 0.25B + 0.1C \leq 150 \text{ MW}$$

In FB with standard hybrid coupling (SHC), A, B and C correspond to the net positions of CCR study zones A, B and C with respect to the other study zones included in the CCR. However, these variables can also refer to setpoints of selected external flows into the CCR (AHC), the setpoints of HVDCs internal to the CCR (evolved flow-based, EFB) and selected PSTs within the CCR. Whereas in SHC, the FB domain only models the impact of exchanges between CCR study zones on CNECs, in AHC the impact of the interconnectors between CCRs is added to the model. The PTDFs (-0.3, 0.25 and 0.1 in this example) for AHC borders refer to the sensitivity of the flow on a CNEC to a change in flow over this AHC border. In EFB, similarly to AHC, the sensitivity of CNEC flow to setpoints of DC elements within the CCR are considered.

With the resulting set of constraints, the market simulation model is able to set the CCR net positions, the setpoints of DC elements and the bilateral exchanges over non-Core borders while respecting the maximum allowed flows on all CNECs. Note that while the NTC constraints between CCR study zones are completely replaced by FB constraints, NTC values remain constraining for the maximum flows over the AHC elements themselves.

Table 11: Conceptual FB domain example

Critical network element	Contingency	Critical network element and contingency	Influence of the net position on the flow on each line (PTDF matrix)			MACZT (MW)
			A	B	C	
Line 1	None	CNEC 1	-30%	25%	10%	150
	Contingency 1	CNEC 2	-17%	35%	-18%	120
	Contingency 2	CNEC 3	15%	30%	12%	100
Line 2	None	CNEC 4	60%	25%	25%	150
	Contingency 3	CNEC 5	4%	-15%	4%	50
…	…	…	…	…	…	…

The constellation of non-redundant constraints can be described as a 'convex hull'. The convex hull forms an n-dimensional polytope. The dimensions correspond to the columns of the FB domain matrix. In the example of Table 11 above, the dimensions are given by A, B and C.

For the visualisation of a domain or the comparison between different domains, it can be useful to project the polytope onto a two-dimensional plane. This is comparable to the concept of casting the shadow of a three-dimensional object onto a wall. However, the computational complexity of creating the projection increases with the number of dimensions as it requires the vertices of the full polytope to be enumerated.

When referring to the 2D projection of a FB domain, the displayed polygon does show all admissible values for the considered two dimensions but it does not show the implication of these values on the variables of the remaining dimensions. As an example, we assume a simplified three-dimensional domain with the shape of a cube as described in Table 12. Its projection onto the dimensions A and B, shown in Figure 6, makes it clear that this assignment forces C to adopt a net position of 0 in this example.

Table 12: Cube-shaped FB domain

CNEC ID	A	B	C	RAM
‘1	1	1	1	1
‘2	1	1	-1	1
‘3	1	-1	1	1
‘4	-1	1	1	1
‘5	1	-1	-1	1
‘6	-1	-1	1	1
‘7	-1	1	-1	1
‘8	-1	-1	-1	1

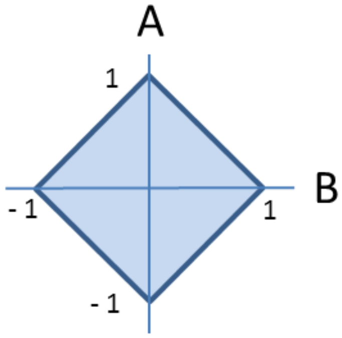

Figure 6: 2D projection of cube-shaped domain for C=0

4.2 FB domain computation steps for TY 2025

The process of computing the TY 2025 FB domains can be summarised in 5 steps, illustrated below:

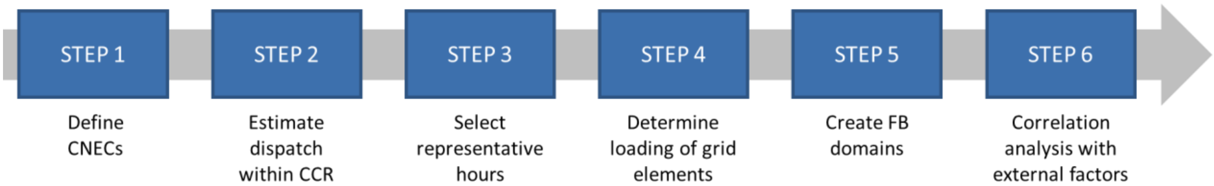

Figure 7: Steps for computing sets of FB domains for TY 2025

4.2.1 CNECs definition (Step 1)

In the first step, a list of CNECs which potentially limit cross-zonal trade is defined. As mentioned above, a CNEC is a combination of a CNE with a contingency that refers, for example, to overhead lines, transformers or underground cables.

4.2.2 Computation of initial market dispatch within CCR (Step 2)

The hourly market dispatch within the studied CCR in addition to exchanges with Study Zones outside of a given CCR, but connected to a given CCR, is computed and given to the grid model as an initial market dispatch to perform load flow analysis and compute FB domains.

4.2.3 Selection of representative hours (Step 3)

Calculating FB domains is computationally-intensive and thus it is impractical to calculate for each hour of each CY of the initial market simulation. To overcome this limitation, a selection of representative hours from the input market study is made on which FB domains will be calculated.

The selection of the representative hours is based on a clustering process and provides a set of statistically representative, differentiated timestamps, to calculate domains which are both meaningful (representative of a sufficient number of hourly situations) and different (to provide a wide range of possible network constraint situations).

The clustering is based on the hourly flows on the monitored CNEs without contingencies, which are a good proxy of the final shape of the FB domains. The process to perform the clustering is as follows:

- A CNECs reduction is performed to remove duplicates in addition to CNEs presenting correlated flows (e.g. parallel lines);
- A load flow simulation is run on a representative grid model for each hour of the selected CYs considering the initial market dispatch computed before. Consequently, the hourly flows on CNEs are computed (without simulating contingencies); and
- The optimal number of clusters and the clusters themselves are computed based on the flows on CNEs, using a k-medoid clustering approach (see below for details). This results in the identification of the representative hours across the selected CYs on which the FB domains will be calculated.

The optimal number of clusters is selected based on the computation of two clustering statistics: the total Within Sum of Square (WSSs) and the silhouette. These indicators are calculated for different numbers of clusters to determine the optimal number of clusters, maximising the consistency within one cluster and maximising the difference between clusters. For the ERAA 2022, this led to the selection of two clusters for winter hours and two for summer hours, resulting in four FB domains to be computed.

4.2.4 Reference loading of grid elements (Step 4)

The reference loading of grid elements is calculated for representative hours by performing a load flow calculation on the input grid model (full load flow calculation).

4.2.5 FB domains computation (Step 5)

Step 5 describes the computation of the FB domains for each representative hour, identified in step 3. The FB domain calculation begins with the power transfer distribution factor (PTDF) matrix, which is derived from the grid model and allows for linear power flow calculations. The PTDF matrix represents all changes to flows over the CNECs in response to injections in individual network nodes in the detailed grid model. This PTDF matrix provides nodal granularity and incorporates all network nodes represented by columns. To allow for a zonal representation in accordance with the European study zone configuration, a generation shift key (GSK) is required. The GSK is a matrix that carries the information of how the nodal power injection changes if the net position of a study zone moves up or down. Multiplying the nodal PTDF and GSK matrices results in a zonal PTDF matrix. Finally, the matrix is augmented by columns representing either DC links or exchanges with external CCRs that are modelled as ARC. This concretely means that PTDFs are calculated for each CNEC for each represented DC link (currently, the Alegro HVDC link) and for NTC borders between a Core and a non-Core study zone. This allows the sensitivity of CNEC flows to be represented within the Core region to the flows on the represented DC links and on the NTC borders between Core and other CCRs. This step concludes the left-hand side of the FB domain constraints (PTFDs).

To establish the right-hand side of the constraints (remaining available margins; RAMs), the MACZT on each CNEC must be known. Its size depends on the one hand on the physical active power transmission capacity, the base or ‘reference-flow’ loading and the flow reliability margin of the CNEC, and on the minimum legal requirements for cross-zonal trade on the other hand. Step 5 also includes a non-costly remedial action optimisation through PSTs, which aims to increase the size of the domain in its narrower dimensions. The outcome of this step may therefore differ depending on the actual constraining CNECs, which are linked to the CNEC list used to build the domain.

Once zonal PTDFs and the RAMs have been computed for each CNEC, a post-processing is performed to adjust RAMs to comply with the 70% requirements. The 70% regulation (Regulation 2019/943, article 16) prescribes a minimum margin of the physical cross border capacity that needs to be made available to cross-border trade. Two checks are performed, and RAMs are adjusted if the requirements are not met. The highest

RAM value is kept, which ensures the compliance of each CNEC with both requirements. The two requirement checks are:

- Check of the 70% minMACZT rule: The Net Positions of all study zones (within and out of the Core region) is set to 0 (using the PTDFs previously calculated), and for each CNEC it is checked whether the resulting flow is lower or equal to 30% of the RAM of the CNEC. If this is not the case, the RAM is increased until the flow in this situation reaches 30% of the RAM for all CNECs.
- Check of the 20% minRAM rule: The Net Positions of Core study zones is set to 0 (using the PTDFs previously calculated), and for each CNEC it is checked whether the resulting flow is lower or equal to 80% of the RAM of the CNEC. If this is not the case, the RAM is increased until the flow in this situation reaches 80% of the RAM for all CNECs.

This process within the FB domains computation methodology ensures that the computed Core domains are compliant with the 70% rule.

As the final part of Step 5, a post-processing to the FB domains can be adopted for better handling. A pre-solving algorithm identifies the convex hull of the domains, i.e. the linear constraints that shape the FB domain. Any remaining constraints (outside of FB domains) are then filtered out, resulting in a smaller set of constraints.

4.2.6 Defining when each FB domain should be used (Step 6)

Step 6 defines the last part of the FB methodology and describes how the computed FB domains are chosen for each hour in the adequacy assessment models.

First, a Random Forest classification algorithm is trained to identify under which conditions each FB domains are more likely to be representative. Total load and RES generation (solar, wind, hydro Run-Of-River generation) are considered as main conditions influencing FB domains, and are called determinants. Each determinant is considered on a study zone level. A large set of determinant data is built considering conditions in each hour of the cluster (identified in step 3), which specific FB domain is representing. With this dataset, the Random Forest classification algorithm identifies under which distinguished conditions each FB domain is representative.

Subsequently, to identify which FB domains should be chosen for every timestep of a prospective study, the trained Random Forest classification algorithm is applied for all possible conditions in a given prospective study. During this step each timestep of each CY is analysed by the algorithm considering determining conditions (total load, RES generation). By analysing the data, the algorithm identifies which FB domain would best fit the conditions of that timestep. The process is repeated for every timestep of the prospective study.

4.3 Calculation steps for FB domain enlargement for TY 2028, 2030 and 2033

Grid expansion projects may lead to increased exchange capacities and strengthen grid stability. NTCs provided by the TSOs for EVA simulations suggested that exchange capacities are expected to increase over coming years. The FB domains for TYs 2028, 2030 and 2033 were unfortunately not computed for the ERAA 2023 and, therefore, the trend of increasing exchange capacities were not represented. However, to account for grid expansion projects in these TYs, the flow-based domains of TY 2025 were enlarged by increasing the RAM of each CNEC based on the trends identified in NTC provisions submitted by TSOs. The resulting FB domains for TYs 2028, 2030 and 2033 enable increased exchange possibilities than the TY 2025 FB domains. A two-dimensional enlargement illustration is shown in Figure 8:

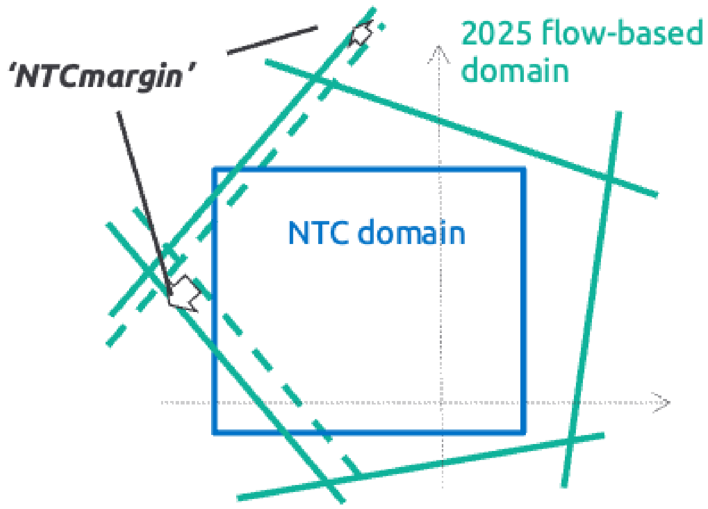

Figure 8: Illustration of flow-based domain enlargement

The NTC margins are computed by analysing the forecasted NTC increases from one TY to another. The principle of enlarging the FB domain is based on the 'LTA margin approach', described in Article 18 of the Core Day-Ahead Capacity Calculation Methodology[5]. However, the methodology deviates so that the FB domain is not enlarged to fit whole the NTC domain but rather to accommodate part of the increase (c.f. NTC margin selection below in process description).

The following calculation steps were carried out to arrive at the FB domains for TYs 2028, 2030 and 2033, respectively:

- Identification of 'NTC corners': conceptually, the NTC corner describes an extreme exchange between Study Zones in the power system in which at least on one border is congested. Therefore, NTC corners are identified as a list of unique possible Study Zone border combinations, which describe if a cross-border exchange is congesting cross-border interconnection. In the Core region for example, an NTC corner could characterise a situation where only DE00 – NL00 and FR00 – BE00 interconnections are congested. In a CORE region this yields over a half million possible cross-border combinations (2^{19} to be precise – as there are 19 borders in the Core CCR), when interconnections with non-CORE Market Coupling regions are ignored (i.e. AHC borders are ignored).
- NTC margins computation: For each CNEC and for each NTC corner a necessary RAM increase is computed to enable exchanges of that NTC corner (considering that all NTCs are used on congested borders and no energy flows on non-congested borders). Essentially, a NTC margin describes how much RAM would be needed to enable every possible extreme cross-border exchange from the NTC model in the FB model.
- NTC margin selection. The NTC margin to be used in the FB domain expansion for each CNEC is selected as the 75th percentile from all NTC margins on a given CNEC. This NTC margin is then added to the RAM of the TY 2025 FB domains. This percentile was determined as a suitable trade-off between increasing cross-zonal capacities in line with NTC increases on the one hand, and not overshooting unrealistically the increase of cross-zonal capacities. Furthermore, note that taking the maximum value of this distribution would result in the FB domain fully containing the NTC domain with FB domain corners being even further than the NTC corners and deviating significantly from estimates provided by TSOs with NTC corners.
- The steps above were performed for:
    - each CNEC of the TY 2025 FB domain;
    - the four seasonal FB domains per TY; and

[5] https://eepublicdownloads.entsoe.eu/clean-documents/nc-tasks/CORE%20-%20ANNEX%20I_III.pdf

- for each of the TYs 2028, 2030 and 2033.

In total, this results in 16 flow-based domains (four per TY). Note that only the effective RAM increased compared to TY 2025, considering NTC increases between CORE study zones (NTC increases between CORE study zones and study zones outside core region were disregarded). Furthermore PTDFs were not altered. In practice, developments in power system also influence PTDFs, the impact of which can be assessed when the process described in section 4.2 is implemented.

The process flow of the above-described computation steps is illustrated in Figure 9 below:

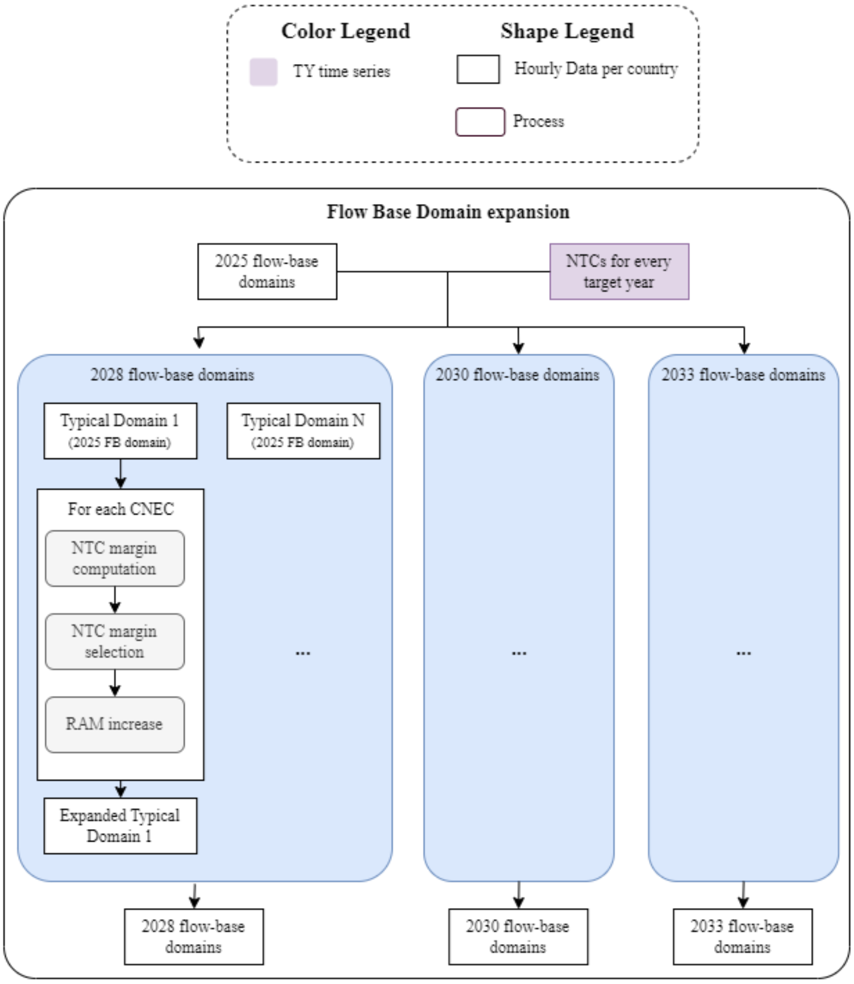

Figure 9: Process flow for flow-based domain enlargement for TYs 2028, 2030 and 2033

5 Maintenance profiles calculation methodology

The main goal of periodic maintenance is to reduce the risk of unavailability of thermal capacity during times of scarcity risk – typically during periods of higher load.

Hourly maintenance profiles for thermal units are calculated centrally by ENTSO-E for most study zones on a TY per TY basis. In case TSOs can provide better-informed maintenance profiles due to better knowledge of the specificities of their power system, these are considered in the models instead of central calculations. Maintenance profiles are calculated for each generation unit for each TY. Maintenance of renewables, other non-renewables and storage units are considered and reflected in the respective infeed time series of these generators.

The objective of the ENTSO-E maintenance optimisation methodology is to maximise available thermal capacity during times of scarcity. Using the annual planned outage rates[6] of each unit, maintenance outage periods are scheduled on a yearly horizon using an objective function which aims to level the weekly capacity margin[7] per market node. Levelling the capacity margin can be achieved as described in Figure 10, therefore aiming at minimising the risk of ENS.

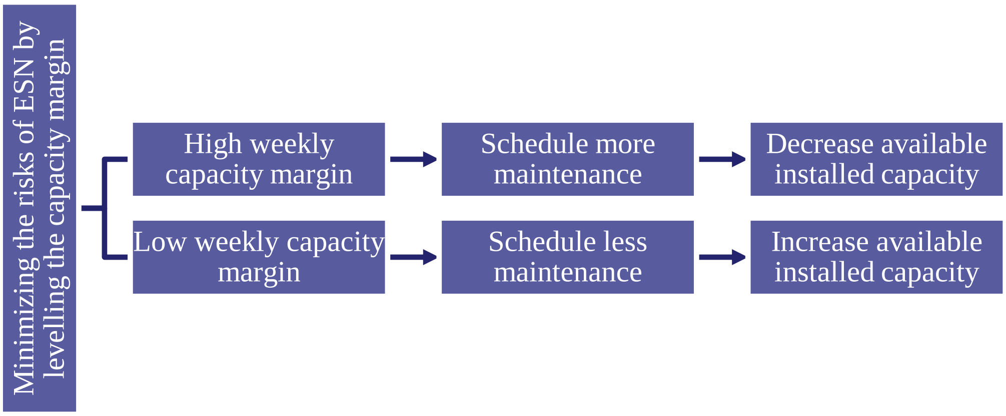

Figure 10: Levelling capacity margin with maintenance optimisation.

The underlying load profile for maintenance planning is a residual load profile as it is expected that producers will consider a certain level of renewable infeed when planning future maintenance. The load profile is obtained stepwise: First, a synthetic profile is computed by taking the minimum infeed of intermittent renewables over all CYs on an hour-by-hour basis. The latter is added to the hourly firm capacity of other generation units as given by the TSOs. Lastly, the resulting profile is subtracted from the asynthetic demand profile computed by taking the maximum native demand over all CYs on an hour-by-hour basis to yield the residual demand. This ensures that renewable infeed is accounted for to optimise the maintenance of thermal generation. The maintenance profiles are optimised on a country by country basis (in practice cross-border interconnection capacities are not considered).

The resulting maintenance profiles, as determined by the above methodology, have been consulted with the respective TSOs. This allows the TSOs to amend and shape the maintenance profiles with specific knowledge that has not been captured by the methodology/model.

More details on how these profiles are used in the EVA model and the adequacy model can be found in Sections 0 and 11.

[6] Total number of days per year required for maintenance
[7] Difference between peak load and available installed capacity during a given week

6 Long Term Storage optimisation

The modelling tool performs an intermediate optimisation step for large storage assets before the UCED optimisation. Available storage capacity is optimised so that energy is stored in times of sufficient supply and is made available for discharging in times of higher demand and/or lower available generation. Such a pre-optimisation step occurs within the modelling tool at a coarser time granularity than the hourly UCED optimisation (described in Section 11.5) as the optimal management of storage resources requires much higher foresight and planning at a seasonal or even yearly level. In this (pre-) optimisation phase, the available energy in storage assets and any cumulated exogenous energy flows (e.g. natural inflows for hydro storages) are optimally pre-allocated in (e.g. daily) energy lots so that energy resources are saved and made available to each daily UCED sub-problem related to the corresponding electricity needs of each study zone, allowing system costs, i.e. resource dispatch costs, to be minimised. The contingent hourly dispatch of the energy available in storage assets is then finally optimised within each sub-problem of the UCED starting from the pre-optimisation targets, which are refined and concretised into the final daily generation based on the contingent availability of the other dispatchable and non-dispatchable resource capacities. Consistent with the assumption of perfect market and non-opportunistic behaviour of market players, storage assets never set the marginal price when entering the merit order, but are rather dispatched as zero-cost resources that exploit marginal price gains by storing energy during hours at low(er) marginal prices (e.g. collecting inflows in hydro reservoirs or by direct power infeed through pumping or battery charge) and releasing energy during hours at high(er) marginal prices.

6.1 Storage modelling and constraints

6.1.1 Hydro storage optimisation

Hydro storage represents the most complex element of storage optimisation. It is constrained not only by hourly available generation capacity and storage capacity but also weekly reservoir level limitations. These constraints represent historical or technical minimum and maximum reservoir levels per week as provided by TSOs. Figure 11 displays an example of minimum and maximum reservoir level trajectories together with the initial and final reservoir level, given as an input to the modelling tool.

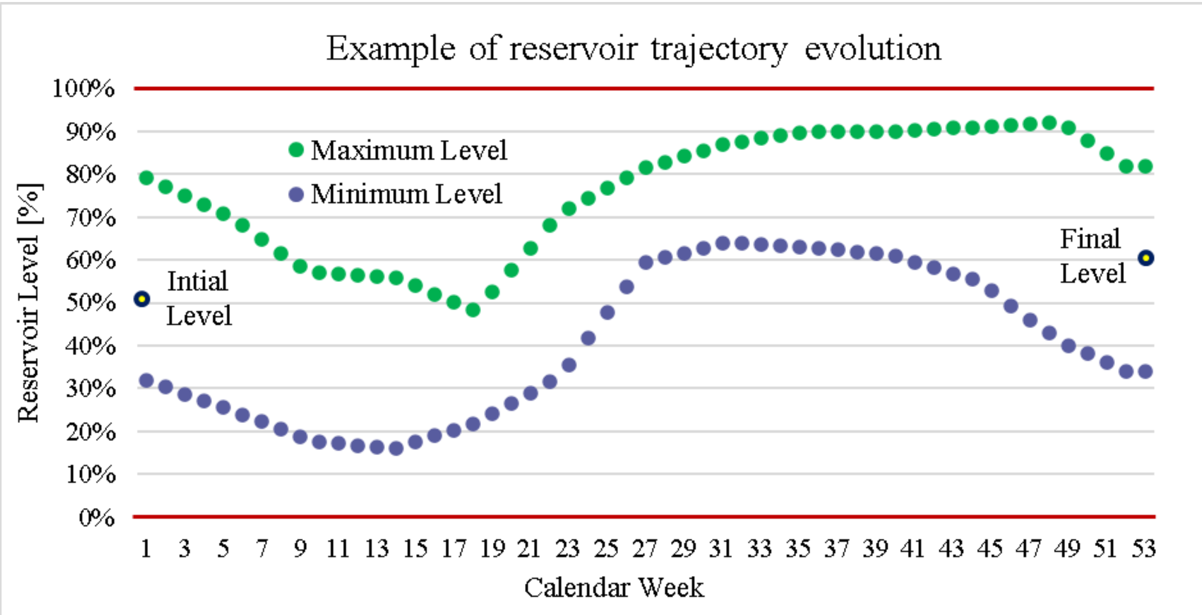

Figure 11: Example of reservoir trajectories and constraints

Alternatively, TSOs can also provide deterministic weekly trajectories per CY to pre-define the reservoir level at the beginning of each week. As minimum and maximum reservoir trajectories provide more flexibility to the system, they are preferred over deterministic climate-dependent weekly trajectories if both are provided. If neither the minimum and maximum trajectories nor the deterministic start/end levels are provided, 0% and 100% of the total reservoir size act as continuous maximum and minimum hard constraints during the whole simulated timeframe.
The initial reservoir level (CY specific) is taken as the fixed trajectory value at week 1 as provided by TSOs. If not available, the average between the minimum and maximum level trajectory at week 1 (historical before technical) is taken. If both pieces of data are missing, 50% of the reservoir size is assumed as the standard value.

Consistently, the final reservoir level is taken as the fixed trajectory value at week 52 or 53. If not available, the initial reservoir level of the following CY (e.g. 2007 for the simulated CY 2006) is selected. In the absence of fixed weekly reservoir levels, the average between the minimum and maximum level trajectory at week 52 is taken. If all data for reservoir levels are missing, 50% of the reservoir size is assumed as the standard value.

In addition to reservoir level constraints, multiple additional parameters limit the operation of hydro power plants, as summarised in Table 6. The standard cycle efficiency (pumping – turbining) for PSPs is assumed equal to 75%.

However, weekly hydro reservoir constraints were not accounted for in the EVA due to the computational complexity.

6.1.2 Batteries

Battery data are provided by TSOs, and as described in sections 2.1.3 & 2.3.2 are composed of ‘in-the-market’ batteries (mostly large-scale) and ‘out-of-market’ batteries (mostly household). The ‘in-the-market’ batteries are price-sensitive and are explicitly modelled while the ‘out-of-market’ batteries are exogenously included in the demand profiles based on information provided by TSOs (e.g. typical consumption pattern for household batteries).

The ‘in-the-market’ capacities are aggregated and modelled using mainly two parameters, namely output capacity measured in MW and storage capacity measured in MWh. The initial battery charge (at the start of the simulation) is assumed to be 50% of the storage capacity. In addition, the battery charging efficiency is assumed according to the values provided by TSOs (or default to 92%). For example, charging efficiency set to be 90% means that for 1 MWh taken from the grid, 0.9 MWh is stored in the battery and 0.1 MWh is lost. The discharge efficiency was assumed to be 100%. This principle is illustrated in Figure 12.

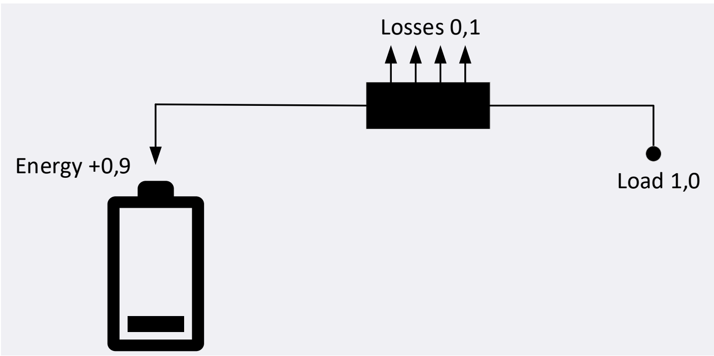

Figure 12: Illustration of the battery charging process

The energy off taken from the grid by the batteries (demand) is valued at market price, whereas energy injected from the battery to the market is valued at zero cost (cost is already covered from the charging). The overall optimisation target is to operate batteries in a manner that minimises total system costs, i.e. discharge at high electricity prices and charge at low electricity prices.

7 Sector coupling - P2X

Electrolysers use the surplus electricity mainly generated in RES to produce hydrogen, which can then be used in various ways (e.g. as a fuel to re-generate electricity; in the transport sector; for heat generation). Only the water electrolysis production process has been modelled in a simplified manner in the ERAA 2023 as it is the only production method that mainly relies on electricity. The electrolysis units were modelled as an additional demand activated below a threshold price, defined in the equation below:

$$P_{act} = P_h * \eta * 3{,}6$$

Where:
P_{act} – electrolyser activation price [€ / MWh]
P_h – hydrogen price[8] [€ / GJ]
η – hydrogen production efficiency[9] [%]
3,6 - conversion factor MWh to GJ (1MWh = 3.6GJ) [MWh/GJ]

The adoption of such assumptions translated into the activation price of electrolysers in the range of 41 – 48 € / MWh depending on TY and electrolysers' efficiency. Schematically, this principle is shown in Figure 13, which shows that the electrolyser starts producing hydrogen if the price of electricity drops below the electrolyser activation price.

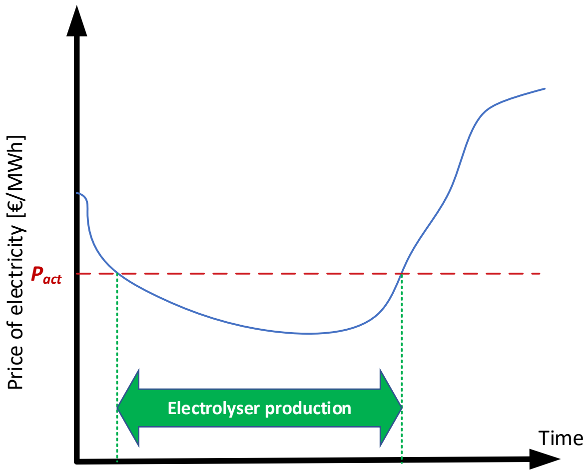

Figure 13: Activation price approach

The hydrogen prices are computed following the methodology of the Scenario Building 2022[10]. The prices are assumed to follow the decarbonised hydrogen imports prices used in the Scenario Building study, supplied by decarbonised sources such as steam methane reforming with a CCS process. These prices then follow the evolution of gas prices.

[8] Hydrogen price was assumed in the range 16.88 – 18.90 € / GJ depending on target year (see Annex 1, Section 6.1)
[9] Hydrogen production efficiency was adopted on the basis of data provided by the TSO and ranged between 59 – 79% (Default 68%). Annex 1, Section 7.1.
[10] Chapter 4.3 of the Scenario Building Guidelines, April 2022, https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf

8 CHP dispatch optimisation & heat credits

In some market zones, CHP units account for a large share of installed capacity. In previous ERAA studies, the dispatch of CHP units followed inelastic generation profiles, also called 'must-run profiles', although a higher feed-in above the must-run profile is possible given the system need. The marginal cost for this feed-in was 0 €/MWh from a system perspective and is thus comparable to the feed-in of RES. This approach in the modelling of CHP units ensures that heat demands are met safely, but it leads to an insufficient reflection of the opportunity costs of heat supply in the electricity price. In addition, the non-market-oriented dispatch of these must-run units results in a feed-in even when electricity prices are low and therefore economic losses as long as the revenues from must-run related deployment (e.g. heat provision) are not accounted for. Because of this bias, must-run units were not considered eligible for decommissioning in the EVA.

To counter these two problems whereby (i) the marginal cost of CHP must be reflected in the electricity price and (ii) some CHP units need to be able to be decommissioned endogenously, this year's ERAA 2022 introduced a 'heat credit method' in addition to the must-run approach[11]. For the heat credit method, revenue profiles are provided for individual units in hourly granularity. These profiles are calculated based on an approach using PEMMDB data, measured historical times series of district heating demand, and standardised data from pre-processed Eurostat statistics (see Figure 14).

The 'Heat Revenue Tool' is shown in Figure 14. Using typical full load hours and the thermal capacity of each unit, slices of the overall heat demand time series are assigned to specific units. Combined with heat prices, each CHP unit receives a profile with revenues per MWh of electricity generated.

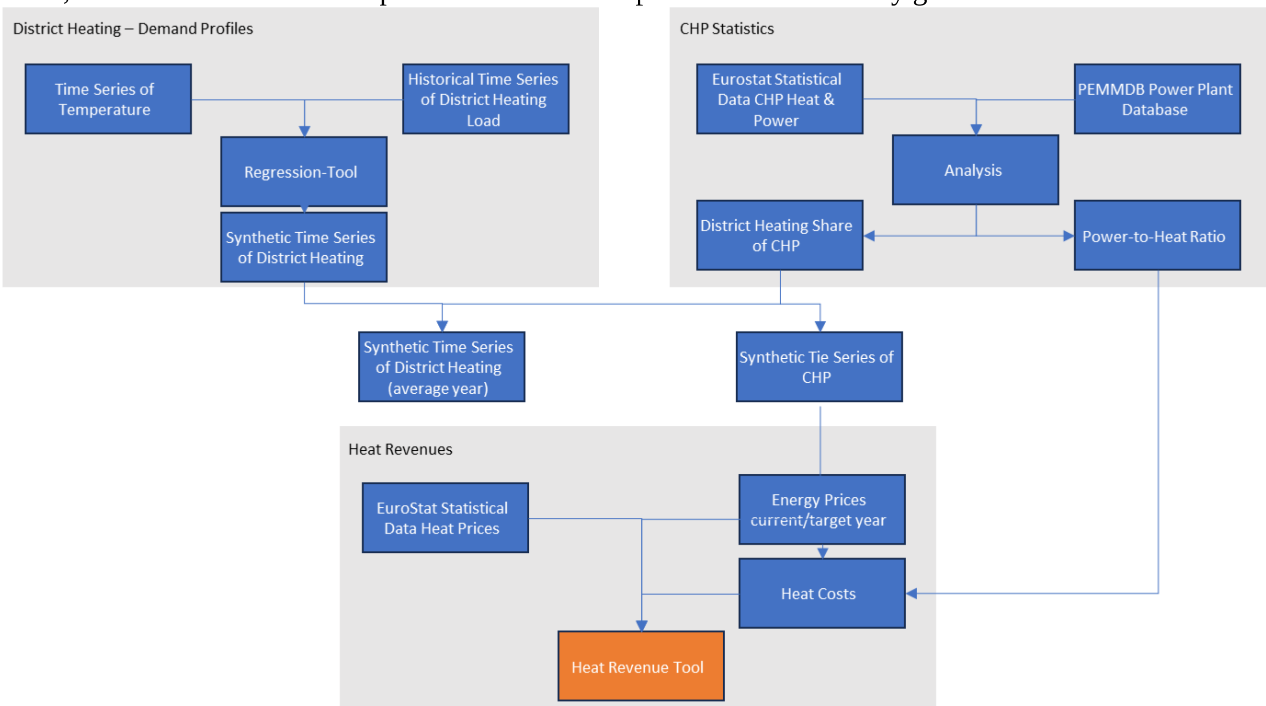

Figure 14: Heat Revenue Tool: Input data and calculation methodology

[11] Due to limited TSO or literature data availability for CHP units, the heat credit approach is applied to public district heating CHP units only. The must-run approach is applied to other types of heat networks such as industrial heat networks, special district heating constructs or heat generation from waste incineration.

Missing TSO data are complemented using Eurostat statistical data[12] as seen in Figure 14. To keep the amount of data processed small, a mean heat demand profile is calculated and used with all the CYs.

Figure 15 shows the resulting stacked CHP unit dispatch (right graph) derived from the total district heating demand (left graph). The share of heat plants is not shown as these units are not modelled in the ERAA.

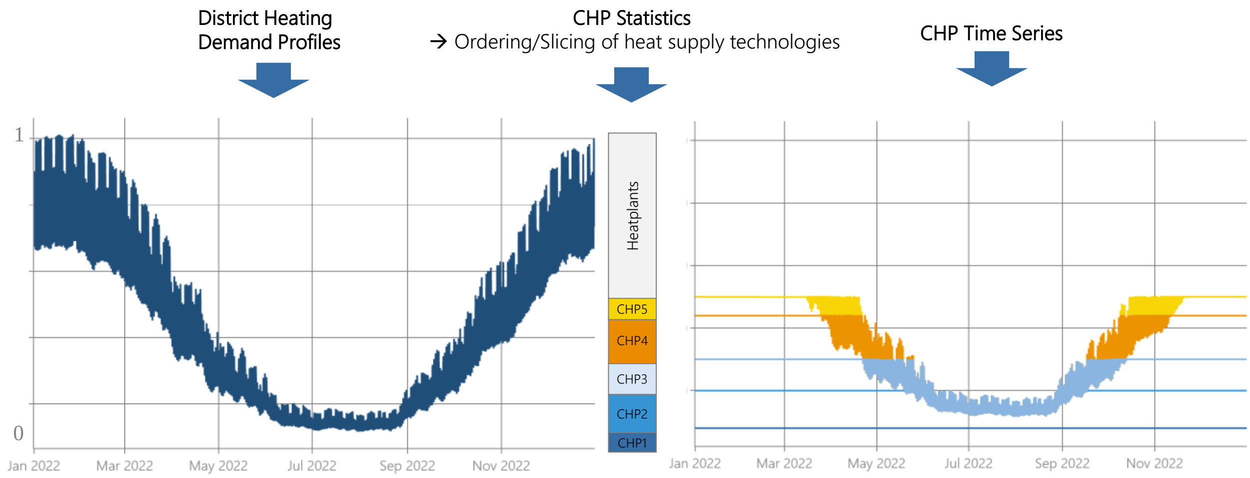

Figure 15: Illustration of splitting the heat demand between various CHP technologies

The revenue profiles are derived from a thermal demand time series based on TSO provided heat prices, power-to-heat ratios and heat prices. Statistical data are used for any missing TSO values, with the exception of heat revenues, for which it is assumed that revenues correlate with the costs of heat supply provided by natural gas fired heat plants. Therefore, heat revenues are dependent on the gas price scenario evolution.

In the total system cost optimisation, the heat credit method implies that CHP units have lower marginal cost at heat demand times. These units thus switch left in the merit order and their profitability is more advantageous due to additional revenues for heat supply than a similar unit (with the same technological configuration and fuel type) without heat extraction.

[12] Eurostat data browser: https://ec.europa.eu/eurostat/databrowser/product/view/nrg_bal_c?lang=en

9 FCR & FRR Balancing reserves

For each study zone, an amount equal to the total FCR and FRR capacity needs to be withheld from the EOM. TSOs can withhold thermal capacity of specific units for reserve requirements by reporting derated maximum unit generation capacities during the data collection. From a modelling perspective, reserve requirements for balancing purposes can be accounted for by withholding generation capacity from the wholesale market or by increasing hourly demand (‘virtual consumption’) and in both cases by the quantity of reserve requirements set by the member states. In the ERAA 2023, the capacity withholding approach was adopted as it has the advantage of not distorting the energy balance and the resulting market prices as ‘virtual consumption’ is not added.

Any reserve requirement quantities not withheld by the TSOs in the collected data are accounted for by procuring thermal capacities, renewable capacities or reducing the maximum hydro generation depending on TSO preference in the modelling tool. As for the procurement by thermal, renewable or hydro generators, the TSO can decide which units / technology is capable of providing the respective system service (FCR or FRR).

If the TSO requests balancing reserve procurement from thermal or renewable units, the respective capacity must be held back from the wholesale market. The model then identifies the cheapest possible method of providing the reserves from the units available to procure balancing reserves. The decision is based on the calculated prices of capacity procurement as the dual values of the reserve requirement constraint.
In some countries, reserves are provided by hydro units. In these cases, reserve requirements are modelled by capping the maximum hydro generation of either reservoir, open-loop pumped storage, closed-loop pumped storage units or all of them, depending on the data reported by TSOs. The maximum generation value is calculated by subtracting the reserve capacity to be provided by the hydro unit from its turbining capacity or from an existing maximum generation constraint.

10 EVA Methodology

The EVA step assesses the viability of capacity resources[13] participating in the EOM[14]. The viability of resource capacities participating in EOM is assessed using a long-term planning model with the objective of minimising the total system costs[15]. The key decision variables of such a long-term model aim to identify the economic-optimal (least-cost) evolution of resource capacity over the modelled horizon. This assessment therefore delivers insight, per each study zone and over the TYs, on the resource capacities that are likely to be (i) retired, (ii) invested in, (iii) (de)mothballed or (iv) extended in lifetime. The decision variables attributed to available resources depend on the specific technologies and fuel types of generation assets, in addition to country-specific data where applicable (e.g. thermal units eligible for (de)-mothballing or life extension). Refer to Section 10.3 for more details about the EVA's scope.

The diagram below (Figure 16) indicates which inputs from the National Trends are used for the EVA step. To increase the consistency between the EVA and the adequacy models, NTC constraints from calculated flows from the ERAA 2022 FB domains are used. This new input is further explained in section 10.2.

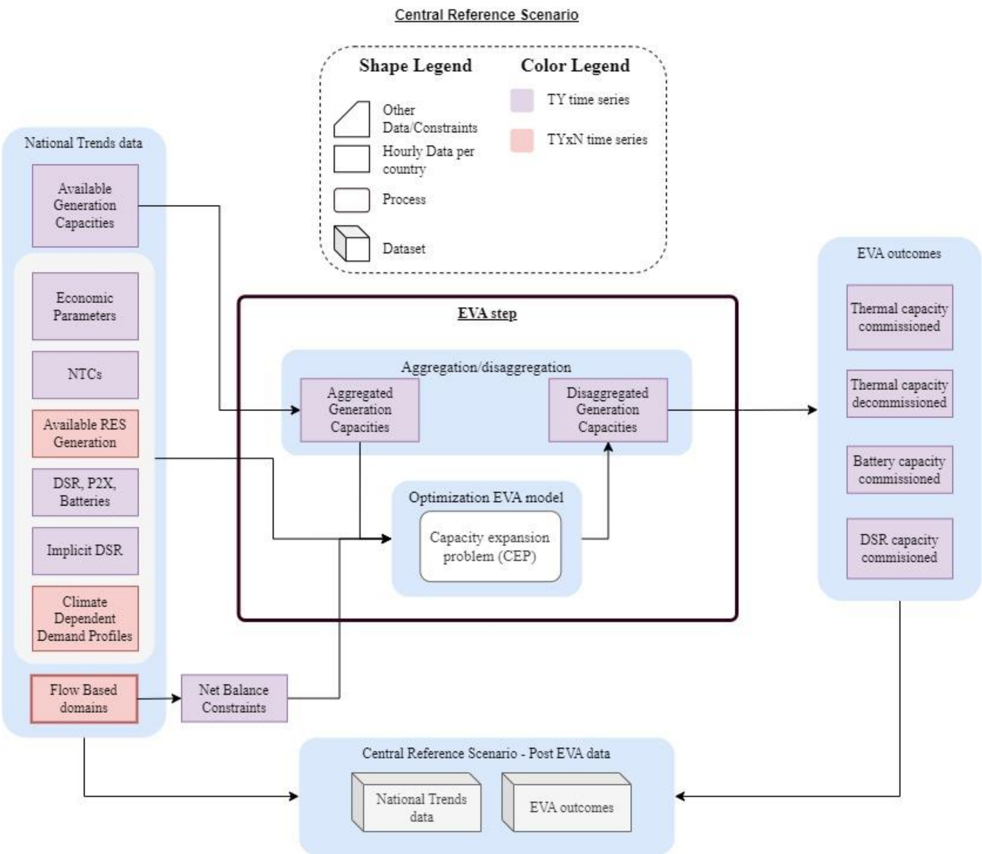

Figure 16: Overview of the inputs and outputs of the EVA step.

[13] Generation resources include storage units, e.g. batteries.
[14] Units with an awarded CM contract are excluded from the EVA for the duration of their contracts.
[15] Article 6.2 of the ERAA methodology acknowledges the use of overall system cost minimisation for the EVA, although as a simplification and assuming perfect competition

10.1 Geographical scope

Resource capacity changes, as a result of the EVA step, are only allowed in explicitly modelled study zones (see Table 1), accounting for fixed exogeneous energy exchanges with non-explicitly modelled study zones (including Ukraine).

10.2 Net position constraints

To increase the alignment of the EVA step using an NTC approach and the adequacy step using a FB approach for the CORE region, the import and export capacities per CORE bidding zone were capped. These constraints are introduced to ensure that the EVA leads to realistic market outcomes, as the NTC approach would allow higher cross border flows compared to the FB approach. The calculation of the maximum import and export limits (i.e. Net Position Constraints [NPC]) is based on the ERAA 2023 FB simulations. For each bidding zone, a distribution with hourly flows across Monte Carlo runs was computed. The NPCs are defined as the 1st percentile and the 99th percentile of each distribution respectively. In addition, the import limits were capped at –2,000 MW and export limits were floored to 2,000 MW to avoid isolation/islanding bidding zones in the EVA. Figure 17 below shows the process steps of the computation of the NPCs for the EVA.

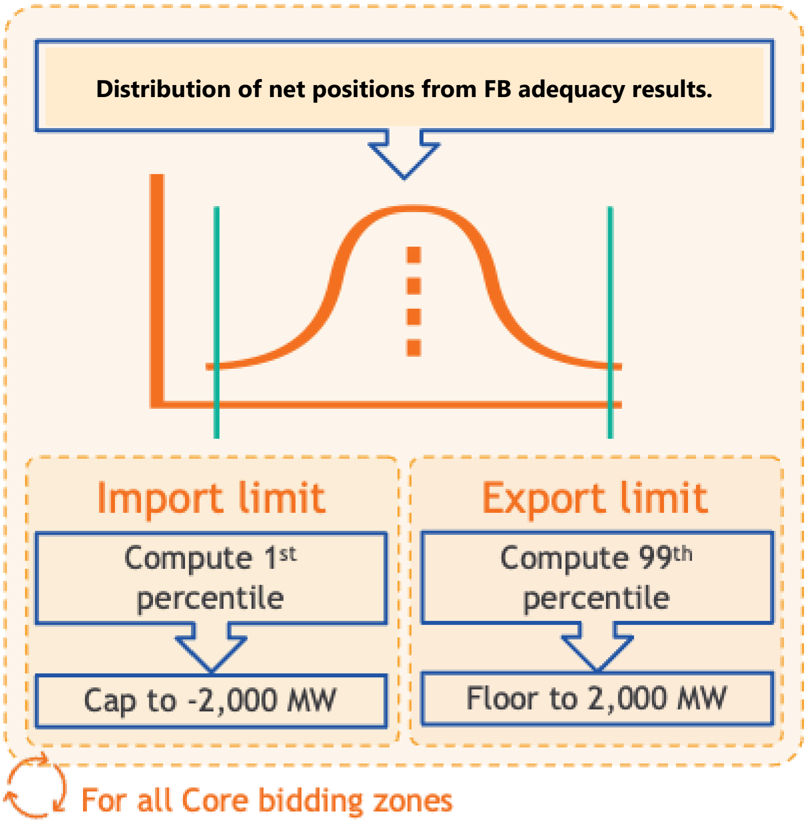

Figure 17: Process steps for computing import and export limits

10.3 EVA technology scope

Only units that depend mainly on the EOM revenues are included in the EVA scope[16]. In addition to decommissioning and new market entries, generation resources are eligible for lifetime extension[17] or mothballing/demothballing[18]. The decision variables of the EVA are summarised in Table 13.

Table 13: EVA decision variables

Technologies	Decommissioning	(De-)mothballing	Life Extension	New Entry
Gas	✓	✓	✓	✓
Lignite/Hard Coal/Oil	✓	✓	✓	
DSR				✓
Battery				✓

10.4 Investment constraints

In the ERAA 2023, the commissioning decisions of the EVA have been constrained by some TSOs with investment constraints that affect individual countries. These constraints come from internal calculations and sources of the TSOs.

Table 14: Investment constraints considered in the ERAA 2023 for individual countries.

Study Zone	Technology	Target Year	Max Expansion (MW)
BE	Battery	2033	2544
BE	DSR	2025	300
BE	DSR	2028	750
BE	DSR	2030	1050
BE	DSR	2033	1450
CZ	Gas	All	No expansion
FR	Gas	All	No expansion
MT	Gas	All	No expansion
PL	Gas	2030	3082
PL	Gas	2033	4487
PL	Battery	2033	1000

[16] There may be additional exogenous assumptions for why units cannot be retired such as local considerations, national policies, support schemes and country specification. Therefore, any other unit labelled by TSOs as a 'policy unit' in the PEMMDB will not be a decommissioning candidate. Similarly, must-run units or units with a CM contract in place are not considered as decommissioning candidates.

[17] Lifetime extension implies replacing or upgrading key elements of the asset to avoid a unit's retirement at the end of its initially calculated economic lifetime.

[18] (De-)mothballing is a common practice in the power sector that puts the unit in a temporary state of preservation with reduced fixed cost to return back in service later when market conditions improve.

10.5 Capacity scoping

The EVA might use as a starting point slightly different resource capacities compared to the National Trend scenario, i.e. TSOs projections. The differences come from:

- simplifying assumptions made on the decommissioning dates of the units subject to EVA. A unit subject to EVA is considered fully commissioned or not at all during a given year: it cannot be commissioned or decommissioned at another moment than in the beginning of the year. The cut-off date is chosen as the 1 July of any given year. A unit whose decommissioning date is before this date is not considered at all the year of its decommissioning, otherwise it is considered to be commissioned the entire year of its decommissioning and effectively decommissioned the next year;

- Neglection of secondary fuels: For units with primary and secondary fuels, the primary fuel is assumed to apply to all of the unit's installed capacity.

10.6 Non-consecutive target years

The ERAA 2023 collected data for 4 non-consecutive TYs of 2025, 2028, 2030 and 2033. However, the EVA is an integrated model over multiple years in horizon 2025 – 2033. To overcome this issue, it is assumed that non-TYs date are duplicates of the latest available TYs. For example, non-TYs 2026 and 2027 are assumed to have the same load, generation capacity, network constraints, etc. as the TY 2025.

The net present value (NPV) of capital expenditure (CAPEX) and fixed operations and maintenance costs (FOM) in the case of commissioned capacities are discounted uniformly over the represented years. For example, if OCGT capacity is commissioned in the first TY, which in fact represents the years 2025, 2026 and 2027, the CAPEX and FOM are discounted, assuming a uniform increase of the capacity from 2025 till 2027, i.e. one-third increase of the capacity in each year. This methodological decision is a compromise between assuming all the fixed costs already from 2025 onward or only from 2027 onward. This approach is taken to have a fair representation of financial parameters throughout the whole horizon.

10.7 Multi-year EVA optimisation function[19]

The EVA simulation is performed over multiple years. The total costs of the system in consecutive years are totalled in the EVA simulation by calculating the NPV of all future costs. A discount factor is applied to translate costs incurred in the future years to present day value, as follows:

$$Minimize \quad \sum_{y} (1+r)^{(1-y)} \left[Total\ cost_y\right]$$

Where: r – discount rate [%]

The total cost is equal to the sum of investment costs of new resources capacity (including a risk premium – see section 10.12), fixed and variable unit operations and maintenance costs (including a risk premium – see section 10.12), and DSR activation costs, in addition to the cost of curtailed energy represented by fictitious generators with the marginal cost equal to the market price cap, Section 10.12.

The resource capacity build cost represents the overnight cost of building a new unit, *i.e.* the all-in capital cost as per commissioning date. Building a new resource means spending a 'lumpy' capital cost with the expectation of benefiting from the favoured market conditions until at least the economic life of the resource.

[19] The detailed formulation of the EVA optimisation model can be found in Appendix 1.

However, the EVA is modelled over a limited horizon, i.e. 9 years ahead. To resolve this, the build cost $CAPEX$ is converted to an equivalent annual charge which is applied in the year of build and every subsequent year.

$$Annuity = CAPEX \times \frac{WACC}{1-(\frac{1}{1+WACC})^{Lifetime}}$$

Where: $WACC$ – Weighted average cost of capital
$Lifetime$ – Economic lifetime of the unit
$CAPEX$ – Capital Expenditure

10.8 Climatic year selection and scenario reduction

The integration of uncertainty into the multi-year model is done through the introduction of climatic scenarios. Each climatic scenario consists of a CY for each target year within the horizon of the model. Given a collection of climatic scenarios, the EVA model finds the optimal stochastic solution. This means that the optimal entry/exit decision of resource capacities, making up the $Fixed\ cost$, are made by considering several possibilities of operational conditions, i.e. a set of climatic scenario, CYs, with their related possibilities, ω_{CY}, as follows:

$$Total\ cost_y = Fixed\ cost_y + \sum_{CY} \omega_{CY}\left[Operational\ cost_{y,CY}\right]$$

However, as formulated in section 10.7, EVA is an optimisation model solved over multiple years, and this makes the EVA a bulky model; therefore, the number of climatic scenarios introduced needs to be reduced. Due to this fact and to limit the number of simulations, a direct approach is taken by solving the EVA model over a reduced number of CYs.

The reduction of climatic scenarios was based on the statistical properties. It was opted to reduce the climatic scenarios based on their impact on the mathematical optimisation problem over a single TY and by selecting the CYs with the most mutually acceptable expansion plans. The methodology consists of three steps. The first step calculates a 'distance' value, named d, between each CY; the second step clusters the closest CYs according to their distances, and the final step calculates the centroid of each cluster.

The distance d measures the impact of a CY on the optimal expansion plan of another CY in terms of system cost[20]. Let x_i be the optimal expansion plan for climatic year cy_i, where $i \in N$ and $h(x_i, cy_i)$ the system cost of using expansion plan x_i when climatic year cy_i realises. It follows that:

$$h(x_j, cy_i) - h(x_i, cy_i) \geq 0. \quad (4)$$

A near-optimal expansion plan x_j for climatic year cy_i would lead to a value close to zero. The symmetric rule is also valid:

$$h(x_i, cy_j) - h(x_j, cy_j) \geq 0. \quad (5)$$

The definition of the distance $d(cy_i, cy_j)$, combines Eq. (4)-(5), as expressed by Eq. (6):

$$d(cy_i, cy_j) = h(x_j, cy_i) - h(x_i, cy_i) + h(x_i, cy_j) - h(x_j, cy_j). \quad (6)$$

[20] The considered distance was proposed in Hewitt, M., Ortmann, J., & Rei, W. (2021). Decision-based scenario clustering for decision-making under uncertainty. *Annals of Operations Research*, 1-25.

It follows that cy_i, cy_j have mutually acceptable expansion plans if their distance is small and thus it is reasonable to cluster these CYs together. In other words, the CYs with the shortest distance are closer for having mutually acceptable expansion plans. The clustering algorithm uses the Wasserstein metric[21] to cluster CYs with the most mutually acceptable expansion plans, this metric also allows for the respective CYs' probabilities to be accounted for.

The clustering algorithm starts by selecting a target number of cluster, namely 3 for the ERAA 2023. The algorithm proceeds to form single-element clusters. During each iteration of the clustering algorithm, the clusters with the shortest distance are grouped. The process continues iteratively until the desired number of clusters is reached. Finally, the centroid of each cluster is computed (the CY with the shortest distance to the remaining CYs within the same cluster) and chosen as the representative CY for its respective cluster.

Following the determination of the representative CYs, a weighting for each CY has been applied based on two different approaches, which are described in Sections 10.8.1 and 10.8.2.

10.8.1 Scenario A: Adequacy-based weights

In this scenario, the probability of occurrence for each centroid representing a cluster is calibrated to reach the same EU level LOLE index as the average EU level LOLE over all 35 CYs of the ED. The calculation of weights is based on the ERAA 2022 ED results for TY 2025.

10.8.2 Scenario B: EVA-based weights

In this scenario, the probability of occurrence for each centroid representing a cluster is calculated as the ratio of the number of CYs the cluster consists of, divided by the total number of CYs. Thus, the more CYs a cluster has, the higher its weight is. This weighting approach is the same as in the ERAA 2022 and corresponds to the original methodology.

10.9 Unit Aggregation

To reduce the size of the EVA model, generators are aggregated according to their main characteristics: node, technology, fuel and techno-economic parameters. This simplification is possible because (i) a uniform derating of NGCs in the EVA model based on FORs is considered instead of random draws of outage patterns and (ii) the EVA model is solved in a linearised manner.

As adequacy models use unit-by-unit data, the aggregated EVA outcomes need to be post-processed to increase the granularity. To this end, a uniform derating approach is applied in which the capacity of all units belonging to the same technology are derated homogeneously and proportionally to their installed capacity in the adequacy model according to the EVA results.

This linear derating approach guarantees the best matching between EVA and adequacy models (i.e. it preserves maintenance patterns across models), and it avoids arbitrary decisions regarding which units are decommissioned. Although in the real world units would not be partially decommissioned, the goal of the EVA is not to determine which units are decommissioned but rather the overall capacity viable per technology in each study zone.

[21] Dupačová, J., Gröwe-Kuska, N., & Römisch, W. (2003). Scenario reduction in stochastic programming. *Mathematical programming*, *95*(3), 493-511.

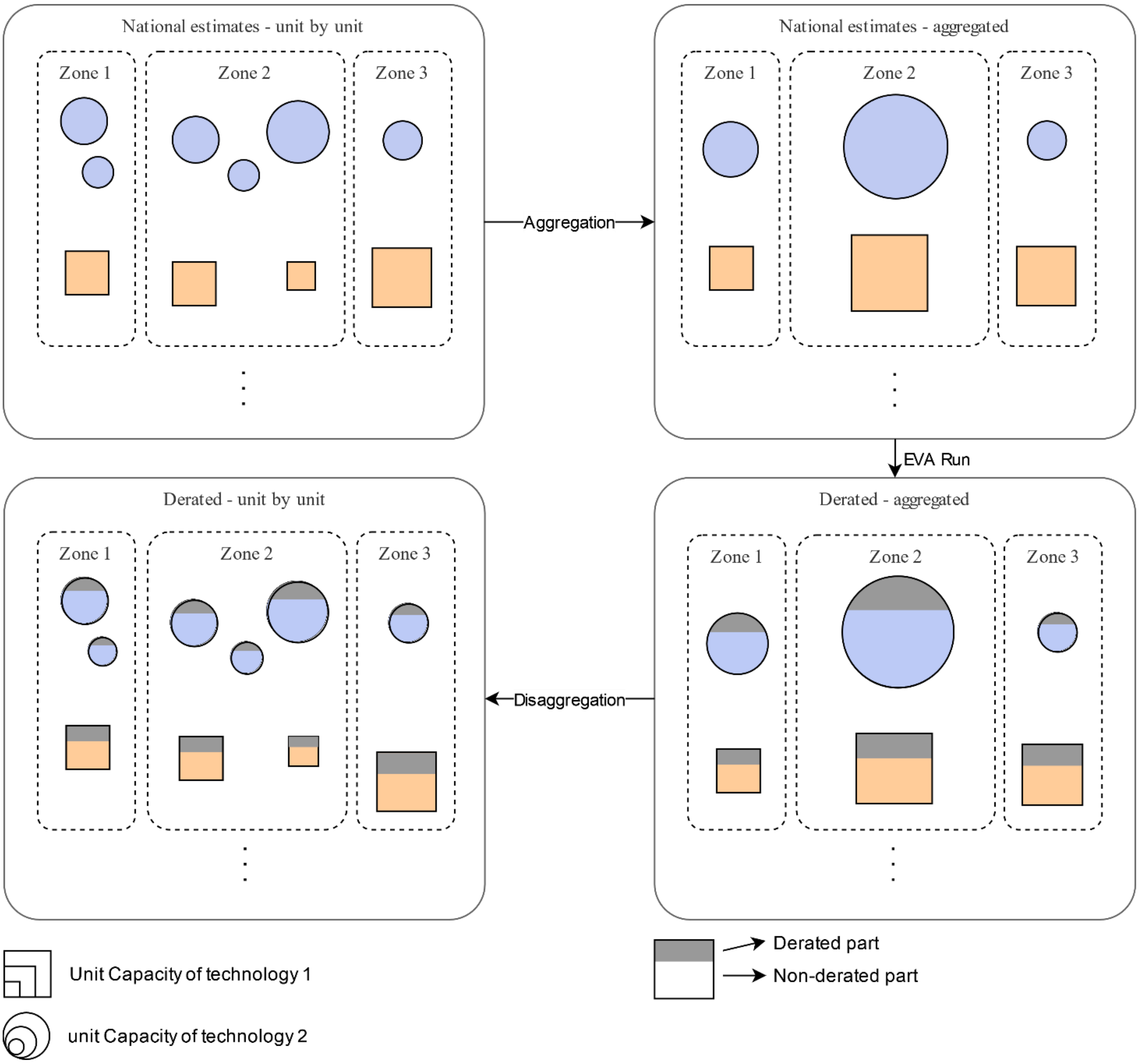

Figure 18: EVA unit aggregation process

10.10 Maintenance profiles

To reduce computational complexity, the maintenance modelling of existing thermal units is simplified compared to the adequacy step by derating the available capacity of the units. The derating of existing thermal units is based on the maintenance patterns calculated for the adequacy step. The derating is applied to the aggregated units following the same logic as explained in chapter 10.8.

For expansion and life extension candidates, a maintenance rate is applied as a derating factor of the generation capacity of some generation technologies. The derating factor is inversely proportional to the load profile in a given region to make more generation capacity available during times of higher load and vice versa.

10.11 Random Forced outage

FOs were considered in the EVA model by simply derating NGCs for thermal units and NTCs for the grid using individual random forced outage rates (FORs) for each technology and line type (see annex 1).

10.12 Price cap Evolution

The value of the price cap is of first order of importance when assessing energy market viability of resource capacities. Price caps exist on markets mainly for technical reasons, in the interests of consumer protection and the prevention of potential anti-competitive practices. The current maximum clearing price of the DA market is 4.000 €/MWh. According to ACER's decision 2023/01[22], in the event that the clearing price exceeds 70% of the harmonised maximum clearing price for (single day-ahead coupling) SDAC during at least two days within each rolling 30-day period, the latter shall be increased by 500 EUR/MWh the next day; however, if a transition period of 28 days is defined before the increase is applied for shall be applied in all relevant study zones 28 days later. During this period, no further price adjustments can be initiated.

The dynamic increase of market price caps described above cannot be modelled endogenously within the available market modelling tools used in the ERAA 2023. Therefore, the yearly evolution of the DA price cap for all the target years was estimated in a simplified manner. The approach consists of the following steps:

(i) Building a set of 10 CYs representing the horizon from 2024 until 2033 (i.e. 26 CY sets) using the available historical data from 1982 to 2016 (35 years) across 20 FO patterns (i.e. 26 × 20 = 520 multi-year scenarios);
(ii) Extracting hourly marginal prices for all Monte-Carlo samples and all bidding zones from the ERAA 2022 ED results for 2025;
(iii) Considering a starting price cap of 4000 €/MWh on 1 January 2024 and mimicking a dynamic price cap increase, applying ACER's rule based on the hourly marginal prices; and
(iv) Computing a mean price cap value for each year of the study horizon.

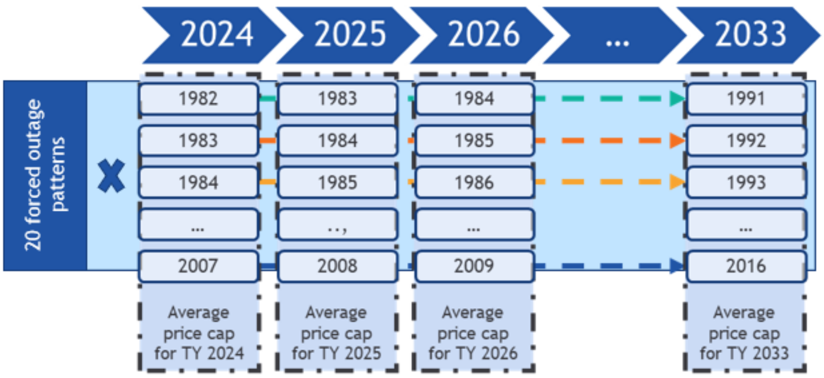

Figure 19: 10-year scenarios considered for estimating the price cap evolution from 2024 till 2033

These new price caps are then set as fixed input values for EVA and adequacy simulations.

[22] ACER Decision 01-2023 on HMMCP SDAC - Annex 1.pdf (entsoe.eu)https://www.acer.europa.eu/Individual%20Decisions/ACER%20Decision%2001-2023%20on%20HMMCP%20SDAC.pdf

10.13 Investor risk aversion

Following the ERAA methodology, the EVA aims to replicate the decision-making process followed by investors and market players. Investors generally show a certain level of risk aversion regarding to their decision process. This means investors typically demand a risk premium on investments, i.e. investments that increase the risk of their portfolio should also increase the expected return of the portfolio. Volatility and uncertainty regarding of the return on investment is a necessary condition of investment risk. The ERAA approach relies on a theoretical and academic framework for investor behaviour[23], considering the revenue distribution and downside risk stemming from the non-normality of the returns distribution in addition to the model and policy risk depending on the technology and economic lifetime of the assets and within different scenarios. Hurdle premiums are set according to the deviation of actual returns from expected returns over a significant number of possible investment paths. These premiums are further calibrated, assessing the return impact of alternative scenarios considering standard $CAPEX$ and FOM costs but different levels of system adequacy, fuel prices, CO_2 prices, etc. Such a calibration of hurdle premiums provides a robust yet pragmatic approach for the consideration of risk in adequacy simulations. The hurdle rate is defined as:

$$HurdleRate = WACC + \ HurdlePremium$$

The hurdle rate is then used to calculate the annuity of $CAPEX$, as follows:

$$Annuity = CAPEX \times \frac{HurdleRate}{1 - (\frac{1}{1 + HurdleRate})^{Lifetime}}$$

The hurdle rate also adjusts the FOM of existing units. As the FOM (noted FOM^* in the equation) is a yearly cost, the annuity of FOM (noted FOM in Appendix 1) is calculated assuming a one-year lifetime.

$$FOM^* \times (1 + HurdleRate))$$

10.14 Centralised approach for estimating explicit DSR potential

As introduced in Annex 1 Section 6.5, a stepwise approach is used to determine the additional explicit DSR potential beyond the ‘National Trends’ assumptions depending on available country data. If no DSR potential is available from a published official VOLL/CONE study or national study for DSR reported by the TSO, a centralised bottom-up approach is used by ENTSO-E to determine any additional explicit DSR potential. Figure 20 illustrates the approach used:

[23] https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20201030_200_report_professorboudt.pdf

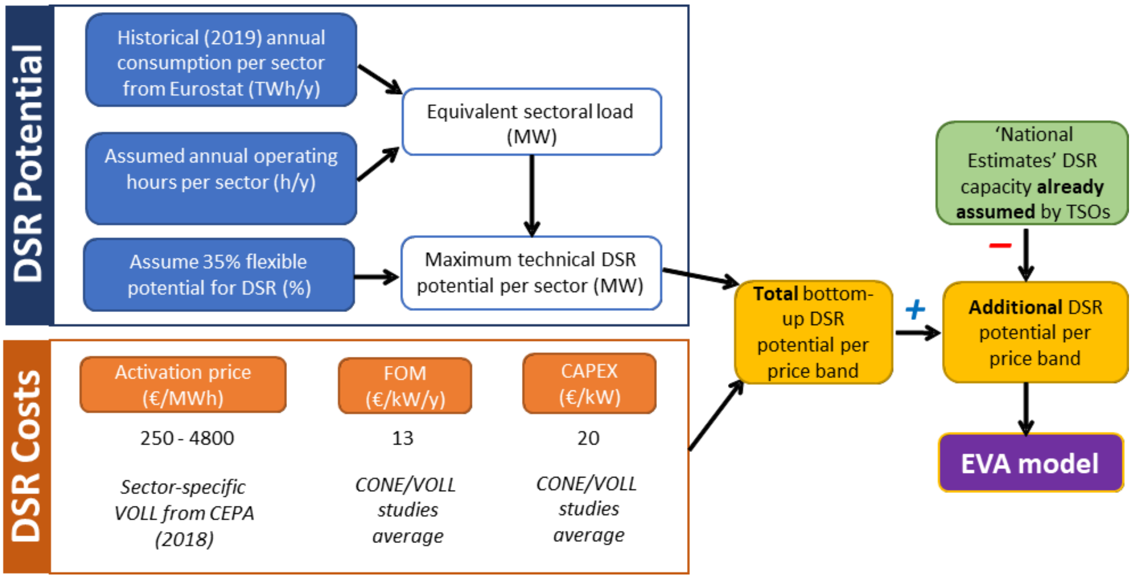

Figure 20: Overview of the explicit DSR potential estimation methodology

The maximum technical DSR potential (per industrial sector[24] per country) is estimated based on:

- Annual sector electricity consumption from 2021 from Eurostat;
- Assumed 8760 operating hours per year (i.e. baseload);
- Assumption on the flexible industrial load (35%)[25]; and
- No minimum threshold on the capacity of DSR from a given industry sector is applied to avoid the risk that the approach overlooks additional DSR capacity in smaller countries.

The potentials are combined with assumed cost parameters, based on the following sources:

- Sector-specific VOLL values from CEPA (2018) as a proxy for the activation price[26];
- FOM value derived from the available VOLL/CONE studies. An average is made across the VOLL/CONE studies where DSR is a reference technology and used as a single value for DSR potential; and
- CAPEX value, following the same approach as for the FOM.

To prevent the double-counting of DSR capacity, the DSR capacity accounted for in the 'National Trends' scenario is subtracted from the maximum technical DSR potential for each country.

Given the lack of high-quality consistent EU-wide datasets for DSR, this simplified bottom-up approach is necessary. However, due to the stepwise approach applied this year, this fallback is applied to a few countries across Europe. 28 study zones have DSR potential, 15 of which have national studies. As more VOLL/CONE and national DSR studies become available, ENTSO-E will endeavour to use these in future years for the ERAA and to improve the modelling of DSR.

[24] Residential DSR is not consider in the centralised approach.
[25] Due to limited data on the flexible share in the literature, this assumption was set by adjusting the flexible share until the total DSR potentials approximately matched the estimated potentials from available national studies. As a sanity check of this 35% assumption, the calculated total DSR potential per country as a share of peak demand fell in the range of 10 – 20%, comparable with other studies.
[26] CEPA (2018), Study on the estimation of the value of lost load of electricity supply in Europe

11 Adequacy assessment methodology

The objective of the ERAA adequacy study is to calculate the risk of security of supply of the post-EVA scenarios through the calculation of LOLE and EENS metrics (see section 11.2 for the mathematical expression). A modern adequacy assessment accounts for uncertain variables in the system and offers a probabilistic indicator of the adequacy situation under a number of plausible realisations of the uncertain system variables. The state-of-the-art methodology in adequacy studies is the so-called Monte Carlo (MC) simulation approach. To avoid any confusion, the MC approach is not applied in the EVA step.

11.1 Monte Carlo Adequacy Assessment

The applied MC simulation consists of a large number of scenarios, consisting of different asset FO realisations/draws for each given TY and CY. More specifically, these FOs occur for the thermal generation and transmission assets (HVDC and HVAC interconnections) and their impact on the installed capacities are known during the UCED step (see section 11.5). The combination of random outages and climate scenarios results in a large set of possible system states to be modelled for each TY. Results can then be assessed probabilistically, well-suited for the modern volatile power systems. The detailed process is described below.

The process starts by defining the climate scenarios, representing consistent historical CYs. CYs from 1982 – 2016 are selected one-by-one (N CYs). Each CY represents a consistent set of:

- Temperature-dependent demand time series;
- Wind and solar load factor time series;
- Time series for hydro generation, inflows, minimum/maximum generation or pumping capacity, and minimum/maximum reservoir level (where applicable); and
- Climate-dependent time series for other RES and other non-RES generation.

Note that the above-mentioned CY data might depend on the selected target year.

As a second step, multiple sets of random FO realisations (hourly time series) are generated for each CY (M forced outage samples per CY, where the quantity M is only known after model convergence is reached). FO realisations do not impact the planned maintenance schedules. More details on the convergence can be found in Section 11.6.

Each model run is executed for one CY and for one random forced outage realisation. This is referred to as an MC year. The combination of N CYs and M FO realisations per CY results in a total of $N \times M$ model runs. Each model run is optimised individually. Figure 21 illustrates the described MC approach for each TY studied.

For more information on input data, please refer to Section 2 and Annex 1.

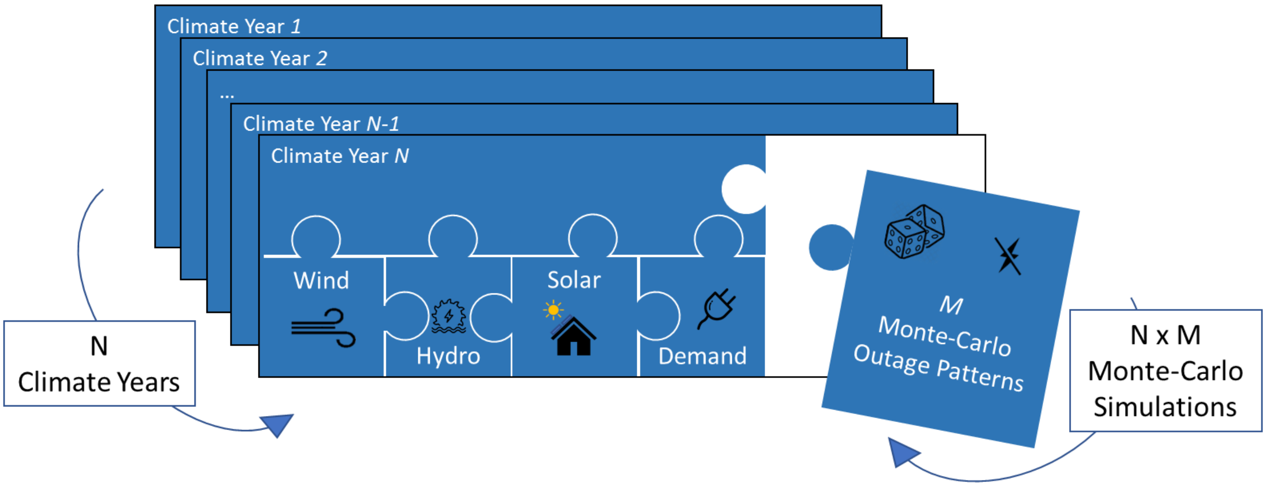

Figure 21: Monte Carlo simulation principles for a given target year

11.2 Adequacy Indicators

In probabilistic adequacy studies, the typical indicators for resource adequacy are either the expectation of indicators (e.g. the EENS) or a percentile of the independent indicator values (e.g. 95th percentile of the ENS values). The following indices are used to assess the adequacy levels for a given geographical scope and for a given time horizon:

- **Loss of load duration (LLD) [h] –** the duration in which resources (e.g. available generation, imports, demand flexibilities) are insufficient to meet demand. This does not indicate the severity of the deficiency (ENS). Note that the model has an hourly time resolution which therefore also transfers to the granularity of the LLD indicator.
- **LOLE [h] –** the expected number of hours during which resources are insufficient to meet demand over multiple scenario runs, i.e. CYs and/or FO realisations. LOLE can be calculated as the mathematical average of the respective LLD over the considered model runs, according to Eq. (2): For J the total number of considered model runs and LLD_j the LLD of model run j, then

$$LOLE = \frac{1}{J}\sum_{j=1}^{J} LLD_j \qquad (1)$$

- **ENS [GWh]** – the sum of the electricity demand which cannot be supplied due to insufficient resources. For a geographical scope with multiple nodes, ENS refers to the total ENS of all its nodes. A null ENS suggests that there are no adequacy concerns.
- **EENS [GWh]** – the electricity demand which is expected not to be supplied due to insufficient resources. For a geographical scope with multiple nodes, EENS refers to the total EENS of all its nodes. EENS can be calculated as the mathematical average of the respective ENS over the considered model runs, according to Eq. (1): For J the total number of considered model runs, and *ENSj* the Energy Not Served of model run j, then

$$EENS = \frac{1}{J}\sum_{j=1}^{J} ENS_j \qquad (2)$$

Note that the final adequacy indicators in the ERAA 2023 reflect the impact of the curtailment sharing implementation in the adequacy assessment, as described in Section Local matching and curtailment sharing 11.7.

11.3 Maintenance for market entries

As described in section 0, maintenance profiles for thermal units references in the ‘national trends’ scenario data are the output of a pre-optimisation step. For units entering the market as a result of the EVA step in the respective TY (demothballed, life extended or new build units), no maintenance (planned) is considered as it is assumed it will occur during times of oversupply and thus not impact reliability standards significantly. Nevertheless, these units are subject to FOs as described in the following section 11.4.

11.4 Forced outage profiles

The following parameters are provided by TSOs to describe the outage behavior:

- FOR – i.e. the likelihood of a forced outage;
- Mean Time To Repair – i.e. the duration of a forced outage
  (default: line – 7 days; Nuclear unit – 7 days; Gas & Coal unit - 1 day).

FORs are fundamental parameters for the computation of FO profiles. They represent the probability of a power plant or an interconnection being out of service unexpectedly for a period of time. These parameters must be set up carefully considering the amount of capacity (thermal generation and interconnection capacity) they can put out of service. FORs are expressed as a single percentage for each generation unit or interconnector and are provided for individual TYs, reflecting power plant or interconnection upgrades or renewals.

FORs are on a unit-by-unit granularity for thermal units and depend on the technology and characteristics. In the absence of FORs provided by TSOs, a default representative value based on the given technology is used. A similar mechanism is applied to interconnections: for some interconnections input data already explicitly consider outages while in other cases random outages on interconnectors are drawn per pole based on FORs (i.e. at borders with multiple poles, an outage of one pole does not reduce the NTC to zero).

FO profiles are generated randomly within each modelling tool for each stochastic element in the simulation, namely resource units and interconnection lines. Based on the parameters mentioned above, FO profiles are drawn which describe the hourly availability of each stochastic element of the system. They can have a significant impact on resource adequacy due to their uncertain nature. Therefore, it is important to draw a sufficient number of possible outage realisations to assess the impact on adequacy in expectation.

11.5 Unit Commitment and Economic Dispatch

The unit commitment problem aims to discover an optimal combination of on/off decisions for all generating units across a given horizon. The on/off decisions must imply both a feasible solution and an optimal solution regarding the total system cost, including the cost of start-up and shutdown. The economic dispatch (ED) refers to the optimisation of generator dispatch levels for the given unit commitment solution. The UC and ED are co-optimised such that the combined costs are minimised.

More specifically, the UCED optimisation is a two-step approach with a system cost minimisation target, i.e. it strives to minimise the sum of electricity production costs (being the main components of the costs: the fuel price, emission price and VO&M) under the objective that electricity consumption must be fulfilled. In the first step, an annual optimisation for the TY is done to account for inter-temporal constraints that may span the whole year. Multiple hours are aggregated and optimised in blocks to deal with the large optimisation problem in a reasonable computation time. The constraints that apply to the unit commitment problem are mainly: derating, annual maximum operating hours, start cost, must run conditions (run up rate or start profile and run down rate or shutdown profile) and energy limits (e.g. end-of-year reservoir targets and upper and lower weekly reservoir limits). This last constraint (energy limits) includes the optimisation of available hydro resources, as described in section 6.1.1. The optimised maintenance schedule for thermal units computed as described in section 0 is anticipated and considered by the pre-optimisation.

The outcome of the hydro optimisation step consists of more granular daily target values for objects with annual constraints. In the case of hydro units, this results in daily reservoir targets that are set as soft boundaries to the total hydro energy available over the day for the subsequent more granular optimisation step.

The UCED optimisation is then performed in smaller/finer time steps (e.g. one day) to determine which units are dispatched for each hour of the optimisation horizon (TY) in addition to the respective dispatch level for each unit. For the optimisation, a given TY is divided into several UCED optimisation time steps/horizons. Each resulting UCED, the problem is optimised based on the hourly system state (demand, RES feed-in, available thermal generation, NTC / FB constraints). Subsequently, each UCED problem is given the final system state of the preceding UCED problem (used as the initial dispatching state for the current UCED problem). Indeed, optimising a given UCED problem with a different initial dispatching state while keeping other parameters unchanged may yield different results. Similarly, dividing a TY into a different set of UCED problems may also yield different results. The entire UCED optimisation process is visualised in Figure 22.

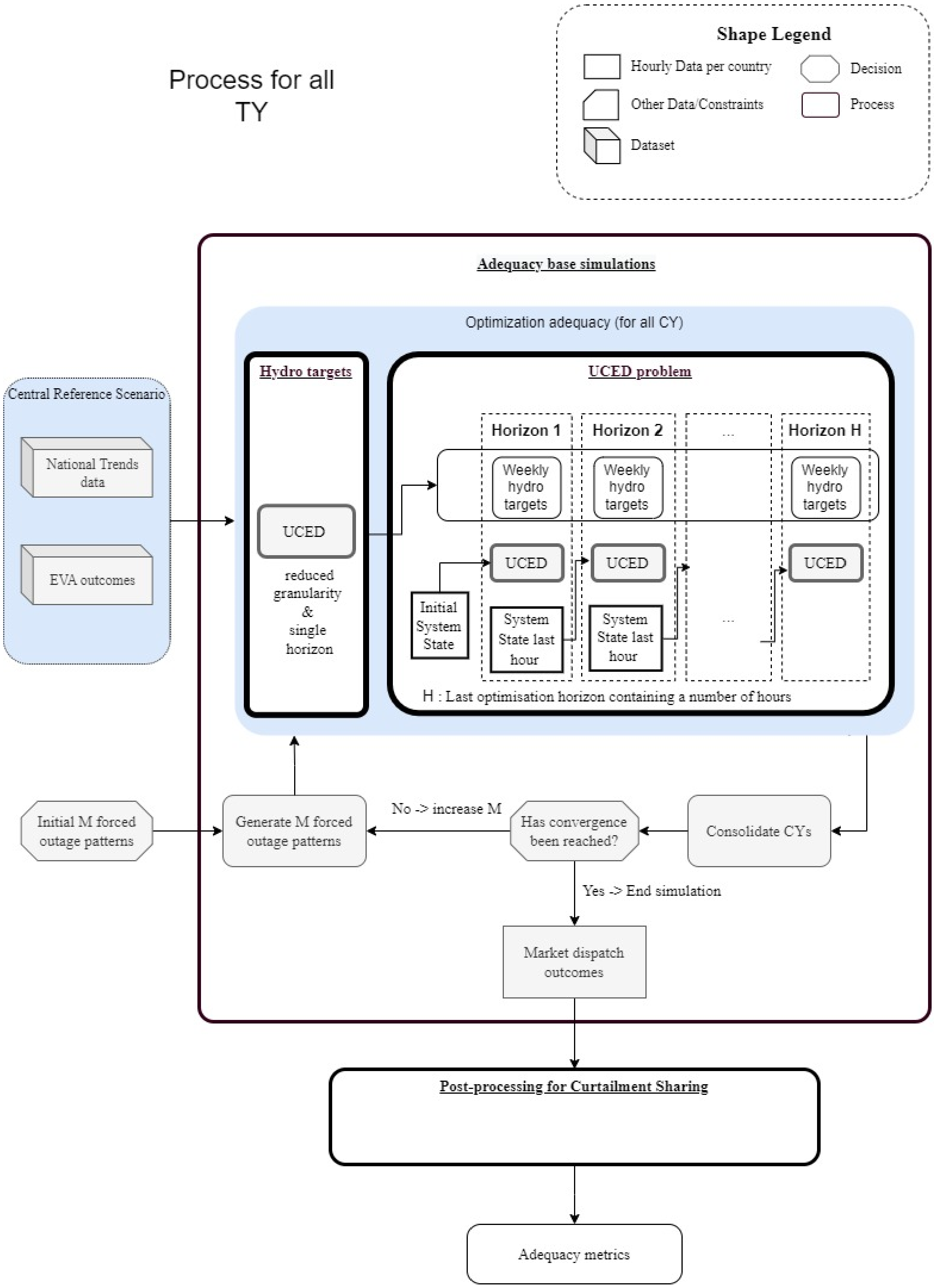

Figure 22: UCED problem

The UCED optimisation problem solver employs flexible hydro storage resources such as reservoirs and PSPs to exploit marginal price gain opportunities from a cost minimisation perspective. The exogenously provided generation constraints and reservoir level trajectories are accounted by the solver. Final marginal prices are a direct result of the hourly optimisation of hydro storages and are set equal to the highest marginal cost (merit order) of the dispatched resources (e.g. RES, thermal, DSR, imports etc.) to cover the hourly domestic demand. As such, the residual load[27] is matched with the least-cost available resource capacities and hydro resources and is sometimes referred to as 'Hydro-Thermal' optimisation. It follows intuitively that storage injection occurs in times of low capacity margins (high electricity prices), whereas storage offtake occurs in times with high capacity margins.

In a system with a high degree of flexibility (i.e. implicit DSR technologies, battery storage systems, hydro storage), the storage dispatch in scarcity periods can impact adequacy indicators[28]. It is therefore necessary to properly account for storage operation strategies in scarcity periods, in particular to avoid an arbitrary temporal distribution of ENS. In this study, a modelling approach minimising the peak residual load has been applied. It is an integral element of this methodology that the total ENS volume and thus the system costs are not increased by the homogenised temporal ENS distribution.

11.6 Monte-Carlo Convergence

FO realisations may have an impact on model results depending on the specific demand and supply situation assumed in the given MC year. A major power plant experiencing an FO might, for example, lead to severe adequacy risk in a high-demand and low-renewable-energy-production situation, whereas it might have a negligible impact in a high-renewable-energy-production situation. Model run results might thus differ significantly. Figure 23 illustrates this aspect, showing a schematic histogram of the ENS over 525 MC realisations.

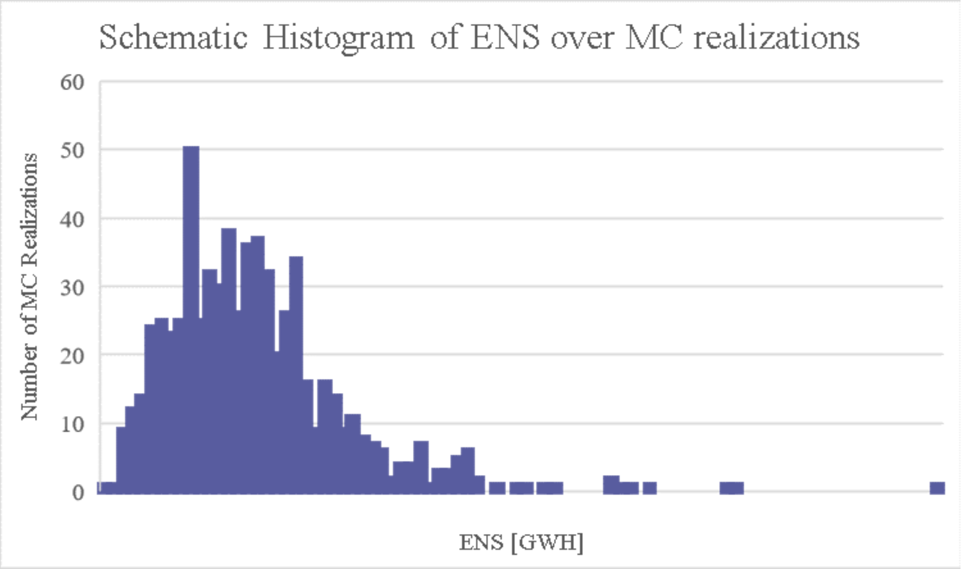

Figure 23: Schematic histogram of the ENS over 525 MC realisations. Each histogram bin covers a range of 5 GWh ENS and contains the number of MC realisations which lie within the respective ENS range.

To obtain robust results, the impact of additional MC realisation results on the existing results should be small or negligible and thus have limited/no impact on the convergence metrics. It can then be said that the model has converged.

[27] Demand minus supply from non-dispatchable generation resources (e.g. wind & PV)
[28] Gonzato, S.; Bruninx, K. Delarue, E.: The effect of short term storage operation on resource adequacy

In the ERAA 2023, the convergence of the adequacy results is calculated in several steps. Following a set of model runs, the models' convergence is assessed and, in the event the convergence is not reached, additional simulations using new FO realisations are launched, increasing M.

The convergence of the models is assessed using the relative change of the coefficient of variation α derived from the ENS of the entire geographical scope, as defined by Eq. (3):

$$\alpha = \frac{\sqrt{\mathrm{Var}[EENS]})}{EENS}, \qquad (3)$$

where $EENS$ is calculated over all MC realisations completed at the moment of assessment and $\mathrm{Var}[EENS]$ is the variance of the expectation estimate (i.e. $\mathrm{Var}[EENS] = \frac{\mathrm{Var}[ENS]}{N}$).

The left side of Figure 24 provides an example of the evolution and the relative change of the coefficient of variation of an MC model in function of the number of MC realisations. No significant changes in α occur past a certain number of MC realisations, meaning no significant changes in averaged results are expected and thus no additional MC realisations are needed to improve results. No explicit simulation stopping criterium is set for α. The decision of whether or not to launch additional model runs is based on a compromise between the relative change in α and the required computational time. Annex 3 offers an insight into the coefficient of variation and its relative change versus the increasing number of MC simulations for the different ERAA 2023 scenarios. The right side of Figure 24 provides an example of the evolution and the relative change of the coefficient of variation of an MC model as a function of the number of MC realisations. No significant changes occur past a certain number of MC realisations, meaning no significant changes in averaged results are expected and thus no additional MC realisations are needed to improve results.

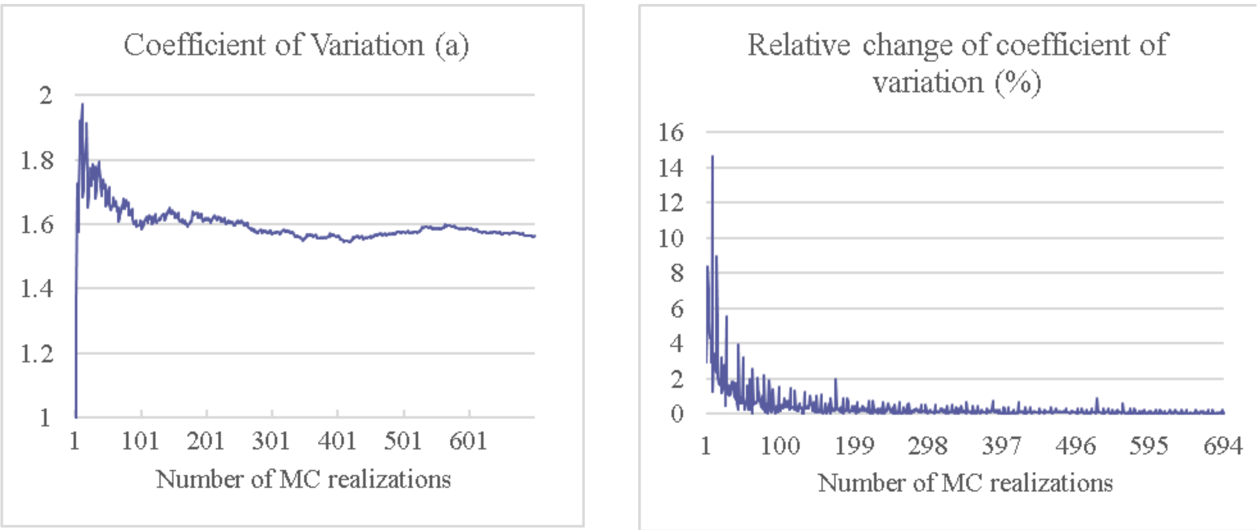

Figure 24: Example of α evolution and its relative change with an increasing number of MC samples for a converging model

Certain inputs and parameters can have a significant impact on the results of those adequacy indices and their convergences, including:

- Hydro power modelling;
- Commercial exchanges between countries;
- The use/absence of extreme, yet realistic, historical CYs;

- Outages and their modelling, including both maintenance and FOs[29]; and
- The number of units with outages in a country (more units lead to faster convergence).

11.7 Local matching and curtailment sharing

Local matching (LM) and curtailment sharing are implemented in the adequacy models in the ERAA 2023 as described in EUPHEMIA ALGORITHM (PCR Market Coupling Algorithm). The curtailment rules are used in the operational FB market coupling algorithm to mitigate the effect of flow factor competition. These rules intervene when a country experiences scarcity/ENS. The solution implemented in EUPHEMIA within FBMC follows the curtailment sharing principles that already existed under the NTC. Two different rules are being introduced: curtailment minimisation and curtailment sharing. Their main function consists of the minimisation of the ENS and the equalisation of the curtailment ratios between the different study zones as much as possible. Moving away from the optimal solution, which is solely the minimisation of ENS towards a solidarity solution of ENS distribution, will result in a sub-optimal solution.

The curtailment rules (curtailment sharing and curtailment minimisation) explained below follow the market behaviour, expected in (simultaneous) scarcity situations. In the ERAA, the 'curtailment of Price Taking Orders of Demand' is referred to as shortage or ENS.

11.7.1 Flow factor competition

If two possible market transactions generate the same welfare, the one with the lowest impact on the scarce transmission capacity will be selected first within FBMC. This also means that, to optimise the use of the grid and to maximise the market welfare, some buy (demand) bids with higher prices than other buy (demand) bids located in other study zones might not be selected within the FB allocation. This is a well-known and intrinsic property of FB referred to as 'flow factor competition'.

Under normal FBMC circumstances, 'flow factor competition' is accepted as it leads to maximal overall welfare. However, for the special case where the situation is exceptionally stressed e.g. due to scarcity in one or several study zones, 'flow factor competition' could lead to a situation where order curtailment takes place non-intuitively / non-fairly. This could mean, for example, that some buyers (order in the market) which are ready to pay any price to import energy would be rejected whereas lower buy bids in other bidding areas are selected instead due to 'flow factor competition'. These 'pay any-price' orders are also referred to as PTO, 'Price Taking Orders', which are valued at the market price cap in the market coupling.

Two situations tend to occur due to the implementation of the FBMC constraints:

1. ENS can be created for net exporting countries to find the lowest ENS for the FB area as a whole; and
2. Countries with low 'flow-factors' are penalised with ENS to the benefit of countries with high 'flow factors', even if all these countries are simultaneously at the maximum market price cap.

Curtailment rules are being introduced to correct market simulation results after the implementation of the FBMC constraints.

11.7.2 Local matching

LM is achieved in EUPHEMIA through the LM constraint. EUPHEMIA enforces the LM of price-taking hourly orders with hourly orders from the opposite sense in the same study zone as a counterpart. Hence, whenever the curtailment of price-taking orders can be avoided locally on an hourly basis.

[29] To understand the impact of FOs, which are random by definition, it is important for all of the tools to use one commonly agreed upon maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs.

In ERAA, the LM constraint is implemented following two different rules:

1. Each study zone is allowed to export only the share of generation capacity exceeding its internal demand; hence, preventing net exporters study zones from having ENS.
2. Net importing countries should primarily use internal resources to cover internal demand, avoiding exports to countries driven by a better flow factor competition.

The LM constraint should be enforced for all study zones in the welfare maximisation problem.

11.7.3 Curtailment sharing

To address the issues of 'flow factor competition' where it concerns price taking orders, EUPHEMIA suggests the implementation of the curtailment sharing principle. Curtailment sharing aims to equalise as much as possible the curtailment ratios between those bidding areas that are simultaneously in a curtailment situation and those that are configured to share curtailment. In other words, curtailment sharing aims to 'fairly' distribute the curtailments across the involved markets by equalising this curtailment ratio. The curtailment ratio is defined as curtailed price-taking orders / total volume of price-taking orders.

11.7.4 Implementation in ERAA

In order to ensure that the implementation of curtailment sharing does not affect the adequacy results either in terms of ENS occurrences or total system LOLE, curtailment sharing is implemented as a post-processing mechanism. Therefore, we perform two different runs: the adequacy run, and the post-processing run.

Adequacy run

The local matching constraint is implemented in the adequacy run as a conditional constraint. The condition of activation is the surplus of generation in a BZ compared to the demand of the BZ for a specific hour. In addition to the local matching constraint, a Flow-Factor Competition (FFC) constraint is implemented in the adequacy run to ensure that the unserved energy for a specific country does not exceed the allowed unserved energy (load – generation) due to FBMC.

<u>Local matching constraint:</u>

Mathematically the condition is written as:

$$If\ NetPosition_{Region} - ENS_{Region} \geq 0\ or \sum Line_{Flows} - ENS \geq 0$$

Mathematically the constraint is written as:

$$NetPosition_{Region} + Load_{Region} - Generation_{Region} \leq 0\ or \sum Line_{Flows} + Load_{Region} - Generation_{Region} \leq 0$$

<u>Flow-factor competition conditional constraint:</u>

Mathematically the condition is written as:

$$If\ NetPosition_{Region} - ENS_{Region} < 0\ or \sum Line_{Flows} - ENS < 0$$

Mathematically the constraint is written as:

$$NetPosition_{Region} \leq 0 \ or \sum Line_{Flows} \leq 0$$

Post-processing

The post-processing run is designed to take the solution of the adequacy run with “frozen” Generation and Demand, in addition to LM and FFC constraints. The optimization of the post-processing model is purely on CS distribution.

The LM and FFC constraints in the post-processing run are based on the Domestic Unserved Energy (DENS) defined from the adequacy run. The DENS can be simply defined as: Demand – Generation. Therefore, the LM is active if the DENS <= 0 and the FFC constraint will ensure than the ENS <= DENS.

In order to share the ENS within the different study zones. A penalty involving a quadratic function is added to the post-processing model.

The quadratic function is defined similarly to Euphemia: **PTO volume * (rejected PTO ratio)** ^{2}

In where, PTO volume = Domestic Energy Not Served (DENS). Hence, PTO ratio = ENS/DENS.

The penalty grows more quickly with increased curtailment, hence equilibrium can be expected where curtailments are roughly equal.

12 Databases and Tools Used for the ERAA

The ERAA methodology uses data collected from TSOs or generated by internal tools using TSOs assumptions/data. The following sections describe the databases and tools used in the ERAA assessment. These databases are common with other ENTSO-E assessments such as the TYNDP, Seasonal Outlook, etc.

12.1 Market modelling database (PEMMDB)

ENTSO-E uses a single source of supply-side and grid data across all its assessments (i.e. the PEMMDB containing data collected by TSOs on plant net generation capacities, interconnection capacities, generation planned outages, etc). The database is aligned with national development plans and contains data about the power system according to the best knowledge of the TSOs at the time of data collection. The PEMMDB contains a highly granular unit-by-unit resolution of European power plants, their technical and economical parameters, their expected decommissioning dates and the forecasted development of RES capacities. Moreover, it provides an hourly time series of must-run obligations in addition to the derating of thermal units.

12.2 Demand Forecasting tool

Hourly demand profiles for most of the European countries are created centrally by ENTSO-E. ENTSO-E uses a temperature regression and load projection model that incorporates uncertainty analysis under various climate conditions. The model comes in a software application developed by an external provider (DFT). It is important to mention that some TSOs have provided their own demand time-series to be used by ENTSO-E, using their own demand forecasting tool.

A more detailed description of input data, methodology and consistency checks is given in the relevant document published[30] alongside this report.

12.3 Climate database (PECD)

12.3.1 Temperature detrending accounting for climate change

The ERAA makes use of climate variables for its simulations. Currently, only historical climate data are considered for ERAA simulations. These simulations extend to the next 10 years (currently up to 2030).

The PECD used by ENTSO-E consists in a downscaling of the ERA-Interim climate reanalysis. Starting from the ERA-Interim geographical horizontal resolution of 75 km and temporal resolution of 6-hour, the climate variables are reproduced at 20 km and 1-hour resolutions, respectively. The database covers 1982–2016.

Using the climate data thus produced, the following energy variables are produced by different providers:

- Demand data;
- Wind and solar capacity factors; and
- Hydropower data (RoR and water incomes to reservoirs, both expressed in terms of available energy).

The final goal is to update the PECD to account for climate change and its effects on energy variables to be suitable for long-term studies.

12.3.1.1 Description of the context

The standard climatology reference period of a 30-year period is deemed as sufficient to represent the mean climate, but is not sufficiently long to sample extreme events. It is therefore critical for adequacy purposes to aim for sufficiently long periods, which shall include sufficient extreme events. In addition, updating the database to consider the latest available data is critical for demand modelling aspects. Therefore, a temporary solution (named PECD v3.1) is used, whereas a long-term forward-looking climate projection is foreseen from the ERAA 2024.

As a first step, the PECD temperature data were recently upgraded by *Météo-France* in late 2020 to use the latest reanalysis, called ERA5, and to simultaneously extend the period to include up to 2019[31].

12.3.1.2 Temperature detrending as a temporary solution

The most applicable and promising solution to date with minimal impact on the current methodology and calculations was the computation of linear trends using the available data, which was prepared by Copernicus Climate Change Service (C3S) and applied to future years to extend the current period. To avoid mapping issues, a pragmatic approach was to target a specific year, namely 2025, meaning that each year in the current 1981–2019 dataset was adjusted to the year 2025. Consequently, years farther in the past will be subject to the largest trend adjustment compared to the more recent years.

Climate change causes trends in climate variables, both in the mean and in the variance. In the context of TSOs studies, both these trends are important. Thus, accounting for both trends, rather than just the trend of the mean, increases the confidence in the extrapolated signals. To analyse all months concurrently, the annual cycle is removed. In the present analysis, we adopt two different methodologies, one that considers all months together and another that considers months separately from each other.

Methodology 1 – All months together
To tackle the former methodology, namely when all months are considered simultaneously, in climate studies a common approach to calculating and then removing the annual cycle is to compute the average of individual monthly means, namely month by month. The annual cycle is then subtracted from the monthly average time series, thus obtaining monthly mean anomalies. The linear trend is then computed considering all months. The same approach is also applied to the standard deviation. The linear trend is then computed for all months together (taking their anomalies). Again, the same approach is taken for the mean values and the standard deviation.

Methodology 2 – Individual months
In methodology 2, months are considered separately from each other; there is no need to remove the annual cycle. The linear trend is computed for each month separately. Unlike in methodology 1, the different month-to-month linear trends might introduce jumps in the timeseries for adjoining months. To alleviate this issue, a smoothing is applied by generating an hourly timeseries from the (12) monthly linear trends (January to December) for each year.

12.3.1.3 Extrapolation of climate variables

Once the linear trend for the historical period is computed, the climate variables (just air temperature in this case) can be extended to the future period 2021 – 2030. Two extrapolation adjustment approaches are considered. The first uses only the (annual) mean linear trend (computed using monthly anomalies). The second is like the first but, in addition, the standard deviation is also adjusted, using the (annual) linear trend

[31] Despite the extended database available, the unavailability of hydro data restricted the use of CYs for the ERAA 2021 to years 1982 – 2016.

of the standard deviation. Consequently, four extrapolation estimates are computed for the year 2025 (two approaches for each of the two methodologies).

1. Methodology 1 – All months together – First approach – Extrapolation based on (annual) mean linear trend only, meaning: Adjust the (annual) mean by extrapolating a single (annual) linear trend based on monthly mean anomalies.
2. Methodology 1 – All months together – Second approach – Extrapolation based on (annual) mean and standard deviation linear trends, meaning: Adjust the (annual) mean and standard deviation by extrapolating a single (annual) linear trend based on monthly mean anomalies.
3. Methodology 2 – Individual months – First approach – Extrapolation based on monthly mean linear trend only, meaning: Adjust the (monthly) mean by extrapolating month-specific linear trends.
4. Methodology 2 – Individual months – Second approach – Extrapolation based on monthly mean and standard deviation linear trends, meaning: Adjust the (monthly) mean and standard deviation by extrapolating month-specific linear trends.

12.3.2 Wind and Solar

The following paragraphs describe the PECD modelling update carried out in 2021. Both the meteorological data and the methods for transforming the meteorological variables to power generation are updated compared to previous PECD versions. The modelling is carried out using the Correlations in Renewable Energy Sources (CorRES) tool at DTU Wind Energy. The updates impact all the variable renewable energy generation time series: onshore and offshore wind, solar PV and concentrated solar power (CSP).

All runs have the same geographical scope, with a split to onshore and offshore regions. All runs are with hourly resolution, covering years 1982–2019; except for the validation run, which covers 2015–2018.

12.3.2.1 Wind

European wind power plant (WPP) installations given per plant are used (thewindpower.net); these installations include installed capacity, hub height, number of turbines and turbine model. We also use a turbine power curve database (thewindpower.net). A generic wake loss model developed at DTU Wind Energy is used when the layouts of the plants are not known. This model is a deep neural network (machine learning [ML]) regression trained on the wake losses of 1000 wind power plants with different layouts, number of turbines and installed capacities. The ML wake model predicts the wake losses as a function of wind speed as a time series for each plant in the modelled onshore wind fleets.

Detailed wake modelling for future installations and offshore wind installations is performed by optimising a wind plant layout to maximise the turbine spacing within a specified plant area. The detailed wake modelling then predicts the wake losses as a function of wind speed and wind direction.

Onshore wind runs
The different onshore wind run setups are shown in Table 15 below. The Validation run is used when comparing to measured data (where WPP fleet changes in time). All other runs are simulated with a fixed fleet, modelling either the existing or new installations, and multiple WPP technologies are considered for the future runs. Validation is focused on onshore wind, as a) measured data are available for multiple countries for multiple years; and b) Information about the existing WPP installations is quite extensive.

Table 15: Onshore wind run setups

Run type	Simulated meteorological years	WPP locations	WPP technology	Losses
Validation	2015-2018	Changed every year to match changing WPP installations	Known turbine types & hub heights (changed every year)	Wakes using ML. And 5 % for other losses & unavailability; these are further adjusted based on measured generation data.
Existing	1982-2019	All years with 2018 WPP locations	Known turbine types & hub heights (always 2018 fleet).	Wakes using ML. And 5 % for other losses & unavailability; these are further adjusted based on the Validation run.
Future: Repowering	1982-2019	All years with 2018 WPP locations	Hub heights remain the same as in Existing, but turbines are changed (3 types are simulated).	Wakes using ML. And 5 % for other losses & unavailability.
Future: New installations	1982-2019	Different locations for the different RGs (three RGs modelled).	3 hub heights & 3 turbine types -> 9 wind technologies. The layout of a plant of 50.4 MW with 14 turbines 3.6MW is optimized per technology.	Wakes using PyWake. And 5 % for other losses & unavailability.

Regarding PECD onshore wind capacity factors (CFs) of the existing installations, it is notable that some regions which do not have very high wind speeds show high CFs. This is because, in addition to wind speeds, the wind technology of the fleet impacts the CFs; e.g. in Finland, very high hub heights and modern low specific power turbines are utilised.

In the future technology runs, the CFs follow mean wind speeds in the regions more directly as a uniform wind technology is modelled in all regions per run. However, within each region, there is a significant difference between the different RGs. Note that whereas the lower specific power turbine at 150m hub height shows high CFs, the low specific power and high hub height also indicate a high CAPEX.

Offshore wind runs

The different run setups for offshore wind are shown in Table 16. All runs are simulated with a fixed fleet, modelling either the existing or new installations. Multiple offshore WPP (OWPP) technologies are considered for the future runs. Specific validation runs have not been carried out for offshore wind.

Table 16: Offshore wind run setups

Run type	Simulated meteorological years	OWPP locations	WPP technology	Losses
Existing	1982-2019	Existing & in-construction OWPPs (dataset from 2019)	OWPP with 210 MW consisting of 70 turbines of 3MW with specific power of 388 MW/m2.	Wakes using PyWake. And 5 % for other losses & unavailability.
Future	1982-2019	The best 10 % of all potential locations*	2 offshore wind turbine types, with generic 504 MW OWPP consisting of 28 turbines of 18 MW capacity in optimized layout.	Wakes using PyWake. And 5 % for other losses & unavailability.

*) For the North Sea, where offshore energy hubs are considered possible for the entire region, all locations are considered potential. For other Sea areas, max 100 km from shore are considered as potential locations.

12.3.2.2 Solar PV

The transformation to solar PV power generation uses PVLib library, with a specified generic PV module (Canadian Solar) and inverter (ABB). Generic models are used because we do not have a pan-European database of solar PV installations available.

The power generation model requires the time series of Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DHI), but also the wind speed and temperature to estimate the performance efficiency (or temperature driven losses). Furthermore, a given PV plant is localised in terms of longitude, latitude, altitude (for pressure estimation) and panel orientation (azimuth and tilt angles).

Solar PV runs
For solar PV, only one run is simulated to model both existing and future installations, i.e. no technology development is considered. Information about existing solar PV installations was not available; thus, a representative generic simulation setup is used. The best 50% of locations (in terms of mean irradiance) within a region are considered to represent solar PV installations in that region. For these locations, multiple tilt angles and orientations were tested. South-facing installations 15 degrees below the optimal tilt angle were found to give the highest correlation compared to measured data (FR, ES, DK and AT were tested). This was considered reasonable as large installations can be at the optimal tilt angle but rooftop installations can often be placed at sub-optimal angles (generally lower angles than the optimal).

An additional solar PV run was carried out for Germany, using measured data provided by the German TSOs for model calibration. Based on this, an even lower tilt angle was used for Germany for these runs, suggesting an even larger share of rooftop installations than in the generic run described above. Specific validation runs have not been carried out for solar PV.

12.3.2.3 CSP

As in the previous PECD version, the CSP model consists of 3 parts: a solar field, a power block and a thermal energy storage. The main parameters required to model the performance are: (a) solar multiple, which is the ratio between the solar field capacity over the turbine capacity, (b) plant installed capacity; (c) turbine, storage charging/discharging efficiencies; and (d) energy storage capacity. The storage capacity is usually given in hours of rated capacity operation. The heat transfer fluid is modelled as a first order dynamical system characterised by a time constant responsible for a delay in the response between a change in DNI and power produced in a CSP plant.

CSP runs
The best 50% of locations (in terms of mean irradiance) are selected for possible installation locations. Two runs are performed in the CSP analysis: (1) CSP plants are simulated without energy storage, and (2) CSP plants with 7h of thermal energy storage. For case (2), the results are given in two time series, one representing the automatic energy dispatchment to use the energy storage as soon as possible after noon every day, or as a time series that includes the excess in power; these time series can be used based on ENTSO-E system-level modelling needs.

12.3.3 Hydro data

Available hydropower generation is an important factor in adequacy assessments as it can have a significant impact on results. Therefore, choosing the appropriate level of detail, evaluating distinct hydrological conditions, and better reflecting the interdependence of hydro generation and climatic conditions, including with other RES, is of great importance.

Since 2019, the PECD has been extended to include hydro generation data using a single source of coherent climatic data. Based on re-analysed data concerning hydro inflows, a standardised central methodology has been designed to map historical inflows of generation data and build a model to project hydro generation, including hydro RoR, hydro reservoirs and pump storage. In 2020, a further improvement was achieved by introducing a higher granularity of north-sea offshore zones and updating the zone configuration in Belgium. More information regarding the methodology and relevant assumptions are included in the document 'Hydro modelling description' which accompanies the Mid-Term Adequacy Forecast (MAF) 2020[32].

[32] https://www.entsoe.eu/outlooks/midterm/

13 Appendix 1: Detailed EVA optimisation function

In this appendix, the detailed formulation of the EVA optimisation model is presented. The EVA optimisation model is formulated as follows:

$$Minimise \quad \sum_{y\ in\ Y} (1+r)^{(1-y)} \left[Total\ cost_y\right]$$

$$Total\ cost_y = Fixed\ cost_y + \sum_{sc\ in\ CY} \omega_{sc}\left[Operational\ cost_{y,sc}\right]$$

$$Fixed\ cost_y = \sum_{n\ in\ BZ} \{ \sum_{g\ in\ G_n^{new}} \left[\left(Annuity_g + FOM_{g,y}\right) \times p_{y,g}^c\right] + \sum_{g\ in\ G_n^{ex}} \left[FOM_{g,y} \times \left(P_g - p_{y,g}^d\right)\right] \}$$

$$Operational\ cost_{y,sc} = \sum_{n\ in\ BZ} [\sum_{\substack{g\ in\ G_n \\ t\ in\ T}} SRMC_{g,y} \times p_{y,sc,g,t} + \sum_{t\ in\ T} PC_{sc} \times l_{y,sc,n,t}]$$

$subject\ to$:

$$p_{y,sc,g,t} \leq P_g - p_{y,g}^d \qquad for\ all\ y, sc, t, n\ and\ g\ in\ G_n^{ex}$$

$$p_{y,g}^d \geq p_{y-1,g}^d \qquad for\ all\ y > 1, n\ and\ g\ in\ G_n^{ex}$$

$$p_{y,sc,g,t} \leq p_{y,g}^c \qquad for\ all\ y, sc, t, n\ and\ g\ in\ G_n^{new}$$

$$p_{y,g}^c \geq p_{y-1,g}^c \qquad for\ all\ y > 1, n\ and\ g\ in\ G_n^{new}$$

$$\sum\nolimits_{g\ in\ G_n^{new}} (p_{y,g}^c - p_{y,sc,g,t}) + \sum\nolimits_{g\ in\ G_n^{ex}} (P_g - p_{y,g}^d - p_{y,sc,g,t}) \geq BR_n \qquad for\ all\ y, sc, t, n$$

$$\sum\nolimits_{g\ in\ G_n} p_{y,sc,g,t} + l_{y,sc,n,t} + \sum\nolimits_{i \to n} f_{y,sc,i,t} - \sum\nolimits_{i \leftarrow n} f_{y,sc,i,t} = Load_{y,sc,n,t}\ for\ all\ y, sc, n, t$$

$$f_{y,sc,i,t} \leq F_{y,i,t} \qquad for\ all\ y, sc, i, t$$

Where:

Sets/indices

n	Index representing study zones
CY	Set of climatic scenarios
sc	Index representing climatic scenarios
G_n	Set of all generation resources in study zone n, existing and new candidates
G_n^{ex}	Set of existing generation resources in study zone n
G_n^{new}	Set of new candidate generation resources in study zone n
Y	Set of the years in the planning horizon
y	Index representing the years of the planning horizon
g	Index representing the generators
T	Set of time steps in each year
t	Index representing the time steps
i	Index representing interconnections ($i \rightarrow n$: default direction of the interconnection is importing to study zone n, $i \leftarrow n$: default direction of the interconnection is exporting from study zone n)

Variables

$p_{y,sc,g,t}$	Generation level of unit g in year y, climatic scenario sc and time step t – [MW]
$f_{y,sc,i,t}$	Flow in interconnection i in year y, climatic scenario sc and time step t – [MW]
$p_{y,g}^c$	Capacity of the new generator g – [MW]
$p_{y,g}^d$	Capacity decommissioned from the existing unit g – [MW]
$l_{y,sc,n,t}$	Load not served in year y, climatic scenario sc, in study zone n and time step t – [MW]

Parameters

r	Discount rate [ratio]
$Annuity_g$	Annuity of the new generator g including risk premium – [EUR/MW]
$FOM_{g,y}$	Fixed operating and maintenance cost including risk premium – [EUR/MW/year]
$P_{\boldsymbol{g}}$	Capacity of the generator g – [MW]
$F_{y,i,t}$	NTC of interconnection i in year y and time step t [MW]
$SRMC_{g,y}$	Short-Run Marginal Cost – [EUR/MWh]
PC_y	Wholesale market price cap used for the year y – [EUR/MWh]
ω_{CY}	Probability of each climatic year scenario
BR_n	Balancing reserve requirement in study zone n – [MW]
$Load_{y,sc,n,t}$	Load level in year y, climatic scenario sc, in study zone n and time step t – [MW]

The $Fixed\ cost_y$ consists of build cost annuity (including the cost of mothballing and de-mothballing and the cost of extending the life of a unit) and FOM costs for new commissioned units and FOM cost of an existing unit (or a reduced value in case the unit is mothballed).
The $Operational\ cost_{y,sc}$ consists of operation costs of producing electricity and the cost of unserved energy. In scarcity periods, the market price is assumed to reach the price cap.

14 Appendix 2: Mathematical Formulation of flexible EV and HP consumer (implicit DSR)

The following section presents the underlying mathematical formulation to the implicit DSR (EVs and HPs) modelling approach developed within the ERAA working group. Such a formulation was translated pragmatically into the modelling methodology, compatible with the characteristics and features of the market modelling tools used for the ERAA. The formulation stems from a recent study[33] published by APG.

The demand time series are provided in hourly granularity and the economic dispatch problem is also solved in discrete hourly time steps. The 'demand' mentioned in the rest of the chapter shall always be intended as referring to the share of price-reactive demand peculiar to HPs or EVs respectively. We define the time index t denoting the time step δ, with $t \in \mathcal{K} \coloneqq \{1, \dots, 8760\}$.

For each δ, two decision variables are introduced, $p_i^{\mathrm{DSR}}(t)$ and $e_i^{\mathrm{DSR}}(t)$, which can be interpreted as follows:

- $p_i^{\mathrm{DSR}}(t)$: curtailed (i.e. reduced) or increased demand of demand object i due to price-sensitive time-shifting of the demand at time step t
- $e_i^{\mathrm{DSR}}(t)$: amount of energy of demand object i that still has to be served or has already been served at time step t

The consumptive limitations of the flexibility resources, quantified by the respective time series, require the definition of the following constraint:

$$\underline{p_i}^{\mathrm{DSR}}(t) \leq p_i^{\mathrm{DSR}}(t) \leq \overline{p_i}^{\mathrm{DSR}}(t),$$

with $\overline{p_i}^{\mathrm{DSR}}(t)$ and $\underline{p_i}^{\mathrm{DSR}}(t)$ denoting the maximum demand that can be curtailed at time step t, and the maximum curtailed demand that can be shifted to time step t, respectively. For the amount of energy shifted to a later point in time, we define the following two constraints:

$$\underline{e_i}^{\mathrm{DSR}}(t+1) \leq e_i^{\mathrm{DSR}}(t+1) \leq \overline{e_i}^{\mathrm{DSR}}(t+1), \text{ and}$$

$$e_i^{\mathrm{DSR}}(t+1) = e_i^{\mathrm{DSR}}(t) + \delta \cdot p_i^{\mathrm{DSR}}(t).$$

Here, $\overline{e_i}^{\mathrm{DSR}}(t+1)$ and $\underline{e_i}^{\mathrm{DSR}}(t+1)$ represent the maximum amount of energy demand that can be curtailed or shifted up to time step $t+1$, respectively. Finally, as an arbitrary boundary condition, we can define:

$$e_i^{\mathrm{DSR}}(1) = e^0,$$

where the superscript 0 refers to the initial condition.

To define discrete timeframes within which the demand can be shifted (either forward or backward), the profiles $\overline{e_i}^{\mathrm{DSR}}(t+1)$ and $\underline{e_i}^{\mathrm{DSR}}(t+1)$ should be such that there exist time steps in which the two bounds coincide, i.e. there exist $h \in \mathcal{K}$ such that:

$$\overline{e_i}^{\mathrm{DSR}}(h+1) = \underline{e_i}^{\mathrm{DSR}}(h+1) = e^{\mathrm{H}}.$$

Consequently, we define the subset $\mathcal{H}$ of all these points in time as:

[33] Haas A., Iotti G., Petz M., Misak K., Methodological developments for European Resource Adequacy Assessments, 17. Symposium Energieinnovation, 16.-18.02.2022, Graz/Austria

$$\mathcal{H} \coloneqq \left\{ t \in \mathcal{K} \text{ s.t. } \overline{e_i}^{\mathrm{DSR}}(t+1) = \underline{e_i}^{\mathrm{DSR}}(t+1) = e^{H} \right\}.$$

Practically speaking, the elements of $\mathcal{H}$ define the boundaries of time windows within which the load can be shifted (i.e. the flexibility windows defined in the previous chapter). To ensure that all the flexible demand is eventually supplied within each time window, bound by the time steps in $\mathcal{H}$, the boundary conditions are set equal to the initial condition, thus:

$$e^{\mathrm{H}} = e^{0}.$$

After introducing the constraints above, an appropriate set of parameters needs to be chosen. Assuming that $\overline{p_i}^{\mathrm{DSR}}(t)$ follows the hourly demand time series of the corresponding iDSR element (e.g. HPs or EVs), we have to define the remaining parameters $\underline{p_i}^{\mathrm{DSR}}(t)$, $\overline{e_i}^{\mathrm{DSR}}(t+1)$, $\underline{e_i}^{\mathrm{DSR}}(t+1)$, e^{H}, e^{0} and $\mathcal{H}$.

To begin with, the set $\mathcal{H}$ is defined with arbitrary time windows of 6 hours; it follows that $\mathcal{H} \coloneqq \{6, 12, 18, 24, \dots, 8760\}$. For the sake of simplicity let $e^{0} = 0$, then:

$$\overline{e_i}^{\mathrm{DSR}}(t+1) \coloneqq \begin{cases} +\infty \text{ if } t \in \mathcal{K} \backslash \mathcal{H} \\ 0 \text{ if } t \in \mathcal{H} \end{cases}, \text{ and}$$

$$\underline{e_i}^{\mathrm{DSR}}(t+1) \coloneqq \begin{cases} -\infty \text{ if } t \in \mathcal{K} \backslash \mathcal{H} \\ 0 \text{ if } t \in \mathcal{H} \end{cases}.$$

To avoid negative values for $e_i^{\mathrm{DSR}}(t)$ the boundary condition $e^{0} = e^{\mathrm{H}}$ can be shifted to an arbitrarily large positive number yielding the same effect (i.e. the default 50% SoC defined in the previous chapter). Finally, we can dimension $\underline{p_i}^{\mathrm{DSR}}(t)$ to allow for a maximum power absorption that matches the maximum demand curtailment in the same time window. Denoting two consecutive indices in $\mathcal{H}$ (e.g., 6 and 12) with h_i and h_{i+1}, then:

$$\underline{p_i}^{\mathrm{DSR}}(t) \coloneqq \max \left\{ \overline{p_i}^{\mathrm{DSR}}(x) \text{ s.t. } h_i \leq x \leq h_{i+1} \right\}, \forall k \in [h_i, h_{i+1}] \subset \mathcal{K}.$$