METHODOLOGICAL DEVELOPMENTS FOR EUROPEAN RESOURCE ADEQUACY ASSESSMENTS

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In recent years, Resource Adequacy Assessments have been subject to significant methodological improvements transitioning from deterministic calculations to probabilistic simulations [1]. Main drivers for these developments are the legal requirements outlined by the Clean Energy for all Europeans Package (CEP), specifically Regulation (EU) 2019/943 [2] and the current transformation of the European energy system triggered primarily by climate neutrality ambitions.

This paper focuses on key methodological developments within the European Resource Adequacy Assessment (ERAA) [3], published in its first edition in 2021. As a successor to the Mid-term Adequacy Forecast (MAF), the ERAA will ultimately be a pan-European resource adequacy assessment covering the horizon from one to ten years ahead. The first edition included a single-year Economic Viability Assessment (EVA) and a Proof-of-Concept (PoC) study for Flow-based Market Coupling (FBMC). Their respective methodologies are summarized and expected improvements in the upcoming editions are investigated, with a special emphasis on the modelling of implicit Demand Side Response (iDSR). Such developments and their planned implementation will follow the structure presented in the ENTSO-E's indicative ERAA roadmap [3, p. 23].

Flow-Based Market Coupling (FBMC)

In its mature implementation, the ERAA is required to be built upon a Flow-Based (FB) model for regions where this capacity calculation methodology (CCM) for cross-zonal trade is in use. In the European Electricity Grid, FBMC is currently applied in the Central-Western Europe (CWE) Region, including Austria, Belgium, France, Germany, Luxemburg and the Netherlands. An extension to the Core region, thus including Croatia, Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia, is planned for 2022. The ERAA 2021 included a PoC study for the pivotal year 2025; hence, the geographical scope of the Core region was used.

Compared to the Net Transfer Capacity (NTC) market coupling – where the amount of energy traded across bidding zone borders is limited by a fixed value – FBMC more realistically represents the physical limitations of the grid through the calculation of a FB domain. The FB domain represents the feasible space for net positions (exports - imports) of bidding zones within a CCR. It is defined by a set of linear constraints and is operationally derived in a forecast process starting two days ahead (D-2). The FB PoC in the first ERAA edition consisted of a five-step approach to calculate FB domains - covered in detail in this paper following the approach presented in [3].

Economic Viability Assessment (EVA)

The ERAA methodology [4] sets the requirements for an Economic Viability Assessment (EVA) of the generation (or flexibility) capacity in the electricity market. The main scope of the EVA is to assess the likelihood of the retirement, mothballing and new investments of generation (or flexibility) assets. An asset is deemed "viable" if its expected future revenues (over its economic lifetime) are sufficient to generate profit over its variable and fixed costs (and CAPEX in case of new investments). The purpose of such an exercise is also to assess the impact of existing and approved future Capacity Mechanisms (CM) in Member States.

The first ERAA edition included EVA as a simplified single-year assessment performed for the Target Year 2025. Two scenarios, "with" and "without" existing and future Capacity Mechanisms, were considered. Several assumptions and simplifications were applied. Given the single-year nature of the market model adopted, the costs faced by an asset were included in the form of annualized fixed and

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variable costs (and annuity of CAPEX for new investments). Considerations of the uncertainty of future revenues and risk aversion of investors were integrated through technology-specific hurdle premiums on expected revenues, following the approach described in [5].

In the scenario without CM, a long-term planning model was used to minimize the overall system costs. The key decision variables were the economic decommissioning of existing units and the investment in new units. The scenario with CM was defined through an iterative approach bringing back retired units or investing in new units in Member States where a CM is in place (for 2025) until the corresponding Reliability Standard (RS) was achieved.

Demand Side Response (DSR)

In the first edition of the ERAA, the modelling of DSR was limited to explicit interruptible load, as opposed to the rest of the demand being assumed inelastic to prices. Future editions of the ERAA will build upon this first approach and enhance the existing modelling of DSR, including price-reactive implicit DSR. In particular, an implementation of iDSR leveraging the explicit modelling of (among others) Heat Pumps (HPs) and Electric Vehicles (EVs) as demand flexibility resources reacting to endogenous marginal prices is projected.

A possible approach to implement iDSR in the modelling tools used for adequacy assessments was benchmarked in a test environment within Austrian Power Grid AG. The ERAA 2021 NTC model for the post-EVA without CM scenario served as a test bench. The geographical perimeter was reduced to amplify the impact on the Austrian bidding zone. To quantify the partition of the total electricity demand to be attributed to iDSR resources, the demand time series were obtained from three sources: a regression model (the tool TRAPUNTA [6]) delivered the demand time series for the bidding zone by analysing historical demand and climate data. On top, the peculiar demand profiles for HPs and EVs were gathered through joint studies commissioned to the Austrian Institute of Technology.

Conclusions

Within this paper, an overview of the methodological developments is presented together with some results of the above described trial calculations. The inclusion of iDSR in the market model for adequacy assessments and its impact on key adequacy indicators such as Loss of Load Expectation (LOLE) or Expected Energy not Served (EENS) is investigated.

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