European Union Agency for the Cooperation of Energy Regulators

ACER Decision on ERAA 2022: Annex I

DECISION No 04/2023

OF THE EUROPEAN UNION AGENCY

FOR THE COOPERATION OF ENERGY REGULATORS

on the European Resource Adequacy Assessment for 2022

Technical annex

27 February 2023

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1. Introduction

1.1. Scope of technical annex

The technical annex provides a detailed assessment of specific elements of the European Resource Adequacy Assessment 2022 ('ERAA 2022') and complements the Decision; the two should be read in conjunction. The technical annex supplements ACER's assessment of ERAA 2022 concerning the high-level requirements of the Electricity Regulation (as described in section 6 of the Decision). It provides a comprehensive technical review of the elements that ACER has assessed as not acceptable in ERAA 2022 and it is structured as follows:

- The second chapter focuses on the alignment of ERAA 2022 with fit-for-55 and renewable energy in particular.
- The third chapter details ACER's assessment of the economic viability assessment (EVA).
- The fourth chapter focuses on the consideration of cross-zonal capacities in ERAA 2022.

Additionally, due to its increasing relevance, the fifth chapter presents ACER's assessment of ERAA 2022 regarding demand-side response (DSR).

2. Fit-for-55 and renewable energy generation

2.1. Introduction

Article 3 of the ERAA methodology stipulates that the central reference scenario needs to be in line with national objectives and targets. National objectives and targets stem from the EU-wide objectives and targets, implying that the central reference scenarios need to be aligned with the EU-wide policy objectives. This section examines the alignment of ERAA 2022 with the EU-wide policy objectives, in particular for renewable energy resources.

The current EU greenhouse gas emissions target for 2030 is to reduce emissions levels by at least 55% from 1990 levels (the so-called “fit-for-55”). To deliver this target the European Commission has proposed an EU-wide renewable energy target in the overall energy mix of at least 40% by 2030 (from the pre-existing target of 32%). This target effectively means a doubling of the share of renewable energy from 2021 to 2030 and translates to an equivalent target of around 65% of electricity supplied from renewable energy resources.

2.2. Comparison of ERAA 2022 with ERAA 2021

In order to examine the alignment of the ERAA 2022 central reference scenario with the EU-wide policy objectives, ACER analysed the ERAA 2022 projections for renewable energy with the ERAA 2021 projections, as a first step. The analysis focuses on the target years 2025 and 2030 and wind (onshore and offshore) and solar technologies in particular, that are expected to be the key technologies deployed for meeting the renewable energy targets. ACER notes that ERAA 2021 did not consider the fit-for-55 policy objectives, as these were set late in the process of developing the assessment. This means that the ERAA 2022 projections for installed renewable capacity should in principle be higher than those for ERAA 2021.[1]

Figure 1 and Figure 2 present the differences in assumed renewable energy capacity between ERAA 2022 and ERAA 2021 for target years 2025 and 2030 respectively. ACER draws the following key conclusions from this analysis:[2]

- Renewable energy capacity projections have remained the same and in some instances even decreased for a significant number of Member States compared to ERAA 2021. Projections have remained unchanged for five Member States across the two years, namely: Bulgaria, Luxemburg, Romania, Slovenia and Slovakia. In addition, projections have decreased for a number of Member States across the two, target years. A few Member States have consistently lower renewable energy assumptions in ERAA 2022 compared to last year’s assessment, namely Austria, Latvia and Portugal, while others have lower projections for 2025 only (Croatia, France, Ireland and Spain).
- Projections have increased for some Member States, in some cases substantially (e.g. Germany and the Netherlands), while in most cases the differences are more subdued (e.g. Belgium and Denmark).
- Overall, projections for renewable capacity have increased more for the long-term (i.e. 2030) compared to the medium-term (i.e. 2025). This effectively indicates that ERAA 2022 assumes the pace of new developments will accelerate further out in the decade, compared to the next few years.

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[1] This might not be the case where a Member State had already set objectives that were higher than the former EU-wide target of 32% and in line with fit-for-55. This appears to be the case for Finland and Sweden for example.

[2] The analysis largely confirm the feedback provided by the TSOs for ERAA 2022. According to those, 7 Member States are aligned with fit-for-55, 11 Member States are partially aligned, while 6 Member States are not aligned (3 TSOs did not provide feedback or responded that this question was not relevant to their Member State).

Figure 1: Differences in installed renewable capacity between ERAA 2022 and ERAA 2021 for 2025

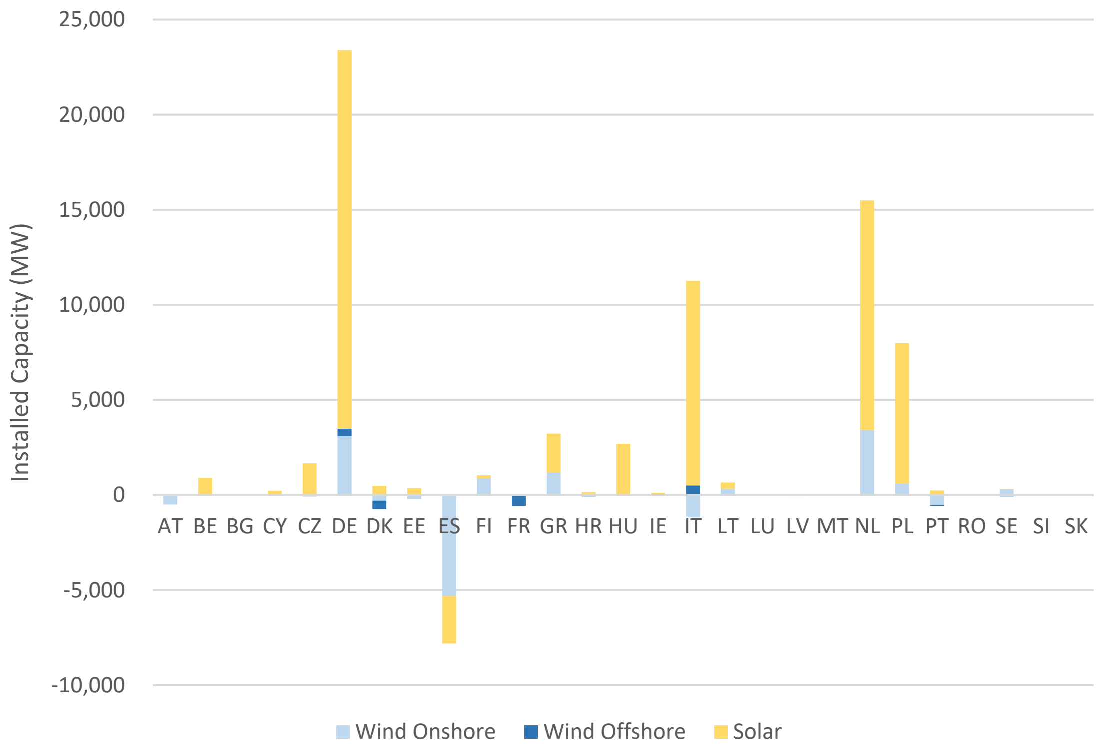
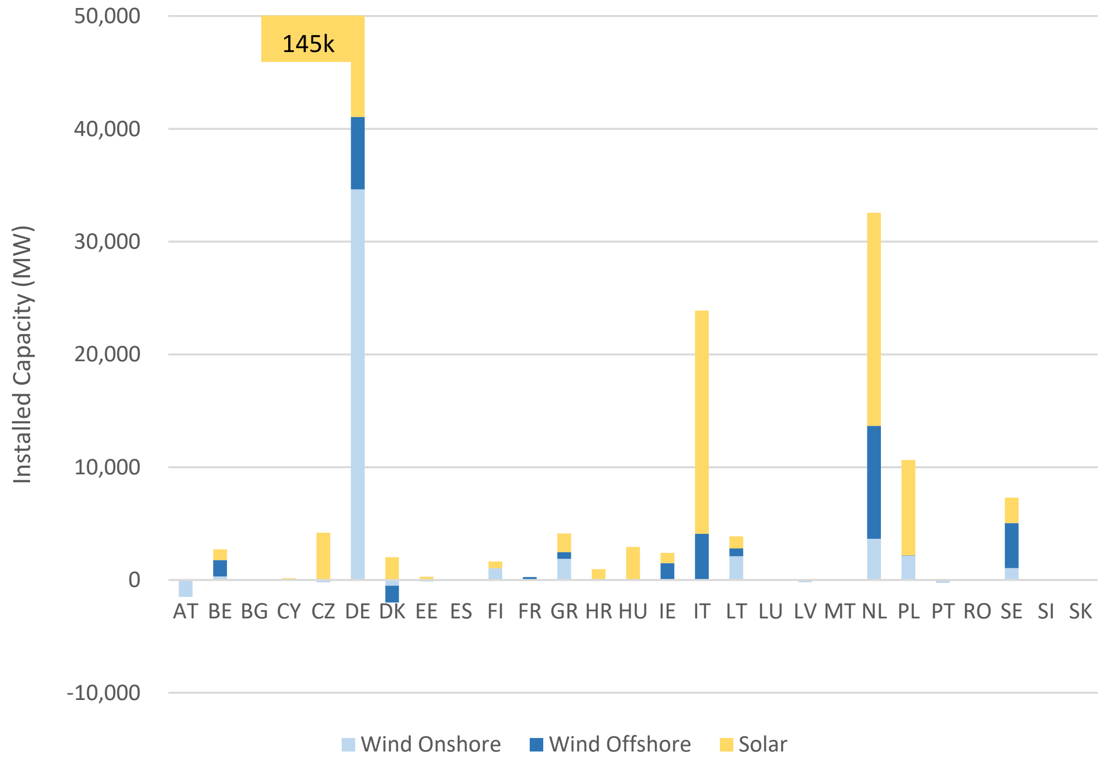


Figure 2: Differences in installed renewable capacity between ERAA 2022 and ERAA 2021 for 2030



2.3. Comparison of ERAA 2022 with the European Commission's Fit-for-55

In addition to the comparison with ERAA 2021, ACER analysed ERAA 2022 against the projections of the European Commission's fit-for-55 scenario.[3] As with the analysis above, this analysis focuses on target years 2025 and 2030, and wind and solar technologies in particular.

Figure 3 and Figure 4 present the differences in installed renewable capacity between ERAA 2022 and the European Commission's fit-for-55 scenario for 2025 and 2030 respectively. One can draw the following conclusions from this analysis:

- In many instances, the assumptions for Member States show differences that go in both directions. Broadly speaking, assumptions for solar power tend to be higher in ERAA 2022 compared to fit-for-55. On the other hand, assumptions for onshore wind tend to be lower in ERAA 2022. Assumptions for offshore wind are lower overall for 2025 and higher for 2030 in ERAA 2022. ACER notes that caution is required when comparing the differences between technologies however, as installed capacity is not equivalent in energy terms.[4] Capacity factors vary across technologies and Member States, but in general, they tend to be higher for wind (higher for offshore than onshore wind) and lower for solar power; this means that the same amount of installed wind capacity tends to produce more energy than the same amount of installed solar capacity.[5] Subsequently, this implies that a negative difference for installed wind power needs to be counterbalanced by a higher positive difference for installed solar power to meet the same renewable energy target.
- For a number of Member States the assumptions for renewable energy capacity are consistently lower in ERAA 2022 compared to the assumptions in the European Commission's fit-for-55 scenario across both years examined. This is for example the case for France, Poland, Romania and Spain. On the other hand, for some Member States, such as Finland, Lithuania and Sweden the assumptions for renewable energy capacity are consistently higher in ERAA 2022.
- All in all, the overall situation for the EU-27 improves from 2025 to 2030, meaning that the negative differences in assumed renewable capacity between ERAA 2022 and the European Commission's fit-for-55 scenario tend to be smaller and there are more positive differences in 2030.
- ACER highlights that the assumed electricity demand in ERAA 2022 is higher, and often significantly higher, than the electricity demand in the European Commission's fit-for-55 scenario.[6] This essentially means that in principle installed renewable capacity in ERAA 2022 needs to be higher than in the fit-for-55 scenario to meet the same renewable energy target.

[3] Specifically, this analysis used the European Commission's MIX scenario for the comparison with ERAA 2022. For more details on the scenarios underpinning the fit-for-55 legislative proposals see the European Commission's Policy scenarios for delivering the European Green Deal.

[4] In other words, one MW of solar is not equivalent to one MW of wind in terms of energy generation.

[5] The capacity factor of a resource represents its annual energy output, expressed as a percentage of the maximum electricity it could generate if it was operating throughout the year at its nameplate capacity. Capacity factors for renewable technologies vary between Member States depending primarily on the availability of the resource. For example, the capacity factors for new onshore wind installed in either 2020 or 2021 varied between 28 and 43 percent and for offshore wind between 42 and 50 percent for selected EU Member States. For more information, see IRENA's Renewable power: Generation costs in 2021.

[6] Specifically, ACER has analysed the annual demand for each Member State between ERAA 2022 (average annual demand across all climate years) and the European Commission's fit-for-55 scenario (final electricity consumption). The analysis shows that Member States' electricity demand in ERAA 2022 is generally higher by a few percentage points up to 50% compared to the fit-for-55 scenario across the two target years (with an average of around 13%). The results of the analysis are presented on Table 7. ACER has neither examined nor qualifies the different electricity demand levels between ERAA 2022 and the European Commission's fit-for-55 scenario. Independent of the reasons for these differences, the conclusion remains valid.

Figure 3: Differences in installed renewable capacity between ERAA 2022 and the European Commission's fit-for-55 scenario for 2025

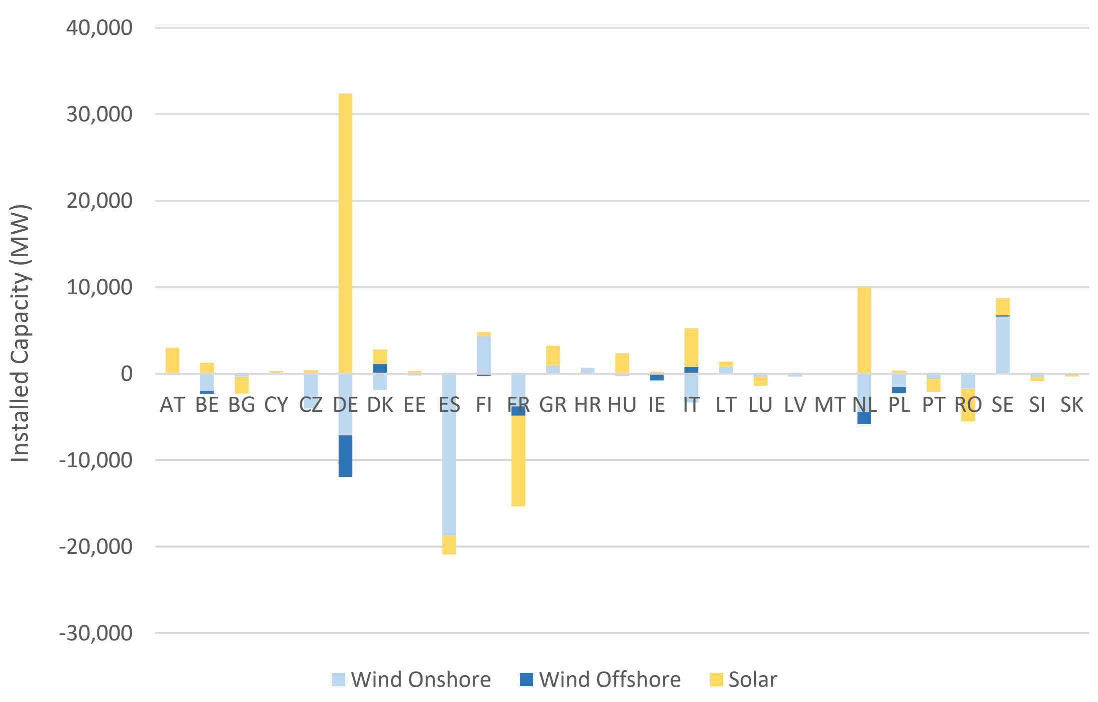
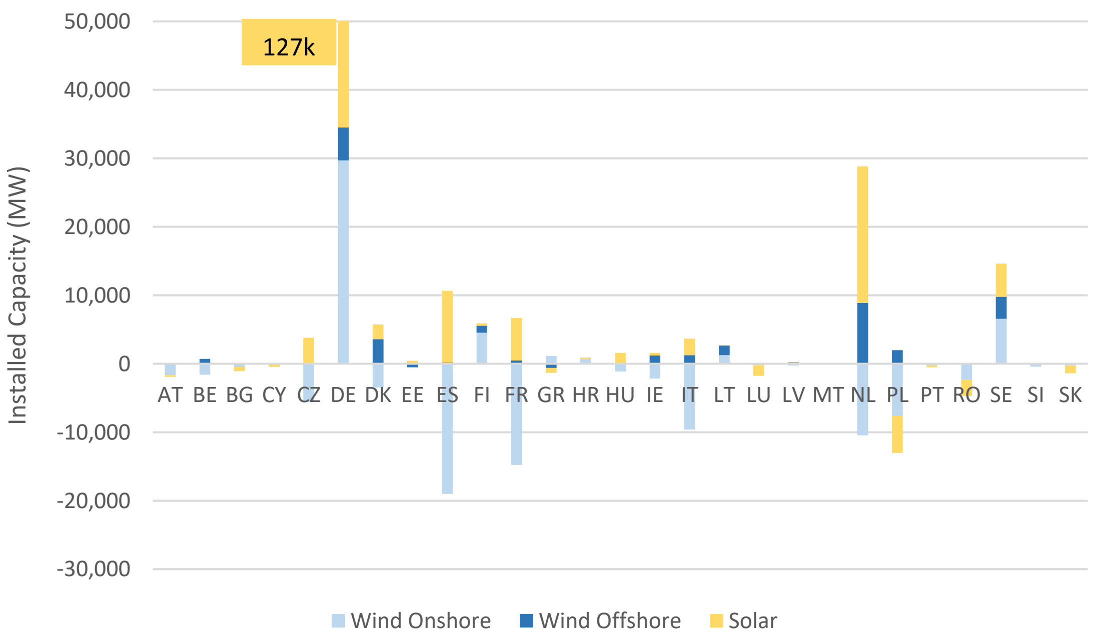


Figure 4 Differences in installed renewable capacity between ERAA 2022 and the European Commission's fit-for-55 scenario for 2030



The above figures show the differences per technology between ERAA 2022 and the European Commission's fit-for-55 scenario. Figure 5 and Figure 6 below treat all technologies as equivalent. Figure 5 shows the difference in total installed renewable capacity between the two scenarios and Figure 6 shows the total installed renewable energy capacity in ERAA 2022 as a share of the installed capacity in the fit-for-55 scenario.

While these figures are for illustration purposes only, they demonstrate clearly that for a significant number of Member States the assumed installed capacity of renewable energy is lower than what would be required in a fit-for-55 scenario. On Figure 5, a negative number indicates a deficit of installed renewable capacity and a positive number a surplus of total installed renewable capacity in ERAA 2022. Similarly, on Figure 6 the gap between the blue or green bars and the 100% horizontal line indicate how far a Member State is from achieving the fit-for-55 trajectory based on the European Commission's scenario. For bars that are higher than the 100% horizontal line, the difference indicate the level of renewable capacity surplus for each year examined. As shown on Figure 6, the majority of Member States are below the 100% line to a greater (e.g. Luxemburg, Slovakia and Romania) or lesser extent (e.g. Portugal, Belgium and Ireland).

Figure 5: Difference in total installed renewable capacity between ERAA 2022 and the European Commission's fit-for-55 scenario for 2025 and 2030

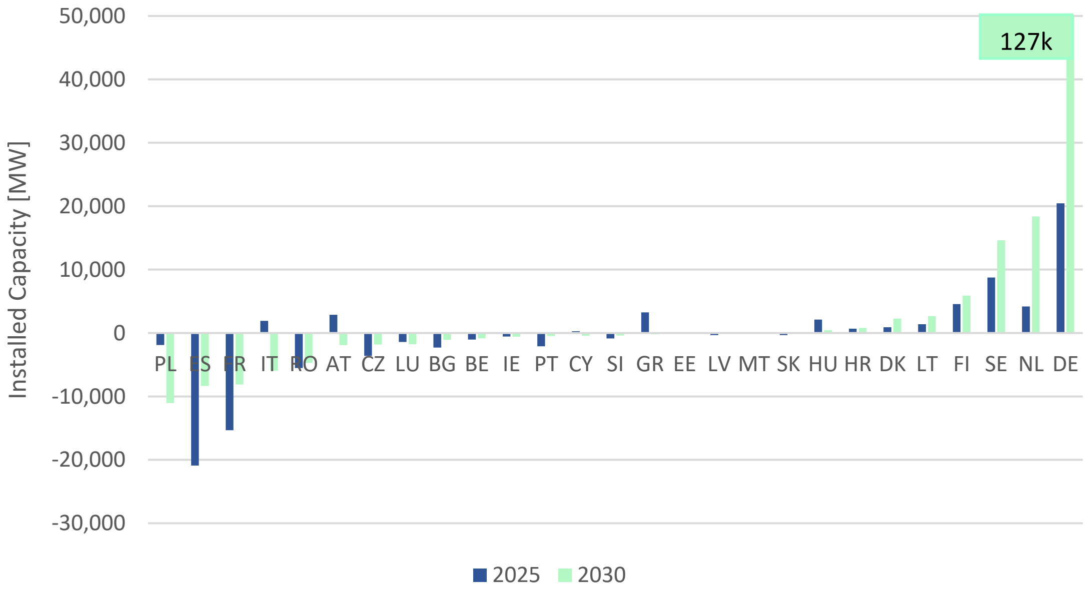
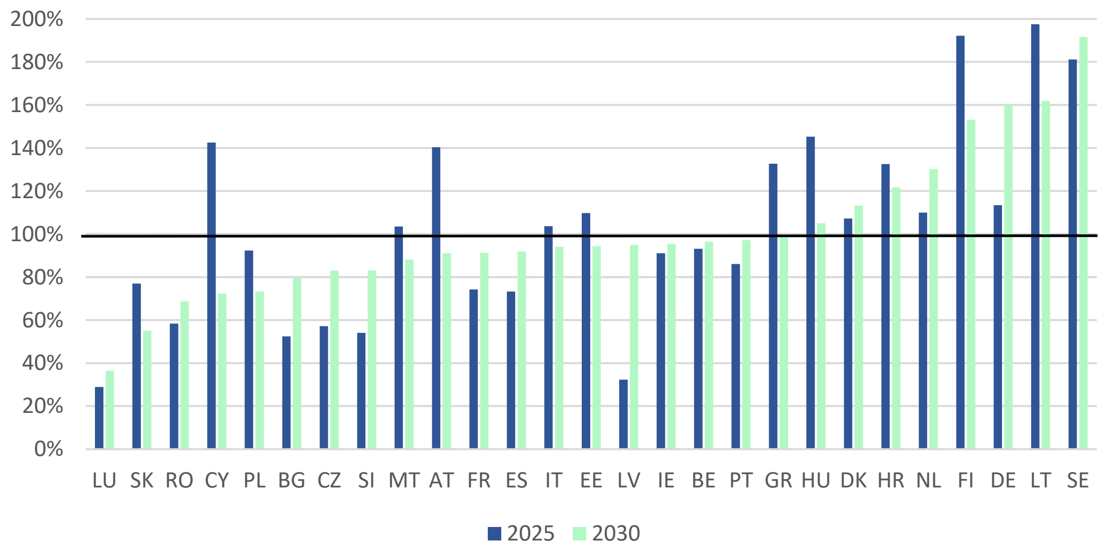


Figure 6: Relative differences in total installed renewable capacity between ERAA 2022 and the European Commission's fit-for-55 scenario for 2025 and 2030



From the above, ACER concludes that ERAA 2022 is significantly misaligned with the fit-for-55 objectives for renewable energy for a significant number of Member States, meaning that the assumptions for installed renewable capacity are lower than what would be required to meet the fit-for-55 objectives.

3. Economic viability assessment

3.1. Introduction

The purpose of the economic viability assessment (EVA) is to assess economic decisions about entry and exit of capacity resources in the electricity market, based on expected revenues and associated costs. Similarly to ERAA 2021, ERAA 2022 formulates the EVA as an optimisation problem that minimises total (fixed and operating) system costs, including the costs of energy non-served over the whole study period.

The European Network of Transmission System Operators for Electricity (ENTSO-E) has implemented a number of improvements in the EVA model, addressing some of the concerns raised in ACER's ERAA 2021 Decision and taking into account ACER's recommendations. However, the significant differences between the adequacy risk indicators of the EVA (investment model) and those stemming from the economic dispatch (risk model) indicate a persistent inconsistency between the two models.

The Report describes the methodology of the EVA in Annex 2 (Chapter 10) and presents the results of the EVA in some detail in Annex 3. In addition and upon ACER's request, ENTSO-E provided ACER with clarifications regarding the methodology and supplementary data regarding the adequacy risk indicators of the EVA and economic dispatch model runs without the implementation of curtailment sharing.[7]

This chapter examines the implementation of the EVA focusing on the consistency between the EVA and the economic dispatch model (section 3.2), and some other key elements (section 3.3)

3.2. Consistency between the economic viability assessment and the economic dispatch models

ACER's ERAA 2021 Decision emphasised the need for consistency between the adequacy risks resulting from the EVA and those resulting from the economic dispatch model.[8] Comparison between the loss of load expectation (LOLE) indicator from the EVA and from the economic dispatch model (Figure 7) reveals significant differences, with systematically higher LOLE in the economic dispatch. This indicates that the inconsistency between the two models remains.

The LOLE values of the EVA model are generally low. For the target years 2025, 2027 and 2030, the LOLE exceeds 3 hours in 3, 2 and 5 bidding zones respectively. In the economic dispatch model the number of bidding zones with LOLE higher than 3 hours per year is 15, 10 and 10 for the same target years respectively. The differences are large for some bidding zones. For example in Germany the LOLE in the economic dispatch is more than four times higher in 2025 and 2027 and more than two times higher in 2030 than the LOLE in the EVA.

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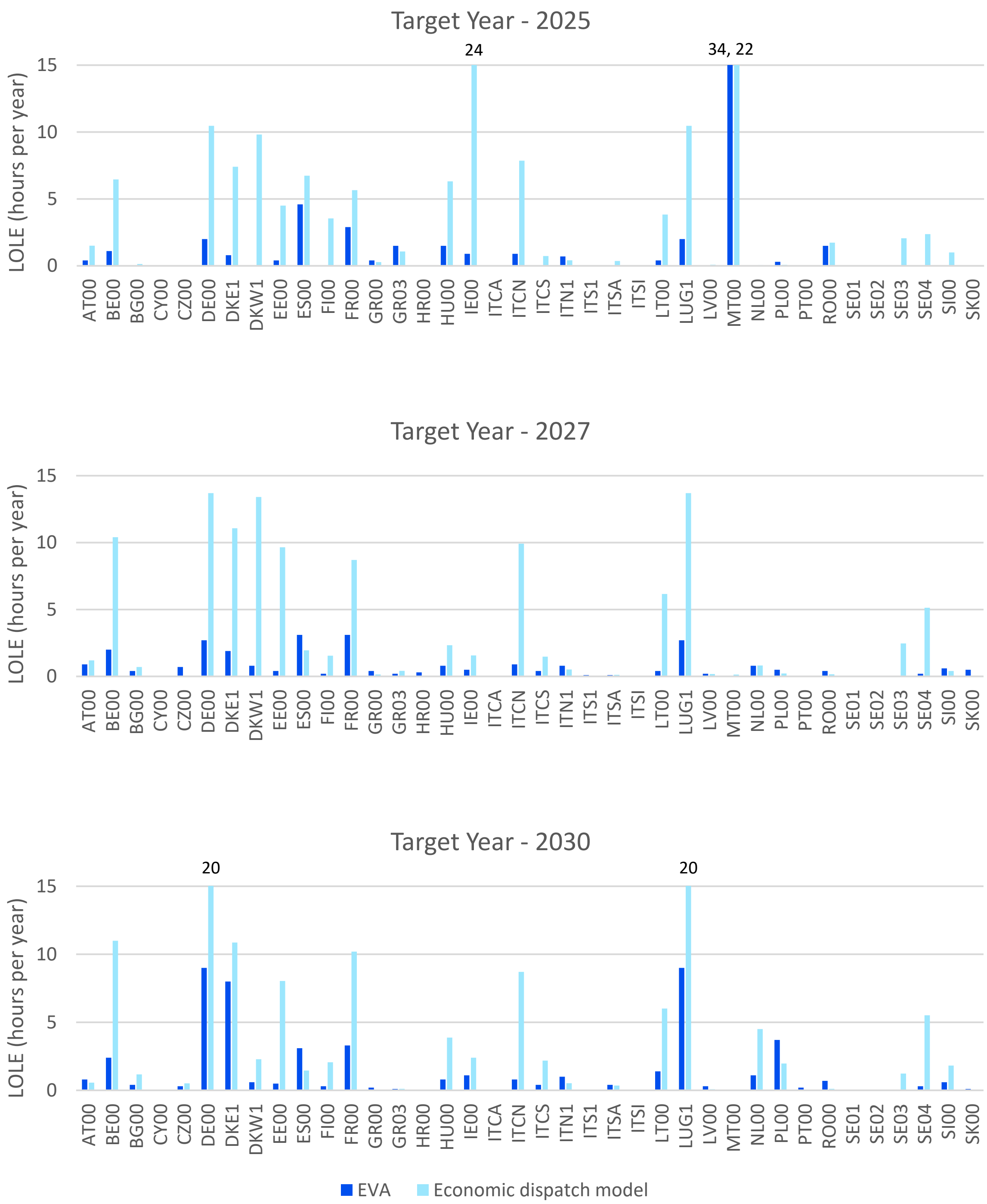
[7] The LOLE and expected energy not served (EENS) indicators of the economic dispatch model with and without the implementation of the local matching and curtailment sharing elements, and the EVA can be found on Table 3 and Table 4 in the Appendix.

[8] Article 6(6) and Article 6(9) of the ERAA methodology require that the EVA relies on the results of the economic dispatch to assess economic decisions. In this way consistency between the two models is ensured.

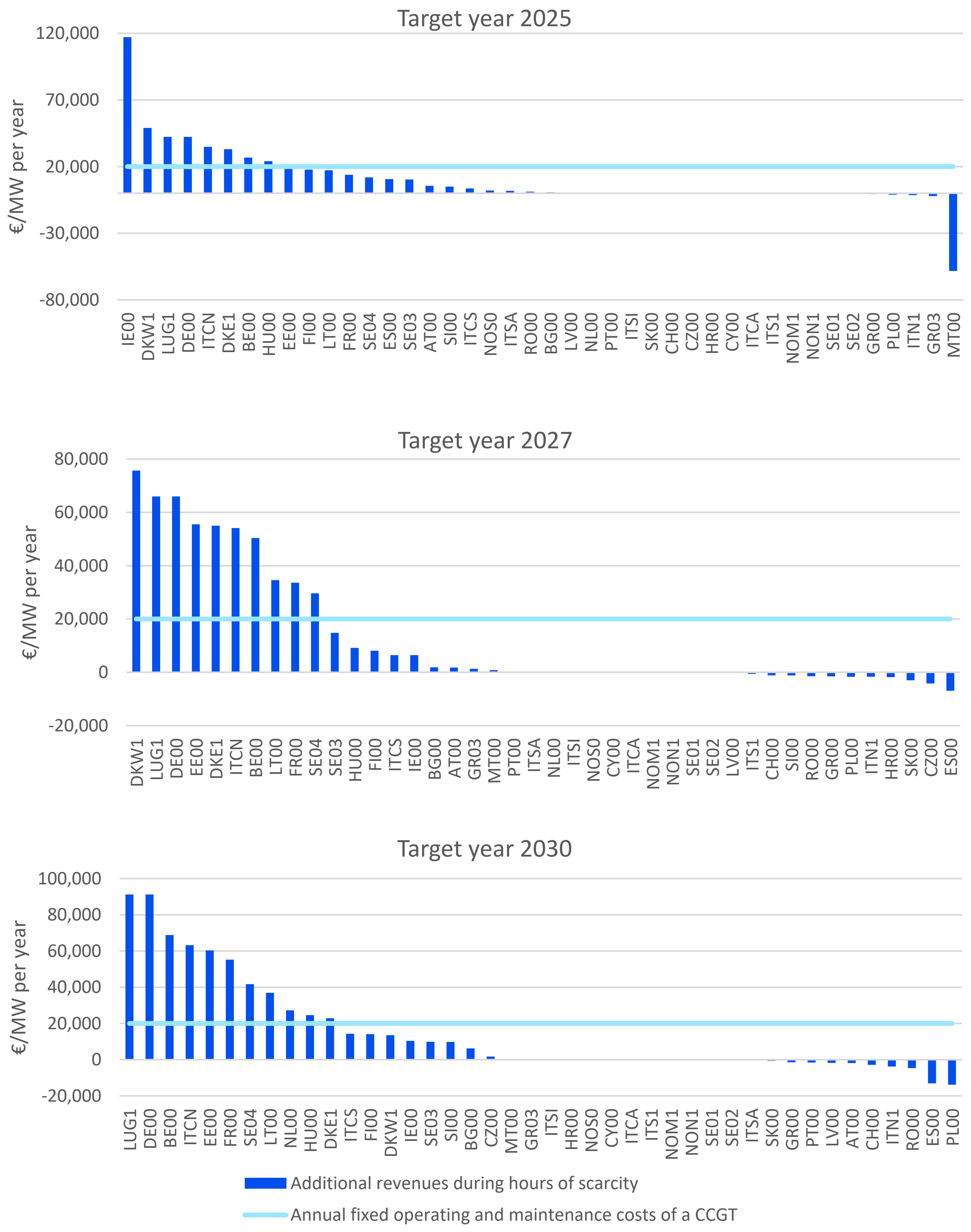
Figure 7: Comparison of LOLE between the EVA and the economic dispatch models – Target years 2025, 2027, 2030



These differences in the risk indicators suggests that the EVA does not estimate the economically optimum resource capacity in a way that is compatible with the assumptions and features of the economic dispatch model. For illustrative purposes, Figure 8 shows the revenues of resources during the additional hours when capacity does not meet demand in the economic dispatch model compared to the EVA (negative values refer to cases when the LOLE in the EVA is higher than in the economic dispatch). In a considerable number of modelled zones these revenues are significant. Hence, if the

EVA reflected the risks of the economic dispatch model properly, it would lead to different economic decisions than the ones actually used in the EVA in terms of either decommissioning of existing assets or commissioning of additional resources. These decisions would result in more capacity in the system, which would in turn reduce the LOLE.

Figure 8. Difference in annual revenues at times of scarcity between the economic dispatch model and the EVA. – Target years 2025, 2027, 2030

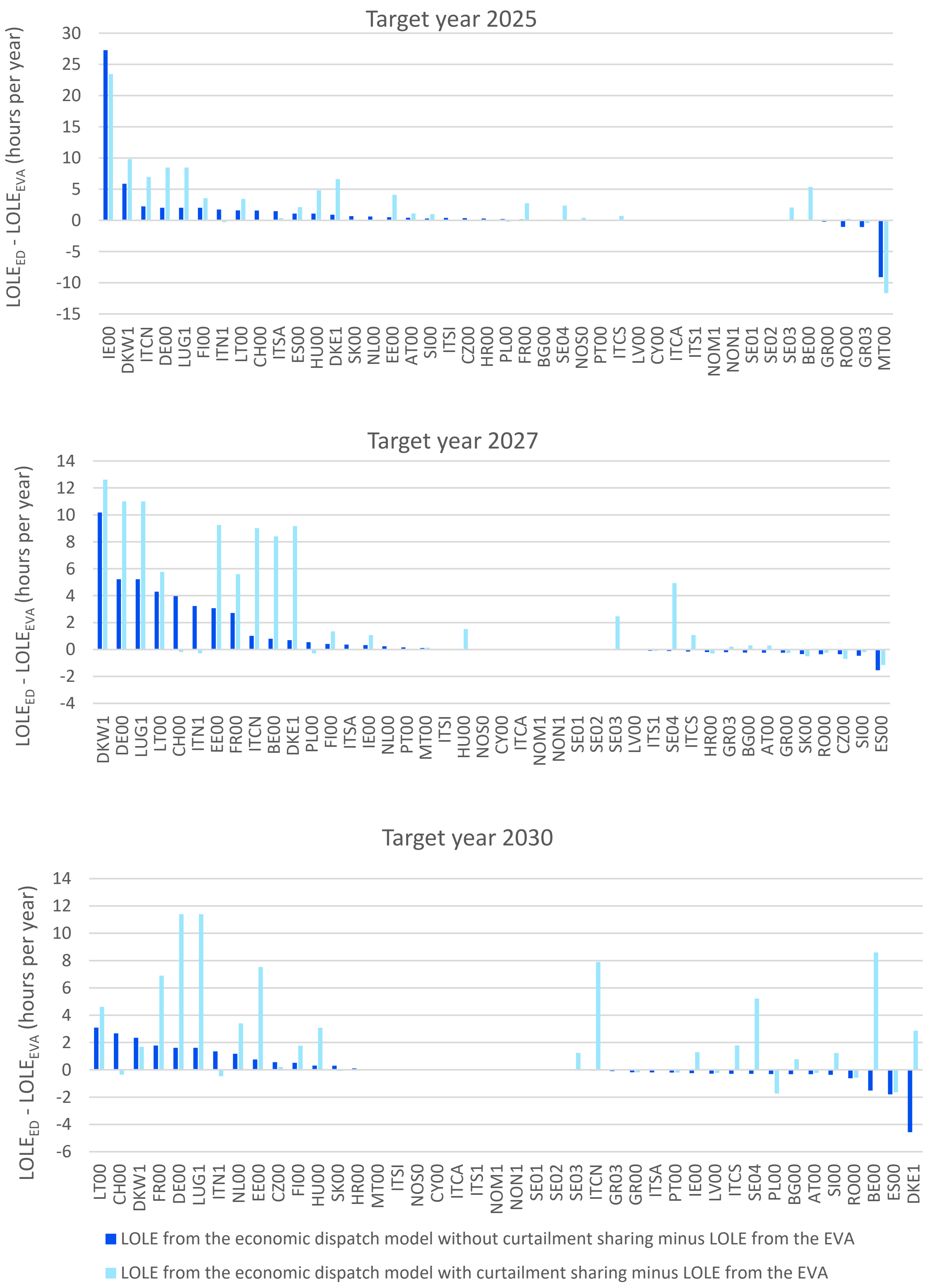


A priori, this difference in the results of the EVA and the economic dispatch is due to the several simplifications[9] introduced into the EVA to cope mainly with the complexity and computational needs of the model and the inclusion of modelling features in the economic dispatch that are not reflected in the EVA. While the Report describes to some extent the necessary simplifications introduced in the EVA model, it does not reflect on how these simplifications affect the consistency between the EVA and the economic dispatch model. Further analysis indicates that the implementation of the local matching and curtailment sharing features in the economic dispatch is a key driver for the resulting inconsistencies.

Figure 9 presents the difference of the LOLE values resulting from the economic dispatch model and the EVA for the all three target years respectively, but considering two versions of the economic dispatch model, with and without the curtailment sharing and local matching features. The comparison shows that the introduction of these two features increases the differences in LOLE values for most modelled zones, and hence, further exacerbates the inconsistency problem between the EVA and the economic dispatch model.

[9] Similar to the ERAA 2021 the simplifications include the limited number of climate years, the modelling of planned maintenance for new generation capacity and of forced outages for all resources and the lack of flow based market coupling. In ERAA 2022 there is also the reduction of the hourly granularity to 18 daily blocks, the break-down of the decision horizon to sets of two or three years and the omission of the curtailment sharing and local matching features.

Figure 9: LOLE differences between the LOLE from the economic dispatch model with and without the implementation of local matching and curtailment sharing, and the EVA. – Target years 2025, 2027, 2030



Article 7(9)(d) of the ERAA Methodology allows for the introduction of curtailment sharing and local matching, in line with CACM Regulation, to appropriately reflect price formation. The single price-coupling algorithm (EUPHEMIA) includes these two features in order to provide a more equitable distribution of resources during periods of supply deficit. The local matching constraint ensures that a bidding zone fully uses the available local supply and thus, for example, does not export electricity when the said bidding zone is in shortage. The curtailment sharing addition seeks to equalize resource allocation between bidding areas that are simultaneously in a supply deficit.[10] This may lead to the sharing of the deficit of one zone by more, usually neighbouring, zones, thus increasing the overall adequacy risks in LOLE terms. In ERAA 2022, ENTSO-E implements the curtailment sharing in a different way than the EUPHEMIA algorithm.[11] Based on the information provided, ACER was not able to validate some of the options of ENTSO-E regarding the implementation of the curtailment sharing and verify whether the way curtailment sharing and local matching is implemented in ERAA is aligned with the EUPHEMIA algorithm.[12]

3.3. Other topics

The following section examines some of the key developments of the EVA in ERAA 2022 compared to ERAA 2021.[13]

3.3.1. Stochastic formulation

In ERAA 2022 the EVA is formulated as a stochastic optimisation problem. This means that the total cost that the model seeks to minimise is the sum of the fixed and operating costs, including the cost of energy non-served, calculated under various climatic conditions and weighted over the probability of occurrence of these conditions. In principle, this formulation is a more realistic representation of the decision making process by market players than the deterministic approach used in ERAA 2021. In this sense, ENTSO-E's efforts towards this direction constitute a major improvement.[14]

At the same time, stochastic models are particularly complex models. This leads to a number of simplifications that may potentially reduce the value of the stochastic formulation. ENTSO-E made an effort to include all seven years of the examined period 2024 – 2030 in the EVA, as opposed to only three target years (2025, 2027 and 2030) considered in the economic dispatch.[15] This made the EVA

[10] For more details see the description of curtailment sharing and local matching in EUPHEMIA here.

[11] The description of these two features are presented in section 11.9 of Annex 2 of the Report.

[12] For example regarding the implementation of the curtailment sharing outside the CORE region or the definition of the curtailment ratio as described in section 11.9.4 of Annex 2 of the Report. Also, in principle, when implementing the curtailment sharing the total amount of curtailed energy is expected to remain at the same level or slightly increase compared to a situation without curtailment sharing. This is because the solution with curtailment sharing leads to sub-optimal welfare, i.e. higher costs in this case, compared to the one without the curtailment sharing. The main driver for these higher costs is normally curtailed energy as the unit cost of it (maximum clearing price) is significantly higher compared to the other cost components. Counterintuitively, total EENS resulting from the model with curtailment sharing slightly decreases compared to the model runs without the curtailment sharing, for target years 2025 and 2030

[13] A number of methodological aspects have remain unchanged from ERAA 2021. The EVA considers demand, hydro and storage operation in the same way as in the economic dispatch. The different bidding zones are coupled using the NTC approach for all capacity calculation regions. Planned maintenance of existing units is modelled in the same way as in the economic dispatch model, while for new candidates a dynamic maintenance rate per technology is used. Forced outages are also modelled in a deterministic way via a uniform derating factor per technology

[14] Due to the simplifications introduced in the EVA the stochastic events affecting the cost structure are restricted to climate conditions which, in the end, are represented by only three climate years. Forced outages are not considered stochastically.

[15] ENTSO-E still does not cover the full ten year period required by the Electricity Regulation. The selection of target years is discussed in Annex 2, Section 10.1.8 of the Report. ENTSO-E collected complete data for the years 2024, 2025, 2027 and 2030.

model too difficult to solve in a single run, hence a reduction of the decision horizon from the full seven years into five overlapping steps was necessary.[16] However, this leads to myopic decisions, as every time step is considered in isolation from the subsequent ones. As ENTSO-E suggests, this formulation effectively limits the scope for the model to consider (de)mothballing decisions. Such a limitation is particularly relevant because mothballing/de-mothballing is cheaper than investing in new capacity.[17] Another possible impact of this approach is the decommissioning of generation capacity in the initial steps of the period followed by extensive investment in new capacity in the last step, observed in the results of the EVA.[18] This kind of model reaction may have an impact on the adequacy indicators as it can affect the available capacity in the system throughout the study period.

3.3.2. Choice of representative climate years

Similar to ERAA 2021, ENTSO-E had to reduce the number of climate years in the EVA to cope with computational complexity. ERAA 2022 introduces a new method for identifying a set of representative years. Instead of relying purely on statistical properties, the new approach uses the economic dispatch model to calculate the total system cost for all climate years.[19] It then uses this information to formulate clusters of climate years, and eventually choose representative climate years from these clusters, to be used in the EVA.

Conceptually the new approach leads to better consistency between the EVA, which uses representative climate years, and the economic dispatch model, which uses all available climate years. Figure 10 shows the differences in LOLE between the economic dispatch model and the EVA in ERAA 2021 and ERAA 2022. For comparability reasons the ERAA 2022 results of the economic dispatch model without the curtailment sharing attributes and for target year 2025 are used.[20] The figure indicates that the resulting differences between the LOLE values from the economic dispatch model and the EVA are significantly lower in ERAA 2022 compared to ERAA 2021.[21]

The differences between the LOLE from the economic dispatch model and the EVA show that while in general they are relatively small, there are still some modelled zones where the differences are exceptionally high (e.g. IE00, MT00, DKW1). These differences may suggest that the clustering methodology works well for the system as a whole but the chosen years may not be representative for all zones of the system. This could relate to the limited number of years that were used in the end (three) or to inherent characteristics of the clustering methodology.[22] The primary purpose of the ERAA is to identify adequacy concerns that will inform Member States on the corrective actions they may need

For the intermediate years 2026, 2028 and 2029 and for unavailable data (NTC, CHP revenues and hydro inflows), the EVA uses either data from the latest year available or through linear interpolation.

[16] These five steps comprise of an initial three year step followed by four consequent two year steps with a one year overlap.

[17] See analysis under Table 4 on page 10 of Annex 3 of the Report. Notably the full cost of mothballing and de-mothballing is a fraction of the investment cost in new assets. For open cycle gas turbines this cost is 20k Euro/MW compared to 537k Euro/MW for new investment. For combined cycle gas turbines the costs are 21k Euro/MW and 593k Euro/MW respectively.

[18] For example as depicted in table 4 of Annex 3 of the Report, in Germany more than 30GW of thermal capacity are decommissioned in the first three years of the study period (Steps 1 and 2) while 32 GW are invested in the last three years of the seven year period (Steps 4 and 5).

[19] The economic dispatch model of the target year 2030 was used in ERAA 2022.

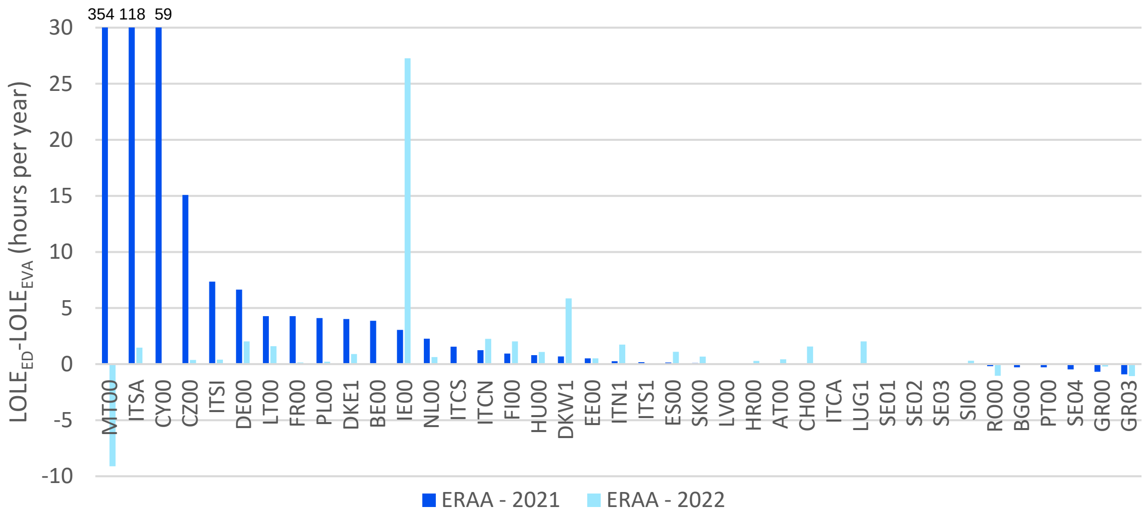
[20] The economic dispatch model of ERAA 2021 does not include the curtailment sharing and local matching elements, while the EVA was implemented only for the target year 2025.

[21] Improvements in other features of the model may also play a role. However, as per discussions with ENTSO-E the choice of the climate years seems to be the main source of inconsistency between the EVA and the economic dispatch model (prior to implementation of the curtailment sharing and local matching).

[22] One reason for this caveat could be the fact that big modelled zones weight more in the total system cost than smaller ones. If there is a mismatch of the climate year effect between big and smaller zones, the new method will choose years that are not representative for the latter.

to adopt. Hence, it is important that the ERAA offers a representative assessment for all modelled zones.

Figure 10: Difference in LOLE between the economic dispatch and the EVA in ERAA 2021 and ERAA 2022 for the target year 2025.



Note: For comparability the ERAA 2022 results of the economic dispatch model without the curtailment sharing attributes are used.

3.3.3. Decision variables

ERAA 2022 introduces new investment decisions compared to ERAA 2021. On top of the commissioning and decommissioning of thermal units, the EVA now considers the options of mothballing and de-mothballing, life extension of some gas and coal generation assets, as well as new investments in storage[23]. In addition, combined heat and power (CHP) units may exit the market based on economic evaluation taking into account revenues from heating services[24]. The EVA therefore covers largely the provisions of Article 6(7) of the ERAA Methodology.[25]

3.3.4. Cost parameters

The EVA calculates total costs taking into account (annualised) capital cost (CAPEX) and fixed operating and maintenance (FOM) costs, as well as operating costs[26], including the cost for energy not served (ENS).[27] Article 6(6)(a) of the ERAA methodology requires that cost assumptions in the EVA are consistent with the assumptions used for the calculation of the cost of new entry (CONE) or cost or renewal and prolongation (CORP), where applicable. Where possible ERAA 2022 uses cost parameters stemming from the relevant Member State studies.[28] For the rest of the modelled zones ERAA 2022 uses default values for each technology calculated as the average of the relevant available data from

[23] Renewable energy sources and nuclear generation technologies are considered as being mainly driven by policy decisions.

[24] Based on the reported results it is not clear whether the model resulted in any CHP units' exit decisions.

[25] At the same time, other modelling choices, i.e. the breakdown of the time horizon, limit the scope of the mothballing/de-mothballing and life extension decision variables. Considering that these options are much cheaper than new investments this could have an impact in the final capacity stock.

[26] Including variable operating and maintenance costs (VOM), fuel costs and cost for CO_2 emission allowances.

[27] ERAA 2022 assumptions on the cost of ENS, i.e. the maximum clearing price, are further assessed in section 3.3.6.

[28] According to Article 5(10) of the ERAA Methodology, where possible, economic parameters in ERAA shall be identical to the best estimates used in the most recent calculations by Member States of the cost of new entry and cost of renewal and prolongation of the lifetime of generation assets.

these national studies.[29] Notably, ERAA 2022 uses lower investment costs for combined cycle gas turbine units compared to ERAA 2021[30]. At the same time the investment cost of open cycle gas turbine units is higher than in ERAA 2021 and higher than all of the relevant reported CONE values, except one.[31]

3.3.5. Investment risks

The EVA uses annualised costs, which reflect a resource's fixed annual costs (including investment and fixed operating costs), augmented with a margin to account for the cost of capital and the (technology specific) investment risks. Essentially, this means that investors require this level of additional revenues as a minimum, on top of recovering their costs, to invest in a technology. In ERAA 2022 this margin is represented by hurdle rates consisting of the weighted average cost of capital (WACC) and a hurdle premium reflecting the various risks of market participants. Similar to the cost parameters ERAA 2022 uses Member State specific WACC values where possible and default values otherwise. At the same time, ERAA 2022 uses uniform hurdle premiums per technology for all modelled zones, based on the same estimates for Belgium that were used for ERAA 2021.[32] These estimates are based on certain inputs and assumptions that are neither necessarily uniform across the EU, nor consistent with the assumptions of ERAA 2022.[33]

3.3.6. Maximum clearing price

According to Article 7 of the ERAA methodology, paragraphs 7(8) and 7(9), the assessment needs to reflect price formation during hours when scarcity occurs in a modelled zone, i.e. during periods of Energy Non-Served. The ERAA methodology further specifies that the price during scarcity periods should equal the harmonised maximum clearing price in line with Articles 10 of the Electricity Regulation, unless Member States apply any indirect restrictions to wholesale price formation.

ERAA 2022 assumes that electricity prices at times of scarcity equal the maximum clearing price of the day-ahead market. This assumption applies to both the EVA and the economic dispatch models. ERAA 2022 assumes a maximum clearing price of 4 k€/MWh in 2022 that increases over time to reach 8 k€/MWh by 2030. The increase of the maximum clearing price is based on ex-ante modelling, given the complexity of modelling its dynamic increase within the ERAA, according to ENTSO-E.

ACER considers ENTSO-E's assumption on the maximum clearing price to be misaligned with the applicable regulatory framework. ERAA 2022 essentially defines the technical bidding limit of the day-ahead market as a universal maximum clearing price, and omits the intra-day and balancing energy

[29] Details provided in section 6.4 of Annex 1 of the Report

[30] In line with ACER recommendations in ERAA 2021 Decision and with the available CONE values.

[31] The default value for open cycle gas turbine is 537 k€/MW, higher than in ERAA 2021. This is merely due to an extreme cost (1250 k€/MW) reported by one Member State. If this outlier was not taken into account the average cost of an open cycle gas turbine would be around 450 k€/MW.

[32] The hurdle premium estimates are based on a methodology described in a report prepared for Elia, the Belgian Transmission System Operator (the report can be found here: https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20201030_200_report_professorboudt.pdf) The report includes a proof of concept implementation using information (inter alia) from Elia's 2019 Adequacy and Flexibility study. ERAA 2022 uses the report's hurdle rates for new and existing thermal units. For batteries a hurdle premium of 8.5% is used.

[33] According to the methodology any change of context, modelling setup or other factors such as market design may lead to different estimations of hurdle premiums. It is therefore necessary to assess consistency of the used hurdle premiums with the assumptions and context of each ERAA version.

markets and the applicable maximum clearing prices in them.[34] In reality however, when scarcity occurs, the real-time price equals the maximum harmonised clearing price and technical price limit (for balancing) in the respective timeframe (first the intra-day market and subsequently the balancing energy market).[35] Balancing responsible parties that anticipate the risk of having a negative imbalance during scarcity hours (i.e. have a deficit of supply compared to their demand), have an incentive to buy any electricity with a cost lower than the technical bidding limits in the respective timeframe. Imbalance prices are expected to back-propagate to the preceding timeframes, starting with intraday and day-ahead markets and ultimately forward markets, meaning that prices in all other timeframes should reflect an expectation of the imbalance price.[36] Moreover, the ERAA 2022 approach omits the fact that peaking resources that tend to operate for limited amount of hours, such as demand side response and open cycle gas turbines, rely on hours of high prices, or price spikes, to recover their capital costs.

The restrictive maximum clearing price used in ERAA 2022 is also contrary to the spirit of the Electricity Regulation. Recitals 23 and 24 of the Electricity Regulation put a renewed focus on short-term markets and scarcity pricing for ensuring security of supply. Article 10 of the Electricity Regulation prescribes there should be no maximum or minimum limits to prices, without prejudice to the application of technical price limits. Even when maximum technical bidding limits apply, the legal framework anticipates they should increase in a timely fashion to avoid restricting trade.[37] A restrictive maximum clearing price undermines security of supply as evidenced for example in ERAA 2021. For ERAA 2021, ENTSO-E run a sensitivity with a maximum clearing price equal to 3 k€/MWh, as opposed to 15 k€/MWh used in the central reference scenario. As a result, an additional 10 GW of thermal capacity was assessed to decommission compared to the central reference scenario.[38]

In ACER's view, the ERAA should consider the technical bidding limits of the day-ahead and intra-day markets in conjunction.[39] The higher intra-day technical bidding limit acts as the effective maximum

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[34] ACER has recently approved changes in the methodologies for automatically increasing the maximum price limit in the spot markets, in case of price spikes. The new rules update the conditions leading to an increase of the maximum price limits and will lead to fewer and smaller adjustments of them. For more information, see ACER's decision on the harmonised maximum clearing price in the single day-ahead market and intra-day market.

[35] Ultimately, the real-time market price in case of scarcity will equal the technical bidding limit in the balancing energy market, which is equal to 15 k€/MWh until July 2026. After that, the technical bidding limit applied in the balancing energy market increases to just under 100 k€/MWh. For more information, see ACER's Decision (03-2022) on the Amendment to the Methodology for Pricing Balancing Energy and Cross-Zonal Capacity Used for the Exchange of Balancing Energy or Operating the Imbalance Netting Process.

[36] This is evident for example in the forward prices for France this winter. Forward prices for winter 2022-2023 delivery rose to unprecedented levels, due to the high levels of scarcity risk caused by the expected unavailability of a significant number of nuclear power plants.

[37] In addition, the Electricity Regulation determines that the limits on maximum clearing price should take into account the maximum value of lost load (VOLL). ACER notes that the single VOLL estimated pursuant to Article 23(6) of the Electricity Regulation varies between around 4 and 69 k€/MWh across Member States. For more information, see ACER's Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy.

A maximum clearing price of 4 to 8 k€/MWh as assumed in ERAA 2022, essentially equates to a reliability standard that is significantly less restrictive than the one estimated by most Member States. For example, France has established a reliability standard of 2 hours LOLE per year, based on a single VOLL value of 33 k€/MWh. If the assumed VOLL value was between 4 and 8 k€/MWh, the resulting reliability standard would be in the range of around 7.5 and 15 hours LOLE per year.

[38] For more information, see ENTSO-E's European Resource Adequacy Assessment 2021, Annex 2 – Detailed results, section 7.

[39] Unlike the day-ahead and intra-day markets, the single balancing energy market is still largely under development. Different rules apply for Balancing Responsible Parties and Balancing Service Providers across Member States. For this reason, ACER believes it is appropriate to consider only the day-ahead and intra-day markets when determining the maximum clearing price for

clearing price for as long as this is higher than the day-ahead technical bidding limit, because it enables participants with greater opportunity costs (including operational and capital costs) than the day-ahead technical bidding limit to participate in the intra-day market. In ACER's view, the only justification for a maximum clearing price lower than the technical bidding limit in the intra-day market would be where restrictions to wholesale price formation are foreseen, pursuant to Article 7(9)(b) of the ERAA methodology. ACER notes that emergency measures applied in certain jurisdictions of Europe, such as the so-called Iberian exception, have a temporary nature. Moreover, ACER highlights that occasional price spikes are fundamentally different to the consistent high electricity prices that Europe has experienced during the energy crisis.

Moreover, ACER notes that the dynamic increase of the assumed maximum clearing price in ERAA 2022 appears significantly misaligned with the level of risks as estimated in the assessment. ACER expects that the technical bidding limit in the day-ahead market would increase more frequently and possibly exceed the current technical bidding limit in the intra-day market, thus leading to an overall increase of the maximum clearing price in ERAA 2022.[40]

the purposes of the ERAA until the integration of the single balancing market has further developed and rules across Member States have been further harmonised.

[40] This is without prejudice to the recently approved rules on the automatic price adjustment mechanisms in the day-ahead and intraday electricity markets. For more details, see footnote 34.

4. Cross-zonal capacities

4.1. Introduction

This section focuses on the approach to cross-zonal capacities in the ERAA 2022 central reference scenarios. The review of cross-zonal capacity covers the following topics:

- Network developments taken into account in the context of capacity calculation;
- Capacity calculation methodologies; and
- Compliance of cross-zonal capacities with the so-called minimum 70% target.

4.2. Network development

Pursuant to the Electricity Regulation, the ERAA must properly take into consideration the level of interconnection, interconnection targets, and real network development (requirements of Article 23(5)(m), Article 23(5)(b) and Article 23(5)(l) respectively). Article 3 of the ERAA methodology specifies that the assessment must reflect best estimates about the future state of the network based on the latest national development plans and ENTSO-E's Ten-Year Network Development Plan (TYNDP). Article 4 of the ERAA methodology specifies the modelling framework for the electricity network.

ERAA 2022 offers limited information about the assumed network development from 2025 onward. For the Core region in particular, ERAA 2022 applies the flow-based capacity calculation. The grid model used for the calculation of the flow-based domains is based on the assumed infrastructure for 2025 from the TYNDP 2020 National Trends scenario. ERAA 2022 uses the flow-based domains calculated for 2025 across all target years.

The ideal configuration for the calculation of flow-based domains is a single market model that includes the network. ERAA 2022 considers two separate models, a market model and a grid model. In such a case, consistency between the two models is important for a robust calculation of flow-based domains. Therefore the considered network must explicitly include:

- infrastructure developments within the capacity calculation regions where the flow-based calculation applies; as well as
- HVDC interconnectors tied to this perimeter, as the calculation implicitly models exchanges on interconnectors with regions where the NTC calculation applies.[41]

Table 1 presents relevant projects to the Core region that are scheduled for commissioning between the beginning of 2025 and end of 2030, in aggregated form per commissioning year. Table 5 lists these projects in detail.

[41] Regions where the NTC calculation applies should therefore reflect infrastructure developments on interconnectors shared with the capacity calculation regions where the flow-based capacity calculation applies.

Table 1: Projects to be commissioned between 1 January 2025 and 31 December 2030 in the Core region

Commissioning year estimated by the promoter	Sum of Transfer capacity increase A-B (MW)	Sum of Transfer capacity increase B-A (MW)
2025	5500	6500
2026	11325	11325
2027	6700	6700
2028	500	1000
2029	1000	1000
2030	2900	2900
Grand Total	27925	29425

Note: Projects impacting at least one Core Member State that have passed the permitting phase, and expected to be commissioned from 2025 onward.
Source: ENTSO-E - https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission

In the context of flow-based calculation, ERAA 2022 omits any infrastructure developments within the Core region over the period 2025-2030. ENTSO-E did not provide full transparency over infrastructure developments on NTC regions adjacent to the Core region over the period 2025-2030. ERAA 2022 details net import and export capacities used as input for NTC values for the target years 2025, 2027 and 2030, per Member State.[42] Evolutions in DE, FR, NL, BE and AT may suggest that some of the investments listed in Table 1 above are taken into account for the calculation of NTC values.

For the Core region, the economic dispatch model applies a flow-based approach, while the EVA model applies a NTC-based approach. Investments taken into account differ between the two approaches, which is a significant discrepancy between the EVA and the economic dispatch. Moreover, network developments are expected to increase cross-zonal capacities. By excluding some, ERAA 2022 overestimates the resource adequacy risks. ACER cannot quantify the extent of the risk overestimation. A first step would be for ENTSO-E to list planned network developments that are excluded from ERAA calculations.

4.3. Capacity calculation methodologies

4.3.1. Introduction

This section focuses on Flow-based capacity calculation, as ENTSO-E provided no calculation methodology for NTC capacity calculation. The compliance of the flow-based capacity calculation with the minimum 70% target is assessed in section 4.4.3.

Compared to NTC, flow-based capacity calculation aims at better reflecting the network constraints underlying cross-zonal exchanges. The flow-based approach relies on critical network elements (CNEs) with contingencies (CNECs) to describe the simplified simultaneous impact of cross-zonal exchanges on network elements. In line with ACER's decision on day-ahead capacity calculation in the Core capacity calculation region, the flow-based approach relies on the following, sequential steps:

1. The construction of a grid model to forecast the detailed grid behaviour (reflecting an expected market situation);

[42] See Figure 8 of Annex 1 – Input Data & Assumption

2. The definition of CNECs, i.e. network elements combined with contingencies, which will limit cross-zonal exchanges;
3. The definition of power transfer distribution factors (PTDFs), i.e. how each cross-zonal exchange affects flows on each CNEC;
4. The estimation of the remaining available margin (RAM), i.e. the share of the physical capacity of each CNEC available for cross-zonal trade; and
5. The validation of cross-zonal capacities, comprising a check of whether the calculated cross zonal capacities ensure safe operation of the grid, based on the detailed grid model. If not, the cross-zonal capacities are adapted accordingly.

On top of these steps, the ERAA includes two other steps, due to its forward-looking and probabilistic nature.

6. The definition of a few types of flow-based domains, which cover the main expected configurations of the power system; and
7. For each hour and Monte Carlo year, the selection of flow-based domains to use for market simulations.

4.3.2. Findings – clustering of FB domains

In the context of ERAA 2022, ENTSO-E provided more transparency over flow-based capacity calculation compared to ERAA 2021. In general, ACER acknowledges that flow-based principles are applied efficiently. Some methodological details, such as the clustering of flow-based domains, require further examination.

ENTSO-E clusters flow-based domains based on a k-medoids clustering methodology. The approach uses three weather years, meant to reflect the entire variability of renewable generation, demand and residual demand. The weather years serve to derive a number of clusters for winters and summers. As a next step, ENTSO-E conducts a systematic testing of the performance of the classification model.

For ERAA 2022, based on this evaluation, ENTSO-E concluded that the optimal number of clusters is two per season. Table 2 presents the identified cluster centres.

Table 2: Clustering of FB domains in ERAA 2022

Custer/season	Number of elements	Average distance to centroid	Centroid	Weekday
Summer1	8882	0.92	15/09/2001 01:00	Saturday
Summer2	4294	0.93	14/06/2001 21:00	Thursday
Winter1	7644	1.11	27/10/2001 06:00	Saturday
Winter2	5388	1.13	09/11/2001 14:00	Friday

ACER observes that the description of the clustering methodology lacks details. ENTSO-E should clarify the following aspects of the methodology: the “Random forest classification”, and the clustering step. ENTSO-E should ideally clarify the dataset used for the random forest classification model, and the so-called “confusion matrix”. Regarding the clustering step, ENTSO-E should provide more information about the detailed methodology to select three climatic years for defining the FB domain clusters, as well as the dissimilarity function and the distance metric used for the computation.

Related to the clustering methodology, the constraints introduced in the economic dispatch simulation model are more complicated in the context of flow-based calculations, compared to NTC ones. Therefore, the associated computational time is greater. The objective of the clustering is to reduce the number of domains from 8760 to 4. This reduction in domains in turn significantly reduces the computational burden of the flow-based market-coupling representation in the model. In order not to lose information through the reduction, each cluster centroid should accurately represent each domain they aggregate.

ACER observes that the cluster centroids resulting from the methodology applied by ENTSO-E may not be sufficiently representative of all aggregated domains. Firstly, three of the four centroids are representative of an inter-seasonal period. Winter conditions (high demand during times of low temperatures) or summer (high PV generation) are not represented. Secondly, for each centroid, the methodology suggests a selection of hours that may not be representative of the overall set of possible conditions. For example, both summer centroids feature hours during night time, without solar PV generation. Ideally, at least one of the summer centroids should include one hour with a high solar infeed.

ACER concludes that considering only 4 different flow-based domains may be insufficient to represent all conditions in the grid over the entire 35 weather years. ACER therefore believes that ENTSO-E should consider increasing the number of clusters for future ERAAs.

ACER suggests considering a potentially more robust approach followed by Elia.[43] As a first step, Elia's approach groups hours in a year based on the season (i.e. winter or summer) the type of day (i.e. week-day or weekend) and the period of the day (i.e. day or night). As a second and final step, the approach selects representative hours for each of these groups. The first step may better ensure that the outcome is more representative than the clustering outcome in ERAA 2022.

4.4. Cross-zonal capacities and compliance with the minimum 70% target

4.4.1. Introduction

The Electricity Regulation introduced a minimum 70% target for capacity available for cross-zonal trade.

In 2019, ACER, regulatory authorities and the Transmission System Operators (TSOs) issued a recommendation for implementing the minimum margin available for cross-zonal trade (hereafter 'the Recommendation').[44] The Recommendation aims to ensure a harmonized implementation, monitoring and compliance assessment of the minimum 70% target. The Recommendation provides a concrete way to implement and monitor the achievement of the 70% target across the EU. In particular, the Recommendation clarifies the calculation of the margin available for cross-zonal trade (MACZT).

ACER's analysis of the compliance of cross-zonal capacity used in the ERAA 2022 with the minimum 70% target is based on this Recommendation, and on the results of the MACZT monitoring that ACER conducted for the year 2021.[45] ACER monitors the minimum 70% target on the bidding-zone borders within and between the EU's Member States, which should be met for all hours throughout the year.

[43] See Adequacy and Flexibility Study for Belgium 2022-2032, Elia, page 100.

[44] Recommendation No 01/2019 of the European Union Agency for The Cooperation of Energy Regulators of 08 August 2019.

[45] To the extent possible, i.e. when sufficient data allows for it.

The Electricity Regulation allows Member States to adopt transitory measures, i.e. action plans or derogations, to gradually reach the minimum 70% target. Action plans expire by the end of 2025, and include a gradual linear increase in cross-zonal capacity from the beginning onwards. As a result, these action plans are likely to have a limited (if any) impact on cross-zonal capacity in 2025. Depending on national regulatory authorities' decisions, derogations may apply in 2025 (or beyond).

The ERAA 2022 does not explain if any derogation to the minimum 70% target has been considered, and ACER expects that derogations will disappear once coordinated security analyses, and re-dispatching and countertrading, are fully implemented.[46] Consequently, ACER's review considers the 70% as the minimum target for all EU borders. Below, ACER presents its analysis to assess the levels of margin regarding the 70% minimum target.

The section focuses on the cross-border capacity on AC borders and assesses compliance with the minimum 70% target.[47, 48]

4.4.2. NTC compliance with the minimum 70% target

Figure 11 shows whether NTCs for 2025 of the ERAA could allow TSOs to meet the 70% minimum target for each AC border.

The analysis of NTCs reveals that for a significant number of borders the minimum 70% target would very likely, or likely, not be met, if the NTCs of 2025 reach the level assumed in the ERAA 2022 model. On some borders, NTCs actually decrease in 2025, as compared to 2021.[49] Lower cross-zonal capacities are expected to lead to higher resource adequacy risks in principle.

Besides, on some borders, the increase in NTCs may stem from additional interconnectors on the borders, rather than increased MACZT on existing interconnectors, and may thus not necessarily mean higher levels of margin. Additional interconnectors are foreseen for example for Germany-Denmark, Germany-Poland, Bulgaria-Romania and Austria-Italy.

The analysis contradicts some of TSOs' answers to ENTSO-E's survey for ERAA 2022,[50] suggesting that the assumed NTCs meet the 70% minimum target. ACER is not in a position to challenge methodological approaches, as the Report does not provide any information on them. ACER highlights that transparency has not improved on this topic since ERAA 2021.

[46] The methodology is currently being implemented in most of the regions and expected to be fully implemented by the end of 2024. For more information see ACER's webpage on Redispatching and countertrading.

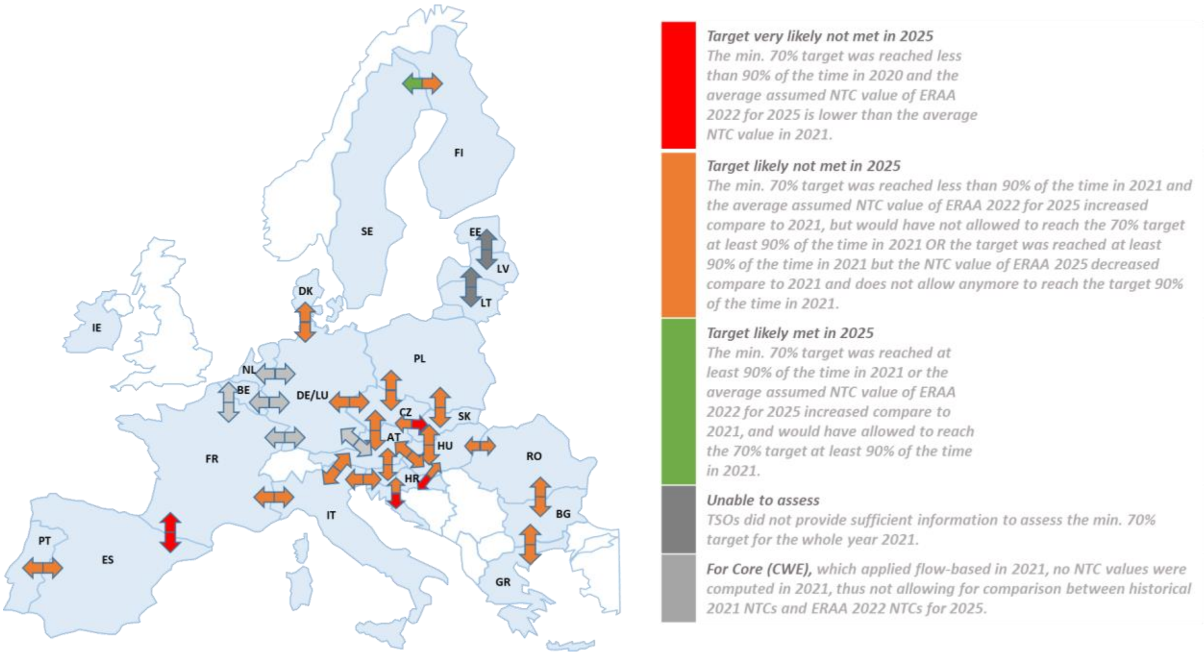
[47] The analysis of DC borders revealed full compliance in the context of ERAA 2021. For a complete review of DC borders, see ACER's ERAA 2021 Decision.

[48] For a detailed description of ACER's methodology for the assessment of NTC compliance with the 70% target, see Annex I of ACER's ERAA 2021 Decision, section 2.4.5.2.

[49] For more detailed information see Table 6 of Appendix 1.

[50] For more information, see Annex 1 of ERAA 2022 on the input data.

Figure 11: ACER's assessment of the 70% minimum target based on the ERAA 2022 NTC assumptions



Notes:
1) The assessment above does not consider allocation constraints.
2) When capacity calculation is not coordinated, the target being reached "at least 90% of the time" means reached at least 90% of the time by each of the two TSOs on the border. Source: ACER calculations based on the ERAA 2022 and on TSOs data provided in the scope of the ACER MACZT reports for 2021.

4.4.3. Flow-based compliance with the minimum 70% target

For the flow-based capacity calculation that applies to the Core capacity calculation region (CCR) in the economic dispatch, ACER understands that compliance with the 70% minMACZT rule is ensured following two steps according to ERAA 2022:

1. First, net positions of all bidding zones (within and outside of the Core region) are set to zero; and
2. Second, ENTSO-E analyses for each Critical Network Element and Contingency (CNEC) whether the remaining available margin (RAM) amounts to 70% of the Fmax of each CNEC. If this condition is not met, the RAM is increased until the sum of the respective flow and reliability margin reaches a maximum of 30% of the Fmax for all CNECs.

ACER concludes that provided the above described two-step approach is followed flow-based compliance with the minimum 70% target is correctly reflected in the flow-based calculations in the context of ERAA.

5. Demand side response

5.1. Introduction

Article 4(3)(c) of the ERAA methodology requires that the ERAA considers both explicit and implicit demand-side response (DSR).[51] This includes both traditional peak shaving and demand shifting. The section below examines ERAA 2022 regarding each type of DSR.

5.2. Explicit demand-side response

For explicit DSR, ERAA 2022 uses a similar approach to last year's assessment.[52] As a first step, the TSOs assess the level of DSR expected to be available in the context of the National Estimates scenario. This level of exogenously determined DSR is assumed available to contribute to resource adequacy (i.e. it is not subject to an economic viability test), within certain technical limitations.[53] As a second step, ERAA 2022 assesses the maximum potential for DSR for each Member State.[54] The difference between the maximum potential for DSR and the TSOs' exogenously determined DSR levels determines the additional DSR potential that could enter the market. This additional DSR potential is considered in the EVA and invested into, if it contributes to minimising the overall costs of the power system.

Figure 12 shows the total installed DSR capacity available for each Member State and target year, consisting of the TSOs assumed DSR levels (National Estimates) and the additional DSR invested into through the EVA (Post-EVA). It is evident from the figure that the approach to DSR is heterogeneous across Member States. The majority of the TSOs (16 in total) assume there will be DSR available in the National Estimates scenario, while the rest assumes there will not be any installed DSR capacity. The TSOs' assumptions represent the bulk of future DSR levels (e.g. for 2027, the TSOs' assumptions account for around 76% of all installed DSR assumptions).[55] In addition, the relative levels of DSR also vary significantly between Member States (e.g. Germany, France and Finland have similar levels of DSR, even though the first two Member States have demand levels that are a multiple of the demand levels of Finland). It is unclear what drives these diverging levels of DSR.

[51] The ERAA methodology defines: i) explicit DSR as the "change of electric demand pursuant to an accepted offer to sell demand reduction or increase in an organised market, either directly or through aggregation"; and ii) implicit DSR as the "change of demand by final customers from their normal or current consumption patterns, in response to time-variable electricity prices or incentive payments."

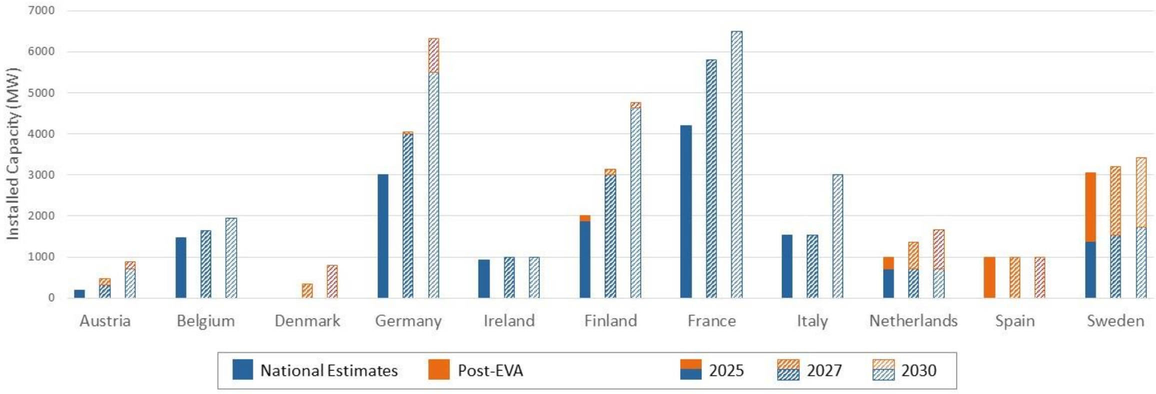
[52] For a detailed description of the ERAA 2021 approach on explicit DSR, see ACER's ERAA 2021 Decision – Annex I.

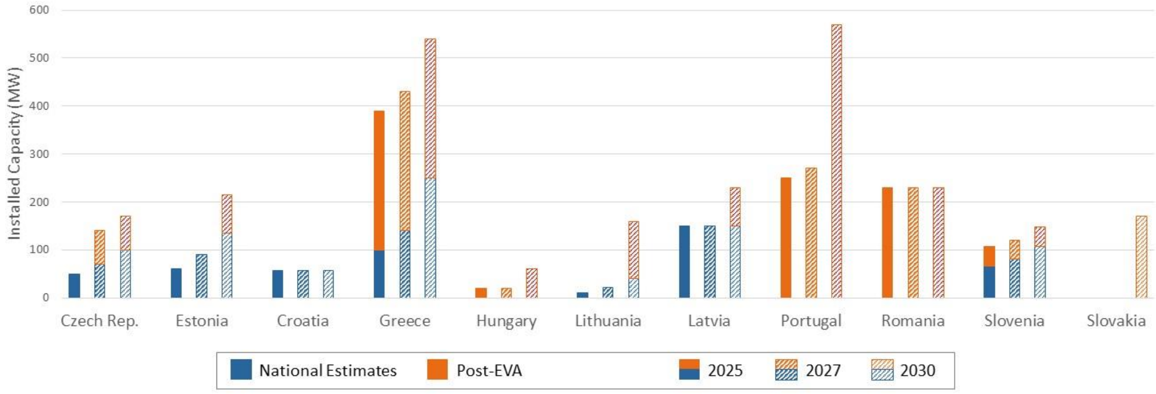
[53] Similarly, with last year the Report does not provide information about what these DSR levels reflect (e.g. whether they reflect current levels of DSR, projections for the development of DSR, DSR with capacity mechanism contracts).

[54] For more details see Annexes 1 and 3 of the Report.

[55] Installed DSR capacity based on the TSOs' assumptions amounts to around 20.1 GW over a total of around 25 GW in 2027.

Figure 12: Total installed DSR capacity per Member State and target year (only Member States with non-zero DSR depicted)





The ERAA 2022 approach for explicit DSR contains two important improvements compared to ERAA 2021:

- The first improvement concerns the use of national studies to assess DSR potentials, wherever possible, and associated economic parameters. Unlike ERAA 2021 that relied on ENTSO-E's centralised approach for assessing DSR potentials and the TSOs views,[56] ERAA 2022 relies on national studies for the Cost of New Entry (CONE) or other national studies to determine the DSR potentials and associated parameters, such as capital and fixed costs.[57] ACER believes that these studies are more detailed and better suited to the national context. The use of CONE studies is in line with the ERAA methodology (Article 5(10) of the methodology) and ensures consistency between the ERAA and the calculation of the reliability standard in a Member State.
- The second key improvement concerns the centralised approach that ENTSO-E uses as a back-up to assess DSR potentials, where a national study is unavailable. ERAA 2022 uses information from the aforementioned national studies to derive certain assumptions for the centralised approach. More specifically, ENTSO-E has updated the cost assumptions of the centralised approach using

[56] ACER reminds that the TSOs could override the assessment of DSR potentials, as estimated by ENTSO-E, in ERAA 2021. This was not the case in ERAA 2022.

[57] ACER notes that the majority of national CONE studies have identified DSR as a reference technology (with the exception of Italy) and in most instances, DSR is assessed to be the marginal technology that defines the reliability standard of a Member State. For more information, see: ACER, Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy.

information from the national CONE studies, instead of relying on a single study like in ERAA 2021. For example, ENTSO-E derives the assumptions for the capital and fixed costs from the national CONE studies (e.g. ENTSO-E estimates the capital costs of DSR for the industrial and commercial sectors as the simple average of the capital costs from the relevant CONE studies). ACER believes this is a more realistic approach for determining these assumptions.

While ACER considers the updated approach for explicit DSR in ERAA 2022 a clear enhancement, some of the concerns highlighted in ACER's ERAA 2021 Decision persist and a new concern has surfaced.[58]

- Most notably, ACER notes that in certain cases ERAA 2022 does not treat existing DSR in an appropriate way, as was the case in ERAA 2021. For example, in the case of Poland, ERAA 2022 does not consider any existing DSR after 2025, neither in the exogenous assumptions nor as potential DSR, even though DSR has consistently participated in the existing capacity mechanism. Most recently, the Polish capacity mechanism awarded around 1.5 GW of contracts to DSR for delivery in 2026. ACER believes that appropriate consideration of this DSR capacity would be to either consider it within the exogenous assumptions or as potential DSR, subject to fixed annual costs only. Any resource that has already incurred investment costs, independent of whether it is a generation, demand or storage asset, should not be subject to investment costs in the EVA. Treating existing DSR as new implies that any development would incur upfront investment costs, thus undermining its profitability. In other words, treating existing DSR as entirely new in the EVA effectively underestimates the level of DSR expected to be economically viable. ERAA 2022 treats existing DSR as entirely new in more Member States, such as Portugal, Spain and Greece.[59]
- In relation to the use of national CONE studies to assess the maximum DSR potential in a Member State, ACER notes that ERAA 2022 has misinterpreted the Italian study, thus underestimating the DSR potential in the country. The Report states that the DSR potential is set at zero for any Member State, for which DSR is not a reference technology in the national CONE study. While DSR was not considered a reference technology in the Italian CONE study, this was due to lack of reliable data on the associated costs.[60] In this sense, and in the absence of better information, ACER believes that ERAA 2022 should have used the ENTSO-E centralised approach to determine the maximum DSR potential in Italy.[61]

[58] For example, as commented in last year's decision, ACER considers that the CEPA study used by ENTSO-E to determine the opportunity (or variable) costs for different DSR types is unsuitable for the ERAA. ACER believes that a better approach would be to use realised data from the market or assumptions from CONE/VOLL studies. For more information, see ACER's ERAA 2021 Decision – Annex I, section 2.4.2.

[59] Ibid. Portugal in particular has deployed a DSR dedicated ancillary service for 2023 only, with a capacity of around 300 MW. ACER expects that this capacity will be available in the wholesale market in future years. More information on the Portuguese ancillary service is available on the Portuguese TSO's (Redes Energéticas Nacionais) website.

[60] For more information, see section 6.2. of the National Regulatory Authority's (ARERA) proposal of the reliability standard to the Italian government (Italian only).

[61] In ACER's understanding, this would have resulted in an additional potential of 2 GW in Italy for target year 2025 and 2027 at least. ENTSO-E estimates the total DSR potential in Italy at 8 GW in the centralised approach. ACER understands that around 6 GW of DSR is currently deployed in the balancing market (considered in ERAA 2022) and through an enhanced frequency response service (not considered in ERAA 2022; for more information, see the "Interruptibility schemes" section of ACER's report on: Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy).

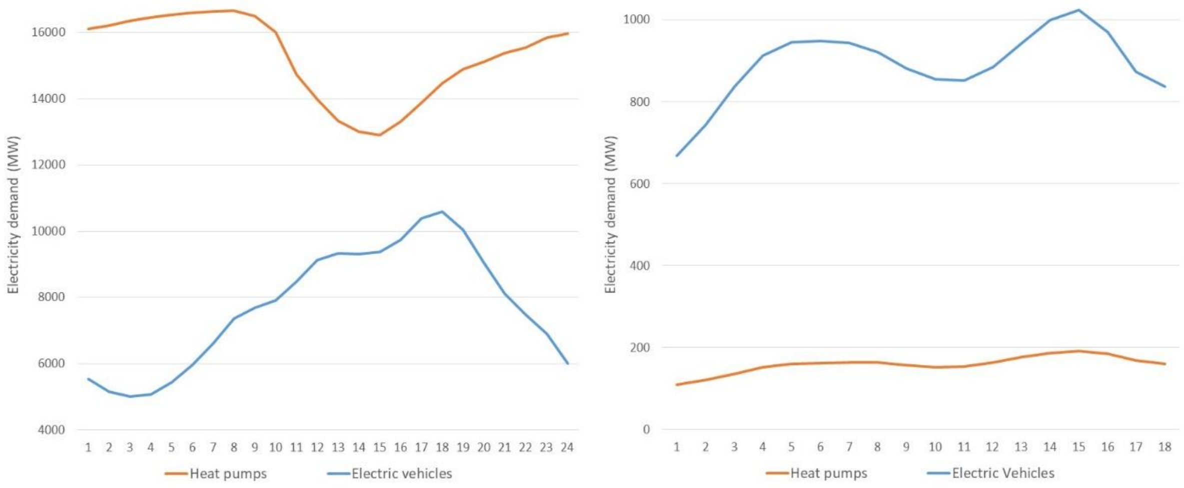
5.3. Implicit demand-side response

5.3.1. Electric vehicles and heat pumps

Electric vehicles and heat pumps represent two key technologies to reduce greenhouse gas emissions in the transport and buildings sectors respectively, while improving overall energy efficiency. Their adoption has grown significantly over the past few years and further accelerated because of the energy crisis, the continuous reduction of the associated upfront costs and policy support measures in several Member States.[62]

Electric vehicles and heat pumps represent significant additional electricity loads and at the same time significant sources of flexibility for the power system. Either application can account for as much as the typical load of an average household.[63] Figure 13 shows the assumed baseline demand (i.e. prior to any demand shifting from 'flexible consumers' as explained further below) for electric vehicles and heat pumps, for Germany (left graph) and Spain (right graph) for a winter day in 2030. It is evident from this figure, that demand of electric vehicles and heat pumps is expected to add a considerable load to the power system.

Figure 13: Electric vehicle and heat pump demand for Germany (left-hand) and Spain (right-hand) for a random winter weekday in 2030 (ERAA 2022 assumptions)



ERAA 2022 considers the flexible operation of both applications to a greater or lesser extent for different Member States. As a first step, the TSOs and ENTSO-E determine the baseline demand for both applications. For heat pumps, the associated load depends on the weather conditions and more particularly temperatures. For electric vehicles, the TSOs determine exogenous charging profiles, i.e. how the daily demand for charging is spread across every hour of the day.[64] While the majority of Member States use common charging profiles, as determined by ENTSO-E, a number of the TSOs

[62] Purchase of new electric vehicles and heat pumps increased by around 70% and 35% respectively in 2021. Sales of both electric vehicles and heat pumps are expected to continue growing exponentially for the remainder of the decade and beyond.

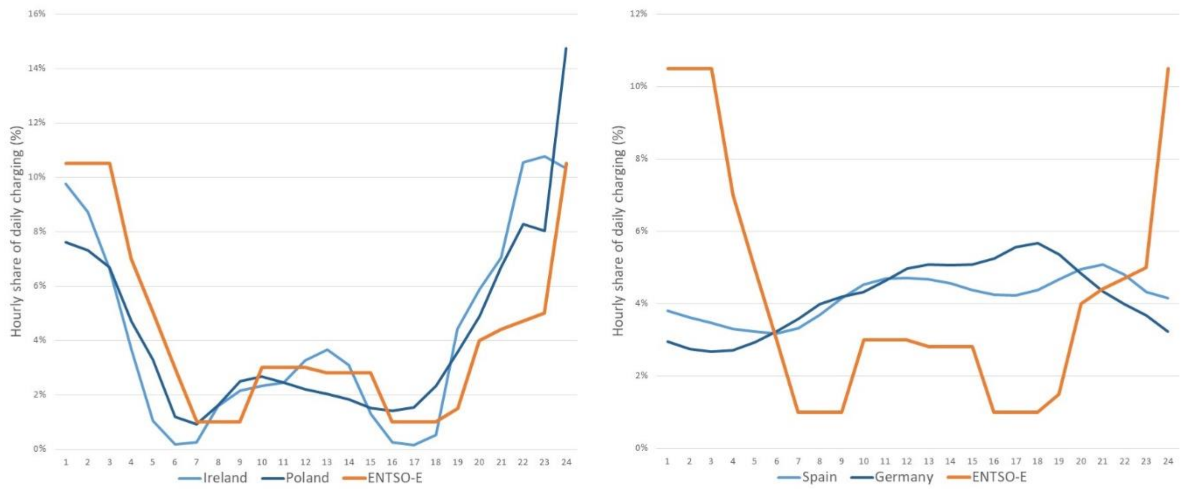
[63] For example, a typical household electric vehicle charger has a capacity of 7 kW, while the average heat pump sold in 2020 had a capacity of 8.8 kW.

[64] For more information on the charging profiles for Member States, see the ERAA 2022 annex on "Demand forecasting: National Estimates Scenario – ERAA 2022".

produce their own charging profiles.[65] Overall, the Report does not explain the basis for these projections (e.g. how ENTSO-E and the TSOs derive them, what factors are taken into consideration and why).[66]

Figure 14 shows the ENTSO-E exogenous charging profile assumptions for electric vehicles alongside the assumptions from a selected number of TSOs. For the majority of Member States, the bulk of charging is assumed to occur in the evening and night hours (possibly associated with home and off-street charging) and during office hours (possibly associated with workplace charging). In the vast majority of cases, some electric vehicle charging happens during the usual peak hours for electricity demand (e.g. between 5 p.m. and 9 p.m. for winter-peaking systems). For a limited number of Member States, such as Germany and Spain, the assumed profiles indicate a significant share of electric vehicle charging takes place during day and evening hours and in some occasions peaking during the existing system-wide peak hours, while limited charging occurs at night hours. Overall, the assumed electric vehicle charging profiles imply that electric vehicle charging is projected to happen during scarcity periods to a greater or lesser extent.

Figure 14: Charging profiles for electric vehicles - assumptions from ENTSO-E and selected countries (percentage of daily charging)



As a second step, ERAA 2022 considers the flexible operation of electric vehicles and heat pumps through enhanced modelling, compared to ERAA 2021.[67] The approach defines the share of 'flexile consumers', i.e. consumers that respond to electricity prices, within certain limitations. More specifically, flexible consumers can shift the load of these applications within pre-determined time intervals. ENTSO-E sets these intervals in an arbitrary way, with a duration of six hours, starting from 3 a.m. on each day, until 3 a.m. of the next day. Flexible consumers can effectively shift their demand within these six-hour windows, from hours of higher prices to hours of lower prices, while respecting the total consumption requirements. The TSOs determine the share of flexible consumers. ACER notes that the Report does not include any information about how these shares are determined, nor the shares themselves thus undermining transparency of ERAA 2022.

[65] Ibid. The TSOs of the following Member States determine own charging profiles: Austria, Belgium, Germany, Spain, France, Ireland, Italy, Netherlands, Poland and Slovakia.

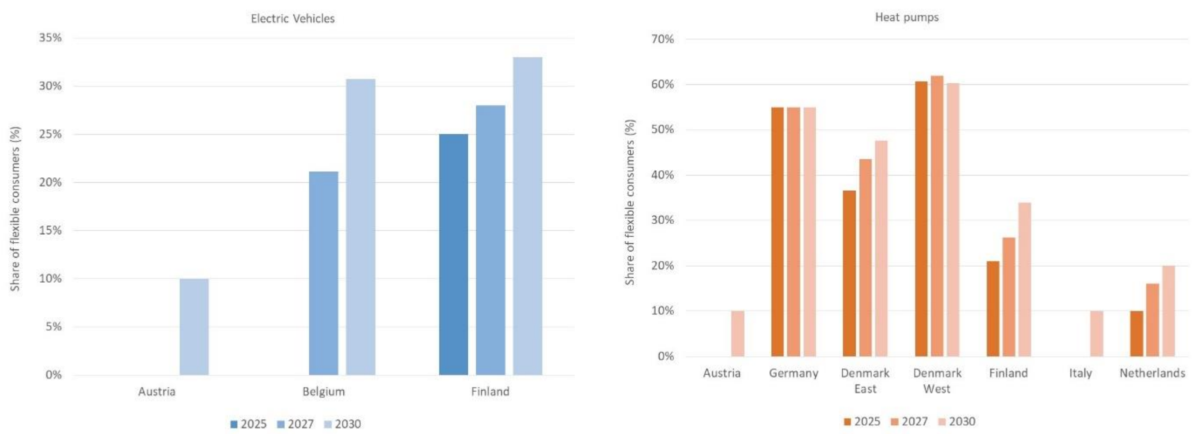
[66] For example, Article 5(11)(e)(ii)(2) of the ERAA methodology prescribes that the assessment considers the share of slow and fast charging profiles. Overall, the assessment lacks a significant amount of information that prohibits a comprehensive understanding of the approach followed by ENTSO-E and the TSOs.

[67] ERAA 2022 follows a similar approach for out of market batteries (or simply behind the meter batteries).

ACER highlights that while this second step for considering the potential for flexible operation of electric vehicles and heat pumps is an improvement, the approach remains conservative overall. Figure 15 show the shares of flexible consumers for electric vehicles and heat pumps where these are higher than 10% for all EU-27 Member States and target years. It is evident from the graphs that with limited exceptions, the TSOs have assumed that the vast majority of users of the two applications are inflexible across the modelled period. For the Member States depicted on Figure 15, ACER observes that the share of flexible consumers increases for the majority of Member States across the modelled period, while remaining constant in limited cases. ACER expects that an increasing number of consumers with electric vehicles and heat pumps will be able to flex their consumption as the deployment of smart technology and adoption of more dynamic tariffs progresses.

Moreover, the time windows within which consumers are allowed to shift their consumption are arbitrarily selected and do not necessarily correspond to the expected user cases. For example, for electric vehicles charged at home, the window of flexibility can span several hours, i.e. from the time that the electric vehicle driver returns home from work until the next morning (e.g. from 6 p.m. in the evening until 7 a.m. the next morning). Similarly, workplace charging (e.g. from 8 a.m. to 4 p.m.) offers a significant opportunity for the flexible charging of electric vehicles. ACER believes that the choice of flexibility windows should aim to capture as closely as possible the real-world.

Figure 15: Share of flexible consumers of electric vehicles and heat pumps for all target years and Member States in ERAA 2022 (only flexible shares equal to, or higher than, 10% depicted)



5.3.2. Other electricity uses

Beyond, electric vehicles and heat pumps, ERAA 2022 omits the potential for additional implicit DSR from other electricity uses. Essentially, ERAA 2022 assumes there will be no additional implicit DSR in the future, compared to current levels that are already reflected in historical demand levels. ACER considers this is a conservative approach in light of market developments and the continued digitalisation of the power system through the roll out of smart meters and other smart technology. As noted in ACER's Decision on ERAA 2021, the smart meter roll-out progresses across the EU. As of the end of 2021, on average, more than 50% of European households had a smart meter in place, with large variations across Member States. Some Member States, such as the Nordic countries, Italy and Spain have achieved a complete or close to complete roll out of smart meters, while others, such as Belgium, Czechia, Croatia and Germany, had negligible levels of smart meters in place.[68] Moreover, the deployment of smart technology continues apace, enabling additional flexibility on the demand side

[68] For more information, see ACER/CEER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 - Energy Retail and Consumer Protection Volume.

to be realised. For example, the IEA projects the deployment of smart thermostats and energy management systems to more than triple between 2022 and 2030.[69] These developments in combination with the availability of time-varying tariffs or other incentives can help to unlock the significant, unexploited potential for demand side response.[70]

Despite the continued digitalisation of the power system, ACER notes that measures applied by governments and national authorities in the wake of the energy crisis to shield consumers from the exposure to high and volatile electricity prices, may dampen the incentives for demand side flexibility. Consumers might also feel inclined to limit their exposure to varying retail tariffs by engaging in fixed price contracts. Overall, there is significant uncertainty about the future levels of demand side flexibility, even though it is widely recognised as a highly valuable resource for the current energy crisis, security of supply and the energy transition (e.g. for enabling the integration of renewable energy) more broadly.

[69] For more information, see IEA's Electricity Market Report - July 2022.

[70] As of the end of 2021, time-of-use and real-time pricing tariffs were available in 17 and 13 Member States respectively, while for a smaller number of Member States critical peak pricing tariffs was on offer. For more information, see ACER/CEER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 - Energy Retail and Consumer Protection Volume.

6. Appendix: Detailed tables

Table 3: Loss of load indicator in hours per year from the economic dispatch model with and without the implementation of the curtailment sharing and local matching element, and from the EVA.

LOLE (hours/year)	Target year 2025			Target year 2027			Target year 2030		
	Economic dispatch without CS&LM	Economic dispatch with CS&LM	EVA model	Economic dispatch without CS&LM	Economic dispatch with CS&LM	EVA model	Economic dispatch without CS&LM	Economic dispatch with CS&LM	EVA model
AT00	0.8	1.5	0.4	0.7	1.2	0.9	0.5	0.6	0.8
BE00	1.1	6.5	1.1	2.8	10.4	2.0	0.9	11.0	2.4
BG00	0.1	0.1	0.0	0.2	0.7	0.4	0.1	1.2	0.4
CY00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CZ00	0.4	0.0	0.0	0.3	0.0	0.7	0.9	0.5	0.3
DE00	4.03	10.5	2.0	7.9	13.7	2.7	10.6	20.4	9.0
DKE1	1.7	7.4	0.8	2.6	11.1	1.9	3.4	10.9	8.0
DKW1	5.9	9.8	0.0	11.0	13.4	0.8	2.9	2.3	0.6
EE00	0.9	4.5	0.4	3.5	9.7	0.4	1.3	8.0	0.5
ES00	5.7	6.7	4.6	1.6	1.9	3.1	1.3	1.5	3.1
FI00	2.0	3.5	0.0	0.6	1.6	0.2	0.8	2.1	0.3
FR00	3.0	5.7	2.9	5.8	8.7	3.1	5.1	10.2	3.3
GR00	0.2	0.3	0.4	0.2	0.1	0.4	0.0	0.0	0.2
GR03	0.4	1.1	1.5	0.0	0.4	0.2	0.0	0.1	0.1
HR00	0.3	0.0	0.0	0.1	0.0	0.3	0.1	0.0	0.0
HU00	2.6	6.3	1.5	0.8	2.3	0.8	1.1	3.9	0.8
IE00	28.2	24.3	0.9	0.8	1.6	0.5	0.9	2.4	1.1
ITCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITCN	3.1	7.9	0.9	1.9	9.9	0.9	0.7	8.7	0.8
ITCS	0.0	0.7	0.0	0.2	1.5	0.4	0.1	2.2	0.4
ITN1	2.4	0.4	0.7	4.0	0.5	0.8	2.4	0.5	1.0
ITS1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
ITSA	1.5	0.4	0.0	0.5	0.1	0.1	0.2	0.4	0.4
ITSI	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LT00	2.0	3.8	0.4	4.7	6.2	0.4	4.5	6.0	1.4
LUG1	4.03	10.5	2.0	7.9	13.7	2.7	10.6	20.4	9.0
LV00	0.0	0.1	0.0	0.2	0.2	0.2	0.0	0.1	0.3
MT00	24.8	22.3	33.9	0.1	0.1	0.0	0.0	0.0	0.0
NL00	0.6	0.1	0.0	1.0	0.8	0.8	2.3	4.5	1.1
NOS0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PL00	0.5	0.1	0.3	1.0	0.2	0.5	3.4	2.0	3.7
PT00	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2
RO00	0.5	1.7	1.5	0.1	0.2	0.4	0.1	0.1	0.7
SE01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE02	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SE03	0.0	2.1	0.0	0.0	2.5	0.0	0.0	1.2	0.0
SE04	0.1	2.4	0.0	0.1	5.1	0.2	0.0	5.5	0.3
SI00	0.3	1.0	0.0	0.1	0.4	0.6	0.2	1.8	0.6
SK00	0.7	0.0	0.0	0.2	0.0	0.5	0.4	0.0	0.1

Table 4 Expected energy not served (EENS) in GWh from the economic dispatch model with and without the implementation of the curtailment sharing and local matching element, and from the EVA.

EENS (GWh)	Target year 2025			Target year 2027			Target year 2030		
	Economic dispatch without CS&LM	Economic dispatch with CS&LM	EVA model	Economic dispatch without CS&LM	Economic dispatch with CS&LM	EVA model	Economic dispatch without CS&LM	Economic dispatch with CS&LM	EVA model
AT00	4.75	1.30	0.37	2.28	0.76	0.32	2.49	0.49	0.33
BE00	3.01	3.60	0.86	2.84	9.79	2.25	2.38	11.74	2.33
BG00	0.03	0.04	0.00	0.09	0.22	0.03	0.04	0.36	0.03
CY00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CZ00	0.46	0.00	0.00	0.52	0.00	0.00	1.42	0.21	0.00
DE00	29.61	57.73	15.85	53.67	91.40	29.62	144.86	174.14	40.45
DKE1	0.91	1.10	0.31	2.17	2.30	0.52	2.76	2.45	0.73
DKW1	8.18	4.50	0.00	19.01	8.71	0.00	3.68	0.85	0.00
EE00	0.22	0.33	0.07	0.52	1.75	0.09	0.32	1.35	0.18
ES00	11.22	11.10	7.86	3.28	3.08	2.48	3.66	2.30	4.43
FI00	1.23	1.43	0.00	0.43	0.57	0.00	0.71	1.00	0.00
FR00	19.16	17.98	16.77	30.31	30.13	18.56	33.54	41.84	21.40
GR00	0.07	0.08	0.23	0.08	0.06	0.08	0.01	0.00	0.00
GR03	0.07	0.04	0.18	0.00	0.02	0.00	0.00	0.00	0.00
HR00	0.42	0.00	0.00	0.15	0.00	0.00	0.13	0.00	0.00
HU00	5.38	5.81	1.65	0.95	1.65	0.20	1.47	2.27	0.01
IE00	10.49	8.19	0.18	0.60	0.40	0.22	0.35	0.57	0.10
ITCA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITCN	2.07	3.72	0.84	1.94	5.11	1.30	1.17	3.72	0.72
ITCS	0.02	0.58	0.00	0.24	1.71	0.08	0.10	2.40	0.00
ITN1	6.34	0.31	0.48	13.40	0.55	0.99	7.21	0.73	0.39
ITS1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITSA	0.26	0.08	0.00	0.08	0.02	0.00	0.09	0.07	0.00
ITSI	0.10	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
LT00	0.98	0.58	0.13	3.17	1.21	0.20	3.06	1.46	0.38
LUG1	0.34	0.67	0.00	0.62	1.06	0.00	1.69	2.00	0.00
LV00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00
MT00	1.61	1.60	0.25	0.01	0.02	0.00	0.00	0.00	0.00
NL00	1.92	0.03	0.00	4.35	0.48	0.07	15.66	4.82	1.14
NOS0	0.18	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PL00	1.39	0.01	0.17	2.39	0.15	0.63	8.70	1.48	3.02
PT00	0.03	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00

RO00	0.56	0.61	0.62	0.06	0.07	0.15	0.09	0.04	0.05
SE01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SE02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SE03	0.00	1.19	0.00	0.00	1.55	0.00	0.00	1.03	0.00
SE04	0.04	1.06	0.00	0.06	2.82	0.00	0.00	3.12	0.00
SI00	0.58	0.12	0.00	0.27	0.03	0.00	0.45	0.44	0.00
SK00	1.32	0.00	0.00	0.22	0.00	0.00	0.53	0.00	0.00

Table 5: Projects affecting at least one Core CCR member state, which have passed the permitting phase, and are expected to be commissioned from 2025 onward

Country	Border	Project Name	Commissioning Year	Transfer capacity increase A-B (MW)	Transfer capacity increase B-A (MW)
AT	Internal (Austria)	St. Peter (AT) - Tauern (AT)	2025	2000	2000
BE	Belgium - Netherlands	BRABO II + III	2025	1000	1000
DE ;PL	Germany - Poland	GerPol Improvements	2025	500	1500
FR ;GB	France - United Kingdom	GridLink	2025	1400	1400
NL	Germany - Netherlands	Reinforcements Ring NL phase I	2025	600	600
AT ;DE	Austria - Germany	Isar/Altheim/Ottenhofen (DE) - St.Peter (AT)	2026	2000	2000
AT ;IT	Austria - Italy	Würmlach (AT) - Somplago (IT) interconnection	2026	150	150
DE	Internal (Germany)	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	2026	4000	4000
DE	Internal (Germany)	HVDC Ultranet Osterath to Philippsburg	2026	2000	2000
DE ;SE	Germany - Sweden	Hansa PowerBridge I	2026	700	700
FR ;GB	France - United Kingdom	AQUIND Interconnector	2026	2075	2075
FR ;IT	Internal (Italy)	SACOI3	2026	400	400
DE	Internal (Germany)	HVDC Line A-North	2027	2400	2400
DE ;GB	Germany - United Kingdom	NeuConnect	2027	1400	1400
ES ;FR	Spain - France	Biscay Gulf	2027	2200	2200
FR ;IE	France - Ireland	Celtic Interconnector	2027	700	700
CZ	Czechia - Germany	CZ Southwest-east corridor	2028	500	500

CZ ;DE	Czech Republic - Germany	Reinforcement of the existing CZ-DE interconnector (Hradec - Röhrsdorf) on the CZ side	2028	0	500
BE ;NL	Belgium - Netherlands	ZuidWest380 NL Oost	2029	1000	1000
AT ;DE	Austria - Germany	St. Peter (AT) - Pleinting (DE)	2030	1500	1500
FR ;GB	France - United Kingdom	France-Alderney-Britain	2030	1400	1400

Source : ENTSO-E - https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission

Table 6: ACER's assessment of the 70% minimum target based on the ERAA 2022 NTC assumptions

Border	Percentage of time when the 70% target is reached (Minimum Value among the TSOs impacted)	Historical Average NTC 2021	Assumed Average NTC 2025	Conclusion ERAA 2022	Conclusion ERAA 2021
AT - CZ	0.07	721	900		
AT - HU	0.01	646	800		
AT - IT	0.28	240	659		
AT - SI	0.07	774	950		
BG - GR	0.07	651	1700		
BG - RO	0	1005	2190		
CZ - AT	0.29	673	900		
CZ - DE_LU	0.25	2732	2900		
CZ - PL	0.06	353	1050		
CZ - SK	0.07	1969	1377		
DE_LU - CZ	0.1	2097	2750		
DE_LU - PL	0.06		2000		
DK1 - DE_LU	0.08	1857	3299		
ES - FR	0.71	2383	2187		
ES - PT	0.6	3729	4200		
FI - SE1	0.92	1004	1102		
FR - ES	0.7	2876	2524		
FR - IT	0.28	2601	4028		
GR - BG	0	610	1400		
HR - HU	0	941	800		
HR - SI	0.32	1494	1000		
HU - AT	0	710	800		

HU - HR	0	1083	900	
HU - RO	0.05	886	1000	
HU - SK	0.01	1454	1800	
PL - CZ	0.19	420	1000	
PL - DE_LU	0.19		3000	
PL - SK	0.07	614	772	
PT - ES	0.57	3012	3500	
RO - BG	0	1021	2190	
RO - HU	0.32	758	1100	
SE1 - FI	0.94	1420	1202	
SE4 - DK2	0.84	1159	1239	
SI - AT	0.29	877	950	
SI - HR	0	1496	1200	
SI - IT	0.28	581	613	
SK - CZ	0.07	1221	1600	
SK - HU	0.07	1800	2512	
SK - PL	0.06	494	809	

Table 7: Comparison of forecasted demand between ERAA 2022 and the European Commission's fit-for-55 scenario for 2025 and 2030

	2025			2030		
Member State	ERAA 2022 (GWh)	Fit-for-55 (GWh)	Relative difference (%)	ERAA 2022 (GWh)	Fit-for-55 (GWh)	Relative difference (%)
AT	75618	61348	23	90182	64242	40
BE	91141	88024	4	101454	106644	-5
BG	37240	30101	24	38000	32034	19
CY	5770	5437	6	6120	6031	1
CZ	71172	57577	24	75565	64514	17
DE	574392	500751	15	649308	576452	13
DK	46807	38256	22	59226	45253	31
EE	9128	8164	12	9416	9156	3
ES	258680	234010	11	262910	248580	6
FI	94049	86477	9	107616	96642	11
FR	480185	394831	22	524941	409567	28
GR	56592	53311	6	55449	57521	-4
HR	17596	16365	8	18540	19293	-4
HU	49034	40519	21	52650	50306	5
IE	39591	34061	16	46500	41470	12
IT	328919	276494	19	344707	308344	12
LT	14116	10168	39	14955	10543	42
LU	8011	6277	28	9019	7067	28
LV	7292	6971	5	7535	7497	1
MT	3009	2990	1	3410	3254	5
NL	124071	121042	3	154000	132847	16
PL	166898	155094	8	184744	181903	2
PT	51523	47580	8	55435	49441	12
RO	62211	56044	11	65286	67427	-3
SE	150759	120773	25	187000	125771	49
SI	14716	14604	1	15666	16802	-7
SK	29563	27626	7	31480	30252	4

Notes: Demand data for ERAA 2022 are estimated as the average of the annual demand values over all climate years. For Member States with multiple bidding zones the demand data are the cumulative demand for all bidding zones.
Demand data for the European Commission's fit-for-55 scenario are the forecasted final energy consumption values with "electricity" as fuel type (data provided in ktoe). For the conversion to GWh a conversion factor of 11.63 ktoe/GWh was used.
The relative difference is calculated with the fit-for-55 demand data as reference.

7. List of Figures

8. List of Tables