ACER
European Union Agency for the Cooperation of Energy Regulators

ACER Decision on the ERAA 2021: Annex I

DECISION No 02/2022

OF THE EUROPEAN UNION AGENCY

FOR THE COOPERATION OF ENERGY REGULATORS

on the European Resource Adequacy Assessment for 2021

Technical annex

22 February 2022

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1. Scope of Technical annex[1]

1.1. Scope of Annex

The Technical annex provides a detailed assessment of the European Resource Adequacy Assessment 2021 (‘ERAA 2021’)[2] and complements the Decision;[3] the two should be read in conjunction. The Technical annex supplements ACER’s assessment of the ERAA 2021 concerning the high-level requirements of the Electricity Regulation (as described in section 6 of the Decision), by providing a comprehensive technical review for a number of them.[4] The scope of the Technical annex is the ERAA methodology itself; as such, it goes one step beyond the Decision. The assessment follows the framework of the ERAA methodology and is structured as follows:

- The second chapter focuses on the scenarios and sensitivities, for example the different scenario elements, such as demand and generation. It primarily covers Articles 3, 4 and 5 of the ERAA methodology.
- The third chapter details ACER’s assessment of the Economic Viability Assessment (EVA) regarding Article 6 of the ERAA methodology.
- The fourth chapter focuses on Article 7 of the methodology that concerns the implementation of the economic dispatch in the ERAA 2021.
- Finally, the fifth chapter presents ACER’s detailed assessment of the flow-based proof of concept included in the ERAA 2021, related to Article 4(6) of the methodology.

Given this is the first ever ERAA, and that the implementation of the ERAA methodology is under development in several areas, the Technical annex focuses on the application of the methodology in the ERAA 2021. It pays particular attention to the new developments in the ERAA 2021, compared to its predecessor (the Mid-Term Adequacy Forecast 2020), specifically the EVA and flow-based approaches. Where the ERAA 2021 diverges from the ERAA methodology, and to the extent possible, ACER assesses qualitatively the potential impacts on the adequacy risk indicators.

The Technical annex offers a review of the ERAA 2021 assumptions used for 2025 that are expected to have the most significant impact on the results.[5] As the implementation of the ERAA methodology progresses, ACER anticipates its review to increasingly shift from implementation aspects of the methodology towards the assumptions used in the annual ERAAs.

[1] ACER would like to acknowledge the contribution of the European Commission’s Joint Research Centre (JRC) in assessing the ERAA 2021. The JRC assisted with the review of certain aspects of the ERAA 2021, i.e.: flow-based proof of concept, ex-ante optimisation of storage and ex-ante optimisation for planned maintenance. In addition, the JRC assisted ACER with refining the minimum expectations for the ERAA 2021 and the recommendations for the ERAA 2022.

[2] The executive summary, annexes and input data of the ERAA 2021 are referred to as ‘the Report’.

[3] The following elements are discussed in the Decision and not explored further in the Technical annex: Geographical scope of the ERAA 2021; Temporal scope of the ERAA 2021; Scenario framework; Scenario framework and the greenhouse gas emissions target; Energy efficiency measures; Interconnection and network development; National implementation plans; Probabilistic assessment; Single modelling tool; Out-of-market capacity resources; and Identification of sources of resource adequacy concerns. ACER’s assessment of the procedural requirements for the ERAA are also discussed in the Decision.

[4] This includes the following aspects: Economic viability assessment; Storage; Cross-zonal capacity calculation (including the flow-based proof of concept); Demand-side response and sectorial integration; and Transparency.

[5] Modelled year 2030 is outside the scope of the Technical annex, due to the significant simplifications considered for this year, for example the lack of central reference scenarios and the consideration of a 40% emissions reduction target, in contrast to the recently established 55% emissions reduction target, which undermines the value of the 2030 scenarios.

Finally, in order to facilitate the preparation of the ERAA 2022 and the progressive implementation of the ERAA methodology, the Technical annex provides non-legally binding recommendations. To be most helpful, next to the recommendations ACER indicates the level of priority: `high priority` indicates that the recommendation is expected to be implemented in the ERAA 2022 and `low priority` that the recommendation is expected to be implemented in subsequent ERAAs.

1.2. Limitations

The review in the present Technical annex is not exhaustive due to the availability of limited information in certain areas of the ERAA 2021 and time constraints for issuing ACER's Decision. The review focuses on the aspects ACER expects to have the greatest impact on the identification of the risks to resource adequacy.

2. Scenario and Sensitivities

2.1. Scope

2.1.1. Geography and temporal scope

ACER's assessment on the geography and temporal scope of the ERAA 2021 concerning the applicable framework is included in the Decision, sections 6.2.1.1 and 6.2.1.2, respectively.

2.1.2. Non-explicitly modelled zones

Beyond the bidding zones modelled in detail, i.e. the entire area of the European Network of Transmission System Operators for Electricity ('ENTSO-E') membership,[6] the ERAA 2021 considers interconnected systems at the periphery of the assessment's geography. This periphery includes Russia, Belarus, Algeria and Morocco that are directly interconnected with Member States. This approach is in line with Article 4(7) of the ERAA methodology. Article 4(1)(j) of the methodology prescribes that non-explicitly modelled zones are represented by hourly energy exchanges with the explicitly modelled zones. The Report does not contain any information about the assumptions on energy exchanges between non-explicitly and explicitly modelled zones, nor how these are determined.

Recommendations

ACER expects ENTSO-E to publish the assumptions about energy exchanges between non-explicitly and explicitly modelled zones and explain how these are assessed (high priority).

2.2. Probabilistic assessment

ACER's assessment of the probabilistic assessment of the ERAA 2021 concerning the applicable framework is included in the Decision, section 6.2.1.12.

2.3. Scenario framework

ACER's assessment of the scenario framework of the ERAA 2021 concerning the applicable framework is included in the Decision, sections 6.2.1.3 and 6.2.1.4.

2.4. Scenario Elements

2.4.1. Demand

The key demand assumptions in the ERAA 2021, such as average annual and peak demand, are largely determined by national TSOs'.[7] ENTSO-E uses those projections and the Trapunta model to produce hourly timeseries for the ERAA modelling.[8] These hourly timeseries need to match the national assumptions provided by TSOs, particularly average annual and peak demand projections.

The Trapunta model effectively relates different climate variables with the level of demand, in line with Article 4(3) of the ERAA methodology. For this purpose the model uses historical data to determine the

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[6] This includes the EU-27 Member States, the United Kingdom, Norway and the Energy Community countries, among others.

[7] ACER understands that the key demand assumptions refer to average climate conditions.

[8] For more information, see Annex on "Demand Forecasting Methodology" of the Report. The Report, additional methodological documentation and data are available on ENTSO-E's website: https://www.entsoe.eu/outlooks/eraa/eraa-downloads/.

statistical relationship between demand and climate variables for each bidding zone. Once the Trapunta model has determined this relationship, it can produce the projected demand timeseries based on all historical years considered in the assessment. On top of the aforementioned modelling, the ERAA 2021 considers the effects of new technologies, such as electric vehicles and heat pumps, on the hourly demand timeseries in line with the ERAA methodology (Article 4(3)(a)).

ACER notes that some national TSOs, such as the Belgian, French and Polish ones, produce hourly demand projections, based on their own tools. The Report does not specify for which bidding zones ENTSO-E uses the Trapunta model and where TSOs produce their own hourly timeseries. The Report fails to explain how these different approaches lead to consistent scenarios across the assessment's geography. In addition, the Report details the different historical years used in the Trapunta model to determine the relationship between demand and climate variables for every Member State.[9] ACER notes that the historical years used for this purpose vary for the concerned bidding zones; for the majority of bidding zones, the ERAA 2021 uses historical demand data for the period 2016-2019, and for others data for the period 2012-2016 or other variations of historical years. The Report does not explain the reasons for the choice of historical years, nor how this choice ensures consistency across the projected demand timeseries. It is also unclear how years as far as ten years back are representative of current demand patterns.

ACER acknowledges the efforts of ENTSO-E to provide more transparency about the methodology used to produce hourly demand projections. The Report provides information about the formulation used in the Trapunta model and the different elements considered outside the model, such as new technologies. At the same time, the Report lacks significant information to understand these demand projections and assess compliance with the ERAA methodology. Below we detail some of the missing information:

- According to Article 3(a) of the methodology, the ERAA scenarios must be consistent with Member States' National Energy and Climate Plans and more specifically national objectives, targets and contributions in relation to energy efficiency measures among others. The Report does not offer any quantitative information regarding compliance with the National Energy and Climate Plans (NECPs) scenarios. More broadly, the Report provides limited information about the key drivers that affect future demand levels. For example, Annex 1 of the Report on Assumptions offers high-level information about the drivers of demand changes and the Demand Forecasting Methodology Annex contains information about the evolution of temperature-dependent and independent demand, however, it does not explain what drives these changes nor what is considered under each category.
- On the same note, the Report does not contain any information about sectorial demand, the impacts of economic growth and energy efficiency on demand. Moreover, the Report does not explain how energy efficiency measures influence the profiles of electricity consumption. The impacts of energy efficiency measures can vary depending on the electricity applications they affect. For example, the expected impact on the demand profiles can be different if an energy efficiency measure affects electricity consumption across the day (e.g. efficiency measures targeting baseload demand in industry) or specific periods of the day (e.g. replacement of electric resistance technologies by heat pumps for heating purposes in the residential sector). It is therefore not possible to assess compliance with Article 4(3)(f) of the Methodology.
- Similarly, the Report lacks information about the sources used to estimate the future number of electric vehicles and heat pumps and what is driving additional baseload demand.[10]
- The description of the Trapunta model explains how the following parameters are incorporated in the modelling: sanitary water, air conditioning fraction and air conditioning load. The Report and datasheets however, do not provide any information on them. It is unclear whether and how these parameters affect the demand timeseries used in the assessment.

[9] Table 2 - Historical load input data used for model training of the Demand Forecasting Methodology Annex.

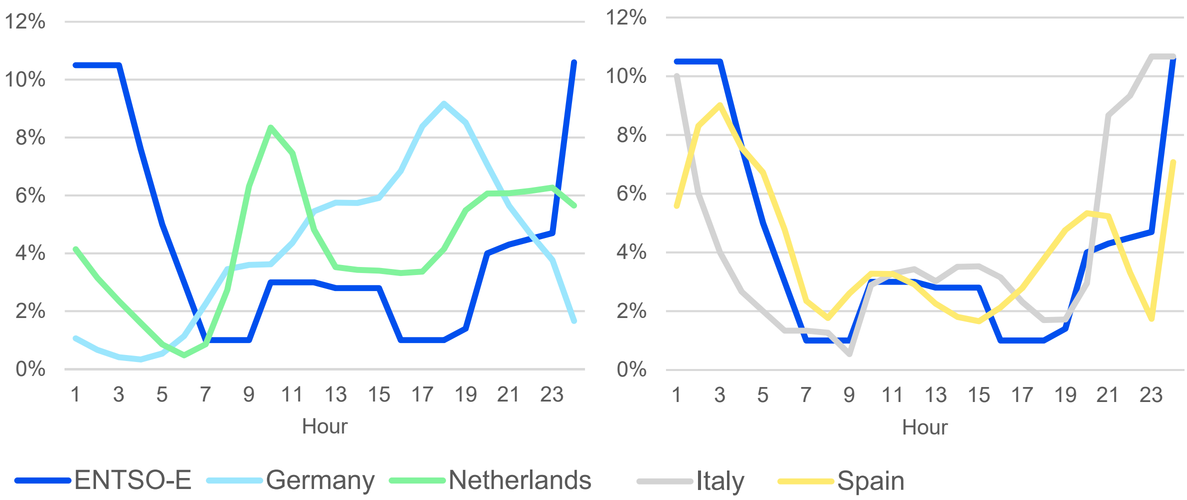
[10] According to information received from ENTSO-E, baseload demand mainly reflects demand from data centres.

Electric vehicles

The ERAA 2021 considers different types of electric vehicles for the modelled years, such as passenger cars and electric buses. Passenger cars represent the bulk of electric vehicles (Type A electric vehicles), as shown in the Demand Forecasting Methodology Annex of the Report. ACER notes that the relevant tables do not provide information about the number of vehicles across all Member States.[11] Moreover, while the aforementioned Annex provides the demand formulation of electric vehicles, it neither provides data on the assumed additional load of electric vehicles nor on the assumptions for each parameter in the formulation.[12] It is therefore not possible to assess the overall impact that electric vehicles have on the daily demand profiles.

In addition, the Report contains information about the charging profiles for the different electric vehicle types considered in the assessment, in the form of probability distribution functions (or how the daily demand for charging is spread across every hour of the day).[13] While the bulk of Member States use common charging profiles, as determined by ENTSO-E, some use their own charging profiles. The Report does not explain the basis for these projections.[14] Figure 1 shows the assumed charging profiles for passenger cars from ENTSO-E and a number of Member States.

Figure 1: Charging profiles for electric passenger cars - assumptions from ENTSO-E and selected countries (percentage of daily charging)



Source: ACER calculations based on the ERAA 2021 data.

Figure 1 points to some similarities and differences across the different passenger electric vehicle charging profiles. 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

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[11] For example, the tables do not contain any data for electric vehicles in Germany. ACER understands that the ERAA 2021 assumes there will be an increase in the number of electric vehicles in Germany throughout the horizon of the analysis from current levels.

[12] For example, the Report lacks information about the “consumption of the average electric vehicle for each category” and the “effective usage of the average EV user of each category”.

[13] ACER notes that the graphs presenting the electric vehicle charging profiles for different countries are heterogeneous, i.e. the y-axis of the graphs differs between them. It is unclear how one should interpret these differences.

[14] 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 assessing compliance with the ERAA methodology.

charging also happens during the common 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 Belgium, the assumed profiles indicate that the bulk of electric vehicle charging takes place during day and evening hours and in some occasions peaking during the existing system-wide peak hours, while negligible 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.

Recommendations

ACER expects ENTSO-E to significantly enhance the description of demand in future assessments (high priority). The ERAA should contain additional information demonstrating how the assessment complies with the NECPs and the targets related to energy efficiency measures, among others. The assessment would also benefit from additional information on sectorial demand, the impacts of economic growth and other factors (e.g. social developments) on demand, and the impact of energy efficiency measures on the shape of demand. ACER also recommends that the assessment provides more information related to the deployment of new technologies, such as electric vehicles and heat pumps, and clearly explains the assumptions associated with them.

The quality of the ERAA depends largely on the quality of the input data and it is important that the model utilises the best possible and most relevant information. The most recent data can be most representative for determining demand profiles, as they implicitly consider any changes to the nature of demand (e.g. changes in consumers' behaviour). For the ERAA 2022, ENTSO-E should as a minimum consider the most recent demand data, from 2016 up to 2019, to determine the relationship between demand and climate variables (the "Trapunta" model) for Member States (high priority).[15] A different approach should be justified by ENTSO-E.

2.4.2. Demand Side Response

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

2.4.2.1. Explicit DSR

The ERAA 2021 considers the traditional type of explicit DSR only, i.e. peak shaving. DSR is determined as a combination of different parameters: maximum capacity, activation price, annual fixed costs (including capital costs), where relevant (i.e. for DSR expressed as potential and not determined exogenously), and maximum duration of activation. The definition of explicit DSR is in line with the ERAA methodology (Article 4(3)(c)). On the other hand, the ERAA 2021 omits the potential for demand shifting, i.e. the ability of consumers to move consumption away from hours of high prices towards hours of low prices.

ENTSO-E uses a tailored methodology to model explicit DSR in the ERAA 2021. As a first step, the TSOs make assumptions about the level of DSR that will be available in the market in the modelled years as part of the 'National Estimates' scenario (details provided in Annex 1 of the Report). This level of exogenously determined DSR is not subject to an EVA and assumed to always be available to contribute to resource adequacy, within certain technical limitations. With some exceptions (e.g. Sweden, Finland, Belgium) it is unclear from the Report what this DSR reflects (e.g. whether it reflects current levels of DSR or projections for the development of DSR).[16]

[15] The most recent historical year for which data is expected to be available, 2020, was an exceptional year due to the Covid-19 outbreak. Exceptional years, such as 2020, should be treated with great caution when used to make projections for the future.
[16] According to Article 4(11)(c), the database of an ERAA must include the currently available DSR volumes. This information is not provided in the Report and it is unclear whether ENTSO-E has collected the relevant data.

In addition, the ERAA 2021 assesses the maximum potential for DSR across Europe.[17] The difference between the maximum potential for DSR and the exogenously determined DSR defines the additional DSR potential that could enter the market. This additional DSR potential is included in the EVA. Effectively, the assessment utilises both available definitions for modelling DSR, i.e. exogenously determined and potential DSR, pursuant to Article 4(3)(c)(iii) of the ERAA methodology.

In order to determine the maximum DSR potentials, ENTSO-E uses a "flexible rate" on the baseline demand for each sector (with exceptions, i.e. the construction and residential sectors) and Member State. The "flexible rate" represents the share of baseline demand that can be shaved for a pre-determined amount of time. The ERAA 2021 determines the "flexible rate" as 35% for all bidding zones and sectors. The ERAA 2021 does not explain the reasons for following this approach nor provides any evidence supporting the choice of this flexible rate. ACER notes there are available studies that assess the technical potential of DSR with more detailed and sophisticated methods.[18] As a final step of this approach, national TSOs may override the results of this centralised approach and determine their own level of additional DSR potentials. The Report does not provide any information about this step. In ACER's view, this lack of information undermines the transparency of the assessment. Several TSOs have reduced or eliminated the DSR potential in this final step; for example, the Polish and French TSOs nullified the DSR potential, and the Austrian and German TSOs decreased it significantly.

Once the ERAA 2021 has established the additional DSR potentials across the assessment's geography, the next step is to match these potentials with cost parameters. The assessment uses two external reports for this step, as described in the paragraphs below. The Report does not provide detailed information on the matching process between the DSR potentials and cost elements, nor the reasons for selecting the specific studies (e.g. the merits of the selected studies over other studies that were examined but not considered for the assessment).

The ERAA 2021 uses the Cambridge Economic Policy Associates (CEPA) study on the estimation of the value of lost load of electricity supply in Europe to determine the activation prices (or variable costs) for each sector or group of sectors considered in the assessment.[19] With regard to the CEPA study, ACER notes that the primary purpose of the study was to experiment on a methodology for the value of lost load (VOLL) based on different consumer types, as a way to assess methodological options before the implementation of the Clean Energy Package (CEP). The CEPA study also produced estimates of value of lack of adequacy (VOLA) for different customer types across Europe.[20] However, estimating VOLA was not the focus of the study and some key assumptions do not fully align with the CEP requirements.[21] CEPA based these estimates on limited survey responses, while national authorities (e.g. Member States or national regulatory authorities) were not involved in the study. For these reasons, ACER considers these estimates to be for illustration purposes only. Overall, ACER considers the CEPA study unsuitable for estimating the activation prices for explicit DSR within the ERAA. ACER is convinced that specific studies related to DSR would be better suited for this purpose.

The ERAA 2021 uses the French ecological transition agency's (Agence de la transition écologique; or 'ADEME') study on Electricity Demand Side Response in France to determine the annual capital and

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[17] Detailed in Annexes 1 and 3 of the Report.

[18] For example, see: https://ec.europa.eu/energy/sites/ener/files/documents/demand_response_ia_study_final_report_12-08-2016.pdf

[19] CEPA, Study on the estimation of the value of lost load of electricity supply in Europe, available on: https://extranet.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf.

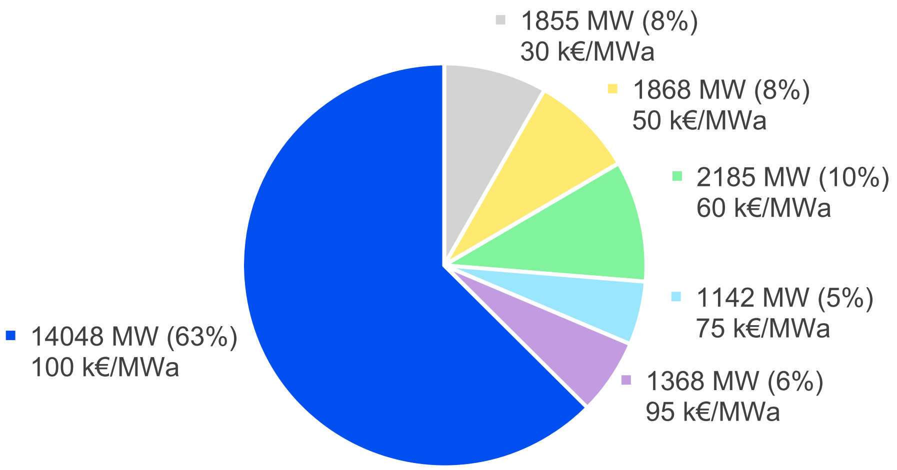
[20] The VOLA is defined as VOLL with one day of notice provided ahead of the interruption.

[21] Annex I to ACER Decision No 23/2020:

fixed costs associated with the investment in new DSR.[22] ACER notes that the ADEME assessment focuses on DSR potential and costs in France, in particular. It is therefore unclear why these estimates can be considered robust and applicable for the rest of Europe. Moreover, the ADEME study considers a type of "expected remuneration" to assess the DSR development potential. The study does not differentiate between capital, fixed and variable costs. Similarly, the ERAA 2021 does not differentiate between capital and fixed annual costs (for variable costs, the assessment uses the CEPA study as explained above). This approach is inconsistent with the approach followed for other technologies whereby the assessment determines capital and other fixed costs separately.[23]

Figure 2 presents the additional DSR potential per cost band across the EU-27, in terms of capacity and as a share of the total DSR potential. The graphs show that the largest share of the additional DSR potential, around 63%, is allocated to the highest cost band. ACER understands that this band relates to DSR potential in the commercial sector. On the other hand, the potential for low-cost DSR (bands with annual costs of 30 and 50 k€/MWa) is limited to less than 4 GW, or 16% of the total DSR potential. Essentially, the ERAA 2021 implicitly assumes that the low-cost DSR potential is largely exploited through the exogenously determined assumptions. The assessment does not provide any evidence for it. Moreover, the total costs of the highest-cost DSR band are higher than the equivalent costs for Open-Cycle Gas Turbine (OCGT) power plants, making this DSR potential uneconomic in any event.[24] In other words, the model would never invest in this DSR potential, as OCGT power plants would always be more economic in the model.

Figure 2: DSR potentials per cost band and as a share of total DSR potential for EU-27 - 2025 assumptions



Source: ACER calculations based on the ERAA 2021 data.

ACER notes that the suggested costs of the ADEME study diverge significantly from other national studies. For example, German authorities have undertaken detailed analysis of DSR potentials and

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https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2023-2020_Annexes/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS%20-%20Annex%20I.pdf

[22] ADEME, Effacement de consommation électrique en France (original title), available on: https://librairie.ademe.fr/energies-renouvelables-reseaux-et-stockage/1772-effacement-de-consommation-electrique-en-france.html.

[23] Separating these costs is essential to differentiate between existing and new DSR capacity.

[24] The annuity costs (reflecting capital and other fixed costs) and variable costs (reflecting fuel and other variable costs) for the highest-cost DSR band are 117.6 k€/MWa and 4800 €/MWh, respectively. The equivalent costs for OCGT plants are 98.3 k€/MWa and 70.8 €/MWh, respectively (ACER calculations, based on the ERAA 2021 data).

associated costs in the Member State, also used in the national resource adequacy assessment.[25] The study shows significantly lower costs and higher potentials associated with the development of DSR. For example, the German national study estimates capital and fixed costs to be a fraction of the costs suggested by the ADEME study: annual fixed costs, reflecting capital and other fixed costs, amount to 8 k€/MWa in the German study compared to a minimum of 50 k€/MWa assumed in the ERAA 2021 for Germany. The equivalent potential in the German study is 14.5 GW in 2025, compared to around 8 GW (including around 1.3 GW of exogenously determined DSR) for the same year in ERAA 2021.

It is therefore questionable why the ERAA 2021 utilises the ADEME study to assess the economic potential of DSR in Germany, instead of the detailed German study undertaken for this purpose. As a minimum, ACER would have expected the assessment to use detailed national studies where these are available.

Finally, ACER would like to highlight that some of the assumptions in the ERAA 2021 are not aligned with relevant national studies and evidence from national markets. More specifically:

- Poland: The ERAA 2021 assumes neither any existing nor any potential DSR in Poland. This assumption is in contrast with evidence and experience from the Member State, where DSR has consistently met a sizable share of the requirement for capacity in the context of the capacity market, including for 2025.[26] More specifically, DSR successfully participated in Polish capacity market auctions with increasing volumes, earning contracts of around 615 MW to 1030 MW across the delivery period 2021-2024.[27] For 2025, 950 MW of DSR have secured contracts in the related auction.[28] The ERAA 2021 assumes that none of this capacity will be available in 2025. The omission of these capacity market contracts is contrary to the ERAA methodology, whereby any already awarded capacity market contracts must be reflected in the central reference scenarios (Article 3(3) and (5)). In contrast, the ERAA 2021 considers awarded contracts for generation in Poland. Generators with such contracts are assumed to be economically viable in the ERAA 2021.
- ACER notes that the assessment does not consider DSR contracted in the context of interruptibility schemes as existing DSR. As of 2020, a number of Member States had interruptibility schemes in place for the purposes of ensuring security of supply.[29] These Member States include Greece, Spain and Portugal with contracted volumes of 800, 2340 and 690 MW, respectively. The ERAA 2021 assumes that none of these Member States have any existing DSR in 2025, only potential for DSR development.[30] ACER expects these amounts of DSR to be available in the future in principle, given that DSR providers have already invested in the necessary technology to be able to provide the required service. The Report does not provide any evidence nor justification for excluding these volumes from the exogenously determined DSR. Even if these DSR volumes are considered as potential DSR, ACER would have expected that their costs relate exclusively with the annual fixed operational and maintenance costs. As noted above, the ADEME study used to derive the annual costs for DSR, does not differentiate between capital and other fixed costs, making this approach infeasible.
- France: The ERAA 2021 assumes that France will have 3.9 GW of DSR in 2025. This value is lower than the amount of DSR assumed in the national resource adequacy study for the same year, by

[25] https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/monitoring-the-adequacy-of-resources-in-the-european-electricity-markets-2021.html

[26] ACER notes that Poland had an interruptibility scheme in place until recently, with a volume of around 700 MW over the winter and summer season (DSR procured separately for each season). For more information, see section 6.5 and Annex 1 of ACER-CEER's MMR 2020 (Electricity Wholesale Market Volume), available on: https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202020%20%E2%80%93%20Electricity%20Wholesale%20Market%20Volume.pdf.

[27] https://ec.europa.eu/energy/sites/default/files/polish_implementation_plan_final_courtesy_translation.pdf

[28] https://www.ure.gov.pl/pl/urzad/informacje-ogolne/komunikaty-prezesa-ure/9237,Informacja-nr-22021.html

[29] For more information see section 6.5 of ACER-CEER's Market Monitoring Report 2020.

[30] Article 5(11)(c) requires that ENTSO-E collects information about existing DSR capacity. The assessment does not report existing DSR capacity and it is unclear if ENTSO-E collects this data.

100-300 MW.[31] ACER also notes that the ADEME study used by ENTSO-E to determine the capital and fixed costs of DSR assesses a DSR potential of 6.5 to 9.5 GW in the Member State, which is not reflected in the ERAA 2021. The latter assumes no additional potential for DSR in 2025.[32]

2.4.2.2. Implicit DSR

For implicit DSR, Article 4(3)(c)(ii) of the ERAA methodology requires that the assessment reflects the expected demand elasticity of the day-ahead market for a modelled year. The ERAA 2021 does not consider implicit DSR in this regard. Essentially, the ERAA 2021 assumes that there will be no additional implicit DSR in the future, compared to current levels.[33] The ERAA 2021 does not contain any evidence to support this assumption. ACER considers that taking such an approach undermines the objective of promoting demand response (Article 1(b) of the Electricity Regulation) and is not in line with the relevant market principles that aim at fostering the development of demand flexibility and consumer empowerment in the energy market and energy transition (Article 3(c) and Article 3(d) of the Electricity Regulation).

Evidence from the market suggests the preconditions to increasingly realise the potential of implicit DSR are gradually being met. ACER expects that implicit DSR will play an increasingly important role, facilitated by the digitalisation of the power system, such as the roll-out of smart meters and other smart technologies, and the possible take-up of time-varying retail tariffs. CEER and ACER's Retail Market Monitoring report shows that the smart meter roll-out progresses across the EU, albeit at a different pace.[34] As of 2020, just under half of EU-27 Member States exceeded a roll-out rate of 50% with nine of them having a rate of at least 80%, while the rest had a rate of less than 50%. The availability of smart-meters is a key enabler for the offering of dynamic retail prices, prices that vary on an hourly basis to reflect the wholesale cost of electricity. As of 2020, electricity consumers in eleven Member States could choose a dynamic pricing contract. Dynamic pricing contracts allow consumers to more actively participate in the electricity market. At the same time, the digitalisation of energy including electricity uses, such as smart lighting and smart thermostats, continues, helping to expand the potential for implicit DSR. According to the International Energy Agency (IEA), digitalisation of the energy system can enable demand shifting and shedding and more broadly help to consume energy more efficiently.[35] The ERAA 2021 effectively does not consider these developments.[36]

Electric vehicles

Section 2.4.1 above, discusses the ERAA 2021 assumptions related to the charging of electric vehicles. Essentially, the ERAA 2021 considers implicit DSR from electric vehicles to some extent through exogenously determined charging profiles. Electric vehicle charging still occurs at peak hours to a greater (e.g. passenger cars for Germany and Belgium) or lesser extent (e.g. passenger cars for Member States using ENTSO-E's charging profile) nevertheless. These charging periods thus include scarcity periods, when supply is projected to be insufficient to meet demand and power prices would

[31] The lower difference refers to the period until the end of June 2025, and the higher for the rest of 2025. The French national resource adequacy assessment considers a different temporal delineation, whereby the year is defined from 1 July of a year until 30 June of the next year. Réseau de Transport d'Électricité (RTE), Bilan prévisionnel de l'équilibre offre-demande d'électricité en France, Edition 2021, available on: https://assets.rte-france.com/prod/public/2021-04/Bilan%20previsionnel%202021.pdf.

[32] More broadly, the French government projects a higher trajectory for the deployment of DSR in the Member State.

[33] Any currently realised implicit DSR should be reflected in the historical demand data.

[34] See https://www.acer.europa.eu/electricity/market-monitoring-report

[35] IEA, Energy and Digitalisation, available on: https://www.iea.org/reports/digitalisation-and-energy.

[36] ACER highlights that implicit DSR is not an innovative concept; implicit DSR has played a significant role in the power system for several decades. For example, RTE estimates that time-varying tariffs delivered up to 6 GW of implicit DSR back in the 1990s (https://www.benelux.int/files/1215/1749/6862/Penta_EG2_DSR_Paper.pdf). Similarly, several jurisdictions across the world have used time-of-use tariffs to guide the behaviour of consumers, especially by incentivising them to shift demand from peak to night hours, and operate the power system cost-efficiently.

reach the highest possible levels (i.e. the maximum clearing price, equivalent to 15 k€/MWh in the central reference scenarios).

Smart charging of electric vehicles, i.e. the process by which the charging of electric vehicles is shifted to hours of lower electricity costs, while fulfilling the mobility needs of the electric vehicle driver, is widely recognised as the most appropriate and cost-effective way to integrate electric vehicles into the power system.[37] The economic benefits of smart charging are much broader than resource adequacy. For example, decreasing demand peaks through smart charging, lowers the needs for new infrastructure, thus delivering greater economic savings to consumers.[38] Achieving economic efficiency would appear all the more important in the current context of high electricity prices in Europe and the concerns raised across consumers, policymakers and other stakeholders.[39]

Recommendations

As noted in the Decision and demonstrated in the section above, the ERAA 2021 relies on simplifications and assumptions that underestimate DSR. The Decision includes recommendations to improve the consideration of DSR in the ERAA 2022 (section 6.4.7). On top of these recommendations, ACER expects ENTSO-E to enhance transparency regarding the assumptions and modelling of DSR in the ERAA 2022 (high priority).

2.4.3. Generation

2.4.3.1. Installed capacity

Article 3 of the ERAA methodology stipulates that the assessment needs to be in line with the NECPs and more specifically with national objectives and targets, among others. This requirement relates in particular to policy decisions regarding the phase-out of coal and nuclear plants and targets for the development of renewable energy. The Report considers these aspects implicitly and does not offer information about how it complies with them; for example, it does not describe how much capacity is assumed to shut down during the timeframe of the analysis as a result of Member States' decisions.

ACER compared the ERAA scenario assumptions for renewable generation with the NECPs. The comparison focuses on wind and solar, which are assumed to be policy related assets in the ERAA 2021 (i.e. subject to targets by Member States and not market-driven). The comparison focuses on the so-called "With Additional Measures" scenario of the NECPs that represents a scenario meeting the 40% emissions reduction target.[40] ACER could analyse 14 Member States due to limited, readily available data. Figure 3 presents the results of this analysis, i.e. the differences in projected installed capacity for wind and solar generation between the NECPs and ENTSO-E's assumptions for 2025. Overall, ENTSO-E's scenarios project a lower installed capacity of over 10 GW. The total difference is

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[37] See for example, ENTSO-E Position Paper: Electric Vehicle Integration into Power Grids, available on: https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/210331_Electric_Vehicles_integration.pdf; IEA Clean Energy Ministerial, Electric Vehicle and Power System Integration: Key insights and policy messages from four CEM workstreams, available on: https://www.cleanenergyministerial.org/sites/default/files/2020-09/2020-9-15%20CEM%20Horizontal%20Accelerator%20FINAL%20FOR%20POSTING.pdf

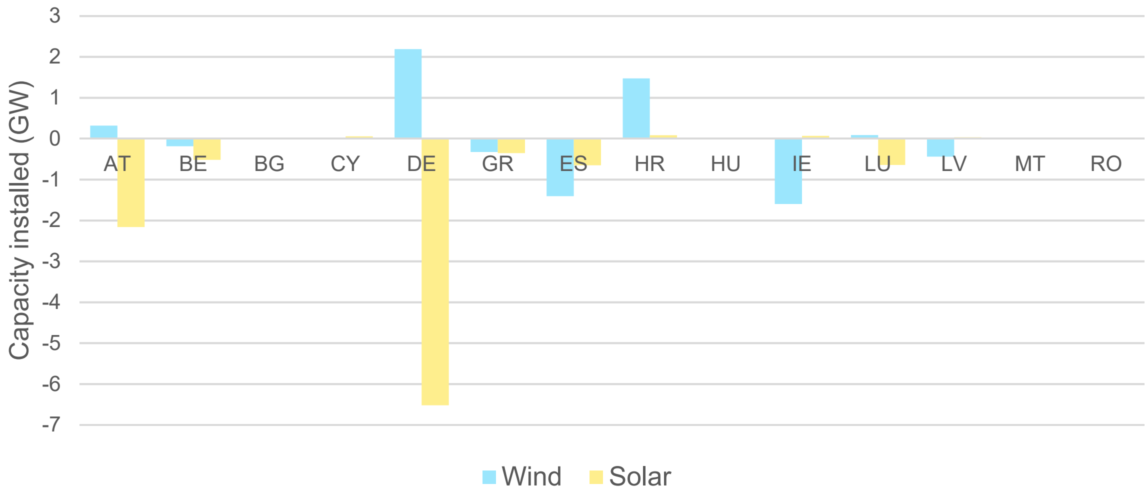
[38] When combining smart charging with Vehicle-to-Grid (V2G) technology, i.e. the ability of the vehicle to inject energy back to the grid, the benefits to the power system can multiply. The ERAA 2021 overlooks the potential for V2G, which is currently largely in its infancy and expected to become more prominent later in the decade. See for example: https://www.iea.org/data-and-statistics/charts/vehicle-to-grid-potential-and-variable-renewable-capacity-relative-to-total-capacity-generation-requirements-in-the-sustainable-development-scenario-2030.

[39] https://extranet.acer.europa.eu//Official_documents/Acts_of_the_Agency/Publication/ACER's%20Preliminary%20Assessment%20of%20Europe's%20high%20energy%20prices%20and%20the%20current%20wholesale%20electricity%20market%20design.pdf.

[40] Member States finalised the NECPs at the end of 2019 and before they agreed on the new emissions reduction target. More information is available on: https://ec.europa.eu/info/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en.

driven by lower installed capacity for solar generation, while the overall figure for wind is similar between the NECPs and ENTSO-E's scenarios. The analysis also shows variations within Member States. ACER notes that these differences are relatively small compared to the total installed capacity of wind and solar.

Figure 3: Difference in assumed installed wind and solar generation capacity assumed in the National Energy and Climate Plans compared to the ERAA 2021 – 2025 (GW)



Note: Positive values mean higher assumption in the ERAA, negative values mean higher assumption in the NECP.

Source: ACER calculations based on the ERAA 2021 data and NECPs.

In addition, ACER has analysed the differences in thermal capacity between today and the ERAA 2021 assumptions for 2025. To perform this comparison, ACER has used the assumed installed capacity in the Summer Outlook 2021 as the most reliable source of currently installed capacity.[41] We compare these installed capacities with the assumptions under the National Estimates scenario drawn by the TSOs, as this largely reflects any known phase-out decisions and development of new plants.[42] The analysis shows that around 67.5 GW of thermal capacity are expected to shut down between today and 2025, while around 16.5 GW are added in the same period.[43] Figure 4 presents the changes in installed capacity between today and the 2025 assumptions of the National Estimates scenarios for natural gas, nuclear, coal and lignite generation. The total amount of closures and additions for these technologies amount to 56.4 GW and 16.5 GW, respectively.[44]

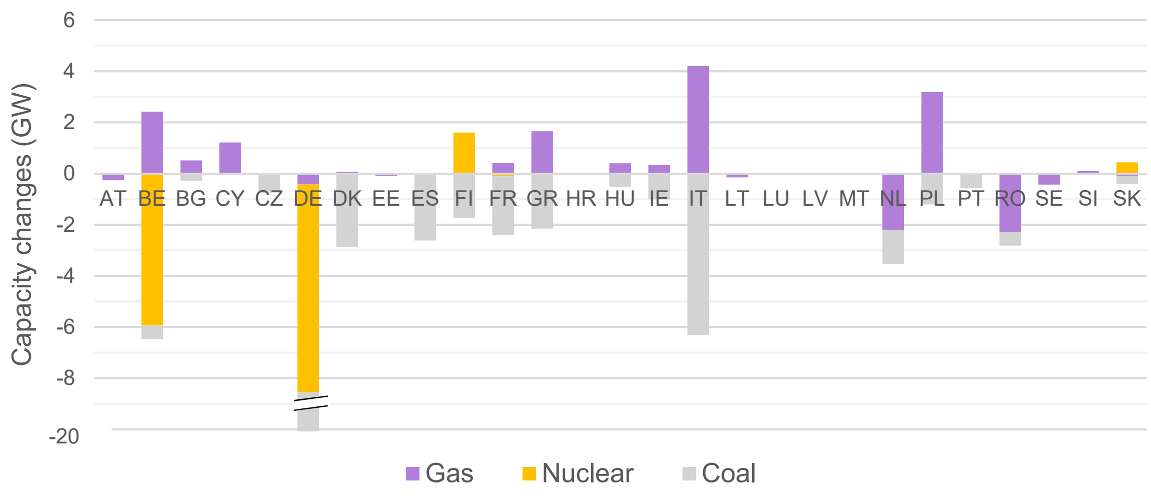
[41]https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/seasonal/SOR2021/1_Summer%20Outlook%202021_Report.pdf.

[42] It is possible however that the National Estimates scenario includes decommissioning and commissioning assumptions beyond known generation phase-outs and new developments.

[43] The changes to the resource mix for the central reference scenarios as a result of the EVA, are on top of these changes.

[44] The remaining amount of closures relates to oil-fired and other non-renewable capacities (not shown in Figure 4).

Figure 4: Differences in installed generation capacity between Summer Outlook 2021 and National Estimate scenario – 2021 and 2025 assumptions, respectively (GW)



Note: Positive values indicate new capacity, negative values indicate plant closures.

Source: ACER calculations based on ENTSO-E's Summer Outlook 2021 and ERAA 2021 data.

2.4.3.2. Variable renewable generation

The Report describes the methodology for modelling each of the different renewable energy technologies in Annex 3. The modelling of variable renewable generation in the ERAA 2021 is broadly consistent with the ERAA methodology. The approach considers the relevant climatic variables for each type of renewable energy, while ensuring consistency between them and with other climate variables (e.g. temperature). Consistency between the climate variables is essential to ensure realistic future representations for the power system.

2.4.3.3. Seasonal availabilities

The ERAA 2021 considers seasonal unavailability of power plants through the so-called "derating" of capacities, in line with the ERAA methodology (Article 4(4)(c)). The consideration of must-run capacity also complies with the methodology (Article 4(4)(c)). The overall unavailable capacity due to derating is limited compared to the total installed capacity, at around 8.5 GW cumulative.[45] For must-run capacity the amount is significantly higher, around 51 GW over EU-27.

2.4.3.4. Planned and unplanned outages

The ERAA 2021 explicitly models planned and unplanned outages for thermal generation, such as gas-fired and nuclear generation. On the other hand, planned and unplanned outages are implicitly considered for variable renewables through the hourly time-series of conversion factors.

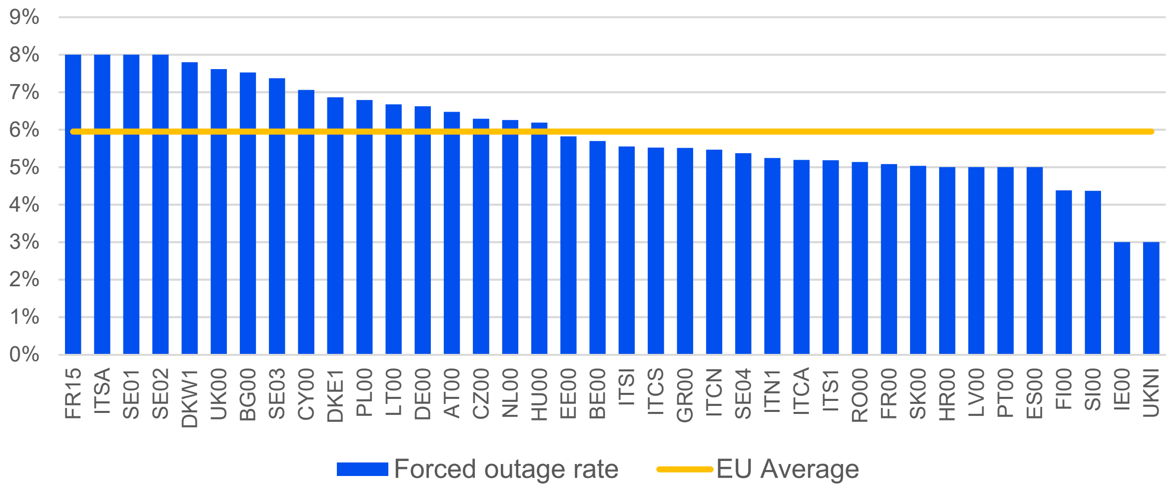
Planned outages are largely modelled with the use of an ex-ante optimisation tool, in accordance with the ERAA methodology (Art. (4)(4)(e)). The tool aims at scheduling maintenance outside the peak season and towards weeks with low peak demand, by levelling the excess available capacity over the weekly peak demand across the year, for each modelled zone. This approach ignores generation from variable renewables and exchanges between modelled zones. The current methodology draws one maintenance schedule for all climate years, based on the 2007 historical demand.

[45] De-rating of capacities does not necessarily mean that the unavailability of capacities coincides in time. The Report does not provide information about when capacities are unavailable.

The assessment determines planned and unplanned outage rates and other characteristics that are essential to model outages, such as the mean time to repair a power plant after a failure, in line with the methodology (Art.(4)(4)(e)). However, it does not contain any information about how TSOs estimate these rates. It is unclear from the report whether all TSOs use the same methodology, such as the number of historical years and periods considered to derive these assumptions.

Figure 5 presents the weighted unplanned outage rate for gas generation, for each bidding zone in EU-27 and the average across the whole of EU-27 (orange line). Gas generation will form the bulk of thermal generation in the future, as several Member States gradually phase-out other thermal generation, such as more polluting coal-fired and lignite-fired power plants, or thermal capacities retire due to unfavourable economics. The figure shows that forced outage rates vary across EU-27 from 3% - 8%, with an average of around 6% across the region. While this range might appear narrow at face value, a 1% improvement in the forced outage rate is equivalent to an additional 2 GW of gas capacity on average across the peak hours. This means that a small change in the unplanned outage rate for gas generation has an appreciable impact on its available, average capacity and may subsequently affect the results of the assessment.

Figure 5: Assumed forced outage rates for gas technologies across EU-27 bidding zones - 2025 (percentage)



Source: ACER calculations based on the ERAA 2021 data.

2.4.3.5. Technical constraints

In addition to the planned and unplanned outages, the ERAA 2021 considers a limited number of technical constraints for thermal generation. These constraints relate primarily to certain restrictions in the minimum or maximum output of power plants, such as an obligation to produce at a minimum level ("must-run" obligation) or the unavailability of part of the capacity of generating plants for certain periods in the year ("derating" constraint).[46] On the other hand, the assessment largely omits technical constraints related to the operation of power plants (further discussed under chapter 4). The consideration of technical constraints is broadly in line with the ERAA methodology (Article 4(4)(f)), albeit in a simplified manner. Section 4.1.3 of the Technical annex discusses in more detail the effects of the broad omission of technical constraints related to the operation of power plants.

Recommendations

Regarding the installed generation capacity, ACER recommends that future ERAAs clearly explain how assumptions on installed capacity relate to policy decisions (e.g. phase-outs of capacities), other developments (e.g. commercial decisions) or TSOs' assumptions (high priority). In general, the Report

[46] For more information see section 2.4.3.3 of the Technical annex, above.

would benefit from showing the differences with the present situation, on this topic and more broadly (low priority).

The methodological approach to modelling variable renewables would significantly benefit from a more detailed description, for example, to better understand the steps followed to estimate the conversion factors for wind and the results of the validation runs and impacts on the Pan-European Climate Energy Database (high priority). The Report could also provide more information and justifications about the choice of different elements related to the assumptions.[47]

Related to the seasonal availabilities of generation, the Report could usefully explain the reasons for these assumptions, especially for must-run units that represent a considerable amount over total installed capacity (high priority), as well as the periods for which the derating of capacities apply (low priority).

ACER invites ENTSO-E to publish complete information about the methodologies used to determine the assumptions for planned and unplanned outages, especially the planned and unplanned outage rates for different technologies (high priority). Ideally, the principles of the methodologies used by national TSOs to derive these assumptions would be consistent across the assessment, without prejudice to the historical data being used for the purpose of estimating the assumptions. ACER therefore recommends that ENTSO-E and TSOs develop a common methodology for determining the relevant assumptions to assess the planned and unplanned outage rates and further characteristics, such as mean time to repair (low priority).

In relation to the ex-ante optimisation methodology for planned outages, ACER notes that the current approach relies on a single historical demand year. The Report does not explain why this year was selected,[48] nor why the use of one climate year is suitable to provide input for predictive maintenance across all modelled climate years. It is also unclear from the Report how this approach relates to current TSO practices. An alternative approach that ACER believes is worth investigating is to use a stochastic optimisation employing as many climatic years as possible (low priority). Such an approach could have the additional benefits of considering the contribution of variable renewables in the optimisation, by considering residual demand (after non-dispatchable renewables) rather than gross demand when scheduling maintenance. This approach would also be consistent with the ex-ante optimisation tool for storage, that also considers residual demand (for more information, see section 2.4.4). ACER also recommends that the maintenance schedule takes into account expected interconnector flows, in line with the real market. ACER recognises that ENTSO-E is planning to "extend the maintenance optimisation by considering more climate years, wind and solar feed-in and interconnection flows". However, ACER notes that the ERAA 2021 does not provide any further information about ENTSO-E's plan and invites ENTSO-E to publish more information about the scope and timeline for this work in the ERAA 2022 (high priority).

In relation to unplanned outages, ACER recommends that ENTSO-E investigates the impact of pricing signals and tighter markets on forced outage rates for gas technologies in particular (low priority). As explained above, gas-fired generation will represent the main form of thermal generation in the future. As the market disposes of current over-capacity and simultaneously market reforms progress to improve the functioning of the wholesale market (e.g. via the market reform plans developed by Member States pursuant to Article 20 of the Electricity Regulation), it is expected that the market signals for gas-fired power plants will improve. At the same time, current unplanned outage rates for these plants are

[47] For example, the Report could offer more information and justifications about the power curves used for wind power and the assumptions for the locations of new wind farms.

[48] Based on information received from ENTSO-E, 2007 was selected as it represents a relatively mild and average climate year.

based on historical years that were until recently favouring coal and lignite-fired generation, and dominated by significant over-capacity in the market.[49]

2.4.4. Storage

The ERAA methodology determines two main types of storage: hydro power plants with storage capabilities, i.e. pumped-storage hydro, and battery storage. The following section reviews each type separately.

2.4.4.1. Hydro storage

Pumped-storage hydro comprises the bulk of storage in the ERAA 2021. Pumped-storage hydro is split into open-cycle and closed-cycle plants, whereby the former have a natural inflow of water, in contrast with closed-loop plants. The definition of hydro storage is in line with the ERAA methodology (Article 4(5)(a)).

The operation of pumped-storage hydro is largely decided through an ex-ante optimisation tool, the results of which are fed into the rest of the model, the EVA and economic dispatch. As a first step, the ex-ante optimisation tool derives the storage levels throughout the year on a weekly (or greater granularity, e.g. monthly) level. In the second step, the available energy profile of pumped-storage hydro is optimised in daily energy lots. These daily energy lots are then fed into, and further refined in subsequent steps of the modelling tool (i.e. the EVA and economic dispatch steps) to derive hourly injection and withdrawal profiles from hydro storage units.

Overall, the ex-ante tool aims at dispatching hydro storage when net load (i.e. load after production from non-dispatchable renewables) is high and store energy when there is significant generation relative to demand. In other words, the ex-ante optimisation tool dispatches hydro storage when prices are expected to be high and stores energy when prices are expected to be low, thereby aiming at minimising total system costs. Even though the Report does not describe how this approach reflects the expected operational principles for hydro storage (Article 4(5)(1)(a)(i) of the ERAA methodology), ACER understands it is consistent with standard market practices for the operation of hydro storage.

The modelling approach uses a number of constraints to guide the operation of hydro storage, such as boundaries about the minimum and maximum levels of the energy stored in reservoirs at the beginning of every week.[50] These constraints are on top of technical constraints, such as the maximum amount of energy that can be stored in a reservoir or the maximum output of a plant based on its installed capacity. The Report usefully explains the constraints that are relevant for the different types of hydro plants. On the other hand, the Report lacks information about how these constraints relate to environmental constraints (Article 4(5)(a)(ii) of the ERAA methodology).

2.4.4.2. Battery storage

On top of relevant hydro plants, the ERAA 2021 models battery storage (or simply 'batteries'). Batteries are split into two categories: in-the-market (or commonly referred to as grid-scale batteries) and out-of-the-market (or commonly referred to as behind-the-meter) batteries. The operation of grid-scale batteries is optimised with the same ex-ante optimisation tool used for the optimisation of hydro generation.[51] Behind the meter batteries are modelled on the demand side, as peak shaving units,

[49] Current overcapacity is evident for example in the recent ENTSO-E seasonal outlooks that overall show negligible risks for Europe.

[50] According to the Report, some TSOs provide deterministic, pre-specified trajectories for the level of energy stored in reservoirs on a weekly basis.

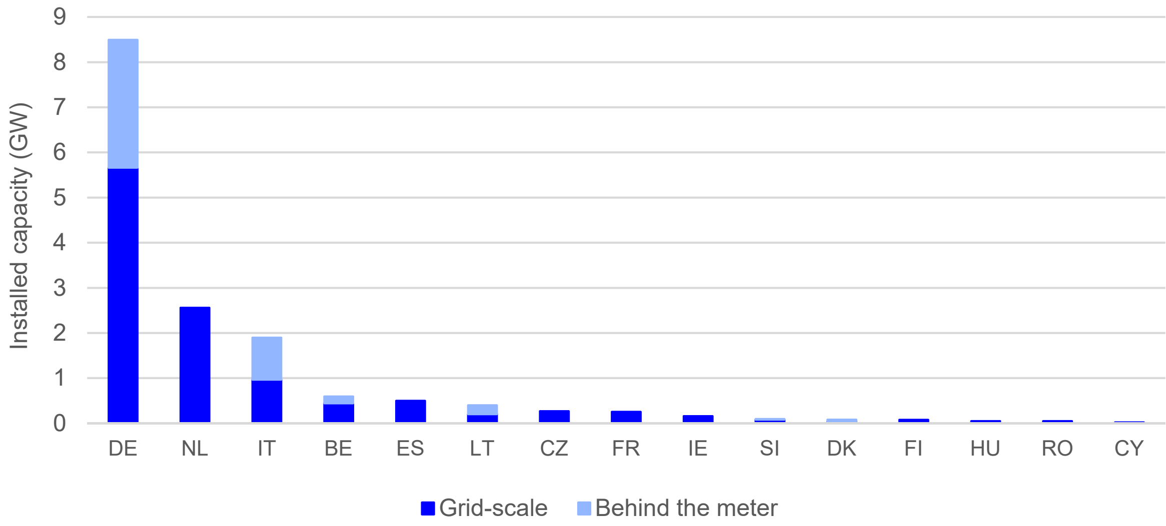
[51] ACER understands that the operation of grid-scale batteries is determined through the daily optimisation, since these batteries tend to have limited energy capacity.

where ENTSO-E and national TSOs determine the rate of peak shaving. The definition of battery storage is in line with the ERAA methodology (Article 4(5)(b)).

The description of the assumptions on battery storage is limited in the ERAA 2021. Importantly, the Report does not contain any information about the sources used to assess the projected levels of installed capacity. ACER understands that the assumptions on battery storage are based on national TSOs' forecasts. The Report does not provide information about how these forecasts are established, for example, whether they are based on market data (e.g. historical trends of installed batteries), projects currently in the pipeline, or other sources. Similarly, the Report does not specify how the rate of peak shaving associated with behind the meter storage is derived (e.g. how peak hours are defined for this purpose).

Figure 6 presents the assumed installed battery storage capacity per bidding zone in 2025. ACER observes that battery storage features in just over half of the Member States in EU-27, and for many of these Member States the assumed capacity is negligible. It is unclear from the Report what drives these significant differences across Member States (e.g. regulatory framework, support policies).

Figure 6: Assumed installed battery storage capacity in the EU-27 – 2025 (GW)



Note: only Member States with non-zero installed battery storage capacity are shown.

Source: ACER calculations based on ERAA 2021 data.

Recommendations

Regarding hydro storage, the overall approach to optimising their operation is broadly in line with the ERAA methodology and appears consistent with their expected operation. Nevertheless, the Report would benefit from additional information about the modelling of hydro storage. ACER recommends that future assessments clearly explain the ex-ante optimisation of hydro storage in more detail, how this optimisation reflects operational practices, and how the assessment considers environmental constraints (e.g. on potable and agriculture uses) at a more granular level (high priority). The assessment could also benefit from a post-evaluation of the results of the ex-ante optimisation tool, to examine how these results compare with the expected use of hydro storage, for example based on electricity prices (low priority).

In relation to battery storage, ACER expects ENTSO-E to publish more information in future assessments, including the basis for the assumptions on installed capacity and assumed operation for behind-the-meter storage (high priority). Future assessments would also benefit from granular information about the storage duration of batteries (low priority).[52] The ERAA 2021 reports battery storage in an aggregate manner.

2.4.5. Network

This section focuses on the approach to cross-zonal capacities and balancing reserves in the ERAA 2021 central reference scenarios. Chapter 5 of the Technical annex presents ACER's review of the flow-based proof of concept in the ERAA 2021.

2.4.5.1. Network development

ACER's assessment on the network development of the ERAA 2021 concerning the applicable framework is included in the Decision, section 6.2.1.8.

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

The Electricity Regulation introduced a minimum 70% target for capacity available for cross-zonal trade. To ensure a harmonized implementation, monitoring and compliance assessment of the minimum 70% target, ACER, in coordination with regulatory authorities (NRAs) and transmission system operators (TSOs), issued a recommendation in 2019 (hereafter 'the Recommendation'). The Recommendation provides a concrete way to implement and monitor the achievement of the 70% target across the EU, calculating the margin available for cross-zonal trade (MACZT).

ACER's analysis of the compliance of cross-zonal capacity used in the ERAA 2021 with the minimum 70% target is based, to the extent possible (i.e. when sufficient data allows for it) on this Recommendation, and on the results of the MACZT monitoring that ACER conducted for the year 2020.

The minimum 70% target is only monitored on the bidding-zone borders within and between the EU's Member States, and should be met for all hours throughout the year.

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 2021 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 countertrading is fully implemented. 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 first on DC borders, then on AC borders. Each subsection details the methodology used to assess compliance with the 70% rule and the findings.

Direct Current borders

[52] Storage duration of batteries is determined as the amount of hours that storage can discharge at its injection capacity before using all its energy

Methodology

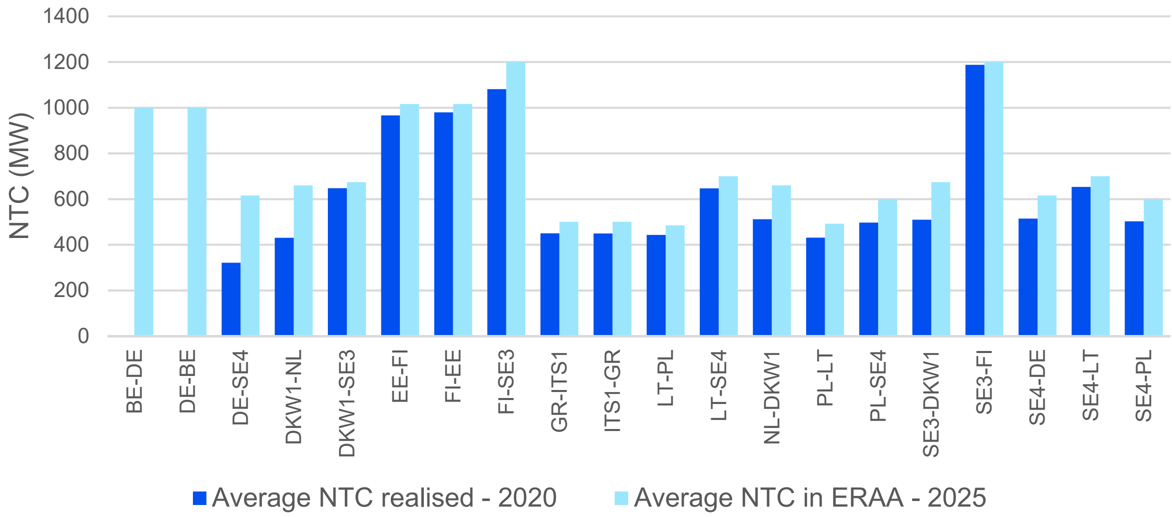
For borders with Direct Current (DC) interconnectors only, ACER recommends to compare the net transfer capacity (NTC) value offered by the TSO on the border, with the maximum admissible flow on the border ("Fmax").[53] NTC/Fmax must be greater than 70% to meet the 70% minimum target.[54]

For the Fmax values for 2025, the ERAA 2021 does not contain information about any infrastructure projects that would affect the maximum capacity on the DC borders between two EU countries. Consequently, the Fmax on borders between EU countries are considered identical in 2025 to Fmax in 2020.

Findings

Figure 7 presents the average NTC value in 2020, and the average NTCs assumed for 2025 in the ERAA 2021, for each DC border.

Figure 7: Average NTCs per border - 2020 (realised) and 2025 (ERAA 2021 assumptions) (MW)



Source: ACER calculations based on the ERAA 2021 and on TSOs data provided in the scope of the ACER MACZT reports for 2020.

There are a few notable developments between the NTCs realized in 2020, and the NTCs foreseen for 2025:

- The ALEGrO cable on the border between Belgium-Germany went live in 2020.
- The forecasted NTCs increase offered on some borders, in particular on the borders Denmark1-Netherlands (in both directions), Sweden3 to Denmark1, and Germany to Sweden4.

Based on Fmax from 2020, the assumed NTCs for 2025 in the ERAA 2021 meet the 70% minimum target in all hours and on all EU DC borders.

[53] Maximum flow respecting operational security limits. Please refer to the Recommendation (page 5, Definitions and abbreviations) for more details.

[54] TSOs may also declare internal Alternating Current (AC) network elements that limit the capacity that they can offer on the DC border. In this case, the MACZT should also be calculated on these elements, and compared to the 70% minimum target. These elements are out of scope of the present analysis, as the ERAA 2021 does not contain any relevant data.

ACER notes that, in 2020, the allocation constraints applied by Poland limited the NTC made available to the market on the borders Poland-Lithuania and Poland-Sweden4.[55] In ACER's understanding, these constraints are not considered in the NTC assumptions of the ERAA 2021. If these allocation constraints remain in 2025, they could reduce the NTC below the 70% minimum target on these borders.

Alternating current borders

Methodology

For borders with Alternating Current (AC) interconnectors, ACER recommends that the 70% minimum target is met on each critical network element and contingency (CNEC). For the borders where NTC-based approach is applied, as long as TSOs are unable to calculate the flow available on all CNECs, the target should be met at least on the CNECs limiting the capacity calculation.

The ERAA 2021 does not contain information on CNECs for 2025, thus ACER is unable to apply strictly the Recommendation. Instead, as a simplification, ACER's assessment uses the following criterion to estimate whether the NTC of the ERAA would allow to meet the 70% minimum target. Where possible (i.e. for NTC-based borders in 2020), ACER's assessment compares the NTC assumptions of the ERAA 2021 with the average NTC of 2020. This allows to estimate, based on whether the minimum target was met or not in 2020, if the NTCs for 2025 could be sufficient to meet the target on the CNECs of 2020.

More precisely, ACER applies the following approach to estimate whether the NTC assumptions in the ERAA 2021 would allow to meet the 70% minimum target:

- On the borders that were NTC-based in 2020:
    - If the average NTC of 2025 is below the average NTC of 2020, and the target was not met in 2020, ACER has high confidence that the target would not be met in 2025.
    - If the average ERAA NTC of 2025 increased compared to the average NTC of 2020:
        - If the ERAA NTCs of 2025 would have allowed to meet the 70% target in 2020 (i.e. using the CNECs and market models of 2020) for a majority of hours (at least 90% of hours), then the target could possibly be met in 2025;
        - Otherwise, the target would likely not be met in 2025.

This simplified approach is subject to some limitations. In particular, the network in 2025 will not be exactly the same than in 2020. Consequently, the elements limiting capacity calculation in 2020 may differ from the elements that will be limiting in 2025, and the flows computed in these elements may also differ. The approach allows to reach conclusions with different levels of confidence.

Another caveat is that allocation constraints that may still apply in 2025 and could reduce the final NTCs (in particular for Poland and Italy North) are likely not considered in the ERAA NTCs. Further considerations on allocation constraints can be found further down in this section.

- For the borders that applied flow-based in 2020:
    - As the MACZT monitoring relied on flow-based, no 2020 NTCs are available.

As a complement to support the analysis, ACER's analysis also compares, for all borders, the ERAA 2021 NTC assumptions for 2025 (that should include the 70% minimum target) with the Mid-Term Adequacy Forecast 2018 NTC assumptions for 2025 (that likely did not reflect the minimum 70% target, as the MAF 2018 was published before the entry into force of the target).

[55] See Table 1 for more details.

In addition, as the ERAA 2021 includes flow-based domains for Core for 2025, a comparison between the flow-based domains assuming 70% capacity for 2025 and the NTC domains for 2025, allows inferring whether the NTC domains for 2025 is likely in line with the minimum 70% target.

Findings

NTCs

Figure 8 shows whether NTCs for 2025 of the ERAA could allow TSOs to meet the 70% minimum target for each AC border.

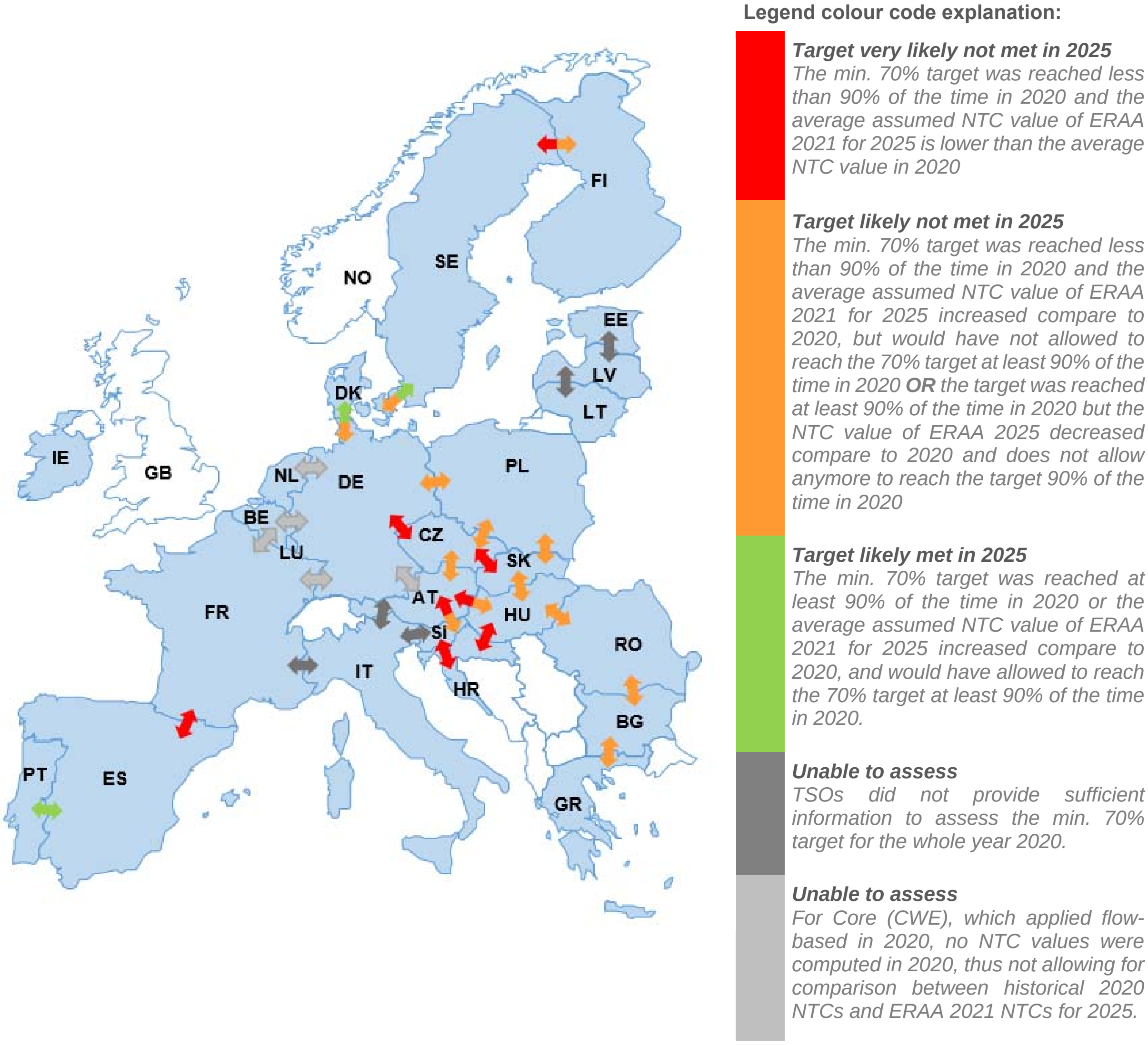
The analysis of NTCs reveals that for a significant number of borders, in particular on Core (non-CWE) borders, the minimum 70% target would be very likely, or likely, not met, if the NTCs of 2025 reach the level assumed in the ERAA 2021 model.

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.[56]

For Core (CWE), the NTCs in the ERAA 2021 have not increased compared to the values in MAF 2018. This would suggest that the NTCs of the ERAA 2021 model were not computed to meet the minimum 70% target. However, for Core, the ERAA 2021 asserts that this is the case (see subsection on Flow-based domains below).

[56] Other infrastructure projects may affect the following borders: Spain-Portugal, Hungary-Slovakia, Bulgaria-Greece, Croatia-Hungary, and Italy North region.

Figure 8: ACER's assessment of the 70% minimum target based on the ERAA 2021 NTC assumptions for 2025



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 2021 and on TSOs data provided in the scope of the ACER MACZT reports for 2020.[57]

Flow-based domains

The conclusions drawn in the previous subsection for Core borders are not in line with ENTSO-E's analysis of the flow-based domains.

[57] For more information, see: https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20MACZT%20Report%20S2%202020.pdf; and https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/MACZT%20report%20-%20S1%202020.pdf.

For Core, the ERAA 2021 reports that the flow-based domains meet the minimum 70% target, and that the NTC domains are larger than them. In other words, the ERAA 2021 suggests that for Core borders, the NTC values are compliant with the 70% target.

However, the analysis of the NTCs presented above leads to the opposite conclusion for some Core (non-CWE) borders. Overall, there is thus significant uncertainty whether the NTC assumptions on Core borders meet the minimum 70% target.

Allocation constraints

The ERAA 2021 contains information about the maximum levels of import or export that TSOs declared would apply in 2025 and 2030. These maximum levels appear equivalent to so-called "external constraints" in the capacity calculation methodologies.

The table below summarises the external constraints reported in the ERAA 2021, compares them with the constraints declared by TSOs for 2020, and assesses whether they could affect the final capacity made available to market participants.

Table 1: Analysis of the maximum constraints of import and export – 2020, 2025 and 2030 (MW)

Member State	2020 (actual)		2025 (ERAA 2021 assumption)		2030 (ERAA 2021 assumption)		Comments
	Import (MW)	Export (MW)	Import (MW)	Export (MW)	Import (MW)	Export (MW)	
BE	5000-7547						If the same allocation constraints would apply in 2025, they could reduce the allocated capacity (sum of import NTCs: 6700MW)
BG			6700	6700	6800	6800	No impact on forecasted NTC
CZ			7100	6800	7100	7300	No impact on forecasted NTC
IT	0-9000						If the same allocation constraints would apply in 2025, they could reduce the allocated capacity (5210MW)
MT			200	200	200	200	No impact on forecasted NTC
NL	5750-6500	5750-6500	5750-6500	5750-6500	5750-6500	5750-6500	Allocation constraints could reduce the allocated capacity (sum of NTCs: 7400MW)
PL (AC)	0-6830	0-13359					If the same allocation constraints would apply in 2025, they could reduce the allocated capacity (sum of NTCs: 3718 MW import, 4981MW export)
PL (DC)	0-9233	0-8800					If the same allocation constraints would apply in 2025, they could reduce the allocated capacity (sum of NTCs: 1100 MW)
SK			4058	2200	4058	2200	Allocation constraints could reduce the import (sum of NTCs: 4931MW), and considerably reduce the export (sum of NTCs: 3960 MW)

Source: ACER calculations based on the ERAA 2021 and on TSOs data provided in the scope of the ACER MACZT reports for 2020

Recommendations

ACER has the following recommendation for future assessments regarding cross-zonal capacity calculation and compliance with the minimum 70% target (high priority):

- When computing the parameters in line with the minimum 70% target, the ERAA 2022 should base their calculation on ACER's Recommendation 01/2019.
- If the ERAA 2022 contains allocation constraints, these should be complemented by justifications on the reasons that make them necessary and on the way the associated levels are computed. In addition, the ERAA 2022 should ensure that the minimum 70% target is reached, even when considering the impact of these allocation constraints. Finally, when allocation constraints currently

apply in a bidding zone and the assessment does not consider any allocation constraints in future years, ACER invites ENTSO-E to clearly explain why such constraints are not necessary anymore.

2.4.5.3. Balancing Reserves

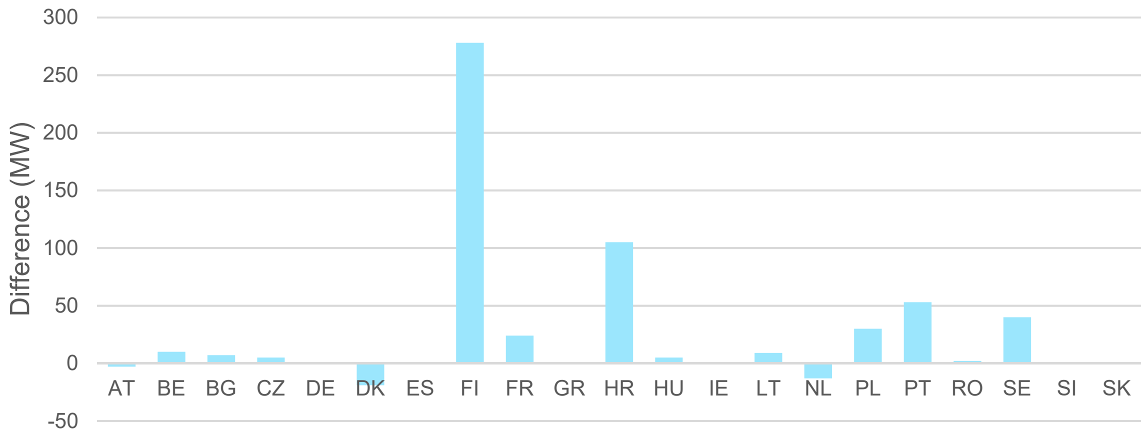
The ERAA methodology stipulates that the assessment must reflect balancing reserves. More specifically, the methodology determines that the assessment must:

- Define frequency containment reserves (FCR) and frequency replacement reserves (FRR) requirements. The dimensioning of these reserves must be based on Article 153 and 157 of the System Operation Guideline (SO GL) (Article 4(6)(g)(i) of the ERAA methodology), respectively. These requirements can be deducted from the available capacity or added to demand if the assessment does not explicitly model imbalances (Article 4(6)(g)(ii) of the ERAA methodology).
- Define replacement reserves (RR) and their size based on Article 160 of the SO GL (Article 4(6)(g)(iii) of the ERAA methodology). RR must always be available in the market for addressing resource adequacy.

The ERAA 2021 determines FCR and FRR explicitly, but not RR. FCR and FRR are treated as non-available capacity to the market, since the assessment does not explicitly model imbalances and the balancing market. The ERAA 2021 does not specify the methodology used to estimate the level of requirements and hence it is not possible to evaluate whether the assessment complies with the ERAA methodology on this point. RR are implicitly considered available to the market, in line with the ERAA methodology.

ACER has compared the ERAA 2021 assumptions for FCR and FRR requirements in 2025, with the actual 2020 requirements based on the volumes collected for ACER-CEER's Marker Monitoring Report 2020 (ACER-CEER's MMR 2020). Figure 9 presents the differences for the FCR requirements. The total requirement for FCR across the EU-27 increases to 4.6 GW compared to 3 GW currently. The graph shows that the requirements either increase or remain constant, while in limited cases the level of FCR reserves decreases slightly. In a couple of cases, FCR requirements increase significantly compared to current practices, notably for Finland (nearly 300 MW) and Croatia (just over 100 MW).

Figure 9: Differences in FCR requirements per Member State – 2020-2025 (MW)



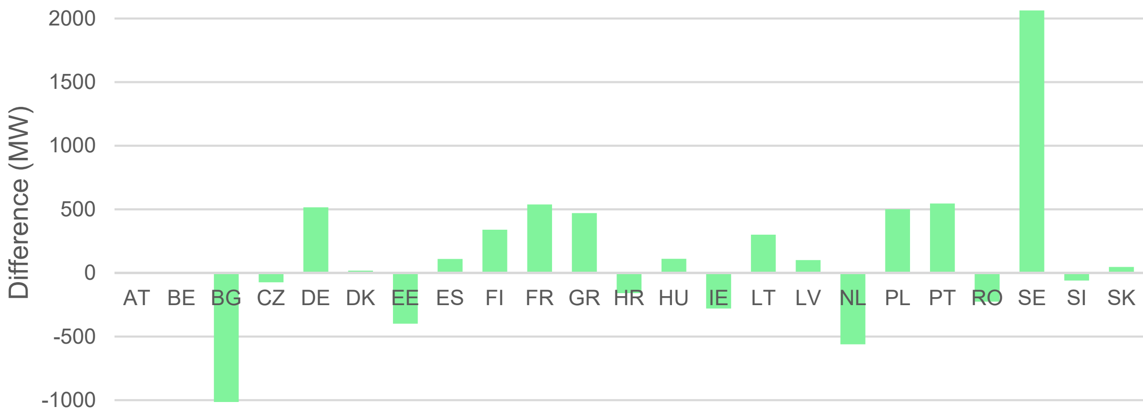
Notes:

1) Present reference requirements are missing for CY, EE, IT, LU, LV and MT. Therefore no comparison is presented for these Member States.
2) Positive value means assumed FCR requirement is higher than present requirement and negative value means assumed FCR requirement is lower than present requirement.

Source: ACER calculations based on the ERAA 2021 and data collected for the purpose of ACER-CEER's 2020 MMR through NRAs.

Similarly, Figure 10 presents the differences for the FRR requirements between the 2025 assumptions in the ERAA 2021 and the actual 2020 requirements, based on data collected for ACER-CEER's MMR 2020. The picture is more mixed in this case. For the majority of bidding zones, the reserve requirement increases. In several occasions, this increase is significant in absolute terms: around 500 MW for Germany, France, Greece, Poland and Portugal. For other bidding zones the increase is less pronounced (e.g. an increase of around 340 MW in Finland) or negligible. For a different group of bidding zones, the reserve requirement decreases compared to 2020. The reduction is more significant for Bulgaria (around 1000 MW) and the Netherlands (around 500 MW). Overall, the reserve requirement for FRR is projected to increase up to 28.2 GW in EU-27.

Figure 10: Differences in assumed FCR requirements per Member State – 2020-2025 (MW)



Notes:
1) Present reference requirements are missing for CY, IT, LU and MT. Therefore no comparison could be included.
2) Present FRR requirements Include automatic (aFRR) and manual (mFRR) upward restoration reserves
3) Positive value means assumed FRR requirement is higher than present requirement and negative value means assumed FRR requirement is lower than present requirement

Source: ACER calculations based on the ERAA 2021 and data collected for the purpose of ACER-CEER's 2020 MMR through NRAs.

Recommendations

Future ERAAs would significantly benefit from clear explanation about the methodology used to determine reserve requirements and the main drivers for any changes compared to present (high priority).

2.4.6. Other elements

2.4.6.1. Climate change and climate-dependent variables

The ERAA methodology prescribes that the assessment takes into account the effects of climate change on climate-dependent variables, and the Pan-European Climate Energy Database (PECD) in particular (Article 4(1)(f)). The methodology sets three different options for achieving this requirement. The ERAA 2021 uses a temporary solution, which is broadly in line with the ERAA methodology. The temporary approach effectively utilises the first option, based on which future climate projections must rely on a best forecast. More specifically, the ERAA 2021 considers the effects of climate change through a de-trending analysis of historical temperatures. The Report usefully describes the methodology used to derive projected future temperatures based on historical data (Annex 3 of the Report). At the same time, the Report could explain in more detail the reasons for the chosen approach and its impacts on temperatures across the geography of the assessment.[58]

[58] For example, the Report states that ENTSO-E considered four different approaches for the de-trending analysis and chose the fourth of them. The Report does not provide the reasons for selecting this approach however. To explain the results of the different options the Report contains a graph for Belgium. ACER notes it is rather difficult to interpret the results of the analysis based on this single graph.

Article 5(12) of the ERAA methodology prescribes that ENTSO-E updates the PECD with the most recent climate data before the first ERAA and then at least every 5 years. For the ERAA 2021, ENTSO-E updated some of the variables (e.g. temperatures) of the PECD for all historical years, but not all relevant variables. Notably, the latest PECD does not include updated hydro data (for all countries) and demand (for some countries). As a result, the scope of the use of the updated data was limited. ENTSO-E used the updated data to perform the aforementioned de-trending analysis of historical temperatures and determine the relationship between demand and climate variables in the Trapunta model where data was available.[59] As such, ENTSO-E could not use the full database for running the ERAA model, as some information was missing and it would not have been possible to maintain the interdependencies between the various climate-dependent variables.

Recommendations

ACER acknowledges that ENTSO-E plans to update the PECD by the end of 2022 for use in the ERAA and other projects with the assistance of the Copernicus Climate Change Service (C3S). The updated database is expected to be available for the ERAA 2023. Considering the depth and significance of the planned update, ACER believes it is of outmost importance that ENTSO-E engages with relevant stakeholders (e.g. climate scientists beyond C3S) considering this pending update of the PECD (high priority).

[59] For more information, see section 2.4.1.

3. Economic viability assessment (EVA)

3.1. Introduction

The purpose of the EVA in the ERAA is to assess economic decisions about entry and exit of capacity resources in the electricity market, based on expected revenues and associated costs. The ERAA methodology provides two alternatives for assessing economic viability of resources and deciding on investing, decommissioning or mothballing/de-mothballing options.[60] The first is to assess the economic viability of individual (or groups of) capacity resources, based on a comparison of expected revenues and costs. The second (simplified) alternative is to assess the relevant decisions by minimizing total system costs, i.e. total fixed and operating costs, including the cost of consumer disconnections. At the same time, the ERAA methodology requires that the EVA relies on the results of the economic dispatch model, ensuring consistency between the two.[61]

In the ERAA 2021, ENTSO-E implements the cost minimisation approach (second alternative) in the central reference scenario without CM for 2025.[62] Justified on the basis of exceptional computational needs, the EVA includes a number of simplifications, such as reduced number of modelled climate years and simplified forced outage modelling. The ERAA 2021 includes a sensitivity analysis, implementing the EVA in the same central reference scenario, in order to assess the impact of different CO_2 prices and maximum clearing prices.

ENTSO-E also applied a qualitative viability assessment of capacity resources for the scenarios National Estimates and National Estimates with Low Thermal Capacity for both modelled target years, i.e. 2025 and 2030, comparing expected revenues and costs of coal, gas, lignite and oil units. This qualitative assessment is not in line with the ERAA methodology, in particular with Article 6(5), as it does not examine the possibilities of entry/exit of capacity resources, and is therefore not analysed further.

Appendix 2 of the Report presents the results of the EVA, including the sensitivity analysis, while Chapter 5 of Appendix 3 describes the methodological approach for the simplified EVA. In addition and upon ACER's request, ENTSO-E provided clarifications regarding the methodology, as well as supplementary data regarding the adequacy risk indicators of the EVA model runs and an additional ex post qualitative viability assessment conducted for the central reference scenario without CM.

3.2. Overview of ACER's review

ACER recognises that the inclusion of an EVA in the ERAA is a challenging undertaking and that the size and interconnectivity of the modelled area in the ERAA increases the complexity of the problem substantially. Hence, the current version of the ERAA constitutes a significant improvement, at least in terms of modelling advancement, compared to MAF. At the same time, a robust and reliable EVA is

[60] Article 6(2) of the ERAA methodology

[61] Article 6(6)(b) and Article 6(9) of the ERAA methodology

[62] The central reference scenario with CM is based on the central reference scenario without CM adding (or removing if necessary) capacity resources to the modelled zones with CMs until the reliability standard of these modelled zones is reached (practically assuming that the CM remuneration will ensure their economic viability). However, an EVA after this addition, in order to assess the impact of the CMs in neighbouring modelled zones, is not performed. Also, the flow based proof of concept simply uses as input the results of the EVA central reference scenario without CM, hence in reality the EVA was not tested with a flow based market coupling approach.

imperative for the proper assessment of adequacy levels, as it essentially determines the available capacity resources that are considered in the resource adequacy assessment itself.

ENTSO-E applies the EVA for a single modelled year only (2025), which is a significant limitation when assessing decisions regarding assets with a long economic lifetime. In addition, the simplifications introduced in the EVA to cope with computational complexity lead to significant inconsistencies between the EVA and economic dispatch. These inconsistencies cause an underestimation of the capacity that could enter or remain in the market and consequently an overestimation of the resource adequacy indicators. Moreover, the EVA considers only investment and decommissioning decisions for a limited type of capacity resources.

Overall, ACER considers that the level of simplifications of the EVA in the ERAA 2021 is not acceptable due to the considerable impacts it has on the results.

3.3. Detailed review

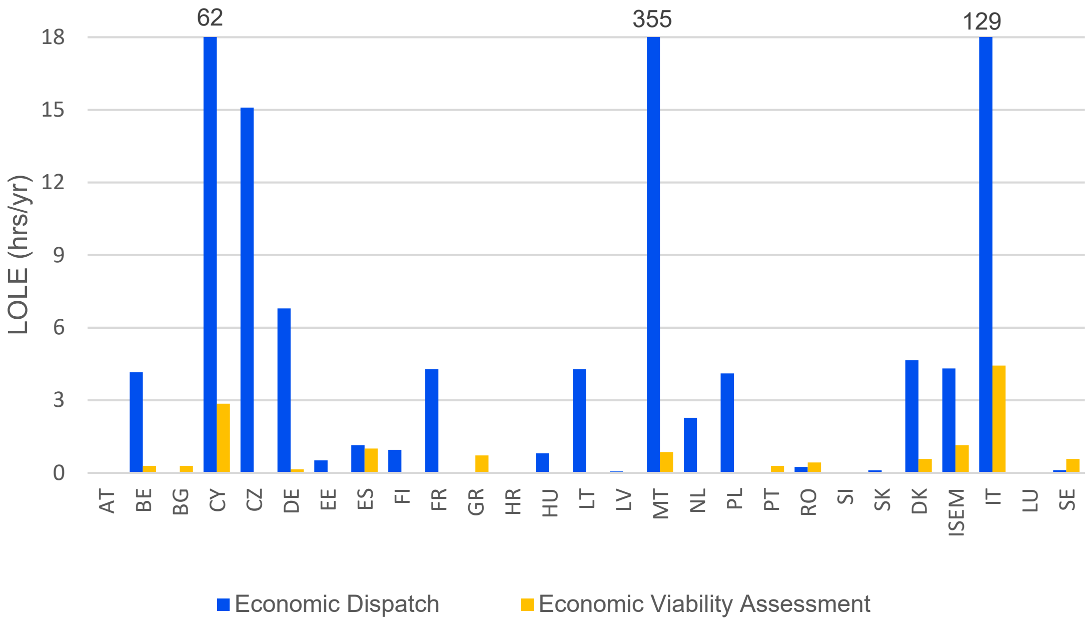
3.3.1. Consistency between the economic viability assessment and economic dispatch

The EVA is formulated as an optimisation problem, which minimises total (fixed and operating) system costs over the whole study period by applying market entry and exit decisions (currently only investments and decommissioning of a number of technologies). In the ERAA 2021, the time horizon of the optimisation is a single modelled year, i.e. 2025. The EVA model includes an economic dispatch model that provides the economic optimal operation of the (existing and new) capacity resources under certain technical constraints. The EVA output is the capacity resource mix that is used in the economic dispatch model to estimate the adequacy indicators.

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. A comparison between the loss of load expectation (LOLE) indicator from the EVA and economic dispatch, for the central reference scenario without CM, reveals significant differences between the two models (Figure 11). The expected energy not served (EENS) values of the EVA are zero or close to zero for almost all modelled zones, compared to the ERAA results that show non-zero EENS values in most modelled zones.[63] Hence, the ERAA 2021 does not provide an appropriate level of consistency between the EVA and economic dispatch, undermining the robustness of the approach followed and leading to dubious results.

[63] See Table 4 for a complete set of data.

Figure 11. Comparison of the LOLE results between the economic dispatch (ERAA 2021 results) and the EVA model (central reference scenario without CM) – 2025 (hours per year)



Source: ERAA 2021 and additional data provided by ENTSO-E.

As the EVA essentially determines the capacity resource mix that is available for serving demand, the implications of such an inconsistency are significant. ENTSO-E conducted a qualitative viability assessment of coal, gas, lignite and oil fired generation units based on the outcome of the economic dispatch model for the central reference scenario without CM.[64] The results indicate that in most cases resources are highly profitable, while in limited cases capacity is not profitable.[65] As an example, the examination of profitability of gas fired units, presented in Figure 12, shows that profits are several times higher than e.g. the fixed costs of existing gas units used in the model.[66] These profits are generally higher in modelled zones with high LOLE,[67] indicating that additional capacity can potentially reduce the adequacy risks without jeopardizing the viability of the existing units. Evidently, the EVA does not accurately capture the risks and opportunities of the economic dispatch market simulations. The results demonstrate an overall underestimation of the capacity resources that could have entered or remained in the market and thus an overestimation of the adequacy indicators.

[64] This qualitative assessment is not included in the Report. ENTSO-E provided the relevant data to ACER upon request.

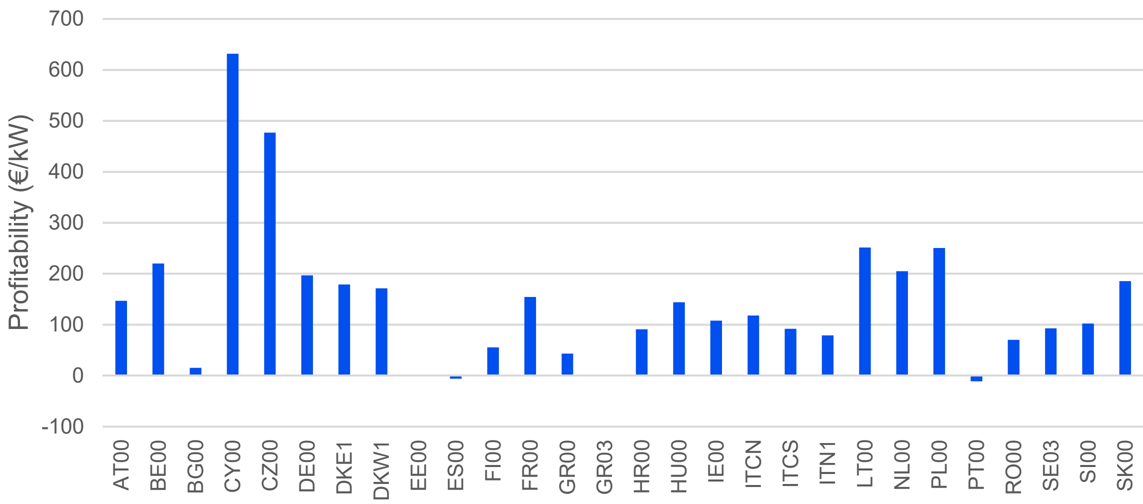
[65] See

Table 5 for a complete set of data.

[66] Annual fixed operating costs for CCGT and OCGT units in the ERAA 2021 are 30 euros/kW and 20 euros/kW, respectively.

[67] As a characteristic example for Czech Republic profits of gas fired units reach 477 euros/kW, while at the same time LOLE is 15 hrs/year, and the EVA resulted in the economic decommissioning of 5GW of thermal units.

Figure 12. Profitability of gas fired units based on expected revenues and costs from the economic dispatch results for the central reference scenario without CM – 2025 (€/kW)



Note: For illustrative purposes, annualised cost estimates for new resources are: for combined cycle gas turbine units 147 euros/kW, for open cycle gas turbine units (98 euros/kW, while for the two lowest cost bands for DSR 34 euros/kW and 57 euros/kW (based on ENTSO-E data and ACER calculations).

Source: ACER calculations based on additional data provided by ENTSO-E.

According to ACER's understanding, the main reasons for this inconsistency are the simplifications regarding the number of climate years and the modelling of forced outages. In order to cope with particularly high computational requirements, ENTSO-E limited the number of simulations performed with the EVA model considering only seven climate years, i.e. 1983, 1984, 1990, 1995, 1996, 2006 and 2009.[68] For selecting climate years, the ERAA 2021 uses a clustering algorithm with the residual load of each climate year as its key variable. The clustering algorithm applies for nine macro regions.[69] The aim of this method is to identify the best candidate group of (seven) climate years that better represent the distribution of the residual load of the full set of (thirty-five) climate years across the geography of the assessment. At the same time, whereas the economic dispatch models probabilistic forced outages of generation units and interconnectors through random unplanned outage scenarios embedded in the Monte Carlo simulations, the EVA only applies deterministic derating factors for generation units, which are uniform throughout the year.[70]

While, in principle, reduction of complexity in order to enhance feasibility is acceptable and expected, any approach chosen should maintain a high degree of consistency between the economic dispatch and the EVA. As a minimum the impact of these simplifications to the calculated adequacy indicators and to the robustness of the ERAA, should be evaluated and properly reported.

3.3.2. Other topics

3.3.2.1. Single year modelling

An appropriate assessment of economic decisions for investments, retirements or mothballing of capacity sources must consider the expected revenues and costs of the relevant assets over their (remaining) economic lifetime. As per Article 6(16) of the ERAA methodology, the EVA may reflect the costs and benefits beyond the ten year study period of a ERAA, in order to address this issue. In this respect, the fact that ENTSO-E applies the EVA for a single year only (2025) reduces confidence on the results of the EVA regarding exit and entry decisions of capacity sources. The current approach is

[68] In contrast the economic dispatch model considers approximately 35 climate years.

[69] See paragraph 5.3 of Appendix 3 of the Report.

[70] I.e. a 10% unplanned outage rate would mean that only 90% of a plant's capacity would be available in all market time units.

not in line with the underlying principle of the ERAA methodology, as described in Article 6, regarding the proper assessment of entry/exit decisions based on an analysis over the whole economic lifetime of the resources or, at least, over the study period covered in the ERAA.

3.3.2.2. General modelling approach

According to the ERAA 2021 report, demand, hydro and storage operation are considered in the same way as in the economic dispatch, while the initial mix of capacity resources (input parameters) originates from the assumptions of the National Estimates scenario. The different bidding zones are coupled using the NTC approach for all capacity calculation regions (CCRs).[71]

The EVA considers investment decisions for gas (open cycle and combined cycle) and DSR, and retirement variables for a sub-set of thermal units (coal, lignite, oil and gas). It does not include other decision options, specifically mothballing, de-mothballing as well as renewal/prolongation of existing units.[72] Renewable energy sources and nuclear generation technologies are considered as being mainly driven by policy decisions.[73] Batteries and CHPs are not considered as possible candidates for entry or exit, since, according to the ERAA 2021 Report, major routes of revenues for these technologies (i.e. heat and ancillary services, respectively) are not modelled in the EVA. Effectively, the installed capacity of the aforementioned technologies is determined exogenously based on the assumptions from national TSOs.

Planned maintenance of existing units is modelled in the same way as in the economic dispatch, while for new candidates a dynamic maintenance rate per technology is used.[74] As explained, forced outages are also modelled in a deterministic way via a uniform derating factor per technology.

While meeting several of the requirements of the ERAA methodology, the current EVA modelling approach is still not in line with the following Articles of the ERAA methodology:

- Article 6(7) that foresees the inclusion of decision variables for mothballing and renewal/prolongation of existing, and for re-entry of mothballed capacity resources;
- Article 6(8) that specifies that network constraints shall be modelled according to Article 4(6) i.e. reflecting the expected capacity calculation method of each CCR;
- Article 6(9)(b)-(d) that requires the EVA to account for expected revenues from other electricity and non-electricity related services; and
- Article 6(12) of the ERAA methodology, which requires generation to be modelled according to Article 4(4), imposing consideration of forced outages in a probabilistic manner.

3.3.2.3. Cost parameters

The EVA calculates total costs considering (annualised) capital cost (CAPEX) and fixed operating and maintenance (FOM) costs, as well as operating costs[75] of resource capacity, including the cost for energy not served (ENS).[76] Article 6(6)(a) of the ERAA methodology requires that cost assumptions in

[71] For more information about the application of the NTC approach see section 2.4.5.

[72] The fact that EVA refers to a single year makes the inclusion of these variables impossible.

[73] The omission of commercial renewable energy sources and storage potential for entry on the basis of market revenues (on top of exogenously defined policy driven deployment) could have implications for the resulting capacity mix and therefore the adequacy indicators.

[74] According to the ERAA 2021 report, the derating factor is "*inversely proportional to the load profile in a given region in order to make more generation capacity available during times of higher load and vice versa*."

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

[76] The EVA assumes a cost of ENS at 15,000 euros/MWh (maximum clearing price). The ERAA 2021 also includes a sensitivity analysis considering cost of ENS at 3,000 euros/MWh.

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. At the time of undertaking the ERAA 2021 no Member State had implemented the methodology for calculating CONE/CORP.[77]

The ERAA 2021 considers uniform cost parameters for thermal units across all modelled zones. ACER has undertaken a comparative analysis of the cost parameters assumptions of the ERAA 2021 with other reference studies. The analysis shows that the cost assumptions for thermal units that are potential new entrants, i.e. combined cycle gas turbine units (CCGT) and open cycle gas turbine units (OCGT), are generally on the higher end of the ranges when compared with other reference studies, as depicted in Table *2*. For example, for CCGTs the assumed capital cost in other reference studies is around 600 €/kW on average while in the ERAA the assumed capital cost is 850 €/kW or 42% higher.

For DSR, CAPEX and FOM are aggregated in a single annual FOM value, while the activation price is estimated based on a macroeconomic approach. Clusters of DSR are then formulated based on the FOM and activation prices and applied uniformly across all modelled zones.[78]

Table 2: Comparison of techno-economic parameters for CCGT and OCGT in the ERAA 2021 and other references

Technology	CAPEX €/kW	FOM €/kW/year	VOM €/MWh	net efficiency	Economic lifetime	Source
CCGT	850	30	1.9	60%	20	ERAA 2021
	600-850	25-30	2	-	20	Elia, 2021[79]
	550-600	20-22	2.0-2.3	57%-60%	30	EU Reference Scenario 2020[80]
	652	14	3.2	60%	30	IEA, 2020[81]
OCGT	500	20	3.5	42%	20	ERAA 2021
	400-500	20	11	-	20	Elia, 2021
	400	12	2.1	35%	25	EU Reference Scenario 2020,
	451-570	6-19	4-1	40%-41%	30	IEA, 2020

Note: VOM refers to variable operating and maintenance costs. Data from the latest Elia adequacy and flexibility study are depicted since Elia's study was used in the ERAA 20201 as reference for some parameters. For data referring to the IEA's calculator database: plants with similar characteristics for Belgium are depicted; the overnight costs are shown as CAPEX; FOM

[77] ACER Decision on the Methodology for calculating the value of lost load, the cost of new entry and the reliability standard https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2023-2020_Annexes/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS%20-%20Annex%20I.pdf

[78] Section 2.4.2 provides detailed information on DSR modelling and assumptions.

[79] https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications/studies-and-reports/20210701_adequacy-flexibility-study-2021_en_v2.pdf

[80] https://ec.europa.eu/energy/data-analysis/energy-modelling/eu-reference-scenario-2020_en

[81] https://www.iea.org/articles/levelised-cost-of-electricity-calculator

and VOM are estimates based on the cumulative fixed unit costs (in $/MWh) provided in the report; a currency conversion of 0.85 from USD to euros was used.

3.3.2.4. Investment risks

The EVA model calculates total system costs in order to determine entry and exit of capacity resources. For this purpose the assessment 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. 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.

The ERAA 2021 uses uniform hurdle rates per technology for all modelled zones, based on estimates for Belgium provided in a recent academic study.[82] The study evaluates the hurdle rates in terms of (mainly) expected returns on investment, based on specific assumptions regarding the model in use, the scenario(s), the Member State as well as the techno-economic characteristics of the studied technologies. It is not evident that these assumptions are consistent with the assumptions and outcomes of the ERAA.[83] Moreover, unless properly justified, the use of uniform hurdle rate values is not in line with Article 6(10) and 5(10) of the ERAA methodology, which prescribes that economic and technical data shall be estimated per modelled zone. As WACC values and perceived risks depend, inter alia, on uncertainties related to a specific Member State or market, estimates of WACC and hurdle premium values should be specific to each modelled zone.

Furthermore, Article 6(9)(a)iii of the ERAA methodology calls for transparency when it comes to inclusion of price risks in WACC. The current description of the use of hurdle rate estimates does not give insights into the specific risk factors per technology and modelled zone.

3.3.2.5. Market and regulatory constraints

As per Article 6(14) of the ERAA methodology, the ERAA needs to reflect existing and expected market and regulatory constraints, i.e. emission limits in CMs, phase-out policies and binding targets and other constraints affecting system costs or economic decisions.

New entries of thermal units include only highly-efficient CCGT and OCGT units that fall below the emission limits. Based on the capacity additions in the central reference scenario with CM for 2025, there is no evidence that re-entry of coal or lignite units occurred. However, it should be checked whether existing units that are manually re-introduced in the market under this scenario (presumably under a CM support) comply with the emission limits, as new CM contracts for units exceeding the limits are not allowed from 1 July 2025 onward.[84]

Since the EVA's starting point is the pan-European market modelling database and especially the National Estimates scenario, phase-out restrictions and technology-specific binding targets are generally properly be taken into account. For possible CO_2 emission targets, in particular, ex-post verification is necessary.

[82] The methodology is described in a report that can be found here: https://www.elia.be/-/media/project/elia/elia-site/publicconsultations/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.

[83] As stated in the academic study (p.50) the estimations of the hurdle premiums are indicative, conditional to the scenario considered and a change in context, modelling setup or other crucial factors may lead to different results.

[84] For example it seems that for Belgium oil-fired units re-entered the capacity mix in the central reference scenario with CM.

3.4. Recommendations

Based on the review of the EVA, ACER provides the following recommendations for future ERAAs:

Key recommendations

- ENTSO-E should ensure consistency between the EVA and the economic dispatch i.e. with respect to expected risks, revenues and costs. If future ERAAs use the same EVA approach (i.e. total cost minimization), ENTSO-E should consider implementing sufficient Monte Carlo simulations in the EVA, increasing substantially the climate years modelled in the EVA and integrating probabilistic forced outage patterns. If clustering of climate years is still necessary, ENTSO-E should also consider investigating an enhanced clustering algorithm e.g. by considering advance spatial representation. ENTSO-E should analyse the impact of any major simplification to the ERAA results and report accordingly (high priority).
- The ERAA should take into account the economic viability of resources over their entire economic lifetime. This means that the EVA should consider an appropriate time horizon, ultimately even beyond the ten-year time horizon of an ERAA. The extension of the horizon and the introduction of longer term (inter-temporal) vision to decision making might indeed prove to be challenging. Hence, ENTSO-E should properly identify these challenges and investigate ways to improve the EVA while keeping the complexity at manageable levels (high priority).
- Along with expanding the timeframe of the analysis, ACER expects ENTSO-E to introduce all remaining decision variables described in Article 6(7) in the EVA, i.e. mothballing, re-entry of mothballed resources, renewal and prolongation. The set of technologies that may potentially enter the market should be expanded to include storage as a minimum, and ideally renewables too, in addition to the policy-driven targets for these technologies (high priority).
- The technical (e.g. potential for new investments) and economic parameters used in the EVA should reflect the specificities of each modelled zone, at least at Member State level. Where applicable, ENTSO-E should ensure consistency between the cost assumptions (including WACC) used in the ERAA and the assumptions used in the calculation of CONE/CORP in the Member States, pursuant to Article 6(6)(a) and Article 6(10) of the ERAA methodology. ENTSO-E should properly consult the EVA input parameters with stakeholders as per Article 11(4) in a timely manner, allowing for stakeholders views to be taken into account in the running version of the ERAA (high priority).
- ENTSO-E should consider ways to account for all types of revenues referred to in Article 6(9)(b)-(e) and include these revenues in the EVA process. ENTSO-E should also proceed with the proper implementation of the hurdle rate method chosen, for estimating WACC values, where necessary,[85] and downside risks per technology, at least at Member State level. Advance risk modelling methods should be explored for the longer term, as per Article 6(9), in order to improve the simulation of hedging opportunities (or lack of them) (high priority).
- ACER retrieved much of the information necessary to understand and review the methodology through bilateral communication with ENTSO-E. In order to increase transparency and stakeholder's understanding and engagement, it is necessary to improve the description of the methodology and provide all data and results of cross-checks and validations. This can facilitate stakeholder's understanding of the way the EVA operates and the evaluation of the ERAA results (high priority).

Other recommendations

- ENTSO-E should explicitly verify that market and regulatory constraints pursuant to Article 6(14) of the ERAA methodology are properly taken into account in the EVA. ENTSO-E should consider adding additional constraints for binding policy targets (e.g. share of renewable energy sources, CO_2

[85] WACC values need to be consistent with the ones used by Member States when calculating CONE. If there are no relevant calculations in place ENTSO-E should follow the principles of the relevant methodology described in ACER's Decision 23/2020.

emissions) directly in the EVA and economic dispatch model to ensure consistency of the ERAA results with those targets (low priority).

- As the penetration of renewable energy sources in the system increases, modelling technical constraints of the available resources, such as start-up and ramping constraints, becomes more important. ENTSO-E should consider ways to incorporate these constraints into the ERAA modelling, including the EVA model (low priority).[86]

ACER acknowledges that the aforementioned recommendations will likely increase complexity significantly. In this respect, ACER suggests that ENTSO-E thoroughly investigates the available approaches towards an enhanced and fit-for-purpose EVA that is consistent with the ERAA methodology. In doing so, ENTSO-E should properly consult stakeholders, including academic community, and conduct appropriate experiments in order to come up with a well-documented and justified target approach (as per Article 6(19) of the ERAA methodology).

[86] For more details see section 4.1.3 of the Technical annex.

4. Economic dispatch

This chapter focuses on the economic dispatch of the ERAA 2021. The economic dispatch, combined with the probabilistic assessment, produces the risk indicators for resource adequacy and is at the core of the assessment. Article 7 of the ERAA methodology determines the relevant requirements for the economic dispatch. Below, ACER examines some of its key features in the ERAA 2021. Broadly speaking, the economic dispatch of the ERAA 2021 functions as intended, however, ACER has identified points that require further attention for future assessments.

4.1. Modelling approach

4.1.1. Economic dispatch - general elements

The economic dispatch minimises the total system operating cost taking into consideration the operational costs for different resources (e.g. variable costs of power plants or the activation prices of DSR) and the cost of demand disconnections (i.e. the cost of energy non-served).

To decrease computational complexity, the economic dispatch is split into daily problems. For each day and hour (the equivalent of Market Time Unit), the model dispatches the optimal mix of resources (either generation, DSR or storage) to meet demand at least-cost, under the assumption of perfect foresight and a number of constraints. These constraints include the unavailability of resources due to planned and unplanned outages and available cross-zonal capacity between modelled zones. When the available resources are insufficient to meet demand, load shedding occurs in the model.

From these hourly results, the model estimates the different risk indicators, such as the number of hours when supply is expected to be insufficient to meet demand (i.e. LOLE) and the associated expected energy non-served (i.e. EENS). Moreover, the solution of the daily problems produces the usage profile for the different resources (e.g. generation profile for power plants, injection and withdrawal profiles for storage units), system prices per hour and the total operating costs. System prices equal the short-run marginal cost of the marginal unit clearing the market or the maximum clearing price when there is loss of load.

The high-level approach for the economic dispatch is broadly in line with Article 7 of the ERAA methodology.

4.1.2. Price formation

4.1.2.1. Price formation and maximum/minimum clearing prices[87]

According to Article 7(9) of the ERAA methodology, the assessment needs to reflect price formation when estimating the prices for each bidding zone and hour. This requirement includes the harmonised maximum and minimum clearing prices, any indirect restrictions to wholesale price formation and the expected impact of market measures in the context of the market reform plans established by Member States.

The ERAA methodology prescribes that the maximum clearing price reflects the automatic increase mechanism introduced by ACER Decision 04/2017.[88] As a simplification given the complexity of modelling this automatic increase in both the economic dispatch and the EVA, and given the limited

[87] Another topic that relates to price formation is the implementation of a shortage pricing function for balancing energy. This is discussed in the Decision, in sections 6.2.1.11 and 6.4.9.

[88] https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2004-2017_Annexes/Annex%20I_ACER%20DA%20MAX-MIN.aspx.

number of modelled years, the ERAA 2021 simplifies this automatic increase by considering a fixed maximum clearing price of 15 k€/MWh at times of supply shortfall, i.e. when Energy Non-Served occurs in the model. In ACER's views, this simplification is acceptable in the absence of full modelling of the harmonised limits on maximum and minimum clearing price in the day-ahead and intra-day market timeframes. The relevant ACER decisions stipulate that:

- The day-ahead technical bidding limit, currently set at 3 k€/MWh, rises by 1 k€/MWh every time the market price reaches 60% of the current limit anywhere across the coupled area, with at most one increase per day.
- The intra-day technical bidding,[89] currently set at 10 k€/MWh, follows the day-ahead limit once the latter surpasses it in value. This means that if the day-ahead technical bidding limit rises to 11 K€/MWh, then the intra-day limit follows suit.

The ERAA essentially considers the technical bidding limits of the day-ahead and intra-day markets in conjunction. The higher intra-day price caps may act as the effective cap, because it would enable participants with greater opportunity costs (including operational and capital costs) than the day-ahead bidding limit to participate in the intra-day market. As long as the intra-day technical bidding limit is higher, it can be expected to set the maximum clearing price in the assessment.[90] Given the level of adequacy risks identified in the ERAA 2021, there is an expectation that the day-ahead bidding limit will increase in the future due to the occurrence of loss of load hours.[91] The assumption of a maximum clearing price of 15 k€/MWh is a simplified way to reflect the prospective rise of the day-ahead technical bidding limit over the coming years.

This also means that any scenario or sensitivity with a low and stable harmonised maximum clearing prices in the day-ahead and intra-day timeframes, such as the sensitivity applying a 3 k€/MWh maximum clearing price cap in the ERAA 2021, has limited value. In ACER's view, the only justification for such an assumption would be where restrictions to wholesale price formation are foreseen, pursuant to Article 7(9)(b) of the ERAA methodology.

A restrictive maximum clearing price in the assessment 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 bidding limits. Even when maximum technical bidding limits apply, the legal framework anticipates they should increase in a timely fashion to avoid restricting trade.

In relation to the minimum clearing price, the lowest possible price in the assessment is '0' €/MWh. The ERAA 2021 thus does not model negative prices and curtailment of renewables is effectively not priced. This simplification is contrary to the current regulatory framework and evidence in the market. The regulatory framework sets a minimum price of -500 €/MWh in the day-ahead market and -9,999 €/MWh in the intra-day market. Furthermore, evidence from the real market suggests that the frequency of negative prices increases over-time. ACER-CEER's MMR 2020 shows that the number of negative prices in the day-ahead market has doubled every year in the last couple of years, and the general trajectory is towards a rising number of negative prices.[92] Negative prices tend to occur at time of low demand and high renewable generation and therefore are less critical from a resource adequacy

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[89] https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2005-2017_Annexes/Annex%20I_ACER%20ID%20MAX-MIN.aspx.

[90] However given the limited size of the intra-day market, this effect is uncertain.

[91] If there is a shortfall in the day-ahead market, or in other words if the day-ahead market fails to clear, then the price should equal the technical bidding limit and trigger a rise of the technical bidding limit.

[92] For more information, see section 3.2 of ACER-CEER's MMR 2020 (Electricity Wholesale Market Volume), available on: https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202020%20%E2%80%93%20Electricity%20Wholesale%20Market%20Volume.pdf.

perspective. They are however important from a system flexibility perspective and to accurately reflect the economics for various resources.

Recommendations

In relation to the maximum clearing price, ACER encourages ENTSO-E to investigate the modelling of a dynamic maximum clearing price that follows the rules in relevant ACER decisions (high priority). ACER acknowledges this is in line with ENTSO-E's roadmap for the implementation of the ERAA methodology. Such modelling would be most meaningful when the assessment covers continuous years, preferably the entire ten-year horizon. In the absence of such consideration, the dynamic modelling of the maximum clearing price will produce sub-optimal results and cannot be considered a fully robust approach. A simplified approach of a pre-determined, high-enough maximum clearing price, as in the ERAA 2021, would be temporarily acceptable in ACER's view.

Regarding the minimum clearing price, ACER suggests that ENTSO-E examines the implementation of negative pricing in the ERAA 2022 (low priority). The lack of negative prices not only contradicts the current legislative framework and practices, but also dampens the pricing signals for flexibility in the modelling. Given the consideration of storage as an investment candidate and the improvement in the DSR modelling, incorporating this element could be important in the ERAA 2022. Recognising that negative prices are generally linked with the curtailment of variable renewables, any negative prices would ideally be set at the level of their opportunity cost of not producing, or in other words, at the level of foregone revenues from any support mechanism.[93] This modelling could be a rather complex exercise. As a simplification, future ERAAs could use historical information about the level of negative prices. ACER also invites ENTSO-E to publish information about the level of variable renewables curtailment in the ERAA 2022 (high priority).

4.1.2.2. Price formation and balancing reserves

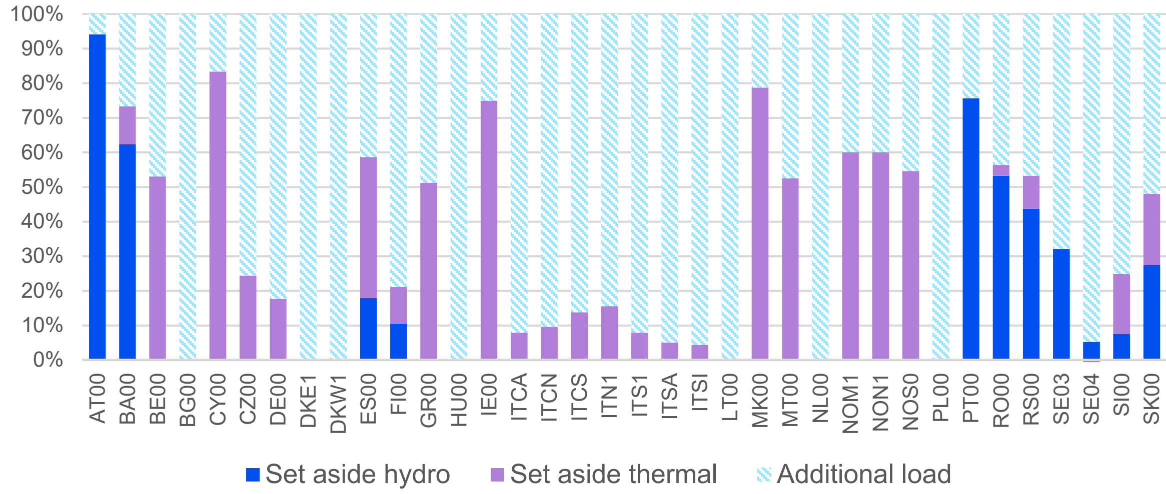
In the ERAA 2021, balancing reserves requirements can either be met directly by setting aside dedicated resources (i.e. hydro and thermal generation), or capacities in the market. In the former case, the assessment effectively assigns the requirement to specific capacities (or units), which are then withdrawn from the market.[94] In the latter case, the reserve requirement manifests as an addition to the hourly demand in the economic dispatch and is met by the available capacity in the market. The reserve requirement can be satisfied exclusively by dedicated resources, market resources, or a combination of the two. This approach is in line with the ERAA methodology (Article 4(6)(g)).

Figure 13 presents how Member States are assumed to meet their reserve requirement across the three types of resources in 2025. It shows that a few Member States are projected to meet their needs through primarily hydro capacity, while in most, the needs are met through a combination of different resource types. In several Member States, the reserve requirement is added as additional load, in full or partially.

[93] Negative prices could relate to other actions than the curtailment of variable renewables however.

[94] Essentially, this capacity is reserved by the system operator to deal with sudden disturbances in the system and is not available to address resource adequacy.

Figure 13: Assumptions for meeting the balancing reserves requirement per bidding zone in 2025

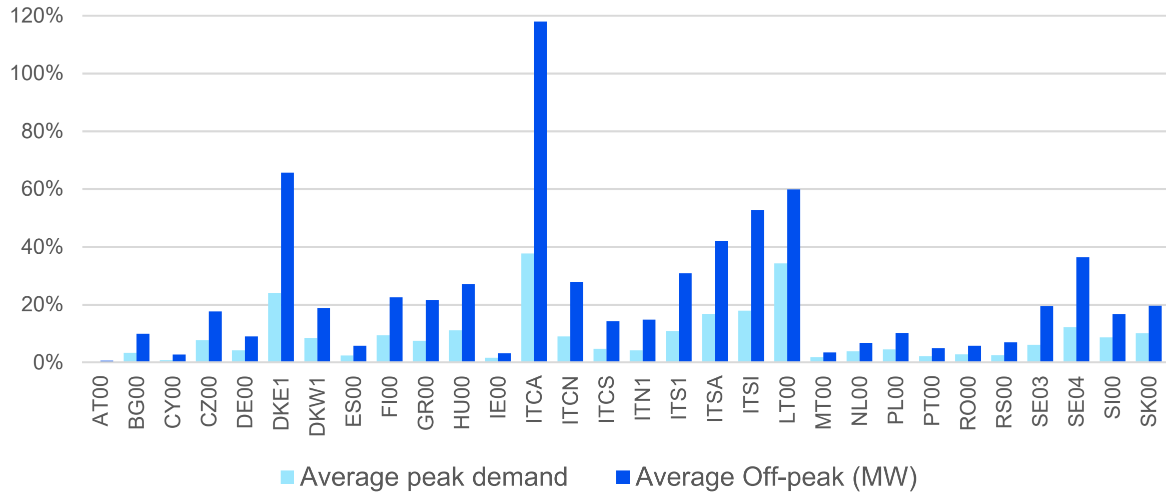


Source: ACER calculations based on the ERAA 2021.

Adding balancing reserves as load can have opposite effects on the assessment:

- On the one hand, it can affect market prices in the economic dispatch modelling. In general, this simplification is expected to drive prices up. By adding load, the optimization algorithm will possibly clear at a higher value than if the reserve requirement was treated outside the energy market. Particularly, this would be the case if the resources serving as balancing reserves were high in the merit order, i.e. have a high short-run marginal cost. ACER expects this approach to affect prices depending on the relative size of the added load in relation to the demand levels; the higher the relative size of the added load, the greater the potential impact on prices. Figure 14 shows the added load, due to the reserve requirement, as a share of the average peak and off-peak demand across all climate years. The added load is particularly prominent in smaller bidding zones, compared to larger ones.
- On the other hand, this simplification conceals revenues that resources reserved by the system operator for balancing purposes would earn through capacity payments. Resources providing ancillary reserves, particularly FCR and FRR, would normally receive an availability payment (in €/MW for being available to the system operator) and a utilization payment (in €/MWh, reflecting their short-run marginal cost). The ERAA 2021 essentially omits entirely the availability payments these resources would receive, thus undermining their profitability in the assessment.
- The addition of balancing reserves requirements as load can have a further negative impact on resources with limited energy capabilities, such as storage. The additional load requires an equivalent amount of energy for supply to meet demand. If this additional production is met by resources with limited energy capabilities, it could deplete their available energy, and thus undermine their contribution to resource adequacy. In reality this capacity resource would not produce such an amount of energy but rather be set aside, to deal with any sudden and short-lived disturbances in the system.

Figure 14: Reserve requirement as added load compared to average peak and off-peak demand (2025 assumptions)



Note: Average peak load is the average of the highest forecasted hourly peak electricity demand across all climate years. Average off-peak is the average lowest forecasted demand across all climate years.

Source: ACER calculations based on the ERAA 2021.

Impacts on risks to resource adequacy

Due to the indirect, complex and contrary effects of the current approach to reflect the reserve requirements as added load, it is difficult to assess its impacts on the risks to resource adequacy.

Recommendations

While the current approach is in line with the ERAA methodology, ACER believes it unnecessarily distorts the results of the assessment. Therefore, ACER recommends that future assessments treat balancing reserves outside the economic dispatch, or in other words the assessment allocates the reserve requirement to specific capacities and does not treat it as added load (high priority). Such an approach would effectively imply that such resources would make sufficient revenues to be economically viable.[95]

Ideally, the exercise of allocating reserve requirement to specific capacity resources would be based on a forward-looking assessment resembling the ancillary services market. Such an approach would have the benefit of considering new resources that can participate in this market segment, such as storage and DSR that can be particularly suitable for these services. However, ACER appreciates that such an exercise can be complex and uncertain, especially further out in the future. For the ERAA 2022, ACER suggests that the allocation is based on current practices and trends. A more sophisticated approach can be considered for future years (low priority).

4.1.3. Technical constraints for generation

The ERAA 2021 largely omits technical constraints related to the operation of thermal generation. For example, the assessment omits parameters, such as:

- ramping constraints, i.e. the ability of a power plant to increase or decrease their output with time (or “ramp rates”);
- the minimum amount of hours that a unit needs to be in operation or switched off (or “minimum up/down time”); and,

[95] The ERAA 2021 uses a similar approach for Combine-Heat and Power plants, whereby the assessment implicitly assumes they are always economically viable, as a result of their heat revenues.

- the minimum production level (or “min stable level”). Even though the Report asserts that the assessment considers the minimum production level, this constraint is effectively ineffectual given the linear optimisation character of the economic dispatch problem.

The ERAA 2021 considers the amount of time that a unit requires to start producing at its minimum production level. This constraint only applies in a simplified way however, when a unit returns to operation from forced outage more specifically, and not for normal operations.[96]

ACER acknowledges that full consideration of technical constraints, would effectively mean the implementation of unit commitment in the modelling and significantly increase its complexity. At the same time, flexibility is widely recognised as one of the key challenges of the power system while transitioning to carbon-neutrality.[97] Even though the ERAA methodology does not specify the technical constraints the assessment needs to consider, the purpose of the ERAA is to provide a robust assessment of the risks to resource adequacy. These risks can extend beyond peak hours, the current focus of the assessment, to other hours in the absence of a flexible resource portfolio. In this context, ACER believes that the consideration of such technical constraints will be highly important to accurately assess future risks for the European power system, especially towards 2030 as the deployment of variable renewables is expected to increase substantially.

Impacts on risks to resource adequacy

While it is difficult to accurately assess the impact of this omission, ACER expects it leads to lower prices in the energy market. In other words, incorporating these constraints in the modelling would lead to higher prices and therefore greater profitability for resources. On the other hand, the current modelling approach may lead to unrealistic outcomes, e.g. a thermal power plant changing its production level from zero to maximum within an hour, when in principle it would require a much longer time, as is typically the case for thermal generation. Due to the multiple implications of the current approach, it is therefore not possible to assess whether the ERAA 2021 over- or under-estimates the risks to resource adequacy on this topic.

Recommendations

The implementation of unit commitment is optional based on the ERAA methodology (Article 7(5)(a)). Nevertheless, ACER encourages ENTSO-E to explore incorporating unit commitment in the modelling in order to, as a minimum, identify the challenges related to its full implementation (low-priority). In the future, ACER will consider and engage with ENTSO-E and stakeholders to assess how essential the implementation of unit commitment is and how quickly it might need to happen. In the meantime, ACER invites ENTSO-E to investigate incorporating all constraints, such as ramping constraints, that would allow maintaining the current, linear optimisation approach in the ERAA 2022 (high priority).

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[96] Similarly, ACER understands that the ERAA 2021 does not consider the start-up costs of resources. Incorporating this aspect would affect the optimisation problem of the EVA and the economic dispatch.

[97] See for example, IEA - Status of Power System Transformation 2019, available on: https://www.iea.org/reports/status-of-power-system-transformation-2019.

5. Flow-based capacity calculation

5.1. Introduction

Compared to NTC, flow-based capacity calculation aims to better reflect 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 (Core DA CCM[98]), the flow-based approach relies on the following, sequential steps:[99]

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

5.2. Overview of ACER's opinion

The ERAA 2021 includes one sensitivity analysis with flow-based in Annex 4 (hereafter 'flow-based proof of concept'), over a partial time (2025) and geographic scope (Core). All other scenarios and sensitivities fully rely on the NTC capacity calculation approach. The ERAA 2021 contains limited information about the flow-based proof of concept, thus hampering ACER's ability for a comprehensive review of the proof of concept. The limited information, and additional documents that indirectly relate to this proof of concept,[100] seem to hint that the flow-based proof of concept is broadly in line with the ERAA methodology, except for the use of two different modelling tools (one for the EVA, and another for the economic dispatch). However, this limited information prevents ACER from assessing the quality of the results of the flow-based proof of concept. Regarding other scenarios, the use of the NTC

[98] Annex I to ACER Decision 02/2019.

[99] See Article 4 to Annex I of ACER Decision 02/2019.

[100] See: https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications/studies-and-reports/20210701_adequacy-flexibility-study-2021_en_v2.pdf. ACER asked ENTSO-E to confirm whether specific aspects of the flow-based approach used for the Belgian adequacy assessment also apply for the ERAA 2021.

approach likely significantly reduces the robustness of calculations in flow-based CCRs, by limiting the accuracy of forecast of cross-zonal exchanges.[101]

5.3. Detailed review

The detailed review first summarises ENTSO-E's approach for the flow-based proof of concept. It then highlights ACER's main comments regarding the flow-based approach. The detailed review also covers the following additional elements:

- The adequacy patch, an additional constraint to capacity allocation, which applies when the market coupling is unable to supply all price-taking consumers; and
- Transparency, i.e. the ability to ensure oversight over the calculations that ENTSO-E conducted.

5.3.1. Overview of ENTSO-E's approach

Annex 4 of the Report summarises the flow-based approach for the proof of concept. ENTSO-E also informed ACER that the methodology is broadly similar to the methodology applied in the latest Belgian resource adequacy assessment (hereafter 'BE NRAA').[102] The flow-based proof of concept models the introduction of flow-based in Core for 2025 only, and includes a qualitative analysis of the expected impact of flow-based on adequacy in the Nordic CCR.

The flow-based proof of concept only applies flow-based within the economic dispatch stage of the ERAA. The economic dispatch relies on a set of capacity resources, the viability of which is assessed (through the EVA) with NTC cross-zonal capacities, and with a different modelling tool. The Report asserts that the modelling of flow-based in Core fulfils the minimum 70% target,[103] while ignoring its impact on redispatching or countertrading (and thus on availability of capacity resources for other purposes).

Finally, the flow-based proof of concept introduces the adequacy patch, which currently applies within the Core (CWE) CCR and introduces additional constraints to capacity allocation when scarcity occurs. The other scenarios do not include this patch.

5.3.2. Review of ENTSO-E's approach

ACER's review focuses on the quantitative proof of concept flow-based analysis conducted for Core for 2025.

ENTSO-E used two different modelling tools, one for the EVA and one for the economic dispatch stages of the ERAA. The EVA reflected economic viability of units with NTC capacity calculation, and without capacity mechanism.

5.3.2.1. Grid model and topology

Flow-based calculations rely on a grid model, which reflects a given forecast market situation. To ensure that the forecast market situation is realistic (i.e. reflects rational decisions of the various capacity resources), an initial market simulation is first conducted. This market simulation is then translated into the capacity resources that consume or generate electricity for each network substation. The proof of

[101] In particular the ability of bidding zones to simultaneously import or export energy.

[102] See footnote 100.

[103] This aspect is however not fully confirmed by ACER's analysis of the Net Transfer Capacities (NTCs). See subsection 2.4.5.2 for more information.

concept relies on MAF 2020 as an initial market simulation. The Report does not explain which scenario and target years were considered, or the level of detail underlying this initial market simulation.

The outcome of the initial market simulation is then combined with a grid model, to build a full forecast of the expected power system. The proof of concept relies on the "reference grid" model from the National Trends scenario of the TYNDP (for Winter).[104] ENTSO-E informed ACER that some changes were applied on this grid model, however, without explanations on the purpose, scope and process for such change. Furthermore, ENTSO-E did not explain how the grid model reflects planned network maintenance.[105]

The Core DA CCM prescribes that TSOs use non-costly remedial actions to optimise the flow-based domain, i.e. to increase the possibilities for likely market exchanges. Such remedial actions include changing the topology of network substations, and setting taps of phase-shifting transformers (PSTs). The flow-based proof of concept annex states that "PSTs have been used (…) to maximize the space for commercial exchanges". ENTSO-E communicated to ACER that this maximisation broadly aligned with the Core DA CCM, albeit by only considering PSTs, whereas the Core DA CCM considers a wider scope of non-costly remedial actions.

5.3.2.2. Definition of critical network elements and contingencies

Based on the grid model, the flow-based approach combines CNEs and contingencies, to define the CNECs, which restrict cross-zonal exchanges. The proof of concept examines three different sets for the definition of CNEs:

- Set A: defining CNEs as only cross-zonal lines from set C with voltage ≥ 380kV;
- Set B: defining CNEs as only cross-zonal lines from set C with voltage ≥ 220kV;[106] and
- Set C: Core TSOs define CNECs based on their outlook for 2025.

ACER invites ENTSO-E to omit set A in future ERAAs, as the Core DA CCM defines all cross-zonal network elements as initial CNEs,[107] thus set B likely is more representative of the minimum set of CNEs to consider within the ERAA.

For the third option, the Report does not explain how Core TSOs defined CNEs, in particular whether (and how) these TSOs followed the related rules of the Core DA CCM.[108] As a result, ACER is unable to assess the robustness or consistency of this set.

The proof of concept omits planned outages, and considers unplanned outages through contingencies of CNECs. The approach defines "relevant contingencies" as the five most limiting contingencies for each CNE in both directions.

ENTSO-E explained that two different flow-based capacity calculation approaches were used: the approach used in the BE NRAA for set A, and RTE's approach for sets B and C.

[104] ENTSO-E relied on the latest available TYNDP data set available at the time of the ERAA 2021 preparation. ENTSO-E further explained that, due to the respective timelines and different frequency of edition (yearly, biyearly) specific updates may occur in one product while the other product input is frozen.

[105] The BE NRAA mentions that such maintenance is ignored, and modelled separately through a sensitivity analysis.

[106] For these sets, only cross-zonal CNEs that were part of set C were considered. As a result, come cross-zonal lines may have been excluded from sets A and B.

[107] Article 5(1) of the Core DA CCM; also, note that in the flow-based CC process, the initial CNEC list is filtered, with the criteria of minimum zone-to-zone PTDF criteria higher than 5%.

[108] See Article 5 of the Core DA CCM.

5.3.2.3. Calculation of power transfer distribution factors

Power transfer distribution factors (PTDFs) describe how cross-zonal exchanges affect physical flows on CNECs. The Report describes in detail generic mathematical elements underlying the PTDF calculation and explains that various approaches were used for the various sets of PTDFs. The BE NRAA approach uses GSKs that are proportional to installed thermal capacity (except nuclear), whereas RTE's approach uses diverse GSKs approaches.[109] Neither approach considered time varying GSKs.

The Report does not describe these approaches in detail, nor explains the impact of the different approaches on the different sets of PTDFs. As a result, ACER is unable to assess whether the differences in the flow-based sets partly come from the different flow-based modelling approaches.

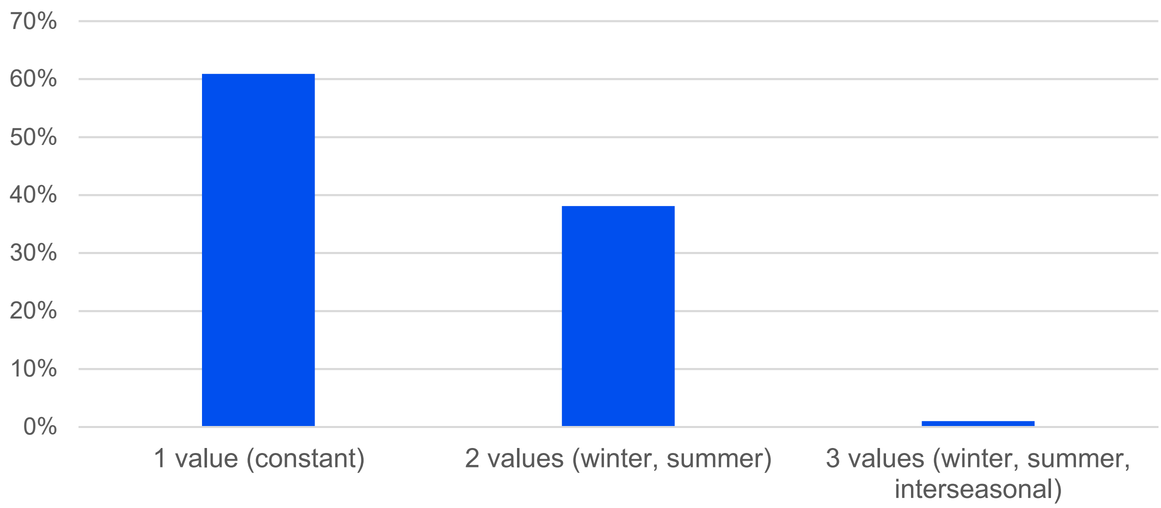
5.3.2.4. Maximum flow admissible by critical network elements and contingencies

Fmax describes the maximum flow that a given CNEC can accommodate. Fmax is split between:

- Flow margin, to account for the uncertainties underlying capacity calculation;
- Flow due to exchanges within bidding-zones;
- Flow due to exchanges beyond the considered CCR (unless advanced hybrid coupling applies); and
- RAM, i.e. the share of the CNEC that is available for cross-zonal exchanges within the CCR.

Figure 15 shows, for all considered CNECs, the number of different Fmax values used for the full year. Despite the ERAA methodology requiring at least seasonal calculation of cross-zonal capacities,[110] only one Fmax value applied for most CNECs. Some CNECs applied two values per year, while only 1% of CNECs also defined an "interseasonal" value.

Figure 15 Number of different Fmax values on considered CNECs



Note: Spring and Fall are referred to as "interseason" within the proof of concept.

Source: ACER calculations based on ENTSO-E data.

[109] The main approach seemed to be GSKs proportional to installed capacity for each specific generation technology (e.g. "Gas OCCG old 1"), all types of generations. Other generic types of GSKs were also used.

[110] See Article 4(6)(d) of the ERAA methodology.

5.3.2.5. Remaining available margin

For each CNEC, the RAM reflects the share of the physical capacity of CNECs, which is available for cross-zonal trade. This physical capacity takes into account:

- The share of CNEC's capacity that is already consumed, due to exchanges within bidding-zones (or beyond the considered CCR);
- The flow by the cross-zonal capacities allocated during previous timeframes (i.e. long-term allocated capacities), if applicable;[111] and
- Legal requirements to offer a minimum share of CNEC for cross-zonal trade, i.e. the minimum 70% target and possible related derogations or action plans (pursuant to Articles 15 and 16 of the Electricity Regulation).

In line with ACER's recommendation on MACZT,[112] the proof of concept assumes that the minimum 70% target applies all the time to all CNECs. Given the lack of data in the Report,[113] ACER is unable to confirm whether the proof of concept meets the 70% target. Furthermore, the BE NRAA states that RAM on CNECs is capped at 100% of Fmax.[114] ENTSO-E explained that such a cap does not apply for the ERAA 2021; ACER welcomes ENTSO-E's stance, as this cap does not reflect a requirement of the Core DA CCM.

Finally, ACER's recommendation on MACZT prescribes that MACZT includes capacity available for cross-zonal trade both within and beyond a given CCR (possibly including trade with non-EU countries). ENTSO-E assumed that advanced hybrid coupling would apply on all bidding-zone borders (including with non-EU bidding-zones), leading MACZT to be equal to the RAM for each CNEC.

5.3.2.6. Validation of flow-based domains

Validation of cross-zonal capacities ensures that the generated flow-based domain leads to safe operation of the system, considering remedial actions available for TSOs. Redispatching, as one of these remedial actions, enables TSOs to adapt the generation schedule to solve network congestion. Redispatching currently is widely used in some bidding-zones,[115] and is expected to increase over time in order to enable increased RAMs on CNECs (e.g. to fulfil the minimum 70% target).

The flow-based proof of concept assumes that all generated flow-based domains enable a secure operation of the power system, without any redispatching or countertrading measures. This assumption seems unrealistic, given the current amount of activated redispatching capacity and the significant expected increase in cross-zonal capacity due to the minimum 70% target. As a result, this assumption likely overestimates the available capacity resources in the market, as some capacity could be reserved for redispatching purposes. For example, significant redispatching was activated in Germany (already with 20% RAM available on many German CNECs in Core (CWE), also to deal with variable renewables), so these activated units would be unavailable for the wholesale market in Germany during at least some hours of the year.

In line with the Electricity Regulation,[116] action plans enable Member States to gradually increase cross-zonal capacity to reach the minimum 70% target by the end of 2025. As a result, these action plans likely have a limited (if any) impact on cross-zonal capacity in 2025. Depending on national regulatory

[111] The flow-based proof of concept ignored long-term allocated capacities when building flow-based domains.

[112] See ACER Recommendation 01/2019.

[113] In particular, ENTSO-E did not provide identifiers enabling to combine Fmax and RAM data for each CNEC.

[114] In the Core (CWE) CCR, an (oriented) CNEC may have a RAM above 100%, when the flow (due to internal exchanges) on the CNEC run opposite to the direction for which the CNEC is considered.

[115] See section 4.3 of ACER-CEER's MMR 2020 (electricity wholesale market volume). See footnote 26.

[116] See Article 15.

authorities' decisions, derogations may however apply in 2025 (or beyond). The flow-based proof of concept does not explain if any derogation[117] to the minimum 70% target are considered.

5.3.2.7. Aggregation of flow-based domains

Based on the previous methodological steps, the ERAA 2021 generates six types of flow-based domains. These types of domains are further aggregated, in order to define a single set of PTDFs for 2025 as a whole (the RAMs still differ among the six types of domains). In further communication between ENTSO-E and ACER, ENTSO-E explained that RTE[118] and the BE NRAA[119] followed various aggregation approaches, with a limited impact on flow-based volumes.[120] ENTSO-E explained that this simplification sped up the computation with little impact on precision of the flow-based domains. However, ENTSO-E did not quantify the impact of this aggregation on simulation results (including adequacy indicators), but explained that an expert analysis concluded that six types of flow-based domains were enough to be representative of the full variety of flow-based domains that may occur in Core in 2025.

Finally, the proof of concept assesses correlations between the hours of the years belonging to specific clusters and external factors like weather-dependent variables. The Report does not list the factors used for this correlation analysis. The BE NRAA mentioned German wind and French consumption as two key correlation factors.[121]

5.3.2.8. Affectation of flow-based domains to various hours of Monte Carlo years

The flow-based proof of concept models multiple Monte Carlo years for 2025, to reflect various probabilistic configurations for this target year. For each hour and Monte Carlo year, the ERAA 2021 performs an economic dispatch. The economic dispatch minimises the cost of supplying demand hour-by-hour, considering cross-zonal capacities. Therefore the analysis needs to define a flow-based domain for each hour for the Core CCR. The proof of concept defines each hourly domain as one of the predefined types of flow-based domains, based on a probability matrix.

In further communication, ENTSO-E explained that

- For RTE's approach, the consumption and critical[122] generation of all Core countries were taken into account to define a deterministic domain for each hour;
- For the BE NRAA, a probability matrix links wind in Germany and demand in France to flow-based domains, possibly leading to add one probabilistic degree of freedom to the economic dispatch.

ENTSO-E did not provide details about this approach, in particular:

- Whether the approach was deterministic or probabilistic, i.e. whether, for the same hour of the same Monte Carlo year, more than one type of domain may be drawn randomly; and
- Which factors were used for the probability matrix, and the forecast precision that such factors enabled.

[117] Pursuant to Article 16(9) of the Electricity Regulation.

[118] Clustering based on yearly flows on monitored CNECs without contingency.

[119] Geometrical clustering based on geometrical distance computation.

[120] 2-3%.

[121] p.101.

[122] ENTSO-E did not explain what "critical" generation means.

5.3.3. Review of additional elements

5.3.3.1. Adequacy patch

When scarcity occurs widely within a region, the market coupling algorithm may lead to undesirable interactions between small and large bidding-zones. To balance energy not served during such hours, an adequacy patch further restricts the standard market coupling, affecting accepted volumes and wholesale prices.[123] The flow-based proof of concept reflects the adequacy patch, whereas the other scenarios and sensitivities do not. The Report does not detail the impact of the adequacy patch on key indicators from the economic dispatch. ACER welcomes this refinement in the modelling of cross-zonal capacity allocation and invites ENTSO-E to ensure that the modelling of the adequacy patch is consistent with the other assumptions underlying the economic dispatch.

The results of the flow-based proof of concept suggest that the adequacy patch may lead to increased LOLE. As a result, the scenarios that do not include the adequacy patch may underestimate LOLE in this respect. However, this effect is rather unclear, given the limited information available about the adequacy patch.[124]

5.4. Recommendations

At a high-level, ACER expects ENTSO-E to consider significant improvements for the ERAA 2022, in particular providing more transparency about the methodology and including the modelling of flow-based for both Core and Nordic CCRs and all target years, which are modelled in detail.[125] In order to ensure internal model consistency and consequently compliance with Article 23(5)(i) of the Electricity Regulation, ACER expects ENTSO-E to use the same modelling tool for all modelling stages (i.e. the economic dispatch and EVA). In particular, NTC modelling does not fully reflect the flexibility that the flow-based approach allows, thus biasing market entry and exit decisions. Below, ACER provides more detailed recommendations for the different steps of the flow-based approach.

In relation to the first step, on the grid model and topology, ACER invites ENTSO-E to describe:

- How the market simulation from MAF was updated to reflect updated assumptions from the ERAA 2021;
- How the (updated) MAF market simulation was converted into detailed grid models (including nodal electricity injections and withdrawals), and with which time granularity;[126] and
- Why ENTSO-E discarded the option to run an optimal power flow to generate the initial network situation,[127] and what would be the difference with the approach that ENTSO-E followed. (low priority)

Furthermore, ACER invites ENTSO-E to increase transparency regarding any changes applied to TYNDP grid models (high priority). Besides, ACER invites ENTSO-E to consider using at least seasonal

[123] See https://www.nordpoolgroup.com/globalassets/download-center/single-day-ahead-coupling/euphemia-public-description.pdf.

[124] In particular, how this patch would affect the economic dispatch and EVA.

[125] If too complex, ENTSO-E may consider relying on NTC for 2030, given that this year is unlikely to affect decision-making in 2022 or 2023. In this case, ENTSO-E should ensure that this simplification does not significantly affect the robust identification of resource adequacy concerns for earlier target years.

[126] E.g. the BE NRAA relies on GSKs which are independent from the initial market simulation, and rather reflect nominal capacities of the capacity resources.

[127] See p.7 of the flow-based proof of concept.

grid models per target year (one for winter and one for summer), to increase the robustness of the ERAA (low priority).

Regarding the second step, i.e. definition of CNECs, ACER invites ENTSO-E to ensure that the definition of critical network elements and contingencies aligns with the applicable DA CCM in future ERAAs (low priority).[128]

For the third step, related to the definition of PTDFs, ACER invites ENTSO-E to consider time varying GSKs, in order to reflect at least the seasonal evolution of the various capacity resources (low priority). Moreover, ACER expects ENTSO-E to rely on a single approach for flow-based capacity calculation (instead of relying on the different RTE and BE NRAA's approaches), to ensure comparability of the results (high priority).

Regarding the fourth step, associated with the estimation of RAM, ACER expects ENTSO-E to at least introduce seasonal Fmax values on all CNECs, which change Fmax between seasons (high priority), and to consider reflecting more detailed variations of Fmax, e.g. when dynamic line rating is expected to apply (low priority). ACER also expects ENTSO-E to provide appropriate data to enable oversight of the RAM estimates (high priority).

For the validation of flow-based domains, the fifth step of the flow-based approach, ACER invites ENTSO-E to reflect (at least in a simplified manner) the expected impact of validation of flow-based domains on available cross-zonal capacities and available capacity resources for the wholesale market. Such a validation will improve the economic dispatch, thus the estimation of economic viability of capacity resources and subsequently the estimation of adequacy indicators. Besides, ACER invites ENTSO-E to clarify the assumptions taken with respect to derogations to the minimum 70% target (low priority).[129]

Related to the aggregation of flow-based domains (the sixth step), ACER invites ENTSO-E to clarify which external factors are considered, and to ensure a large-enough number of factors to guarantee satisfactory correlation of flow-based domains with such external factors within each CCR. In particular, ACER invites ENTSO-E to rely on more than one flow-based domain for Summer. Overall, ACER invites ENTSO-E to provide more transparency about the main drivers that underlie the variations of flow-based domains, and the key choices made to select the situations used to build the various types of flow-based domains (low priority).

Finally, for the final and seventh step, ACER invites ENTSO-E to clarify the impact of the various approaches on the affectation of flow-based domains, and on the results of the economic dispatch. In particular, ACER expects ENTSO-E to justify why wind in Germany and demand in France are enough to affect flow-based domains to the whole Core CCR, covering 13 Member States (high priority).

Finally, ACER would like to highlight that full transparency of the flow-based calculation is crucial in order to enable oversight and gradual improvement of all aspects of the methodology (including its software implementation). ACER notes that some TSOs publish the source code underlying alternative approaches to flow-based capacity calculation for forward-looking assessments.[130] ACER thus invites ENTSO-E to consider publishing (at least parts of) the source code underlying the flow-based approach, in order to enable stakeholders to reproduce calculations, conduct what-if analyses, and suggest improvements to the flow-based approach (low priority).

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[128] For example, in Core, the definition should align with the Core DA CCM.

[129] Derogations are expected to disappear once coordinated security analyses and re-dispatching countertrading is fully implemented. This recommendation also applies for NTC capacity calculation.

[130] E.g. RTE published the source code underlying flow-based clustering, see https://github.com/rte-antares-rpackage/flowBasedClustering.

Regarding the adequacy patch, to ensure a more realistic modelling of market functioning during scarcity situations, ACER expects ENTSO-E to clarify the impact of this patch on the economic dispatch and EVA, and to reflect this patch in all central reference scenarios (high priority).

6. Appendix – Detailed tables

Table 3: ACER's assessment of the 70% minimum target based on the ERAA 2021 NTC assumptions for 2025

Border	Average NTC 2020	Average NTC 2025	TSO 1	TSO 2	% time target when TSO 1 reached 70% in 2020	% time target when TSO 2 reached 70% in 2020	Conclusion
CZ-DE	2,844	2,100	CZ	DE	74.0	12.5	
DE-CZ	2,104	1,500	DE	CZ	4.0	59.5	
CZ-SK	2,035	1,378	CZ	SK	74.0	40.0	
SK-CZ	1,182	1,600	SK	CZ	0.0	59.5	
EE-LV	848	841	EE	LV	0.0	0.0	
LV-EE	778	841	LV	EE	0.0	0.0	
ES-FR	2,457	2,187	ES	FR	61.5	65.5	
FR-ES	2,637	2,524	FR	ES	64.0	75.5	
SE01-FI	1,476	1,200	SE	FI	90.7	100.0	
FI-SE01	1,034	1,100	FI	SE	100.0	14.7	
SI-HR	1,499	1,200	SI	HR	57.0	1.5	
HR-SI	1,499	1,000	HR	SI	27.0	38.0	
HU-HR	1,200	900	HU	HR	0.0	0.0	
HR-HU	1,000	800	HR	HU	1.0	0.0	
SI-ITN1	500	519	SI	IT	48.5	21.0	
ITN1-SI	641	638	IT	SI	0.0	0.0	
LV-LT	1,060	947	LV	LT	0.0	0.0	
LT-LV	695	851	LT	LV	0.0	0.0	
AT-CZ	782	900	AT	CZ	5.0	59.5	
CZ-AT	743	900	CZ	AT	74.0	11.5	
AT-HU	684	800	AT	HU	5.0	3.0	
HU-AT	769	800	HU	AT	0.0	11.5	
AT-ITN1	225	639	AT	IT	48.5	21.0	
ITN1-AT	101	460	IT	AT	0.0	0.0	
AT-SI	805	886	AT	SI	5.0	38.5	
SI-AT	897	946	SI	AT	7.5	11.5	
BG-GR	511	1,700	BG	GR	6.0	95.0	
GR-BG	502	1,400	GR	BG	69.0	6.0	
BG-RO	827	2,190	BG	RO	0.0	16.0	
RO-BG	827	2,190	RO	BG	9.0	0.0	
PLE0-CZ	296	1,200	PL	CZ	54.5	59.5	
CZ-PLI0	402	900	CZ	PL	74.0	25.5	
DE-DKW1	1,749	3,299	DE	DK	87.0	22.5	
DKW1-DE	1,499	3,299	DK	DE	23.5	67.5	
PLE0-DE	1,415	3,000	PL	DE	54.5	12.5	
DE-PLI0	1,043	2,000	DE	PL	4.0	25.5	
ES-PT	2,974	4,200	ES	PT	85.5	45.0	
PT-ES	2,960	3,500	PT	ES	45.0	88.0	

FR-ITN1	2,354	4,027	FR	N1	47.0	21.0	
ITN1-FR	1,020	1,992	IT	FR	0.0	0.0	
HU-RO	639	1,000	HU	RO	0.0	16.0	
RO-HU	615	1,100	RO	HU	9.0	0.0	
HU-SK	990	1,800	HU	SK	0.5	3.5	
SK-HU	1,244	2,513	SK	HU	0.0	22.0	
PLE0-SK	543	781	PL	SK	54.5	15.0	
SK-PLI0	494	818	SK	PL	0.0	25.5	
DKE1-SE04	1,278	1,610	DK	SE	99.8	66.7	
SE04-DKE1	1,049	1,239	SE	DK	9.6	99.8	
AT-DE		5,400	AT	DE	39.5	0.0	
DE-AT		5,400	DE	AT	0.0	39.5	
BE-FR		2,800	BE	FR	0.5	2.5	
FR-BE		4,300	FR	BE	2.5	0.5	
BE-NL		2,400	BE	NL	0.5	0.0	
NL-BE		2,400	NL	BE	0.0	0.5	
DE-FR		3,000	DE	FR	0.0	2.5	
FR-DE		3,000	FR	DE	2.5	0.0	
DE-NL		5,000	DE	NL	0.0	0.0	
NL-DE		5,000	NL	DE	0.0	0.0	

Legend of the column “Conclusion”:

Target very likely not met in 2025
The min. 70% target was reached less than 90% of the time in 2020 and the average assumed NTC value of ERAA 2021 for 2025 is lower than the average NTC value in 2020

Target likely not met in 2025
The min. 70% target was reached less than 90% of the time in 2020 and the average assumed NTC value of ERAA 2021 for 2025 increased compare to 2020, but would have not allowed to reach the 70% target at least 90% of the time in 2020 ***OR*** *the target was reached at least 90% of the time in 2020 but the NTC value of ERAA 2025 decreased compare to 2020 and does not allow anymore to reach the target 90% of the time in 2020.*

Target likely met in 2025
The min. 70% target was reached at least 90% of the time in 2020 or the average assumed NTC value of ERAA 2021 for 2025 increased compare to 2020, and would have allowed to reach the 70% target at least 90% of the time in 2020.

Unable to assess
TSOs did not provide sufficient information to assess the min. 70% target for the whole year 2020.

Unable to assess
For Core (CWE), which applied flow-based in 2020, no NTC values were computed in 2020, thus not allowing for comparison between historical 2020 NTCs and ERAA 2021 NTCs for 2025.

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 ERAA 2021 and on TSOs data provided in the scope of the ACER MACZT reports for 2020

Table 4: Comparison of EENS and LOLE results between the economic dispatch model (ERAA 2021 results) and the EVA model for the central reference scenario without CM - 2025

Bidding Zone	EENS (GWh/year)		LOLE (hrs/year)	
	Economic dispatch model	EVA model	Economic dispatch model	EVA model
AT00	0.0	0.0	0.0	0.0
BE00	8.3	0.1	4.2	0.3
BG00	0.0	0.0	0.0	0.3
CY00	3.7	0.0	61.8	2.9
CZ00	15.4	0.0	15.1	0.0
DE00	31.0	0.2	6.8	0.1
DEKF	0.0	0.0	0.0	0.0
DKE1	2.2	0.1	4.6	0.6
DKKF	0.0	0.0	0.0	0.0
DKW1	0.2	0.0	0.7	0.0
EE00	0.1	0.0	0.5	0.0
ES00	2.0	0.6	1.1	1.0
FI00	0.6	0.0	0.9	0.0
FR00	21.2	0.0	4.3	0.0
GR00	0.0	0.3	0.0	0.7
GR03	0.0	0.2	0.2	1.1
HR00	0.0	0.0	0.0	0.0
HU00	0.8	0.0	0.8	0.0
IE00	1.2	0.1	4.2	1.1
ITCA	0.0	0.0	0.0	0.0
ITCN	1.4	0.1	1.4	0.1
ITCS	1.6	0.4	2.4	0.9
ITN1	0.1	0.0	0.3	0.0
ITS1	0.0	0.0	0.2	0.0
ITSA	21.9	0.1	122.4	4.4
ITSI	2.3	0.0	7.5	0.1
LT00	1.4	0.0	4.3	0.0
LUB1	0.0	0.0	0.0	0.0
LUF1	0.0	0.0	0.0	0.0
LUG1	0.0	0.0	0.0	0.0
LUV1	0.0	0.0	0.0	0.0
LV00	0.0	0.0	0.1	0.0
MT00	18.8	0.0	355.4	0.9
NL00	2.3	0.0	2.3	0.0
PL00	4.6	0.0	4.1	0.0
PT00	0.0	0.2	0.0	0.3
RO00	0.1	0.0	0.2	0.4
SE01	0.0	0.0	0.0	0.0
SE02	0.0	0.0	0.0	0.0
SE03	0.0	0.0	0.0	0.0
SE04	0.0	0.1	0.1	0.6
SI00	0.0	0.0	0.0	0.0
SK00	0.0	0.0	0.1	0.0

Source: ERAA 2021 and additional data provided by ENTSO-E.

Table 5: Profitability for different types of existing thermal generation per bidding zone based on revenues and costs for the central reference scenario without CM – 2025 (€/kW)

Bidding Zone	Coal	Gas	Lignite	Oil
AT00		147		
BE00		220		146
BG00		15	-21	
CY00		632		765
CZ00		477	335	
DE00	-46	197	-69	
DKE1		179		143
DKW1		171		
EE00				248
ES00		-6		
FI00	95	55		
FR00		154		116
GR00		43		
GR03		0		-20
HR00		91		
HU00		144		91
IE00	59	108		
ITCN		118		
ITCS		92		
ITN1		79		
LT00		251		230
NL00	186	205		
PL00	176	250		
PT00		-11		
RO00		70		
SE03		93		
SI00		102	87	
SK00	406	185		

Source: ACER calculations based on additional data provided by ENTSO-E.

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