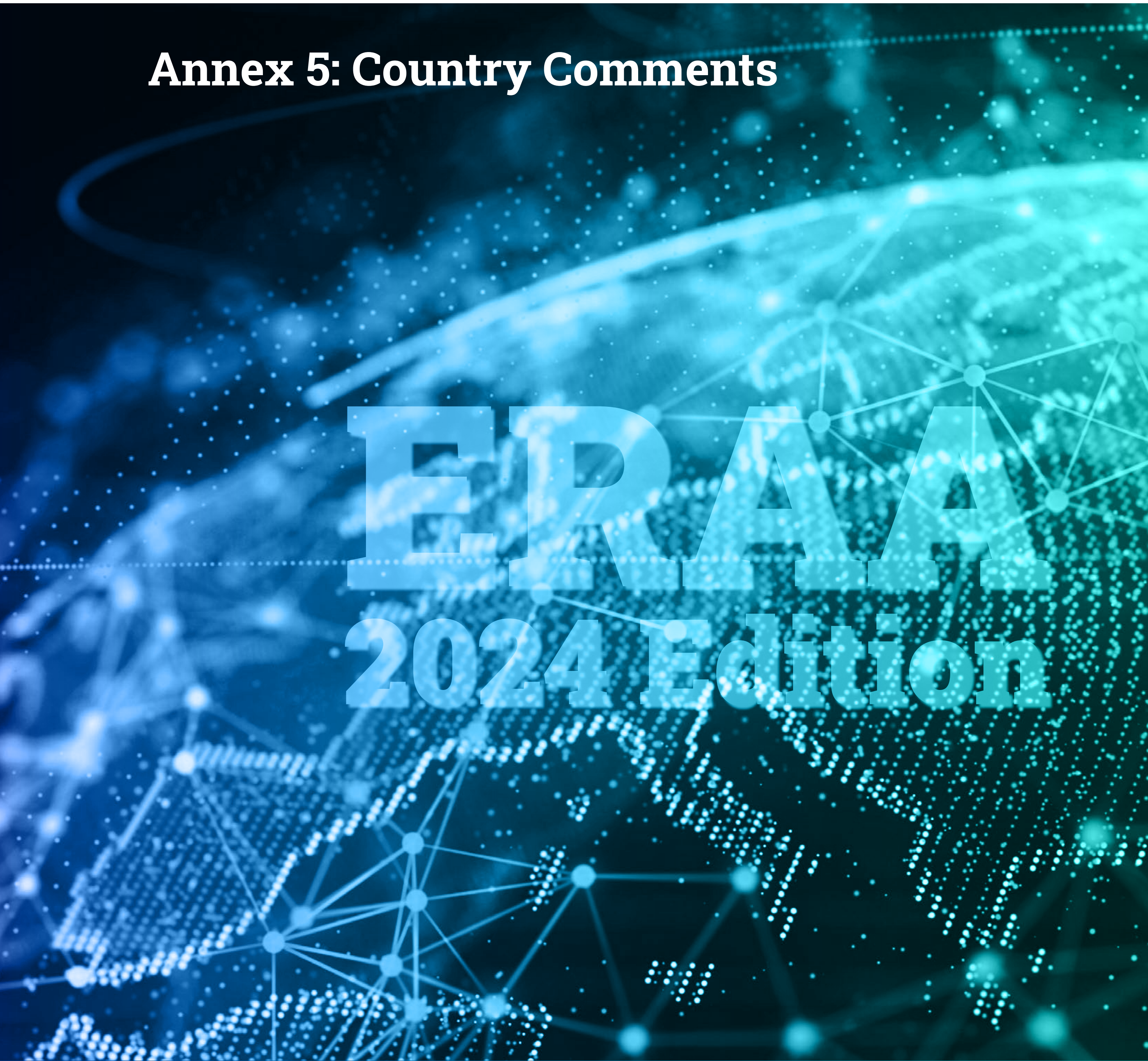
European Resource Adequacy Assessment

2024 Edition

Annex 5: Country Comments



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Disclaimer: This Annex aims to present specific national insights linked to the present ERAA, provided by TSOs on a voluntary basis. These insights reflect only the positions of the concerned TSOs who have submitted their comments and shall not be considered as ENTSO-E's statement.

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Austria

1. Adequacy Indicators

The adequacy indicators for Austria depicted in ERAA 2024 show non-zero potentially substantial values of LOLE and EENS for all the target years (TYs) assessed (2026, 2028, 2030 and 2035). The average LOLE values are above 2 hours in both TYs for the mid-term horizon (up to 2028). After showing a marginal decrease in 2030 (1.53 h), they reach a high value for the target year 2035 up to 6.66 h. These results show a remarkable worsening of expected adequacy levels compared to ERAA 2023 results and highlight additional concerns in ensuring security of supply in Austria. Especially in the longer horizon (2035), the LOLE value is high above the 3h/year threshold taken as reference Reliability Standard (RS) for several Members States in Europe. Building on the experience of ERAA 2023, these results confirm that, despite the expected internal growth of RES capacity (mainly solar PV and wind onshore) following targets in line with the Austrian NECP, and the commissioning of key strategic hydropower projects, the expected rapid growth of the electricity demand and the pervasive electrification of the heating and transportation sectors can pose significant challenges to maintain the desired level of domestic security of supply. To assess the penetration of electric vehicles and heat pumps, ad-hoc scientific work was produced, which helped with identifying drivers for demand growth for electric mobility and heating/cooling, as well as with refining the corresponding hourly profiles in the electricity demand forecasts. The resilience of the system needs to be supported by growing availability of flexible resources, especially paving the way to a reliable and decarbonized system for Austria already in 2040.

Currently there is no legally binding Reliability Standard in Austria. Nevertheless, APG (the Austrian TSO for electricity) closely monitors the domestic availability of resources to ensure resource adequacy in Austria in all time horizons, from the short to mid-term and especially in the long-term perspective. Aside from the average adequacy indicators addressed above, particular attention needs to be reserved to the P95 values of Loss of Load Duration (LLD), indicating that 5% (27 out of 540) of the combined climate and outage scenarios assessed in ERAA 2024 have a number of load disruption hours higher or equal to the reported P95 value. The P95 indicators also show an increase in comparison to ERAA 2023 and are steadily above 10h/year for all TYs assessed, with a concerning peak P95 value of 42h/year in 2035. Such low-probability but high-impact scenarios may be extreme, yet certainly plausible given the increasing sensitivity of adequacy indicators with respect to several factors such as (i) peak-load high dependence to the outdoor temperature profiles (e.g. due to heat pump loads) and (ii) increased risk of simultaneous adverse conditions from both demand and generation side (e.g. dunkelflaute events).

APG intends to keep monitoring the national level of adequacy to provide both the TSO and the national key stakeholders with tailored and complementary insights on the domestic adequacy indicators, aside from those reported in ERAA 2024, especially taking into account the peculiar characteristics of the Austrian power system, which cannot be properly reflected in a European reference study such as the ERAA. These include but are not limited to (i) more precise modelling of complex hydropower storage systems, (ii) specificities of the internal high voltage transmission grid, (iii) refined sensitivities and scenarios on economic and climate-dependent availability of capacity, demand, and other key input data.

2. Economic Viability Assessment

Another key factor that affects generation resource adequacy is the economic viability of existing thermal generators. The EVA of ERAA 2024 indicates that only less than 100 MW of thermal generation capacity are at substantial risk of "early decommissioning" in the mid-term (2026 - 2030) in relation to their economic viability. Additionally, according to the EVA, around 300 MW of modern traditional gas-fired capacity would be an economically viable investment in Austria as of 2035. These results need to be carefully interpreted within the peculiar context of the modelling methodology and assumptions adopted in the EVA of ERAA 2024. The current modelling framework captures the "marginal capacity" theoretically viable at long-term economic equilibrium based on few high price scarcity signals (e.g. above 2000€/MWh). As clearly shown in Figure 2, 3, and 4 of Annex 3 of ERAA 2024, the new OCGT capacity in Austria would be "viable" only relying on the high revenues of Weather Scenario (WS) 25 (rather extreme climate conditions), with ca. 95% of the revenues captured in hours with market price setting above 2000 €/MWh. In the other two WS included in the EVA, the capacity factor settles to only 70 and 130 full load hours of yearly operation, with high economic losses for the potential investor that would not be capable to recover the yearly costs of the investment and operation of the capacity. It follows that the comparative EVA results included in Annex 3 Section 3, showing even higher fossil capacity expansion for Austria for the two sets of EVA results obtained with country-specific CONE, are detached from any reasonable investment signal, rather a mere proof of the high sensitivity of the EVA model to asymmetrical differences in the CONE input data, proposing a geographical allocation of capacity which is not sustained by domestic needs or business case, but rather an exogenously biased outcome of the EVA model. The market and price signals reported by the EVA model, would not justify realistic actual risk-averse investments decision in new generation capacity. The same considerations can be extended to the gas investments reported for the other Member States, as highlighted in the Executive Report of ERAA 2024. Therefore, APG considers that the adequacy assessment based on the post-EVA scenario accounting for all the new entry of capacity underestimates generally the adequacy risk. A careful reflection among policy makers is necessary also concerning the underlying system costs, which are implicit when accepting a similar EVA reference scenario. Under the current market conditions, with a traditional "pay as clear" policy and price settled via a unique merit order, sustaining more than 70 GW (in 2035) of new traditional capacity expansion in the system, based on recurring price spikes driven by scarcity, comes at a high welfare cost to be carried by electricity consumers, which may not be an expectable nor affordable scenario in line with a sustainable transition.

The current methodological framework of the EVA does not only risk delivering over-optimistic expansion of capacity but also underestimates the economic viability concerns of existing assets. A substantial part of Austria's thermal generation capacity is already today maintained operational through a network reserve mechanism. Very serious concerns on the capability to keep flexible capacity within the next 5-year period 2026-2030 were addressed by the Austrian facility operators, mostly gas generation facilities, in the frame of the national consultation on network reserve 2024. APG monitors closely the availability of Austria's thermal generation capacity, given its critical importance to ensure not only resource adequacy, but also a safe and secure operation of the national electricity grid. The current assumptions as well as the actual economic viability of such plants depict potential higher risk of mothballing or even early decommissioning over the next decade, highlighting the significance of complementary mechanisms to maintain enough flexible generation resources operational in Austria.

APG highly requests and recommends a revision and an improvement of the current EVA methodology, to further and deeper reflect common practices in real-business investment decisions, additionally to the risk aversion metrics already considered (e.g. hurdle premiums). When observing the results described above against the current geo-political and macro-economic landscape, it is apparent that volatile market signals driven by rare scarcity price hours

– especially when such events are linked to extreme weather events which may or not occur once in a decade – may not be deemed sufficient to economically sustain long-term investment decisions in generation capacity.

Belgium

1. Economic Viability Assessment

We refer here first to the official EVA results of ERAA 2024 for the 'Central Reference Scenario', (Annex 3 Section 2). These are based on the total cost minimization approach of ENTSO-E, using harmonized CONE assumptions and weights. The use of harmonized CONE across countries on economic decisions is the most appropriate approach since there is no substantial reason for the CAPEX of technologies to vary significantly between different countries. Furthermore, the usage of weights for the relative contribution of the three weather scenarios (WS) used in the EVA approach, aims to provide an improved level of consistency between revenues considered in the EVA runs and in the Adequacy Economic Dispatch (ED) runs.

In any case, the use of only three WS in EVA does not provide a fully robust method, since investments are prone to be 'selected' based of few running hours of high prices, e.g. mainly from within one of the three WS selected. Therefore, the observed economic decisions found in ERAA 2024, might not represent credible investor decisions.

Regarding the results for Belgium, specifically:

- Only 1740 MW out of the total 2728 MW of existing units eligible for 'Life Time' extension are extended by the model in all target years, 2026, 2028, 2030, 2035.
- Furthermore, decommissioning of 30 MW Gas CCGT in 2026 and 300 MW Gas CCGT in 2028 is observed.

These results are therefore indicating that without additional revenues (such as those from the CM), not all existing capacities subject to 'Life Time' Extension would be profitable and that CM revenues are important to ensure the economic case of existing units throughout the entire period 2026-2035 considered in ERAA 2024.

No expansion of new build capacity is found in the EVA results. These results confirm the trend observed in Belgium over the past recent years as there is no incentive for new build thermal capacity in Belgium, if relying exclusively on energy-only market revenues.

The revenue-based EVA results, using harmonized CONE assumptions and weights, are also presented as Annex 4 in ERAA 2024. Both the results from the implementations A and B confirm the same trends as the official results from the total cost minimization approach for Belgium, namely:

i) Not all existing capacity subject to 'Life Time' Extension will be profitable. CM revenues are important to ensure the economic case of existing units throughout the entire period 2026-2035.

ii) No new thermal capacity is expected to appear in Belgium throughout the entire period 2026-2035.

Lastly, the EVA total cost minimization approach results, using "Country specific CONE" + "Country specific CONE + EU Ref 2020 scenario" (ACER requested), are presented in Annex 3 Section 3. Elia would like to stress that these results (New entry in 2035: 6660 MW Gas CCGT and 1770 MW Gas OCGT respectively) do not represent any credible investor decision for Belgium for the period 2026-2035 and are purely the result of a bias in the EVA algorithm when using "Country specific CONE" values within the EVA model. As mentioned in Annex 3, these results are not part of the official results of the 'Central Reference Scenario' of ERAA 2024 and hence have no legal value.

2. Adequacy Indicators

The adequacy indicators for Belgium in ERAA 2024 show values of LOLE > 3h (higher than the Reliability Standard for BE = 3h) for all TYs assessed (2026, 2028, 2030 and 2035). It is important to note that the data for Belgium is based on information available at the beginning of 2024, when ENTSO-E froze the data for all countries.

Furthermore, expanded parameters to better capture the probabilistic characteristics of the availability of the French nuclear fleet have been considered for the long-time horizons 2030 and 2035. We refer to the main report for further details. This showcases a first nuance of probabilistic modelling of maintenance profiles in ERAA.

Since the French nuclear fleet represents more than 60 GW of thermal capacity in Europe, the improved modelling of its availability is crucial when assessing future adequacy requirements for Europe. In particular, this is of crucial importance not only for the adequacy of France but also for the adequacy of Belgium. Given Belgium's high dependence on imports, any event related to a reduced availability of the French nuclear fleet greatly affects the level of adequacy in Belgium. This was demonstrated several times in national adequacy assessments performed for Belgium over the past decade.

2026 (LOLE = 4.7h), 2028 (LOLE = 7.9h) The results of all known CM auction at the time of the data freeze by ENTSO-E have been considered in the input data. It is noted, however, that the results of CM auctions, which have occurred after the data freeze period, are not considered in the input data of ERAA 2024. The LOLE >3h results confirms that the CM is an appropriate and necessary measure to ensure the adequacy levels of Belgium but also highlights that the level of adequacy of Belgium heavily relies on the level of SoS and hence the assumptions of its neighbours (notably FR, DE, UK), which are beyond Belgium's control. Therefore, a prudent approach is necessary regarding the level of SoS in Belgium. Furthermore, the results stress the importance of the Belgian CM to ensure the desired level of adequacy in Belgium.

2030 The central reference scenario results of ERAA 2024 **LOLE = 6.1h**, which consider the improved modelling of the French nuclear availability (with two additional French nuclear availability cases), highlight that the level of adequacy of Belgium heavily relies on the level of SoS and hence on the assumptions of its neighbours, notably on the French nuclear availability. Even the results, without the improved modelling of the French nuclear availability above mentioned, already confirmed that the reliability standard for Belgium would be higher than > 3h. Therefore, the planned CM auctions for 2030 will play an important role to ensure that the reliability standard in Belgium is met. Also, the impact on adequacy of delays in infrastructure and renewable development should be accounted for in future studies.

2035 The central reference scenario results of ERAA 2024 **LOLE = 10.4h**, which consider the improved modelling of the French nuclear availability, highlight that the level of adequacy of Belgium heavily relies on the level of SoS and hence on the assumptions of its neighbors, notably on the French nuclear availability. Furthermore, the results without the improved modelling of the

French nuclear availability mentioned above, already confirmed that the reliability standard for Belgium would not be respected (LOLE > 3h) in 2035 if assumed that the nuclear extension of D4/T3 terminates by end of 2035, as defined in the input data of ERAA 2024.

Bulgaria

Input Data

National trends generation mix data is based on the updated Bulgarian NECP (update 2024), where RES development is significantly accelerated in comparison to the old version of the NECP. Since the submission of the inputs for ERAA 2024, there was another update of the NECP, however changes were not essential.

Two new large hydro storage projects are being investigated with an expected commissioning around 2035. Batteries are expected to play a significant role as balancing capacities in the next few years although their target trajectory according to the new NECP is very underestimated (only 1100 MW are envisaged by 2035). Two new nuclear units (AP 1000) are in the pipeline with the earliest commissioning possible in 2035.

Domestic yearly demand (NECP based) is in the range of 35 – 38 TWh for the period 2026 – 2036, which assumes that EV demand picks up, is a reasonable figure.

EVA and Adequacy results comments

The conducted EVA suggests that practically all of Bulgaria's thermal lignite fleet is endangered from decommissioning due to low revenues. However, the updated NECP does not hold commitments for phase out of lignite-fired plants and instead foresees new entry capacity from CCGT.

The adequacy risk for Bulgaria, however, remains quite low (LOLE P50 – close to 0, and LOLE P95 – in the range from 7-8 h/y for TY 2026 and 2028). This could be attributed to the good level of interconnectivity of the Bulgarian power system, the marginal increase of demand and peak loads, and the expected growth of batteries and hydro storage in the region.

Czech Republic

Results of ERAA 2024 reveal significant breaches of reliability standard (6.7 h/y in the Czech Republic) in every target year (TY) of the study. In 2028, the Czech Republic reaches one of the highest LOLE values in continental Europe; high LOLE values above the reliability standard are present in further years as well.

The main explanation of these phenomena lies in the insufficient capacity of dispatchable resources (i.e. gas) which are to fill the gap after the phase-out of coal power plants. This is a temporal issue as the coal phase-out is far faster than the construction of new gas plants. Economically, the retirement of coal power plants is simply inevitable with the ever-growing carbon allowance prices. This was confirmed by the EVA simulation with harmonized CONE values which decommissioned substantial volumes of the Czech coal fleet (approximately -1.9 GW capacity in 2026 and -2.9 GW in 2028). The net position analysis of scarcity hours suggests potential issues related to the lack of available generation capacities in Central Europe. This problem arises despite sufficient cross-border capacities.

However, a satisfactory volume of newly built gas capacity intended to offset coal capacity decommissioning is still in the initial planning stage. This is because there are only few financial incentives motivating investors to fund these projects and ensure their timely completion. This suggests the need to adopt relevant measures (market and non-market) to keep minimal required existing capacity in stand-by mode to maintain supply-demand balance within the grid until at least 2030 when a new gas fleet is expected to start become available (according to EVA simulation results and stakeholder’s operational assumptions).

Concerning renewables, wind and solar capacities were not fully aligned with the National Energy and Climate Plan (NECP) as this legislation was approved only in December 2024. The values used in ERAA 2024 were nevertheless even more ambitious than those presented in NECP and correspond to the “rough edges” of the legislation.

Denmark

Submitted data for Denmark
The overall trends for Denmark have not changed drastically regarding the data submitted to ERAA 2023 and ERAA 2024. The only one to highlight is the estimated postponed commissioning date of Bornholm Energy Island wind capacities from 2030 to 2031. Changes in the adequacy results for Denmark from ERAA 2023 to ERAA 2024 is therefore expected to be mainly due to changes in the general European energy system, Economic Viability Assessment results and methodology changes in ERAA, such as projected weather scenarios instead of historical climate years and updated flow-based data.

Since data submission for ERAA 2024, Energinet has received new and updated Danish energy system assumptions from the Danish Energy Agency, which are noticeable different from the ones submitted to ERAA 2024. This updated data has been submitted for ERAA 2025 and TYNDP 2026 during December 2024, and it is expected that this will affect the Danish resource adequacy results in ERAA 2025. Additionally new political statements have since been published regarding offshore wind plans in Denmark and additional postponing of the Danish energy island project at Bornholm, which means postponed interconnector capacities and offshore wind capacities. These changes will materialize in the Danish NRAA for 2025, where ERAA 2024 data will be used for Europe and the updated assumptions for Denmark from the Danish Energy Agency and political statements will be implemented.

Results for Denmark
Over the next decade it is expected that Denmark will become more dependent on electricity imports to secure resource adequacy. Hence, the development in the resource adequacy situation across Europe, especially in Northwestern Europe, is very important for Danish resource adequacy assessments. This can also be seen from ERAA 2024 results for Denmark and explains the dynamics over time for the Danish adequacy results. When the adequacy risk increases in Denmark's neighbouring countries, the Danish adequacy risk increases as well and vice versa.

Further, it is important to see the relative high adequacy risk in Denmark already in 2026/2028 in light of the identified risk for decommissioning of capacity across Europe in ERAA's EVA in 2026/2028. The significant decommissioning of capacity in both 2026/2028 based on ERAA's EVA increase the adequacy risk across Europe, which also affects the Danish adequacy results.

In relation to the EVA results the commissioning of 1140 MW conventional gas power in DKE1 in 2035 by the EVA is potentially not in accordance with the NECP, of climate neutrality in 2045 for Denmark[1]. Additionally, it is not Energinet's understanding that the power plant investors are willing to base entire investment decisions on a few potential scarcity pricing hours, as is the case in the EVA, based on Figures 2 to 4 in Annex 3. As a consequence of this, Energinet believes that the insights gained from also having adequacy results from the National Trends scenario before the EVA-loop would be valuable. Having results for both scenarios would aid readers and actors bridge the gap between adequacy indicator results in the economically viable system of the EVA and the politically expected system of the National Estimates scenario.
[1] https://www.stm.dk/statsministeriet/publikationer/regeringsgrundlag-2022/

Finland

In Finland, the overall trends in energy system development and adequacy have not significantly changed. Adequacy of electricity supply faces its greatest challenges during the winter season, particularly during cold and calm weather periods with high demand and low wind generation. During these periods, Finland needs electricity imports to cover the peak demand, especially in case of forced outages or extreme cold. Therefore, most adequacy challenges are faced during the coldest years, which drive up the average values for the adequacy indicators in Finland.

The Finnish standard for system reliability, which is set to 2.1 h/year, is met in the earliest target year (TY) but not in the later TYs, which indicates adequacy risks increasing in mid- to long-term. The lower adequacy risks in the early TY are explained by increased interconnector capacity as Aurora Line between Northern Sweden and Finland is commissioned by the end of 2025. The adequacy risks identified in mid- to long-term are highly dependent on the development of the thermal fleet and demand-side response. Expected and modelled decommissioning and/or mothballing of thermal units increases adequacy risks, while modelled commissioning of new flexible thermal units and expected increase in demand-side response (DSR) from the industry as well as households lowers the risks. Both of these developments include uncertainties that affect the security of supply. Overall, however, the increasing risks show that there might be need for measures to support adequacy in mid- to long-term.

Currently, Finland has a strategic reserve measure in place until 2032, however, no capacity is contracted to the reserve. Instead, the National Emergency Supply Agency has reserved the Meri-Pori coal power plant until the end of 2026 for severe disruptions and emergencies to guarantee security of supply. In addition, the government has established a working group to consider a non-fossil flexibility scheme, which would also support security of supply. Fingrid perceives well-designed support schemes to ensure adequate electricity supply in Finland as a positive development.

France

Important general considerations

RTE believes that a robust Adequacy Assessment must be based on an exhaustive study of risk situations that Member States face. European risks on security of supply as modelled in the ERAA are mostly correlated to generation availability, both from nuclear and renewable sources, as well as residual load. Considering a broad range of nuclear and weather variabilities is important not only for the robustness of France's adequacy assessment but also for that of all modelled perimeter, as cross-border exchanges have a more and more crucial role to play for security of supply.

RTE welcomes the numerous methodological improvements that were carried out in this edition of the ERAA, on both EVA and ED studies, such as the implementation of the new climate database, the extension of *flow-based* use to Nordics domain and to EVA in general.

Moreover, RTE salutes the inclusion of a Revenue-Based EVA study case, which appears to give promising early results and would allow for both better understanding of EVA results and, in future editions hopefully, a better grasping of investor risk-aversion. One of these implementations showcases the methodology and implementation of Revenue-Based EVA developed jointly by RTE and other TSOs.

Still, while results are consistent on the identification of security of supply concerns in France, ERAA 2024 does not fully capture the specific characteristics of the French electricity system, which is heavily reliant on nuclear availability and highly sensitive to temperature, the two main factors influencing France's security of supply.

To take these sensitivities into account, the French NRAA conducts adequacy studies using a dataset that combines 200 weather scenarios with 60 nuclear availability scenarios (including extended maintenance shutdowns). This extensive dataset enables the NRAA to capture a wide range of system configurations and enhances the robustness of its security of supply analysis.

In contrast, ERAA 2024 relies on only 36 climate scenarios for Economic Dispatch and three climate scenarios for EVA. Regarding planned nuclear outage data, the single average set used in the EVA and short-term ED leads to a high underestimation of adequacy risks linked to nuclear unavailability, especially since their impact is largely asymmetrical: capacity shortage and consequent loss of load are far more costly than capacity excess. The introduction of two additional French nuclear availability scenarios (low and high) in TY 2030 and 2035 strengthens ERAA 2024's security of supply analysis for both France and Europe, incorporating a broader range of potential system configurations.

For further editions of ERAA, RTE encourages the continuation of improvements, by taking into account more variability, especially in the EVA. In general, RTE welcomes the work currently underway in the ERAA Repurposing Task Force as it leads future editions towards greater methodological robustness.

The National Energy and Climate Plan

The updated version of the French NECP has been submitted to the European Commission mid-2024. It relies on three framework documents: the National Low-Carbon Strategy, the National Plan for Adaptation to climate Change and the Multiannual Energy Plan, under public consultation at the time of writing. These documents provide a roadmap for the energy sector in the coming years. The new NECP is also supported by RTE's latest NRAA.

It integrates the Fit for 55 package in the French energy roadmap, with ambitious RES development targets, yet also a new nuclear strategy, with expectations of expanding lifetime of several nuclear units up to 50 years and the building of several new reactors. These developments support the target of decarbonisation through a rapid electrification of uses to reach Fit for 55 targets and carbon neutrality by 2050.

Load forecast provided for 2026, 2028, 2030, 2035

After remaining stable over the past decade, the French electricity demand fell in 2022 (461 TWh, i.e. 12 TWh less than in 2019). This decrease happened after the COVID crisis and can be explained by a combination of sufficiency from consumers and high market prices.

In 2024, electricity consumption in France has stopped falling (+0.7% corrected consumption between 2024 and 2023 according to the latest national electricity balance).

In the medium term, French electricity demand is expected to rise from 2025 onwards, according to decarbonisation acceleration scenarios. The recovery of economic activity and the development of electricity as a decarbonisation vector will more than counterbalance the effects of energy efficiency actions on the annual demand. Furthermore, to meet the *Fit for 55* target, RTE provided a reference load scenario in this ERAA edition, which was presented as well in the 2023 NRAA, the *Bilan Prévisionnel* (published in September 2023).

Main drivers of this rising demand are:

- Approximately 9% of the French electricity demand dedicated to hydrogen production by 2035;
- Approximately 40% of the vehicle fleet and 20% of trucks will be electric by 2035;
- Increasing the share of electricity in heating systems and industrial processes.

This trajectory is aligned with that of the previous ERAA 2023.

Net generating capacity forecast provided for 2026, 2028, 2030, 2035

The scenario presented in 2024 ERAA follows the NECP's evolutions on short term trajectories of electricity production:

- Accelerated development of RES (wind and solar capacities are multiplied by more than three in the next ten years);
- Concerning the last two coal units, Cordemais operator recently announced plans to stop production in 2027. For Saint Avold, the operator is considering a conversion of the power plant;
- The new Flamanville nuclear unit is gradually operating as of 2025;

- No commissioning of new thermal fossil units is authorised according to current regulation[1].

Regarding nuclear availability, the recent corrosion stress crisis has come to an end in 2024, however, it had led RTE to review nuclear availability forecasts. Still, even though the crisis has come to an end, it bears impact on nuclear maintenance planning to this day.

National view on adequacy and economic viability

RTE produces an annual risk assessment through its national adequacy outlook on a time horizon of up to ten years or more, and is currently elaborating the next edition of the French NRAA.

The key messages from the NRAA (published in September 2023) regarding adequacy were:

- Security of supply in France is expected to improve in the coming years, after a setback in the last years caused by the COVID crisis and the stress corrosion of a number of nuclear reactors.
- From 2030 onwards: a need for new capacities has been identified, which can be fulfilled by several combinations of demand-side response and production

Levels of vigilance remain necessarily high, monitoring nuclear availability and the speeding up of electrification.

In general, with the introduction of two additional nuclear availability scenarios in medium-term, ERAA 2024 numerical results are consistent with ERAA 2023 results (which were consistent with the NRAA's conclusion) on security of supply concerns in France. Both ERAA 2023 and ERAA 2024 identify concerns from 2026 on to 2035, just as *Bilan Prévisionnel 2023*, once taking into account the impact of the economic viability.

As mentioned, some technical simplifications of ERAA 2024 linked to the global complexity of calculations raise specific attention points. Mainly, **the very low number of Weather Scenarios (WSs) used in the optimisation-based EVA (3)** can lead to result instability, as one of these years only carries drive for investment. The economic equilibrium output is represented by a balance of a single, low-probability, year with very high revenues, and two years with little or negative revenues but high ponderation. Hence, the weighting of this WS 25[2] becomes the most prominent driver for capacity commissioning or decommissioning, and hence for security of supply in general.

This precarious equilibrium between expansion costs and scarcity revenues is not representative, or representative enough, of a real risk-averse behaviour in capacity commissioning. RTE believes that the ongoing work on *revenue-based* approaches would be better tooled to avoid these phenomena while being in line with the ACER methodology.

[1] This point is not in the next version of the Multiannual Energy Plan for France, under public consultation at the time of writing

[2] Which unfortunately takes the role of Climate Year 1985 of previous ERAA editions.

Consequently, the results of this ERAA edition for France must be read jointly with the French NRAA *Bilan Prévisionnel*, to mitigate possible uncertainties due to the sheer complexity of the ERAA exercise. The last edition of the *Bilan Prévisionnel* was published in autumn 2023, with detailed chapters having been published since. They depict a central scenario pointing towards a need for investment by 2030 to ensure fulfilment of the **2h/yr Reliability Standard.**

Estonia

Non-market resources

In February 2025, the Baltic countries synchronized within the Continental European Synchronous Area (CESA) and introduced a new reserve market. Due to the high reserve requirements and the limited number of market participants able to offer frequency reserves, the Baltic Transmission System Operators (TSOs) are allowed to use TSO-owned capacity as the last option in the merit order to procure a part of these reserves until the end of 2027 (Directive EU 2024/1711[3]).

For TY 2026, Estonia accounted for this capacity in ERAA 2024 by reducing the overall reserve need in the model. This approach implies that neither the power plant nor the frequency reserve it held were explicitly modelled. For the rest of the TYs, this power plant in Estonia was categorized as out-of-market/cannot be used for adequacy.

Reserve modelling

The three Baltic countries Estonia, Latvia, and Lithuania are part of the Baltic Load-Frequency block and between the countries the reserves are procured jointly and reserves are shared across borders. The NTCs between the countries are divided between day-ahead electricity flow and reserve market. Currently, the ERAA methodology does not enable such a modelling approach, which means that the closest combination is achieved by assigning each country to hold a share of the total Baltic reserve need and reducing the NTCs between the countries to make sure the share of reserves held in Lithuania and Latvia would still reach Estonia (and vice versa).

[3] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=OJ:L_202401711&qid=1741166824186

Germany

The scenario input provided by German TSOs reflects the current legislation and policy targets in Germany at the time of the data collection (end of 2023) with updated power plant strategy in the beginning of 2024. Hard coal and lignite-fired power plants shall be shut-down by 2038 at the latest according to national law. Renewable expansion goals result in installed capacities of 115 GW of wind onshore, 30 GW of wind offshore and 215 GW of photovoltaics in 2030. The scenarios are in accordance with the Fit For 55 package and the German NECP. The scenarios of the national processes like the Network Development Plan Electricity (NEP 2037/2045 (2023)), which are approved by the national regulatory authority (NRA), are the framework for the ERAA 2024 scenarios. Further scenario sources are the German legally mandated processes on determining the need for grid reserve generation capacity for congestion management called “Systemanalyse 2024” and “Langfristanalyse 2030 (V2022)”. Other national strategies to ensure resource adequacy (“Kraftwerksstrategie”) have been considered according to the latest available information at the time of the data collection. However, this national strategy has not yet been finally passed into law and, due to the current political situation, it is uncertain whether and when a strategy can be expected. More relevant information about the input data and clarifications regarding the call for evidence of ERAA 2024 input data are elaborated further below:

Renewable energy sources
All RES capacities are based on policy targets. Rooftop PV was modelled in combination with the household electricity demand to allow a correct modelling of households’ self-consumption. Due to a massive extension of solar PV in 2023 and 2024 of ca. 30 GW, which was not visible at the time of the data collection, the assumed PV capacity might be underestimated in TYs 2026 and 2028. Wind onshore capacities were adjusted according to a remark from the call for evidence, as the previously published data did not take the 2035 target of 157 GW installed capacity into account. The values for offshore wind capacities are based on actual projects. The missing installed capacity mentioned in the public consultation can be accounted to a project delay. The run-of-river capacities in national studies amount to 3.9 GW, the published number of 5.6 GW represents all hydro power plants (excluding pump storages).

Demand
In ERAA 2024, a gross electricity demand of 750 TWh is assumed for Germany in 2030. Considering flexible load components, it is important to note that by 2030, approximately 550 TWh are non-flexible, 110 TWh are accounted to heat pumps and electric vehicles, which are partly flexible. The remaining 90 TWh are accounted to market-driven demand like the electricity consumption of electrolysers, which is determined in the market model. Therefore, the input data cannot guarantee that the final demand amounts to exactly 750 TWh.

It is important to state that this figure originates from a political target. The input data for ERAA 2024 was generated to meet this political target. Since then, several studies were published pointing out that a slower increase in the electricity demand is to be expected. The electricity demand in the last years underlines this development. The predicted net electricity consumption in 2030 ranges from 530 TWh to 670 TWh.

Coal phase out
In contrast to ERAA 2023 an accelerated phase-out of coal fired powerplants until 2030 was not included in the input data of ERAA 2024 as there are no further legal regulations planned to support this. A legally mandated coal-phase out is considered by 2038. Planned decommissionings at the plant operators’ own discretion and legally mandated decommissionings (also as result of decommissioning auctions) are taken into account. The remaining coal fired

power plants are subject to the EVA, to represent the possibility of an earlier and market driven coal phase-out.

Gas and hydrogen power plants

In ERAA 2024, the German power plant strategy as of February 2024 has been considered. This means that additional 10 GW of H2-ready power plants as well as 0.5 GW H2 power plants are considered as policy units. A capacity of 2.5 GW in 2030 and 8 GW in 2035 was assumed. Assumptions regarding commissioning dates have been made based on planned calls for tenders and expected realization times. However, a final political decision on the power plant strategy is missing.

Reserves

Input data on German non-market resources contain:

- Capacity reserve: Since 1 October 2024 and until 30 September 2026, a total contracted capacity of 1.2 GW of power plants is available for unforeseeable resource adequacy events. These power plants must be available within twelve hours.
- Grid reserve: This is used to resolve congestion and contains different types of power plants in Southern and Western Germany. It comprises a total capacity of 8.2 GW as of 31 December 2024.
- Special network equipment power plants: These are fast-starting gas-fired power plants with an overall capacity of 1.2 GW, primarily intended to restore grid stability after a disturbance in the transmission grid.

Due to a central methodological requirement, reserves must have their primary purpose defined in addressing resource adequacy incidents. Therefore, the simulation run for TY 2026 takes into account the capacity reserve as non-market resource in Germany. Non-market reserves will consequently not be considered in other TYs.

Home storage battery systems

Home storage battery systems are modelled as dual use entities. Most of the year, home storage systems optimize the self-consumption of electricity produced by rooftop-PV: they charge in accordance with solar irradiance and discharge during evening load peak. As this kind of usage of home storages is very limited during winter months, it is assumed that a share of those (e.g. 65 % in 2030) is flexible and can also react to spot market prices. This approach was already used in ERAA 2023.

Comments on the results

In contrast to ERAA 2023, the fuel price assumptions in ERAA 2024 (lower gas prices in ERAA 2024 compared to ERAA 2023) lead to a high market-driven decommissioning of coal-fired power plants in Germany between 2026 and 2030. At the end of 2035, 5 GW lignite-fired power plants remain in the system. It should be noted that the viability of these units in the EVA model may have been influenced by simplifications in their representation, such as the exclusion of start-up costs. Additionally, 400 MW gas-fired power plants are decommissioned in 2026. These decommissioned plants may have been subject to de-mothballing in later TYs if this option were included in the EVA model. The consideration of country-specific CONE values compared to harmonized CONE values results in a higher net expansion capacity in countries with lower CONE assumptions. A geographical shift of capacity expansion is particularly noticeable in 2035 from the Czech Republic (-1.4 GW), Germany (-2.7 GW) and the Netherlands (-1.9 GW) to Austria (+1.3 GW), Belgium (+6.7 GW) and Italy (+1.9 GW). Such spatial deviations can be interpreted as an inefficient allocation of resources within the model run, since no major cost differences between neighboring countries are to be expected in reality. The EVA suggests 18.3 GW of gas expansion in Germany in 2035 with harmonized CONE values. With country-specific CONE values, gas is expanded by 15.6 GW in 2035. Regarding the profitability of new expansion units in Germany, Figures 2 to 4 in Annex 3 “Detailed results” show for the target year 2035 and the harmonized CONE scenario that the capacity factors of such units are relatively low (below 5 %), meaning that their revenues stem to a large extent from near-scarcity hours (i.e. with day-ahead market prices above 2000 €/MWh), and that such hours occur primarily during extreme climatic conditions, which are mainly triggered by one out of three weather scenarios in the EVA stage (WS25). This implies that a lack of near-scarcity events can put at risk the profitability of new expansion units, posing a high financial risk for investors who may not be willing to take. Such ‘missing money’ problem can therefore lead to a lower capacity expansion in Germany, which in turn directly impacts resource adequacy. This is especially relevant from 2030 onwards, as Germany shows a net expansion capacity, and the profitability of controllable power plants is increasingly affected by the expansion of renewable energy sources and the electrification of demand.

In terms of resource adequacy results the high market-driven decommissioning of coal-fired power plants in the EVA lead to high LOLE values of 10.79 h/year in 2026 and 18.79 h/year in 2028. Considering the out-of-market reserves the LOLE value in 2026 reduces to 8.7 h/year. In 2030, the LOLE value drops to 8.21 h/year, and in 2035, it increases to 9.87 h/year. Therefore, the German Reliability Standard of 2.77 h/year is not met in any TY. It should be noted that for computing the LOLE values, only non-market resources which are either dedicatedly or at least primarily contracted for resource adequacy issues were considered.

For TYs 2026-2030, the EVA model suggests an earlier decommissioning of existing power plants in Germany compared to the reported data. Avoiding such early decommissionings could increase resource adequacy. A less ambitious increase in load until 2030 could also reduce adequacy concerns in the next years. However, 2.5 GW of controllable gas capacity as part of the power plant strategy ‘Kraftwerksstrategie’ are assumed to be already available in Germany in 2030, which is highly uncertain from today’s perspective, as the current government formation process could lead to delays regarding the power plant strategy. In 2035, despite a large expansion of gas power plants of around 18 GW and additional 8 GW as part of the power plant strategy, the Reliability Standard could not be met. Even with a delayed electrification of demand it can be emphasized with certainty that an expansion of controllable power plants is required. Furthermore, according to the EVA results in ERAA 2024, it is essential to provide further incentives to power plant operators and investors to ensure the necessary expansion and to retain existing units in the market in the years leading up to 2035.

Comparison with the NRAA

The next revision of the NRAA for Germany (“Versorgungssicherheitsmonitoring 2024”) is expected to be published in Q1/2025. The German NRAA is published every two years. The last version showed no resource adequacy concerns for Germany and neighbouring countries until 2031.

Hungary

Unfortunately, a mistake was found in Hungarian frequency restoration reserve (FRR) requirements data. Accidentally, both the up- and downward requirements were considered. For future ERAA editions this will be corrected. However, for ERAA 2024, this could not be modified due to the late notice. This might affect both the EVA and ED results, since the available thermal capacities would be higher in the initial runs with the correct FRR value.

Ireland

Ireland and Northern Ireland together comprise the Single Electricity Market (SEM.) This wholesale electricity market is designed to be compliant with the European Target Model. It aims to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand and to support long-term sustainability. The SEM incorporates a Capacity Market, with Capacity Auctions taking place annually.

The adequacy standard for Ireland is three hours of Loss of Load Expectation (LOLE)[4][1], as set by the Department of the Environment, Climate and Communications (DECC) working with the Commission for Regulation of Utilities (CRU).

EirGrid provided inputs to the ERAA 2024 PEMMDB data collection, which were aligned with the latest published national study at the time of data freeze - this was the 'All-Island Generation Capacity Statement 2023-32' (GCS23).

Throughout 2023 and 2024, EirGrid worked collaboratively with SONI, the Commission for Regulation of Utilities (CRU) and the Utility Regulator (UR) to develop the pathway for transitioning to the new methodology that better aligns with Article 24 of the Regulation on the internal market for electricity (EU/2019/943). The first All-Island Resource Adequacy Assessment (AIRAA) covering the period 2025-2034 was published in early 2025[5].

It should be noted that material differences may arise due to differences in data freeze dates. The AIRAA data freeze date was approximately one year after the equivalent freeze date for which ERAA 2024 inputs are derived.

There have been significant concerns in recent years regarding the security of supply outlook in Ireland. Both GCS23 and AIRAA report large LOLE results for 2026 in particular. This has led the CRU to initiate a programme of actions[1] including:

- securing enduring capacity through market measures;
- improving demand side response; and
- in the short-term, keeping units open or delivering generation on a temporary basis over the next four to five years through the transition from older power plants to new capacity.

CRU directed EirGrid to procure Temporary Emergency Generation (TEG) to mitigate the security of supply risks identified. The TEG can only be used in emergency situations, such as an alert that the buffer between electricity supply and demand is tighter than is required to operate a secure system.

Despite the national studies showing significant adequacy problems, the main ERAA 2024 scenario (‘with OOM measures’) reports no adequacy concerns for 2026 (or in subsequent target years). This is because ERAA 2024 includes 1.4 GW of Temporary Emergency Generation (TEG) in Ireland. This TEG is not included in the core adequacy studies for GCS23 or AIRAA, but it was categorised erroneously in ERAA 2024 as ‘Out of Market / Can be used for adequacy’. While it is

4 SEM - 24 - 051 2027-28 T-4 Volumes Information Note.pdf

5 All-Island Resource Adequacy Assessment 2025-2034

important to report the existence of this emergency generation, subsequent cycles of ERAA will not include it in the main adequacy simulations.

ERAA 2024 adequacy results for Ireland without the TEG are provided in the 'without OOM measures' scenario in Annex 3, and are shown here to compare with the AIRAA results:

LOLE (hrs)	2026	2028	2030	2034	2035
ERAA 2024 'without OOM measures' (i.e. without TEG)	18.17	0.64	0.39	NA	2.35
AIRAA Base scenario	29	3	2	4	NA
AIRAA Secure scenario	67	11	12	40	NA

Please note that the AIRAA base scenario is considered to align closest with ERAA results. The AIRAA also has an alternative 'Secure Scenario' which analyses the system considering low imports, annual run-hour limits and other operational requirements. This shows that Ireland is significantly outside the standard of three hours for all years analysed.

EirGrid considers the secure scenario is most prudent and should be adopted for decisions relating to securing capacity for the continued secure and sustainable operation of the power system. Additional sensitivities are utilised to understand the impact of factors that have higher levels of uncertainty such as demand, renewable capacity, storage and flexibility forecasts.

The ERAA 2024 'without OOM measures' scenario shows 18 hours of LOLE in 2026, which is in better agreement with the base AIRAA studies of 29 hours. Both studies also show an improving situation in 2028 and 2030, which is due to a few reasons:

- The connection of the Celtic interconnector between Ireland and France; and
- New thermal generation capacity is commissioned.

By 2034 and 2035, we see that rising demand has the effect of increasing LOLE, in both the ERAA 2024 and in national studies.

A second North South Interconnector is planned to increase grid capacity between Ireland and Northern Ireland. This is not included in EirGrid's assessment for Ireland adequacy; however it was included in the ERAA 2024 assessment from 2028, thus providing extra benefit to adequacy as compared to AIRAA. Additionally, a recent EirGrid publication indicates expected energisation of the new North South interconnector in October 2031[1]. The inclusion of this delay in ERAA 2024 would have the effect of increasing LOLE results.

EirGrid acknowledges that capacity market auctions are still an option to procure new generation which could address the capacity shortfalls. Due to the freeze date for this report, results from the 2028/2029 T-4 capacity auction, in which 560 MW of new de-rated capacity was successfully awarded in Ireland, are not included in this adequacy assessment.

[1] Network-Delivery-Portfolio-Publication-Q4-2024.pdf

[1] Security of Electricity Supply – Programme of Actions | CRU.ie

[1] SEM - 24 - 051 2027-28 T-4 Volumes Information Note.pdf

Italy

The ERAA results for Italy show significant differences compared to the National Assessment and differ from operating condition of electricity system observed by the Italian TSO in 2024.

Compared to the NRAA, ERAA 2024 indicates a significantly lower adequacy risk in Italy in the post-EVA scenario, across all target years (TYs), thus likely underestimating the adequacy risk in Italy. This is primarily due to methodological choices that may not fully reflect the real-world investor behavior and the complexity of the European power system.

First and foremost, the cost-based economic viability assessment (EVA) is likely overestimating the available capacity in all time horizons, leading to an underestimation of adequacy risks. More specifically, the EVA results show that Europe will build more than 70 GW of new gas-fired capacity until 2035, only based on volatile spot market revenues. Most of the new gas capacity would have an average usage factor below 500 running hours (less than 6%) and be strongly dependent on extreme weather events, which may only occur once in a decade, without knowing whether it will be at the beginning or the end of the decade. Consequently, a risk-averse investor is likely to postpone any investment decision linked to such a high risk and might never build this capacity, unless secured by capacity mechanisms.

For 2026, the EVA results indicate that about 50 GW of thermal capacity in Europe would become economically unviable. Despite that, only a few countries would face adequacy risks. ERAA 2024 suggests that Italy would not see any adequacy concerns in 2026, despite the decommissioning of about 10 GW of thermal capacity due to economic unsustainability. This conclusion does not match with recent observations from the Italian' TSO: in early September 2024, the minimum adequacy margin in Italy was about 2 GW (including import contributions), leaving no room to decommission 10 GW of thermal capacity next year.

For 2028, 2030 and 2035, ERAA 2024 indicates that there are no adequacy concerns for Italy, while the NRAA shows severe adequacy concerns, if all economically unviable capacity were to be decommissioned. The following paragraphs illustrate key reasons for the differences.

	2028		2030		2035	
	ERAA	NRAA	ERAA	NRAA	ERAA	NRAA
Decommissioned or mothballed capacity [GW]	-9.45	-20.8	-9.45	-20.7	-9.45	-23.6
Average LOLE [hr/y]	1.23	740	0.17	275	0.95	136
P95 LOLE [hr/y]	8	1021	--	411	7	370

Italian National Resource Adequacy Assessment (NRAA) 2024

For TYs 2028, 2030 and 2035 a direct comparison of ERAA 2024 with the National Resource Adequacy Assessment (NRAA) 2024 is available.[6] As required by national regulation, Terna publishes a national assessment every year ("Rapporto Adeguatezza Italia"), based on the same EU methodology approved by ACER also used in the ERAA. The report conducts an economic viability assessment (EVA) and analyses potential adequacy issues in the post-EVA scenario. The underlying scenario of the NRAA 2024 is based on Italy's final National Energy and Climate Plan (NECP), published by the government in July 2024.[7] The scenario data is generally coherent with the ERAA 2024 data collection, unless more recent information is available, which could not be considered in the European process because the ENTSO-E data collection closed in late 2023 / early 2024, more than a year before the publication of ERAA 2024.[8]

Economic Viability Assessment (EVA)
Both in the National Report and in ERAA 2024, an EVA of power plants is performed to determine those units that face the risk of being decommissioned for economic reasons and to identify potential new entry capacity.

However, the two studies present the following key differences:

- While ERAA 2024 uses a system-cost approach for EVA, Terna adopts a revenue-based analysis to assess the economic viability of power plants. Instead of aiming to minimize the total system costs from a central planner perspective, the revenue-based approach assesses costs and revenues of each individual production unit. This allows to represent the perspective of power plant operators and the willingness of the investors to build new capacity, based on spot market prices. The revenue-based approach is in line with the ERAA methodology (see ACER Decision 24/2020, Annex I, Art. 6.2.a).
- In the national report, following an ad-hoc analysis concluded only after the ERAA 2024 data collection, the perimeter of units subject to an EVA is about 10 GW larger than the one of ERAA 2024. The additional units subject to EVA in the NRAA consist of two groups: 1) CHP plants that strongly depend on electricity market revenues for their overall profitability and 2) power plants that have only been awarded repowering contracts in the capacity market.[9] The EVA perimeter of ERAA 2025 will be aligned to that of the NRAA 2024 (ca. 29 GW).

[6] See https://www.terna.it/it/sistema-elettrico/dispacciamento/adeguatezza
[7] Based on the NECP, Terna and the Italian gas TSO jointly prepared the Future Energy Scenarios Report 2024, which elaborate the government targets in further detail (technology split, distribution per bidding zone, scenario beyond 2030), see https://www.terna.it/it/sistema-elettrico/programmazione-territoriale-efficiente/piano-sviluppo-rete/scenari
[8] In particular, the national report considers more updated scenario data on renewables and storage. For storage, the NRAA considers the most updated auction calendar of the MACSE scheme, which foresees the first delivery of 10 GWh in 2028 but not necessarily in January 2028. For the purpose of the national adequacy analyses, we therefore consider the capacity fully available only in 2029. For renewables, minor adjustments have been made to reflect Italy's final NECP.
[9] In the case of repowering, the long-term contract does not apply to the whole capacity but only the additional (repowered) capacity.

For these reasons, the national report shows a higher amount of capacity out-of-money in all analyzed years. Specifically, the decommissioned and mothballed capacity in 2028 is almost 21 GW vs. 9.5 GW in ERAA 2024 (cost-based EVA), and in the long term (2035) it increases to up to about 24 GW.

Latvia

Latvian TSO AS Augstsprieguma tikls is a responsible party for the secure and reliable power system operation and manage the power system balance and reserve service exchange within Republic of Latvia. Looking into ERAA 2024 study results, Latvian TSO does not expect any significant shortages and adequacy risks in terms of adequacy purpose for mid-term and long-term. In the beginning of 2025, the Latvian TSO and Baltic States TSOs have a sizeable challenge ahead to disconnect from IPS/UPS power systems and synchronize to Continental European power systems.

Demand

Due to current economic situation in Latvia, the yearly forecasted consumption is expected to increase up to 1-3% from year to year depending on the scenario. The demand development is rather flat/stable and no significant growth is expected. The demand very significantly varies from average wholesale electricity market price in Nord Pool electricity market, which has been established in Baltic States since 2014.

Generation

60% of total installed generation capacity in Latvian power system is run-of-the-river hydro power plants which are located on Daugava river. Daugava HPPs are designed for "peak", "half-peak" and emergency modes of operation and today on the Daugava river Latvian TSO is keeping the main power system reserves (aFRR and mFRR). During the high water in-flow period in spring, Daugava HPPs are going to work on the base power mode.

Despite sufficient installed capacity on the hydro power plants, shortage of inflow water is the main limiting factor for generation availability. The main periods of stress for Latvia power system are possible if water inflow in Daugava river is very low and all consumption must be covered by natural gas CHPPs which production after 2022 is much more expensive. The Latvian CHPPs are running on natural gas where the gas prices are one of the most significant indicators, which could affect CHPPs generation availability in are of Latvia. Latvian high capacity natural gas CHPPs are the main power plants for Riga district-heating and they compete in both electricity and district-heating sectors.

In the nearest future, Latvia is forecasted to have a very high increase of RES generation, which is in line with Fit-for-55 regulation and the NECP. It is expected to develop very high amounts of onshore wind and solar (PV) generation up to 2030. Latvia is located near the Baltic Sea where the identified potential of offshore production is also very significant and could reach up to 15 GW. The offshore wind is also under development up to 2033 where the dedicated project – ELWIND (Latvia and Estonia 4th hybrid offshore interconnection) from Latvia and Estonia is under development.

Role of interconnections

The interconnection capacity in the winter periods is usually higher than during the summer periods in normal power system operation modes. In the beginning of next year (2025), Baltic States are going to synchronize with Continental European power systems. This switch from the current power system operation mode (IPS/UPS) will cause some cross-border capacity reduction within the Baltic States. Currently estimated reduction of NTCs between internal cross-borders and around Baltic States is insignificant and no critical adequacy risks or some unexpected shortages of electricity supply in Latvia and Baltic States are not expected. The reduction of cross-border capacity within Baltic States is related to power system security issues and other system services, like power system balance and exchange of required reserve service. However, the Baltic States TSOs are going for such kind of switch already since 2014, where the Baltic States synchronization with Continental Europe has been set as top priority for the entire Europe Union. Baltic States TSOs have introduced already many investments in the regional power system to maintain secure power system operation with Continental Europe. AST is looking forward to a successful Baltic States synchronization with Continental Europe in February 2025.

Lithuania

Data for ERAA 2024 were collected at the beginning of 2024. The situation has changed slightly over the year, and we see that implementation of some projects, which affect the adequacy situation, is being delayed. This is in regards to the implementation of offshore wind projects and the second interconnection with Poland.

The highest adequacy risks identified in the medium term (for 2026 and 2028), while there is no second interconnection with Poland and offshore wind in operation. For 2030, the adequacy situation is improved (LOLE decreases from 10.96 h to 8.54 h.) with the new interconnection LT-PL and start of operation of 2x700 MW offshore wind. Thus, we see the ERAA 2024 results for 2030 as quite optimistic, as the completion of the LT-PL interconnection is postponed to 2031, and the offshore wind capacity will reach 1400 MW in the best case in 2033.

Another issue, relevant to the Baltic States, that is not addressed in the ERAA 2024 is the increased risk of damage of the subsea cables. Within the last 2.5 years, there have been two incidents, when HVDC infrastructure between Estonia and Finland was damaged and each outage lasted around six months. As the risk of another “incident” in the Baltic Sea region is still very high under today's geopolitical situation, availability of the offshore infrastructure in the Baltic Sea should be accordingly reflected in the next ERAA edition.

Malta

It is important to note that due to its specific electricity network characteristics, Malta does not have an electricity transmission system and although the generation has been opened for competition, there is currently no liquid wholesale electricity market on the island. The Maltese electricity system has been synchronised with the Italian electricity grid since April 2015 through the 225 MW HVAC 200kV cable link.

Malta also has an additional 175 MW of non-market resources in the form of emergency gas oil-fired back-up plants available for dispatch at any time to meet local demand and/or abrupt scenarios which may arise.

Netherlands

Coal decommissioning in the Netherlands

According to the EVA results, which rely on the assumption of ideal market conditions, 3.4 GW of coal capacity in the Netherlands is projected to be decommissioned starting in 2026. However, insights from market participants suggest that this capacity will likely remain operational until 2029. As a result, we believe that the ERAA 2024 LOLE estimates for the Netherlands in 2026 and 2028 may be overstated. In our national analysis (NRAA), we incorporate the assumption that this capacity will not be decommissioned.

DSR investments in EVA

The ERAA 2024 EVA results show significant DSR investments of more than 3 GW in 2035. The DSR investment potential for the Netherlands was based on a study by DNV published in 2020. This potential is, however, highly uncertain, as well as the DSR investment cost and activation cost. Given these uncertainties, there is a high likelihood that in reality these investments will not materialize or be replaced by other investments in peaking technologies such as OCGTs, or even by lower-cost DSR in a neighbouring country. New studies are currently being commissioned to better understand the potential of demand response to ensure security of supply and barriers to exploiting this potential. The ERAA 2024 LOLE results for the Netherlands for 2035 may therefore be too low.

Furthermore, in ERAA 2024, it is foreseen that current Dutch methane gas fired power plants will be converted to hydrogen-fired power plants. The conversion of these 3500 MW at 4 locations would be considered available at the start of TY 2035. In the ERAA 2024 database, these units were inadvertently placed in the Fuel Type category ‘Gas/CCGT/new’ instead of the new category ‘Hydrogen/CCGT’.

Adequacy results

In this ERAA edition, a revised configuration for curtailment sharing has been applied in the post-processing step, compared to ERAA 2023. This change, which allows for more flexible curtailment of generation rather than preserving the dispatch from the UCED optimisation, has led to a noticeable redistribution of ENS across countries. For the Netherlands, this resulted in a significant increase in LOLE, shifting the results from well within reliability standard (i.e. in the Netherlands below 4h LOLE) to above it.

Given this impact and while detailed investigations are still ongoing which setting best reflects the actual implementation of curtailment sharing in SDAC, we have decided, for now, to maintain the same curtailment sharing settings as in ERAA 2023 for our national NRAA. We are working closely with ENTSO-E and relevant stakeholders to further assess and refine these methodologies to ensure consistency and robustness in future adequacy assessments.

We remain committed to contributing actively to improving and harmonizing curtailment sharing approaches within the broader adequacy assessment framework.

Northern Ireland

Northern Ireland and Ireland together comprise the Single Electricity Market (SEM.) This wholesale electricity market is designed to be compliant with the European Target Model. It aims to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand and to support long-term sustainability. The SEM incorporates a Capacity Market, with Capacity Auctions taking place annually.

The adequacy standard for Northern Ireland is 4.9 hours of Loss of Load Expectation (LOLE), as set by the Department for the Economy (DfE).

SONI provided inputs to the ERAA 2024 PEMMDB data collection, which were aligned with the latest published national study at the time of data freeze - this was the 'All-Island Generation Capacity Statement 2023-32' (GCS23).

Throughout 2023 and 2024, SONI worked collaboratively with EirGrid, the Utility Regulator (UR) and the Commission for Regulation of Utilities (CRU) to develop the pathway for transitioning to the new methodology that aligns with Article 24 of the Regulation on the internal market for electricity (EU/2019/943). The first All-Island Resource Adequacy Assessment (AIRAA) covering the period 2025-2034 was published in early 2025[10].

It should be noted that material differences may arise due to differences in data freeze dates. The AIRAA data freeze date was approximately one year after the equivalent freeze date for which ERAA 2024 inputs are derived.

ERAA 2024 adequacy results are compared with the preliminary AIRAA results for LOLE:

LOLE (hrs)	2026	2028	2030	2034	2035
ERAA24	0.39	0.32	0.19	NA	1.34
AIRAA Base scenario	2	2	2	8	NA
AIRAA Secure scenario	6	6	8	25	NA

Please note that the AIRAA base scenario is considered to align closest with ERAA results. The AIRAA also has an alternative 'Secure Scenario' which analyses the system considering low imports. The secure scenario shows Northern Ireland to be outside of the 4.9 hour LOLE standard from 2026 onwards.

SONI considers the secure scenario as a prudent approach and should be taken into account for decisions relating to securing capacity for the continued secure and sustainable operation of the power system. This scenario accounts for the impact of low imports, and the need to ensure there is sufficient capacity to cover operational requirements. Additional sensitivities are utilised to understand the impact of factors that have higher levels of uncertainty such as demand, renewable capacity, and storage forecasts.

Comparing ERAA 2024 to AIRAA 2025-2034, the general trends are similar, i.e. low adequacy concerns for the initial target years to 2030, and then an increasing LOLE for 2034 and 2035 due to increasing demand.

1. [10] https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034-SONI-EirGrid-Report.pdf

However, the detail shows that LOLE is higher in the national studies, due to some differences in modelling methodologies:

- AIRAA includes a more detailed assessment of run-hour limitations on some generators, reflecting a critical risk to security of supply in Northern Ireland and resulting in higher LOLE. SONI is actively supporting the Utility Regulator and relevant government departments in relation to mitigating risks related to run hour limitations on two new gas plants in Northern Ireland.
- A second North South Interconnector is planned to increase grid capacity between Northern Ireland and Ireland. This is not included in SONI's assessment for Northern Ireland adequacy; however it was included in the ERAA 2024 assessment from 2028, thus providing extra benefit to adequacy as compared to AIRAA. Additionally, a recent EirGrid publication indicates expected energisation of the new North South interconnector in October 2031[11][1]. The inclusion of this delay in ERAA 2024 would have the effect of increasing LOLE results.

SONI acknowledges that capacity market auctions are still an option to procure new generation which could address the capacity shortfalls. Due to the freeze date for this report, results from the 2028/2029 T-4 capacity auction, in which 46 MW of new de-rated capacity was successfully awarded in Northern Ireland, are not included in this adequacy assessment.

[11] Network-Delivery-Portfolio-Publication-Q4-2024.pdf

Poland

Input data description

The input data for Poland was valid during the data collection period, i.e. April 2024. The data for Poland took into account a dedicated scenario for the purpose of developing NECP and Energy Policy of Poland until 2040. This scenario includes the national vision for a low-carbon energy transition in the context of strengthening energy security and energy independence, as well as structuring Poland's contribution to the EU's 2030 climate and energy targets. Additionally, the data considered the necessary updates regarding:

- The dates of commissioning and decommissioning of thermal units already known to PSE.
- The information of the already concluded auction in Polish Capacity Market.
- Offshore projects submitted to PSE by investors.

According to the requirements, the data provided for ERAA 2024 takes into account information on already concluded contracts in Polish Capacity Market (CM). It includes results of all held, until moment of data collection, CM auctions i.e. delivery periods up to 2028. It does not include results or estimations for further years especially Target Year (TY) 2030, for which capacity auctions are already planned. The same assumption was applied to the already concluded contracts for DSR coming from CM, which means for TYs 2026 and 2028. Due to specific conditions of activation of Polish DSR, it was not a subject of the central simulation in ERAA 2024, however, it was used to reduce hourly ENS and LOLE results in post-processing. For information, PSE presents the result of this post-process also for TY 2030 below. Although the contracts on CM for these years are not yet concluded, PSE, observing the current interest in such DSR, expects at least to maintain the level of DSR capacity that has been already proven.

Results analysis

Following the final results of ERAA 2024, PSE has made in-depth analysis:

Main observation is the results of the EVA model, where it appears that overall cost minimisation approach tends to over-estimate investment and under-estimate risk of capacity exit. This approach is focused on minimising total system cost, rather than the optimisation of capacity providers profits. It results in a capacity mix, where some of the units are not profitable i.e. not economically viable. Result of the EVA are input to the ED models where adequacy metrics are calculated. Optimistic EVA results tend to cause underestimation of the adequacy concern in many bidding zones for each TY.

In addition to selected EVA approach, two other factors significantly impact EVA output and, as the result, adequacy results:

1. Simplified consideration of perpetuity after the end of the planning horizon.
2. The predominant impact of the post-2030 period on the economic viability of the units for the ERAA 2024 time horizon.

The first of those factors has a major impact on the economic viability of Polish units. Simplified application of perpetuity after the end of the planning horizon implies that the model does not take into account the real decommissioning dates provided by TSOs in the input data. The last year modelled within ERAA 2024 i.e. TY2035 repeats an infinite number of times. The Discount factor is applied to each year after last modelled TY. It causes that TY2035 has highest weight of the modelled TYs. This is correct for modelling of new expansion units, however, for existing capacity, it results in assigning additional revenues after 2035. In the case of Poland, many coal units, due to their lifespan, are scheduled for decommissioning at the end of 2035 or in the near future (beyond 2035). For such units (not only Polish ones, not only coal ones), the way of current perpetuity modelling has a direct impact on the units' lifetime revenues and their economic viability. For Poland, this results in an overestimation of coal units' capacity, which remain in the system in the ERAA 2024 time horizon, i.e. until 2035.

As an example, PSE analysed a group of units that are decommissioning candidates. For the majority of those units, the technical lifetime is end of 2035. For each TY, the net profit is different and jumps from negative to positive, however, for TY2035 the net profit is the highest. Applied in the EVA model, the discount factor of 6.37% results in an estimated weight of TY2035 amounting to 15.7:

TY	Net generating Capacity (MW)	Net Profit (k€)	TY's weight		Net Profit (k€) – cumulative with weights	
			Considered real lifespan	With perpetuity in ERAA 2024	Considered real lifespan	With perpetuity in ERAA 2024
2026	4 156	-3 497	2 (2026 & 2027)		-6 994	
2028	3 824	48 267	2 (2028 & 2029)		89 540	
2030	3 824	-54 438	5 (2030-2034)		-182 650	
2035	3 824	75 439	1 (2035)	15.7 (2035 and beyond)	**-107 211**	**1 001 742**

Based on this example, according to the Polish TSO, the level of capacity resulting from the EVA model of ERAA 2024 tends to be overestimated, because in ERAA2024 the profits beyond 2035 are accounted for units that do not operate or operate shortly after 2035 (due to end of technical lifetime). In fact, less capacity in the EVA would be viable, if we enhance the modelling of perpetuity. It can significantly impact the adequacy results. It is therefore challenging for the Polish TSO to assess the adequacy results for Poland in ERAA 2024.

The second possible limitation relates to the predominant impact of the post-2030 period on EVA results. It is worth noting that the first 2 TYs (2026 and 2028) represent a relatively short 4-year period, i.e. 2026-2029, while the last 2 TYs (2030 and 2035), especially after taking into account the perpetuity, represent a disproportionately long period of several years or more. This has implications for the results in the coming years, which are the most important from a security of supply point of view.

As mentioned in the previous section, ENS / LOLE results are presented for Poland with and without DSR coming from CM in the table below:

Out of Market Measure (OMM) for Poland - DSR coming from Capacity Mechanism

Target year	EENS [GWh]		LOLE [GWh]	
	Before OMM	After OMM	Before OMM	After OMM
2026	n.a.[1)]	3.25	n.a.[1)]	3.89
2028	n.a.[1)]	15.45	n.a.[1)]	13.17

2030	10.48	7.78 [2)]	9.19	7.27 [2)]
2035	11.96	n.a.[3)]	9.75	n.a.[3)]

[1)] CM auctions already concluded, DSR applied by default

[2)] CM auctions not concluded yet, estimated value

[3)] Beyond the period of the existing CM in Poland

Portugal

1. General appreciation of ERAA 2024

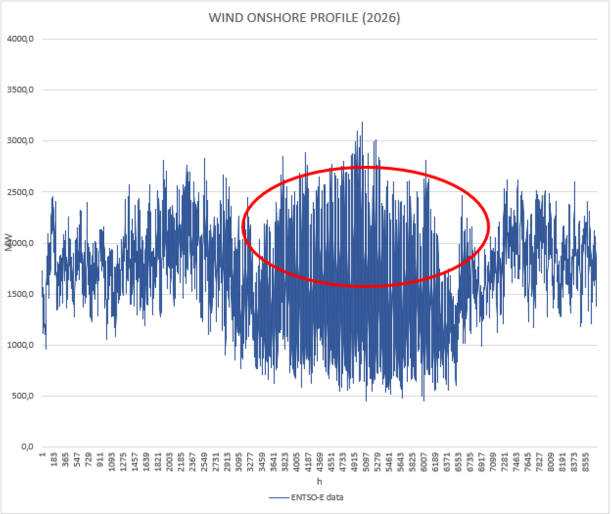
The Portuguese TSO (REN) highlights that ERAA 2024 has been an important step forward compared to the previous ERAA editions in terms of methodological implementation and also development of capabilities, in a continuous effort to gradually improve the quality and the usefulness of the product, fruit of a collaborative framework between stakeholders, ENTSO-E and TSOs.

Nevertheless, REN has some concerns/comments regarding this ERAA 2024 exercise:

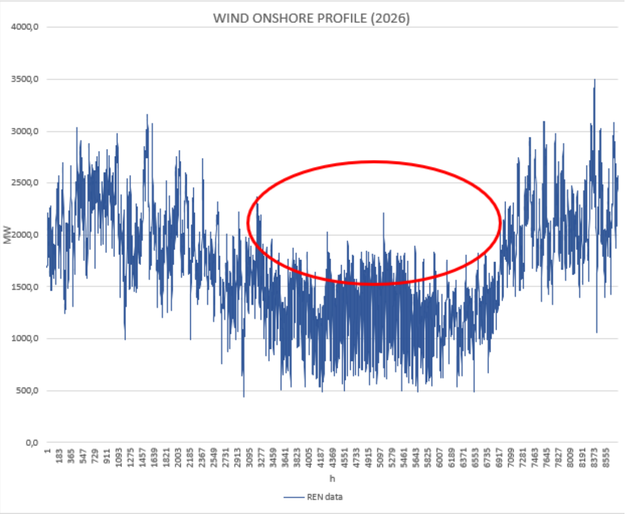
2. Input data

For ERAA 2024, REN provided input data in order to create a scenario that represents the expected reality to the best possible extent, based on the National Resource Adequacy Assessment Report (Portuguese NRAA) published in December 2023, RMSA-E 2023[12]. The "National Estimate" data for the target years (TY) 2026 and 2028 is aligned with conservative approach "Trajetória Conservadora – Sensibilidade[13]" scenario, while 2030 and 2035 data are aligned with the Portuguese NECP[14] - based "Trajetória Ambição" scenario, both as assumed in RMSA-E 2023. In these scenarios, CCGT "Tapada do Outeiro" is to be decommissioned by the end of 2029.

Regarding climate data used in ERAA 2024, REN has identified non negligible differences between onshore wind profiles coming from ENTSO-E's PECD (Pan-European Climate Database) v4.1 and those built upon REN historical data (2008-2023 wind generation series). A detailed analysis for TY 2026 can be found below.



PT wind onshore hourly profile based on ENTSO-E PECD 4.1 data



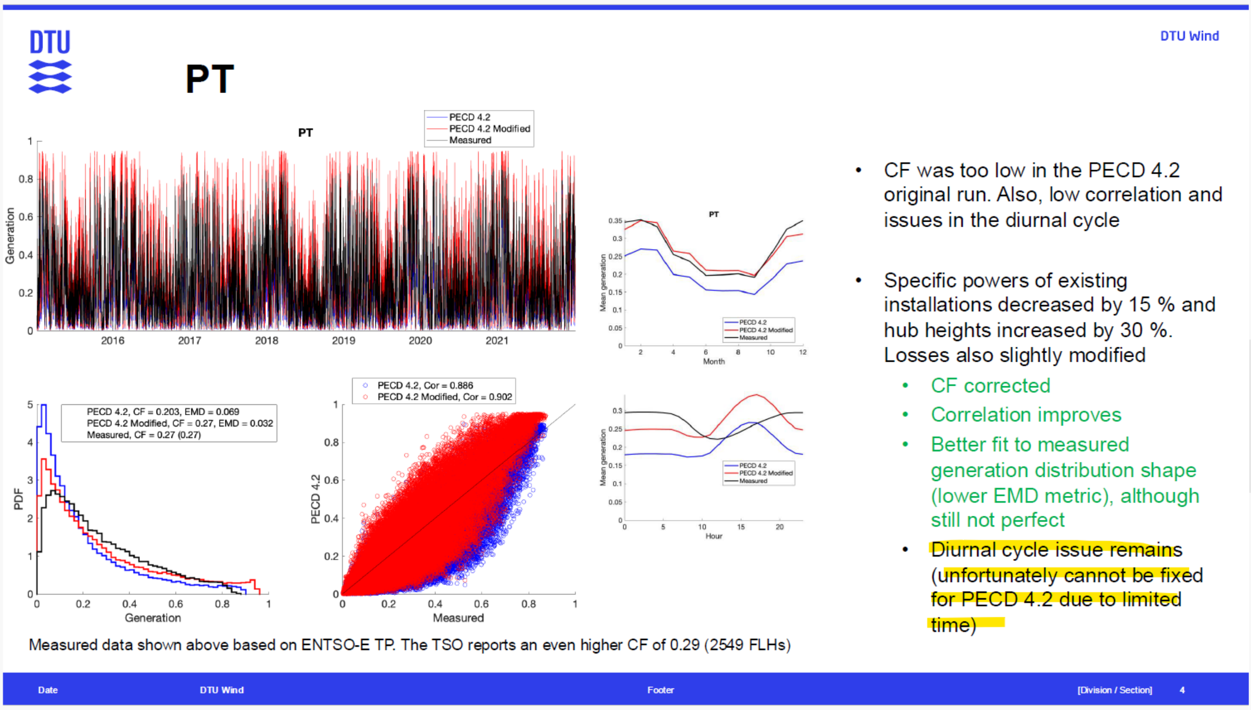
PT wind onshore hourly profile based on REN historical data

12 https://www.dgeg.gov.pt/media/phynkr2y/rmsa-e-2023.pdf
13 Sensitivity analysis to lower installed capacities of wind and solar power.
14 National Energy and Climate Plan.

As depicted in the figures above, ENTSO-E's PECD v4.1 series are overestimating generation provided by onshore wind farms during summer periods. The wind variability between winter and summer is clearly not being captured, which may lead to underestimation of adequacy reliability indicators in Portugal.

This discrepancy was reported in advance and handled in the preparation of the new climate database (PECD v4.2, that will be used in ERAA 2025). REN expects this issue to be solved for ERAA 2025.

Moreover, a critical issue concerning wind diurnal cycle was also spotted in PECD v4.1 (which is not expected to be fixed in PECD 4.2 - see figure below). **In order to ensure the accuracy of adequacy results for Portugal, REN would like to emphasize the importance of improving the overall quality of upcoming PECD versions, with focus on wind onshore series for Portugal.**



PT diurnal cycle issue (PECD 4.1 vs 4.2)

3. Short-term perspective (2025)

The ERAA, the Seasonal Outlooks and the Ten-Year Network Development Plan (TYNDP) aim to model and analyse possible events that could adversely impact the balance between supply and demand of power system in different time horizons ahead. The seasonal adequacy assessments, such as the Winter Outlook (WO) and Summer Outlook (SO), assess the situation in the short-term period for the upcoming season (weeks to months ahead). In this way, in recent WO 2024-2025 published by ENTSO-E for the Winter 2024-2025 (out of scope of ERAA 2024), REN presented some insights (included in the National Comments Annex) in terms of assessment of security of Supply in Portugal in 2025. With minor adjustments, the main messages were:

- The most recent NRAA (RMSA-E 2024[15]) was officially published on February 18, 2025 and addresses electricity security of supply for the horizon 2025–2040. Although not fully

[15] https://www.dgeg.gov.pt/media/uu3dlpkj/rmsa-e-2024-vers%C3%A3o-final.pdf

comparable with WO and SO in terms of methodology and assumptions, for year 2025, it is foreseen that there will be a risk of dependence of the Portuguese system on imports from Spain and a risk of noncompliance with the current national reliability standards, assuming that CCGT "Tapada do Outeiro" is out of operation. Under these conditions, the operational LOLE[16] reaches the value of 291 h/year[17] and some mitigating measures may be necessary to handle operational reserve needs and ensure security of supply in the Portuguese power system, as listed below:

#	Measures
Demand	Load reduction market product for eligible consumers with whom there are annual contracts for the provision of this service
Supply	Request for the activation of a support program with the Spanish System Operator
Demand	Occasional load shedding of non-priority consumptions, according to the protocol between the electricity transmission and distribution network operators

- In RMSA-E 2024, load reduction needs (1st measure in the table) were identified, depending on hydro conditions. For this purpose, an auction for this specific market product was launched by the Portuguese NRA on November 28, 2024[18]. On December 12, the auction results were published[19] – for annual and quarterly products, all capacity was allocated; for monthly product, a maximum of 36% of auctioned capacity was allocated (January and February). The results of the auction were lower than the submitted values and at critical hours the available capacity is usually nearly 50%.

4. ERAA 2024 results

The ERAA focuses on the mid- and long-term horizon of 2 to 10 years ahead. The purpose of the ERAA is to identify adequacy assessment concerns and serve as an action guidance, with a moderate uncertainty up to 5 years ahead, increasing to higher uncertainty beyond five years.

4.1 Economic Viability Assessment (EVA) results

The table below presents a comprehensive analysis of Economic Viability Assessment (EVA) for Portugal for each TY focused on global minimization of overall system costs. These EVA results are based on three different assumptions for CCGT Cost of New Entry (CONE) values: a) an harmonized CONE value for gas investments candidates across the study perimeter; b) the EVA using country-specific CONE values (derived from national VoLL/CONE/RS studies when available); and c) the EVA using default CCGT technology CONE value that was taken from the EU 2020 Reference Scenario instead of using the average of available national values (this default CCGT CONE value is only applied when country specific values are not available).

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[16] Operational LOLE in Portuguese NRAA also includes needs for flexibility capacity between Day-Ahead and real time operation.

[17] In a scenario with CCGT 'Tapada do Outeiro' in operation, this value is reduced, but not enough to comply with current reliability standard (LOLE ≤ 5 h/year). To comply with it, additional capacity between 500 and 650 MW is required.

[18] https://www.erse.pt/media/b3bh4efb/convocatoria_04_leilao_bmfrr_20241128.pdf

[19] https://mercado.ren.pt/PT/Electr/InfoMercado/Consumidores/mFRR/Leiloes/BibLeiloesGPRes/4%C2%BA%20Leil%C3%A3o%20BmFRR%20-%20Comunica%C3%A7%C3%A3o%20Resultados_site%20REN.pdf

Decommissioning CCGT present capacity	Target Year 2026	Target Year 2028	Target Year 2030	Target Year 2035
	GW	GW	GW	GW
Harmonized CONE (central reference scenario)	**-1,77**	**-1,77**	**-0,78**	**0,00**
Country-specific CONE	**-1,77**	**-1,77**	**-0,78**	**0,00**
Country-specific CONE (EU 2020 Reference Scenario default investment cost)	**-1,77**	**-1,77**	**-0,78**	**0,00**

Concerning the EVA model results for the Portuguese power system, it can be observed a decommissioning of part of existing CCGT units in operation. In both sets of results using different assumptions for CCGT CONE value, regarding existing capacity of CCGT in Portugal, decommissioning of 1770 MW in TY 2026 and 2028 was identified, corresponding with the total capacity of CCGT "Tapada do Outeiro" (CCGT TO) - that may be decommissioned in 2029 - and a decommissioning of two more units of 400 MW that would not be economically viable in the electricity-only market. In TY 2030 (after decommissioning of CCGT TO in 2029) the same two CCGT units of 400 MW are still not viable in the electricity-only market. Finally, in TY 2035, the total existing CCGT capacity presented in the 'National Trends' scenario is viable in the electricity-only market. **Based on these results, one can conclude that maintaining part of the existing CCGT capacity in operation in the Portuguese power system is no longer economically viable. Consequently, the implementation of a capacity payment mechanism would be needed in Portugal, given the crucial role that these generators play in electricity security of supply.**

In Annex 4, a Case Study with results of two alternative ways of implementing one methodology for the EVA according with revenue-based approach is presented, which evaluates the performance of each unit on the electricity-only market in order to estimate its profitability in given conditions. The table below presents a comprehensive analysis of the EVA results for Portugal for each TY and type of implementation focused on net generation capacity.

Net Capacity (expansion capacity - decommissioning)	Target Year 2026	Target Year 2028	Target Year 2030	Target Year 2035
	GW	GW	GW	GW
Implementation A	**-0,85**	**-1,26**	**-1,35**	**-0,96**
Implementation B	**-2,30**	**-2,30**	**-2,84**	**-2,05**

Regarding the results proposed by the EVA model for Implementation A, higher decommissioning of CCGT units can be observed in comparison with EVA using global minimization of overall system costs, however, some of this decommissioning units are compensated by new expansion capacity in DSR technologies. For implementation B, the results present a significant amount of CCGT decommission in Portugal as they are not viable in the electricity-only market (no new expansion capacity occurs in this implementation).

According to these results for both EVA analyses (using global minimization of overall system costs or revenue-based approaches), one can conclude that a high amount of CCGT capacity already in operation in Portugal could not be viable in the next years. As stated before, a capacity payment mechanism would be needed in order to guarantee electricity security of supply in Portugal.

4.2 Economic Dispatch (ED) results

Regarding the ED results, the analysis of the scenarios was performed after the decommissioning of the economically unviable units. The results for the Portuguese power system show no adequacy issues considering the current reliability standard in the horizon of this study. Extremely low LOLE results were not expected for all TYs and were very different from the most recent NRAA (RMSA-E 2024) that identified resource adequacy concerns for Portugal. The main justifications found for those differences were:

a) **Overoptimistic onshore wind profiles used in ED studies**, that assume much more wind power in Portugal than measured historical data mainly in the summer period (see input data section for further detail);
b) **Way of modelling CCGT units**[20] **and consequently reserve requirements (FCR, aFRR and mFRR) for the Portuguese system**, that excessively increases the number of thermal units in hourly operation to fulfil those requirements and minimizes the impact of forced outages;
c) **Optimist assumption of 100% NTC (Net Transfer Capacity) always available for commercial exchanges with the Spanish system**. In real operation, the maximum power exchange capability is not available in all hours of the year.

The discrepancies a) and b) were reported in due time, however, it was not possible to rerun new simulations due to the short timeline to deliver the ERAA. Therefore, they will hopefully be analysed in more detail in ERAA 2025.

It should be noted that in RMSA-E 2024 ("Trajetória Ambição" similar to "National Trends" scenario) adequacy assessments showed some cases of no compliance with current national reliability standards that set LOLE < 5h/year with NTC limited to conservative 10%. In fact, for the TYs 2030 and 2035, contributions from NTC with Spain are required up to 25% and 100%, respectively.

Furthermore, the current central reference scenario for TY 2030 and TY 2035 is based on the delivery of targets presented in the Portuguese NECP. This plan describes the trajectories of the future installed capacity (renewables, storage and others technologies) and demand (electrification, energy efficiency) according to the EU's ambitious targets and represents the best available plan depicting the future of the energy system during the energy transition. However, this scenario does not take into account that delays may occur in the implementation of the measures described in the Portuguese NECP and that such delays could affect system adequacy. In this way, the adequacy results from ERAA 2024 for TY 2030 and TY 2035 may be very optimistic. As mentioned before, the Portuguese NRAA presents other scenarios and sensitivities for these target years and shows some adequacy concerns.

ERAA 2024 has provided some insights regarding the Portuguese resource adequacy assessment in a European context, nevertheless, national and regional assessments should provide deeper analysis of local constraints. The ERAA takes a pan-European approach that should be complemented by regional analysis, e.g., the application of FNA (Flexibility Needs

[20] In the Economic Dispatch (ED) simulations, the decommissioning of CCGT capacity should preserve the real capacity of each unit rather than a proportional decrease regarding total installed capacity (derating) as followed in ERAA 2024 studies. This last assumption results in keeping the total number of CCGT unchanged despite the decommissioning results from EVA.

Assessment) methodology to quantify “ramping needs” and “short-term flexibility needs” indicators.

Romania

Although low adequacy concerns have been identified for Romania in ERAA 2024, it should be noted that these results are relying on the implementation of the assumptions depicted from the National Energy and Climate Plan (NECP), in place on the date of the data collection, as well as from the investment plans, permits, connection requests and available inputs from the market participants.

Alongside the increase of renewables within the NECP targets, the expansion of nuclear capacity (up to more than double by 2032), is considered a strategic option in the long-term national plans. The life-extension of nuclear unit 1, commissioned in 1996, is planned to take place from 2027 to 2029.

The central reference scenario also reflects the coal phase-out process assumed in national documents and further plans for the replacement of the decommissioned capacity with, mainly, gas CCGTs.

The commissioning of these gas CCGTs is, however, highly uncertain and national analyses reveal that the validity of the adequacy indicators depends on the implementation of these generation goals. The uncertainties related to the commissioning date of the new capacities may have an adverse impact on Romania and, potentially, on the region.

Moreover, the EVA results show that 2.15 GW of gas CCGT capacity would not be economically viable by 2035 horizon and should be decommissioned in TY2035. However, considering that this is not existing capacity, rather assumed to be commissioned in 2026-2030 period, it is most likely that these investments will not materialize at all and thus, the correspondent capacity should be excluded from the analysis for the earlier TYs too, not only TY2035, with a negative effect on LOLE results.

Slovakia

The ERAA 2024 results show non-zero LOLE / EENS values for Slovakia, with an increasing trend for all target years (TYs). The maximum LOLE is indicated for TY 2035 at 4.33 h/year and considerably high values appear for P95, with maximum of 29 h/year for TY 2035. On the contrary, the ENS values, both average and P95, are very low, close to 0 GWh in most cases. In Slovakia, a reliability standard has not yet been set, however we consider the values of LOLE and EENS worthy of attention, and the scenarios will be analysed within the Slovak NRAA.

A high ratio of stable generation from nuclear power plants, alongside the new nuclear unit Mochovce 4, which is expected to be commissioned in 2026, and the increase in RES capacity, mainly solar PV and wind onshore, which is in line with the actual draft version of the NECP, should help to guarantee the acceptable levels of LOLE and EENS.

On the other hand, the ERAA results may be slightly distorted and even higher, as the real development of wind power plants in Slovakia is not so optimistic as expected in the NECP and in ERAA 2024, since the current installed capacity is close to 0 MW and the NECP expects 750 MW in 2030.

Slovenia

Slovenia appreciates the efforts of ENTSO-E in preparing ERAA 2024 and acknowledges the high quality and extensive work that goes into this important document. Additionally, over the years, Slovenia has conducted its own adequacy assessments.

Based on performed assessments and due to its small size, Slovenia has specific characteristics that distinguish it from larger countries. Certain principles applicable to larger power systems do not necessarily translate directly to Slovenia. For instance, the outage of a single large generating unit can result in a loss of up to one-third of national generation. Such an event could lead to a sharp increase in import dependency, posing a significant challenge to system adequacy and security of supply, especially during winter and in times of bad hydrology.

Due to these concerns, Slovenia conducted an analysis of the current adequacy situation in 2024, the reason for this being the decision to slowly withdraw the biggest coal power plant Šoštanj unit 6 from the market (limited operation due to unfavourable market conditions causing partial unavailability of unit 6 throughout the year in 2025 and onward). The analysis indicated that, in the event of conventional unit decommissioning, Slovenia would not be able to meet the targets set in its NECP, which mandates a specific share of domestic production during the 100 most critical hours of the year. The study revealed that conventional generation units are facing market competitiveness challenges. Increased reliance on electricity imports, especially during winter peaks, threatens supply security as neighbouring countries also experience similar adequacy constraints during high-load hours.

To address these challenges, it appears prudent to consider the introduction of CM in the form of a strategic reserve, capable of re-entering the market when needed. The suggested capacity range for such a reserve is between 70 MW and 150 MW (possible increase with l additional analysis). In the long term, Slovenia should continue with advancing of procedures for the implementation of market-based CMs to encourage investment in flexible generation assets. This measure would help reduce import dependency, particularly during peak demand hours when neighbouring countries face similar resource adequacy challenges.

Since the latest developments in Slovenia, as described above, have not been included in the data collection for ERAA 2024, results for Slovenia are not totally representative. Following the developments, the situation in Slovenia in the near future regarding operation of coal power plants in Slovenia will be similar as foreseen in the input data for TY 2035 calculations. Slovenia remains committed to working collaboratively within the ENTSO-E framework and supports the ongoing improvement of the ERAA process to ensure that specific national characteristics are adequately reflected in the adequacy assessments.

Spain

General overview of ERAA 2024

ERAA 2024 has been an important step forward in terms of methodological implementation and also development of capabilities, in a continuous effort to gradually improve the quality and the usefulness of the product. This is the fruit of a collaborative framework between stakeholders, ENTSO-E and TSOs. In this edition, building on top of the first ERAA approved, important efforts have been made to consider the impact of climate change by using weather projections instead of historic climate data, improved EVA-Adequacy (ADQ) consistency by using a new climate representation methodology for EVA and including Flow-Based also in EVA, also extended to the Nordic region. In addition, a case study to apply the revenue-based approach at European scale has also been delivered. The results for the Spanish peninsular power system confirm the conclusions of previous editions and national assessments performed by Red Eléctrica, and make evident that it is important to continue monitoring adequacy in future assessments, especially in the mid and long-term.

Spanish assumptions for ERAA 2024

Similarly as in ERAA 2023, Red Eléctrica has provided input data in order to create a scenario that represents the expected system reality to the best possible extent. In this sense, in the long term (2030, 2035), the scenario was set in line with the expected final version of the updated NECP (considering the best available information at the moment of the data delivery), as the ERAA methodology prescribes that the scenario shall be consistent with the NECPs. For the short to mid-term (2026, 2028), the scenario is based on the best information available for the TSO from the stakeholders and the recent evolution of the installed capacities and permits issued. The resulting scenario represents a gradual transformation of the current system into the desired future one, instead of a lineal progression towards the NECP.

In terms of evolution of the expected resource capacities, solar photovoltaic and onshore wind increase in each TY. Pumped hydro, offshore wind and solar thermal is expected to develop, yet mainly as of 2030. Nuclear capacity is expected to gradually phase out along the horizon, while the combined cycle fleet is assumed remain stable. Regarding batteries, a certain evolution is expected up to 2028, with an important growth after.

In terms of demand, the short-term demand levels are expected to grow at a slower pace, and then increase in the mid and long-term, in line with the deeper electrification considered in the reviewed NECP and grid planning requests received. Electrolysers are also assumed to have an important evolution, although assumptions consider an electricity price-driven operational mode demand that, therefore, has no impact on adequacy, while peak hours will not have attractive market prices for H2 production. SRAD (Spanish acronym for “automatic demand reduction system”) type demand side response (DSR) was kept at the 2023 contracted value, while an evolution towards the historical maximum potential of 2600 MW is assumed for additional DSR.

Cross-border capacities for the Spain-France border assume no additional interconnectors until 2030 (beyond Biscay Gulf HVDC project), while Navarra-Landes and Aragón-Atlantic Pyrenees are considered to be available only for 2035, according to the last available NECP. For the Spain-Portugal border, the proposed cross-border capacities already consider the future interconnector Beariz-Ponte de Lima since 2025. In addition, Balearic Islands and Ceuta have been considered in this edition as implicit regions, as well as Morocco, with the objective of improving the global model.

Finally, reserve requirements are expected to increase slightly across the horizon, in line with operational scenarios that have recently occurred and suggest that as variability grows an increase of reserves is needed for system security.

The incorporation of future improvements in the input data, due to improvements in the dataset or new requirements, must be monitored in order to be able to include them adequately and thus allow the comparison of results between the different analyses of the ERAA to be understood.

Economic viability assessment (EVA) results

Regarding the capacity modifications proposed by the EVA model for the Spanish peninsular power system, it can be observed that no expansion is proposed, rather only decommissioning. More specifically, up to 9.2 GW of combined cycles would not be economically viable across the 2026-2035 horizon. This tendency is in line with previous ERAA and NRAA reference results, and with the additional results provided in ERAA 2024 as additional system cost EVA sensitivities and revenue-based EVA case study (which also show some mothballing in the shorter term). Differences in terms of assumptions and methodology explain certain numerical differences, however, the conclusion is solid.

Adequacy assessment (ADQ) results

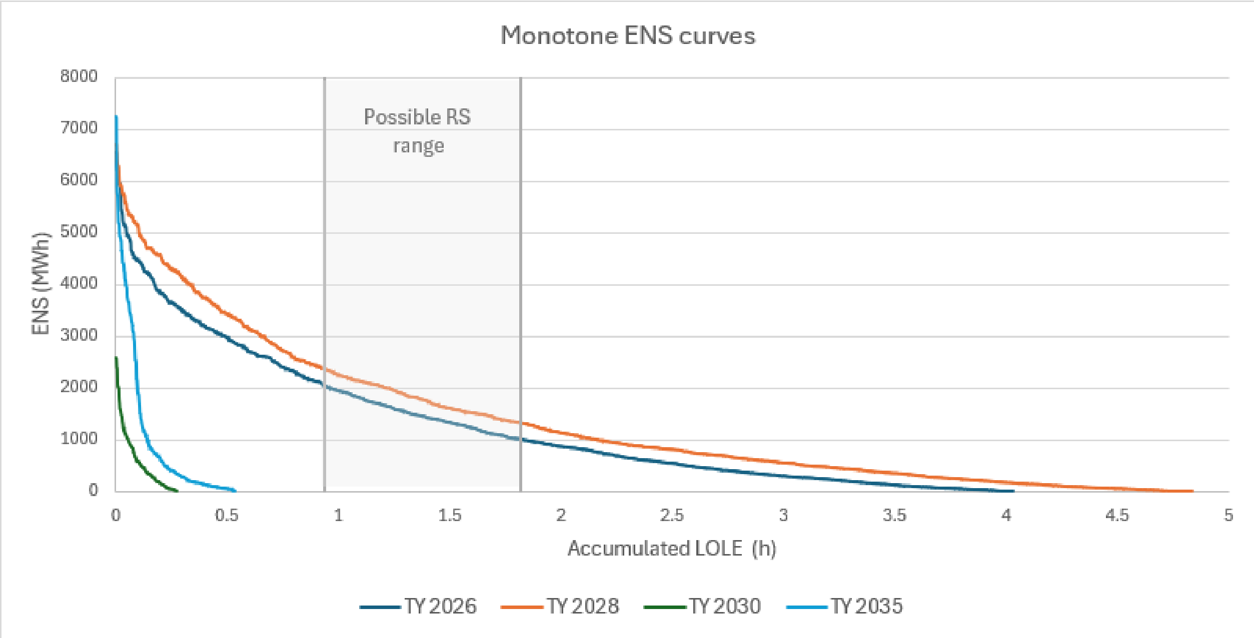
After the EVA results (decommissioning of part of the thermal fleet that would not be economically viable) are applied to the initial set of data), the adequacy assessment is carried out. The Spanish Reliability Standard (RS) expressed as maximum acceptable Loss of Load Expectation (LOLE) is not yet approved, as a value of 0.94 h/year was proposed in October 2023[21] and a new CONE study was released in October 2024[22] considering a possible RS range of 1.19-1.82 hours/year. Therefore, when analyzing the adequacy results, a range of 0.94-1.82 hours/year for the RS could be considered.

ERAA 2024 shows the same tendency for the Spanish peninsular power system as the two previous editions: under the given scenarios and methodological framework following the considerations set out by the Regulation EU 2019/943, the economic viability of a part of the generation mix is not guaranteed in the short, mid and long-term. The assessment of the scenarios which would result after the decommissioning of the economically unviable units shows a risk of adequacy issues above the reliability standard in the short- (2026) to mid-term (2028). The risks tend to be reduced to values below the reliability standard in the long-term (2030, 2035) although nonzero, despite the expected demand increase, due to the targeted investments both in new generation and international interconnection capacities according to the NECP.

The following figure shows a detailed distribution of Energy Not Served (ENS) in the Spanish peninsular power system for the different TYs, which allows to extract some key values such as the maximum value of ENS observed in a single hour for a given Montecarlo simulation, or to estimate the additional firm capacity that would be required in order to be compliant with the RS. The table below also shows the average and maximum values of yearly ENS and LOLE (indicating the most severe weather scenario). Risks typically appear during the evening hours of autumn and winter months.

[21]https://www.miteco.gob.es/content/dam/miteco/es/energia/files-1/_layouts/15/Propuesta%20de%20Resoluci%C3%B3n-68419.pdf

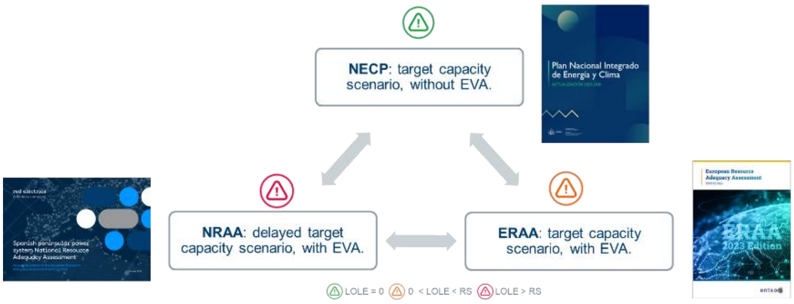
[22] https://www.cnmc.es/sites/default/files/5650953.pdf



	ENS [GWh/y]		LOLE [h/y]		Hourly ENS [GWh/h]
	Avg	**Max (WS)**	**Avg**	**Max (WS)**	**Max (WS, sample, hour)**
TY 2026	5.16	29.6 (33)	**4.03**	21.93 (26)	6.54 (33, 2, 17/1 20:00h)
TY 2028	6.46	36.63 (33)	**4.83**	27.93 (32)	6.7 (33, 10, 17/1 20:00h)
TY 2030	0.16	5.76 (32)	**0.28**	9.8 (32)	2.59 (32, 12, 13/12 18:00h)
TY 2035	0.57	19.27 (32)	**0.54**	15.67 (32)	7.26 (32, 11, 13/12 19:00h)

Conclusion
A certain amount of combined cycles that can be economically unviable in the next years are necessary to ensure security of supply above the national draft RS. These conclusions, derived from ERAA 2024, are aligned with the ones obtained in ERAA 2022, ERAA 2023 and also the ones derived in the NRAA that Red Eléctrica has performed complementarily to the ERAA 2022. This is robust despite the results in terms of economic equilibrium and adequacy indicators reasonably differ due to differences in the considered assumptions (national and international) and methodology used in each analysis.

The Spanish NECP also includes an adequacy assessment for TY2030 following the ERAA methodology (without applying an EVA). This allows the comparison of, for this key target year, adequacy in three different scenarios and extract some key messages. While the NECP shows that with 2030 target capacities no adequacy risks are observed, ERAA 2024 shows that in NECP scenario for TY2030 a part of the thermal fleet is not economically viable and their decommissioning would imply adequacy risks, although below the considered RS. However, the NRAA shows that if the storage targets set in the NECP are not achieved in the expected time, adequacy risks would rise above the RS. Therefore, a combined look of these three assessments allows us to understand the importance of implementing system planning measures that guarantees the achievement of the targets in time.



The recent Communication of the European Commission on the assessment of possibilities of streamlining and simplifying the process of applying a capacity mechanism includes a proposal for the ERAA methodology revision related to this point. More specifically, the proposal is to revise the scenario framework in order to include an additional scenario that takes into account that delays may occur in the implementation of the measures described in NECP and that such delays could affect system adequacy. This is very similar to the approach Red Eléctrica already considered in the NRAA published in 2023[23], and thinks is a priority that should be considered in next ERAA editions.

As a final idea, it is important to keep monitoring adequacy in future assessments, especially in the mid and long-term as the uncertainty is higher moreover in the current energy transition and globally unstable context. Faster or slower developments in terms of demand evolution and pace of investments in new capacities can have a relevant impact on the representativity of the assessment. This is also particularly important in the case of new storage investments, in which close monitoring of the measures can bring effectively new commissioned capacity by the time horizons in the official scenarios, and their behavior is required, due to the high impact it has to adequacy results. As in any other analysis, the representativity of the results depends on the representativity of the assumptions considered and the applied methodology.

[23]https://www.ree.es/sites/default/files/14_OPERACION/Documentos/Red_Electrica_SpanishPeninsularPowerSystem_NRAA_23_v3.pdf

Sweden

The LOLE in the ERAA results are higher than the reliability standard currently used in Sweden (1.0 h/year). The LOLE for southern Sweden increases to over 12 h/year towards the end of the studied period, which is considered a high value. It is also higher than similar figures from national studies, although many differences in methodology exist.

The input data from Sweden are based on our "EF"-scenario from Svenska kraftnät's long term market analysis[24]. It is a scenario with high electrification of the industry resulting in a high demand growth. The demand in this scenario implies a higher demand growth than the planning target adopted by the Swedish Parliament in 2024. The production growth consists of plenty of offshore wind and solar.

The Swedish government rejected the applications of 13 offshore wind farms, planned for the Baltic Sea due to defence concerns (in November 2024).[25] This may delay the expansion of offshore wind in southern Sweden in the foreseeable future.

In the time horizon up to 2035, installed dispatchable generation is relatively unchanged compared to current capacities. The Swedish government has announced plan for new nuclear in Sweden, which, if realized, may add dispatchable generation around 2035 at the earliest. This is not reflected in the input data for Sweden.

[24] Långsiktig marknadsanalys
[25] Reuters link:
https://www.reuters.com/business/energy/sweden-rejects-baltic-sea-wind-farms-citing-defence-concerns-2024-11-04/

Switzerland

Although no significant adequacy issues have been identified for Switzerland in the present exercise, ERAA 2024 shows that adequacy indicators will remain tight in the coming years. The results of this adequacy study are based on the input assumptions coming from the Swiss “Scenario Framework for Electricity Network Planning” and the "Energy Perspectives EP2050+". Thus, their validity depends on the implementation of the generation and electrification goals in these documents.

In order for the system adequacy not to deteriorate, the integration of Switzerland in the European grid must be ensured. Any reductions of the cross-border capacity between Switzerland and its neighbours will have adverse impacts on Switzerland and, potentially, on the whole region. To mitigate these effects, Swissgrid has entered into relevant agreements with the CCR Italy North, Core and Central Europe. For continuous secured system adequacy, it is important to maintain current cross-border capacity values even with the absence of an electricity agreement.