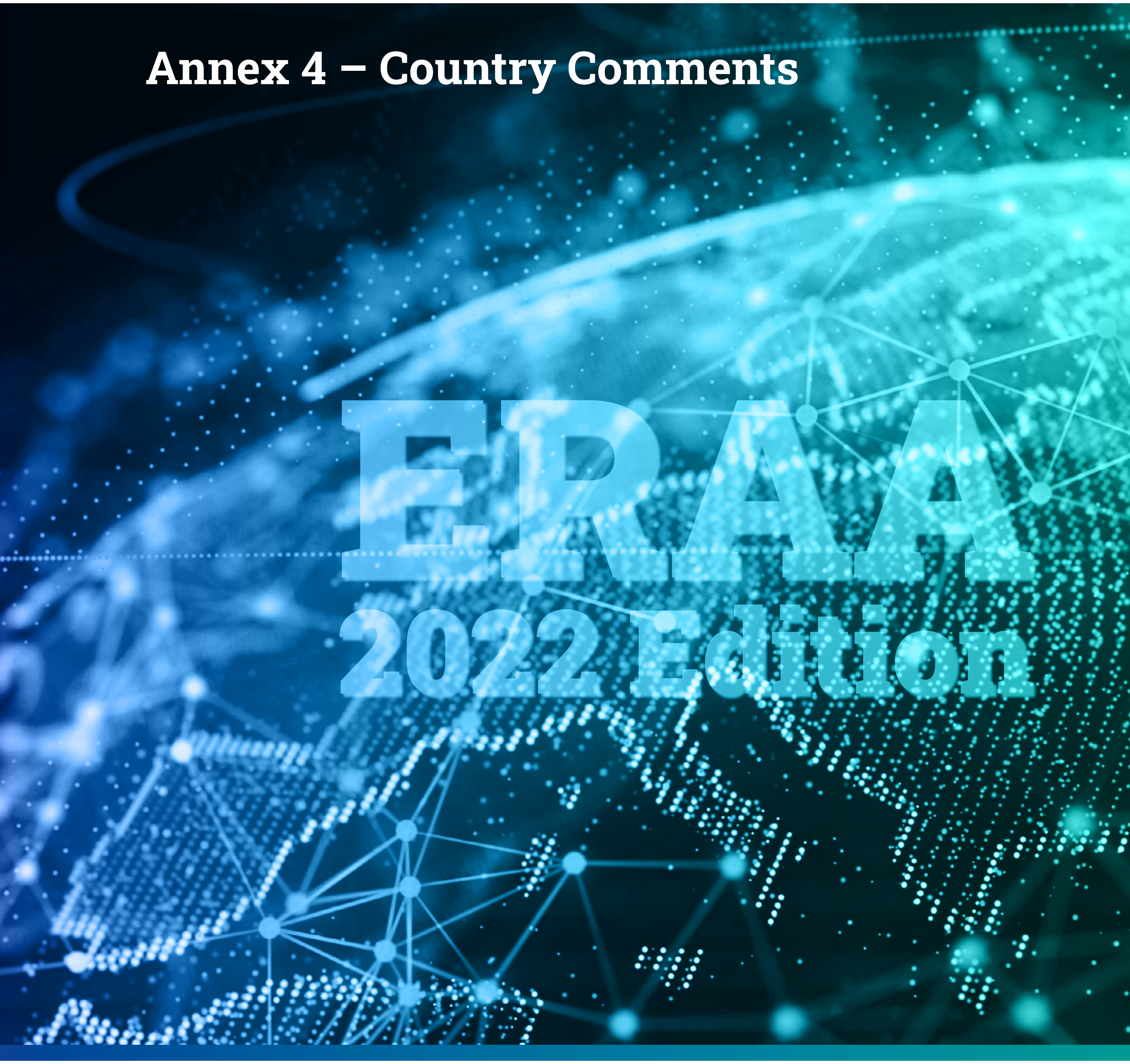
# European Resource Adequacy Assessment

2022 Edition

## Annex 4 – 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.



# 1 Austria

## 1.1 Adequacy Indicators

The adequacy indicators for Austria depicted in the ERAA 2022 report show non-zero values of LOLE and EENS for all the target years assessed (2025, 2027 and 2030). The LOLE values are 1.5 hours in 2025, 1.2 hours in 2027 and 0.76 hours in 2030: the reasons for decreasing LOLE values, and thus improving system adequacy over the horizon, can be linked to the internal growth of RES capacity (mainly wind and solar PV), as well as the commissioning of key strategic hydropower projects. The resilience of the system is also supported by the expected growing availability of flexibility resources, namely implicit and explicit DSR and battery storage. Over the whole horizon, the LOLE values stay well below the 3 hours per year threshold, set by many Member States as Reliability Standard. Thus, the ERAA 2022 results for Austria currently do not indicate a severe risk in terms of security of supply, or a structural inadequacy in terms of generation capacity. They do however identify the need to closely monitor the domestic availability of resources to ensure resource adequacy in Austria in the mid- to long-term perspective. APG (the Austrian TSO for electricity) intends to keep monitoring the national level of adequacy in the short, medium and long-term perspective, especially taking into account the current tense situation in the electricity and in the gas markets. APG's ad-hoc analyses and internal assessments, accounting for Austrian-specific figures and peculiarities, proved to be a useful instrument to provide both the TSO and the national key stakeholders with tailored and complementary insights on the domestic adequacy indicators, aside from the ones reported in the ERAA 2022 report.

The LOLE and EENS figures show higher values in comparison with the ERAA 2021 results for the Central Reference Scenario: the reasons for this can be attributed mainly to the inclusion of the Flow-Based market coupling in the CORE region (in compliance with the ENTSO-E roadmap towards a full implementation of the ERAA methodology), as well as to the implementation of the "Local Matching" and "Curtailment Sharing" principles (consistent with Chapters 6.8.1 and 6.8.2 of the Euphemia Public Description 2020).

## 1.2 Economic Viability Assessment

Another factor that affects resource adequacy is the economic viability of existing thermal generators. The EVA of ERAA 2022 indicates that around 1000 MW of thermal generation capacity is likely to be at risk of retirement in Austria as of 2024 in relation to their economic viability. APG acknowledges the progress and achievements in ERAA 2022 in terms of EVA methodology. Yet, due to the unavoidable modelling simplification, the EVA results of the ERAA 2022 and its impact on the adequacy indicators should be considered with care. APG will monitor the availability of Austrian's thermal generation capacity, given its critical importance to ensure not only resource adequacy, but also a safe and secure operation of the electricity grid.

# 2 Belgium

Previous adequacy studies performed for Belgium have all concluded that – without intervention – Belgium will face serious security of supply challenges as of 2025, due mainly to the phase-out of nuclear capacity and the energy transition evolutions in Belgium and neighboring countries. It was also established that this creates a significant need for new capacity as the existing capacity, in addition to ambitious assumptions regarding imports and future capacity developments such as Demand Response or renewable energy sources (RES), prove insufficient to cover the future needs.

In order to mitigate this risk on security of supply, the Belgian authorities installed a market-wide capacity remuneration mechanism (CRM) with winter 2025-26 as first delivery period. The European Commission approved the Belgian CRM on 27 August 2021. Meanwhile, two year-4 auctions have taken place, for winters 2025-26 and 2026-27. The first auction led – amongst other – to contracting two new large CCGT units, supporting the Belgian system as from winter 2025-26. In order to fully secure Belgian Security of Supply as from 2025, year-1 auctions will still be organized for every delivery period one year in advance.

## 2.1 General assumptions

The assumptions provided for Belgium in the ERAA 2022 are in line with the most up to date information available at the time of the data collection.

## 2.2 Market capacity resources

The assumptions for Belgium are in line with the recent 'Elia study 2021'. These assumptions were however – in coordination with the Belgian authorities – updated to reflect the best estimates available at the time of the data collection. As such, for example PV capacities, electrification of heat and mobility, electrification of industry and offshore wind capacities were updated compared to previous hypotheses.

From 2025 onwards, no nuclear capacity is assumed in Belgium, in accordance with the planned nuclear phase-out. However, as decided by the Belgian authorities, the nuclear units of Doel 4 and Tihange 3 will be prolonged with ten years. As a best estimate, it is assumed that these units will be back in service as from winter 2026-27, after the required extension works have been completed.

The new capacity contracted in the Y-4 CRM auction for delivery period 2025-26 is taken into account for ERAA 2022.

## 2.3 Grid

Belgium has one of the highest interconnection capacities when compared with its peak consumption. Belgium's central location in Europe means that the country's import and export capabilities are defined following the principles of FB capacity calculation and capacity allocation within market coupling, as introduced by the European guidelines on Capacity Allocation and Congestion Management.

Since the beginning of 2020, the ‘Clean Energy for all Europeans Package’ has been in effect. As a consequence, 70% minimum Remaining Available Margins (minRAM) has to be offered to the market for commercial exchanges and by 31/12/2025 onwards, the 70% minRAM requirement has to be applied rigorously to all CNECs. The 70% minRAM requirement is duly considered for all Belgian borders and for all borders modelled within the FB modelling in the ERAA.

## 2.4 Out-of-market measures

No strategic reserve mechanism for Belgium is in place for the time horizons considered in the ERAA 2022.

## 2.5 Comments with regards to the ERAA Adequacy results

It is important to note that the ERAA analysis defines a specific target year as the concerned calendar year: e.g. target year 2025 refers to the period from January 1st 2025 until December 31st 2025. For the Belgian national adequacy assessments, a different convention is taken: target year 2025 refers to the period from November 1st 2025 until October 31st 2026. This convention was taken to ensure that a full winter period is kept together, as such avoiding strange effects from splitting the winter period in two. This difference in convention can explain the different results when comparing both analysis among each other.

In the central reference scenario without capacity mechanisms (CMs), the simulated Loss of Load Expectation (LOLE) for Belgium is above the reliability standard for all simulated time horizons. This confirms that Belgium will need to rely on a CRM to ensure its adequacy after 2025.

# 3 Czech Republic

Even though the Czech Republic, as well as other European countries, will face challenging times, the report of ERAA 2022 does not expect aggravated values of both EENS and LOLE for the CZ region within the given outlook until 2030. These values are quite aligned with the preliminary results of the Czech National Resource Adequacy Assessment (MAF CZ 2022). In line with the recommendation of the Czech Coal Commission, the aim is to phase out coal by 2038. This can cause growing LOLE and EENS values and lead to inadequacy if the coal-fired power plants are forced to retire earlier (for example due to economic unviability), the risk of inadequate power mix will increase steadily and the Czech Republic will then consider introduction of state-aid measures, such as capacity mechanism. Currently, the application of EVA does not flag viability risk for a significant part of the Czech thermal power fleet, because these units are marked as ‘policy units’ in PEMMDB and excluded from EVA, as they provide ancillary services.

However, as there was an overall substantial increase in RES capacities reported in the PEMMDB data collection, detailed ERAA 2022 results show significant growth of imports in the Czech Republic. This causes the production of Czech generating (primarily thermal) units to become economically ineffective and, therefore, the utilization of these units decreases. Even though it has no impact on adequacy situation in the country based on the adequacy model, it significantly changes economic viability of Czech thermal units that are providing ancillary services (needed in an amount of more than 1 000 MW in total for CZ), hence arising a risk of lacking power for balancing reserves. Regarding the nature of the Czech power mix, absorbing such large imports would rather be problematic, especially given that these imports are supposed to be mainly RES-generated (high level of variability). In consequence, respective reserve capacities and ancillary services would be necessary to compensate for the variability of RES-generated imports.

This challenge is also further interlinked with significant electricity dumps (mainly RES generation curtailment and redispatch), which are outside the scope of the ERAA.

# 4 Denmark

The Danish adequacy indicator results presented in the Executive Report (Section 4.2) and Annex 3 (Section 3.2) should in Energinet's opinion be viewed in light of both the National Estimates scenario without alterations and the EVA results, which together creates the central scenario Without Capacity Mechanism (CM) for which adequacy results are presented in aforementioned sections.
The Danish National Estimates scenario in itself, as apparent from Annex 1 section 8.2 (complete TSO feedback), is characterized by:

- Significant increases in electricity demand due to increasing amounts of Power to X, electrical heating, electrification of transport and large scale datacenter consumption.
- Decrease of installed thermal capacity as a results of a gradual coal phase-out towards 2030 together with relatively stagnant gas-, oil- and biomass-fired capacity.
- Significant capacity increases for intermittent renewables in the form of wind power and photovoltaics.
- Stagnant interconnector import and export capacity between 2024 and 2030.

These Danish developments seen in isolation would indicate increased risk of the adequacy indicators results over the ERAA 2022 time scope. However, as can be seen from the Executive Report (Section 4.2) and Annex 3 (Section 3.2), Danish adequacy indicators (both EENS and LOLE) in especially DKW1 decreases significantly between 2027 and 2030. This is, at least in part, due to the massive investments in gas CCGTs in both DKE1 (380 MW) and DKW1 (2750 MW), life extensions of gas OCGT in DKE1 (50 MW) and DKW1 (30 MW) and DSR in DKE1 (290 MW) and DKW1 (500 MW) deemed economically viable by the EVA between 2025 and 2030. The thermal investments correspond to a 66% increase of Danish installed thermal capacity between the National Estimates and the post-EVA scenario without capacity mechanisms.

As a consequence of the above, Energinet believes that the insights gained from also having adequacy results from the National Estimates scenario before the EVA-loop are still extremely valuable. Having results for both scenarios would help 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.

# 5 France

## 5.1 The National Energy and Climate Plan

Since 2015, a legal framework known as 'loi de transition énergétique pour la croissance verte' with its planning documents 'stratégie nationale bas-carbone' and 'programmation pluriannuelle de l'énergie' has been established to provide a roadmap for the energy field in the coming years. In April 2020 the current NECP, elaborated in these two documents[1,2], was officially passed by the energy ministry after a two-month public consultation.
In 2023, a new NECP will be presented. Its targets are currently under discussion, but it is expected to integrate the *Fit for 55* and *RePowerEU* plans in the French energy roadmap, as well as potential new evolutions for the electrical mix. In a speech in Belfort (10 February 2022 – after the ERAA data collection), President Macron has expressed his intention to support a new nuclear strategy (building of new power plants, extension of the lifespan of existing plants), whereas the current NECP plans to decommission 14 plants until 2035, beginning with 2 in 2027. An acceleration of the development of solar and offshore wind power was also announced.

## 5.2 Load forecast provided for 2025, 2027 and 2030

After remaining stable over the past decade, the French electricity demand fell sharply in 2020 (460 TWh, i.e. 13 TWh less than in 2019). This decrease was circumstantial and due to the health crisis, in particular due to its impact on the industrial and tertiary consumption during the first lockdown. In 2021, the rebound of economic activity increased the demand, but it did not reach its former 2019 level. The electricity consumption in 2022 is then considered with great uncertainty, emphasised by the current geopolitical situation.

However, in the medium term, French electricity demand is expected to increase, especially from around 2024 onwards. The recovery of the 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 this ERAA with a more ambitious demand scenario, "Electrification +", presented in the long term adequacy study Futurs énergétiques 2050 (published in November 2021).
Main drivers with a rising effect on demand are:
- Approximately 5% of the French electricity demand dedicated to hydrogen production in 2030;
- Approximately 40% of the vehicle fleet will be electric in 2030;
- Increasing the share of electricity in heating systems and industrial processes

This trajectory is above the one from the previous ERAA 2021 (and the current NECP). It reflects an increased electrification, especially in transports and industry.

## 5.3 Net generating capacity forecast provided for 2025, 2027 and 2030

The targets of the French NECP are reached within the central scenario of the ERAA 2022. The paramount evolutions considered for the French energy mix are:
- Accelerated development of RES (wind and solar capacities are multiplied by more than three in the next ten years);

[1] https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000031044385&categorieLien=id
[2] https://www.ecologie.gouv.fr/programmations-pluriannuelles-lenergie-ppe

- Decommissioning of two of the remaining coal units by the end of 2022. The decommissioning of the last two coal units (Cordemais power plant) has been postponed to 2024, for security of supply concerns;
- No commissioning of new gas units, except CCGT Landivisiau in 2022;
- Commissioning of the new Flamanville power plant after 2023;
- Four nuclear units will be shut down between 2027 and 2030 (in addition to the closure of the two Fessenheim reactors that occurred in mid-2020) to reduce the nuclear share in electricity production to 50% by 2035. The NECP has also allowed the possibility of decommissioning two other units in 2025/2026, with conditions relating to security of supply and economic interest. RTE concluded in its latest national resource adequacy assessment (NRAA) that these conditions are not be likely to be met. Hence, these two additional closures have not been considered in this ERAA.

As these evolutions come from the current NECP, they may evolve in the months to come, especially concerning the decommission of nuclear plants (cf earlier NECP part).

Concerning the availability of the nuclear generation capacity : during winter 2021-2022, a stress corrosion has been discovered in several plants. The nature of the issue imposes that a large number of the nuclear plants will have to be checked in the years to come, leading to expected increased levels of unavailablility. However, the data collection of the nuclear maintenance planning has been performed in January 2022, the availability of nuclear plants is therefore probably overestimated, especially in 2025.

## 5.4 National view on adequacy and economic viability

RTE produces an annual risk assessment through its national generation adequacy report on a time horizon of five to ten years.
The key messages from the NRAA[3] (published in March 2021) were:

- Security of supply in France is under vigilance for the next three years, mainly due to the coal phase-out, the delayed commissioning of the new nuclear reactor, and the several nuclear outages planned during the next winters;
- From 2025: uncertainty on the level of margins, conditioned by (i) factors which may be uncertain (improved nuclear availability, achievement of national targets in France and in neighboring countries, etc.) and (ii) maintaining the French CM;

The level of vigilance and uncertainty expressed are likely to be heightened by the stress corrosion issue on the nuclear plants, the geopololitical situation in Europe and the *Fit for 55* targets (namely, the demand scenario) which are more ambitious than the one considered in the NRAA.

On a general basis, the ERAA 2022 numerical results do not contradict the NRAAs, but several methodological approaches remain fundamentally different and invites to general prudence with numerical results.

Specifically for the EVA, RTE provided analyses with a significantly different approach, among others:

- Fewer Monte-Carlo years have been considered in the ERAA (3) than in the NRAA (200). This can lead to underestimating the high variability of the climatic conditions (renewable production, thermal sensitivity) and their impact on electricity prices. Though the results do remain within coherent range of those of RTE, RTE believes that setting such a low number of MC years, imply high cautiousness

[3] https://assets.rte-france.com/prod/public/2021-04/Bilan%20previsionnel%202021.pdf
https://assets.rte-france.com/prod/public/2021-05/Bilan previsionnel 2021 - annexes techniques.pdf

when analysing quantitative results. Of all methodological differences, that one is by far the most critical.
- Although the ERAA models the risk aversion via a modified weighted average cost of capital (WACC; based on fixed values), the EVA from the NRAA relies on statistical indicators of the revenue distribution allowed by using a high number of Monte-Carlo years.
- The NRAA also considers the dynamic constraints (start-up costs, start-up time, …) which have not been modelled in this ERAA.
- RTE's EVA uses an actor-based model, which simulates individual actor decisions instead of global optimisation. Both methods fit within ACER's methodology. Actor-based simulation would lead actors who are not viable to decommission plants in every country, and would most likely lead to more generalised decommissioning. Typically, RTE's EVA would lead to decommissioning of several GW of fossil fuel powered plants in France, whereas ERAA's does not decommission a single unit in France. This shows the need for national studies to supplement ENTSO-E's analysis with understanding of subnational dynamics.

On adequacy analysis as well, some methodological approaches differ:
- They do not use the same climate database. Although the one used in the French study models 200 potential forecasting climatic years (consistent with the effect of climate change for the next decade) with a full correlation between load, solar and wind conditions, the one used for the different studies at ENTSO-E (Seasonal Outlook, ERAA, TYNDP) is based on 35 historical climatic years (with a temperature detrending[4]).
- The nuclear availability in France is considered differently in both resource adequacy assessments. The French generation adequacy study combines a deterministic approach for all the planned outages (information shared via the official transparency channels – REMIT) for which each duration is probabilistically extended consistently with what has been observed in the past years, with a probabilistic one for the other outages. In the ERAA, the simulated availability of nuclear power plants considers uncertainty on the extension of the duration of outages in a deterministic manner instead of probabilistically.
- The flow-based domains represented in ERAA are calculated taking into account constraints on the cross-borders elements only and no internal grid limitations. The considered exchange capacities are then higher in the ERAA simulations.

Consequently, the results of this ERAA for France have to be treated cautiously and read jointly with the French NRAA (also called 'Bilan prévisionnel'). The last study was published early 2021, a more up-to-date version will be available in 2023.

# 6 Germany

The ERAA 2022 report shows for the interconnected European energy system an interdependency between resource adequacy in each country and the development of the energy system in its neighbouring countries. Therefore, the four German TSOs underline that regional coordination in incentives and interventions to prevent and mitigate adequacy risks is necessary.

[4] See Annex 1

The scenario input provided by German TSOs (scenario “National Estimates”) reflects the current legislation and political targets in Germany. The last nuclear power plants will be shut down in 2023, whereas hard coal and lignite-fired power plants shall be shut-down by 2030 at the latest according to the ambitions of the current government.  Related revisions of the legislative framework are in progress. The generation capacity reserve currently in place in Germany is not included in any of the scenario results shown. This is due to the fact that this reserve is only contracted under EC state aid rules until end of 2024.

The second edition of the ERAA has taken multiple efforts to improve compliance with the ERAA Methodology requirements in line with the stepwise implementation of the complete methodology as agreed between ENTSO-E and ACER.

When assessing the results for Germany in ERAA 2022 the following elements should be noted:

1. The ‘EVA - Economic Viability Assessment’ simulation run

The EVA provides important insights on how the generation capacities in Europe may develop from a perspective driven by energy market economics only without any other revenue sources, such as balancing reserves. It considers regional interdependencies and represents a valuable complementary scenario to TSOs’ National Estimates. Methodology wise, the implementation in the ERAA 2022 contains simplifications and assumptions that can have an important impact on the results. The EVA applied in the 2022 edition is covering a time span of 2 to 3 years in order to manage computational complexity. Thus, the impact of later target years (e.g. 2030) is ignored in the EVA for 2025 and 2027. As a consequence, ERAA results indicate significant decommissioning of gas capacity in Germany in 2025 and 2027, while in contrary new gas units are built in 2030. This is driven by large decommissioning of coal capacity between 2029 and 2030, which is exogenously assumed to achieve the national ambition of an accelerated exit from coal-fired power generation by 2030. It can be assumed that an investor would take a more comprehensive approach and consider a longer time span of at least 10 years to offset the short-term volatility of fuel prices, and probably keep gas power plants in 2025 and 2027 in operation in Germany to avoid investments in new plants in 2030. Overall, it is important to recognize the ERAA scenarios as one possible development in the short- and mid-term future, which should be understood complementary to other scenario outlooks in national or regional adequacy studies. Exemplarily, the evolution of fuel prices is very uncertain and has significant impact on EVA outcomes (e.g. coal / gas fuel switch and trajectory of market based decommissioning of coal units). Additionally, exogenous assumptions, such as the degree of demand flexibility and demand increase due to electrification of consumption add further uncertainties when assembling the scenarios.

2. The “Adequacy” run

LOLE values in Germany are high for all target years. This is driven by a larger amount of decommissioned thermal capacity as compared to the National Trends scenario (based on typical lifetime of power plants and policy driven coal phase out). LOLE values also increase significantly as compared to the previous ERAA edition. It should be noted that the results of the adequacy simulation are valid conditionally that the power system evolves as indicated by the ERAA scenarios. Additionally, curtailment sharing has been implemented the first time in ERAA 2022. The curtailment sharing methodology tends to distribute ENS among countries which are exposed to scarcity simultaneously, instead of allocating it to a single country. This effect contributes to the German LOLE increase in ERAA 2022.

3. Theoretical long-term equilibrium of EVA and adequacy

In theory, the ERAA methodology as required by ACER should in the long-term result in a LOLE value that is equal to Cost of New Entry (CONE) of the cheapest available investment candidates divided by Value of Lost Load (VoLL). However, due to the high complexity of the EVA model, some simplifications are applied, which are not part of the adequacy model. Exemplarily, the number of climate years used in the EVA is reduced (three weighted climate years) as compared to the adequacy model (35 unweighted climate years). This leads to deviations from the long-term equilibrium.

Overall, the computations carried out in ERAA 2022 represent very complex optimizations. Future ERAAs should strive for a deeper understanding of decisive interdependencies and leverages for adequacy issues. LOLE and EENS parameters might summarize well the overall resource adequacy risks. However, additional insights on causes and distribution of scarcity and characteristics of scarcity events will add additional value when interpreting the results.

# 7 Great Britain

The Great Britain data was based on the 2021 Future Energy Scenarios which were published in July 2021. There has been a further annual update to the Future Energy Scenarios which were published in July 2022.

National Grid ESO analysis from both the Future Energy Scenarios 2021 and 2022 editions concluded that in all scenarios there is enough supply to meet demand. This analysis includes consideration of capacity procured through the Capacity Market in the calculations. This means all scenarios meet the reliability standard as prescribed by the Secretary of State for BEIS – currently three hours per year Loss of Load Expectation (LOLE). The calculation of how capacity market is considered for LOLE is given in our modelling methods document (page 42) – available here:
https://www.nationalgrideso.com/document/263871/download

National Grid ESO data has been provided as an input into process, this data is publicly available.

Given the current energy crisis, National Grid ESO have set out in the GB Electricity Winter Outlook Report for 2022/23 two scenarios to illustrate the risks and uncertainties for this winter. However, these scenarios are not forecasts and they do not indicate an expectation or likelihood of these situations materializing.

# 8 Ireland

Ireland and Northern Ireland together make up 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. EirGrid inputs to the PEMMDB data collection reflect the best information available at the time of the collection (Dec. 2021 for ERAA22).

EirGrid carries out national studies of adequacy in the SEM and publishes these in the annual 'All-Island Generation Capacity Statement' (GCS[1]). These assessments incorporate the most up-to-date information at the data freeze dates for demand forecasts (March 2022) and generation availability (June 2022).

Both the ERAA22 and GCS 2022-2031 highlight a breach of adequacy standard for Ireland. There are a range of factors that affect Ireland's security of supply over the coming years; in particular,

- deteriorating availability of existing generators,

- rising demand,
- run hour restrictions on new gas fired capacity,
- and the termination of capacity that had previously been awarded capacity contracts[2].

However, in later years the deficits may reduce as new capacity is expected to come forward through the SEM capacity auctions, and new interconnection links provide more security of supply.

The adequacy standard in Ireland is set at 8 hours of Loss of Load Expectation (LOLE). From a national resource adequacy perspective, the LOLE figures reported in the GCS 2022-2031 run to thousands of hours, particularly from 2025 to 2031. In contrast, the ERAA reports lower LOLE for Ireland, in the region of 20-30 hours for 2025 (for the post-EVA adequacy studies). EirGrid note the differences in the input assumptions:

- The EVA (Economic Viability Assessment) part of the ERAA process, builds 350 MW of new fictitious OCGTs in the IE00 market. This additional capacity contributes to adequacy in the Post-EVA adequacy studies, lowering the reported LOLE values compared to the GCS.
- Another significant difference is that the accommodation of operational requirements in the ERAA process does not reflect Ireland's full replacement reserve requirement, as catered for by the GCS and capacity market.
- Currently the GCS uses convolution adequacy modelling and uses External Market De-rating Factors consistent with the SEM capacity market. In contrast, the ERAA optimises the hourly flows between Ireland, Northern Ireland (UKNI), UK00 and onwards to continental Europe – this approach uses market scheduled dispatches and does not consider operational and network related constraints captured by the GCS methodology.
- There is a difference in the demand input assumptions, due primarily to different freeze dates of the two publications.
- The EirGrid adequacy model (GCS) employs annual run hour restrictions to some new capacity that has notified the market that they have restrictions. These restrictions are not modelled in the ERAA process.
- There is a difference in how units are retired in the models, with the GCS only making changes in January for a particular capacity year, whereas the ERAA uses specific dates.
- Wind is accounted for in the EirGrid Adequacy models (GCS) by using its capacity credit, while the ERAA uses 35 years of climate data. It is acknowledged that the different methods account for further differences in reported LOLE.

To understand the impact of the differences noted, EirGrid ran a limited number of studies to evaluate the range of LOLE should all the national resource adequacy issues be modelled in addition to the ERAA Pan-EU baseline model. To this end EirGrid ran sensitivities on the ENTSOE Pan-EU Plexos baseline model, for the study year 2025, when all the aforementioned national adequacy inputs assumptions were considered, EirGrid observed an exponential growth in the LOLE, recording up to 4000 hours of LOLE.

Over the next decade the adequacy situation in Ireland is in a position of capacity shortfall. To this end, the Commission for Regulation of Utilities (CRU) have in place an SOS programme of actions supported by the Irish Government and EirGrid. Actions include:

- by 2030, delivery of over 2000 MW of enduring gas-fired generation capacity which is renewable gas ready,
- in the short term, procurement of temporary generation,
- on a temporary basis, to delay closure of older generators, to allow time for the enduring measures to be implemented,

- and to enhance the responsiveness of Demand Side Units and develop additional demand side capacity.

While these mitigating measures are not included in the ERAA22 or the GCS22 studies, they will be considered for future assessments.

Furthermore, following on from ACER's DECISION No 24/2020 on the methodology for the European Resource Adequacy Assessment (ERAA); EirGrid in collaboration with the CRU are currently reviewing the Generation Capacity Statement methodologies to move to towards the National Resource Adequacy Assessment (NRAA) as specified under Regulation (EU) 2019/943 Article 24. As part of this review of Ireland's reliability calculation, EirGrid will consider the impact of weather dependent renewable sources (for example: solar and wind), conventional generation, demand, operational requirements, interconnection, demand side response, storage and energy limited technologies.

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_SONI_Ireland_Capacity_Outlook_2022-2031.pdf
[2] See Article 20 of REGULATION (EU) 2019/943 - Where the European resource adequacy assessment referred to in Article 23 or national resource adequacy assessment referred to in Article 24 identifies a resource adequacy concern, the Member State concerned shall identify any regulatory distortions or **market failures** that caused or contributed to the emergence of the concern.

# 9 Northern Ireland

Ireland and Northern Ireland together make up 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. SONI inputs to the PEMMDB data collection reflect the best information available at the time of the collection (Dec. 2021 for ERAA22).

SONI carries out national studies of adequacy in the SEM and publishes these in the annual 'All-Island Generation Capacity Statement' (GCS[1]). These assessments incorporate the most up-to-date information at the data freeze dates for demand forecasts (March 2022) and generation availability (June 2022).

The adequacy standard in Northern Ireland is set at 4.9 hours of Loss of Load Expectation (LOLE). National adequacy studies, as published in the recent GCS, show Northern Ireland to be outside of this standard for 2024 and 2025, as the existing coal/oil fired generation closes. However, the ERAA22 shows Northern Ireland to be within standard for all years. The main reason for this discrepancy is that for the GCS studies, some generating plant in Northern Ireland were modelled with more up-to-date information, where their running hours were restricted. As this information was not available for the ERAA22 data collection, the ERAA shows no adequacy issues.

In 2026, the GCS outlook returns to a surplus, due to the planned commissioning of a steam turbine unit. Any delays to this new capacity will have a significant negative impact on capacity adequacy in Northern Ireland.

[1] https://www.soni.ltd.uk/media/documents/EirGrid_SONI_2022_Generation_Capacity_Statement_2022-2031.pdf

## 10 Poland

Regarding Poland, the National Trends scenario is essentially based on the official document Energy Policy of Poland until 2040. Nevertheless, some updates were necessary in terms of the actual development of renewable energy sources (e.g. rapid growth of PV installed capacity).
Economic Viability Assessment (EVA) results show that additional 6.3 GW of coal & lignite capacity is economically retired in the analysed horizon. Furthermore, after EVA, there is no economic commissioning in sight. Realization of such scenario may not be feasible for the following reasons:

- Complexity of EVA and adequacy models for ERAA 2022 require many simplifications which may not reflect operation of the power system entirely.
- In ERAA 2022, Poland seems to be an import-dependent system, as both EVA and adequacy simulations allow full utilization of interconnections, according to the forecasted NTCs / provided CNECs for the flow-based domain building. However, recent PSE observations show that even during periods of tight power balance in Poland commercial import is very often not available, while availability of power outside Poland is confirmed.
- Compared to the moment when input data for ERAA 2022 was closed, the geopolitical situation has changed significantly. That caused growth of likelihood of inability to ensure fossil fuels for conventional generation units. This situation may lead to changes of power flows in Europe and – as the result – reduction of import availability to manage power shortages.
- The main LOLE / EENS results are weighted average for all Climate Years, while significant adequacy risks can be noticed in years with severe conditions. This means that weather conditions which affect both RES generation and level of demand are crucial for interpreting the results.

In addition to the points described above, it is important to highlight conditions that typically affect energy mix:

- Commissioning of new capacity might be delayed.
- The implementation of RePowerEU as well as Fit for 55 package (e.g. electromobility) can lead to a significant demand increase, which will affect adequacy situation.

In conclusion, according to the PSE, future system adequacy in Poland may be worsened compared to ERAA 2022 results, if mentioned above topics materialized.

## 11 Portugal

As required by the current Portuguese national legal framework, REN collaborates with the Directorate General for Energy in the elaboration of the annual National Adequacy Assessment Monitoring Report to identify the mix of resources required to comply with the reliability standards in force: Probabilistic Load Supply Index ≥ 1 and LOLE ≤ 5h/year. The most recent National Adequacy Assessment Monitoring Report (RMSA-E 2022) addresses the horizon 2023–2040.

On that report (RMSA-E 2022[5]), for year 2023 (not included in the ERAA 2022 analysis), the decommissioning of all coal power plants before the end of 2021 and the unavailability of a Combine Cycle Gas Turbine unit in the beginning of 2023, results in noncompliance with the current national reliability

[5] https://www.dgeg.gov.pt/media/ck2pa4s2/rmsa-e-2022.pdf

standards. Under these conditions, some mitigating measures may be necessary to handle operational reserve needs and ensure security of supply, 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 2022 (in ´Trajetória Ambição' similar to 'National Estimate' scenario) for the target years 2025, 2027 and 2030, contributions from NTC with Spain are required up to 20%, 10% and 50%, respectively, in order to comply with current national reliability standards.

The EVA for year 2025 indicates a significant potential capacity retirement in the Iberian Peninsula (net effect of -9 GW) which results in LOLE of 6.7 h/year in Spain and LOLE of 0 h/year in Portugal. In this target year, in the central scenario without CM (i.e. adequacy assessment of the 'National Estimate' scenario, following an EVA without CM), the retirement of 210 MW (of part of a combined cycle natural gas power plant which is expected to be decommissioned in 2029) and the expansion of 250 MW (DSR) in Portugal (net effect of 40 MW) complies with the national reliability standards (LOLE = 0 h/year). In RMSA-E 2022, a sensitivity analysis performed to assess the decommissioning of that combined cycle power plant (without any retirement of thermal power plants in Spain) results in further needs of imports (up to 60% of NTC) to comply with national reliability standards in this year.

To note that the climate years that were used for EVA (1985, 1988 and 2003, with probabilities of 0.028, 0.057 and 0.914, respectively) correspond to average/wet years in Portugal.

Surely the most relevant and impactful factors for assessing the European adequacy situation were identified in this study. 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.

REN highlights that the methodology used in ERAA 2022 is improving and is still in progress. In the next studies, until the assessment of the methodologies is fully implemented, efforts will be made with stakeholder engagement to improve the approach.

# 12 Spain

It must be noted that ERAA 2022 is highly impacted by the extreme uncertainty of currently used scenarios as a consequence of fuel prices and the geopolitical situation. Although it should be positively recognized that ERAA 2022 used the new fuel prices of REPowerEU plan, the results remain affected by the energy crisis in Europe high uncertainties.

Furthermore, this second edition of the ERAA exercise represents an important step forward in the implementation of Regulation 2019/943 on the Internal Energy Market, although it still will evolve in future exercises.

Input data provided by the Spanish TSO for 2025 was partially updated and improved based on the best information available, and stakeholder comments received after ERAA 2021, mostly to consider a more realistic rate of new generation capacity construction. Nevertheless, the scenario for 2030 was set in line with the official NECP (PNIEC), a plan which is currently under review. This review may impact future exercises.

Noticeable efforts have been made to produce a multiyear EVA with a stochastic approach, better reflecting the decision-making process of markets parties given that commissioning or decommissioning decisions by power producers or demand side response aggregators will necessarily consider the expected revenues and costs of their assets for several years across different scenarios. However, some simplifications such as a perfect market behaviour and other methodological issues could have relevance in the Spanish system due to national specificities related to the reduced available net transfer capacity or to the high variability of the hydro resources not specifically reflected in the selection of climate years.

In this ERAA 2022 edition, advances on the flexibility of the models have allowed the Spanish hydro modelling to be much more detailed than in ERAA 2021, as some of the restrictions that govern hydro output have been considered as input. However, in order to keep appropriate computation times some of these constraints have been softened in order to allow convergence of the model, thus overestimating hydro flexibility that may have led to an underestimation of adequacy risks. In addition, the current hydro modelling does not consider real market behavior as a zero variable generation cost is simulated and a perfect information simplification has been used both of which introduce additional uncertainties on the availability of hydro generation in most critical periods.

When analyzing the results, it should be noted that Red Eléctrica is currently considering a non-binding reference reliability standard of LOLE < 3 hours/year, similar to other average European reliability standards.

Accordingly, the "Central scenario without Capacity Mechanism" of this ERAA 2022 show **concerning adequacy results** of LOLE higher than 3 h/year **for the year 2025** after a significant EVA capacity reduction consisting of of the decommissioning of 9.6 GW of CCGTs and 540 MW of coal, and commissioning of 1 GW of DSR, which both together imply a net capacity reduction of 9.1 GW. In fact, **the results shows high levels of loss of average load expectation, 6.7 h/year, more than doubling the reference reliability standard**. In terms of the energy not served, the average expected unserved energy is 11 GWh in the main scenario after EVA. The results show that energy only remuneration even with the simplification of perfect market information for all participants and discarding other uncertainties associated with the commissioning of new RES generation will not suffice to achieve proper system adequacy in Spain.

Looking at the results **for 2027 and 2030, adequacy concerns are less probable considering the new expected investments in renewable generation and storage. However, these results are conditioned to the fulfilment of the main assumptions over which they are built**, specifically the materialization of these RES and storage investments. Uncertainties arise mainly due to economic, logistic or socioenvironmental difficulties. It shall be taken into account that the NECP will be updated shortly. Also, the reserves requirements have been recently reviewed for the Spanish system by Red Eléctrica considering the experiences of the last few months showing a higher need for reserves in the next years. This new reserve values will need to be updated in the next ERAA process.

ERAA 2022 could not finally deliver 2024 results as initially expected, due to the complexity of the analysis, the numerous advances that have been implemented this year and the sequentiality of some of the subprocesses. Red Eléctrica would like to indicate that there are reasons to believe that adequacy issues could have been even higher for 2024 than the ones obtained for 2025 after the EVA portfolio reduction, due to the following factors:

- EVA projected very similar results for 2024 and 2025. According to EVA results, the thermal capacity in 2024 would only be 540 MW higher than the one in 2025 as coal would remain economically viable due to high gas prices.
- In 2024 a lower RES installed capacity is expected compared to 2025, while demand levels would remain similar.
- There is a low probability of 2023, and potentially 2024, being humid years with regards to hydro storage due to the alarmingly low current levels in Spain.
- As a consequence of the energy crisis, output from cogeneration (usually 10% of yearly generation) is expected to be reduced compared to the output values considered in this ERAA for the year 2025. These units are facing difficulties as a result of high gas prices affecting their production. There is still high uncertainty on the future evolution of their contribution.
- The causes of the high unavailability of nuclear power plants in the French system could be extended up to 2025 leading to a probable reduction of availability of these nuclear plants from the values considered in ERAA 2022. This is an additional source of uncertainty with potential impact in the Spanish figures.
- In 2024 the Spanish system will have lower cross border capacity with the Portuguese system, since the new interconnection Beariz-Ponte de Lima 400 kV is expected to be in service along 2024 and therefore was considered only from 2025 onwards.

These factors and additional considerations could be introduced in a complementary National Resource Adequacy Assessment that would reflect all these national specifities in a detailed manner.

# 13 Switzerland

No significant amounts of ENS have been detected for Switzerland. However, the adequacy margins have decreased, compared to previous assessments, and the results show that they will decrease further in the future. Since adequacy is a regional topic, it remains important that Switzerland stays well integrated in the European power exchange system.
Any reductions of the cross-border capacity between Switzerland and its neighbors will have adverse impacts on Switzerland and, potentially, on the whole region. For this reason, Swissgrid entered into relevant agreements with the CCR Italy North and works on agreements with CCR Core.