French National Resource Adequacy Assessment 2025

Etabli en application de l'article L.141-8 du Code de l'Energie

In accordance with Article 24 of Regulation (EU) 2019/943

October 2025

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1 Executive summary

Context

The current French capacity mechanism has been approved until 2026. For this reason, France has initiated a process to set up a new capacity mechanism after 2026, which must be approved by the European Commission in accordance with EU regulation and state aid process.

The necessity of the new capacity remuneration mechanism (CRM) must be informed by a Resource Adequacy Assessment, prepared according to ACER's methodology for the European Resource Adequacy Assessment[1]. Regulation (EU) 2019/943 (Electricity Regulation) sets out that a Member State may conduct a national resource adequacy assessment (NRAA) to complement the European resource adequacy assessment (ERAA) when monitoring resource adequacy within its territory.

Under the current regulatory framework, NRAA or ERAA can be used to demonstrate the necessity of the CRM. **As part of the notification process of the new capacity mechanism, the French authorities intend to demonstrate its necessity through the 2025 edition of the NRAA**.

The present NRAA (*i.e.*, NRAA25) is to be understood as an extract from the *Bilan Prévisionnel 2025*, which will be officially published by the end of 2025. While the *Bilan Prévisionnel* is an extensive study of power system dimensioning and operation under several prospective combinations of load trajectories and generation mixes, the NRAA focuses on adequacy and EVA in the scenario fulfilling public policy targets (*Fit For 55),* that is to say the Central Reference Scenario under the Electricity Regulation (Articles 1 and 26), hereafter denominated as the Policy target scenario.

The NRAA25 identifies *adequacy concerns* in France in the next years if no capacity mechanism is implemented, and hence, the need for a Capacity Remuneration Mechanism in the coming years.

The most recent edition of ERAA (ERAA24), approved by ACER on August 11, 2025, identifies adequacy concerns in France through all horizons but 2030. This latest edition of ERAA features two case studies regarding revenue-based EVA implementation (essential to capturing actor behavior) and additional nuclear availability scenarios (essential to capturing impact winter adequacy risks in France). RTE was essential in the conducting of both studies. RTE instructs both aspects in this NRAA's Policy target scenario.

TABLE 1 : ADEQUACY CONCERNS IN THE FRENCH NRAA25 AND ERAA24

	NRAA25 (post EVA)				ERAA24 (post EVA)			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
Adequacy concern ?	YES	YES	YES	YES	YES	YES	NO	YES

Where the NRAA, as defined in Article 24 of the Electricity Regulation, identifies an adequacy concern that was not identified in the ERAA, the NRAA must include reasons for the divergence between the two assessments, including details of the sensitivities used and the underlying assumptions. This report introduces French NRAA 2025 and describes the divergences with the ERAA24 providing elements to justify them as well as to understand the consequences in terms of the results.

[1] ACER (2020), « Methodology for the European resource adequacy assessment ».

The full *Bilan Prévisionnel 2025* report, planned by the end of 2025, will have a broader scope and extend beyond Adequacy and EVA in the Central Reference Scenario, but the results presented within this report will not evolve between this document and the final publication.

Main takeaways

Both NRAA and ERAA are based on the ACER methodology and therefore share the same fundamentals and have many similarities. In particular:

- they are largely based on information reported by TSOs (PEMMDB24) in Europe,
- they cover a wide geographical perimeter,
- they provide a rigorous study of system adequacy in a central reference scenario,
- their analyses are based on a probabilistic optimization model (economic dispatch),
- they both conduct economic viability analyses (EVA).

However, certain aspects of the implementation of this methodology differ, which can be explained by their different objectives. ERAA aims to provide a European-wide vision of the power system and its overall adequacy. It therefore adopts a broad, cross-country approach with some simplifications in the modelling.

ERAA is a reference study for assessing adequacy at European level, which directly feeds into the national adequacy studies conducted in France by RTE as part of its legal mandate. As a result, many of the assumptions used in RTE's forecast balances are taken directly from the ERAA. However, as ERAA aims to provide a European-wide vision of the power system and its overall adequacy, it therefore adopts a broad, cross-country approach with some simplifications in the modelling.

On the other hand, the French NRAA presents a more precise and detailed view of the French situation and complements the ERAA by incorporating several specific features of the French electricity system and factors determining the security of France's electricity supply.

Firstly, it is necessary to consider the significant temperature sensitivity of the French electricity consumption, which requires specific modelling of the national power demand during extreme cold spells. Secondly, the significant share of nuclear power in the French mix means that security of supply is highly dependent on the availability of nuclear power plants, making it important to accurately represent the risks of nuclear unavailability in statistical terms. Finally, these specific characteristics have also historically led to very high variability in winter consumption peaks in France from one year to the next, resulting in considerable uncertainty as to whether or not price spikes will occur, depending on weather conditions.

This high level of uncertainty creates a significant risk to the revenues of the generation and demand-side capacities, which can have an impact on the decisions (investment, decommissioning, etc.) taken by operators. This issue of inter-annual revenue variability and the associated risk for capacity providers has long been identified and documented in France, particularly at the time of the implementation of the capacity mechanism in 2017 (see, for example, the *Impact Assessment of the French capacity market*[2] published by RTE in 2018).

[2] RTE, 2018, *Impact Assessment of the French capacity market*, https://www.services-rte.com/files/live/sites/services-rte/files/pdf/MECAPA/20180901_RTE_Capacity_Market_Impact_Assessment_Executive_summary.pdf

These characteristics of the French electricity system therefore play an important role in the modelling used for the NRAA developed by RTE, whereas they are often integrated in a more simplified manner in ERAA (even though RTE has often worked in the past to try to improve these modelling issues in ERAA).

The differences in results between the NRAA and the ERAA can be explained by these differences in implementation as well as by the underlying assumptions. Given some structural choices in the implementation of the ACER methodology (for example, the optimization model used, the role of EVA, etc.), it is difficult to establish the individual impact of each difference on final results. For this reason, we subsequently provide a set of indicators that broadly explain the differences in results.

From a technical point of view, the divergence in the identification of adequacy concerns in 2030 is mainly driven by four methodological differences:

- A different climate database, with a wider statistical modelling of climate conditions, using 200 weather scenarios, to capture the effect of high thermosensitivity in France
- A broader modelling of uncertainties regarding nuclear availability, in order to capture the impact of forced and planned outages on the French security of supply
- A different approach to represent European Adequacy, with no extensive over- or undercapacity in other Member States when assessing viability of French capacity
- A representation of risk aversion in the economic viability assessment (EVA) in line with concrete industrial practice of investment and operation decision-making process. RTE has led several sensitivities assessing that both risk-aversion parameters and price cap assumptions are not critical to the identification of adequacy concerns by 2030.

Some minor differences in assumptions, in particular short-term consumption, RES capacities trajectories in France and other European countries may also explain a part of the divergence. This report provides the elements justifying the choices made in the NRAA.

In conclusion, this report provides the necessary evidence to justify RTE's choices and to demonstrate that these choices offer a more accurate representation of France's security of supply challenges in France, in compliance with both Electricity Regulation and ACER methodology for ERAA.

The body of this document is divided in two sections:

- *Section 2 - NRAA – Bilan Prévisionnel 2025* focuses on the methodologies, assumptions and results of the study conducted by RTE throughout this year, focusing on the Central Reference Scenario, the EVA and Adequacy Results.
- *Section 3 – Analysis and justification of divergences with* ERAA24 focuses on the comparison between the NRAA study and ERAA24 as approved and amended by ACER's decision.

This report was submitted to ACER for Opinion by the Directorate General for Energy and Climate of France in accordance with article 24(3) of Regulation (EU) 2019/943 on October 27th, 2025. Two waves of additional material were then shared with ACER for clarification purposes. This additional material is now reproduced within the body of this document[3]. No quantitative changes were made. ACER issued on December 15th its Opinion No12/2025 on the differences between the French NRAA and ERAA 2024.

[3] Most of this material is now in sections 2.2.6 regarding EVA methodology, 3.2.6 regarding NTC sensitivity analysis, 3.3.4.5 regarding the EVA stress test on CVaR revenues discounting

2 NRAA – Bilan Prévisionnel 2025

2.1 General overview and principles

2.1.1 Process and publication

The "*Bilan Prévisionnel 2025"* has been mainly drawn up during 2025 and should be published by the end of 2025. As part of the process, a public consultation focusing on the data used for the study was held by RTE between March 18 and April 8, 2025. Over a hundred stakeholders have replied, and a public webinar was held on June 3, 2025. Between February and October 2025, several technical working groups were held to discuss the final assumptions of the study and present initial results.

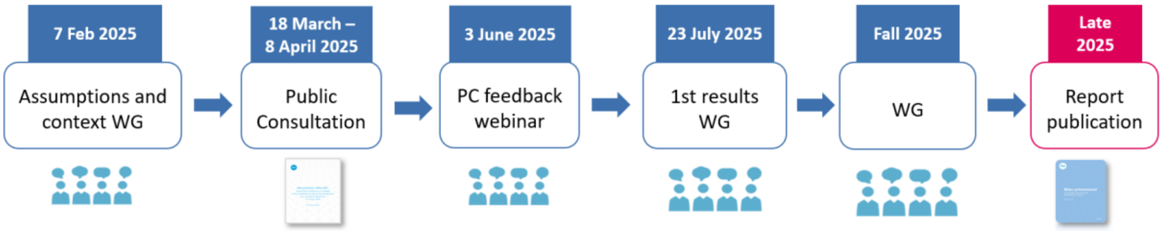

FIGURE 1 : TIMELINE OF STAKEHOLDERS INVOLVEMENT PROCESS

2.1.2 Scenarios and target years

Achieving French climate and sovereignty objectives, as part of the European Green Deal *("Fit for 55")* and French government plans for strengthening the country's economic sovereignty ("*France 2030", "green industry law"*[4]), necessarily requires going through an electrification of uses and an increase in French electricity consumption. However, even though the French electricity consumption has stopped declining (+0.7% between 2023 and 2024, adjusted for weather conditions), its growth remains weak and highly uncertain.

In this context, to ensure a robust and forward-looking assessment of France's needs and to capture the **uncertainties surrounding the evolution of the French power system, different combinations of electricity consumption and power generation mixes are considered to study their impact on the operation of France's electricity system**.

The main load trajectories studied in the *Bilan Prévisionnel 2025* are*:*

- *A **Policy Target trajectory*** ("*Trajectoire Haute –objectifs publics atteints*"): featuring a power load growth compliant with the decarbonization trajectory,
- A ***Policy Shortfall trajectory** ("Trajectoire basse – objectifs publics non atteints")*: featuring a slowed down load growth, not meeting policy targets,
- A ***Load Stagnation trajectory** ("Stagnation – test de sensibilité")*: featuring a stagnant load as of 2025.

[4] LOI N° 2023-973 Du 23 Octobre 2023 Relative à l'industrie Verte (1), in *2023-973*, 2023.

Different power generation mixes varying mainly by capacity and availability of low-carbon generation are jointly considered:

- For renewable generation, from capacity stagnation from 2027 on to growth aligned with France's current energy policy and announced targets, in particular the latest available draft version of the Multi Annual Energy Plan (PPE3)5 updated in March 2025 (which is still under discussion)
- For nuclear generation, with availability variants from ~300 to ~400 TWh

The ***Policy Target scenario considered in the NRAA*** is the combination of the Policy Target load trajectory and the generation mix aligned with France's current energy policy and announced targets regarding RES generation. It is an update of the "*A-Référence*" load trajectory of the previous French "*Bilan Prévisionnel 2023*". **This scenario matches the policy goals of the Central Reference Scenario of ERAA2024. Under the Electricity Regulation, the Policy Target Scenario is the Central Reference Scenario for this NRAA.**

Adequacy results regarding these sensitivities with different combinations of load trajectories and generation mix will not be the focus of this NRAA, accordingly to Article (1)(a) of the Electricity Regulation regarding objectives of the Energy Union, as well as Article 24 regarding NRAAs. They are nevertheless studied in the full version of the Bilan prévisionnel 2025.

Regarding target years (TYs), the *Bilan Prévisionnel 2025* covers four simulated horizons: 2026/27 – 2028/29 – 2030/31 and 2035/36. Unlike ERAA, the NRAA uses overlapping years (starting from July of year N to June of year N+1) to have a better modelling of seasonal constraints during a full winter, which is for France the main season that is significant in terms of security of supply.

2.2 Methodology

2.2.1 Overall general process

Calculations performed in the *Bilan Prévisionnel* follow the process below:

1. A first simulation of the central scenario is run using Antares as Economic Dispatch (ED) Model. This simulation is based on European data reported by TSO in the PEMMDB24 data collection and French assumptions defined for the Policy Target Scenario.
2. Then, the European thermal power fleet is progressively adapted to ensure that European countries meet their respective reliability standards from 2030 onwards, as it is both a legal requirement (should they have a Reliability Standard) and socially optimal. This step is done in order not to overestimate or underestimate the contribution of other European countries to the French power security of supply.
3. Once the European fleet adjusted, French system adequacy assessments are performed on different scenarios and sensitivities. Those assessments aim to find the adequacy gap that is required to meet the French reliability Standard in the different scenarios. Where the French reliability Standard is not met, the French power fleet is adapted by adding additional

[5] Consultation du public sur le projet de troisième édition de la Programmation pluriannuelle de l'énergie (PPE) | Consultations publiques – Updated version of March 2025

capacities to satisfy the legal reliability standard[6]. This is the reference **with CRM** scenario where France satisfies its Reliability Standard by 2030.

4. The Economic Viability Assessment (EVA) is finally performed on ED studies as a counterfactual scenario to identify capacities at risk without CRM in France, and their impact on security of supply.

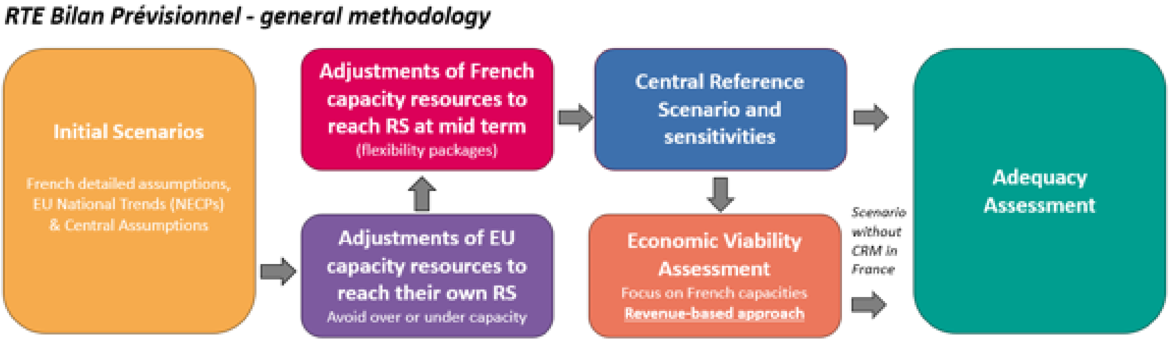

FIGURE 2 : RTE "*BILAN PRÉVISIONNEL*" GENERAL METHODOLOGY

2.2.2 Geographical scope

France's electricity system is highly interconnected with the rest of Europe and operated under economic dispatch principles, where generation and imports are optimized across borders. To accurately assess dispatch and adequacy, the geographical scope of RTE study covers **17 countries**, some of them being divided into several bidding zones (Denmark, Italy, Norway, Sweden, United Kingdom), reaching a total of **32 explicitly modeled bidding zones.** This allows the interdependent nature of electricity markets and grid dynamics to be reflected and allows to evaluate the ability of neighboring countries to export during scarcity periods in France.

FIGURE 3 : COUNTRIES EXPLICITLY MODELLED IN THE *"BILAN PRÉVISIONNEL 2025"*

[6] This step is first performed with perfect capacity (*ie* always available) to evaluate the adequacy gap, then fitted with real capacity.

2.2.3 Climate database

Each of the target years is assessed on 200 different climate year profiles, meaning weather-dependent generation and consumption are modelled on an hourly basis, under a very broad set of possible conditions. These 200 year profiles allow to have a broad description of seasonal and hourly load factors on the generation side in order to have a proper analysis of the impact of the known thermosensitivity of the French consumption on the load side. Note that French power load in winter alone stands for half of the European temperature gradients. Concretely a 1°C temperature variation in winter induces an a approximately 2000 MW French power load variation, that is to say the capacity of two nuclear power plants.

The climate database used by RTE is provided by the French weather and climate service, Météo-France, and represents the projected climate conditions in 2025. The large number of climate scenarios allow for a broader understanding of climate variability and for a good probabilistic representation of climate scenarios, which is a prerequisite for robust adequacy analysis. Further NRAA will switch to the PECD, maintaining a high number of climatic scenarios. RTE was instrumental in pushing for a more robust, complete, and forward-looking climate database, in order to assess security of supply more robustly.

2.2.4 Economic dispatch model

RTE uses a single modelling tool, ANTARES[7], which is an open-source dispatch modelling tool developed by RTE and used by several TSOs in Europe (e.g. ELIA, APG, etc.) as well as other stakeholders[8].

This model minimizes the total system costs by dispatching the different generation, storage and demand response units while taking the commercial exchange capabilities between countries into account.

For each country within the simulated perimeter, the following assumptions are provided:

- Hourly consumption profiles for each climate year: RTE uses its own model (ORPHEE) to convert the 200 climate scenarios into 200 scenarios of sectoral consumption for each country within the simulated perimeter, based on historical and prospective statistical studies;
- Thermal production capacities with their technical parameters and costs;
- Hourly generation profiles of thermal production facilities: RTE uses 60 availability profiles based on probability parameters for planned and forced outages;
- Hourly generation profiles of nuclear powerplants: RTE uses 60 availability profiles based on detailed availability assumptions by reactor and shutdown categories publicly declared by EDF[9] and assumptions regarding extended nuclear shutdowns based on historical data;
- Hourly generation profiles related to each climate year for renewable sources: RTE uses its own statistical models to convert the 200 climate scenarios into 200 generation factors for each country within the simulated perimeter;

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[7] For complete details on Antares tool see RTE (2025), « Antares Simulator Documentation », available at: https://antares-simulator.readthedocs.io/en/stable/

[8] E.g. : Natran (gas TSO in France), *Commissariat à l'énergie atomique*...

[9] EDF DOAAT (2025), « Listes des indisponibilités et des messages », available at: https://doaat.edf.fr/indisponibilites/list

- Demand-side-respond capacities and their associated constraints (number of hours per day…);
- Power-to-X capacities and their associated constraints (flexible or non-flexible modes);
- Hydro facilities type, installed capacity and their technical and economic parameters[10];
- Installed capacity of storage facilities and their technical constraints (round-trip efficiency and reservoir constraints);
- Cross-border capacity between countries: RTE models those constraints as follows:
  - For the 26/27 horizon, flow-based constraints are modelled within the CWE region, complemented with Advanced Hybrid Coupling (AHC) between CWE and non-CWE countries. For links outside of CWE, bilateral exchange capacities between countries ("Net Transfer Capacities") are defined.
  - For other horizons (28/29, 30/31 and 35/36), Net Transfer Capacities (NTC) are modelled for all links.
  - For HVDC links in Europe, RTE uses 60 availability profiles based on probability parameters.

2.2.5 Reliability standard and adequacy assessment

Reliability Standard

On 20 October 2022, ACER approved the methodology for calculation the value of lost load (referred to as "VOLL methodology"), the cost of new entry (referred to as "CONE methodology"), and the reliability standard (referred to as "RS methodology") in accordance with Article 23(6) of Electricity Regulation.

In 2022, France published its VOLL/CONE/RS study[11] setting its CONE value to 60k€/MW.yr and its VOLL value to 33k€/MWh. It sets the reliability standard value for France at 2h of load curtailment per year on average over all possible future states. However, during emergency situations, some last resort actions taken by RTE (e.g., reducing voltage of distribution network, etc...) may avoid effective load curtailment. It was then estimated that this type of actions could enable avoiding curtailment for an extra hour, hence the double reference value of 3h/yr of "*défaillance*" ; and 2 h/yr Loss of Load Expectation ("*délestage*"*)*, currently implemented in French law[12] are equivalent.

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[10] Hydro reservoir management used in the French NRAA is performed in 3 steps based on input inflow data:

- Pre-allocation of hydro resources to determine monthly energy targets, based on monthly residual load, thus ensuring a good representation of the observed seasonality of hydro generation
- Second allocation based on the previous one, to determine daily generation targets, compliant with reservoir constraints (Storage level, Maximum generation of the reservoir, level curves) and accounting for inflow patterns. They are then aggregated into weekly generation targets
- Combined hydro-thermal hourly dispatch for each week optimizing system overall-cost

This modeling of hydroelectric reservoirs allows us to reproduce observed reservoir management and avoid over-optimizing the use of the hydro inflows.

[11] RTE (2022) « Proposition pour la mise à jour du critère de sécurité d'approvisionnement du système électrique français ».

[12] Article D141-12-6 - Code de l'énergie.

This double reference enables a more accurate assessment of adequacy, without double-counting both margin and safeguard levers when evaluating needed resource capacity to ensure reliability standard.

Adequacy assessment

The goal of the adequacy assessment is to find the capacity required to meet the French reliability Standard**.**

To ensure a robust probabilistic analysis, the adequacy assessment is **performed over 1000 Monte-Carlo years**. A Monte-Carlo year is defined as a combination of:

- One of the 200 climate years and associated wind, solar, hydro and load time-series;
- One of the 60 thermal generation profiles;
- One of the 60 HVDC links availability profiles.

For each Monte-Carlo year, the model quantifies the number of hours during which the system is not adequate. If one or more bidding zones suffer from scarcity at the same time, the rules for curtailment and sharing, referred to as "**adequacy patch" is applied in order to realistically distribute the Energy Not Served (ENS) across the concerned countries.**

The reliability standard is assessed considering the average value over the 1000 Monte-Carlo simulated years.

2.2.6 Economic Viability Assessment

2.2.6.1 Revenue-based algorithm

The Economic Viability Assessment (EVA) featured in the French NRAA is performed downstream of ED studies. EVA functions as an economic counterfactual scenario assessing the viability of the reference scenarios tested, and allowing to flag which of the existing, refurbished or new capacities are at risk in the case of absence of CRM, as well as what could be the impact of this risk on security of supply. **This study is performed on French capacities exclusively**, meaning that the European capacities are not expected to make any commissioning or decommissioning decisions based on economic viability during this step.

Following the methodology, the EVA from NRAA25 is a multi-year (26/27-28/29-30/31-35/36) revenue-based[13] **process for French capacities** that are subject to the viability assessment. Those include existing thermal capacities (excluding CHPs under a regulated support scheme) and DSRs as well as refurbished or new capacity (new batteries, new thermal power plants, etc.) identified to reach reliability standard in the medium term target years.

It is important to mention that EVA studies are realized using the same ED model as adequacy studies. For computational reasons, however, the EVA has been computed on a restricted subset of 20 Monte-Carlo (MC) years being representative of the full set of 1000. This selection was performed with a scoring algorithm optimizing the representativity of the subset's revenues (see next section).

The general functioning of the iterative EVA algorithm is depicted in Figure 4 :

1- **ED runs:** When studying a given TYs, present and all future TYs are simulated thanks to Antares

[13] Revenue-based is understood as the implementation specified in Article 6 – 2 (a) in ACER (2020), « Methodology for the European resource adequacy assessment »., as opposed to the minimization of overall system costs in the expansion problem (used in ERAA).

2- **Price and production data** are extracted on hourly granularity to compute, per MC year, yearly revenues from Energy-Only Market: (Q_h are hourly productions, λ_h hourly prices[14], c_v is variable production cost). Additional revenues from system services are computed exogenously but integrated in the decision process (see below).

$$R_{EOM} = \sum_h Q_h(\lambda_h - c_v)$$

3- These yearly revenues data are then used to **compute a partial Net Present Values (NPV)** on the considered forecast horizon.

$$NPV = \sum_{TY} \frac{1}{(1 + WACC)^{TY-1}} (R_{TY} - FOM - CAPEX)$$

- With:
  - $WACC$ the weighted average cost of capital, standardized to 6%
  - R_{TY} the revenues per MW from all modelled sources on studied TY
  - FOM the Fixed Operation and Maintenance Costs
  - For investment candidates only, $CAPEX$ the yearly annuities of investment.
- The considered forecast horizon is set at 5 years for decommissioning candidates, since it was pointed out in consultations that thermal plants are not able to withstand a prolonged loss. For commissioning candidates, the forecast horizon is 10 years – full horizon.

4- **Economic Viability Check:** A candidate with positive NPV is considered viable to stay in the market or for expansion (if CAPEX are considered). Reciprocally, a candidate with negative NPV is deemed unviable to remain in the market or not viable to enter the market (if CAPEX are considered).

5- Following these checks, the decommissioning candidate with negative lowest profits is decommissioned, and the commissioning candidate with positive highest profits is added to generation. If no decisions are to be made, the study may go on to the following target year.

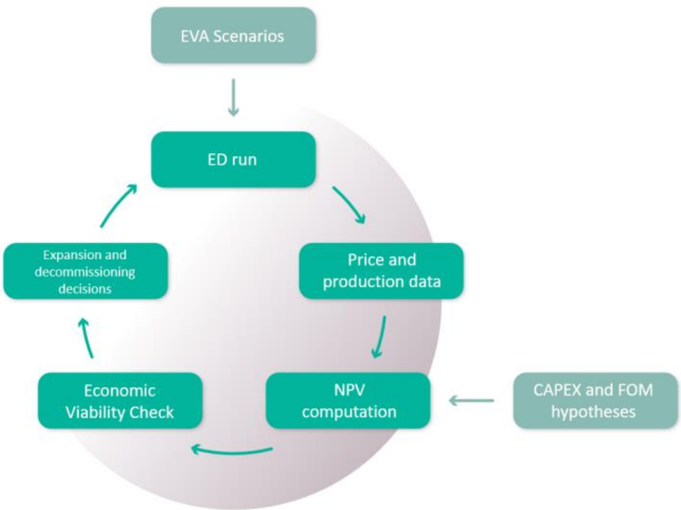

FIGURE 4 : EVA PROTOCOL DESCRIPTION SCHEMATIC

[14] In this work frame, prices mean marginal system costs of Antares simulation.

At the end of the process, all end states of target years are reprocessed with the complete set of 1000MC years to consolidate their results in terms of LOLE and ENS.

2.2.6.2 Monte Carlo years selection algorithm

This algorithm ensures that the reduced set of 20MC years is representative of the original set of 1000 Monte-Carlo years. First, a set of 100,000 candidate subsets of 20 years among the original 1,000 Monte Carlo years is generated[15]. Each candidate subset contains 20 years, with no recurring year.

For each of this subset, we compute for each target year:

- Average LOLE
- Average yearly revenues of an OCGT
- Average yearly revenues of an OCGT considering risk aversion (CVAR 10%).

These three criteria allow to capture position and dispersion of system state in each subset.

For each criterion and each target year, a score is given to each subset: the absolute difference in the subset's criterion, and that of the 1,000 year set.

We then search for the subset that is the better performing of those twelve criteria (4TY x 3 criteria), looking for the smallest possible intersection of score centiles on each criterion. The subset existing at this smallest non-empty intersection is the "best subset".

To maximize the EVA-ED alignment, this step was repeated twice. A first EVA was run with a primary selection (run on pre-EVA state). The selection was then re-run in this first post-EVA state, and the EVA was run on this final selection, reaching alignment that was deemed sufficient, as is shown in Figure 17 and 18 of the NRAA.

2.2.6.3 Model for ancillary services revenues simulation

The revenues associated with ancillary services, particularly those related to primary (FCR) and secondary (aFRR) reserves, were calibrated using two methods. The first method is based on the recent historical remuneration of the different technologies (notably CCGTs, OCGTs, and demand response). The second method is a forward-looking approach that models both prices of ancillary services and capacities engaged by 2030.

The prospective model is an extension of the ANTARES supply–demand model used by RTE in adequacy and security of supply analyses, where ancillary services and reserves are implicitly represented (through specific capacities dedicated to providing these services). The extension enables an explicit representation of both the supply side (FCR/aFRR certified capacities, participation constraints, costs) and the demand side (evolution of FCR/aFRR requirements), thereby allowing the derivation of market prices and selected capacities.

The prospective model anticipates a gradual decline in ancillary service revenues for thermal generation assets over time, mainly driven by the increasing deployment of batteries and the resulting saturation of ancillary service markets by these technologies.

[15] Trying all 20-size subsets is not manageable : $\binom{1000}{20} \approx 3 \times 10^{41}$

2.3 Data and assumptions

2.3.1 France

2.3.1.1 Electricity consumption

RTE's approach for long-term annual electricity consumption scenarios relies on a detailed bottom-up analysis. French electricity consumption is split into sectors of activity (industrial, transport, services and residential), each of them being divided into branches/subsectors or end uses. The energy consumption of each branch/subsector or use is then estimated by multiplying extensive variables (produced quantities, heated areas, equipment rates per dwelling …) and intensive variables (unit consumption per unit produced, per square meter, per dwelling) and aggregated by sectors. The assumptions regarding changes in electricity consumption aim to consider on one hand, the increased need for electrification in the various sectors, and on the other hand, the energy efficiency and energy sufficiency gains that can compensate part of this increase, all to meet the targets of decarbonization (European "*Fit for 55*" package) and reindustrialization set by the public authorities. They are based on an extensive technological and regulatory monitoring such as the sectoral "*decarbonization roadmaps*" mandated by Article 301 of the French Climate and Resilience Act, along with external studies, RTE-commissioned analyses, and input from public consultations.

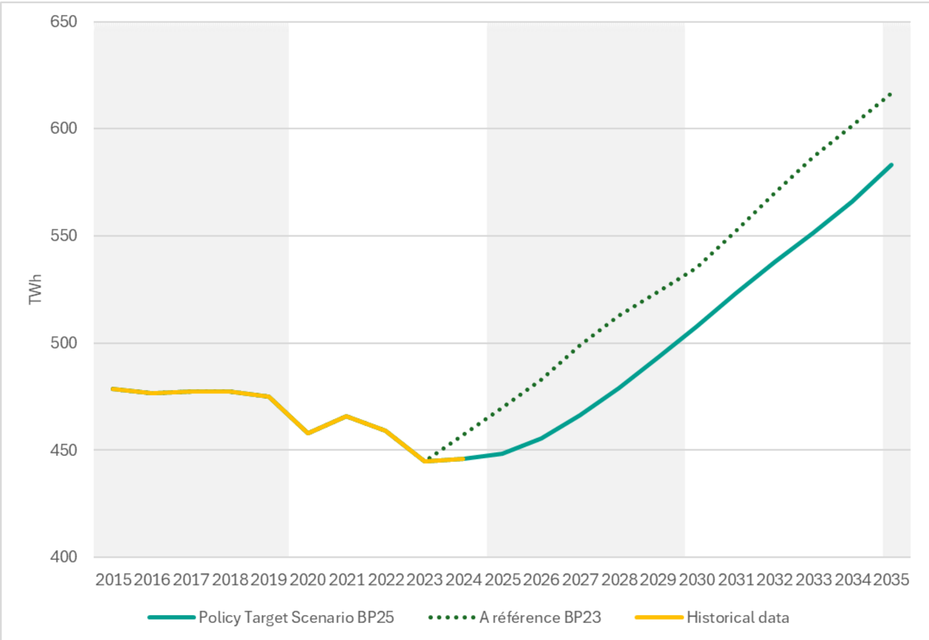

FIGURE 5 : DOMESTIC ELECTRICITY CONSUMPTION IN FRANCE (TWH) IN THE A - REFERENCE SCENARIO OF THE *BILAN PREVISIONNEL 2023* AND IN THE POLICY TARGET LOAD TRAJECTORY OF THE *BILAN PREVISIONNEL 2025*

In the previous Bilan Prévisionnel 2023, the "A-Référence" scenario (aligned with the ERAA 2023 Central reference scenario) projected French electricity consumption at 535 TWh in 2030 and 615 TWh in 2035. However, the incorporation of the history of the last two years led to revise downward the starting point for consumption trajectory in the Bilan Prévisionnel 2025. The updated Policy Target Scenario trajectory now projects around 510 TWh in 2030 and 580 TWh in 2035. Indeed, in 2024, French electricity consumption (weather-adjusted) reached around 449 TWh. Even if it represents a slight increase (+3 TWh) compared to 2023 and a break from the downward trend of the previous two years, it still remains below the level initially projected in the "A – Référence" Scenario of the Bilan Prévisionnel 2023. This increase remains significantly below the consumption implied by granted grid connection offers: if all projects behind granted grid connection offers (data centers, industry, etc.) were actually taking place and consumed at full capacity, electricity load would be significantly higher. This is the rationale for the study of additional load paths as risk analysis on security of supply.

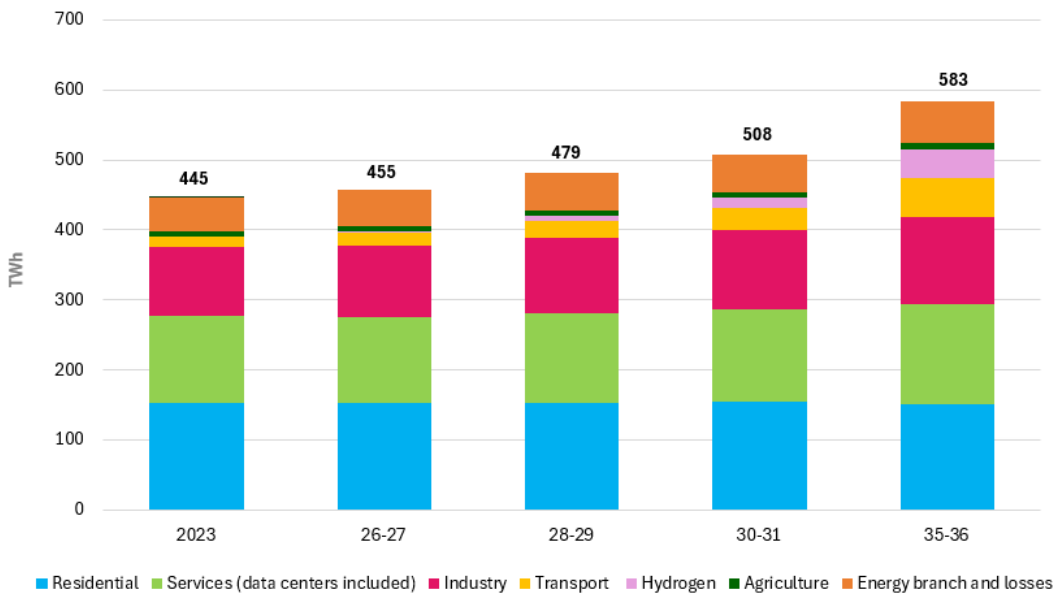

FIGURE 6 : DOMESTIC ELECTRICITY CONSUMPTION IN FRANCE (TWH) BY SECTOR, IN THE POLICY TARGET LOAD TRAJECTORY OF THE *BILAN PREVISIONNEL 2025*

TABLE 2 : DOMESTIC ELECTRICITY CONSUMPTION ASSUMPTIONS IN THE CENTRAL REFERENCE SCENARIO OF THE *BILAN PREVISIONNEL 2025* (TWH):

TWh	26-27	28-29	30-31	35-36
Residential	152	153	154	150
Tertiary	124	127	133	144
including off-premises dedicated data centers	*5*	*8*	*15*	*32*
Industry	101	108	112	123
Transportation	18	24	32	56
Including EVs/HEV	*5*	*9*	*15*	*35*
Agriculture	8	8	8	8
Energy	13	13	13	13
Hydrogen Production	2	8	15	42
Losses	37	38	41	47
Domestic consumption	**455**	**479**	**508**	**583**

Electricity consumption in buildings (except for data centers)

The decarbonization of the building sector rests primarily on the rapid electrification of heating – through the replacement of oil and gas systems with heat pumps – combined with energy-saving measures and an ambitious program of energy renovations. After a record year in 2023, heat pump installations slowed in 2024 due to a downturn in the new construction market and a shortfall in renovation activity, which remained well below national targets. However, all studies confirm that the rise of heat pumps and energy renovation are crucial for achieving carbon neutrality. Given the high level of uncertainty surrounding both the pace of heat pump adoption and the impact of renovation support schemes, RTE has opted to retain the consumption trajectory defined in *Bilan Prévisionnel 2023,* with a slight adjustment in the early years to account for 2023-2024 data. This led to a slightly downward consumption trend to 2035 in the Policy Target Scenario, with most of the decline occurring between 2030 and 2035.

Data centers

In France, data centers currently account for around 10 TWh of electricity consumption. The regulatory framework has recently evolved to both facilitate the implementation of data centers on the national territory and strengthen the country's digital sovereignty. The upcoming adoption of a law to simplify economic life should make it possible for certain projects to be classified as being "*of major national interest*", thus facilitating and accelerating their implementation in France. In addition, in May 2025, the French energy regulator (CRE) approved a new "*fast-track*" grid connection procedure for high-power consumers (400 MW to 1 GW) designed to ease constraints for large-scale project developers.

In the *Bilan Prévisionnel 2025*, RTE sets the electricity consumption trajectory for data centers by monitoring connection requests and factoring in project completion rate, site ramp-up times (often exceeding ten years), and the fact that maximum load may remain significantly below connection capacity. Under this updated scenario, RTE projects that data center consumption will reach 20 TWh in 2030 and around 35 TWh in 2035 (for both *off-premises and on-premises data centers*), including 15 TWh in 2030 and 32 TWh in 2035 for off-premises dedicated data centers.

Electric vehicles

Sales of electric vehicles (both full electric and plug-in hybrids) reached a record high in 2023, accounting for nearly 26% of new light vehicle registrations. However, this share declined slightly in 2024, reflecting the overall downturn in car sales. The slowdown extended into the first half of 2025, mainly due to tighter subsidy schemes for electric vehicle purchases compared with 2024.

However, there is a broad consensus that decarbonizing the road transport sector will primarily rely on electrification. In this context, RTE's Policy Target Scenario trajectory assumes a rapid electrification of the light vehicle fleet, projecting that the share of electric vehicles will reach 42% by 2035 in order to meet European decarbonization targets. The trajectory has been revised downward to reflect the slowdown in sales observed in 2024 and early 2025, with a catch-up expected in 2028–2029 to remain on track with climate objectives.

Industry

Industrial electricity consumption has remained relatively stagnant in recent years, with highly contrasting trends across subsectors—for instance, growth in energy-intensive industries in the aftermath of the energy crisis, but a decline in the chemical industry due to site closures.

In line with the political ambition to support and redevelop industrial activity in France, industry is projected to account for around 10% of French GDP by 2035, compared with about 9.5% in 2024. However, the inclusion of recent historical data (from the past two years) has led to a downward revision of the 2025 point for the industrial sector's consumption trajectory of roughly 10 TWh compared to the *Bilan Prévisionnel 2023*.

Hydrogen

In France, the National Strategy for Decarbonized Hydrogen (SNH) was updated in April 2025, setting targets for electrolysis-based hydrogen production capacity of up to 4.5 GW in 2030 and 8 GW in 2035. However, today, the decline in electrolytic hydrogen production costs is slower than expected, resulting in delays across the sector. To accelerate the deployment of hydrogen production projects using electrolysis, France has introduced support mechanisms. In December 2024, the first phase of a plan, ultimately aimed at developing 1 GW of hydrogen production capacity through electrolysis by 2030, has been announced by the French government.

In the *Bilan Prévisionnel 2025*, the Policy Target Scenario trajectory for hydrogen production reflects both the objectives set by the public authorities and the recent delays and uncertainties affecting the sector. Under this scenario, hydrogen demand is projected to reach 15 TWh in 2030 and 40 TWh in 2035.

Electricity consumption thermosensitivity and climate database

All these sectoral yearly trajectories are then issued into 200 hourly datasets, based on climate assumptions issued from the Météo-France database (see page 9) and the sectoral thermosensitivity. **France being significantly thermosensitive in the building sector (France stands half of European thermosensitivity), this last part is instrumental in building the load dataset.**

2.3.1.2 Demand flexibility

The prospective studies conducted by RTE traditionally feature several contrasting paths for developing demand flexibility to capture the impact on the operation of the electricity system. RTE central scenario is based on the "*median flexibility*" trajectory which considers following assumptions.

Residential flexibility (except EV)

RTE prospective studies consider flexibility provided by peak/off-peak tariff (through regulated tariffs or equivalent) which is simple to deploy and has proven its effectiveness in the past (in the case of hot water tanks in particular). In its deliberation[16] of February 15, 2024, the French energy regulator (CRE) decided to move up the off-peak hours of the regulated tariffs toward the middle of the day, progressively from November 1, 2025 to the end of 2027. The tariff profiles used in the *Bilan Prévisionnel 2025* have therefore been adjusted to take into account this change. New tariff profiles are differentiated by season (winter/summer), with three off-peak hours being placed during midday hours and five off-peak hours during night-hours. The Policy Target Scenario considers that the number of residential consumers having subscribed to such tariff offers, reaches 14 million in 2030 and is extended to the tertiary sector.

[16] Délibération de la CRE du 15 février 2024 portant décision relative à la mise en oeuvre de la généralisation des options tarifaires à 4 plages temporelles du TURPE HTA-BT

In addition of peak/off peak tariff, RTE assumes the development of peak day load shedding tariffs. The number of residential consumers having subscribed to such tariff offers increases from around 270 000 in 2023 to 500 000 in 2030.

Finally, in the residential and tertiary building sector, explicit demand response providers have been offering services to the grid for several years, currently representing several hundred megawatts on the markets, with upward prospects in the coming years. In the Policy Target Scenario, RTE considers that the number of residential consumers subscribing to an aggregation offer is expected to at least double between now and 2030. In households, this type of flexibility is predominantly associated with heating.

Electric vehicles flexibility

Concerning the light mobility sector, RTE identifies four charging modes: uncontrolled charge, time-of-use tariff charging, unidirectional dynamic smart charging and bidirectional smart charging (also known as vehicle-to-grid, V2G).

In its central scenario, RTE assumes in 2030 that 32% of vehicles do not control their charging, 60% are controlled by "static" peak/off-peak tariff, 6% of vehicles are using dynamic unidirectional charging and 2% are using bidirectional charging.

TABLE 3 : ELECTRIC VEHICLE CHARGING MODES IN THE *BILAN PREVISIONNEL 2025*

	2026-2027	2028-2029	2030-2031	2035-2036
Uncontrolled	50%	45%	30%	30%
Time-of-use tariff charging	50%	53%	62%	60%
Dynamic smart charging	0%	2%	8%	10%
Unidirectional	*0%*	*2%*	*6%*	*7%*
Bidirectional (V2G)	*0%*	*0%*	*2%*	*3%*

Industrial load shedding (apart from hydrogen production)

In association with the increase of industrial consumption (apart from hydrogen production), RTE assumes an increase in load-shedding capacity at 3.5 GW in 2030 and 4 GW in 2035 (compared to around 3 GW in 2023). These capacities are still particularly associated with electro-intensive processes (such as metallurgy, chemicals, etc.).

Hydrogen flexibility

RTE identifies three operating modes for electrolyzers: non-flexible, occasional load shedding and optimized mode (electricity consumption for hydrogen production occurs when electricity prices are lowest).

In 2025, a working group on electrolyzer flexibility conducted by RTE identified that part of the first projects for hydrogen production using electrolysis would only be able to provide occasional load shedding (no possibility to reduce their consumption during multiple hours during periods of stress for the electricity system). Therefore for short-term horizons, RTE considers only two operating modes for electrolysers : non-flexible (55%) and occasional load shedding (45%).

For the medium term, RTE assumes that by 2030 around 70% of electrolyzers will operate flexibly, primarily through occasional load shedding (45%) and through optimized operation (25%). This share is expected to increase to 80% by 2035, while the first commercialization of saline cavern storage capacity is anticipated by 2029.

TABLE 4 : ELECTROLYZER OPERATING MODES IN THE *BILAN PREVISIONNEL 2025*

	2026-2027	2028-2029	2030-2031	2035-2036
Non-flexible	55%	55%	30%	20%
Occasional load shedding	45%	45%	45%	35%
Optimized mode	0%	0%	25%	45%

2.3.1.3 RES generation capacity

Solar generation

On December 31, 2024, the solar total installed capacity reached 24.4 GW with 5 GW of new capacity commissioned in 2024, setting a new record in France.

The development of photovoltaic production is an important lever to meet growing electricity needs and achieve carbon neutrality. However, its impact on the supply-demand balance, in particular in case of a moderate increase in consumption, is subject of particular attention in public and parliamentary debate as it could accentuate the technical and economic challenges already observable. As a result, the last Multi Annual Energy Plan (PPE3) public targets for the development of photovoltaic energy have been revised several times. Ultimately, the latest draft of the PPE3 published in March 2025, sets a target of 54 GW in 2030 and a range of 65 to 90 GW in 2035.

In this context and following public consultation, RTE assumes in the reference trajectory of the *Bilan Prévisionnel 2025,* a solar installed capacity of 65 GW in 2035, which corresponds to an average rate of 4 GW/y.

Wind onshore generation

Since 2023, onshore wind farms have continued to develop at an average pace of 1.2 GW/year of new capacity (including new installations and power increases related to repowering, bringing the total installed capacity in France to 22.9 GW at the end of 2024.

The last Multi Annual Energy Plan (PPE3) sets a minimum trajectory of 1.5 GW/year and a high trajectory of 2 GW/year for the development of onshore wind energy. To achieve this objective, the public authorities plan to continue issuing calls for tenders (two per year for approximately 900 MW per period) and to explore ways of freeing up areas for onshore wind power.

In this context and in accordance with the feedback of the public consulting, RTE assumes in the reference trajectory of the *Bilan Prévisionnel 2025,* an onshore wind installed capacity of 39.4 GW in 2035, which corresponds to an average rate of 1.5 GW/y consistent with public objectives.

Wind offshore generation

On December 31, 2024, the installed offshore wind capacity reached 1.5 GW with three fully operational wind farms (St Nazaire, Fécamp, Saint Brieuc). Since, the floating wind power pilot projects have been commissioned in the Mediterranean Sea.

The development of offshore wind farms will continue with several projects currently under construction or in development which should enable an installed capacity of more than 3GW by 2030. In addition, all existing calls for tenders have been awarded or will be awarded in 2025, which should lead to a minimum installed capacity of 10 GW between 2030 and 2035.

The "offshore wind pact"[17] set by the government sets a target of 18 GW of offshore wind installed capacity by 2035. The PPE3 draft, submitted for consultation in March 2025, relaxes this target allowing RTE to develop an optimized connection schedule, a delay that should not exceed 2 years.

In this context, RTE has adopted a reference trajectory with a downward revision of the capacity to be commissioned in 2035 (~13 GW).

Hydropower

Hydroelectric power plants represent approximately 26 GW of installed turbining capacity and produce an average of nearly 60 TWh/year (including turbining from PSPs).

In the PPE3 in project, an increase of 2.8 GW of installed capacity is targeted by the public authorities by 2035, mainly consisting of new PSP (+1.7 GW), additional equipment (+0.6 GW) and small-scale facilities (+0.5 GW). To achieve this target, the French government plans to adapt the regulatory and economic framework and use dedicated calls for tenders. However, given the many uncertainties surrounding the development of new projects, RTE considers a cautious assumption, assuming 500 MW of additional PSP capacity in 2035.

Bioenergy

The bioenergy sector (~2 GW) has made little progress in recent years, with an average increase in installed capacity of 30 MW per year since 2019. To optimize the overall cost of renewable energy targets and promote greater energy efficiency, public authorities are favoring the use of biomass for heat production and the direct injection of biogas into the gas network.

2.3.1.4 Nuclear availability and generation

Installed capacity

Until the end of 2024, the French nuclear fleet was composed of 18 power plants with 56 pressurized water reactors, for a total installed capacity of 61.3 GW. **On December 21, 2024, the Flamanville EPR, with a nominal capacity of 1.65 GW, was connected to the grid bringing the total installed capacity of the French nuclear fleet to 63 GW.** No new projects—apart from the Flamanville EPR (FLA3) —are planned within the time frame covered by the *Bilan Prévisionnel 2025*.

[17] « Pacte éolien en mer entre l'état et la filière ».

Production target and availability

In 2024, the French nuclear power production reached 362 TWh (13% more than in 2023) and thus slightly exceeded the assumption used as a reference in the *Bilan Previsionnel 2023* (360 TWh/year from 2026-2027). Consequently, on January 30, 2025, EDF updated its production forecasts (including the Flamanville EPR) to between 350 and 370 TWh for 2025, 2026 and 2027.

For the coming years, the existing fleet will continue to face challenges, particularly related to the aging of units, the duration of ten-year inspections, and the possibility of extending the operating life of reactors beyond their fifth ten-year inspection. In addition, the stress corrosion cracking (SCC) problems that emerged at the end of 2021 have mostly been addressed but are still being monitored. **Given these uncertainties and based on detailed availability assumptions by reactor and shutdown categories publicly declared by EDF[18] on REMIT, the average winter nuclear availability assumed in the *Bilan Previsionnel 2025* is the following:**

- 2026-2027 and 2028-2029: 51 GW,
- 2030-2031 and 2035-2036: approximately 51 to 52 GW with greater dispersion to 2026-2027.

These availability levels could lead to an annual production of 360-370 TWh (including the Flamanville EPR) based on the assumption of a normal modulation volume. For the first few years, production may be slightly lower due to the ramp-up of the Flamanville EPR. **These production levels are in line with the production targets of the current Multi Annual Energy Plan (PPE3).**

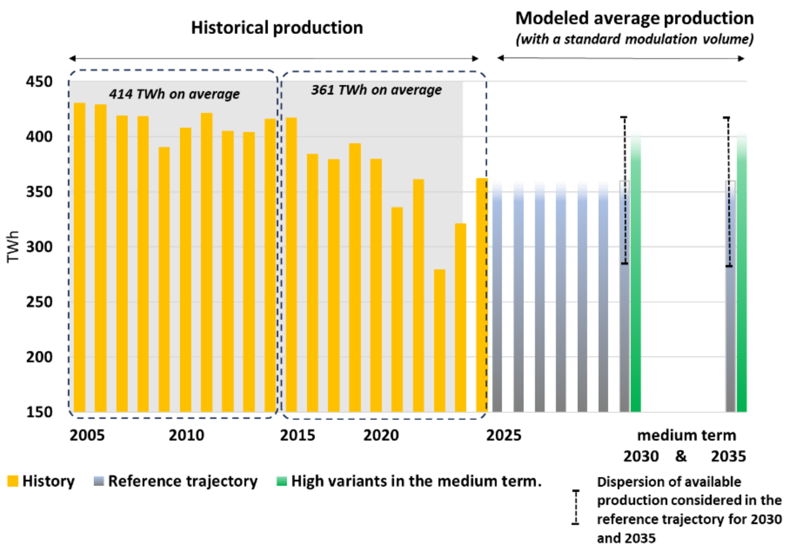

FIGURE 7 : ASSUMED TRAJECTORY FOR NUCLEAR POWER GENERATION (TWH)

[18] EDF DOAAT (2025), « Listes des indisponibilités et des messages », available at: https://doaat.edf.fr/indisponibilites/list

Modelling of the uncertainties on nuclear availability

The French power system is heavily reliant on nuclear availability. To take this sensitivity into account, in its **national adequacy studies**, RTE uses extensive datasets that combine 200 weather scenarios with 60 nuclear availability scenarios to capture **a wide range of system configurations and enhance the robustness of its security of supply analysis**.

The 60 nuclear availability scenarios are designed to ensure sufficient variability between scenarios and to consider the many uncertainties surrounding nuclear availability. They consider both forced and planned outages and the consequences of drifts in planned outages as observed historically. As in the *Bilan Prévisionnel 2023*, this average availability is accompanied by significant dispersion in the probabilistic simulations covering a range exceeding 100TWh, which is reflected in the annual output obtained, as shown in Figure 8.

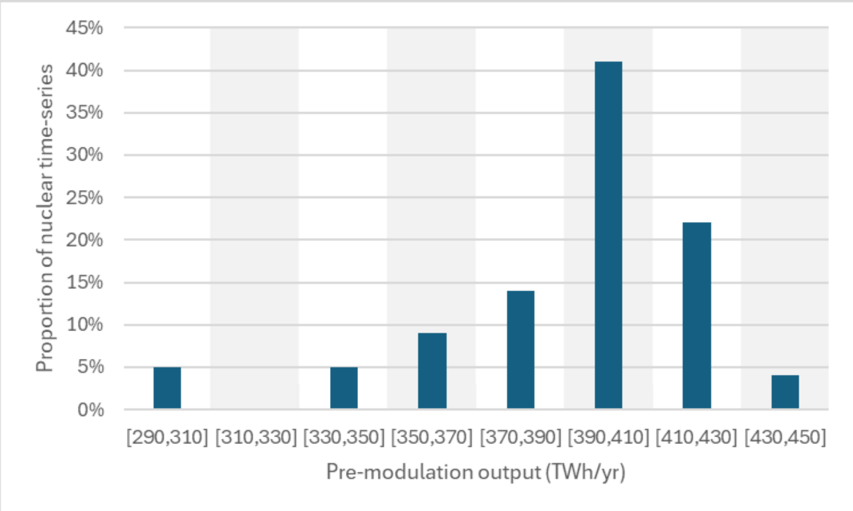

FIGURE 8 : NUCLEAR GENERATION DISPERSION

2.3.1.5 Thermal generation

The installed capacity of the thermal power plant fleet has remained relatively stable since 2021 and represents a total of 17.4 GW.

For the *Bilan Prévisionnel 2025*, the following assumptions are made:

- **The three coal-fired units** (Cordemais and Saint-Avold), with an installed capacity of 1.8 GW, are considered to be closed at the end of winter 2026-2027. It should be noted that, in September 2024, EDF announced that it was abandoning plans to convert the Cordemais power plant to biomass, while indicating its intention to convert the site into a factory for the supply of components for future EPR2 power plants.
- **The CCGT fleet** is considered unchanged except for the two DK6 units, for which a cautious approach is proposed, with the assumption that the first unit will be closed before 2030 and the second in 2035, as reported by the power plant operator.
- **Combustion turbines**: in the absence of any closure announcement by the operator, the reference trajectory assumes that all existing units will be maintained, with the exception of the oldest oil-fired plants (~400 MW) from 2030 onwards.
- **CHP and other small-size thermal power plants**: a reference trajectory based on a gradual closure validated in consultation is used.

2.3.1.6 Batteries

By the end of 2024, about 1 GW of large-scale batteries were connected to the French grid. So far, these batteries contribute mainly to the provision of the frequency containment reserves (nearly 600 MW certified) and are beginning to participate in the provision of the automatic frequency restoration reserves (~80 MW certified). So far, it seems likely that batteries will continue to develop for the provision of ancillary services.

New batteries could emerge and diversify their incomes (day-ahead and intra-day markets, grid congestions...) but the economic viability of battery business models remains largely uncertain. RTE and DSOs receive many connection studies or actual connection demand but yet the number of batteries that will actually connect remain uncertain and so far no national targets have been set.

In this context, the *Bilan Prévisionnel 2025* uses the following approach:

- A reference trajectory is used which considers a 300 MW/yr increase up to 2030 with batteries mainly dedicated to ancillary services provision (FCR and aFRR);
- Addition of extra batteries is studied in sensitivity cases to examine their contribution within market simulations.

TABLE 5 : TRAJECTORY FOR BATTERIES (GW)

GW	24-25	26-27	28-29	30-31	35-36
Batteries *(mainly dedicated to ancillary services)*	1	1.6	2.2	2.8	2.8

2.3.1.7 Synthesis

The table below summarizes the installed capacities of the French power fleet considered in the Policy Target Scenario of the *Bilan Prévisionnel 2025.*

TABLE 6 : INSTALLED CAPACITY ASSUMPTIONS (GW) IN THE POLICY TARGET SCENARIO IN THE *BILAN PREVISIONNEL* 2025

GW	Installed capacities				
	24-25	26-27	28-29	30-31	35-36
Hydropower	26.0	26.0	26.0	26.0	26.5
Onshore Wind	22.9	25.9	28.9	31.9	39.4
Offshore Wind	1.5	3.0	3.0	3.0	12.8
Solar PV	24.4	31.8	39.2	46.5	65.0
Bio – Energies and Waste	2.3	2.3	2.3	2.3	2.3
Nuclear	63.0	63.0	63.0	63.0	63.0
Coal	1.8	1.8	0.0	0.0	0.0
CCG	6.7	6.7	6.7	6.3	5.9
OCGT and oil fired peakers	2.1	2.1	2.1	1.7	1.7
CHP and small-size plants	6.8	6.0	5.2	4.6	2.4
Batteries *(mainly dedicated to ancillary services)*	1	1.6	2.2	2.8	2.8

2.3.2 Interconnections and exchange capacities

Non-french cross-border capacities are taken from the dataset available from ENTSO-E for ERAA24[19] and cross checked with TYNDP24.

For trading between France and its neighbors, assumptions are based on the last national network development plan[20] and take into account the arrival of new interconnexion lines listed in the table below.

TABLE 7 : NEW INTERCONNEXION LINES BETWEEN FRANCE AND ITS NEIGHBORS

		26-27	28-29	30-31	35-36
Spain	**Gulf of Gascogne**		x	x	x
Ireland	**Celtic Interconnector**		x	x	x
Germany-Belgium	**TD Aubange**	x	x	x	x
Germany-Belgium	**Mulhbach-Eichstetten**		x	x	x
Germany-Belgium	**Vigy-Uchtelfangen**			x	x
Germany-Belgium	**Lonny-Achène**				x

[19] Latest data available at the time of the study
[20] France's network development plan (SDDR) | RTE

NTC modeling

Except for flows within the CORE region which are modelled using flow-based constraints for 26/27, flows between countries are modelled using bilateral exchange capacities (NTC), taking into account capacity increases enabled by the arrival of new interconnection lines mentioned above.

The graph bellow summarizes the imports capacities taken into account in the *Bilan Prévisionnel 2025,* for non-CORE French borders. Considering feedback from recent years on various events that can affect cross-border exchange capacity, some cross-border exchange capacity adjustments were added to the modeling. These reductions were set to reflect the impact of several phenomena that are not explicitly modelled in the market simulations ("copperplate" assumptions), and which can lead to capacity reductions: maintenance, limitations on national networks or various hazards (equipment failures, fire, cable theft…). Those reductions were set either by analyzing effective and day-ahead cross-border exchange capacities observed in recent years or using detailed network simulations.

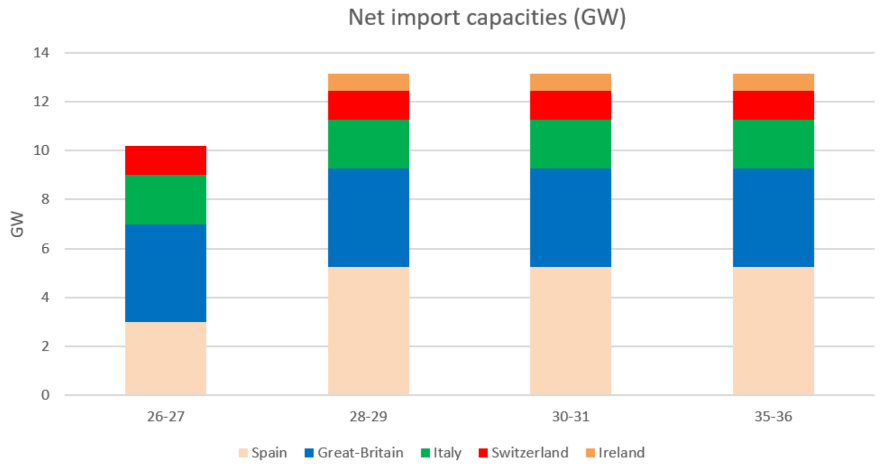

FIGURE 9 : MAXIMAL SEASONAL NET IMPORT CAPACITIES FROM NON-CORE FRENCH BORDERS (GW)

Flow-based modeling

For the target year 26/27, flow-based constraints are modelled within the CORE region. RTE is currently working on the development of flow-based domains for other horizons, but at the time of the *Bilan Prévisionnel 2025* preparation these were not yet available.

Flow-based domains were set using the *Porygon*[21] methodology developed by RTE. This methodology enables to produce flow-based domains for future years in a similar way to the operational process, starting from a network situation and a list of Critical Network Element and Contingencies (CNECs) representatives of the future grid and taking into account the future evolution of the electricity mix. Interactions between the flow-based region and countries beyond CWE are modelled using Advanced Hybrid Coupling.

[21] See Lhuillier et *al.* (2024) *"Modeling flow-based exchange capacities in medium to long-term studies"*

For each target year, hourly flows are computed on all CNECs. A clustering approach is then used to group situations with similar flows on the CNECs assuming they are representative of similar flow-based domains. Several clusterings are tested to identify the optimal number of clusters. Finally, four clusters have been selected (2 for winter and summer). A single flow-based domain is then computed per cluster. This reduced number of domains allows the adequacy simulations to stay within acceptable computation times. Then a random forest classification algorithm is used to map the typical domains on climate variables. The classification model is trained on the clusters determined before by analyzing the adequacy variables (renewable production and load) on each CWE country for each hour of each cluster. The model uses every variable to guess, for a given adequacy situation, which cluster it should belong to. It also provides as an output a score of the most explanatory variables for this classification. Once the model is trained, it is used to allocate the clusters based on the climatic data in the adequacy model.

2.3.3 Europe

2.3.3.1 General

The EU-data extraction used in *Bilan Prévisionnel 2025* was performed on the PEMMDB24 data collection.

For each simulated year starting from July 1st of year Y up to June 30th of year Y+1, capacities (thermal, batteries, RES, DSR …), that were considered in *Bilan Prévisionnel 2025* correspond to the capacities reported by the TSOs for January 1st of year Y+1.

2.3.3.2 Consumption

In line with the ERAA24, the European consumption trajectory used in the *Bilan Prévisionnel 2025*, considers two significant trends: (i) consumption levels below those seen before the Covid and the 2022 energy crisis in the short-term, (ii) the spread of electrification across all European countries to reach the EU climate targets at mid-term horizons.

Compared to the previous French NRAA *Bilan Prévisionnel 2023*, the European electricity consumption trajectory considered in the NRAA *Bilan Prévisionnel 2025* has been revised downwards for short-term horizons and is approximately 150 TWh (5% of consumption within the RTE modeling scope) lower in 2025, including France's revision. By 2030, this shortfall is half recovered, returning to unchanged consumption levels in 2035.

Table 8 : Assumed electricity consumption (except EV and H2) at EU-perimeter modelled in the *Bilan Previsionnel 2025* (TWh)

TWh	26-27	28-29	30-31	35-36
AT	79.0	83.9	91.4	103.0
BE	94.1	103.6	111.7	130.7
CH	63.2	63.6	64.2	67.1
CZ	67.8	70.6	75.1	84.0
DE	524.7	561.3	634.5	814.3
DK	50.1	55.6	61.4	71.6
ES	251.6	262.4	274.1	286.2
IE	40.4	43.1	45.6	48.7
IT	324.4	336.0	347.1	369.6
LU	6.9	7.3	7.8	9.1
NL	130.3	145.5	156.4	194.6
NO	154.9	167.4	179.8	188.1
PL	170.5	181.2	190.4	204.8
PT	51.8	52.3	52.5	50.7
SE	161.5	179.4	205.8	225.4
UKGB	291.0	306.0	328.5	417.1
UKNI	9.5	9.9	10.3	11.5
Total	**2 471.8**	**2619.2**	**2 836.4**	**3 276.5**

2.3.3.3 RES and battery capacities

For each simulated year starting from July 1st of year Y up to June 30th of year Y+1, RES and battery capacities that were considered in *Bilan Prévisionnel 2025* correspond to the capacities reported by the TSOs for January 1st of year Y+1.

TABLE 9 : ASSUMED SOLAR INSTALLED CAPACITIES AT EU-PERIMETER MODELLED IN THE *BILAN PREVISIONNEL 2025* (GW)

GW	26-27	28-29	30-31	35-36
AT	9.4	11.8	14.5	24.7
BE	11.0	12.7	14.5	19.7
CH	7.5	9.0	11.0	17.7
CZ	9.1	11.7	13.0	13.8
DE	154.4	194.8	237.5	327.0
DK	12.2	17.7	21.8	27.4
ES	50.3	59.5	72.2	115.7
IE	2.8	3.7	4.7	5.8
IT	57.5	71.9	82.4	99.4
LU	0.9	1.1	1.4	1.8
NL	46.9	55.2	62.2	81.2
NO	1.1	3.1	4 .6	7.6
PL	22.1	25.4	28.8	37.8
PT	9.3	13.0	16.4	23.5
SE	2.8	3.5	4.2	7.9
UKGB	24.7	30.9	36.4	51.4
UKNI	0.5	0.6	0.7	0.7
Total	**422.5**	**525.5**	**627.1**	**863.2**

TABLE 10 : ASSUMED WIND INSTALLED CAPACITIES AT EU-PERIMETER MODELLED IN THE *BILAN PREVISIONNEL 2025* (GW)

GW	Onshore Wind				Offshore Wind			
	26-27	28-29	30-31	35-36	26-27	28-29	30-31	35-36
AT	5.4	6.3	7.3	9.7	0.0	0.0	0.0	0.0
BE	4.3	4.9	5.8	7.0	2.3	3.0	5.8	5.8
CH	0.2	0.3	0.4	0.8	0.0	0.0	0.0	0.0
CZ	0.6	1.0	1.5	2.4	0.0	0.0	0.0	0.0
DE	72.5	87.2	104.7	157.8	14.3	18.1	34.1	58.4
DK	6.0	7.0	7.5	7.3	3.7	4.3	4.3	5.8
ES	39.1	46.1	53.8	71.8	0.0	0.3	2.8	2.8
IE	6.4	7.0	7.0	9.0	0.0	2.9	7.1	9.3
IT	19.8	24.2	26.7	30.0	0.0	0.0	2.9	7.0
LU	0.4	0.4	0.5	0.6	0.0	0.0	0.0	0.0
NL	8.2	9.1	9.1	10.8	6.1	12.0	21.4	25.1
NO	5.4	5.4	5.8	6.3	0.0	0.0	1.5	1.5
PL	12.1	13.3	14.4	17.5	4.0	6.8	8.2	11.5
PT	7.5	9.2	10.5	11.8	0.6	1.4	2.4	6.4
SE	20.2	22.2	24.0	29.4	0.2	0.5	0.9	4.1
UKGB	18.7	24.0	27.0	31.6	27.2	36.7	54.0	83.2
UKNI	1.8	2.2	2.7	3.0	0.0	0.0	0.5	1.0
Total	**228.6**	**269.8**	**308.6**	**406.9**	**58.4**	**86.0**	**145.9**	**221.7**

TABLE 11 : BATTERY CAPACITIES IN THE *BILAN PRÉVISIONNEL 2025* (GW)

GW	26-27	28-29	30-31	35-36
AT	2	3	4	7
BE	1	1	2	2
CH	1	1	1	3
CZ	2	3	3	3
DE	17	38	54	85
DK	0	0	0	0
ES	2	5	9	15
IE	1	1	1	1
IT	4	8	12	18
LU	0	0	0	0
NL	2	4	6	13
NO	0	0	0	0
PL	0	2	2	2
PT	0	1	2	6
SE	0	0	0	0
UKGB	18	23	25	29
UKNI	0	0	0	0
Total	**50**	**90**	**121**	**184**

2.3.3.4 Thermal capacities

In the *Bilan Prévisionnel 2025*, the thermal European power fleet has been adapted to ensure that other European countries meet their respective reliability standards by medium-term horizons (from 2030/2031 on). This step is done in order not to overestimate or underestimate the contribution of other European countries to the French power security of supply, as it is both a legal requirement (should they have a Reliability Standard) and socially optimal. For the short-term horizons, a linear approach to the adjustment of 2030/2031 has been performed to strike a balance between reducing overcapacity and limiting fleet movement on a very short horizon.

The European thermal capacity adjustment is performed using an investment tool that will expand or decommission least cost candidates (OGCTs, CCGTs) to ensure MS meet their reliability standard should they have one.

The tool proceeds in several steps, starting from the initial "National Trends" Scenario:

- At each step, the Loss of Load of each bidding-zone is assessed.
- If a bidding zone enforcing a Reliability Standard is not meeting it (± 30 mins), it is assumed to expand capacity. 500 MW of the least-cost[22] expansion candidate[23] will be added to the system.
- If a bidding zone is overshooting its Reliability Standard (± 30 mins), it is assumed to decommission capacity. 500MW of the highest-cost existing capacity is then removed from the system.

These steps are iterated until a state where all MS enforcing a RS are reaching it (± 30 mins).

TABLE 12 : THERMAL CAPACITIES IN THE *BILAN PRÉVISIONNEL 2025* BEFORE AND AFTER EUROPEAN FLEET ADJUSTMENT (GW)

GW	Before adjustment				After adjustment			
	26-27	28-29	30-31	35-36	26-27	28-29	30-31	35-36
AT	5	5	4	2	5	4	4	2
BE	9	10	9	12	9	11	12	16
CH	4	4	2	1	4	4	2	1
CZ	14	14	14	10	13	11	10	11
DE	60	55	52	46	50	51	74	100
DK	5	5	4	3	5	5	6	12
ES	37	35	34	29	30	23	16	8
IE	5	5	5	5	4	5	5	5
IT	52	50	49	49	45	37	30	30
LU	0	0	0	0	0	0	0	0
NL	22	20	15	15	19	20	13	16
NO	0	0	0	0	0	0	0	0
PL	33	32	31	24	31	31	27	31
PT	5	5	4	3	5	5	4	3
SE	8	8	7	7	8	8	10	10
UKGB	51	49	42	42	43	35	30	37
UKNI	2	2	2	2	2	2	1	1
Total	**312**	**299**	**274**	**250**	**273**	**252**	**244**	**283**

[22] In the sense of total system costs, assuming generic investment and operational costs
[23] Which can also mean, the least unviable, as MS enforcing a RS are expected to take measures securing their supply.

2.3.4 Economic assumptions

The economic assumptions used in NRAA25 are a combination of extensive stakeholder consultation results from RTE flagship study Energy Pathways 2050, with updates when needed, and of macroeconomic studies.

Commodity prices

TABLE 13 : COMMODITY PRICES IN NRAA25

Fuel type	NRAA Fuel prices and CO2 prices per TY			
	26-27	28-29	30-31	35-36
Natural Gas [€2024/MWht]	32.9	26.1	25.7	26.1
Hard coal [€2024/ton]	86.2	75.0	68.6	63.9
CO2 [€2024/ton]	92.8	111.1	125.1	145.5

Cost assumptions

Economic assumptions used in EVA analysis are based on stakeholders' contributions to the public consultation.

TABLE 14 : FIXED OPERATION AND MAINTENANCE COSTS AND CAPEX ASSUMPTIONS IN NRAA25

Technology	FOM (k€/MW.yr)	CAPEX (k€/MW)
OCGTs	23	[800 , 1000]
CCGTs	45	-
Hard Coal	64	-
Lignite	64	-
Oil	23	-
DSRs	[30,100]	
Batteries (2h)	[6,17]	[300,850]

WACC: a common value of 6% (real, including taxes) has been used as reference in Policy Target Scenario.

Risk aversion in Economic Viability Assessment

When assessing yearly revenues in the EVA, risk aversion from market participants must be accounted for. Both academia and actor feedback from public consultation point out that market players are not likely to account for exceptionally high-revenues, low probabilities occurrences. To fit this phenomenon, RTE uses *Conditional Value-at-Risk*, set at 10%. Practically, this means considering that the top 10% of yearly revenues from the distribution are deemed unlikely by actors and not considered in the calculation of mean yearly revenues. Both method and value are backed by academia[24], and explained by the revenue profile of peaker units. More details on this matter can be found in section 3.3.4.

2.4 Results

Pre-EVA Results

The 2025 edition of NRAA updates the short-term analysis to a better security of supply situation than the 2023 edition, thanks to updated consumption assumptions, as well as higher nuclear availability. Hence, the pre-EVA results show no issues regarding security of supply on the short-term. Both France and Europe have overcapacity. Still, the sharp increase in electricity consumption from 2030 on as well as the decommissioning of older and emissive thermal generation point out the need for additional capacity if France should be to meet its Reliability Standard.

TABLE 15 : PRE-EVA ADEQUACY RESULTS OF NRAA2025

		2026-2027	2028-2029	2030-2031	2035-2036
Pre – EVA	LOLE (h)	0.2	1.4	5.0	4.4
	EENS (GWh)	0.1	2.3	10.6	9.2

As was already done in the previous edition of Bilan Prévisionnel, RTE includes for the Policy Target Scenario a *package of additional generation and flexibility means*[25] to ensure reaching the Reliability Standard by 2030. This represents 2.7 GW of thermal capacity.

TABLE 16 : PRE-EVA ADEQUACY RESULTS OF NRAA2025 – WITH FLEXIBILITY PACKAGE

		2026-2027	2028-2029	2030-2031	2035-2036
Pre – EVA	LOLE (h)	0.2	1.4	3.0	2.7
	EENS (GWh)	0.1	2.3	5.4	4.6

Post EVA results

Results pre-EVA do not take into account economic viability of capacity assets, in particular in a situation without CRM. The EVA points out the lack of viability of a significant part of the thermal generation as well as flexibility-related capacities, which do not have enough revenues from the energy-only market to reach viability considering risk aversion. This is especially true for DSRs, which have, as known already, a capacity value first and foremost.

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[24] R. Tyrrell Rockafellar and Stanislav Uryasev, 'Conditional Value-at-Risk for General Loss Distributions', *Journal of Banking & Finance*, 26.7 (2002), pp. 1443–71, doi:10.1016/S0378-4266(02)00271-6; Kevin Favre, 'Designing Long-Term Contracts in Electricity Markets: Risk Allocation, Incentives, and Challenges for Power System Operation' (unpublished, 2025); Alexis Lebeau, 'Economic Analysis of the Impacts of Market Design and Investor Behavior on the Long-Term Dynamics in a Power Sector under Decarbonization' (unpublished, Université Paris-Saclay, 2024).

[25] While several package options are pointed out, they mostly gather new or converted thermal and new batteries

As well as existing capacity from 2026 on, the EVA points out the risk on the new investments required to reach the Reliability Standard from 2030 on. Those capacities, more expensive as they need to recover capital expenditures as well as operational ones, are highly at risk if not supported by a capacity remuneration mechanism.

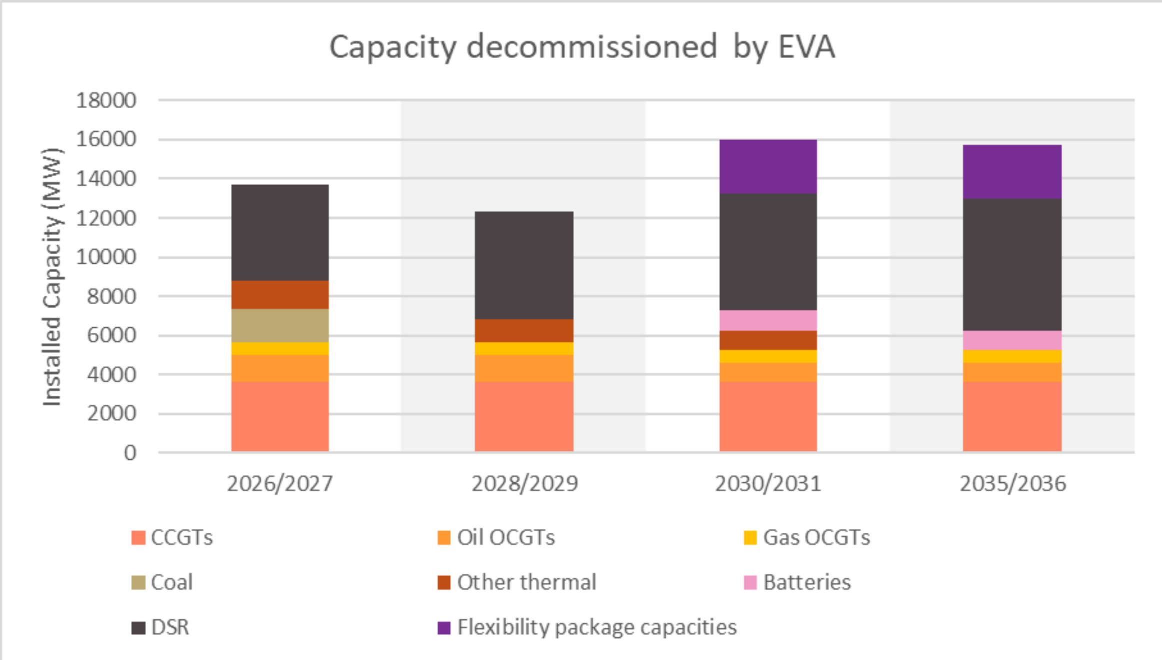

FIGURE 10 : NET DECOMMISSIONING IMPACT OF EVA WITHOUT CRM

Figure 10 above presents the decommissioning of installed capacities, starting from the reference generation of pre-EVA, accounting for the absence of a CRM from 2026 on. This severe decommissioning/non-commissioning of capacities throughout all horizons has a significant impact on security of supply and points out the existence of **adequacy concerns in France from 2026 to 2036.** While results in the short-term benefit from the relative overcapacity of the pre-EVA scenario, reaching LOLE levels between 5 and 9 hours, the medium-term horizons are heavily impacted, reaching more than 15h loss of load. The relative diminution of scarcity from 2030 to 2035 could be explained by the entry of new RES generation (notably, more than 15GW wind power).

TABLE 17 : POST-EVA ADEQUACY RESULTS OF NRAA 2025 WITHOUT CRM

		2026-2027	2028-2029	2030-2031	2035-2036
Post -EVA	LOLE (h)	5.0	8.3	19.8	15.4
	EENS (GWh)	13.1	25.7	73.8	52.9

These results are consistent with previous editions of the French Bilan Prévisionnel, which has been pointing out the risks on mid-term security of supply if the CRM was to disappear since its 2020 publication.

The results of NRAA25 show severe adequacy concerns from 2026/27 to 2035/36 if no new CRM is implemented in France.

2.5 Compatibility with EU regulation

The Article 24 of Electricity Regulation provides the required methods to perform a National Resource Adequacy Assessment (NRAA). It sets out that the National Resource Adequacy Assessment *"shall be based on the methodology referred in Article 23(3) in particular in points (b) to (m) of Article 23(5)"*, set out in ACER's methodology for ERAA.

The French NRAA edition 2025 is compliant with provisions of the Articles 23 & 24 of Electricity Regulation, as it:

- covers a regional scope (the model is applied to 17 countries);
- is based on a central reference scenario of projected demand and supply including an economic viability assessment;
- contains a central scenario and several sensitivities and includes variants without existing or planned capacity mechanisms;
- takes account of the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation;
- ensures that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration;
- applies probabilistic calculations;
- uses a single modelling tool, Antares;
- includes with and without capacity remuneration mechanism results;
- considers real network development and includes a market model using flow-based;
- includes Loss of Load Expectation and Expected Energy not Served results;
- identifies the sources of possible resource adequacy concerns.

3 Analysis and justification of divergences with ERAA24

This section aims to present, discuss and justify the main divergences identified between the French NRAA25 and ERAA24 as the most recent edition of ERAA approved by ACER.

NRAA25 and ERAA24 are based on the same fundamentals and have many similarities :

- they are largely based on information reported by TSOs in PEMMDB24 database for Europe,
- they cover a wide geographical perimeter,
- study system adequacy in a central reference scenario,
- their analyses are based on a probabilistic optimization model (economic dispatch),
- both studies conduct economic viability analyses (EVA), etc.

The NRAA, and more generally the *Bilan Prévisionnel 2025*, is mostly based on the hypotheses set for ERAA 2024, and ERAA 2025 if available at the time of elaboration, especially regarding foreign assumptions.

Nevertheless, there are certain differences in assumptions, modelling and methodology that can lead to discrepancies in results, given the specificities of the studies: ERAA's aim is to carry out general and harmonized adequacy study across all European countries, while NRAA25 is focused on detailed modelling aspects having significant adequacy impact in France, accounting for the specificities of the French power system. Indeed, for computational and simplification reasons, ERAA may not be fully able to capture the potential risk factors leading to adequacy concerns in France. The NRAA aims at complementing the ERAA on these specific matters, updating where needed for a best possible assessment, both assumptions and methodology.

Discrepancies between ERAA and NRAA drives differences in results in terms of identification of adequacy concerns. While the ERAA24, as amended by ACER, does not recognize any adequacy concerns for France over the 2030 horizon, the NRAA25, on the contrary, identifies adequacy concerns from 2026 to 2035. This divergence fully justifies a closer examination, as it directly affects the recognition of the need for a capacity mechanism. The comparison shows that ERAA24 tends to underestimate adequacy concerns without a CRM, while French's national study identifies higher LOLE levels, which in turn justifies the need for a CRM in France.

TABLE 18 : NRAA VS ERAA - ADEQUACY RESULTS WITHOUT CRM

	NRAA25 (post EVA)				ERAA24 (post EVA)			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
LOLE (h/yr)	5.0	8.3	19.8	15.4	4.1	3.6	1.8	4.9
Adequacy concern	YES	YES	YES	YES	YES	YES	NO	YES

This section is structured as follows:

- General, tool-oriented, technical comparison between NRAA25 and ERAA24 studies (3.1)
- Assumptions comparison of NRAA25 and ERAA24 (3.2)
- Focus on major methodological drivers of divergence between NRAA25 and ERAA24 (3.3).

3.1 General technical considerations

Both NRAA and ERAA are based on the ACER methodology. However, certain aspects of the implementation of this methodology differ, which can be explained by their different objectives. ERAA aims to provide a European-wide vision of the power system and its overall adequacy. It therefore adopts a broad, cross-country approach, whereas the French NRAA offers a more detailed and precise focus on the French situation, complementing the ERAA on France and its neighbors with a more detailed and up-to-date modelling and assumptions.

First, the two exercises rely on different models. NRAA is built on Antares, a modelling tool developed by RTE from more than 10 years, which is peer-reviewed and now open source, whereas ERAA uses Plexos, a commercial model. Both Antares and Plexos models are designed to optimally dispatch hourly generation to fit a fixed demand. Still, the exact tools and toolkits being different, some methodological points differ between the two studies.

Second, the model used by RTE focuses on 17 countries (32 bidding zones), which are important to accurately describe security of supply in France[26], whereas the ERAA covers all bidding zones in Europe.

The NRAA uses overlapping years (starting from July of year N to June of year N+1) to have a better modelling of seasonal constraints during a full winter, which is for France the significant season of security of supply risks, and therefore essential to evaluating the need of a CRM, since the future design will be focused on winters. ERAA uses civil years (from January to December). This cut right in the middle of winter might undermine the impact of seasonal storage constraints such as hydropower for instance in evaluating adequacy risks.

The table below summarizes comparison of technical general considerations of NRAA and ERAA, as well as some methodological aspects that will be further detailed in this section:

[26] This is in line with article 24 of the Electricity Regulation excluding recital 23.5.(a) *at least all Member States* of the NRAA requirements

TABLE 19 : GLOBAL COMPARISON OF NRAA AND ERAA METHODOLOGIES

		NRAA25	ERAA24
Geographical scope		17 countries (32 bidding zones)	35 countries (51 bidding zones)
Scenarios		Central reference scenario with and without CRM	Central reference scenario **without CRM**
Target years (ED and EVA analysis)		2026/27, 2028/29, 2030/31 and 2035/36	2026, 2028, 2030 and 2035
ED modelling	**Monte-carlo scenarios**	1000 Monte-carlo scenarios	540 (36 x 15) Monte-carlo scenarios
	Main modelling Tool	ANTARES	PLEXOS
	Model principle	Cost minimization	Cost minimization
	Hydro generation modelling	Heuristic to place hydro generation proportional to average residual demand in line with operational practice	Weekly values are computed within a yearly optimization between min and max values
	Exchange modelling with CORE	Flow-based (RTE domains) for target year 26/27	Flow-based for all target years
	Curtailment sharing rules	Algorithm representing EUPHEMIA rules (local matching + curtailment sharing)	Algorithm representing EUPHEMIA rules (local matching + curtailment sharing), constrained on total thermal production
EVA modelling	**Geographical scope**	France	Europe
	Rationale	EVA as a counterfactual scenario identifying capacity at risk without capacity mechanism in France (assuming other European Member States to enforce their reliability standards).	EVA used to model Europe if no further capacity mechanism was present anywhere in Europe
	Model principle	Multiyear revenue-based approach	Multiyear cost-minimization approach
	Core EVA model	ED model (ANTARES)	Simplified model (PLEXOS LT)
	Monte-carlo scenarios included in EVA	20 representative MC years selected with scoring algorithm	3 representative weighted WS years selected with scoring algorithm
	Risk aversion	Conditional value at risk (endogenous / depending on modelled revenues)	Hurdle rates (exogenous)
	Price Cap increase	Not modeled in the central scenario (only as a sensibility)	For target years 2026, 2028, 2030, and 2035 respectively, the applied price caps are 4500, 5000, 6000, and 6500 EUR/MWh.

3.2 NRAA25 and ERAA24 assumptions comparison and justification of differences

The following subsection focuses specifically on the assumptions and data that distinguishes NRAA25 from ERAA24. Two key elements must be taken into account when comparing the assumptions of these studies.

First, the two studies were conducted over different periods, in particular in terms of data collection and assumptions definition (ERAA24 from December 2023 to April 2024[27] and NRAA25 from March to April 2025). The assumptions of the NRAA25 are therefore more recent and better reflect the best available estimates at the time. Most differences in assumptions between the two studies can be explained by this temporal gap, especially regarding the French generation and consumption.

Second, the target years are not entirely identical, as NRAA considers overlapping years (2026/27; 2028/29 ; 2030/31 and 2035/36) while ERAA uses calendar years (2026 ; 2028 ; 2030; 2035). This six-month shift inherently introduces differences in the assumptions, particularly for those that evolve rapidly over time (e.g., installed renewable capacity).

3.2.1 Electricity consumption in France

The ERAA24 assumptions for France are inherited from the French NRAA23, as they were the latest available at the time of collection. The NRAA25 features updated assumptions based on extensive prospective work, including the most up-to-date economic, industrial, and policy developments. This time effect naturally leads to differences in consumption trajectories.

Electricity consumptions trajectories have been revised downward for most sectors. This trend is particularly notable in the industry and hydrogen sectors. A slight downward trend in industrial consumption is now anticipated. This shift can be explained by the low share of industrial GDP in national GDP and the difficulty in achieving reindustrialization ambition. The hydrogen sector is also experiencing a downward revision in its consumption trajectories. Consumption projections for hydrogen production fall within the low median range of those studied in the NRAA23, considering the objectives set out in the PPE3. These downward revisions are shown in the following comparative summary table:

TABLE 20 : FRENCH ELECTRICITY CONSUMPTION COMPARISON

TWh	NRAA25				ERAA24			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
Domestic consumption	455	479	508	583	483	513	535	617

In conclusion, electricity consumption trajectory of the NRAA25 is more recent and better reflect the best available estimates at the time.

[27] With numerous data fixes up to July 2024

3.2.2 Renewable generation in France

ERAA24 uses a set of assumptions for the development of RES consistent with those used in NRAA23. NRAA25 updates these assumptions with the most recent data and political guidelines.

Solar capacity forecasts have been updated upwards, while offshore wind capacity trajectories have been adjusted downwards. However, the main explanation for the differences lies in a temporal effect: ERAA works on calendar years, while NRAA25 relies on overlapping years, which leads to systematic shifts in the reference volumes.

TABLE 21 : FRENCH RES CAPACITY COMPARISON

GW	NRAA25				ERAA24			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
Wind	28.9	31.9	34.9	52.2	26.8	30.7	34.1	52.4
Onshore	*25.9*	*28.9*	*31.9*	*39.4*	*24.8*	*27.6*	*30.5*	*37.6*
Offshore	*3.0*	*3.0*	*3.0*	*12.8*	*2.0*	*3.0*	*3.6*	*14.8*
Solar	31.8	39.1	46.5	65.0	24.7	32.5	40.3	62.2

3.2.3 Nuclear generation in France

ERAA24 uses a set of assumptions for average nuclear availability consistent with those used in NRAA23, i.e., around 50 GW of availability in winter.

The assumptions regarding nuclear fleet availability are slightly revised upward in the NRAA25 (average winter availability between 51 and 52 GW by 2030). This upward revision is mainly explained by EDF's updated production forecasts and the initial feedback from the START program, which aims to reduce maintenance outage durations.

3.2.4 Thermal generation in France

ERAA24 uses a set of initial assumptions (pre-EVA) for the thermal consistent with those used in NRAA23 (pre-EVA). NRAA25 (pre-EVA) updates the assumptions with the most recent information following public consultation (in particular information collected from power plant operators).

NRAA25 assumes a gradual decline in thermal capacities, with a smoother phase-out of oil and gas compared to ERAA24, due to updated industrial assumptions. Both studies align on the disappearance of coal by 2028-2029.

The figures in the table below correspond to pre-adjustment data:

TABLE 22 : FRENCH THERMAL CAPACITY COMPARISON

GW	NRAA25 (pre EVA)				ERAA24 (pre EVA)			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
CCGTs	6.7	6.7	6.3	5.9	6.6	6.6	6.6	6.6
OCGTs and oil-fired peaker units	2.1	2.1	1.7	1.7	1.9	1.6	1.6	0.6
CHP and small-size plants	6.0	5.2	4.6	2.4	5.3	5.1	4.8	2.8
Hard Coal	1.8	0.0	0.0	0.0	1.7	0.0	0.0	0.0

Forced outage rates are identical for OCGT and CCGT in both studies:

- for "OCGT old" units, the forced outage rate is set at 8%, with an average duration of 1 day and 13 days of planned maintenance per year.
- For "OCGT new" units, the forced outage rate is set at 5%, with an average duration of 1 day and 13 days of planned maintenance per year.
- For the "CCGT fleet", the NRAA models only "CCGT new" units. For these units, the forced outage rate is set at 5%.

3.2.5 European consumption and generation assumptions

European assumptions in NRAA25 fully rely on the PEMMDB24 data set, which was built for the ERAA24 collection, and on the *Future Energy Scenarios 2024* data for the United Kingdom. The European assumptions are therefore largely similar between the two studies.

For each simulated year starting from July 1st of year Y up to June 30th of year Y+1, capacities (thermal, batteries, REN, DSR …), that were considered in NRAA25 correspond to the capacities reported by the TSOs for January 1st of year Y+1.

Electricity consumption assumptions

TABLE 23 : COUNTRY-WISE ELECTRICITY CONSUMPTION (WITHOUT H2 & P2H) COMPARISON

TWh	NRAA25				ERAA24			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
AT	79.0	83.9	91.4	103.0	78.0	82.0	89.0	107.0
BE	94.1	103.6	111.7	130.7	94.0	106.0	113.0	133.0
CH	63.2	63.6	64.2	67.1	63.2	63.0	64.2	67.1
CZ	67.8	70.6	75.1	84.0	67.8	70.0	75.1	84.0
DE	524.7	561.3	634.5	814.3	585.0	622.0	662.0	801.0
DK	50.1	55.6	61.4	71.6	50.1	54.0	61.4	71.6
ES	251.6	262.4	274.1	286.2	251.6	259.0	274.1	286.2
IE	40.4	43.1	45.6	48.7	40.4	42.0	45.6	48.7
IT	324.4	336.0	347.1	369.6	324.4	333.0	347.1	369.6
LU	6.9	7.3	7.8	9.1	6.0	7.0	7.0	9.0
NL	130.3	145.5	156.4	194.6	135.0	144.0	153.0	191.0
NO	154.9	167.4	179.8	188.1	154.9	164.0	179.8	188.1
PL	170.5	181.2	190.4	204.8	172.0	179.0	189.0	203.0
PT	51.8	52.3	52.5	50.7	51.8	52.0	52.5	50.7
SE	161.5	179.4	205.8	225.4	161.5	176.0	205.8	225.4
UKGB	291.0	306.0	328.5	417.1	265.0	285.0	315.0	430.0
UKNI	9.5	9.9	10.3	11.5	9.5	10.0	10.3	11.5
Total	**2 471.8**	**2 619.2**	**2 836.4**	**3 276.5**	**2 510.2**	**2 648.0**	**2 843.9**	**3 276.9**

Regarding consumption, the overall figures are broadly consistent with NRAA25 (less than 2% difference throughout all countries notably due to some differences occurring in the last published version of PEMMDB24). However, a closer look is needed for certain countries, particularly Germany and the UK.

Germany's electricity consumption trajectory in NRAA25 is lower than in ERAA24. Indeed, the ERAA24 trajectory is well above their short-term estimates for the Winter Outlook and even above actual results. The difference seemed significant enough to RTE to issue a correction on the short to medium term from 2026 to 2030[28]. The latter is found well aligned with the last forecast by the German government issued in September 2025[29].

Similarly, the UK electricity consumption trajectory has been corrected based on the *Future Energy Scenarios 2024* report by NESO. Indeed, based on a comparison of PEMMDB24 dataset with different scenarios from *FES 2024* showing a major discrepancy concerning the historic data (that may be attributed to a geographical or technical difference perimeter), it was deemed more consistent to retain the data from *FES 2024*. The UK figures are thus based on the FES 2024 report.

All foreign outage rates are identical in the NRAA25 and the ERAA24.

Renewable Energy Sources (RES) capacities assumptions

RES capacities in NRAA25 are based on data from PEMMDB24, except for the UK (data from Future Energy Scenario 2024) and Germany (data from PEMMDB25), and consequently aligned with the ERAA Central Reference Scenario.

TABLE 24 : RES CAPACITY COMPARISON

GW	NRAA25 (17 countries)				ERAA24 (NRAA perimeter)			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
Wind Onshore	228.7	269.8	308.6	406.9	210.4	255.1	309.0	395.5
Wind Offshore	58.4	86.0	145.9	221.7	47.5	66.3	119.8	200.1
Solar PV	422.5	525.5	627.1	863.2	345.3	452.8	566.3	793.6

TABLE 25 : RES CAPACITY COMPARISON - DE AND UK FOCUS

GW		NRAA25				ERAA24			
		26-27	28-29	30-31	35-36	2026	2028	2030	2035
Wind Onshore	*DE*	73	87	105	171	66	86	115	157
	UKGB	19	24	27	32	17	21	23	26
Wind offshore	*DE*	14	18	34	58	11	15	28	49
	UKGB	27	37	54	83	22	29	40	47
Solar	*DE*	154	195	237	327	114	162	215	308
	UKGB	25	31	36	51	15	16	16	19

Two key factors account for the discrepancies observed in RES capacities: i) The NRAA25 outlook for Germany and the UK has been adjusted based on the most recent and consistent data available, ii)

[28] This is as well being addressed in ERAA 2025

[29] Press : Germany's Reiche presents 'reality check' ET report aimed at reducing costs | S&P Global ; Report : Bundesministerium für Wirtschaft und Energie, *Versorgungssicherheit Strom Bericht 2025* (2025).

the difference between targets years definition (overlapping vs. civil target years) which leads to systematic shifts in the reference volumes.

Thermal generation capacity assumptions

European assumptions are based on data transmitted by TSOs for ERAA24. As mentioned, there are significant changes modelled in the power system in both studies (European thermal capacity adjustment and EVA). Those are addressed in 3.3.3 and in 3.3.4. The table below presents the generation assumptions before both adjustments.

TABLE 26 : COLLECTED THERMAL GENERATION CAPACITIES

GW	NRAA25 Pre-Adjustment				ERAA24 Pre-EVA			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
AT	5	5	4	2	5	5	4	2
BE	9	10	9	12	9	10	9	9
CH	4	4	2	1	4	4	2	1
CZ	14	14	14	10	11	11	9	8
DE	60	55	52	46	60	55	49	46
DK	5	5	4	3	5	5	4	3
ES	37	35	34	29	37	35	34	31
IE	5	5	5	5	5	5	5	5
IT	52	50	49	49	52	51	49	49
LU	0	0	0	0	0	0	0	0
NL	22	20	15	15	22	20	15	15
NO	0	0	0	0	0	0	0	0
PL	33	32	31	24	32	34	32	25
PT	5	5	4	3	4	4	4	3
SE	8	8	7	7	8	8	7	7
UKGB	51	49	42	42	52	53	49	39
UKNI	2	2	2	2	2	2	2	2
Total	**312**	**299**	**274**	**250**	**308**	**302**	**274**	**245**

The minor differences in assumptions are correlated to a later data extraction from PEMMDB for the NRAA, as well as other extractions (UK).

3.2.6 European cross-border capacities assumptions

Flow-based modelling: comparison of winter theoretical maximum import and export net positions of FB domains

In NRAA25, flows within the CWE region are modelled using flow-based constraints for the target year 26/27. Flow-based domains were set by RTE using the *Porygon* methodology and so differ from those used in ERAA24.

To compare the size of the flow-based domains, Figure 11 below represents the winter theoretical maximum import and export net positions for France enabled by RTE's and ERAA's domains (ERAA24 and ERAA25). Given that NRAA25 uses flow-based only on the target year 26/27, the comparison was made against ERAA24 TY2026 and ERAA25 TY2028 flow-based domains. To ensure a robust comparison, the same methodology was used by RTE to illustrate these metrics: AHC borders were included in the computation but with a net position fixed to zero. For the computation, data for

ERAA24 flow-based domains (resp. ERAA25) that was shared to LACs in April 2024 (resp. April 2025) during the flow-based validation process, was used by RTE. These values are useful to assess and compare FB domain size, but remain theoretical and do not reflect the level of exchanges that can be encountered in the simulations: this level can be in practice lower or higher depending on how AHC borders are considered in the computation.

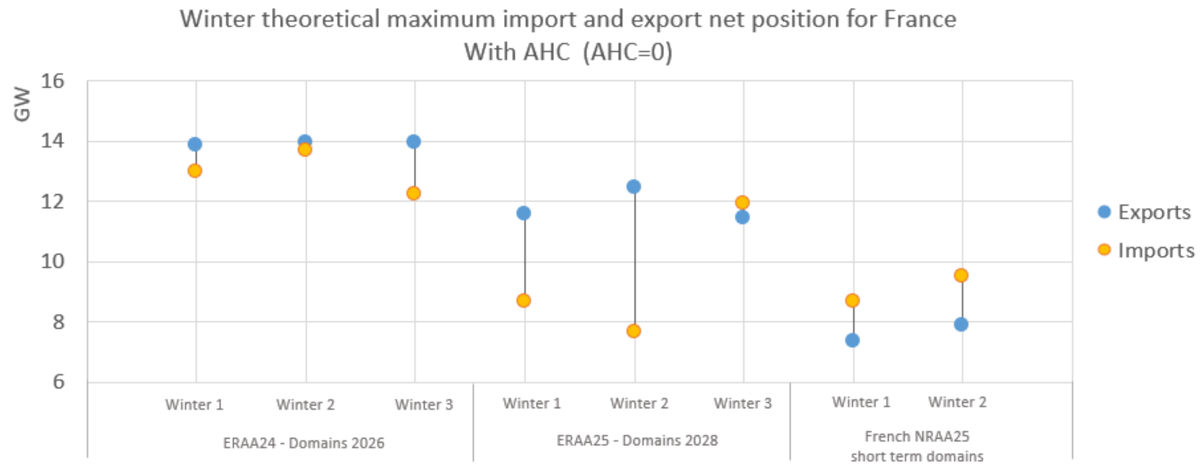

FIGURE 11 : COMPARISON OF WINTER THEORETICAL MAXIMUM IMPORT AND EXPORT NET POSITION FOR FRANCE IN RTE AND ERAA FLOW-BASED DOMAINS

The comparison shows that the maximum theoretical net positions for France derived from the RTE flow-based domains are lower than those obtained from the ERAA24 domains. However, they are closer to the ERAA25 domains, particularly regarding maximum import net position which fall within a comparable range. It should be reminded that one of the previously identified limitations of the ERAA24 flow-based domains was their excessive size: the ERAA25 domains are much smaller. Furthermore, as already mentioned, these metrics do not indicate the maximum exchange levels that can actually be achieved in the simulations: even if the ERAA flow-based domains display higher theoretical net positions than RTE domains, these levels may never be reached in practice. To complete this analysis, a comparison of the maximum achievable exchange levels in the simulations, especially during scarcity hours, was performed.

Comparison of maximum import levels for each French border during scarcity hours in France

This section compares the maximum import observed for each French border during scarcity hours in France, in NRAA25 and ERAA24 simulations for the target years 2026 and 2030. The maximum import per border in ERAA24 was derived from ENTSO-E data.

TABLE 27 : MAXIMUM FR IMPORT PER BORDER

Maximum import per border (MW)	NRAA25 2026/2027	NRAA25 2030/2031	ERAA24 2026	ERAA24 2030
FR-CH	1200	1200	1400	1400
FR-IT	2000	2000	2080	2160
FR-CORE	7465	7600	8509	10872
FR-UK	4000	4000	4000	4000
FR-ES	2700	4950	2900	5600
FR-IE	0	700	0	700
Maximum import across all borders[30]	**16700**	**20450**	**17616**	**23629**

Regarding cross-borders exchanges with Spain, Switzerland and Italy, maximum imports during scarcity hours are quite in line in NRAA25 and ERAA24 and correspond to the NTC values used in the simulations. Differences are due to capacity reductions that were set in NRAA25 to reflect the impact of phenomena (maintenance, limitations on national networks) that can lead to import limitations and are not explicitly modelled in market simulations.

Regarding maximum import levels with CORE:

- For target year 2026, the maximum import level from the CORE region reaches 8.5 GW in ERAA24 compared to 7.5 GW in NRAA25. These values are relatively close despite the use of different flow-based assumptions. This confirms that even if net positions derived from ERAA24 domains are significantly higher than those of RTE domains, they are in practice not reached in the simulations during scarcity hours.
- For the target year 2030, flows between France and the CORE region are modelled using NTC approach in NRAA25 while flow-based modelling is used in ERAA24. The maximum import level is 7.6 GW in NRAA25 compared to 10.9 GW in ERAA24. This level corresponds to the NTC value that was set in NRAA25 for the target year 2030/2031 (4.8 GW from DE and 2.8 fom BE). This value corresponds to the historical NTC value established for BE-FR and DE-FR borders (before the switch to flow-based), to which capacity increases for new projects have been added.

NTC sensitivity analysis for 2030/2031

For the target year 2030, the maximum import level in NRAA25 from the CORE region is 3 GW lower than in ERAA24. To ensure the robustness of the adequacy results obtained in NRAA25 and their sensitivity to NTC assumptions used in NRAA25, a sensitivity analysis was performed by adding 3 GW of additional exchange capacity between France and the CORE region in the NRAA25, evenly between Belgium and Germany. These additional 3 GW of exchange capacity between France and the CORE

[30] Imports cannot be fully synchronous, hence maximum import across all borders being inferior to the sum of maximal imports per border.

region were added pre-EVA (but post-EU capacity adjustment, *i.e.,* the reliability standard is fully respected in simulated countries).

In this new simulation, the maximum possible import from CORE is then in line with ERAA24 (10.6 GW). The analysis shows that increasing the exchange capacity with CORE has little effect on the French adequacy results. The French LOLE is slightly reduced by 0.2h and so the capacity gap identified for 2030/2031 remains unchanged. This can be explained by the fact that the contribution of Germany and Belgium to the French security of supply (average exchanges levels during scarcity hours) does not significantly change with an increase in cross-border exchange capacity, due to the European thermal capacity adjustment that was performed (see 3.3.3). Given the low impact on security of supply, we would not expect that simulations would result in significant changes in EVA decisions.

3.2.7 Summary – NRAA25 and ERAA24 assumptions' comparison

We summarize the comparison between NRAA25 and ERAA24:

TABLE 28 : GLOBAL ASSUMPTIONS COMPARISON

<table>
<tr><th colspan="2">Assumptions</th><th>NRAA25</th><th>ERAA24</th></tr>
<tr><td rowspan="4">French power system assumptions</td><td>Electricity consumption</td><td>2025 updated projections in line with national policies</td><td>PEMMDB24 (NRAA23)</td></tr>
<tr><td>Nuclear availability</td><td>2025 updated projections in line with EDF's latest evaluations (dispersion is addressed in section 3.3.2)</td><td>PEMMDB24 (NRAA23)</td></tr>
<tr><td>RES development</td><td>2025 updated projections in line with national policies</td><td>PEMMDB24 (NRAA23)</td></tr>
<tr><td>Thermal capacities (pre EVA)</td><td>2025 updated projections</td><td>PEMMDB24 (NRAA23)</td></tr>
<tr><td rowspan="3">European power system assumptions</td><td>Electricity consumption</td><td>PEMMDB24
and specific data for Germany and UK</td><td>PEMMDB24</td></tr>
<tr><td>RES development</td><td>PEMMDB24
with some adjustments</td><td>PEMMDB24</td></tr>
<tr><td>Thermal capacities (pre EVA)</td><td>PEMMBD24</td><td>PEMMBD24</td></tr>
<tr><td rowspan="2">Exchange capacity modelling</td><td>CORE region</td><td>RTE flow-based domains for TY 26/27
NTC assumptions for TY 28/29, 30/31 and 35/36</td><td>ERAA24 flow-based domains</td></tr>
<tr><td>Other cross-borders</td><td>PEMMDB24 for EU/EU NTC. FR/EU coherent with ERAA25 collection, with some capacity reductions for NTC with Spain, Switzerland and Italy based on historical observations</td><td>PEMMDB24</td></tr>
</table>

Eventually, NRAA25 and ERAA24 are both largely based on information reported by European TSOs in PEMMDB24 and globally share the same inputs. However, there are some differences in assumptions.

This section provides the elements justifying the choices made in the NRAA and therefore the differences between the two studies.

Regarding short-term consumption or RES capacities trajectories in France and a few other European countries, minor differences are linked to the NRAA being based on more recent data than the ERAA. Moreover, assumptions used in the NRAA consider the shift of 6 months corresponding to simulated overlapping years (2026/27; 2028/29; 2030/31 and 2035/36).

Differences regarding cross-border exchanges are explained by different calculations when computing flow-based domains in 2026/2027 and transfer capacities for later years. These differences do not impact significantly the adequacy results.

3.3 Methodological choices leading to divergence between NRAA25 and ERAA24

This section aims at an in-depth analysis of the main and most impactful methodological drivers for divergence between the French NRAA25 and the ERAA24:

- Climate database and modelling (3.3.1);
- Nuclear availability modelling (3.3.2);
- Thermal capacity adjustment in the NRAA25 (3.3.3);
- EVA modelling and risk-aversion (3.3.4).

3.3.1 Climate database and modelling

ERAA24 marks the transition to the PECD4 climate database, which is a positive improvement. This database covers 36 prospective years (3 climate models x 12 simulated years) while the previous climate database (used in ERAA23 and before), PECD3.5 was based on historical data spanning from 1980 to 2015.

As described in section 2.2.3, the climate database used by RTE is provided by the French weather and climate service, Météo-France, and includes 200 correlated scenarios over Europe of the projected climate conditions in 2025.

TABLE 29 : CLIMATE DATABASES PARAMETERS

Feature	NRAA25	ERAA24
Number of scenarios	200 correlated scenarios	36 scenarios (3 models x 12 years)
Data source	Météo-France	PECD4 database
Geographical scope	Europe	Europe

The large number of climate scenarios used by RTE allows for a broader understanding of climate variability and for a better probabilistic representation of climate scenarios, which is a prerequisite for robust adequacy analysis. The significant number of scenarios is essential: since adequacy risks represent a restricted number of years (as loss of load is a statistically rare event), and since a good understanding of adequacy issues require a high number of inadequate modelled years, a reliable security of supply analysis require a very significant number of modelled years and conditions altogether.

This is important for all power systems in Europe as weather conditions can considerably impact security of supply due to the development of variable renewable energy sources but also new electricity uses that will be increasingly thermosensitive (heat pumps…). **Accurately representing this last point is crucial for properly assessing security of supply in France, given the high thermosensitivity of French electricity demand.**

3.3.2 Nuclear availability modelling

The French power system is heavily reliant on nuclear availability. To take this sensitivity into account, in its national adequacy studies, **RTE uses extensive datasets that combine 200 weather scenarios with 60 nuclear availability scenarios (including extended maintenance shutdowns) and allow to capture a wide range of system configurations and enhances the robustness of its security of supply analysis**.

Differences between NRAA25 and ERAA24 nuclear availability modelling

Despite an average nuclear availability similar in both studies (near 50 GW in winter in ERAA24 vs 51-52 GW in NRAA25), the number of nuclear availability scenarios and their dispersion is different. In ERAA 24, only 15 scenarios are modeled compared to the 60 scenarios of RTE NRAA. Moreover, the ERAA modelling process only allows for dispersion due to forced outages which greatly limits the dispersion of scenarios, compared to the NRAA where scenarios consider forced outages as well as extensions of planned outages. On a yearly basis, the range of dispersion of nuclear production is more than 100 TWh wide in NRAA25 case, whereas it is only 3.5 TWh wide in ERAA's case. These differences in modeling lead to significant differences in the results in terms of adequacy.

The ERAA24 as approved by ACER features a proof of concept including 2 scenarios of nuclear availability for economic dispatch: high and low. RTE believes these results to be essential to grasp the complete impact of nuclear availability on France's security of supply, including in the Policy Target Scenario. For RTE, this proof of concept is an important first step towards improving the relevance of the security of supply analysis carried out in the ERAA. Nevertheless, RTE considers that ERAA's methodology still needs to evolve in particular (i) to reach the same order of variability in availability range as the French NRAA and (ii) to take into account a larger number of scenarios to improve the representativeness (the 2 scenarios studied in ERAA24 - high and low – could not be seen as such).

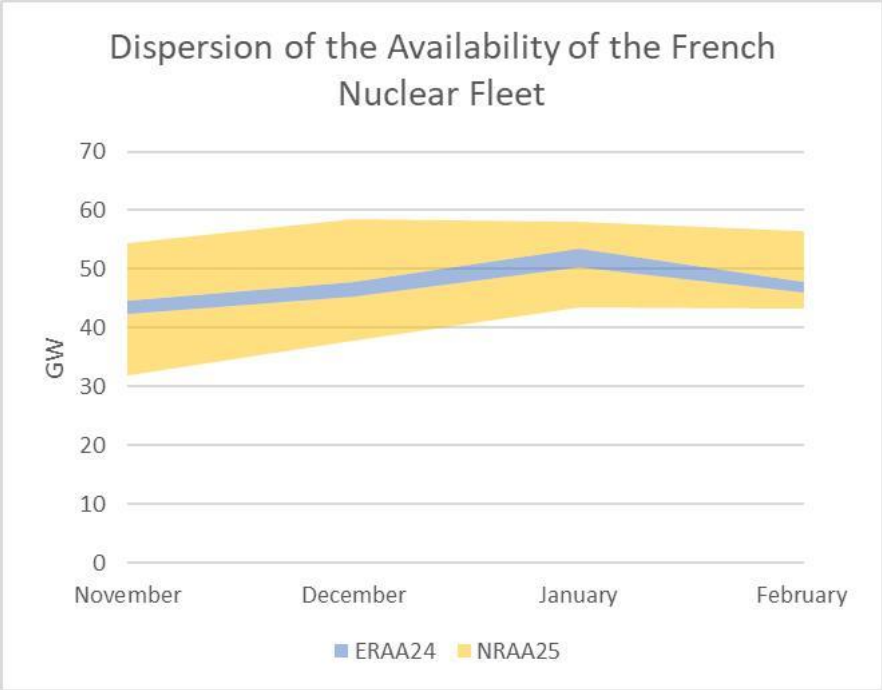

FIGURE 12 : MONTHLY AVAILABILITY RANGE IN WINTER IN NRAA25 AND ERAA24

Modelling the variability of planned shutdowns is essential

For security of supply purposes, nuclear maintenance planning (with production shutdowns for reloading) is designed to allow maximum availability during the winter, when residual load is highest (due to the important development of electric heating). Three types of planned shutdowns are scheduled every 12 to 18 months: reloading only, partial inspection, 10-years inspection with respective average projected durations of ~40, ~85 and ~180 days.

For each, history shows that **duration delays can last several days or even months** (> 1 year for worst cases) **due to:**

- **isolated technical issues** (such as the fall of the steam generator on Paluel 2 in 2016, the refurbishment of emergency diesel generators on Flamanville 2 in 2020, steam generator repairs…)
- or **different kinds of generic phenomenon** such as delay in the maintenance work following the COVID crisis in 2020, or the stress corrosion crisis in 2022-2023 which affected a large part of the fleet.

In addition to these planned outages for maintenance, **other planned shutdowns** appeared recently. These had not been originally included in the multi-year refuelling schedule, and were scheduled belatedly (shutdowns for ASN inspection at the end of 2016, securing the Cruas plant following the Teil earthquake in 2019,…), in addition to usual short forced-outages usually faced by thermal plants.

In the recent history, nuclear generation has evolved over a wide range, with **some low years** (279 TWh in 2022, 321 TWh in 2023, 335 TWh in 2020), **medium years** (361 TWh in 2021 or 362 TWh in 2024), and **high years** (416 and 417 TWh in 2014 and 2015, which without Fessenheim plant – closed in 2020 - would have been more than 400 TWh for a 61 GW fleet), see figure 12.

For these different reasons, RTE use a **probabilistic approach with a wide enough to be representative dispersion,** which also includes other variability causes (unforeseen shutdowns, variations in maximum available power due to fuel stretch or thermo-sensitivity). The **possibility of an**

occurrence of generic phenomenon as experienced during the stress corrosion crisis is also taken into account in the time-series, in accordance with feedback from stakeholders during the NRAA25 consultation process (occurrence of historically low generation levels iso-2022 in 5% of simulated years).

Here is a representation of the dispersion profile of nuclear production modeled for 2030 in the NRAA25 study and historical production over the last 15 years.

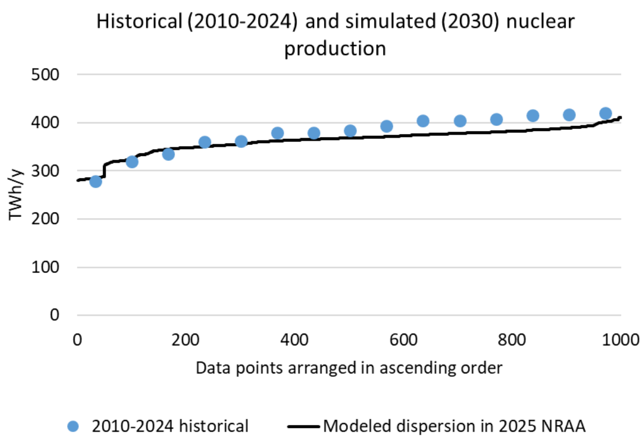

FIGURE 13 : HISTORICAL AND MODELLED NUCLEAR GENERATION

Considering availability records covering a wide dispersion provides an accurate representation of the risks weighing on France's primary source of production, without overestimating them. This translates into a wide generation capability range, from ~300 TWh to guard against new generic faults (comparable to the stress corrosion crisis in 2022-2023) to ~400 TWh to capitalize on the opportunity for a recovery in the reliability of the fleet, given that the fleet is aging and safety standards have increased since the years when it reached its production records.

In conclusion, a better and wider representation of nuclear availability may lead to a massive impact on security of supply, since the impact is mostly asymmetrical: a year with higher availability might not compensate fully the impact on mean LOLE of a year with low availability. Given the very significant role of the nuclear generation in the French power system, a full-on availability analysis and description is required to accurately evaluate the impact of nuclear outages on the French security of supply.

3.3.3 European thermal capacity adjustment

In NRAA 2025, the first stage once the initial "National Trends" scenario is built is to adapt European thermal power fleet to correct under- or overcapacities from 2030 on. This is done by ensuring that national Reliability standards in European countries are met, in order not to overestimate or underestimate their contribution to the French security of supply. Then, the Economic Dispatch (ED) tool is used to perform French system adequacy studies on different scenarios and sensitivities, including cases where the French power system is adapted (i.e., adding new capacity) to reach France's Reliability standard for MT target years. This allows to have a complete view of adequacy in different situations. The protocol to reach such state is described in 2.2.1.

The protocol is thus different between the two studies (see figure below). In short, the Policy Target Scenario of NRAA is one where all MS meet their RS if they enforce one from 2030 on[31], as opposed to the current Central Reference Scenario of ERAA, which features a Europe-wide without CRM situation.

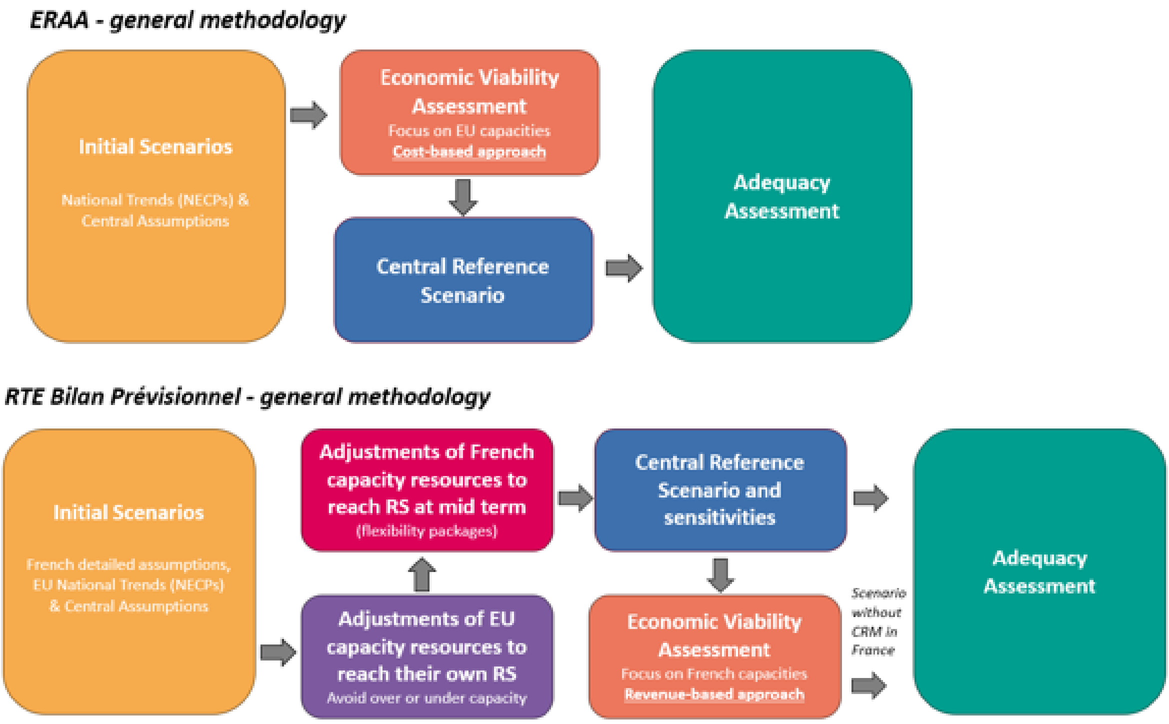

FIGURE 14 : BILAN PRÉVISIONNEL 2025 AND ERAA24 GENERAL METHODOLOGIES

This divergence in protocol explains the difference in EU-wide thermal adjustment between the ERAA's EVA and the French NRAA pre-EVA. This table corresponds to the net impact of the first arrow in the figure above in both studies (from "initial scenarios" to respectively "adjustments of EU capacity resources to reach their own RS" and "Economic Viability Assessment").

[31] Representing a perfect implementation of CRMs (*ie* succeeding to meet adequacy standards) in MS enforcing a RS.

TABLE 30 : COMPARATIVE NET IMPACT OF THERMAL ADJUSTMENT IN NRAA AND EVA IN ERAA

GW	NRAA25: Thermal adjustment to meet RS by 2030				ERAA25: EVA net impact on NRAA25 perimeter			
	26-27	28-29	30-31	35-36	2026	2028	2030	2035
AT	0	-1	0	0	0	0	0	0
BE	0	1	3	4	2	1	2	2
CH	0	0	0	0	0	0	0	0
CZ	0	-2	-3	1	-2	-3	0	3
DE	-7	-1	22	54	-6	-4	1	24
DK	0	0	2	9	0	0	0	2
ES	-5	-10	-16	-19	-9	-9	-9	-9
IE	-1	0	0	0	0	0	0	0
IT	-3	-9	-15	-15	-9	-9	-9	-9
LU	0	0	0	0	0	0	0	0
NL	-1	0	0	1	-2	-2	2	7
NO	0	0	0	0	0	0	0	0
PL	-1	0	-3	7	-7	-7	-3	4
PT	0	0	0	0	-2	-2	-1	0
SE	0	0	3	3	1	2	7	7
UKGB	-6	-12	-10	-3	0	0	0	19
UKNI	0	0	-1	-1	0	0	0	0
Total NRAA perimeter	**-24**	**-34**	**-19**	**41**	**-34**	**-35**	**-10**	**50**

The use of protocols following a different logic leads naturally to different results. The most important divergences between two studies can be explained as such:

- The French NRAA accommodates the heavy undercapacity of Germany, with a high commissioning of new capacity to reach an adequacy level close to Germany's Reliability Standard, which is both economically senseful and legally implemented.
- Oppositely, a significant part of thermal generation in Italy and Spain is decommissioned throughout the later horizons, to prevent accounting for overcapacity in the evaluation of France's security of supply, so that both countries reach their reliability standard as legally pushed.
- The differences in UKGB bidding zone are mostly due to the difference in initial assumptions of the studies (see 3.2.5).

RTE estimates the NRAA's protocol is better tailored to evaluate the need for a domestic CRM, in a world where neighboring countries manage to enforce their standards, however they reach it: the thermal adjustment hence allows to evaluate France's need for a CRM and an exact contribution of foreign countries to France's security of supply.

3.3.4 EVA

3.3.4.1 EVA general philosophy

The French NRAA's Economic Viability Assessment (EVA) is performed on the output of the thermal capacity adjustment ED model, as a counterfactual scenario able to identify capacities at risk without CRM, and the impact of their decommissioning or lack of commissioning on security of supply.

This process, which is different from ERAA's implies that the French NRAA's EVA does not address the same question as ERAA's:

- In the ERAA, the EVA is used to model Europe *if no further capacity mechanism was present anywhere in Europe (besides capacities already contracted)*
- In the French NRAA, the EVA is used to model *France if no further capacity mechanism was present in France, assuming other European Member States do enforce their reliability standards should they have one.*

The latter is, according to RTE, better suited to assess the risks on domestic capacities without foregoing heavy assumptions on foreign generation. This allows the NRAA to[32]:

- assume no overcapacity in foreign countries (meaning French capacities would be unviable because of them, and France's security of supply would rely on foreign unsure capacities);
- assume no undercapacity in foreign countries (meaning French capacities would rely for viability on a very uncertain export volume during foreign scarcity);
- And hence allow for an evaluation of the need for a CRM *in a situation where other MS do ensure their own security of supply, but do not cover for France's.*

3.3.4.2 EVA approach

The EVA of the French NRAA is based on decentralized decisions and on expected revenues, and accurately reflects the risk-related behavior of French market participants, as described by them during consultations conducted by RTE. On the other hand, ERAA is based on a theoretical representation of market functioning, relying on a centralized global optimization of investments and decommissioning at European level. The revenue-based approach is being pushed by the European regulator as a better way of ensuring consistency and mitigating the complexity of calculations[33].

3.3.4.3 Risk aversion modelling

Extreme variability of peak capacity revenues

As mentioned before, NRAA includes 1000 Monte Carlo years representing properly contrasting weather scenarios as very low temperature and/or low RES capacity factors as well as high dispersion in nuclear power availability. This implies high variability of tension of the system which is directly translated into high volatility of revenues for peak capacity.

Figure 15 below depicts the distribution of OCGT revenues among the 1000 Monte Carlo years in the 2030/2031 adequacy run and compares these yearly revenues to yearly fixed operation and maintenance costs. A very high majority of cases features revenues severely below yearly costs. Still,

[32] Moreover, performing the economic viability assessment exclusively in France leads to a more robust result, as this approach helps to avoid degeneracy issues (i.e., multiple equivalent solutions in terms of installed capacities across different bidding zones, but with a significant impact on the LOLE of each Member State). Such degeneracy issues cannot be fully excluded under the current ERAA protocol.

[33] ACER decision on ERAA 2023

those yearly revenues can reach extremely high values in years with severe scarcity. In short, the very long tail of this distribution is not considered as a reliable revenue source for risk-averse actors.

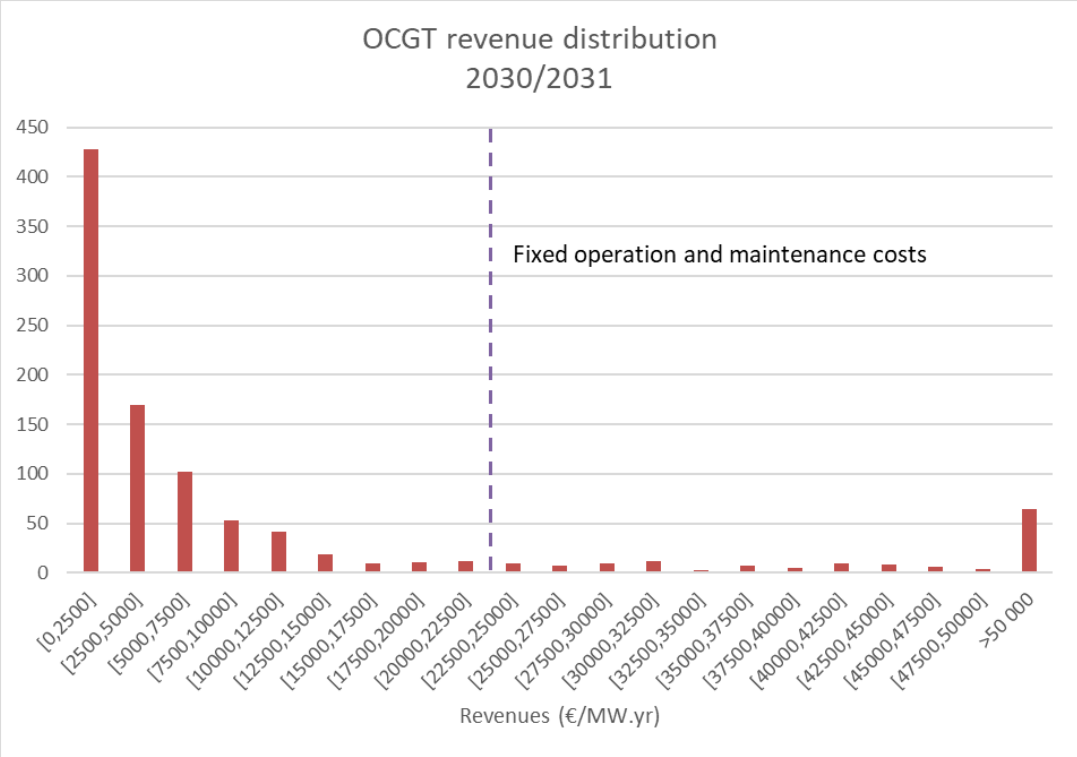

Figure 15 : OCGT Revenue Distribution in 2030/2031

Conditional value-at-risk

NRAA25 represents risk aversion of market player using *Conditional Value-at-Risk* approach. This approach is applied on endogenously simulated revenues.

The modelling of risk aversion through *Conditional Value-at-Risk* intervenes during the 2nd step mentioned in section 2.2.6, when aggregating the MC values of yearly revenues into one. Instead of computing the mean revenues, we consider that a small fraction (10% in the reference case) of those values are considered as highly unlikely and excluded by actors.

This modelling approach does not exclude all instances of elevated revenue, but rather acknowledges that market participants typically do not base their investment strategies on exceptional or non-recurring income. For example, the 2022 energy crisis led to unusually high revenues for certain actors due to extreme market conditions. However, such events are not considered representative of normal market functioning and therefore are not relied upon in long-term business planning.

The difference between the mean of the full set and that of the reduced set can be understood as *risk premium* in accordance with risk management practice of market players. This practice is consistent with academic literature[34] and relevant considering the very high distribution tail of revenues that is observed in simulations.

The approach used by RTE is consistent with feedback from stakeholders during public consultation, both in methodology and in the value used for CVAR. This is also consistent with the feedback from the recent questionnaire led for ERAA Repurposing on investor behavior[35], which points out that a significant number of actors do not take exceptional revenues into consideration when assessing business plans.

Comparison with ERAA24

This practice is different from ERAA's hurdle premium, which is based on an exogenous increase applied to the WACC. These values, as presented in Table 31 below, are computed exogenously based on academic work. In particular, they do not account for the simulated system risk induced by a rise of scarcity and the high revenue volatility.

TABLE 31 : HURDLE PREMIA USED IN ERAA

Technology	WACC	Hurdle premia	
		Decommissioning	Expansion
OCGT	6.17 %	3.5 %	6.0 %
CCGT	7.54 %	3.0 %	4.5 %
DSR	6.32 %-7.85 %	3.5 %	

For comparison purposes, we present the induced risk premiums on commissioning and decommissioning capacities, computed as such: for NRAA, the decrease in the mean revenues of excluding the top 10%, and for ERAA, the yearly difference in annuities due to the use of hurdle rates, both for operation costs and for capital expenditures in the case of commissioning.

[34] See Rockafellar and Uryasev, 'Conditional Value-at-Risk for General Loss Distributions'; Alexis Lebeau and others, 'Long-Term Issues with the Energy-Only Market Design in the Context of Deep Decarbonization', *Energy Economics*, 132 (2024), p. 107418, doi:10.1016/j.eneco.2024.107418; Favre, 'Designing Long-Term Contracts in Electricity Markets: Risk Allocation, Incentives, and Challenges for Power System Operation'.
[35] ENTSO-E, *Investor Survey: How Can ERAA Better Reflect Real Investment Behaviour?* (2025).

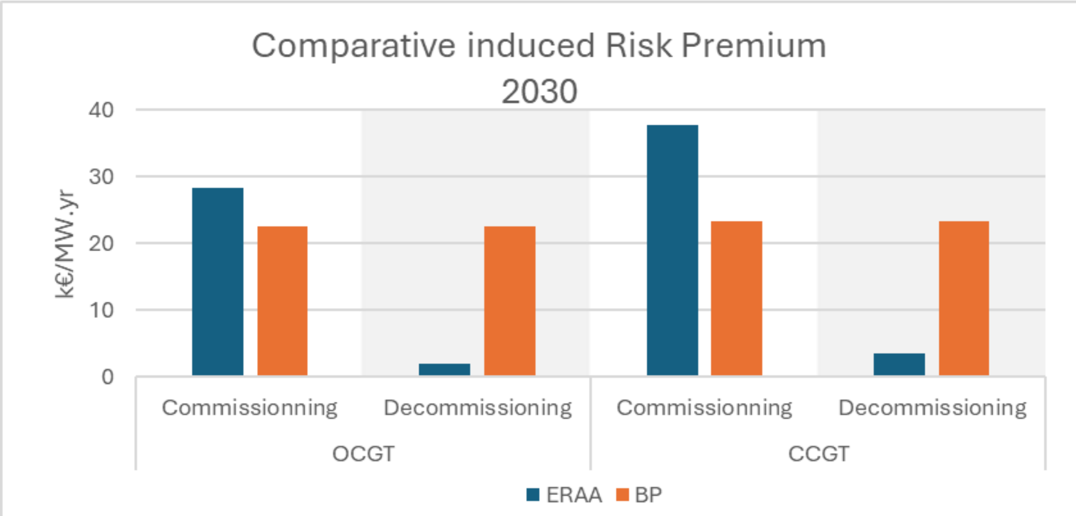

Figure 16 : COMPARISON OF RISK PREMIUM FOR EXPANSION AND DECOMMISSIONING OF THERMAL CAPACITIES

This comparison shows that the NRAA is, given the current hurdle premiums used in ERAA, more conservative than the ERAA for its EVA regarding commissioning decisions, but sees more risk for the decommissioning decisions. This vision is backed by actor feedback from the public consultation. This higher risk representation for existing capacities contributes to explain the difference with ERAA regarding the EVA decisions in France, and hence the post-EVA adequacy results. RTE's approach is backed by public consultation, including dating back from the implementation of the first French CRM, when both public stakeholders and private actors had made it abundantly clear that the *Energy-Only Market* is not sufficient to ensure the perennity of peaker units.

Forward pricing

The French NRAA, like ERAA, does not consider the possible hedging with forward products in its assessment, especially regarding peaker units, which are the focal point of EVA. The lack of liquidity in peak products does not allow for a risk coverage through forward markets for this type of assets. This vision is backed by actor feedback.

Sensitivity analysis

To assess the impact of risk aversion parameters, RTE has run a sensitivity analysis with a lower level of risk aversion, from a CVAR of 10% to a CVAR of 5%. This sensitivity with less risk averse actors (that could represent some forward hedging possibilities even if this is very unlikely as mentioned before) also points the persistence of adequacy concerns in France in 2030, even with the very thick revenues distribution tail, and confirms the robustness of the EVA analysis.

TABLE 32 : SENSITIVITY - RISK AVERSION - 2030

	LOLE (h)	EENS (GWh)
Reference case – CVAR 10%	19.8	73.8
Sensitivity – CVAR 5%	12.5	41.1

3.3.4.4 Potential price limit increases

The French NRAA does not apply price cap evolution and models a stable day-ahead price cap at 4000 €/MWh. This is consistent with the previous editions of the NRAA, as it was established during public consultation that investors are not likely to account for price cap increase in business plans. This is corroborated by the freeze on Harmonized Maximum Clearing Price in September 2022 and the subsequent evolution of methodology [36].

In ERAA2024, this computation is based on an exogenous post-treatment of ERAA2023 results, by creating 10-years price datasets and counting the occurrences of high prices. This methodology has been pointed out by ACER as likely to trigger cyclical behavior between ERAA editions. It reaches prices caps of 4500 €/MWh in 2026/2027; 5000 €/MWh in 2028/2029; 6000 €/MWh in 2030/2031; 6500 €/MWh in 2035/2036.

In spite of these differences, considering trajectories with Price Cap increases (based on current triggers) may not affect significantly results of the NRAA, given the Conditional Value At Risk approach used to represent risk aversion of market operators. Indeed, an important part of scarcity rents earned during hours where Price Cap is reached is not considered by market operators, however high is the price cap. This is also backed by the aforementioned ERAA Repurposing Stakeholder consultation: investors, for the part considering price spikes, do not model price cap increases, as they are deemed uncertain and subject to political risk.

To assess the impact of price cap increases in the EVA, RTE has run an EVA sensitivity with the same price caps as ERAA2024, still identifying adequacy concerns in 2030.

TABLE 33 : SENSITIVITY – ERAA24 PRICE CAP INCREASE – 2030/2031

	LOLE (h)	EENS (GWh)
Reference case – Price cap = 4000 €/MWh	19.8	73.8
Sensitivity – ERAA2024 Price caps	16.9	60.5

RTE has also issued a cross- sensitivity, including both ERAA24 price caps and lower risk aversion at CVAR 5%, still identifying adequacy concerns by 2030 as well.

TABLE 34 : CROSS-SENSITIVITY – ERAA24 PRICE CAP INCREASE AND CVAR5% – 2030/2031

	LOLE (h)	EENS (GWh)
Reference case – Price cap = 4000 €/MWh and CVAR10%	19.8	73.8
Cross sensitivity ERAA2024 Price caps and CVAR5%	10.9	34.0

[36] SDAC (2022), « 13 September 2022: No changes in harmonised maximum clearing price for SDAC from 20 September: it remains at 4,000 EUR/MWh »; ACER (2023), DECISION No 01/2023 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS of 10 January 2023 on the Nominated Electricity Market Operators proposal for the harmonised maximum and minimum clearing price methodology for the single day-ahead coupling.

3.3.4.5 CVaR revenues discounting

This subsection was initially provided to ACER as additional elements

For all cases studied above, the CVaR method consists of excluding the 10% (or 5% in dedicated sensitivities) highest revenues of the distribution when computing the yearly revenues mean value considered in commissioning or decommissioning decisions. The difference between the mean of all possible revenues and the mean of revenues excluding the highest ones may be then to be understood as the risk premium.

ACER raised the question of the impact on EVA of discounting instead of excluding the top revenues in the computation of final yearly revenues. In principle, this would reduce the risk aversion, increasing the revenues considered for commissioning/decommissioning decisions. To accommodate ACER's request of such a modelling, RTE includes this sensitivity with a discount on exceptional revenues above CVaR threshold instead of exclusion.

This sensitivity is implemented as follows: first, the N%-best quantile of revenues is computed, N being the CVaR threshold used (10% or 5%). Second, all revenues above are standardized to the level of the revenue of the last considered year, instead of excluded in the normal CvaR implementation. Figure 17 below illustrates the implementation of CVaR for the reference case (excluding highest revenues - left) and for the new additional sensitivity (discounting highest revenues - right) considering OCGT energy revenues in pre-EVA state in 2030/2031. The illustration is presented with a log scale Y-axis to accommodate a very "fat tail" distribution. The shape of the distribution highlights the importance of extreme high revenues with low probability on the mean value without CVaR considerations[37].

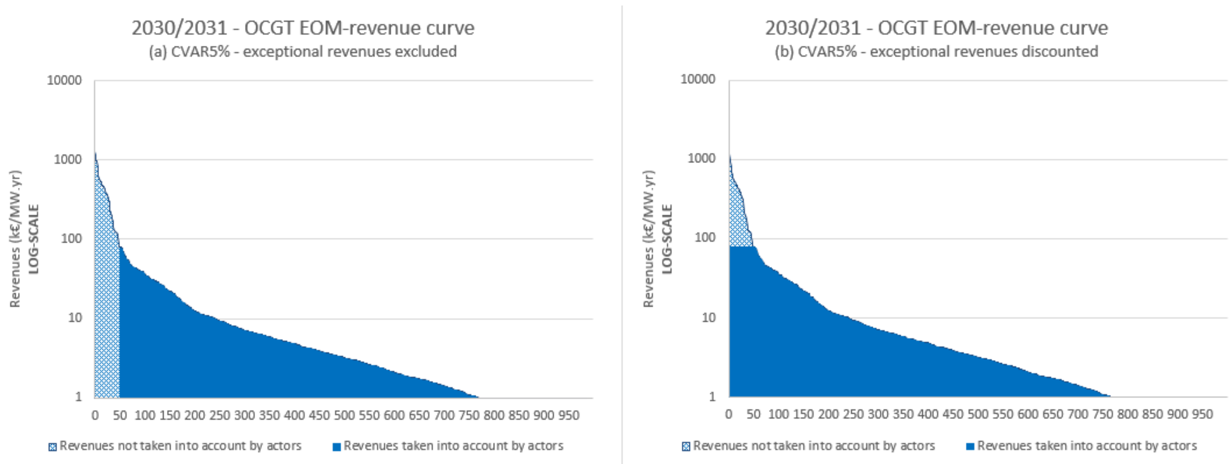

FIGURE 17 : COMPARISON OF DISCOUNT AND EXCLUSION OF EXCEPTIONAL ENERGY REVENUES IN 2030/2031 ON OCGTS, 1000 SAMPLES

This approach allows for considering the impact of exceptional revenues without having to extrapolate a discounting coefficient.

[37] In this particular case (OCGT in 2030/2031), the mean revenue is 28.4 k€/MW.yr, more than 6 times the median revenue (4.2 k€/MW.yr).

Revenues retained and excluded under different sensitivities

Figure 18 below presents a comparison of revenues and costs under different risk-aversion sensitivities in the pre-EVA scenario, showcasing the impact of risk aversion on revenues in 2026/2027 and 2030/2031 for two technologies (existing CCGT and OCGT). The figure illustrates well the impact of different settings on the risk aversion of operators, in particular the fact that the new additional sensitivity on discounting corresponds to the case with the less risk aversion. Indeed, in this sensitivity the revenues taken into account by actors are the highest ones.

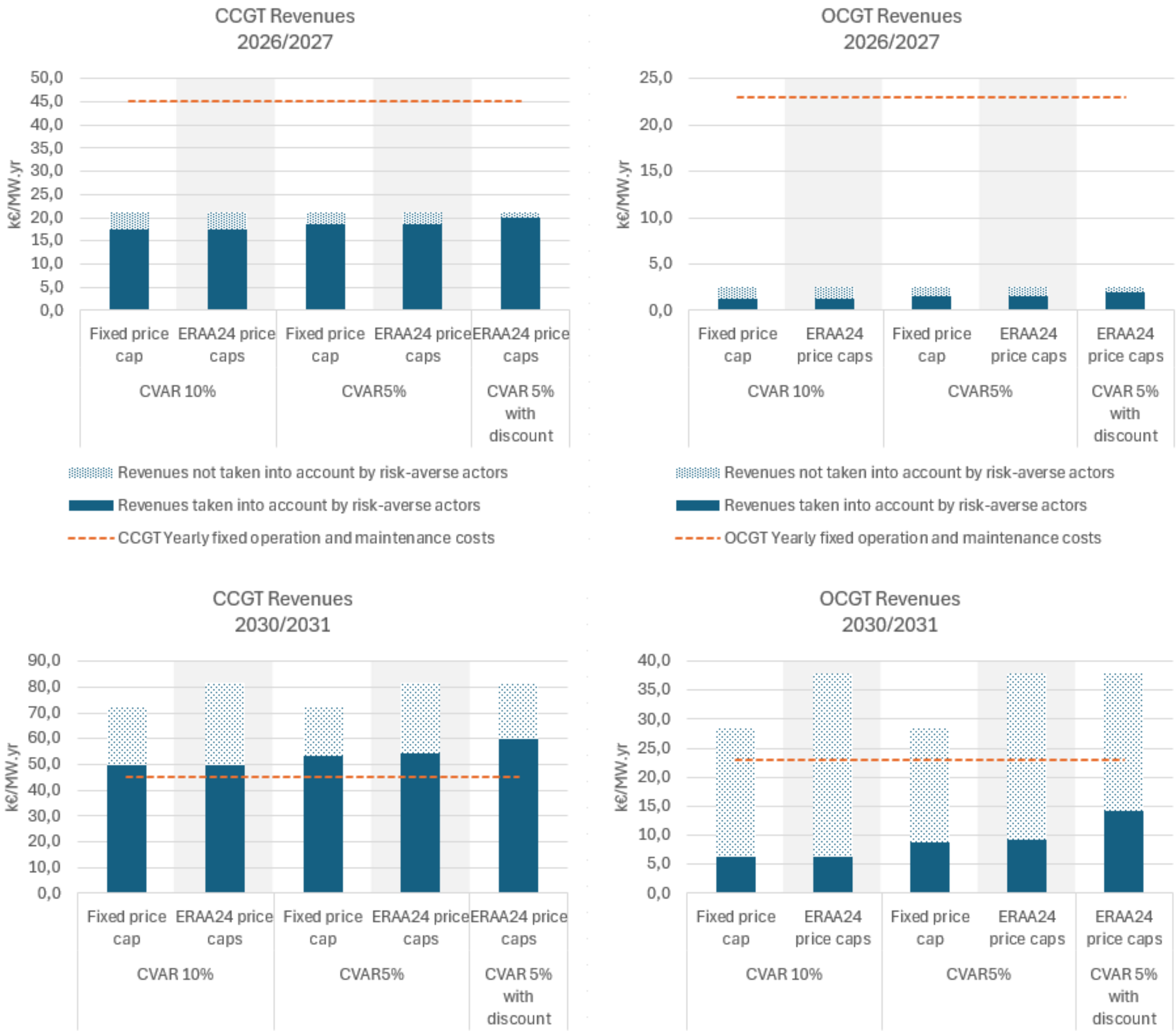

FIGURE 18 : YEARLY REVENUES (RETAINED AND EXCLUDED BY RISK AVERSE ACTORS) AND COSTS FOR OCGT AND CCGT

The higher scarcity situation in 2030/2031 leads to higher revenues for both CCGTs and OCGTs, part of these revenues being still highly related to exceptional situations, not accounted for by risk-averse actors. These low revenues in 2026/2027 and unsure revenues in 2030/2031 lead to the EVA decommissioning decisions.

Figure 18 also integrates FOM costs for comparison purposes. It should be noted however that EVA decisions cannot be directly implied by a simple comparison of yearly revenues and FOM costs. As explained in section 2.2.6, decisions are based on a Net Present Value, computed with sums of actualised yearly revenues and costs for the considered horizon.

EVA results for the additional stress-test sensitivity

The revenue discount method described was implemented in the revenue computation step of the EVA process (on all years of the horizon). As requested, it was implemented on the top of cross sensitivity included in the NRAA considering a CVaR 5% case and ERAA price caps. As such, this additional sensitivity should be considered as a stress-test because it combines all the parameters to reduce the risk aversion integrated in the EVA.

TABLE 35 : SENSITIVITIES IMPACT ON ADEQUACY INDICATORS IN 2030/2031

	Price caps	CVaR threshold	Revenues above threshold	LOLE (h)	EENS (GWh)
Reference case	Fixed	10%	Excluded	**19.8**	**73.8**
CVaR5% Sensitivity	Fixed	**5%**	Excluded	**12.5**	**41.1**
ERAA Price Caps Sensitivity	**ERAA2024**	10%	Excluded	**16.9**	**60.5**
Cross-Sensitivity	**ERAA2024**	**5%**	Excluded	**10.9**	**34.0**
Stress-Test	**ERAA2024**	**5%**	**Discounted**	**6.5**	**16.7**

The main takeaway is that applying in this stress-test: CvaR 5% with a discount on exceptional revenues instead of exclusion, as well as ERAA 2024 price caps does not change the conclusion of the NRAA regarding the identification of adequacy concerns in 2030/2031, confirming its robustness.

3.3.4.6 EVA-ED consistency

For the same computational reasons as in the ERAA, the EVA problem is reduced to a lower statistical complexity, switching down from 1000 to 20 Monte Carlo samples in the French NRAA. The model and the tool used are still the same. On ERAA side, the ED model features 36 WS × 15 FO and the EVA 3 WS × 1 mean FO, using a simplified model. The higher number of years used in the NRAA as well as model consistency ensures methodologically a better EVA-ED consistency than in both approved editions of ERAA.

The criteria that are used to select Monte Carlo samples are, in all Target Years, average LOLE in France, average revenues of OCGT in France, average post CVAR revenues of OCGTs in France.

Representativity of adequacy metrics

As LOLE is the driving selection criteria, the consistency of adequacy metrics is ensured by design. OCGT revenues, which are as well selection criteria, also hold up between 20 and 1000 Monte Carlo years.

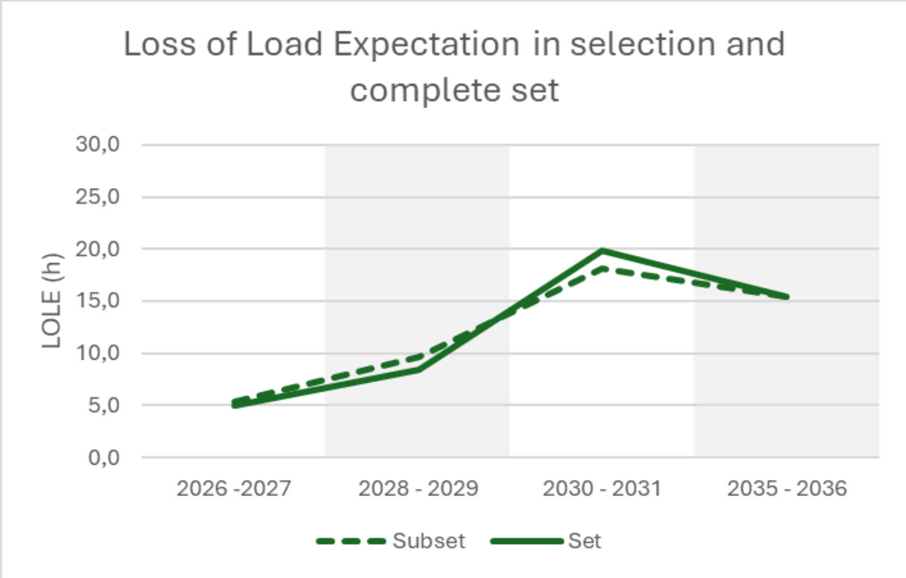

FIGURE 19 : IMPACT OF SELECTION ON LOSS OF LOAD EXPECTATION

This selection ensures, as best as possible given the reduction of 1000 to 20 years, that the EVA is not biased towards conservative decisions, as the revenue difference is minor.

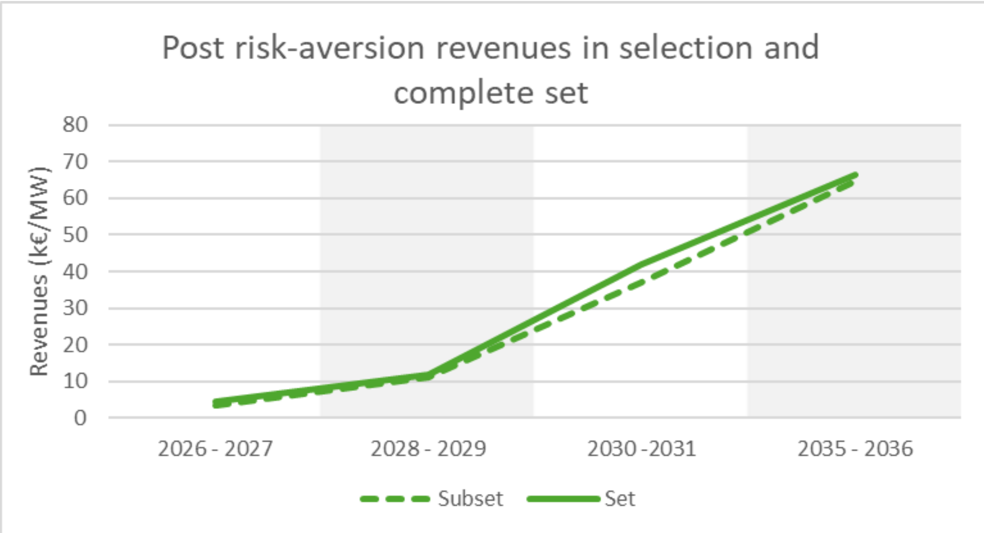

FIGURE 20 : IMPACT OF SELECTION ON OCGT REVENUES

Representativity of nuclear generation:

Even though nuclear generation is not aimed for in the selection of Monte Carlo samples, the high correlation of nuclear generation and adequacy ensures that the subset represents quite well the complete set. Figure 21 below compares the distribution of nuclear generation among the 1000 Monte Carlo years, and of the 20 selected Monte Carlo Years.

FIGURE 21 : COMPARISON OF NUCLEAR GENERATION IN MC SELECTION AND FULL SET (TWH)

In conclusion, selected Monte Carlo samples used in EVA protocol allow to properly represent the whole set of Monte Carlo scenarios used in adequacy analysis.

3.4 Conclusions

A complete one-to-one impact comparison of every divergence identified would hardly be manageable, since RTE's and ENTSO-E's studies rely on different models, using different tools. While the problem to solve is mostly similar, and the assumptions mostly aligned, the software and expertise difference between the two tools makes a complete divergence analysis a difficult task.

The French National Resource Adequacy Assessment *Bilan prévisionnel 2025* finds out that France is subject to *adequacy concerns* from 2026/2027 on and up to 2035/2036, pointing out the need for a Capacity Remuneration Mechanism as soon as winter 2026. This conclusion is not fully aligned with ERAA24, which does not identify an *adequacy concern* in 2030, but does in 2026, 2028 and 2035.

This report has managed to identify several assumptions divergences, mostly related to data updates and corrections in 2025. This leads to revised RES and nuclear capacity, load assumptions, as well as cross-border exchange capacities. **Still, the main finding of this report is that the ERAA/NRAA divergence in conclusions is mostly explained by 4 main methodological drivers.**

Firstly, climate modelling. The NRAA25 uses an extended climate database, featuring 200 weather scenarios issued by Météo-France. It is essential to fully grasp the state of French security of supply and enable the NRAA25 to have a finer representation of scarcity situations in France.

Secondly, the extended range of nuclear scenarios represented in the NRAA. RTE's extensive models, as well as public consultation feedback all point out to the importance of nuclear availability on France's and its neighbors' security of supply. The NRAA features 60 scenarios of nuclear availability which contribute to an extensive assessment of this driver on adequacy, while the ERAA, even in its proof of concept remains restricted to 3 scenarios.

Thirdly, NRAA and ERAA differ in the handling of European adequacy, the NRAA featuring a fit for purpose approach for evaluating the domestic need for a CRM. The NRAA does not allow relying on extensive foreign over- or undercapacity when assessing viability of French capacity. This view, allows the NRAA to assess a situation where the need for a domestic CRM is properly evaluated, allowing no freeriding from other MS in its CRM, and not basing France's security of supply on an unsure overcapacity by its neighbors. While understandingly not that of ERAA, this methodology allows the NRAA to focus more on the need of a domestic CRM, while the ERAA is more of an assessment of a completely CRM-free Europe. Fundamentally, the NRAA and the ERAA do not answer the same questions: they are complementary.

Finally, the approach to risk aversion in EVA is different between the two studies. The NRAA features an endogenous statistical approach to risk aversion, focusing on revenues. This approach is, according to actor feedback, consistent with industry practices following financial viability requirements. ERAA's exogenous approach and methodology lead to differences in risk premiums for existing and newly commissioned capacities, explaining the absence of decommissioning in ERAA's EVA. RTE provides evidence to show that risk is better represented by the Conditional-Value-at-Risk metric, and it is this approach that drives the EVA decommissioning results. RTE has led several sensitivities assessing that both risk-aversion parameters and price cap assumptions are not critical to the identification of adequacy concerns by 2030.

The NRAA and ERAA are complimentary in that they answer significantly different questions. While the ERAA as approved is an evaluation of the European-wide system in absence of any Capacity Remuneration Mechanism, the French NRAA presents an estimate of an adequate EU, and then evaluates in France the impact of not having a CRM. This protocol is, according to RTE, better suited to evaluate both need and dimensioning of a CRM locally.

Hence, the most impactful divergences between the two studies are mostly correlated to a more precise modelling of critical drivers on security of supply in France in the NRAA, as well as methodological elements on peaking units better fitted to evaluate the need and the dimensioning of a local CRM in France. RTE estimates these divergences to be legitimate in the carrying of its mission to evaluate the power system and adequacy risks on the medium-term.