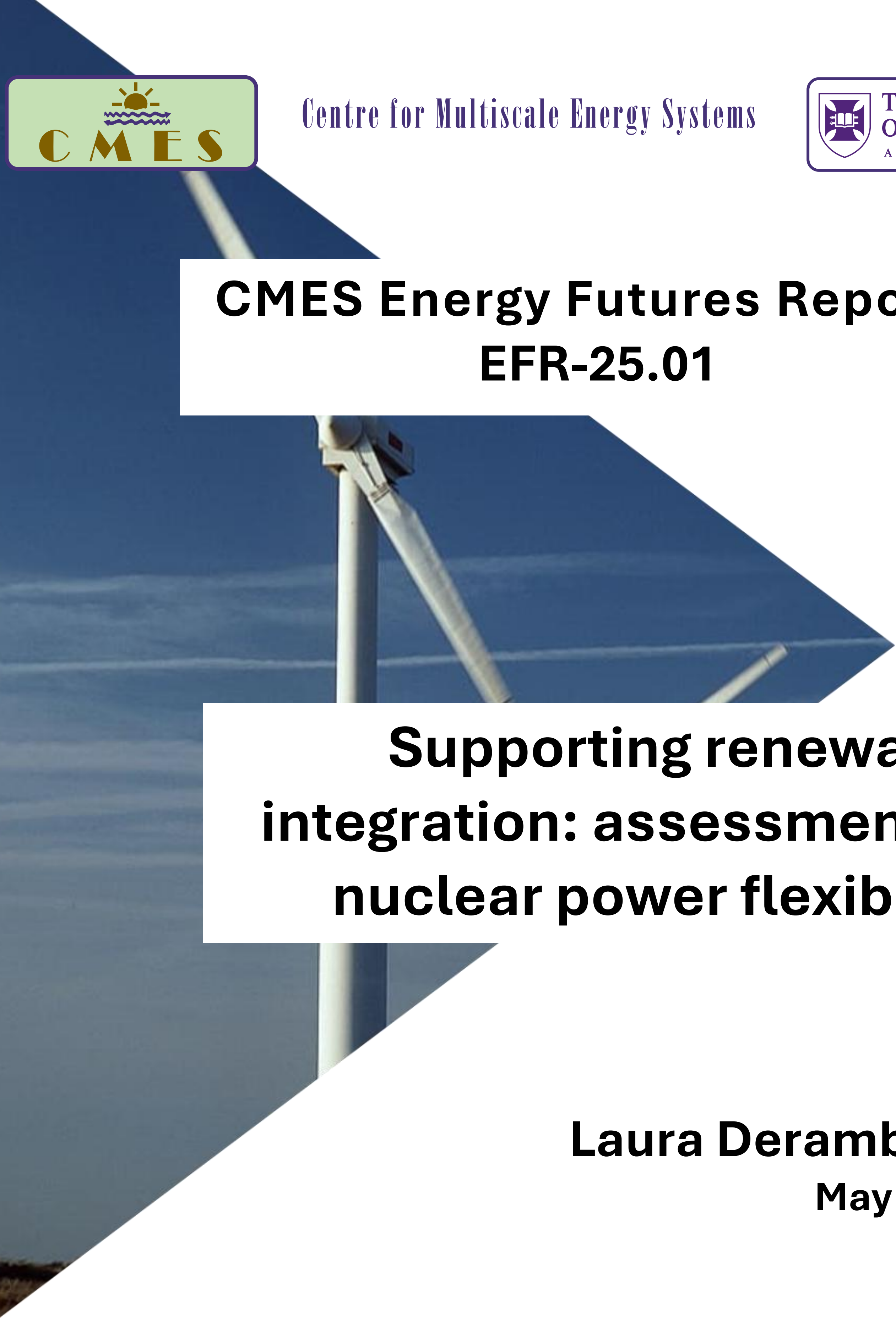

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Supporting renewable integration: assessment of nuclear power flexibility

Laura Derambure

May 2025

Foreword

This report was prepared by an outstanding French student and examines the flexibility of nuclear power generation in France. Although the study focuses on France, its findings are directly relevant to the energy transition currently underway in Australia.

France faces the challenge of adapting its predominantly baseload generation—represented by **around half a hundred nuclear reactors**—to the realities of an emerging renewable era characterised by rapid fluctuations in electricity supply and demand. A key question arises: can nuclear power operate flexibly enough to complement a high share of renewables? The answer is complex, as nuclear plants must operate within strict stability and safety constraints that become more restrictive toward the end of each fuel cycle.

Through comprehensive research, **Laura Derambure** demonstrated that flexible operation and partial curtailment of nuclear power are technically possible but operationally demanding, even when coordination is modelled assuming approximately forty-four reactors are available at a given moment. The study shows that while France's nuclear fleet can provide a degree of load-following capability, maintaining grid balance under high renewable penetration remains a major challenge. At the same time, France's nuclear generation contributes substantially to the stability of the European grid, often exporting surplus electricity to neighbouring countries such as Germany and Spain.

Laura Derambure extended her analysis to a hypothetical case of two nuclear power stations in Queensland. The results showed that such a limited fleet would not provide sufficient flexibility to follow daily variations in renewable generation. This limitation is not unique to nuclear power—coal-fired plants face similar operational challenges—but nuclear systems require particular care and continuity in their operation.

These findings do not imply that nuclear power cannot play a role in Australia's energy future. Rather, they suggest that conventional nuclear technologies would be best suited to applications demanding continuous, high-load supply, such as desalination plants, aluminium smelters, or hydrogen production facilities. Another promising avenue could involve coupling **baseload power** with **thermal energy storage** to moderate variability, as discussed in recent publications [1,2].

Overall, this professionally executed study offers a clear, technically grounded examination of nuclear flexibility. It provides valuable insight while avoiding the political bias often found in public discussions, making it a balanced and informative contribution to the broader discourse on energy transition in both France and Australia.

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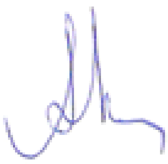

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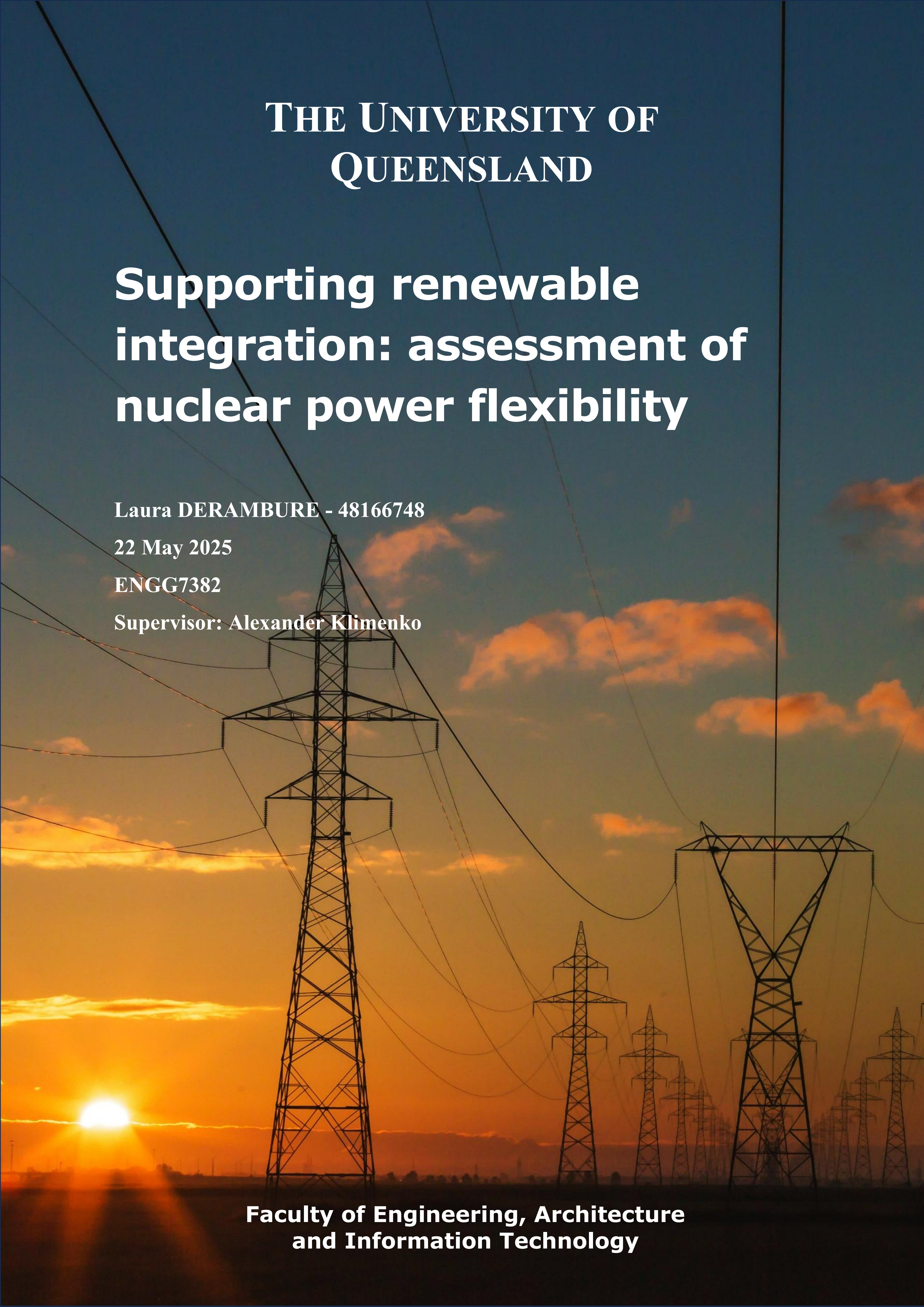

THE UNIVERSITY OF QUEENSLAND

Supporting renewable integration: assessment of nuclear power flexibility

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1. Abstract

This thesis explores the limits of nuclear power flexibility in supporting increasing renewable energy integration, using the French power system as a case study. Nuclear flexibility is assessed based on its ability to respond to variations in load, solar photovoltaic production, and wind production. Only these three production sources are considered. For nuclear power plants, only Pressurized Water Reactors (PWR) and European Pressurized Reactors (EPR) technologies are considered. It further examines the optimal sizing of the nuclear fleet in relation to the share of Variable Renewable Energy (VRE) curtailment, as well as the economic implications of this flexible operation.

First, a review of the literature on power system flexibility is conducted. On general power system flexibility, common definitions and classifications are identified. Methodologies and metrics used to assess flexibility needs, particularly in the context of increasing renewable energy integration, are reviewed. Then, common methodologies for evaluating flexibility provision by electricity generation sources are examined.

The literature review then focuses specifically on nuclear power flexibility. First, physical and operational constraints to nuclear flexibility are identified, then the most frequently used methodologies for evaluating nuclear flexibility are reviewed. The impacts of nuclear flexibility on renewable energy curtailment are analysed, along with the economic implications for both electricity markets and nuclear power plant operators.

The methodology to assess the hourly flexibility of nuclear power plants is then presented. First, the impact of renewable energy integration on net load profiles is studied using examples from France. Using data from Réseau de Transport d'Electricité (RTE), France's electricity grid operator, eight representative days in France are studied, under scenarios of increasing renewable penetration. For these eight cases examined, the main impact of renewable energy integration comes from solar generation. As expected, the net load profiles decrease, while the absolute value of the gradients, the standard deviation, and the coefficient of variability increase.

A Mixed Integer Linear Programming (MILP) model is developed to simulate a nuclear power system representative of France's current fleet across eight selected days that typify annual load variations. The model is first illustrated through a few simplified scenarios, followed by application to the full case studies. The results show that the main physical and operational limitation on an hourly time scale is the nuclear fleet size: if too small, the nuclear fleet cannot meet power demands on high-demand days; if too large, significant curtailment occurs during low-demand periods because of the minimum power output requirements (up to 49% of total daily renewable generation is curtailed at a 70% renewable share). However, the results also indicate that a fleet comparable in size to the current French nuclear fleet can ramp up and down quickly enough to accommodate renewable energy penetration levels of up to 70% (the highest level examined in this study).

The unserved demand not met by nuclear generation, along with the curtailed renewable output, is then analysed as a function of both the share of VRE and the size of the nuclear fleet. In each case, the average capacity factor of the reactors is also calculated. At constant VRE share, this study finds that the unserved power appears to decrease in proportion to the inverse of the number of reactors, while curtailment appears to rise linearly with the fleet size. Moreover, as both the VRE share and the nuclear fleet size increase, the average capacity factor of the reactors declines significantly, challenging the economic viability of oversized nuclear fleets in high-renewable scenarios.

Typically, a fleet size of 56 reactors is found not to be able to maintain an average capacity factor above 75% above 30% of VRE share.
The MILP model is then applied to studying France's net zero pathways, as well as Queensland nuclear proposals. The two most plausible scenarios from RTE currently under consideration are studied using the same model. Results suggest that, while nuclear remains a major source of electricity production in both cases, the fleet sizing tends to limit the need for significant flexibility manoeuvres. In a scenario resembling RTE scenario N1, nuclear is found to serve 59% of the netload and 75% of the netload in scenario resembling RTE scenario N2, indicating that significant additional dispatchable power plants will be necessary to complement nuclear. Curtailment is found to represent 6% of total renewable production in N1 and 4% in N2. The ability of nuclear power to adapt to net load conditions in the context of Queensland's electricity system is also studied, particularly in light of recent nuclear proposals put forward during the latest federal campaign. Exploratory results are presented and offer an initial indication of how nuclear generation could behave under Queensland-specific conditions. However, these insights remain exploratory and should be interpreted with caution, as further modelling would be required to tailor the model to the Australian case.
Finally, the limitations of the developed model are assessed by comparing simulated nuclear generation results, based on current levels of renewable energy production in France, with actual nuclear generation data under the same conditions. This comparison helps identify the discrepancies and gaps in the model's assumptions and performance. The comparison suggests that the model tends to overestimate the availability of nuclear reactors, which leads to discrepancies on days with high net load. On such days, the actual availability of the nuclear fleet becomes a critical factor in determining whether the system can meet demand, highlighting this limitation of the model. However, on days with low net load or high renewable generation, these discrepancies are less pronounced, suggesting that the model remains well-suited for exploring scenarios with increasing shares of variable renewable energy.

2. Introduction

2.1 Trends in electricity generation

To fight climate change, multiple countries worldwide have set the objective of achieving carbon neutrality in 2050. However, achieving this objective requires reducing their use of fossil fuels, including in electricity production as it represents a significant share of fossil fuel utilization and CO2 emissions. Consequently, renewable energy sources are being increasingly developed, and renewable electricity represents a growing share of global electricity generation. In parallel, electricity consumption patterns are also evolving, with a growing number of systems being electrified to substitute fossil fuels, and the electricity consumption being more and more controllable. Amidst this evolving and growing electricity demand and the shift in electricity production, the electric system faces new challenges while having to maintain high reliability.

In the electric system, electricity supply and demand must always be balanced to prevent blackouts. However, as the electric load constantly fluctuates, the electricity supply must constantly adapt. Additionally, some renewable energy sources, such as solar, wind and run-of-river hydropower, are not dispatchable, meaning their electricity production is not controllable. The intermittency and the variability of these renewable sources add to load fluctuations, creating imbalances between the supply and the demand that the rest of the electric system must compensate for.

2.2 What is flexibility?

This ability of the electric system to accommodate for the variations in the residual load (the load which is not supplied by variable renewable energy (VRE) sources) is called flexibility. This flexibility is required across multiple time scales (variations in energy consumption from one year to another, seasonal variations due to weather, hourly fluctuations during the day, last minute forecasting error in demand or supply, second or millisecond imbalance that need compensation). The time span of various electricity markets reflects the different flexibility timescales. In the National Electricity Market in Australia, for instance, the spot electricity market operates on a 5-minute timespan. Shorter instabilities are addressed by the Frequency Control Ancillary Services (FCAS), which are designed to respond to frequency instabilities over 5 minutes, 60 seconds, and 6 seconds.

Multiple sources contribute to power system flexibility. The most obvious one is the flexibility provided by dispatchable means of production, but flexibility can also be provided by demand-side management (controlling the load), energy storage, or the curtailment of VRE sources. The choice and the sizing of the flexibility solutions depends on the time scale and the amplitude of flexibility needed, which depends on the already existing electric mix, the share of renewable energy it integrates, and the dispatchable means it uses.

2.3 Case studies: Flexibility provision in France and Australia

France currently generates most of its electricity, slightly more than 60%, from nuclear power plants, with about 25% coming from renewable sources, 10% from gas, and 5% from coal and oil. The country has set the objective of expanding its renewable energy capacity, targeting 197 TWh of electricity from VRE (such as solar, wind, and hydropower excluding pumped-storage) by 2030 and to reach net-zero by 2050, as outlined in the latest National Energy and Climate Plan (NECP) (2024). To support this transition, nuclear power will continue to represent a large share of the production of electricity in 2030. However, looking further ahead, most French nuclear reactors are ageing, and many of them will be phased out by 2050, to reach between 16 and 24 GW of historical nuclear reactors in 2050. Decisions regarding how many reactors will be phased out and whether to construct new nuclear reactors need to be made. Six net zero scenarios for 2050 have been studied by France's electricity grid operator, Réseau de Transport d'Electricité (RTE). These scenarios range from a complete transition to 100% electricity generation from renewable sources by progressively phasing out the nuclear reactors, to a scenario with 50% of the electricity generation from renewable sources and 50% from nuclear power plants, necessitating a fast development of new nuclear, with new EPR reactors as well as Small Modular Reactors (SMR). All the scenarios plan on an increase of the electricity consumption of 35%. Considering the strategy developed in the last NECP, the scenario privileged seems to be either 26% nuclear / 74% renewable (with 8 additional reactors and 16 GW of historical nuclear for a total of 29 GW of nuclear capacity) or 36% nuclear / 64% renewable (with 14 additional reactors and 16 GW of historical reactors for a total of 39 GW of nuclear capacity). In both scenarios, flexibility provision becomes a cornerstone of system reliability due to the high share of VRE. Nuclear power remains the main source of dispatchable generation, complemented by hydroelectric pumped storage (STEP), newly developed low-carbon thermal capacity, cross-border imports, demand-side response mechanisms, and various forms of energy storage.

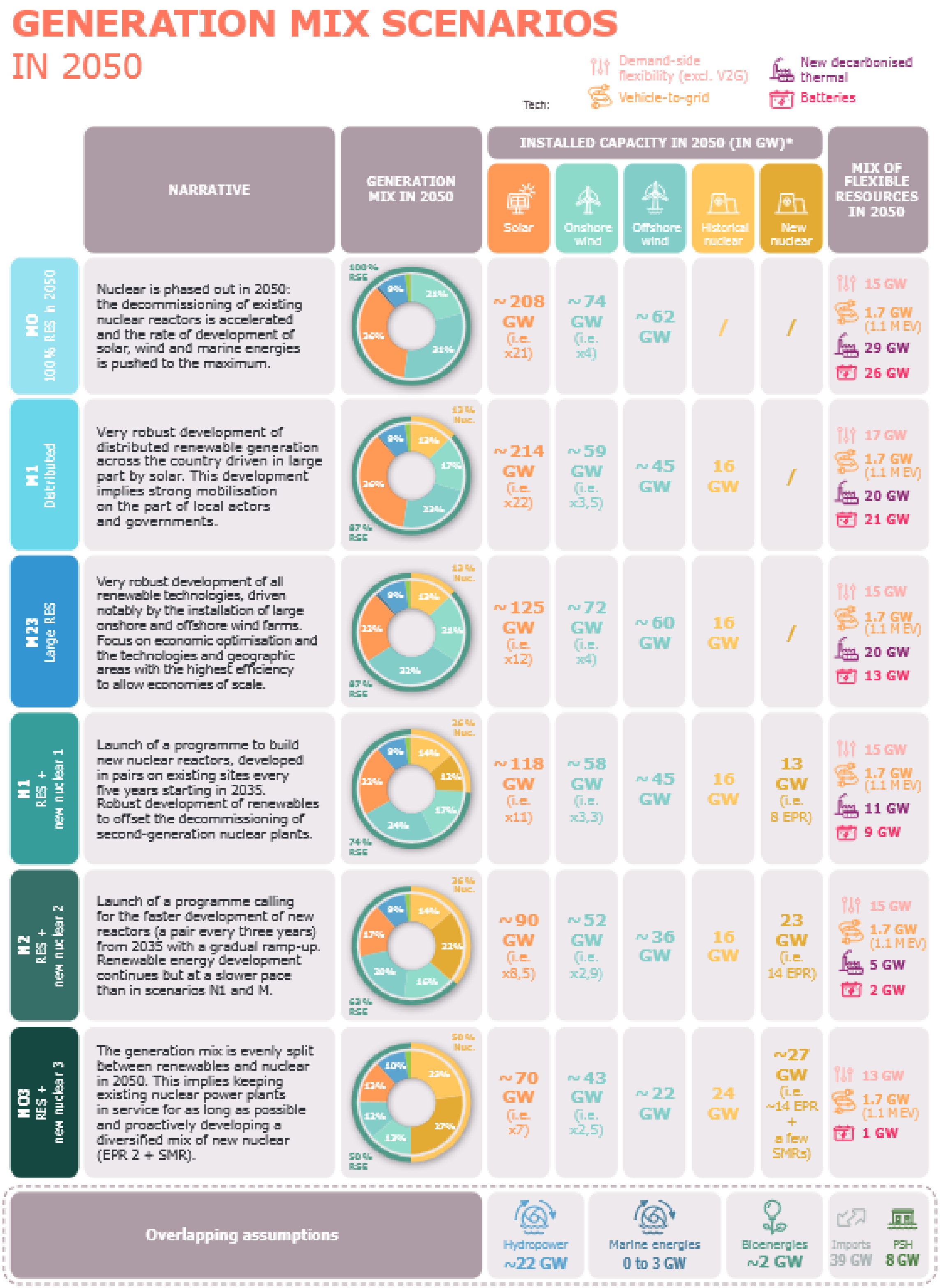

Figure 1: Energy mix scenarios as envisaged by RTE

Australia is also committed to reaching net-zero emissions by 2050; however, it is pursuing a completely different approach. As shown in the Electricity and Energy sectoral plan of the Department of Climate Change, Energy, the Environment and Water, key technologies to decarbonize the electricity sector include renewable energy, gas with carbon capture, hydrogen and storage. As for nuclear, Australia has historically opposed its use for civil power. However, the debate on its potential role in supporting the energy transition, especially in states that still need to get rid of coal, is gaining momentum. In the last federal elections for instance, the liberal party proposed to install two reactors of 1.4 GW each to replace coal power plants in Queensland. Each state and territory have the autonomy to shape its own energy policy. While Queensland and Victoria remain heavily dependent on coal, both have set ambitious targets for their share of renewable energy by 2035. Meanwhile, South Australia has already reached a 70% share of renewables. With the growing share of renewable energy and the decline of coal use, the National Electricity Market (NEM) is expected to experience larger peaks in net load, increasing the need for flexibility providers, as illustrated in the figures below.

Figure 2 Capacity, NEM (GW, 2009-10 to 2049-50, *Step Change*)

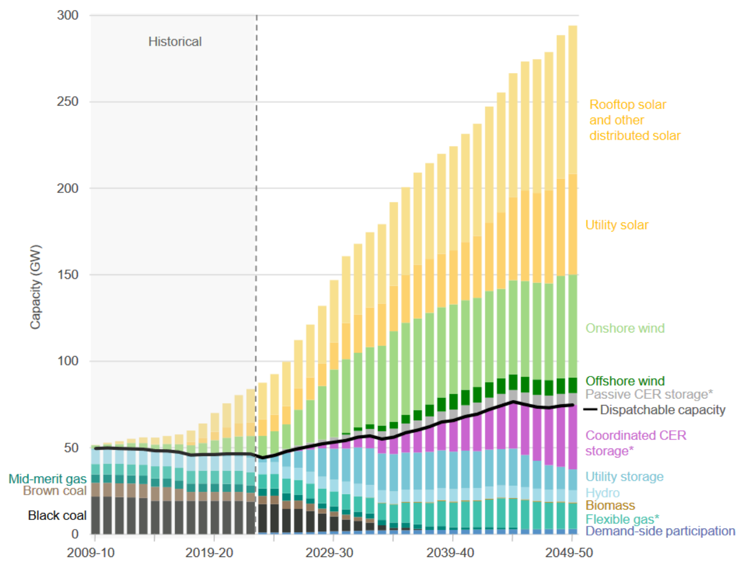

Figure 23 Gas-powered generation offtake, NEM (TJ/day 2014-15 and 2039-40, *Step Change*)

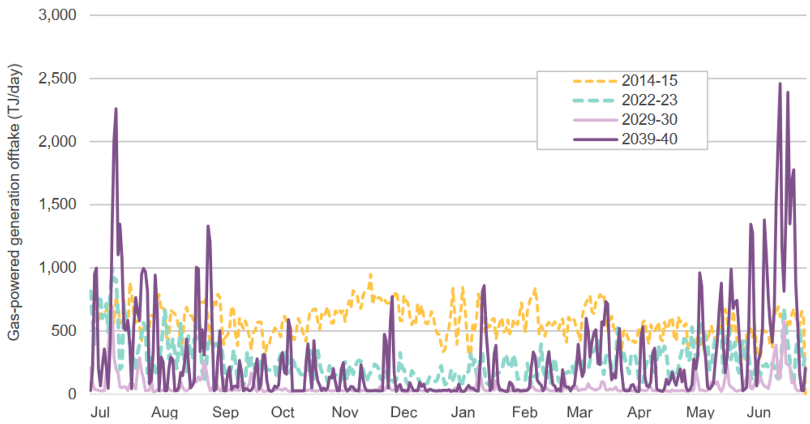

Figure 2: Installed electricity generation capacities in the NEM and resulting variations in the gas-powered electricity generation profile as foreseen by the AEMO.

2.4 Research gap

Although traditionally considered inflexible, nuclear power is one of the dispatchable means now increasingly considered for its potential participation in power system flexibility provision. As countries examine various strategies to progressively decarbonise their electric mix, assessing the limits of nuclear flexibility, its ability to support this transition, and whether to reduce, maintain or expand its role, is becoming increasingly important.

2.5 Research questions

This thesis aims to investigate the power system flexibility provided by nuclear power under increasing renewable energy penetration scenarios. It aims to answer the following research questions:

- What are the maximum shares of renewable penetration that nuclear alone can support?
- Under various increasing share of renewables in electricity generation scenarios, what are the optimal sizing requirements for nuclear to preserve system balance?
- How do power curtailment and nuclear reactor profitability evolve with nuclear flexible use?
- How do the French energy mix scenarios align with the findings in this study?
- How about Queensland nuclear proposals?

2.6 Expected outcomes

The expected outcomes are insights into the limits of nuclear flexibility for supporting increasing renewable electricity penetration, and on the optimal sizing of nuclear to limit renewable electricity curtailment. These insights are expected to enable to assess the flexibility gaps of the nuclear production in different mix scenarios aligned with the net-zero pathways of France, as well as give some insights on the flexibility provided in Queensland nuclear proposals.

2.7 Scope

Only the flexibility of nuclear in an isolated system will be assessed. For nuclear power plants, only Pressurized Water Reactors (PWR) and European Pressurized Reactors (EPR) technologies will be considered. Small Modular Reactors (SMR) will not be included. The geographical scope will be limited to France as an isolated system. Other electricity sources than intermittent renewables (solar power and wind power) will not be considered (except for hydropower when mentioned). Policy impacts or regulatory frameworks will not be considered either, as the report will focus purely on the technical and economic aspects of flexibility and system stability.

2.8 Overview of the document

The rest of this document is structured as follows:

- A literature review, first focusing on general power system flexibility and specifically on nuclear flexibility in a second time (section 0)
- The presentation of the methodology used to answer the research questions (section 4)
- Explanation of simplified results to illustrate how the model works (section 5)
- Presentation and discussion of general results (section 6)
- The application to France's net-zero scenarios (section 7)
- The application to Queensland's nuclear proposals (section 8)
- A confrontation of the model with real production data (section 9)
- A conclusion (section 10)
- References (section 11)

- Appendices, including net load variations with increasing renewable energy share (Appendix 1), general results (Appendix 2) and application to France’s net-zero pathways (Appendix 3) (section 12)

3. Literature Review

3.1 Studying the flexibility of electric systems

This literature review aims to specifically examine literature's findings on the flexibility provided by nuclear power plants. However, to provide a better understanding of power system flexibility and the general methodologies used to study it, the first part of the review addresses the general topic of power system flexibility. The second part will specifically address nuclear flexibility. Considering that many studies have explored the topic of general power system flexibility since the early 2010s, this review focuses on most recent papers, published after 2020.

General understanding of power system flexibility

Definitions

Power system flexibility (PSF) has been defined in various ways across the literature. Kaushik et al. (2022) compiled a comprehensive list of definitions. The definitions they listed are presented in the table below. Overall, most definitions across literature share the concept of a power system's ability to support variations in residual load (defined as the load which is not already served by variable renewable energy production) and to maintain system stability.

Table 1: Definitions of power system flexibility

Definition of PSF
"The ability of a system to deploy its resources to respond to changes in net load, where net load is defined as the remaining system load not served by variable generation".
"Flexibility expresses the extent to which a power system can modify its electricity production and consumption in response to variability, expected or otherwise".
"The potential for capacity to be deployed within a certain timeframe".
"The ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons".
"The system's capability to respond to a set of deviations that are identified by risk management criteria through deploying available control actions within predefined timeframe and cost thresholds".
"Operational flexibility is defined in terms of power capacity (MW), ramp rate (MW/min), i.e., the ability to increase energy production with a certain rate, and ramp duration (min), i.e., the ability to sustain ramping for a given duration".
"The general characteristic of the ability of an aggregate set of generators to respond to variations and uncertainty in net load".
"The ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant time scales".
"Readiness of power system network for higher shares of variable RE".

Despite the variety of definitions, there is a strong consensus around a few key ideas. First, the notion of net load is central. Net load represents the share of demand not met by VRE, and it must be supplied by dispatchable or controllable sources. Second, the time dimension is crucial: most definitions explicitly refer to the speed or timeliness with which a system or asset must respond.

Flexibility Across Different Timescales

Power system flexibility is required and provided over various timescales**.** Several papers, including the review of Kaushik et al. (2022), and the review of Heggarty et al. (2020), divide flexibility provision into different time intervals. While they do not all agree on the exact definitions of these intervals, the general breakdown is as follows: on the scale of seconds to an hour, rapid deviations occur, compensated for by capacity reserves known as regulation reserve. Kaushik et al. (2022) underline that the 15 min time horizon is important to assess the flexibility provision to preserve supply-demand balance. On the scale of an hour to a day, forecasting errors in load or supply can create instabilities, which are managed on the supply side by the most responsive production methods, known as "balancing" or "load following". As noted by Kaushik et al. (2022), generator commitment planning is carried out on an hourly basis, which highlights the relevance of using a one-hour time horizon in this study. On an hourly scale, Kaushik et al. also emphasize the importance of a six-hour time horizon, as most power plants can start up or shut down within that window. Beyond this short-term flexibility, net load is influenced by cyclical patterns, daily routines, and seasonal weather variations. On the supply side, these fluctuations are managed through unit commitment based on the merit order at the daily level, and through long-term investments in new capacity.

Table 2: Time scales of power system flexibility

Time scale	Variability sources and solutions
Seconds to an hour	Variability sources: incidents, weather variations, Solutions: reserve for frequence stability
An hour to a day	Variability sources: daily variations (load, renewable generation) Solutions: unit commitment, load following
Days, weeks, seasons	Variability sources: weekly variations and seasonal variations (load, renewable generation) Solutions: unit commitment, load following

Metrics for power system flexibility

Once power system flexibility is defined, the next question is how to assess it. With increasing renewable integration, many papers provide metrics and methodologies to evaluate the flexibility needs of power systems.

System wide flexibility metrics

Throughout their literature review, Kaushik et al. (2022) listed several flexibility metrics at the entire electric system scale, including periods of flexibility deficit, expected unserved ramping, insufficient ramp resource expectation, ramping capability shortage expectation, and expected flexibility shortfall. These metrics are multiple and provide various insights on power system flexibility, and the choice of metrics depends on the methodologies chosen to assess flexibility needs. Their definitions as well as usages are presented in the table below.

Table 3: Metrics of power system flexibility

Name	Definition	Usage
Periods of flexibility deficit (frequency)	*"It measures the number of instances when there is a deficit*	Highlights frequency of flexibility shortages but does

	of power from available flexible resources".	not quantify the magnitude of deficits; only frequency.
Expected unserved ramping (EUR) (MW/h)	*"It indicates the total magnitude of deficit of net flexibility".*	Quantifies severity of flexibility shortages, but does not show timing of events
Insufficient ramp resource expectation (IRRE) (probability)	*"A probabilistic method is used to determine the likelihood of flexibility deficit over a variety of time horizons".*	Captures uncertainty and risk, gives a probability, but not easy to convert in specific action.
Ramping capability shortage expectation (probability)	*"Similar to IRRE, this metric is capable to assess the probability for which the net load variations are not covered by the system's ramping capability".*	Captures uncertainty and risk, gives a probability, but not easy to convert in specific action.
Expected flexibility shortfall (MW)	*"This effectively measures the conditional expectation of load loss due to right arrow insufficient flexibility".*	Integrates frequency and severity.
Flexibility envelope (MW)	*Identify the flexibility needs as "95% of the probability distribution function of VRE intra-hourly deviation from forecast"*	Simple and intuitive representation of short-term reserve needs by accounting for forecast uncertainty of VRE Only useable for timescales shorter than a day.

Load variability metrics

To assess the flexibility needs of a system, one must understand the variability of residual load. Several metrics can be used to measure the variability of the demand. Mladenov et al. (2021) for instance used the *"standard deviation of the hourly fluctuation of the residual load"*, the *"absolute annual minimum residual load"*, the *"maximum 24-hour range of residual load variation",* the *"maximum negative hourly gradient of the residual load"*, the *"maximum positive hourly gradient of the residual load",* and *"the number of hours per year when the residual load is lower than the absolute minimum total load".* Similarly, Mikulik and Jurasz. (2020) conducted an analysis of the Polish power system, using the standard deviation of the net load, as well as its coefficient of variability and its maximum and minimum values.
The metrics and the definitions are summarised in the table below:

Table 4: Metrics to assess load variability

Name	Definition
"Standard deviation of the hourly fluctuation of the residual load"	Measures the average magnitude of hourly changes in residual load over a given period.
"Absolute annual minimum residual load"	The lowest value reached by the residual load over the entire year.
"Maximum 24-hour range of residual load variation"	The largest difference between the highest and lowest residual load values within any 24-hour period

"Maximum negative hourly gradient of the residual load"	The steepest hourly decrease in residual load observed over the year.
"Maximum positive hourly gradient of the residual load"	The steepest hourly increase in residual load over the year.
"Number of hours per year when the residual load is lower than the absolute minimum total load"	The number of hours during which residual load falls below the minimum level of total demand
Coefficient of variability	The ratio of the standard deviation to the mean of the residual load

Generator flexibility metrics

In their literature review, Kaushik et al. (2022) listed several common metrics to model flexibility provision by electricity generators. These metrics include the minimum power at which generators can operate, ramping rates (either measured in MW or as a percentage of nominal power, as noted by Heggarty et al. (2020)), and start-up time. Additionally, Degefa et al. (2021) included other technical criteria such as recovery duration, ramp frequency, flexibility time, minimum up and down time, and controllability. These metrics are summarized in the table below:

Table 5: Metrics to assess generator flexibility

Name	Definition
Minimum operational power (MW)	Lowest power output at which the unit can stably operate.
Maximum operational power (MW)	Maximum power output the unit can deliver under normal conditions.
Ramp rate (MW/min or %Pn/min)	Rate at which a generator can ramp its power output.
Start-up time (min or hour)	Time required for the unit to go from off to minimum stable load
Recovery duration (min or hour)	Time between two load-following actions
Ramp frequency (/hour or /day)	Number of times the plant changes output within a time period
Service duration (min or hour)	Time over which the plant can maintain a given ramp rate
Reaction duration (min or hour)	Time delay from an activation signal to the time at which the power ramping begins
Flexibility time (min or hour)	The time period when flexibility is available
Minimum up time (min or hour)	Minimum time the flexibility unit can stay in operation
Minimum down time (min or hour)	Minimum time the flexibility unit can stay out of operation during service provisioning

Methodologies to assess flexibility gaps

Multiple studies have developed quantitative methods to evaluate whether flexibility needs are met under varying levels of VRE integration.

- Mladenov et al. (2021) conducted a statistical analysis of the net load based on the assessment of seven parameters that they defined to quantify flexibility needs. These seven parameters they used include the standard deviation of the hourly fluctuation of the residual load, the absolute annual minimum residual load, the maximum 24-hour range of residual load variation, the maximum negative hourly gradient of the residual load, the maximum positive hourly gradient of the residual load, and the number of hours per year when the residual load is lower than the absolute minimum total load. They evaluated these indicators for various levels of renewable penetration and established linear regressions to model all these parameters as functions of the installed solar and wind capacities. The study concluded that increasing the integration of VRE leads to more variability in the net load, and to increased backup capacity needs to cover it. They then used a probabilistic method to assess flexibility needs and gaps by analysing the statistical variations of the net load, including ramping rates. They were able to plot the cumulative distribution function of hourly capacity ramps. From this, they analysed the ramping rates of conventional generation means, and they were able to compute the Insufficient Ramping Resource Probability over these various time intervals.
- Heggarty et al. (2020) used a similar but different methodology, which consists in identifying flexibility requirements as 95% of the probability distribution function of VRE difference from forecast. They introduced two tools based on the calculation of the Fourier transform and its breakdown into various time intervals: the Flexibility Solution Modulation Stack and the Flexibility Solution Contribution Distribution. These tools are designed to show how different flexibility sources contribute to flexibility for different time intervals.
- On another hand, Olsen et al. (2020) used a completely different methodology. They took the net load and calculated the corresponding discrete Fourier transform and then separated the frequencies into several time intervals corresponding to minute, hourly, daily, weekly, and seasonal timescales. They then computed the inverse Fourier transform for each time interval and derived the corresponding ramping requirements. They then modelled various types of electricity generators, applying the metrics presented above to optimise the system by minimising total operational costs while respecting several constraints, such as balancing supply and demand at each timestep and meeting the flexibility constraints of each generator type. This methodology uses a Mixed Linear Integration Programming (MILP) model, which optimises unit commitment and helps assess when generation cannot balance the net load. This is a very common methodology for assessing the flexibility performance of power systems, typically used for short but not immediate timescales (ranging from tens of minutes to several hours), although it can also be applied to longer timescales.

These methodologies constitute interesting leads to assessing the flexibility of nuclear and gas power plants. A summary is presented in the table below:

Table 6: Methodologies

Reference	Methodology	Pros and cons
Mladenov et al. (2021)	Probabilistic method computing the Insufficient Ramping Resource Probability	Accounts for uncertainty, but does not capture complex generation flexibility constraints like recovery time
Heggarty et al. (2020)	Fourier transform based method	Allows flexibility analysis based on generator types but neglects complex generation flexibility constraints such as recovery time.
Olsen et al. (2020)	Unit commitment model using linear optimisation	Considers all generation flexibility constraints and provides precise unit commitment results, but is case study-based and does not include load fluctuation uncertainty

Overall, this literature review on general power system flexibility has made it possible to identify key definitions, metrics, and methodologies commonly used to evaluate flexibility needs and gaps within an electricity system. The main takeaways include:

- Metrics for assessing load variability, which will be particularly useful for analysing how load patterns evolve with increasing shares of renewable energy
- Metrics for characterizing generator flexibility, which provide a foundation for describing the technical constraints of nuclear power plants
- Widely used methodologies for assessing system flexibility, among which unit commitment optimization models stand out as the most suitable for evaluating nuclear flexibility, due to their ability to incorporate complex operational constraints.

These findings provide a foundation for the subsequent review of the literature focused specifically on nuclear flexibility

3.2 About nuclear power flexibility

This section of the literature review focuses on PWR and EPR reactors, as the objective is to apply the findings to the case study of France, where these reactors are currently in operation.

Considerations of nuclear power flexibility in literature

For many years, the flexibility of nuclear power has been overlooked. In most studies conducted before 2015, nuclear energy was either considered solely as a baseload power source or not considered at all, such as Genoese et al. (2012), Lannoye et al. (2011), or Huber et al. (2014). Even in more recent studies focusing on power system flexibility to foster renewable energy integration and studying renewable electricity curtailment, such as Pilpola and Lund (2019), nuclear power is still treated as a constant-output source, primarily used for baseload generation. However, as highlighted by Morilhat et al (2019), nuclear power plants in France regularly demonstrate load-following capabilities.

In recent years, more papers have begun exploring nuclear flexibility. They are examined in the following sections. First, key physical and operational constraints to nuclear flexibility are identified. Then, common methodologies to study nuclear flexibility are reviewed. Finally, results on its economic consequences and impacts on curtailment are discussed**.**

Principles and constraints of nuclear flexibility

To adjust their power output, nuclear PWR operators can control the absorption of neutrons to control the reaction rate of the nuclear reaction. To do so, they can either change the concentration of boric acid, a neutron absorber, in the primary circuit, or adjust the insertion of neutron-absorbing control rods. Usually, for flexible operations, control rods are preferred because they allow for more precision and speed (Nuclear Energy Agency, 2012). These two methods allow nuclear reactors to perform load following operations.

Stable time constraints

However, several constraints affect flexible manoeuvring. First, nuclear reactions are inherently complex and involve various chemical elements, each having different reaction speeds. Notably, Xenon 135, which is a significant neutron poison, is usually produced several hours after the beginning of the reaction and significantly affects the core's reactivity due to its influence on the reaction rate. Consequently, nuclear operators need to compensate for and consider this feedback effect, which occurs with a notable delay after operations. Special caution is required following a ramp-down operation, as this decreases the core's reactivity, while the xenon produced prior to the ramp-down continues to affect the core by absorbing additional neutrons, further reducing reactivity. To better control the reactivity in the core after ramping, nuclear power plant operators typically keep the power output constant for a few hours (at least 2), which allows them to better compensate for the reactivity changes due to xenon transients (Morilhat et al, 2019). Lynch et al. (2022) however note that this is a conservative practice done by the operators to simplify the operations but that this is not a technical limitation.

Ramp-up rate and ramp-down rate constraints

Moreover, the ramp-up and ramp-down rates are not only limited by how fast neutrons are produced and absorbed. A rise or a decrease in the core's reactivity indeed also creates an important change in the core's temperature. However, this creates thermal and mechanical stress on the pellet and the cladding of the control rods, as they are not made of the same materials and therefore have different thermal properties. To avoid breeches forming, nuclear plant operators must therefore respect limitations regarding ramping rates. PWR are typically designed to ramp-up and ramp-down at a maximum rate between 2% and 5.2% of the nominal power of the reactor per minute. This impacts the flexibility response on short timescales (minutes) but this is enough to not add any additional constraint on flexibility on longer timescales (hours), as the reactors can vary their power output from 20% to 100% in less than an hour with this ramping rate.

Constraints on the number of cycles

In addition to ramp-up and ramp-down rates constraints, there are also constraints on the number of ramp-ups and ramp downs a reactor can do per day. To avoid a premature aging of the nuclear reactors, the French nuclear power plant operator limits the number of cycles of a reactor (which corresponds to a power ramp-down followed by power ramp-up) at 2 per day (Morilhat et al, 2019).

Minimum power output constraints

Furthermore, the minimum power output of a nuclear reactor is constrained by where it is in its irradiation cycle. An irradiation cycle lasts between 12 and 18 months depending on how a reactor is used, before it must be refuelled. Throughout the irradiation cycle, the core's reactivity gradually decreases, which leads to the decreasing concentration of boric acid in the primary circuit. As a result, the margin for controlling the fission reaction rate using boric acid narrows over time. For this reason, the reactor's minimum power output rises as the cycle progresses. For the first two-thirds of the cycle, the minimum power remains at 20%, then it increases linearly until the end of the cycle to finally reach 100% (Morilhat et al, 2019).

Reactor outages

At the end of an irradiation cycle, every 12 to 18 months, nuclear reactors must be shut down for one month to be refuelled. This has a significant impact on the availability of the nuclear fleet. The reactor schedule is planned by the nuclear plant operator, who generally maximises the fleet availability when the demand is anticipated to be high, to maximise their profit.

A summary of the main flexibility constraints is proposed in the table below, using the generator flexibility metrics identified earlier:

Table 7: Summary of main constraints

Constraint	Description
Minimum operational power (MW)	20% of maximum operational power output during the first two-thirds of the irradiation cycle, then linear increase until reaching 100% of maximum operational power output
Maximum operational power (MW)	Depends on reactors
Ramp rate (MW/min or %Pn/min)	Maximum 5% Pn/min
Recovery duration (min or hour)	2 hours after ramping
Ramp frequency (/hour or /day)	Maximum 2 cycles per day
Outage	Minimum one month every 12 to 18 months

Methodologies to model nuclear flexibility

Studies utilise different methods to evaluate the flexibility of nuclear power plants, and not all of them account for the same flexibility constraints. Their approaches also vary depending on the timescale of the assessment.

On short timescales - ranging from seconds to minutes - both Mazauric et al. (2022) and Vajpayee (2020) used point kinetics reactor equations to model nuclear reactors' ability to participate in frequency control and load following for a few minutes. Point kinetics reactor equations constitute a model which is useful to study the time-dependent behaviour of nuclear reactors, as it can account for the feedback effects of the delayed neutrons, as well as other feedback effects such as the fuel temperature feedback effect (Doppler effect) or the moderator temperature feedback effect. The model captures fast time-dependent behavior of neutron population through the prompt neutron generation term, which is on the order of microseconds. However, it is not able to account for spatial effects. Here is an example of simplified point kinetics reactor model (the ones used by Mazauric et al. (2022) and Vajpayee (2020) are more complex as they account for more feedback effects with equations to account for temperature variations):

- Neutron population general dynamics:

$$\frac{dn(t)}{dt} = \frac{\rho(t) - \beta}{\Lambda} n(t) + \sum_{i=1}^{N_g} \lambda_i C_i(t)$$

With

- $n(t)$: normalized neutron population (relative to the steady-state power)
- $\rho(t)$: reactivity
- β: total delayed neutron fraction
- Λ: prompt neutron generation time
- N_g: number of delayed neutron groups (usually chosen around 6, depends on the precision of the model)
- λ_i: decay constant of the i-th group of delayed neutron precursors
- $C_i(t)$: concentration of the i-th group of delayed neutron precursors among the total neutron population

- Delayed neutrons equations:

$$\frac{dCi(t)}{dt} = \frac{\beta_i}{\Lambda} n(t) - \lambda_i C_i(t)$$

With

$$\beta = \sum_{i=1}^{N_g} \beta_i$$

- Adding thermal feedback:

$$\rho(t) = \rho_0 + \alpha_f T_f(t) + \alpha_m T_m(t)$$

With

- α_f: fuel temperature reactivity coefficient (Doppler effect)
- $T_f(t)$: fuel temperature
- α_m: moderator temperature reactivity coefficient
- $T_m(t)$: moderator temperature

Using this model, they were able to simulate how reactors respond to changes in reactivity caused by control rod movement and simulate reactor behaviour over a few seconds (primarily for primary frequency control). However, these methods are not accurate for modelling longer-term flexibility because some additional constraints must be considered at these timescales.

On longer timescales, most papers use roughly similar methodologies: they consider several generation sources, which all have different flexibility constraints, and try to find an optimal commitment of these generation sources to minimise the total system costs while maintaining the balance between supply and demand. The tools they use differ, and the constraints they consider and the way they model them too, but the methodology is generally quite similar.

Over an hourly timescale, Jenkins et al. (2018), Lynch et al. (2022) and Alqahtani and Almerbati (2023) used Mixed-Integer Linear Programming (MILP) to assess the impact of nuclear flexibility on the generation dispatch in the system. They developed unit commitment (UC) and economic dispatch (ED) models, which consist in optimising the power output of all electricity generation sources at each time step to minimise total operational costs of the electric system while respecting balance between supply and demand. Jenkins et al. (2018) adapted an existing model from Wu et al. (2015), which did not consider nuclear power, to include nuclear flexibility constraints in their optimization process. On the other hand, Lynch et al. (2022) used Antares, an open-source MILP-based software developed by RTE in their analysis. Finally, Alqahtani and Almerbati (2023) built their own model, similar to the one used by Jenkins et al.

(2018), to assess the maximum possible solar penetration depending on the flexibility of nuclear power. The three studies took different approaches to modelling nuclear flexibility. Jenkins et al. (2018) included the maximum ramp-up and ramp-down rates constraints (30 % of the maximum power output per hour), arguing that French nuclear reactors mostly perform ramp-ups or ramp-downs within this limit, as well as a minimum stable time after ramping down (1 hour or 3 hours depending on their study cases). On the other hand, Lynch et al. (2022) did not consider these constraints, arguing that they reflect conservative operational practices rather than true technical limitations. Alqahtani and Almerbati (2023) on the other hand only modelled maximum ramp-up and ramp-down rates (between 70% and 100% in an hour depending on the cases).

On longer timescales, from monthly to seasonal, some papers consider the flexibility related to the scheduling of reactor outages. Lynch et al. (2022) optimised the reactor schedules using MILP to maximize availability during peak demand periods before using Antares to optimise unit commitment on an hourly basis based on reactor availability. Similarly, Lykidi and Gourdel (2017) optimised reactor schedules and production levels monthly using MILP, but they also considered thermal and hydro production. They then maximised nuclear profitability based on the merit order and electricity prices.

Overall, on timescales ranging from hourly to seasonal, papers use MILP to assess nuclear flexibility. On hourly timescales specifically, they generally use UC / ED models built using MILP.

Impacts on renewable integration and electricity curtailment

By modelling nuclear flexibility, studies were able to assess its impact on electricity curtailment. Studies by Jenkins et al. (2018) examined the reduction of renewable electricity curtailment with hourly flexible operations compared to baseload operations. Jenkins et al. (2018) investigated three different scenarios: the first with constant nuclear power generation, the second with flexible nuclear generation under a set of constraints, and the third with more relaxed flexibility constraints than in scenario two. They found that greater flexibility led to less renewable energy curtailment in every case. In their case study, curtailment was reduced by 46% in the second scenario compared to the first, and by 58% in the third scenario compared to the first.

Economic impacts

Studies from Jenkins et al. (2018), Lynch et al. (2022), Loisel et al. (2018), Cany et al. (2016) and Alqahtani and Almerbati (2023) have looked up the economic impacts of flexible nuclear operation on the electricity market and on the electric system costs. Additionally, Lynch et al. (2022), Lykidi and Gourdel (2017) and Loisel et al. (2018) also studied the economic impact of flexibility for nuclear operators.

On the economic impacts on the electricity market, Jenkins et al. (2018) found that hourly flexible nuclear operation do not significantly impact average electricity prices but reduces the frequency of negative prices. Lynch et al. (2022) determined that the effect of seasonal nuclear flexibility on market prices depends on renewable energy penetration. At lower shares of VRE (20% to 40%), flexible nuclear increased market prices compared to baseload nuclear, but at renewable shares above 60%, flexible nuclear reduced prices. Like Jenkins et al. (2018), they also found the occurrences of the negative prices to decrease. However, they also noted that seasonal nuclear flexibility increased peak price occurrences, especially at low renewable penetration, because the nuclear availability is lower during low demand seasons, which are also the seasons when the prices tend to peak more.

On the economic impacts for nuclear power plant operators, Alqahtani and Almerbati (2023) found the total operational costs to be decreased with flexible nuclear power to support solar penetration compared to constant nuclear power. However, this does not consider capital costs, which are significant for nuclear power plants. When taking them into account, the profitability of nuclear flexibility is less obvious. In their report on behalf of the Nuclear Energy Agency, Lokhov (2011) pointed out that flexible operations generally reduce the load factor of nuclear power plants. However, since nuclear power plants have important fixed costs but low operating costs, they do not save a lot of costs by decreasing their output and instead lose revenues. Cany et al. (2016) corroborated this after comparing the Levelized Cost of Electricity (LCOE) in a scenario with nuclear power used for load following with a scenario where nuclear power is used only as a baseload, completed by gas for backup operations. They found the first option to be more costly than the second. However, these results are sensitive to the choice of discount rate used to calculate the LCOE, as well as changes in carbon prices that could influence the results. Contrary to Cany et al. (2016), Jenkins et al. (2018) argued that the reduction of the occurrence of negative prices enabled by flexible operations can be an economic incentive for nuclear operators to adopt more hourly flexible operations. In their case study, they indeed found hourly flexibility to improve the profitability of nuclear plants. Ponciroli et al. (2017) found the same results. Loisel et al. (2018), on the other hand, found that under certain conditions (depending on the mix of energy sources, grid interconnections, carbon prices, and electricity market prices), operating nuclear power plants flexibly (over short timescales like hours) is not financially advantageous, particularly if the plants become backup generators with the highest marginal cost in high-renewable systems. They also pointed out that increased cycling of nuclear power plants raises fuel costs and reduces reactor lifespan. Over longer flexibility timescales (month to season), Lykidi and Gourdel (2017) concluded that baseload generation is not the most profit-optimal strategy for nuclear operators, which was corroborated by Lynch et al. (2022), who found nuclear revenues to increase in scenarios involving flexible monthly nuclear operations.

These findings show that there does not seem to be a consensus over the economic profitability of nuclear plants when they are used flexibly compared to when they are used for baseload operations only in the literature, hence the necessity to study it more.

Research gap

After reviewing the literature on nuclear power flexibility, it is evident that few studies have thoroughly assessed the limits of nuclear flexibility in supporting renewable energy integration. Most papers focus on comparing the baseload use of nuclear power with flexible use, but few evaluate the absolute limits of this flexibility, particularly in relation to increasing renewable penetration. Additionally, the optimal sizing of nuclear power for flexible use is rarely discussed.

4. Methodology

4.1 General explanations

As a reminder, here are the questions that the thesis aims to answer:

- What are the maximum shares of renewable penetration that nuclear alone can support?
- Under various increasing share of renewables in electricity generation scenarios, what are the optimal sizing requirements for nuclear to preserve system balance?
- How do power curtailment and nuclear reactor profitability evolve with nuclear flexible use?
- How do the French energy mix scenarios align with the findings in this study?
- How about Queensland nuclear proposals?

To answer these questions, nuclear flexibility is assessed in relation to simultaneous variations in load, solar photovoltaic generation, and wind generation. To do so, this study uses the concept of net load. Net load is defined as the portion of electricity demand not already met by variable renewable energy sources.
Nuclear flexibility is thus evaluated based on the ability of nuclear generation to track this net load, specifically by minimizing unserved energy (when nuclear output falls short of net load) and curtailed energy (when nuclear output exceeds net load).

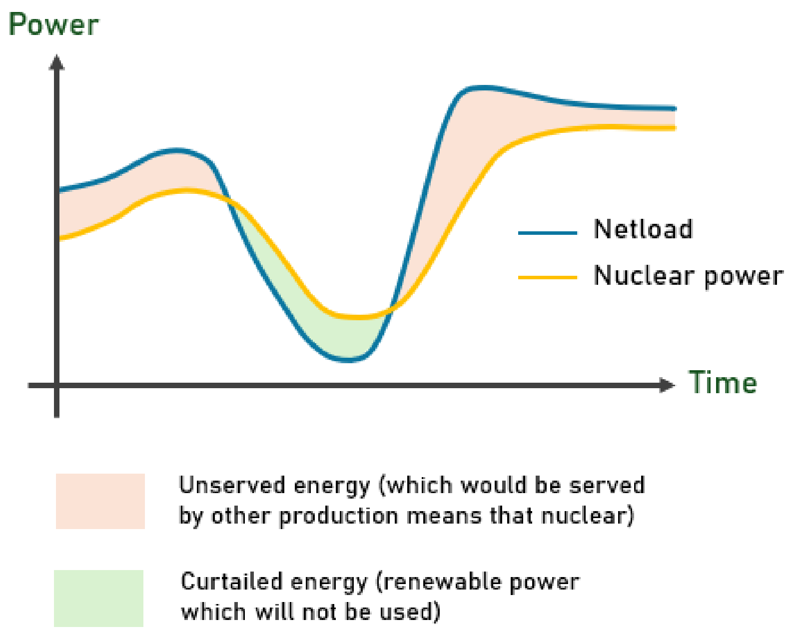

Figure 3: definitions of the concepts used to evaluate how nuclear power generation adjusts to variations in net load

4.2 Scope and hypothesis

The methodology used aims to assess nuclear flexibility in response to load, solar photovoltaic production, and wind production. Only these three production sources are considered. For nuclear power plants, only Pressurized Water Reactors (PWR) and European Pressurized Reactors (EPR) technologies are considered. Additionally, interconnections with other countries are not included in the model. Data is based on France's 2023 data, retrieved from RTE's website.

4.3 Timescale

In this study, the focus is on the reactivity and rapid response of nuclear power. Therefore, intra-daily timescales must be considered. An hourly timescale is considered, as the literature review indicates that nuclear flexibility constraints are expected to allow nuclear power plants to respond effectively within this timescale.

However, evaluating flexibility on an hourly timescale can become computationally intensive when applied over long time horizons. To reduce the model's computation time, the analysis of nuclear power's ability to follow net load is therefore performed on a daily basis.

Specific days are therefore selected to represent the demand profile. 8 dates are considered: two days per week, one during the work week and one on the weekend, for 4 different months in the year, chosen to represent the variety of load conditions during the year. This approach ensures a variety of representative demand scenarios. The specific dates chosen are Wednesday 1 February 2023, Sunday 5 February 2023, Wednesday 5 April 2023, Sunday 9 April 2023, Wednesday 12 July 2023, Sunday 16 July 2023, Wednesday 11 October 2023 and Sunday 15 October 2023.

4.4 Net load scenarios with increasing renewable penetration

The data used to compute the net load for these different days was retrieved from RTE's website. The net load is calculated as follows:

$$NL = Cons - Gen_{SOLARP} - Gen_{WIND}$$

Where NL is the net load, $Cons$ is the consumption, Gen_{SOLARP} is the generation from solar photovoltaic, and Gen_{WIND} is the generation from wind. Consumption is provided for each hour of each day in 2023. For solar and wind generation, the values are based on the production data from 2023. In that year, solar and wind together accounted for roughly 14% of France's total electricity production. To compute various renewable penetration levels, scaling factors are applied to this data to represent 20%, 30%, 40%, 50%, 60% and 70% renewable penetration. It should be noted that RTE's data had several missing values and outliers. In the following analysis, they were replaced by data of the previous or the following day.

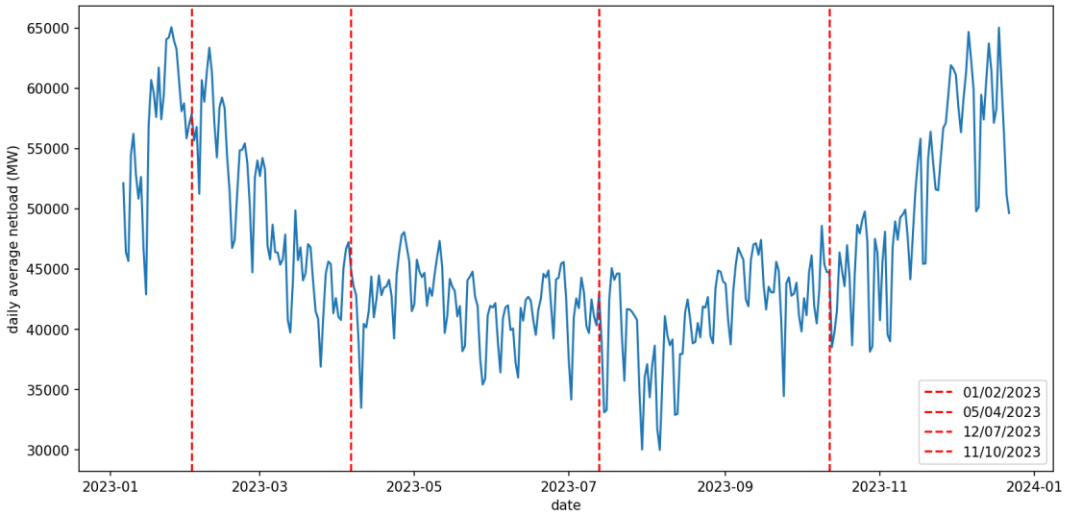

Figure 4 : Evolution of the French netload in 2023 and four weekdays chosen to study the flexibility of nuclear power

The obtained net load for the four weekday scenarios can be found in

Appendix 1: Net load scenarios with increasing renewable energy penetration.
Metrics used in the literature – maximum, minimum, average, standard variation, coefficient of variability - (Mikulik & Jurasz, 2020), (Mladenov et al.,2021) are used to analyse them. The impact of increasing renewable energy penetration is generally similar across the days examined: the maximum and minimum net load logically decrease, while the absolute values of the maximum positive and negative hourly gradients generally increase. The standard deviation also rises. This is consistent with the findings in the literature and demonstrates the increasing flexibility needs as renewable penetration rises.

4.5 Flexibility constraints considered

All the flexibility constraints mentioned in the literature review are considered.

- Maximum power output: 1100 MW
- Minimum power output: 20% of maximum power output for the 2/3 of the cycle, then linear increase until 100% of maximum power output at the end of the irradiation cycle.
- Maximum ramp up and ramp down rates: 3% of the maximum power output per min (which is enough to vary the power from 20% to 100% within an hour)
- Minimum stable time after ramping: 2 hours

4.6 Reactor availability

As mentioned in the literature review, the outage schedule of the reactor fleet is important to consider, even at a daily timescale. It has an impact on the results for two key reasons: the number of reactors available and the stage each reactor is at in its irradiation cycle, which affects its minimum power output. Unfortunately, the irradiation cycles of French nuclear reactors are not publicly disclosed, therefore a reactor outage schedule derived from 2023 nuclear production data (which is public) was built. The schedule was built so that the nuclear availability follows the trends in nuclear output and scaled so that all the reactors are available on the fortnight with peak demand, as inspired by the paper of Lynch et al. (2022). The outage duration is between 4 and 6 weeks for each reactor, and the length of the irradiation cycles is considered to be one year. The obtained availability schedule, with an example of one reactor's irradiation cycle is shown below.

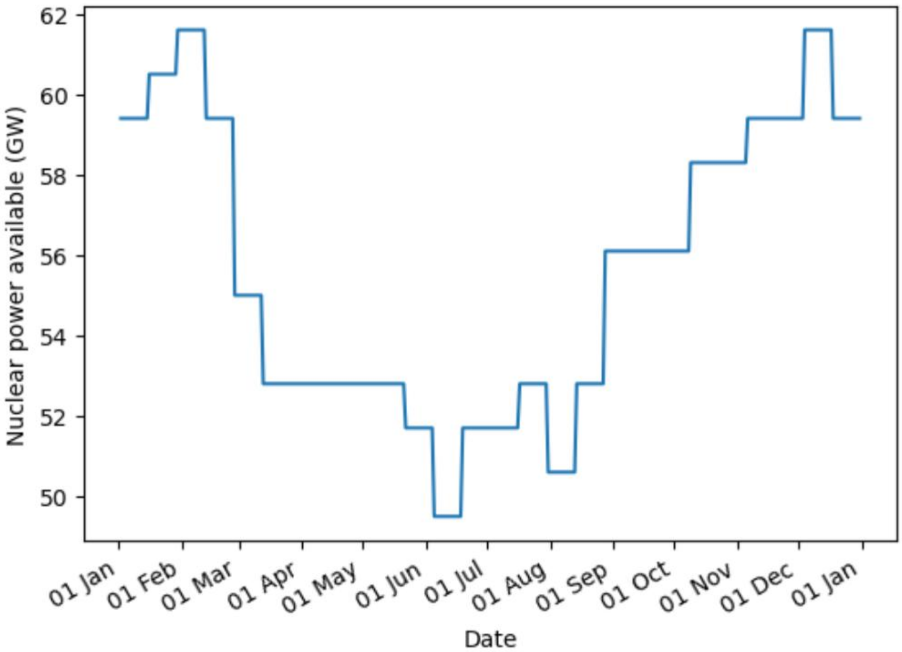

Figure 5 : Available power throughout the year for a fleet of 56 1.1GW reactors

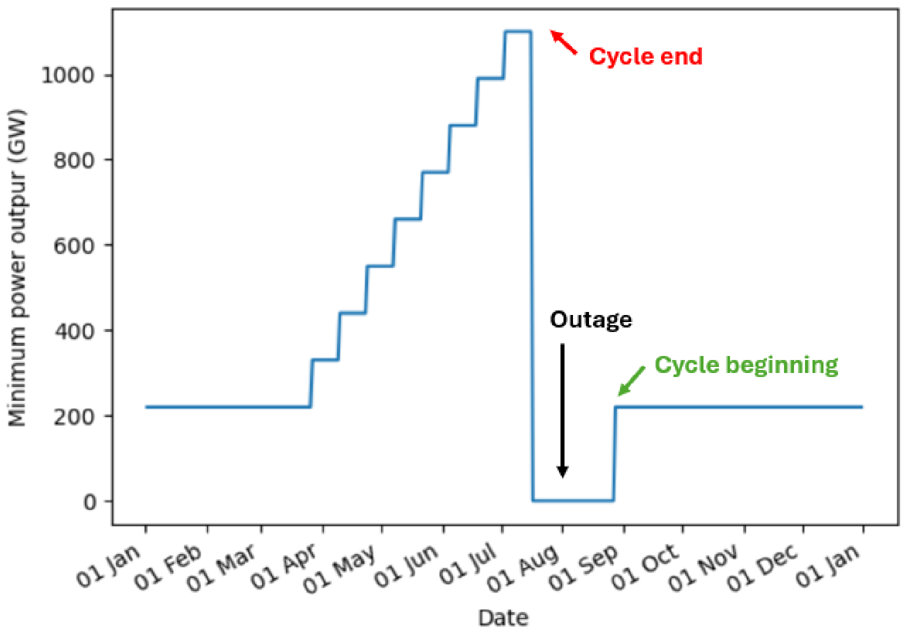

Figure 6 : Example of resulting irradiation cycle schedule for one of the 56 reactors.

4.7 Model

A Mixed Integer Linear Programming (MILP) model is used to optimise the nuclear fleet dispatch compared to the net load at each hourly step in order to minimise unserved energy and curtailed energy.

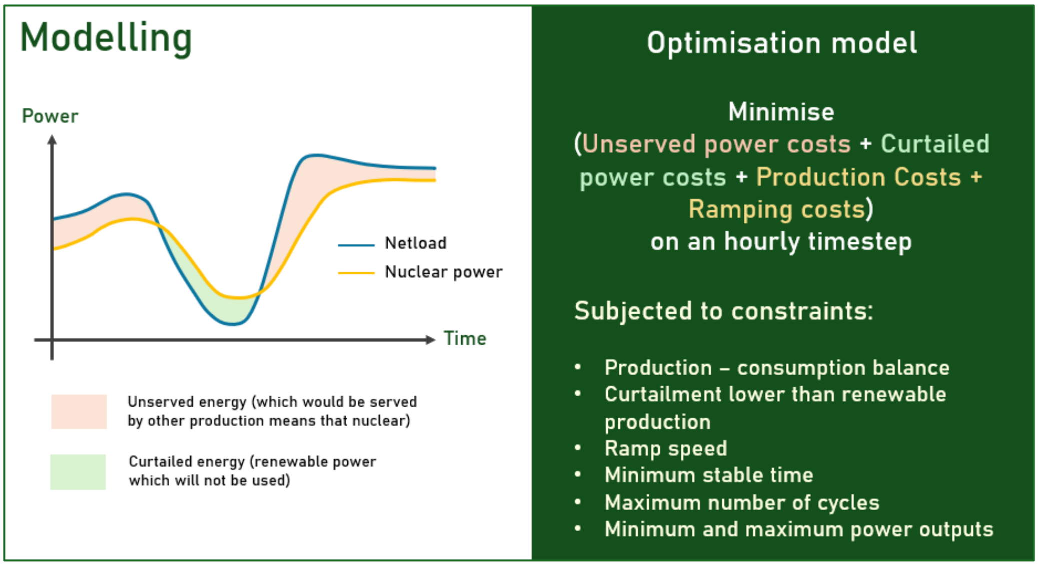

Figure 7: Illustration of model functioning

This model is inspired by the model developed by Jenkins et al. (2018) to optimise the dispatchment of generation sources (including VRE sources, hydro, nuclear and gas) in an electric system. However, a few adaptations are made:

- First, only nuclear power sources are considered. VRE sources are considered to have already produced electricity, following the merit order logic.
- In the objective function, which aims at minimizing the costs, ramping costs are considered in addition to marginal generation costs. This prevents two reactors from simultaneously ramping up and ramping down when they can both keep a stable output.
- The number of cycles of nuclear reactors is limited to 2 per day.
- Regulation reserve constraints are not considered. In the original model, they resulted in additional power limitations (a portion of the available power is saved for the reserve). They are considered negligeable here.

Here is the MILP model:

Indices:

- $t,\ t\ \in [\![1, 24]\!]$ index of time, hour
- $d,\ d\ \in [\![1, 365]\!]$ index of day of the year
- $j,\ j\ \in [\![1, 56]\!]$ index of nuclear unit

Variables:

- $p_{t,j}$ power output at time t of nuclear unit j (MW/h)
- Cur_t curtailment at time t
- $Unserv_t$ unserved energy at time t
- $St_{t,j}$ binary state variable, equal to 1 if $p_{t,j} = p_{t-1,j}$ at time $t\ \in [\![2, 24]\!]$ for nuclear unit j and 0 otherwise
- $Ru_{t,j}$ binary state variable, equal to 1 if $p_{t,j} > p_{t-1,j}$ at time $t\ \in [\![2, 24]\!]$ for nuclear unit j and 0 otherwise
- $Rd_{t,j}$ binary state variable, equal to 1 if $p_{t,j} < p_{t-1,j}$ at time $t\ \in [\![2, 24]\!]$ for nuclear unit j and 0 otherwise

- $CycleDown_{t,s,j}$ binary state variable, equal to 1 if nuclear unit j ramps down at time t, is table from time t+1 to time s-1 and ramps up at time s
- $CycleUp_{t,s,j}$ binary state variable, equal to 1 if nuclear unit j ramps up at time t, is table from time t+1 to time s-1 and ramps down at time s

Parameters:
- N total number of reactors
- $Load_{d,t}$ net load at time t during day d
- $Solar_{GEN\,d,t}$ solar generation at time t during day d
- $Wind_{GEN\,d,t}$ wind generation at time t during day d
- $Tminstable_j$ minimum time that nuclear unit j needs to stay at a stable power output (hours)
- $Pmax_{d,j}$ maximum power output of nuclear unit j during day d (MW)
- $Pmin_{d,j}$ minimum power output of nuclear unit j during day d (MW)
- $MinR_j$ minimum ramp rate of nuclear unit j (MW/min)
- M very big parameter used to linearize constraints

- GC generation Cost of a nuclear unit
- RC additional cost associated with ramping up or down
- UC unserved power from nuclear generation cost

Table 8 : model parameters values

PARAMETERS	VALUE
$\boldsymbol{N}$	56
$\boldsymbol{Load_{d,t}}$	Net load data computed with RTE's data
$\boldsymbol{Solar_{GEN\,d,t}}$	Production data from RTE
$\boldsymbol{Wind_{GEN\,d,t}}$	Production data from RTE
$\boldsymbol{Tminstable}$	2
$\boldsymbol{Pmax_{d,j}}$	0 if outage, 1100 MW otherwise
$\boldsymbol{Pmin_{d,j}}$	20% of maximum power output for 2/3 of the cycle, then linear growth until reaching 50% of maximum power output at the end of the irradiation cycle (see schedule).
$\boldsymbol{MaxR}$	$0.05 \times PMAX_{d,j}$
$\boldsymbol{\varepsilon}$	0.001
$\boldsymbol{GC}$	Random value between 30 euros/MWh and 99 euros /MWh depending on the reactor
$\boldsymbol{RC}$	5 euros/MWh when ramping
$\boldsymbol{UC}$	100 euros/MWh (marginal cost of the generation source following nuclear power in the merit order

These cost parameters do not represent real-life economic costs, but they allow to draw a hierarchy of preference in our model: meeting demand with nuclear generation only is the cheapest option, and if it is not possible overproducing with nuclear and curtailing renewables will be preferred to underproducing and not being able to serve all the demand. Moreover, ramping nuclear operations are more costly than steady-state operations.

Objective function:

The objective of the model is to minimise the total operational costs of the system:

$$Min \sum_{t=1}^{24}\sum_{j=1}^{N}[p_{t,j} \cdot GC + Unserv_t \cdot UC] + \left(Rd_{t,j} \cdot [p_{t-1,j} - p_{t,j}] + Ru_{t,j} \cdot [p_{t,j} - p_{t-1,j}]\right) \cdot RC$$

Constraints:

Supply-demand balance constraint:

$$\sum_{j=1}^{N} p_{t,j} + Cur_t + Unserv_t \ = \ Load_{d,t} \ \forall d \in [\![1,365]\!], \qquad \forall t \in [\![1,24]\!]$$

Maximum curtailment:

$$Cur_t \ \leq Solar_{GEN_{d,t}} + Wind_{GEN_{d,t}} \ \forall d \in [\![1,365]\!], \qquad \forall t \in [\![1,24]\!]$$

Binary variable setting (enables to identify when there is a ramp up, a ramp down, or a stable output):

$$p_{t-1,j} - p_{t,j} \ \leq MaxR \ \cdot Rd_{t,j} - \ \varepsilon \cdot Ru_{t,j} \quad \forall t \in [\![2,24]\!], \forall j \in [\![1,N]\!],$$
$$p_{t,j} - p_{t-1,j} \ \leq MaxR \ \cdot Ru_{t,j} - \ \varepsilon \cdot Rd_{t,j} \quad \forall t \in [\![2,24]\!], \forall j \in [\![1,N]\!],$$
$$Rd_{t,j} + Ru_{t,j} + St_{t,j} = 1 \quad \forall t \in [\![1,24]\!], \qquad \forall j \in [\![1,N]\!]$$

Minimum and maximum power outputs:

$$p_{t,j} \ \geq \ Pmin_{d,j} \quad \forall t \in [\![1,24]\!], \forall j \in [\![1,N]\!]$$
$$p_{t,j} \ \leq \ Pmax_{d,j} \quad \forall t \in [\![1,24]\!], \forall j \in [\![1,N]\!]$$

Minimum recovery time constraint after ramping down. At every time step, if there has been a ramp down in the Tminstable hours before, the reactor cannot ramp up again:

$$\forall t \in [\![2,24]\!], \forall j \in [\![1,N]\!], \ (Ru_{t,j} - Ru_{t-1,j}) \cdot Tminstable \leq \sum_{s=t-TMINSTABLE}^{t-1} (St_{s,j} + Ru_{s,j})$$

Maximum number of down cycles (with a maximum of two up ramps per day, not counting repeated up ramps with a stable interval in between):

Setting the constraints to detect a cycle:

$$CycleDown_{t,t',j} \leq Rd_{t',j} \quad \forall \ j \in [\![1,N]\!], \quad \forall \ t \in [\![1,24]\!], \forall \ t' \ \in \ [\![1,24]\!],$$
$$CycleDown_{t,t',j} \leq Ru_{t',j} \quad \forall \ j \in [\![1,N]\!], \forall \ t \in [\![1,24]\!], \forall \ t' \ \in \ [\![t + Tminstable + 1, 24]\!],$$
$$CycleDown_{t,t',j} \cdot (t' - t - 1) \leq \sum_{s=t+1}^{t'-1} St_{s,j} \quad \forall \ j \in [\![1,N]\!], \forall \ t \in [\![1,24]\!], \forall \ t' \in \ [\![t + Tminstable + 1, 24]\!],$$
$$CycleDown_{t,t',j} \geq Ru_{t',j} + Rd_{t,j} + \sum_{s=t+1}^{t'-1} \left(St_{s,j}\right) - t' + t \quad \forall \ j \in [\![1,N]\!], \forall \ t \in [\![1,24]\!], \forall \ t' \in \ [\![t + Tminstabel + 1, 24]\!]$$

Maximum number of cycles:

$$\sum_{t=1}^{24} \sum_{t'=t+TMINSTABLE+1}^{24} CycleDown_{t,t',j} \leq 2 \quad \forall \ j \in [\![1,N]\!]$$

Additional limitation to the number of cycles. The model constrains the number of cycles to a maximum of two per day, whereas the real constraint is two per 24h. There is still a possibility for a reactor to start the day in the middle of a cycle, do two full cycles afterwards and finish the day in the middle of another one, as shown by Figure 8. To limit this scenario, mathematical (they do not account for physical constraints) constraints on the number of up cycles are added:

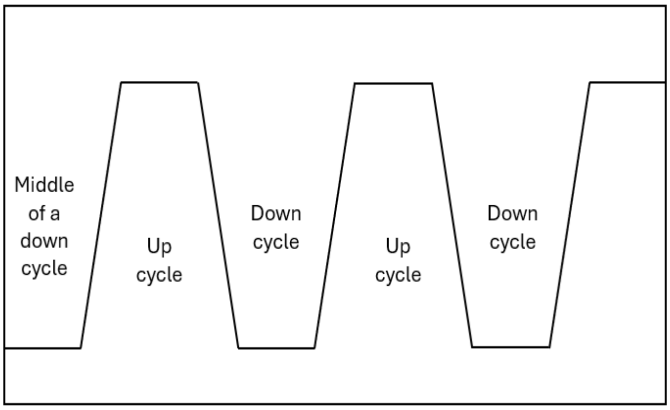

Figure 8 : example of scenario with two full down cycles and one cycle already started at the beginning of the day (power of reference is the maximum power output of the reactor)

Setting the constraints to detect a cycle:

$$\forall\, j \in [\![1, N]\!], \forall\, t \in [\![1, 24]\!], \forall\, t' \in [\![1, 24]\!], CycleUp_{t,t',j} \leq Ru_{t',j}$$

$$\forall\, j \in [\![1, N]\!], \forall\, t \in [\![1, 24]\!], \forall\, t' \in [\![t + Tminstable + 1, 24]\!], CycleUp_{t,t',j} \leq Rd_{t',j}$$

$$\forall\, j \in [\![1, N]\!], \forall\, t \in [\![1, 24]\!], \forall\, t' \in [\![t + Tminstable + 1, 24]\!], CycleUp_{t,t',j} \cdot (t' - t - 1) \leq \sum_{s=t+1}^{t'-1} St_{s,j}$$

$$\forall\, j \in [\![1, N]\!], \forall\, t \in [\![1, 24]\!], \forall\, t' \in [\![t + Tminstable + 1, 24]\!], CycleUp_{t,t',j} \geq Rd_{t',j} + Ru_{t,j} + \sum_{s=t+1}^{t'-1} (St_{s,j}) - t' + t$$

$$\forall\, j \in [\![1, N]\!], \forall\, t \in [\![1, 24]\!], \forall\, t' \in [\![t + Tminstable + 1, 24]\!], CycleUp_{t,t',j} \geq Rd_{t',j} + Ru_{t,j} + \sum_{s=t+1}^{t'-1} (St_{s,j}) - t' + t$$

Maximum number of cycles:

$$\forall\, j \in [\![1, N]\!], \sum_{t=1}^{24} \sum_{t'=t+TMINSTABLE+1}^{24} CycleUp_{t,t',j} \leq 1$$

Maximum and minimum power constraints:

$$\forall d \in [\![1, 365]\!], \forall t \in [\![1, 24]\!], \forall j \in [\![1, N]\!], \quad p_{t,j} \leq Pmax_{d,j}$$

$$\forall d \in [\![1, 365]\!], \forall t \in [\![1, 24]\!], \forall j \in [\![1, N]\!], \quad p_{t,j} \geq Pmin_{d,j}$$

5. Simplified illustrative cases

To illustrate how the model operates, a few simplified cases are presented below.

- $N = 1, P_{max} = 20\,000\ MW$

Here are the results obtained for the 1st of February 2023, with 20% renewable penetration, with only one reactor of 20 GW capacity. As expected, it is not enough to support the net load, and the gap between the net load and the reactor's maximum power output would be served by other means of production, such as biomass or gas.

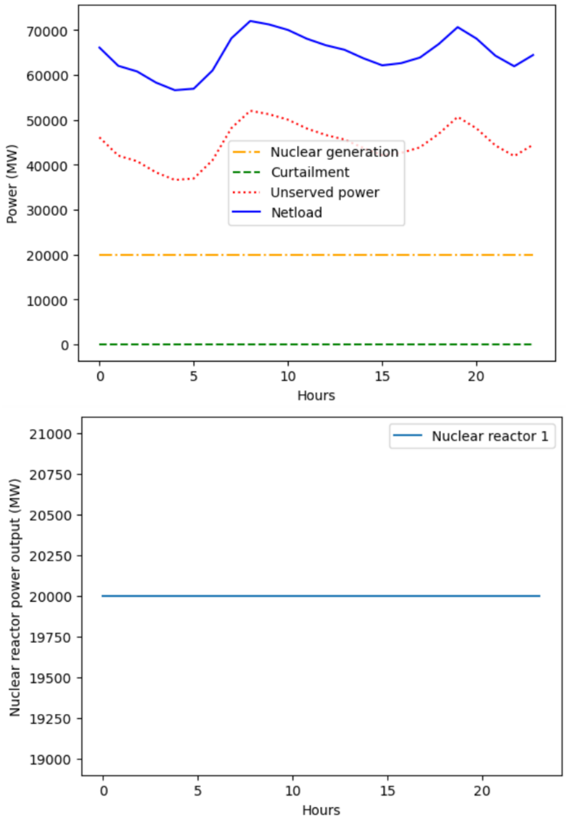

*Figure 9 : Results for 01/02/2023, with 14% with renewable energy penetration and **one 20GW reactor**. The graph on the left shows the total aggregated nuclear power output's ability to follow the net load, and the resultant unserved power from nuclear generation and curtailed power. The graph on the right shows the power output of each nuclear reactor.*

- $N = 1, P_{max} = 70\,000\ MW$

This result corresponds to the same day and the same VRE penetration level, but with a single reactor of 70 GW capacity. In this case, the reactor is large enough to meet the net load, which brings its flexibility into play. The constraints related to the maximum number of allowed ramping cycles are clearly visible in this example.

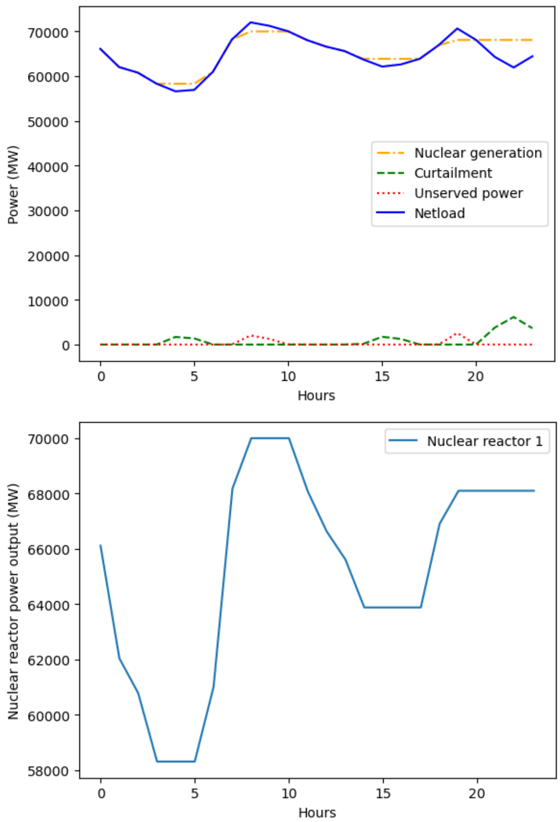

*Figure 10 : Results for 01/02/2023, 14% with renewable energy penetration, **one 70GW reactor**. Total aggregated nuclear generation (left) and generation of each reactor (right).*

- $N = 2, P_{max} = 35\,000\ MW$

This result corresponds to the same day and the same VRE penetration level, but this time with two reactors of 35 GW capacity each. As expected, increasing the number of reactors improves the ability of the aggregated nuclear output to follow the net load. Although the total maximum power output remains the same as in the previous example, the difference between the combined nuclear production and the net load is reduced.

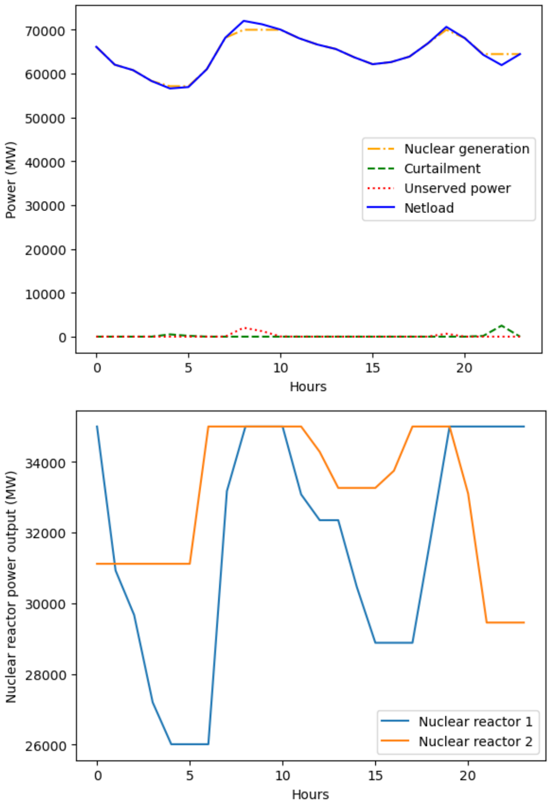

*Figure 11 : Results for 01/02/2023, 14% with renewable energy penetration, **two 35GW reactors**. Total aggregated nuclear generation (left) and generation of each reactor (right).*

- $N = 4, P_{max} = 17\,500\ MW$

This is the result obtained for the same day, same penetration, with four reactors, but only 17.5GW each. The same observations as for the previous example apply.

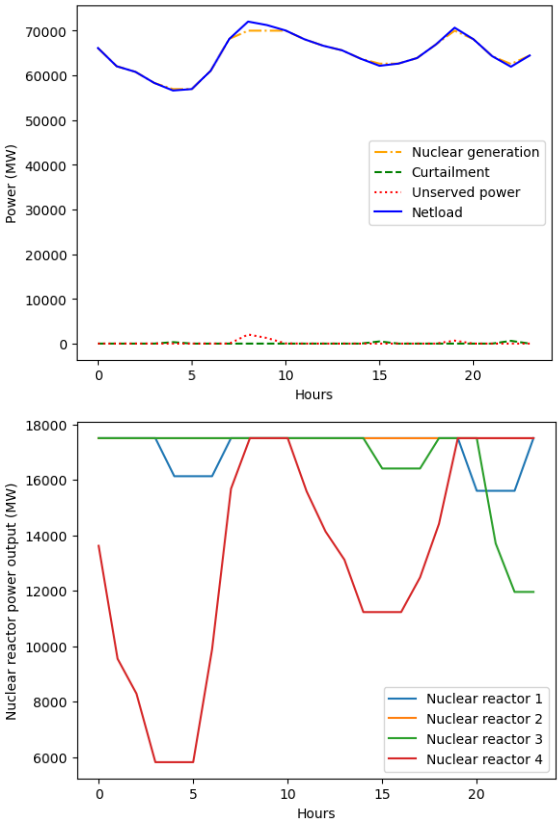

*Figure 12 : Results for 01/02/2023, 14% with renewable energy penetration, **four 17.5GW reactors**. Total aggregated nuclear generation (left) and generation of each reactor (right)*

6. General results with increasing renewable shares

The model is then applied to a fleet of 56 reactors, each with a capacity of 1100 MW, across the eight selected dates and for VRE shares of 20%, 30%, 40%, 50%, 60%, and 70%. Examples of simulation results for Wednesday 12 July 2023 are presented in Appendix 2: Simulation results for increasing renewable energy penetration.

6.1 General discussion

As established in the previous sections, increasing the share of renewable energy tends to reduce both the maximum and minimum values of net load, while also amplifying the steepness of net load ramps, both upward and downward. These effects are particularly pronounced during the summer months. The results indicate that the nuclear fleet's ability to meet the net load peak is generally better in summer and improves as the share of VRE increases. However, matching the net load minimum becomes more challenging under the same conditions, due to the nuclear units' minimum power output constraints. Despite these limitations, the results show that, regardless of the VRE share, the nuclear fleet remains capable of ramping up and down rapidly enough to follow the net load variations.

6.2 Flexibility limiting factors identification

Four main factors are identified as limiting the nuclear fleet's ability to fully match the net load:

1. Maximum power output constraint: The nuclear fleet has a fixed maximum generation capacity that cannot be exceeded. When the net load peak surpasses this limit, the fleet is unable to meet demand, resulting in unserved energy.

2. Minimum power output constraint: Nuclear reactors must operate above a minimum power threshold, determined by technical and operational constraints. When the net load minimum falls below the fleet's aggregate minimum output, often due to reactor schedules, the excess generation leads to renewable energy curtailment.

3. Reduced flexibility near minimum output: As the fleet approaches its minimum total output, an increasing number of reactors reach their individual minimum levels and can no longer contribute to ramping. This reduces the overall flexibility of the system and impairs the fleet's ability to follow rapid net load variations, leading to additional renewable energy curtailment.

4. Third net load dip during the day: Nuclear reactors are typically limited to two power output cycles per day. If a third significant dip in net load occurs, common in high VRE scenarios, it becomes difficult for the fleet to adapt, often resulting in further renewable curtailment.

Figure 13 exemplifies this limiting factors.

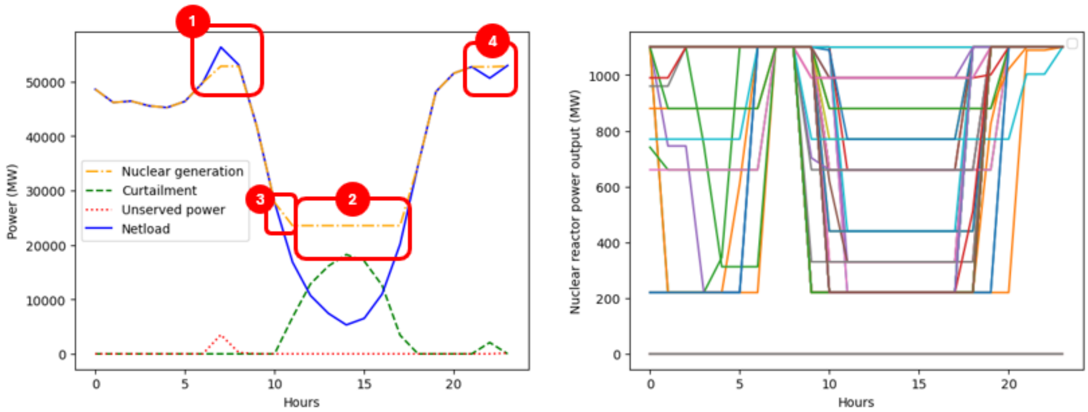

Figure 13: Flexibility limitation factors identification, using the simulation results of 05/04/23, 60% renewable energy share, 56 reactors

The cumulative unserved and curtailed power are computed over the 8 days is computed as a function of the VRE share to observe larger tendencies. The results are shown by Figure 14. As identified with the flexibility limiting factors analysis, the cumulative curtailed and unserved evolve with the relative size of the nuclear fleet to the net load: the lower the size of the fleet compared to the net load, the higher the unserved power because the net load surpasses the maximum power output of the fleet, and the bigger the size of the fleet compared to the net load, the higher the curtailed power as the net load falls below the minimum power output of the fleet.

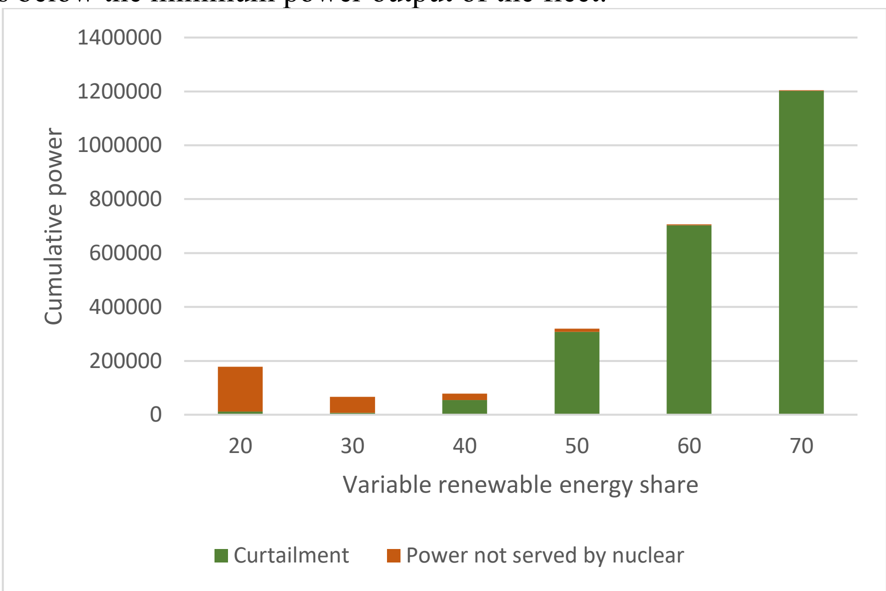

Figure 14 : : Illustration of cumulative unserved and curtailed power for a 56-reactor fleet, for each VRE share.

6.3 Sensitivity to fleet size

Simulation results indicate that, among the identified limiting factors, the most significant constraints on the hourly flexibility of nuclear power are the fleet's maximum and minimum power output limits. This reveals a key trade-off: a fleet that is too small will be unable to meet demand during high-load periods, leading to unserved energy; conversely, a fleet that is too large increases the risk of renewable energy curtailment during periods of low net load, particularly on days with high solar generation, due to the minimum power output constraint.

Given that the number of reactors in the fleet (assuming a fixed reactor size) significantly influences both the fleet's overall flexibility and its ability to follow net load profiles, it is valuable to examine how unserved energy and curtailed energy evolve with fleet size. To this end, a sensitivity analysis was performed, assessing total unserved and curtailed power for fleets of 15, 20, 25, 30, 40, 50, and 56 reactors across renewable penetration scenarios of 20%, 30%, 40%, 50%, 60%, and 70%. For each scenario, the total unserved and curtailed energy was aggregated over the same eight representative dates. Figure 15 to Figure 17 show the results of this study.

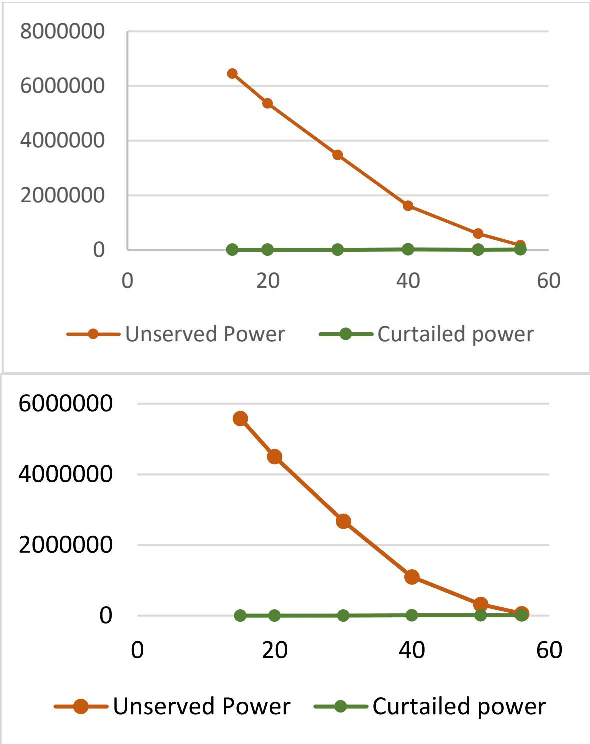

Figure 15: Cumulative curtailed power and unserved power from nuclear generation over the 8 days depending on the number of reactors in the fleet for 20% VRE share (left), and 30% VRE share (right)

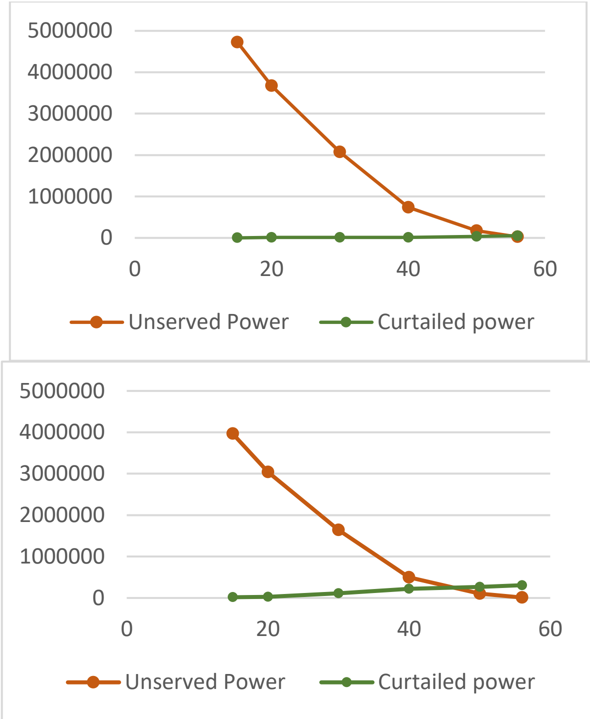

Figure 16: Cumulative curtailed power and unserved power from nuclear generation over the 8 days depending on the number of reactors in the fleet for 40% VRE share (left), and 50% VRE share (right)

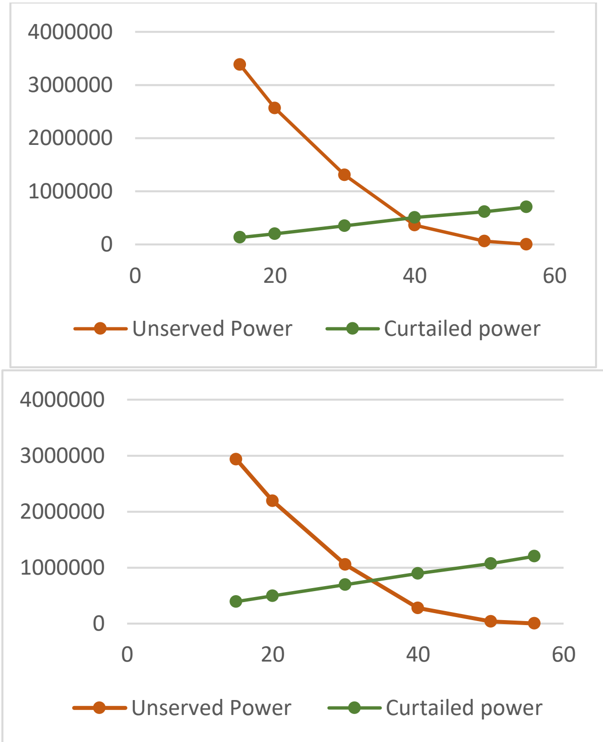

Figure 17: Cumulative curtailed power and unserved power from nuclear generation over the 8 days depending on the number of reactors in the fleet for 60% VRE share (left), and 70% VRE share (right)

Unsurprisingly, at constant fleet size, the cumulative unserved power decreases as the share of renewables increases, and the cumulative curtailed power increases as the share of renewable increases. At constant renewable share, the cumulative unserved power appears to decrease approximately in proportion to the inverse of the number of reactors, while the curtailed power seems to increase linearly as the number of reactors increases.

6.4 Economic considerations

The previous analysis of the trade-off between unserved and curtailed energy as a function of VRE share and nuclear fleet size is based purely on technical considerations, specifically, the flexibility constraints that limit the reactors' ability to follow net load variations. However, operational constraints are not the sole factors influencing the optimal fleet size. Economic viability also plays a key role in determining the appropriate number of reactors. While profitability is complex to evaluate, primarily due to its dependence on market electricity prices, a useful first indicator is the average capacity factor of the nuclear fleet under different scenarios. Although computing annual capacity factors was not feasible due to computational limitations, average capacity factors were calculated over the same eight representative dates used in the flexibility study, for each combination of VRE share and fleet size. The obtained results are presented by Figure 18. In comparison, the average nuclear capacity factor in France currently ranges between 70% and 75%. This serves as a useful benchmark: for each fleet size, the maximum renewable energy share that can be supported while maintaining a capacity factor above these levels provides an indication of the economically sustainable limits of nuclear deployment.

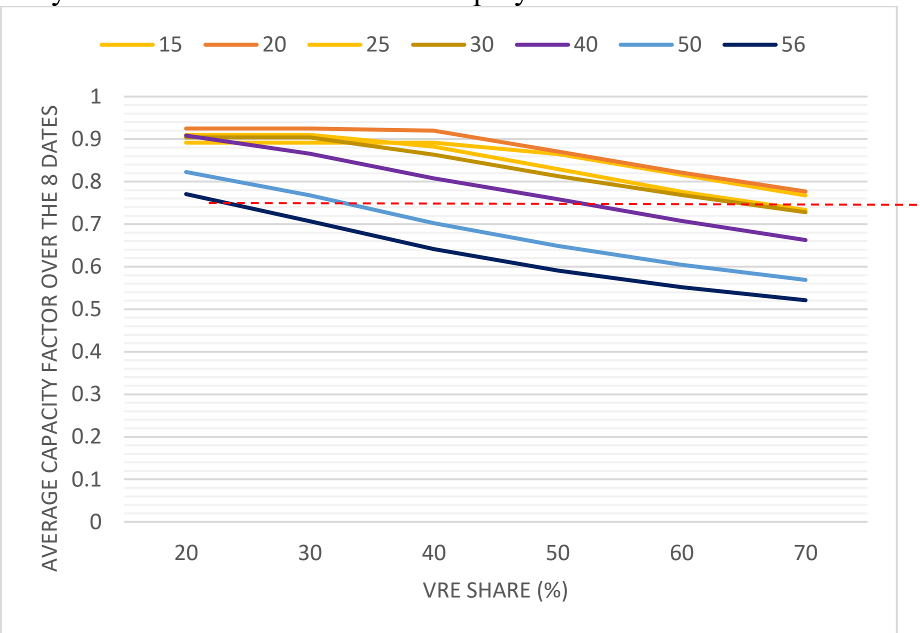

Figure 18: Evolution of the average capacity factor over the 8 days studied with the increase of the VRE share, for various nuclear fleet size

These results clearly show that, for a fleet of 56 reactors, a VRE share above 30% leads to a capacity factor falling below 70%. Similarly, for a fleet of 50 reactors, the 70% threshold is crossed beyond 40% VRE share, and for 40 reactors, it occurs at 70% VRE share, assuming that only VRE sources and nuclear power are used to meet demand.
This highlights an important economic constraint: oversizing the nuclear fleet to gain flexibility can significantly reduce capacity factors, potentially affecting profitability. However, as noted by Jenkins et al. (2018), increased share of VRE and enhanced nuclear flexibility could shift market price patterns, creating new economic incentives for nuclear operators to adopt more flexible, hourly-responsive operations. Under such evolving market conditions, capacity factors below 70% may still prove economically viable.

7. Case study: France's net-zero pathways

Considering the two most plausible carbon neutrality pathways identified by RTE for 2050, this study investigates the expected flexibility of the French nuclear fleet under future system configurations. Both scenarios assume total electricity demand will be multiplied by 1.3 compared to today and emphasize a mix of nuclear and renewable energy sources to achieve net-zero targets. The first scenario, referred to as N1, envisions a system with 26% nuclear, 63% VRE and 9% hydroelectricity. It involves the deployment of 8 new nuclear reactors in addition to 16 GW of historical capacity, for a total of 29 GW of nuclear power. The second scenario, N2, relies more heavily on nuclear energy, with a 36% share, alongside 53% VRE and 9% hydro, requiring the construction of 14 new reactors to reach a total of 39 GW. In both cases, the high penetration of VRE significantly increases the need for flexible operation of dispatchable generation. This study therefore aims to assess how much flexibility the projected nuclear fleets in these two scenarios could provide and how they compare with previous results.

7.1 Scenario N1

Methodology

In this section, a nuclear fleet resembling the fleet planned in scenario N1 was simulated. The model optimised the output of 26 reactors, each with a capacity of 1100 MW. The net load was calculated using consumption data from 2023, multiplied by 1.3, and generation data from all production sources with a marginal cost lower than that of nuclear power, in accordance with the merit order principle. Accordingly, the net load was computed as follows:

$$NL = CONS - GEN_{SOLARP} - GEN_{WIND} - GEN_{HYDRO} - GEN_{WASTE}$$

with the solar, wind, hydro and waste electricity generation data based on the generation data of 2023 with scaling factors applied so that VRE generation represent 60% of the electricity generation, and hydro represent 9%.

The model was then run to assess how nuclear power would respond to the calculated net load, considering the technical constraints outlined earlier, on eight specific days: Wednesday 1 February 2023, Sunday 5 February 2023, Wednesday 5 April 2023, Sunday 9 April 2023, Wednesday 12 July 2023, Sunday 16 July 2023, Wednesday 11 October 2023, and Sunday 15 October 2023.

Results

Example of simulation results for Wednesday 12 July 2023 are presented in Appendix 3: Simulation results for France's net-zero pathways. They indicate an average capacity factor of 78.4% over the eight representative days, with 14.3 GWh of net load (41% of total net load) unserved by nuclear generation, and 1.6 GWh of curtailed renewable energy (equivalent to 6% of VRE production).

Since scenario N1 features higher electricity consumption and includes hydropower and waste generation, it does not have a direct equivalent in the general analysis of unserved power and curtailed energy as a function of fleet size presented earlier. Nevertheless, Figure 19 offers a comparative perspective by positioning the results obtained for N1 alongside those from the general analysis corresponding to a 60% VRE share.

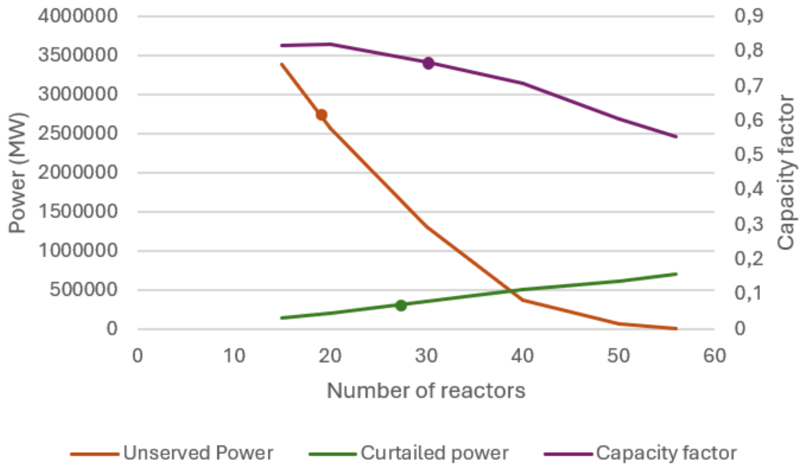

Figure 19: Placement of the results obtained for scenario N1 with 26 reactors (represented as dots) overlaid on the results from the previous section for a 60% VRE share (represented by solid lines).

7.2 Scenario N2

Methodology

In this section, a nuclear fleet resembling the fleet planned in scenario N1 was simulated. The model optimised the output of 35 reactors, each with a capacity of 1100 MW. The net load was calculated using consumption data from 2023, multiplied by 1.3, and generation data from all production sources with a marginal cost lower than that of nuclear power, in accordance with the merit order principle. Accordingly, the net load was computed as follows:

$$NL = CONS - GEN_{SOLARP} - GEN_{WIND} - GEN_{HYDRO} - GEN_{WASTE}$$

with the solar, wind, hydro and waste electricity generation data based on the generation data of 2023 with scaling factors applied so that VRE generation represent 50% of the electricity generation, and hydro represent 9%.

The model was then run to assess how nuclear power would respond to the calculated net load, considering the technical constraints outlined earlier, on eight specific days: Wednesday 1 February 2023, Sunday 5 February 2023, Wednesday 5 April 2023, Sunday 9 April 2023, Wednesday 12 July 2023, Sunday 16 July 2023, Wednesday 11 October 2023, and Sunday 15 October 2023.

Results

The simulation results indicate an average capacity factor of 81.6% over the eight representative days, with 10.3 GWh of net load (25% of total net load) unserved by nuclear generation, and 0.8 GWh of curtailed renewable energy (equivalent to 4% of VRE production).

Since the N2 scenario features higher electricity consumption and includes hydropower and waste generation, it does not have a direct equivalent in the general analysis of unserved power and curtailed energy as a function of fleet size presented earlier. Nevertheless, Figure 20 offers a comparative perspective by positioning the results obtained for N2 alongside those from the general analysis corresponding to a 50% VRE share.

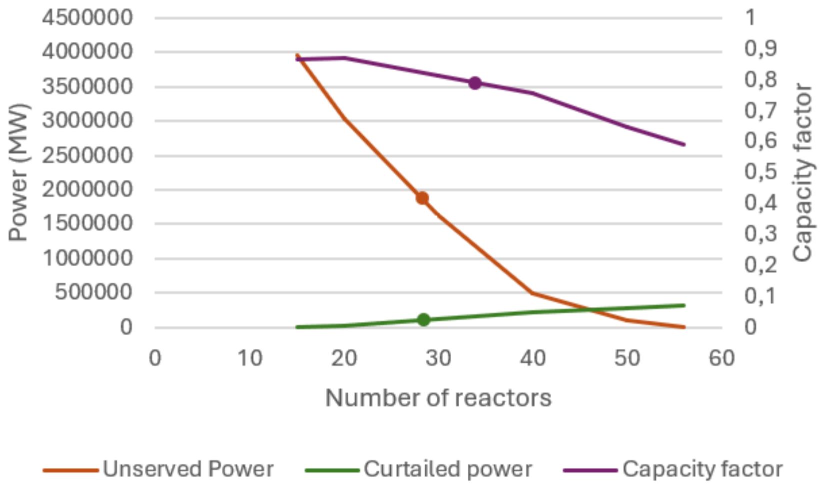

Figure 20: Placement of the results obtained for scenario N2 with 35 reactors (represented as dots) overlaid on the results from the previous section for a 50% VRE share (represented by solid lines).

It seems that scenarios N1 and N2, while relying on a significant share of nuclear power, do not involve a fleet size that would necessitate substantial flexibility manoeuvres. The average capacity factor remains high, curtailment levels are moderate, and the presence of unserved power from nuclear generation is considerable, suggesting a significant needs for additional complementary dispatchable low-carbon generation. Simulations for specific days however still reveal challenges in avoiding curtailment during midday hours, when solar energy production peaks.

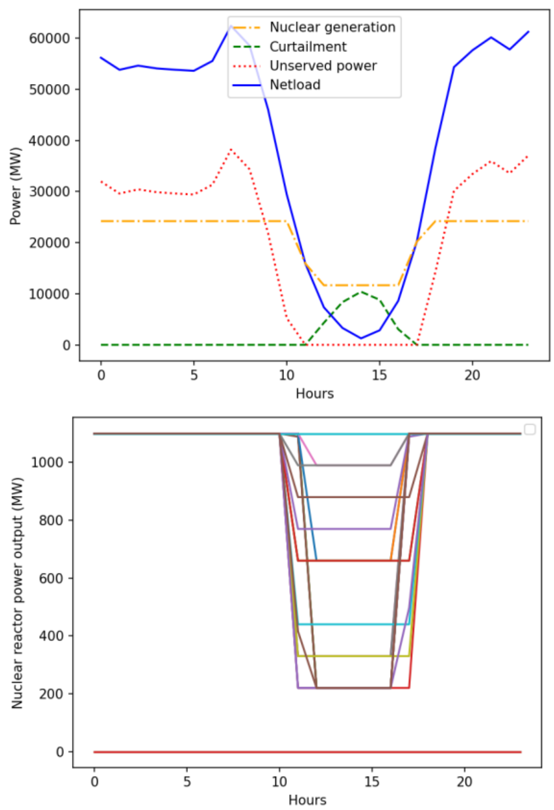

Figure 21: Simulation results for N1 scenario on April 5, 2023 (26 reactors, 60% VRE)

8. Case study: Queensland nuclear proposals

Although this thesis primarily focuses on the French context (both the current energy mix and future net-zero scenarios) it is nonetheless valuable to briefly explore how nuclear power might adapt to net load conditions in the context of Queensland's electricity system, particularly in light of recent nuclear proposals put forward during the latest federal campaign. The preliminary results presented here offer an initial indication of how nuclear generation could behave under Queensland-specific conditions. However, these insights remain exploratory and should be interpreted with caution. A comprehensive assessment would require further dedicated modelling that accounts for Australia's distinct seasonal patterns, demand profiles, existing generation mix, and grid structure. Therefore, while informative, these results should be seen as a starting point for further investigation rather than definitive conclusions.

8.1 Methodology

The exact same methodology used for the general case study of France with a 56-reactor fleet is applied here, with the only differences being the substitution of France's consumption and generation data with those of Queensland, and the modelling of a smaller nuclear fleet composed of two reactors, each with a capacity of 1.4 GW. The net load in this case is computed as follows:

$$NL = Cons - Gen_{SOLARP} - Gen_{WIND}$$

Where NL is the net load, $Cons$ is the consumption, Gen_{SOLARP} is the generation from solar photovoltaic, and Gen_{WIND} is the generation from wind.

However, the analysis is limited to a single day (May 10th, 2025) due to data availability constraints. In Queensland, hourly renewable production data is only publicly accessible for a few days following real-time generation, making it impossible to retrieve data for multiple representative days across the year. As a result, the findings presented offer only a preliminary perspective based on this specific snapshot in time.

The availability schedule used to model France's nuclear fleet is not applied in the Australian context, as the seasonal patterns in Australia differ significantly from those in France. Consequently, the nuclear availability results obtained to and its ability to follow demand in France cannot be directly transferred to the Australian power system. Therefore, two scenarios were considered: one in which both reactors are fully available, and another in which only one reactor is operational while the other is offline for maintenance or refuelling. Of course, these represent two simplified limit cases, and a wide range of intermediate situations is also possible in practice, for example, both reactors being online, but with only one operating at full capacity while the other nears the end of its irradiation cycle and is subject to output limitations.

8.2 Results

The results of the simulations are presented below:

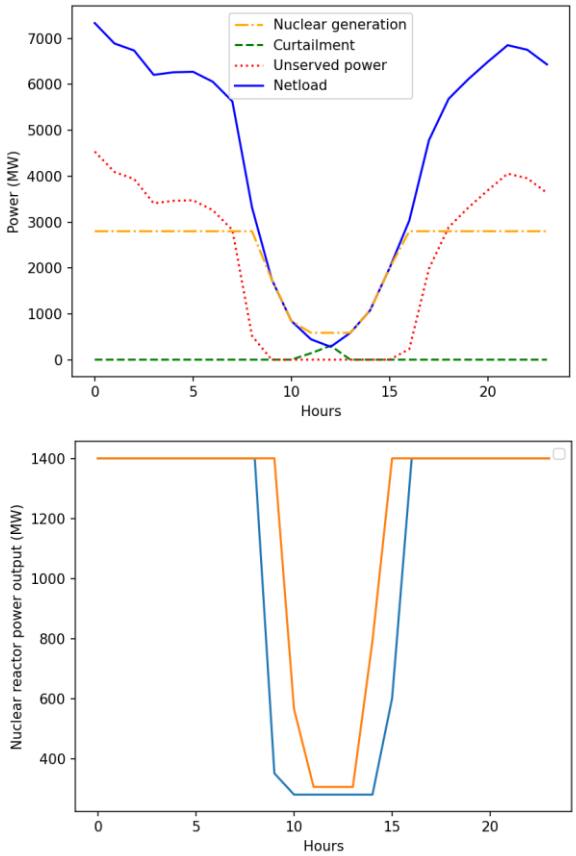

Figure 22: Results for 10/05/2025, 2 reactors of 1.4 GW each, fully available

For this case with only one reactor available, 51% of the necessary power was served by nuclear, and curtailment represented less than 1% of the total renewable energy production.

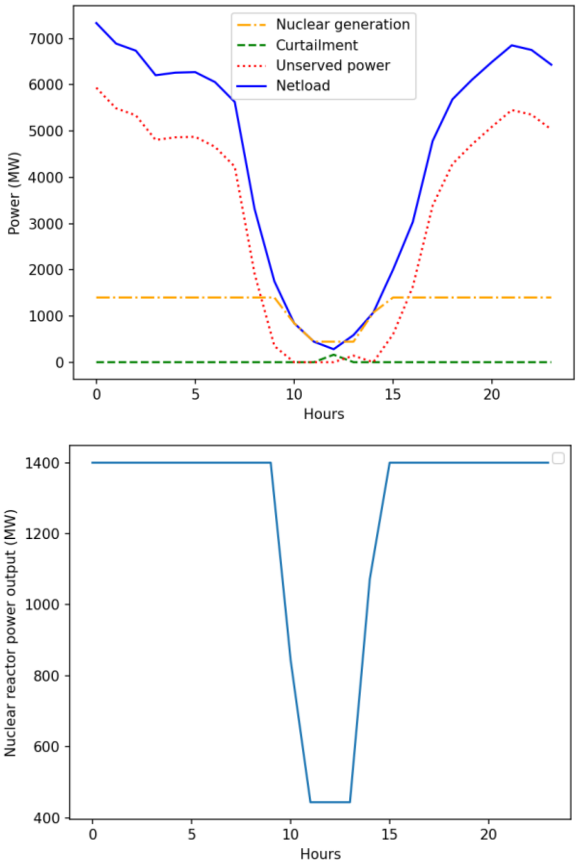

Figure 23: Results for 10/05/2025, 1 reactor of 1.4 GW, fully available

For this case with only one reactor available, 28% of the necessary power was served by nuclear, and curtailment represented less than 1% of the total renewable energy production.

8.3 Discussion

These results indicate that, even with only one or two reactors available, nuclear generation is capable of adapting to the midday dip in net load. However, curtailment still occurs. Moreover, even when both reactors are operational, nuclear power supplies only about half of the total electricity demand. This highlights the continued need for additional generation resources to ensure system balance and meet the remaining load. A tailored model would be necessary to conduct a more detailed assessment.

9. Model validation: confrontation with real data

It is particularly insightful to compare the model's results under current French renewable energy penetration levels with actual historical nuclear generation data. This comparison serves two main purposes. First, although the model is conducted to assess nuclear power's flexibility limitations and not to predict nuclear generation (which is driven by many other factors), it is insightful to see how real production evolves compared to simulated nuclear generation. Second, it helps identify the model's limitations, particularly regarding its assumptions about nuclear flexibility. By contrasting simulated and observed nuclear output, this section highlights whether the model may be overestimating the responsiveness of the nuclear fleet. Such an analysis is interesting to ensure that the model reflects realistic operational conditions and to inform any refinements needed for more accurate assessments of nuclear flexibility in future energy scenarios.

9.1 Methodology

To assess the realism and accuracy of the model, a nuclear fleet replicating the characteristics of the current French fleet is simulated. This simulation uses the same optimization model as in the previous case studies, applied to a system composed of 56 nuclear reactors, each with a nominal capacity of 1100 MW. The reactors' availability follows the schedule previously introduced. The objective is to evaluate how well the model reproduces actual operating behaviour under real-world conditions. To this end, the simulation results are directly compared with observed nuclear generation data from 2023, provided by RTE.

In order to ensure a meaningful comparison between the model and reality, a small but important adjustment is made to the computation of the net load. Unlike in the case studies, where net load was simplified to total consumption minus VRE generation, this section adopts a more realistic approach. Specifically, the net load is calculated as the remaining demand after accounting for all electricity generation sources with a marginal cost lower than that of nuclear power. This follows the merit order principle, which dictates that the lowest-cost generation sources are dispatched first. An illustration of the merit order principle is provided by Figure 24.

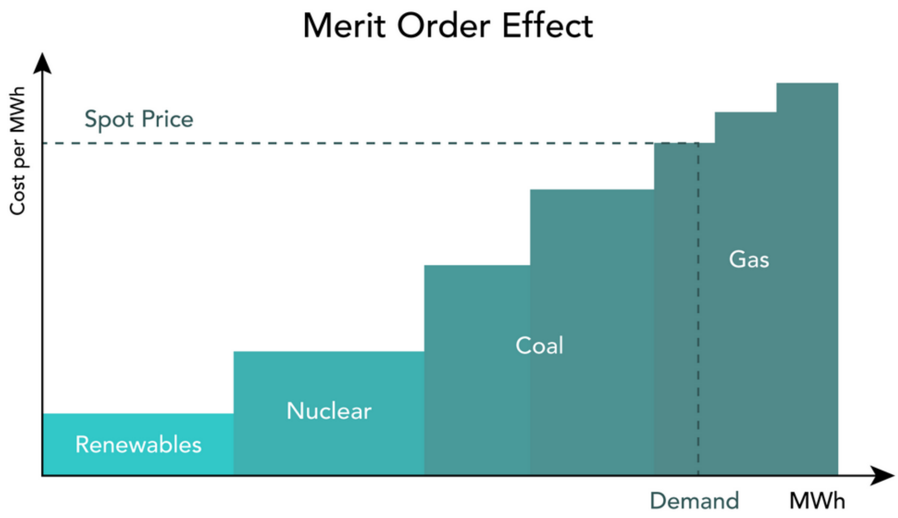

Figure 24: Illustration of the merit order. Credits: squeaky energy

Accordingly, the net load used in this comparison reflects the portion of demand that would economically be met by nuclear generation, and is computed as follows:

$NL = CONS - GEN_{SOLARP} - GEN_{WIND} - GEN_{HYDRO} - GEN_{WASTE}$

with the real solar, wind, hydro and waste electricity generation data from 2023.

The model is then run to assess how nuclear power would respond to the calculated net load, considering the technical constraints outlined earlier. The results are compared with actual nuclear power production data from 2023. The analysis focus on eight specific days: Wednesday 1 February 2023, Sunday 5 February 2023, Wednesday 5 April 2023, Sunday 9 April 2023, Wednesday 12 July 2023, Sunday 16 July 2023, Wednesday 11 October 2023, and Sunday 15 October 2023.

9.2 Results

The results of the eight comparative analyses, corresponding to the selected dates, are presented in detail below:

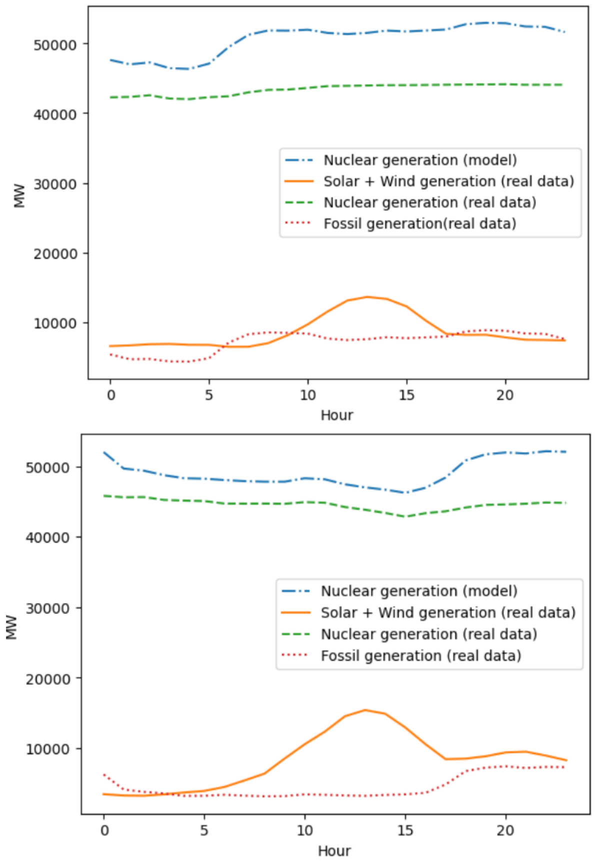

Figure 25 : Comparison between actual nuclear generation data and model results with 56 reactors for Wednesday 1 February 2023 (left) and Sunday 5 February 2023 (right)

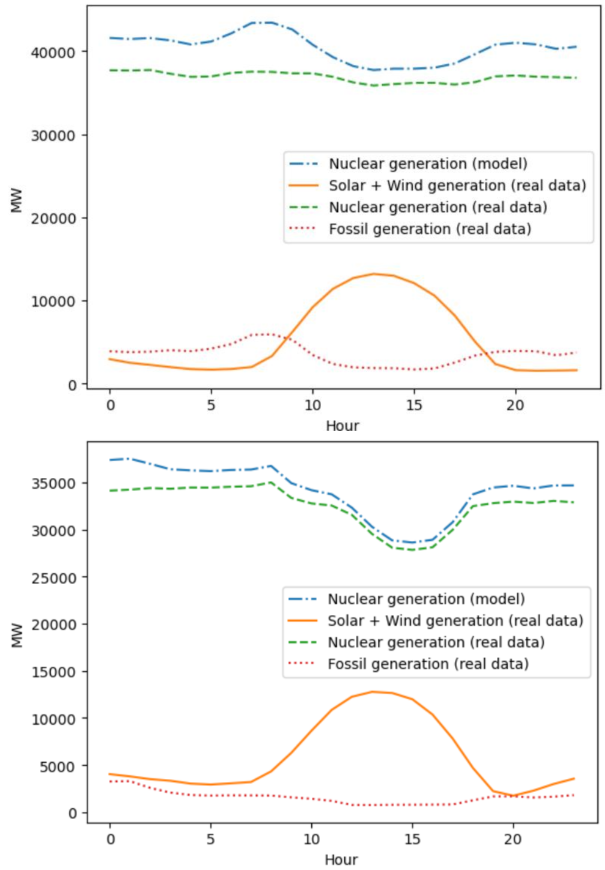

Figure 26 : Comparison between actual nuclear generation data and model results with 56 reactors for Wednesday 5 April 2023 (left) and Sunday 9 April 2023 (right)

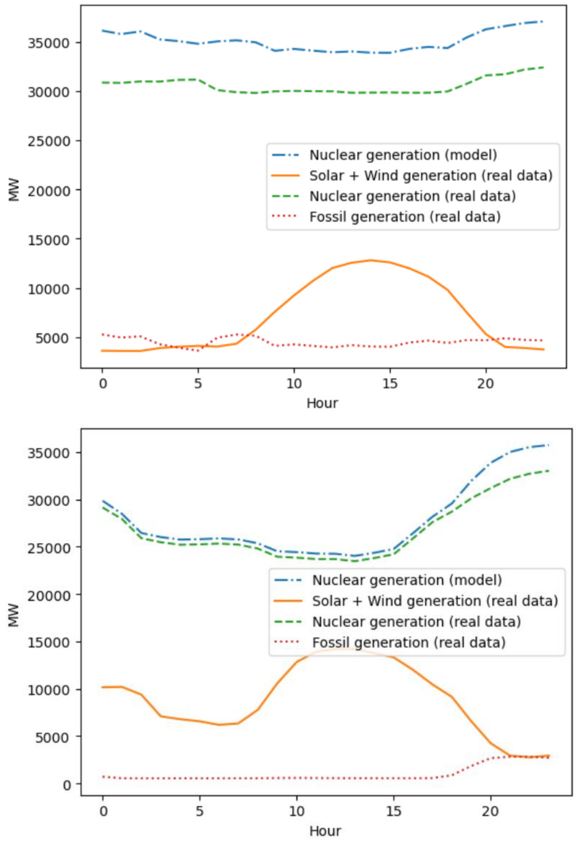

Figure 27 : Comparison between actual nuclear generation data and model results with 56 reactors for Wednesday 12 July 2023 (left) and Sunday 16 July 2023 (right)

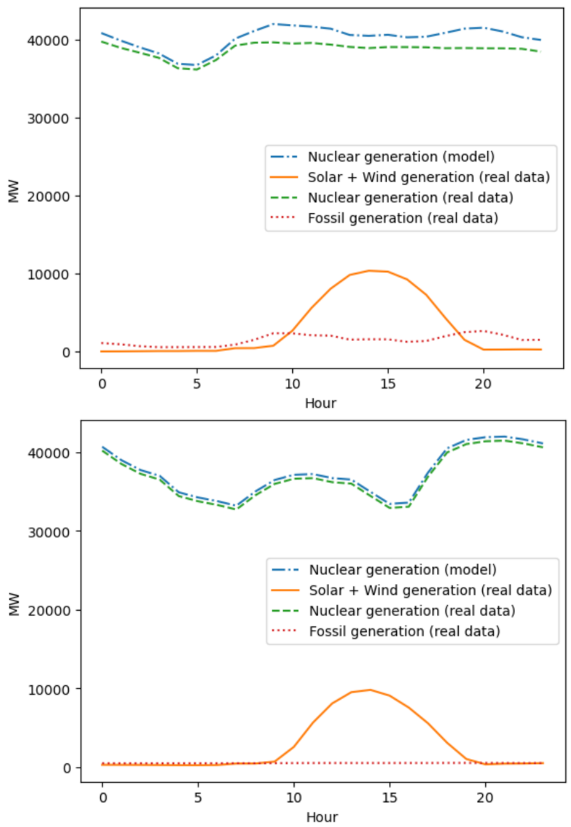

Figure 28 : Comparison between actual nuclear generation data and model results with 56 reactors for Wednesday 11 October 2023 (left) and Sunday 15 October 2023 (right)

9.3 Discussion

Alignment between the model and real production data

The results show that, for certain days, the modelled nuclear generation aligns particularly well with actual observed data. This is an encouraging outcome, as the primary purpose of the model is not to predict real-world nuclear output, but rather to assess the technical limitations of nuclear flexibility. The fact that the model is able to closely reproduce actual generation on some days suggests that it accurately captures the physical behaviour and constraints of the nuclear fleet, reinforcing its relevance and reliability for flexibility analysis.

Overestimation of nuclear power availability

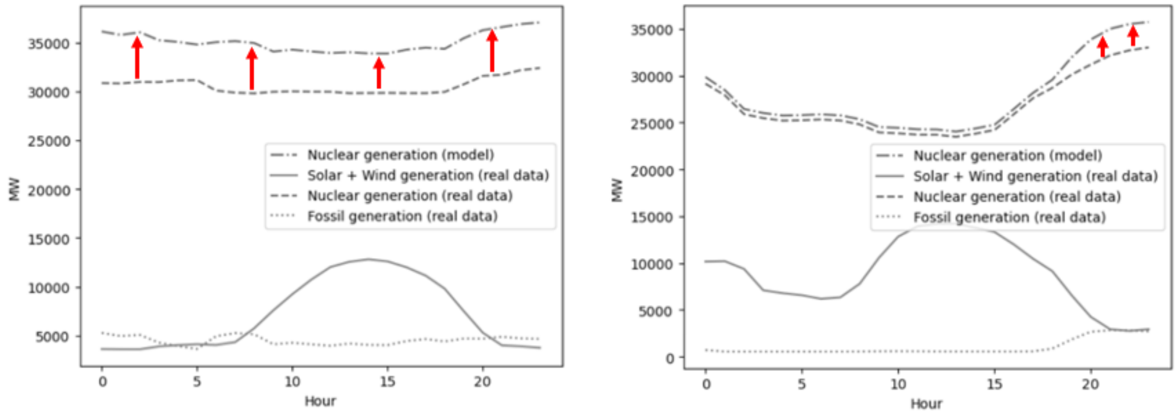

Figure 29: Illustration of nuclear overgeneration in the model compared to real data

The results obtained for these eight days offer valuable insights into the differences between the model's predictions and the actual nuclear generation data, shedding light on possible overestimations of the nuclear fleet's operational flexibility. A key observation from this comparison is that the model consistently forecasts higher nuclear generation levels than those recorded in reality, as shown by Figure 29. Several factors could contribute to this discrepancy, including the fact that the model does not account for electricity imports and exports, which can influence the net load and dispatch patterns for instance.

However, a closer examination of reactor availability data provided by RTE for these specific days suggests that the model may be overestimating nuclear power availability itself. In 2023, the French nuclear fleet was still grappling with the aftermath of the stress corrosion cracking issues first identified in 2022. This widespread technical challenge forced numerous reactors to be taken offline for inspections and repairs, and not all had been fully restored by 2023. As a result, the average capacity factor for the year fell to approximately 64%, substantially below typical historical levels. Given these exceptional circumstances, it is unsurprising that the model, based on nominal availability assumptions, overestimates the nuclear fleet's actual operational capacity during this period. Figure 30 shows how the overestimated availability can explain why the model results are always higher than real production data.

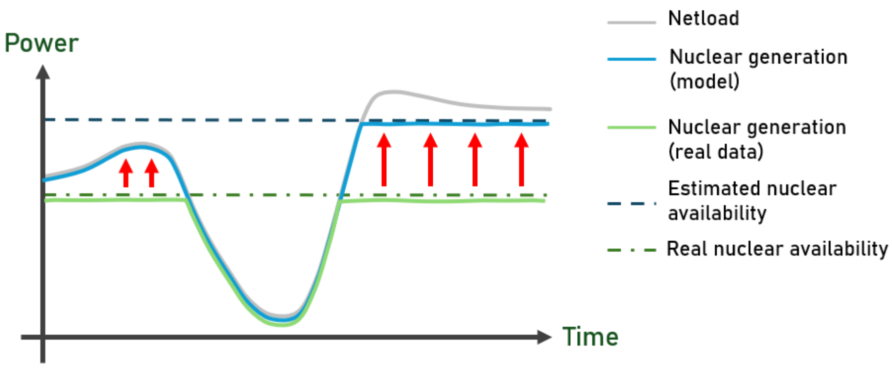

Figure 30: Illustration of the impact of overestimated nuclear availability on the discrepancy between model results and actual generation data

Ramp up discrepancies

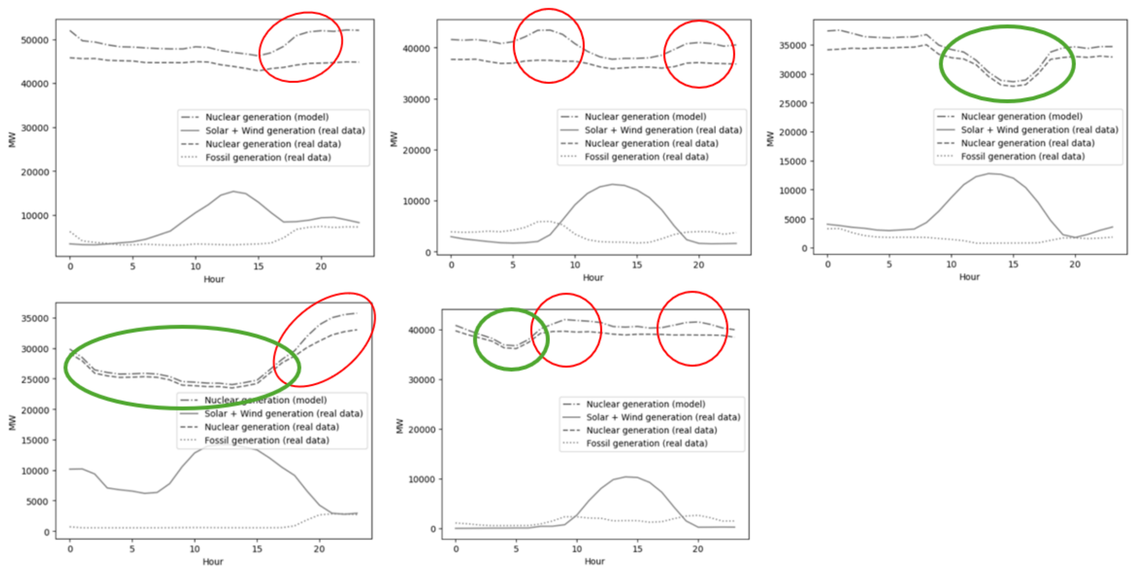

Figure 31: Illustration of inaccurate (red) vs accurate (green) variation predictions from the nuclear generation model

A second notable observation is that the discrepancies between the model's predictions and the actual nuclear generation data tend to be smaller during sudden decreases in nuclear output than during sudden increases. In other words, the model aligns more closely with reality when simulating rapid ramp-downs of nuclear generation but tends to overestimate the nuclear fleet's ability to ramp up quickly.

An overestimation of upward flexibility might initially seem to explain the discrepancy during ramp-ups. However, this explanation becomes less convincing when considering that the model does accurately predict instances of sudden decreases in nuclear generation. This suggests that the nuclear fleet is indeed capable of downward flexibility at levels consistent with the model's assumptions. A more plausible interpretation connects back to the first observation regarding overall availability: the actual availability of nuclear reactors is lower than the model assumes. This lower availability likely limits the fleet's ability to ramp up generation swiftly, even though it can manage sudden generation drops relatively well. Therefore, while the model captures downward ramping flexibility reasonably accurately, it tends to overestimate the fleet's upward ramping capacity due to optimistic assumptions about nuclear availability. Figure 32 illustrates this explanation.

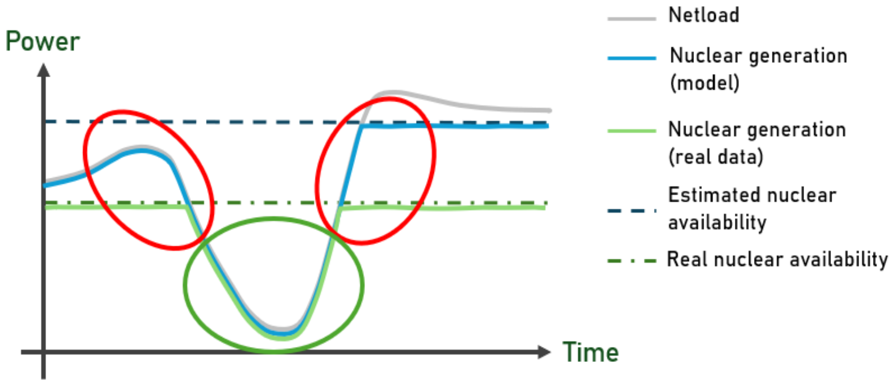

Figure 32: Illustration of the impact of overestimated nuclear availability on the discrepancy between model results and actual generation data

Finally, the discrepancy between the model's results and the actual nuclear generation data tends to be smaller on Sundays compared to the corresponding Wednesdays of the same month. This difference likely stems from the distinctive electricity demand patterns typically observed on Sundays, where demand is generally lower or exhibits a lower minimum than on weekdays. Because net load (demand minus variable renewable generation) is usually reduced on Sundays, it is more common for available nuclear capacity to exceed demand on these days. As a result, the nuclear fleet must provide greater flexibility on Sundays to prevent oversupply and adjust output according to net load variations.

Conversely, on weekdays, the actual availability of nuclear capacity is often insufficient to surpass net load levels, meaning the fleet's output is primarily constrained by demand rather than by flexibility limits. Since the model assumes higher nuclear availability than is observed in reality, it allows the fleet to exceed demand and exhibit greater flexibility on weekdays, leading to a larger gap between simulated and observed generation.

In contrast, on Sundays, actual nuclear availability is frequently high enough to require the fleet to actively adjust to net load fluctuations, causing the model's predictions to better reflect the real operational behaviour. This explains why the model's results tend to align more closely with observed data on Sundays than on weekdays.

Conclusions

In conclusion, the model generally forecasts greater nuclear flexibility than what is observed in actual generation data. The primary cause appears to be an overestimation of the availability of nuclear reactors rather than their operational flexibility. Unfortunately, detailed data on individual reactor cycle durations, as well as the precise start and end dates of reactor outages, are not publicly accessible. This limitation necessitated relying on the aggregated fleet availability schedule introduced earlier.

Nonetheless, as demonstrated by the results from Sundays, this overestimation of availability is less problematic when the net load remains below the maximum nuclear power output. Such conditions become more frequent with increasing shares of VRE in the mix. This suggests that, despite its limitations, the model remains well-suited for exploring future scenarios characterized by higher renewable penetration, where nuclear generation is more likely to operate below its maximum capacity and adjust flexibly to net load variations.

10. Conclusion

10.1 Summary

In this study, a Mixed Integer Linear Programming (MILP) model was developed to assess the hourly flexibility of a nuclear fleet in a future electricity mix with high shares of VRE. The model was designed to simulate a fleet representative of France's current nuclear system across eight strategically selected days, chosen to reflect the seasonal and weekly variations in net load throughout the year.

The model was used to explore scenarios with VRE shares ranging from 20% to 70%, enabling a detailed examination of the technical interactions between nuclear power and renewables at different penetration levels. The analysis revealed that, although the nuclear fleet can ramp up and down quickly enough to accommodate up to 70% VRE share, it is subject to several flexibility constraints.

Four key limitations were identified:

1. A maximum power output constraint, restricting the fleet's ability to serve demand peaks.
2. A minimum power output constraint, which can result in renewable energy curtailment during low net load periods.
3. Reduced flexibility near minimum output, where many reactors hit their individual minimum generation limits.
4. The difficulty in adapting to a third net load dip in the day, which is increasingly common in high VRE scenarios.

Among these, the first two factors (maximum and minimum output constraints) were found to be the most influential in shaping a trade-off around the nuclear fleet size.

A detailed analysis was conducted to assess how unserved demand and curtailed renewable energy vary across combinations of VRE shares and fleet sizes. This sensitivity analysis showed that while increasing the fleet size reduces unserved energy, it also leads to rising levels of curtailment from around 50% VRE share onward.

To complement this technical assessment, the economic implications of oversizing the nuclear fleet were also explored by calculating average capacity factors across all configurations. These results showed that a larger fleet operating in a high VRE environment may experience significantly lower capacity factors, dropping below 70% for the current-sized fleet (56 reactors) beyond 30% VRE share. This suggests that, beyond a certain point, expanding the nuclear fleet to increase flexibility could be economically challenging under current market conditions.

The model was applied to the two most plausible RTE scenarios currently under consideration. The results suggest that, while nuclear remains a major source of electricity production in both cases, the fleet sizing tends to limit the need for significant flexibility manoeuvres. However, the more detailed analysis highlights that curtailment remains an issue worth studying, particularly during solar production peaks, which are difficult to accommodate. Beyond these two scenarios, it is also important to consider the entire transition phase: moving from a historically nuclear-dominant system to one with a greater share of renewables and a more moderate nuclear presence is likely to generate situations where both nuclear and VRE outputs are simultaneously high, potentially increasing the need for flexibility during the transition period.

Finally, the model's validity was tested by comparing its outputs under current French VRE conditions with actual generation data from 2023. This comparison revealed a tendency of the model to overestimate nuclear power generation, primarily due to overestimated reactor availability rather than an incorrect representation of flexibility. Nevertheless, the model's performance was more accurate on low-demand days (like Sundays), where net load was generally below nuclear capacity, which is an increasingly frequent situation in high VRE scenarios.

10.2 Answers to research questions

Overall, this work contributes to answering the research questions that guided the study:

1. **What is the maximum share of renewable penetration that nuclear alone can support?**

The maximum renewable penetration that nuclear power can support is inherently context-dependent, influenced by factors such as the relative size of the nuclear fleet compared to total electricity demand, seasonal variations in weather, and the generation profiles of variable renewable energy (VRE) sources. Focusing specifically on the French case, the concept of "support" must be clearly defined. If we define support as nuclear's ability to perfectly balance VRE on an hourly basis, eliminating both unserved demand and curtailment, then nuclear alone cannot achieve this. Across all scenarios tested, with nuclear fleets ranging from 15 to 56 reactors and VRE shares between 20% and 70%, there was never a scenario where both curtailment and unserved energy were reduced to zero. The closest approximation occurs with the full 56-reactor fleet paired with around 30% VRE, which nearly meets these criteria but still falls short. Moreover, even in this near-optimal scenario, nuclear alone cannot guarantee system stability at shorter timescales due to operational constraints. Therefore, nuclear power, while highly flexible, cannot single-handedly support very high renewable penetrations without additional flexibility sources.
However, it is important to recognise that nuclear power can provide significant flexibility and contribute substantially to balancing efforts. Therefore, nuclear flexibility is a not solitary component in the transition towards higher shares of renewables.

2. **Under various increasing share of renewables in electricity generation scenarios, what are the optimal sizing requirements for nuclear to preserve system balance?**

Determining the optimal size of the nuclear fleet in scenarios of growing renewable penetration requires balancing several competing objectives. The key trade-off lies between minimising unserved energy and curtailment while maintaining an economically viable nuclear capacity factor. Larger nuclear fleets reduce unserved energy and curtailment by providing more flexible capacity, but they also risk driving down the capacity factor, which can undermine economic sustainability. Conversely, smaller fleets maintain higher capacity factors but may result in greater curtailment or insufficient supply. Hence, the optimal sizing is a nuanced compromise that depends on acceptable thresholds for unserved energy, curtailment levels, and economic performance metrics. This balance is essential to preserving system reliability while ensuring the financial health of nuclear assets.

3. **How do power curtailment and nuclear reactor profitability evolve with nuclear flexible use?**

The relationship between power curtailment and nuclear profitability is closely tied to the relative size of the nuclear fleet compared to the net load. As the nuclear fleet expands relative to electricity demand, curtailment tends to increase. This is primarily because the total minimum power output of the fleet rises, making it increasingly difficult to adapt to dips in the net load, particularly during periods of high VRE generation. In such situations, nuclear units are unable to ramp down sufficiently, leading to excess generation that must be curtailed. This trend is clearly reflected in the simulation results.

In the case of France with 56 reactors, at lower levels of VRE penetration, specifically 20% and 30%, curtailment remains minimal. With a fleet of 15 reactors, no curtailment is observed, and even with 56 reactors, curtailment stays below 1% of total VRE production. However, as the share of VRE increases, curtailment becomes more pronounced, increasing roughly linearly with the fleet size. At 40% VRE penetration, curtailment rises from 0% with 15 reactors to 3% with 56 reactors. At 50% VRE, it increases from 0% to 7%; at 60%, from 2% to 13%; and at 70%, from 7% to 22%. This increase highlights the growing mismatch between supply and demand as the nuclear fleet size expands in high-renewable contexts.

Higher number of reactors also correspond to lower utilisation rates for nuclear reactors, as reflected in declining average capacity factors. At lower VRE shares, specifically 20% and 30%, all fleet sizes from 15 to 56 reactors maintain an average capacity factor above 75%. However, as the share of VRE increases, fewer configurations are able to sustain this threshold. At 40% VRE, a fleet of 56 reactors falls below the 75% capacity factor mark. At 50% VRE, even a 50-reactor fleet can no longer reach this level. At 60%, the threshold is no longer met with a 40-reactor fleet, and at 70%, only the smallest fleets, comprising 15 and 20 reactors, still achieve an average capacity factor above 75%.

Reduced capacity factors adversely affect the economic viability of nuclear plants by spreading fixed costs over fewer operating hours and increasing operational wear. However, the results also show that a carefully sized and flexibly operated nuclear fleet can limit curtailment while preserving economic viability. When appropriately dimensioned to match the shape and variability of net load, nuclear generation can remain a cost-effective and reliable complement to VRE, helping to balance the system without excessive curtailment or underutilisation.

4. How do the French energy mix scenarios align with the findings in this study?

France's net-zero pathways N1 and N2 appear to fall within a moderate flexibility requirement zone, where the nuclear fleet size is relatively balanced with net load. In these scenarios, nuclear power remains a central pillar of the generation mix but cannot fully meet demand alone, as it serves 59% of the netload in N1 and 75% of the netload in N2, indicating that significant additional dispatchable, low-carbon resources will be necessary to supply the residual load. While overall renewable curtailment remains limited (6% of total renewable production in N1 and 4% in N2), it is expected to occur during peak solar generation periods, especially in summer months. Nuclear plants, operated with some flexibility, are projected to sustain relatively high-capacity factors (78% in N1 and 82% in N2), consistent with maintaining economic viability.

5. How about Queensland nuclear proposals?

Only one day was studied to examine Queensland nuclear proposals. First results indicate that two reactors is enough to demonstrate flexibility and adapt to midday net load dips. However, results also demonstrate minimal curtailment, which would probably be greater during summer months. Finally, a significant share of the load is not served by nuclear power (at least 49% in the results). However, these insights remain exploratory and should be interpreted with caution. A comprehensive assessment would require further modelling, tailored to the Australian situation.

10.3 Limitations and future research

To deepen the understanding of flexibility challenges in these scenarios, future research should explore alternative scheduling assumptions that would better account for the real availability of the reactors among the fleet. Additionally, further economic analysis of nuclear flexibility, particularly examining how market dynamics interact with capacity factors and operational constraints, would offer valuable insights on the real impacts of flexibility on reactor's economic profitability. Lastly, expanding the analysis to shorter timescales, or similar timescales with probabilistic components to model net load variation uncertainties, is essential to comprehensively evaluate the contribution of nuclear power to real-time grid stability.

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12. Appendices

Appendix 1: Net load scenarios with increasing renewable energy penetration

01/02/2023

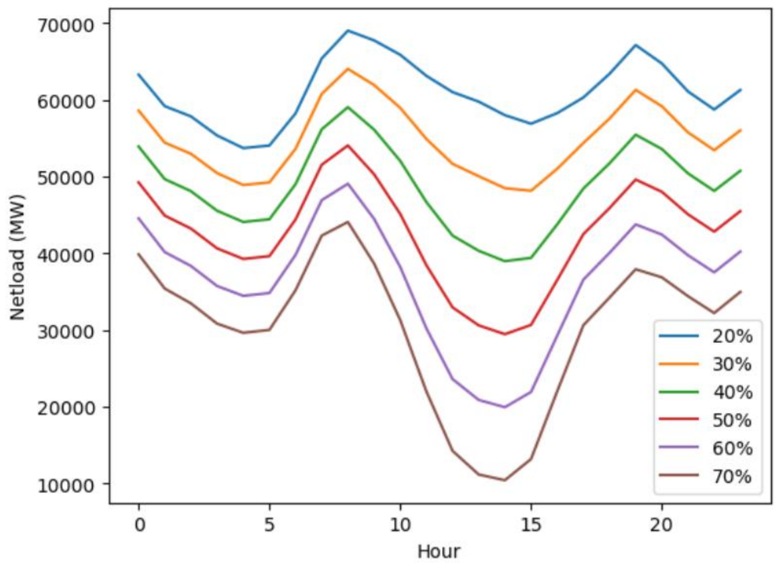

Figure 33 : Net load profiles of 01/02/2023 with increasing VRE penetration. From top to bottom: 20%,30%;40%,50%,60% and 70% renewable energy penetration.

Table 9 : Net load metrics for various renewable penetration scenarios on 01/02/2023

RENEWABLE PENETRATION	20%	30%	40%	50%	60%	70%
MAXIMUM	69039	64048	59058	54067	49076	44085
MINIMUM	53724	48155	38977	29459	19940	10422
MAXIMUM POSITIVE GRADIENT	7158	7151	7144	7137	7343	8833
MAXIMUM NEGATIVE GRADIENT	-4116	-4186	-5371	-6684	-7997	-9310
STANDARD DEVIATION	4159	4553	5454	6659	8032	9501
COEFFICIENT OF VARIABILITY	0.068	0.083	0.112	0.156	0.220	0.314

05/04/2023

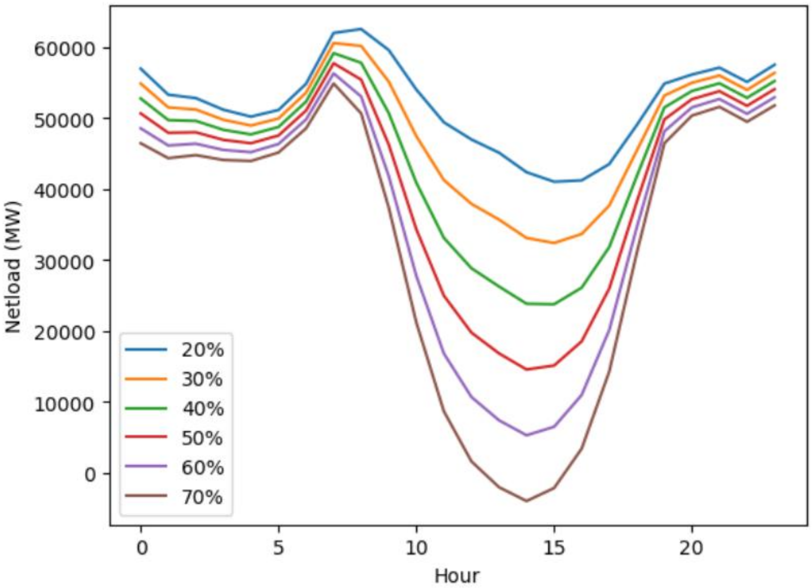

Figure 34 : Net load profiles of 05/04/2023 with increasing VRE penetration. From top to bottom: 20%,30%;40%,50%,60% and 70% renewable energy penetration.

Table 10 : Net load metrics for various renewable penetration scenarios on 05/04/2023

RENEWABLE PENETRATION	20%	30%	40%	50%	60%	70%
MAXIMUM	62548	60576	59151	57727	56303	54879
MINIMUM	41039	32407	23776	14579	5313	-3953
MAXIMUM POSITIVE GRADIENT	7162	7762	9987	12234	14481	16728
MAXIMUM NEGATIVE GRADIENT	-5558	-7685	-9811	-11938	-14064	-16191
STANDARD DEVIATION	6098	8643	11483	14444	17465	20520
COEFFICIENT OF VARIABILITY	0.117	0.179	0.259	0.358	0.479	0.629

12/07/2023

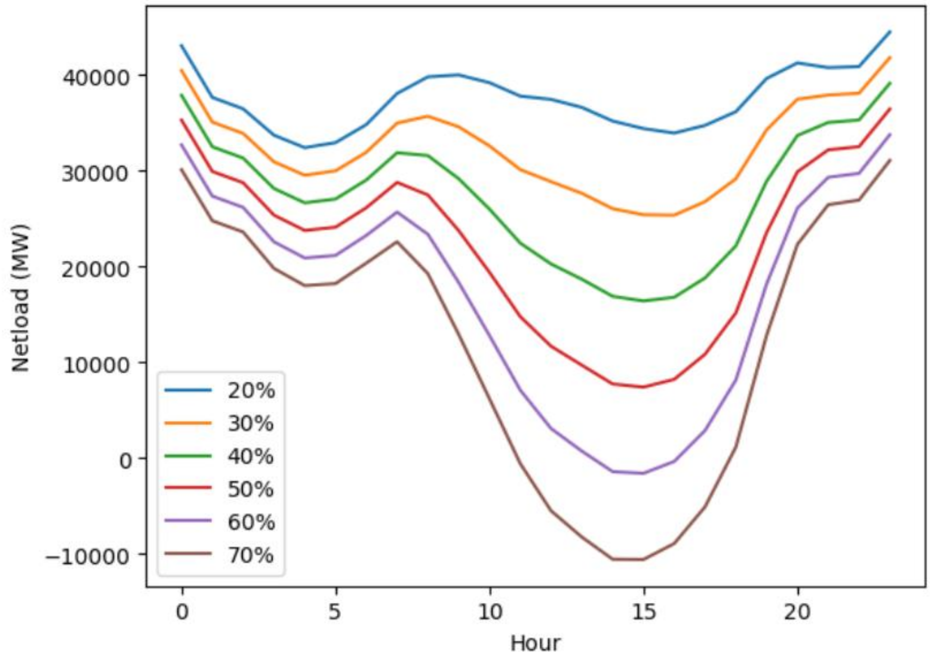

Figure 35 : Net load profiles of 12/07/2023 with increasing VRE penetration. From top to bottom: 20%,30%;40%,50%,60% and 70% renewable energy penetration.

Table 11 : Net load metrics for various renewable penetration scenarios on 12/07/2023

RENEWABLE PENETRATION	20%	30%	40%	50%	60%	70%
MAXIMUM	44498	41815	39131	36448	33764	31081
MINIMUM	32418	25368	16412	7414	-1584	-10582
MAXIMUM POSITIVE GRADIENT	3617	5116	6759	8402	10045	11687
MAXIMUM NEGATIVE GRADIENT	-5400	-5387	-5373	-5360	-5695	-6769
STANDARD DEVIATION	3178	4632	6753	9085	11500	13956
COEFFICIENT OF VARIABILITY	0.084	0.142	0.247	0.409	0.673	1.16

11/10/2023

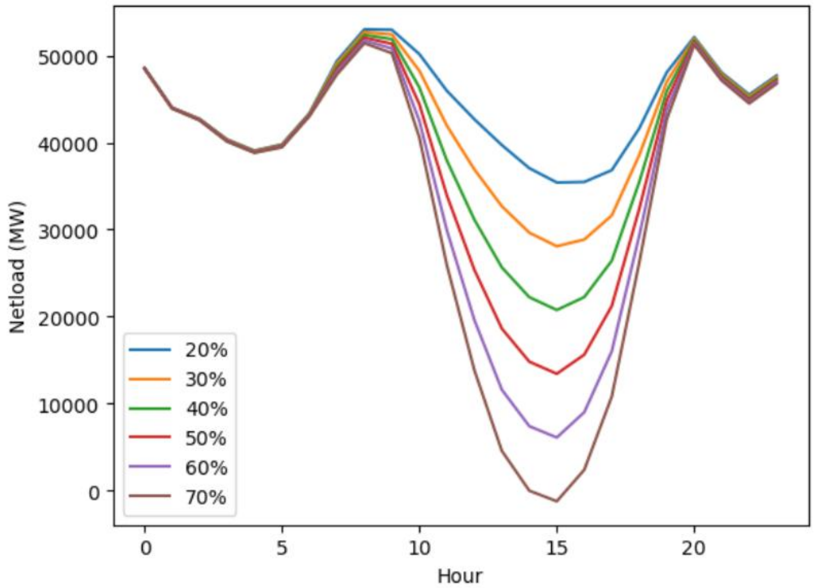

Figure 36 : Net load profiles of 11/10/2023 with increasing VRE penetration. From top to bottom: 20%,30%;40%,50%,60% and 70% renewable energy penetration.

Table 12 : Net load metrics for various renewable penetration scenarios on 11/10/2023

RENEWABLE PENETRATION	20%	30%	40%	50%	60%	70%
MAXIMUM	52998	52680	52361	52043	51724	51406
MINIMUM	35406	28084	20762	13440	6118	-1204
MAXIMUM POSITIVE GRADIENT	6430	8434	10439	12443	14447	16451
MAXIMUM NEGATIVE GRADIENT	-4543	-6301	-8388	-10475	-12562	-14650
STANDARD DEVIATION	5384	7436	9836	12383	15003	17663
COEFFICIENT OF VARIABILITY	0.121	0.177	0.246	0.328	0.422	0.529

Appendix 2: Simulation results for increasing renewable energy penetration

12/07/2023

30% renewable penetration: suboptimal solution found after 200,000 iterations

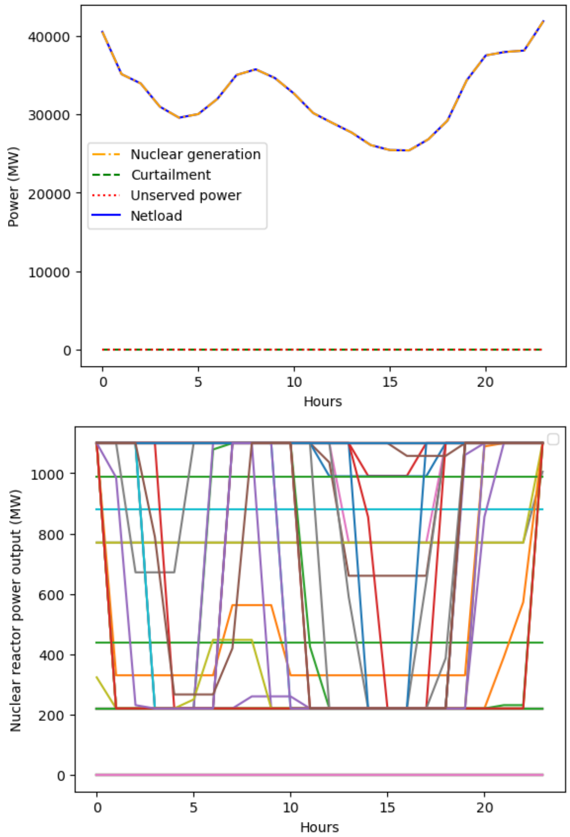

Figure 37: Simulation results for 12/07/2023, 30% renewable energy share, 56 reactors

40% renewable penetration: suboptimal solution found after 200,000 iterations

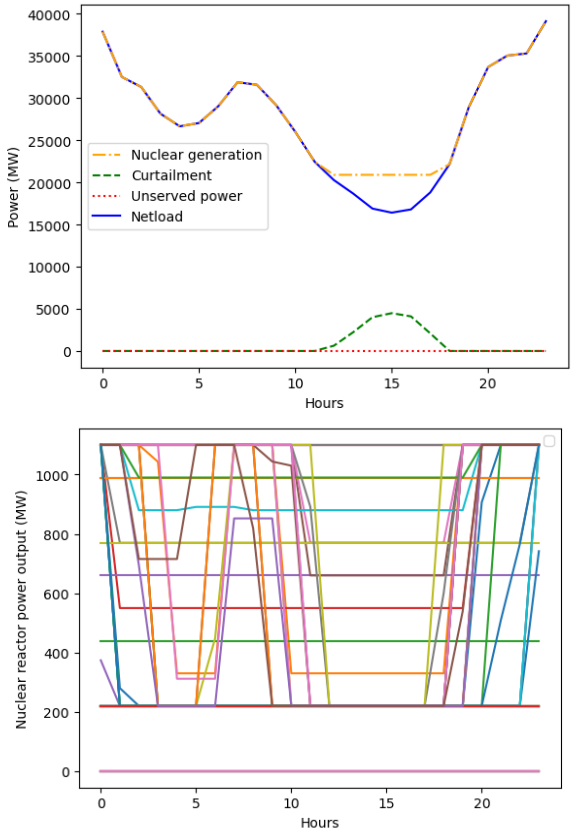

Figure 38: Simulation results for 12/07/2023, 40% renewable energy share, 56 reactors

50% renewable penetration: suboptimal solution found after 200,000 iterations

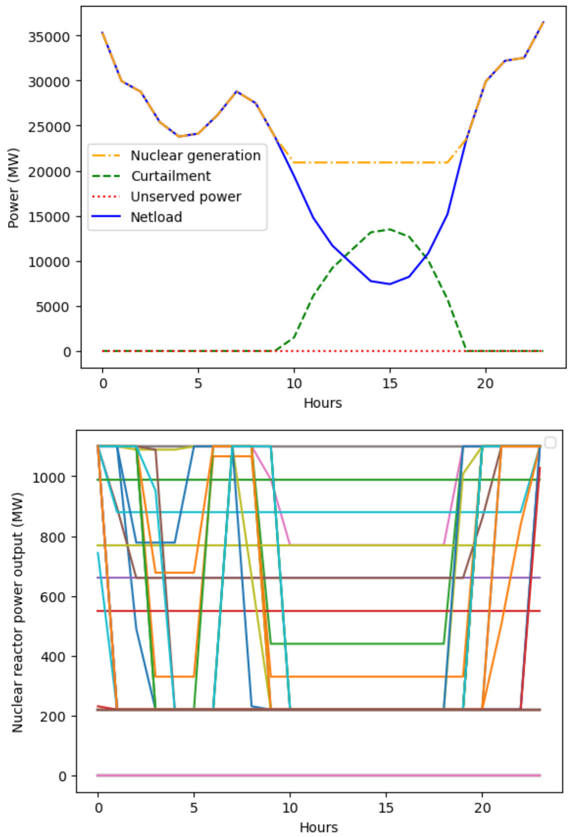

Figure 39: Simulation results for 12/07/2023, 50% renewable energy share, 56 reactors

60% renewable penetration: suboptimal solution found after 200,000 iterations

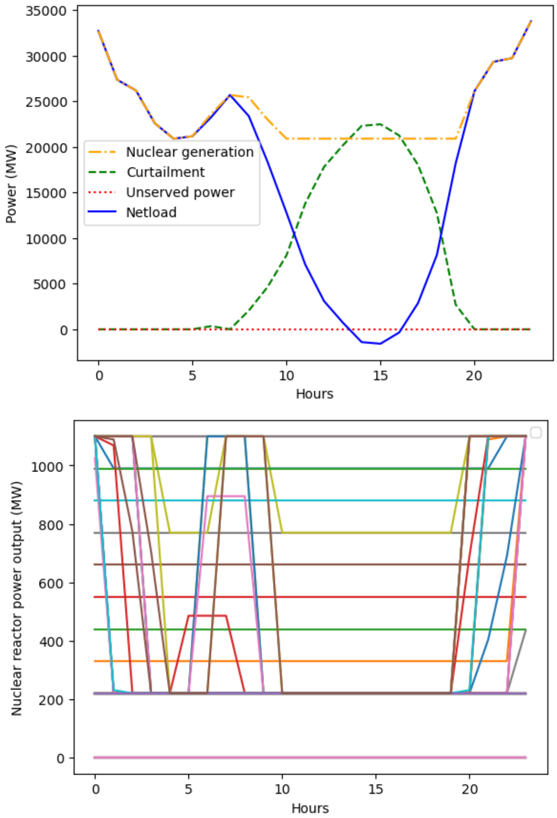

Figure 40: Simulation results for 12/07/2023, 60% renewable energy share, 56 reactors

70% renewable penetration: suboptimal solution found after 200,000 iterations

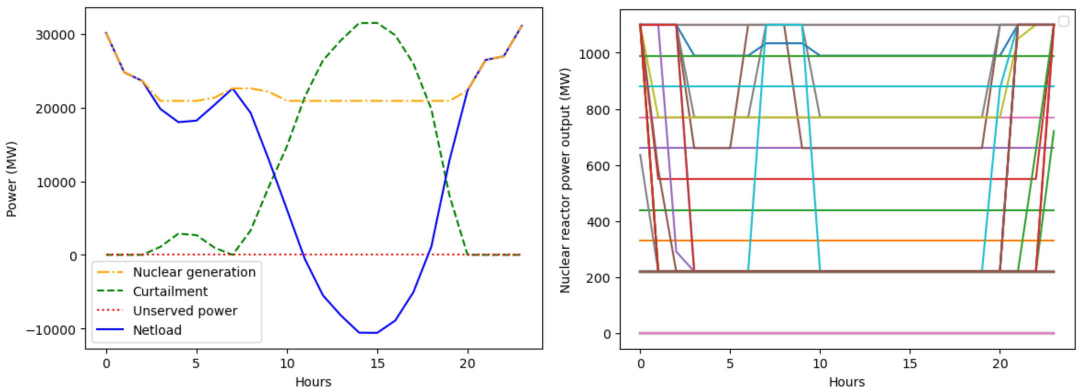

Figure 41: Simulation results for 12/07/2023, 70% renewable energy share, 56 reactors

Appendix 3: Simulation results for France's net-zero pathways

Scenario resembling N1: 26 reactors, 60% VRE share

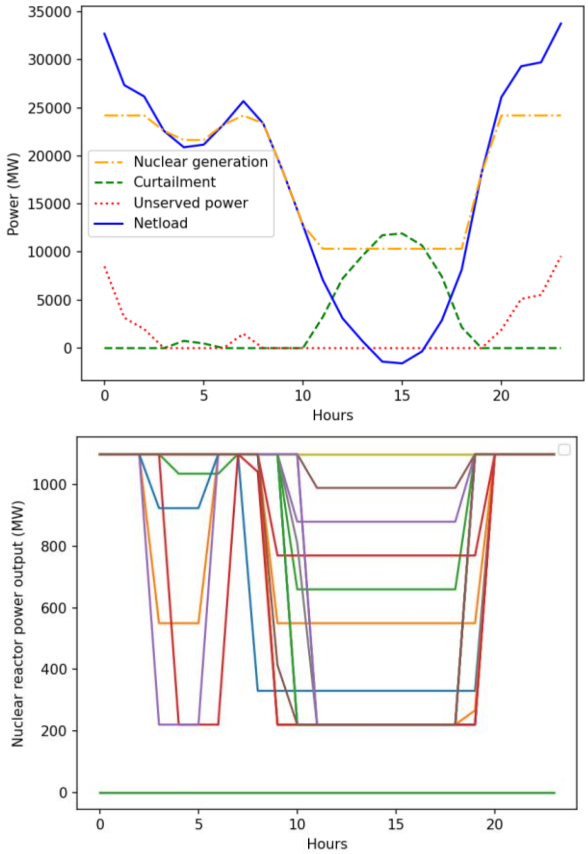

Figure 42: Simulation results for 12/07/25, 60% renewable energy share, 26 reactors

Scenario N2-like: 35 reactors, 50% VRE share

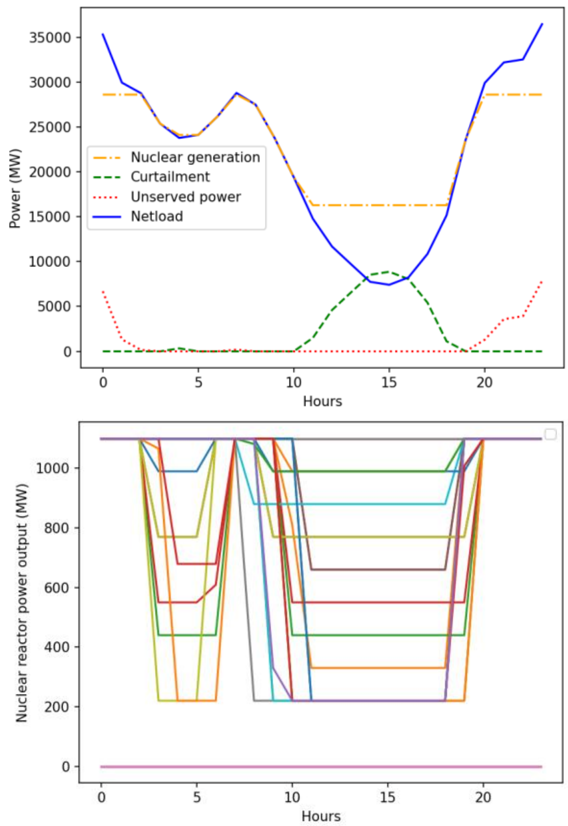

Figure 43: Simulation results for 12/07/25, 50% renewable energy share, 35 reactors

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