Nuclear generation and flexibility in renewables-driven electric systems: Simulation and optimization models

Arthur Lynch, Gilles Mathonnière, Sophie Gabriel, Yannick Perez

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Arthur Lynch[1][2], Gilles Mathonnière[1], Sophie Gabriel[1], Yannick Perez[2]

[1] *Institute for Techno-Economics of Energy Systems (I-TESE), CEA, DES, Université Paris-Saclay, F-91191 Gif-sur-Yvette, France*
[2] *Laboratoire Génie Industriel, CentraleSupélec, Université Paris-Saclay 3 rue Joliot-Curie, 91190 Gif-sur-Yvette, France*

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Highlights :

- The need for balancing services grows as the share of variable renewable technologies in the capacity mix heightens.
- Although nuclear reactors are optimally used as baseload generation, they are flexible and can ensure effective balancing services to electric systems.
- To determine the optimal capacity mix and/or foresee future costs and carbon footprint in renewables-driven systems, capacity expansion, and simulation models need to account for nuclear's flexibility potential.
- Current models seem to include short-term flexibility characteristics such as ramping constraints but ignore long-term characteristics like operational schedule seasonality.
- Potential misestimation of nuclear flexibility may invalidate models' results regarding variable renewables integration, optimal capacity mix, generating technologies' competitiveness as well as electric systems' costs, supply's security, and carbon footprint

Abstract:

The recent development of variable renewable technologies in electric systems calls for prospective work regarding, among others, the future optimal capacity mix as well as its related carbon footprint, security of supply, and overall costs. In the context of diminishing and fickle residual electric demand, each generating technology's operational flexibility will partly determine whether they shall participate in future de-carbonized electric systems, and nuclear technology is no exception. Hence, prospective capacity expansion models and simulation models focusing on renewable-driven electric systems while including nuclear technology should appropriately define and model its operational flexibility. This paper aims to identify the underlying physical mechanisms that frame this technology's flexibility and operations. We compare this "physics-induced" flexibility to the modeling practices found in the literature and discuss how neglecting some aspects of nuclear flexibility may lead to misestimation in the models' results. We find that crucial aspects such as Xenon transients' impact on reactors' flexibility and the fleet's operational schedule are not considered in the literature, even though these significantly impact actual nuclear operations. Other aspects like ramping constraints are often implemented in models, but we argue that the models' insufficient time resolution may undermine their impacts. Ultimately, this paper aims to highlight the potential benefits of a "physics-induced" nuclear modeling in renewable-driven prospective models and the advantage of adopting a fleet perspective when considering nuclear technology. Enhancing nuclear modeling would better renewables-driven models' evaluation of overall costs, carbon footprint, and security of supply at first and the need for new development in electric systems such as storage facilities, sector-coupling, and demand-side response.

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Acronyms :

ASN: Autorité de Sûreté Nucléaire – French Nuclear Safety Authority

BWR: Boiling Water Reactor

CANDU: Canadian Deuterium Uranium

CCS: Carbon Capture and Storage

ENTSO-E: European Network of Transmission System Operators for Electricity

KIT: Karlsruhe Institute of Technology

LP: Linear Programming

MILP: Mixed Integer Linear Programming

MIP: Mixed-Integer Programming

MIT: Massachusetts Institute of Technology

PWR: Pressurized Water Reactor

RTE: Réseau de Transport d'Electricité – French Transmission System Operator

VRE: Variable Renewable Energy

The rising concern surrounding climate change issues calls for a significant shift aiming to de-carbonize energy systems significantly. This shift naturally encompasses electric systems, which still mainly rely on environmentally damaging generating technologies. In this context, some states made commitments to reduce their generating mix's carbon emissions gradually, notably through massive development of variables renewables technologies like wind –onshore, offshore- and solar –photovoltaic, concentrating solar power. It is a significant change in the supply-side of electric systems. Variable Renewable Energy (VRE) technologies are characterized by their high capital – negligible variable costs and their primary position in the economic "merit order"[3] dispatch to meet the electric demand. Adding the fact that their generation is highly dependent on the weather, making it a fatal non-dispatchable generation technology, also makes it optimal to prioritize them to meet the demand. Thus, the overall effect of developing high shares of variable renewables in the generation mix is to replace technologies such as coal, lignite, and even nuclear progressively as the "baseload" means of generation of electric systems. Although variable renewable and thermal technologies are not entirely substitutable as one is fatal and the latter dispatchable, global environmental commitments aim to ensure a more significant share of the electricity demand using renewable sources.

[3] We refer here to the ranking of available generating units of an electric system, based on ascending order of price (i.e. marginal costs), aiming to minimize the overall generation costs of the system. Low marginal cost technologies then take priority over high marginal cost technologies in responding to the corresponding electricity demand.

The recent rise of variable renewables installed capacities already shapes the environmental and economic aspects of electric systems. As their share in the mix has grown, both market prices and residual demand[4] levels have lowered, and their variabilities increased [1], [2]. The integration of variable renewables into the system, coupled with higher carbon and lower gas prices, also significantly affected carbon emission levels [3]. There are, however, emerging concerns on the viability of electric systems at a higher level of penetration regarding their technical (e.g., transport and distribution grid management) and economic characteristics (e.g., cost of variable renewable subsidies). Putting aside network considerations, the main concerns, directly emerging from price and residual demand decreases and increasing variability, revolve around: 1) the balancing challenge between electricity supply and demand with a high share of variable renewables; 2) the fact that carbonized flexible units or nuclear usually ensure most of this balancing; 3) the growing difficulty to renew investments in flexible technologies at a decreasing market price, decreasing residual demand and carbon-constrained environment. Other challenges notably arise when integrating renewables, especially at the local network level, but we limit our scope to "copper-plate" electric systems neglecting spatial constraints (apart from interconnection network). These remain crucial to assess the future economic, technical, and environmental impact of variable renewables.

Substantially, whether the system is sufficiently flexible will significantly influence the challenges of integrating variable renewables. Indeed, the growing difficulty of maintaining the electricity supply-demand equilibrium in the context of a massive renewable capacity development creates a strong need for flexible services. Flexibility, as defined in [4], is *"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."*

Throughout this paper, we will also refer to generating unit flexibility –or maneuverability–, which broadly defines plants' ability to modify their output over time. In this context, numerous prospective studies have been conducted to understand better an electric system combining a significant carbon constraint, variable renewable generation, and the flexibility it implies. Those are critical parameters of the modeling paradigm we discuss in this paper. It is essential to consider all available flexible options and accurately account for their prices, operational constraints, and carbon footprint. This concern is critical as we aim to determine which generating technology is likely to meet the flexibility requirements. This paper discusses the underlying assumptions of the different approaches found in the literature defining and operating nuclear flexibility.

Nuclear power plants typically operate in a "baseload" mode, meaning that they produce at their nominal power level most of the time. As nuclear fixed costs are high and variable costs low, it is economically optimal to use this operation mode. Most countries using nuclear adopt the "baseload" operation mode, mainly because nuclear does not represent a significant share of their capacity mix. However, countries with a higher share of nuclear capacities may be forced to maneuver their nuclear power plants' output to balance electricity demand and supply. The case of the French electric system is an obvious example. As nuclear power plants represent 46.6% of the country's installed capacities and 70,6% of its electricity generation [5], they frequently maneuver to participate in load-following or ancillary services. The nuclear fleet then provides a significant part of the current French flexibility requirements. Even though nuclear power plants are mostly considered as an "inflexible" generating technology, part of the installed nuclear fleet was initially designed to operate flexibly [6] or can be adapted to this regime through re-designing work [7]. The literature regarding nuclear flexibility, its ability to follow load, and the additional costs generated - wear of components, cost of retrofit and re-designing, fuel, and staff costs- is rich [7]–[16]. In the context of rising demand for balancing services to ensure the integration of variable renewables, part of this demand could be met using the reactors' capacities to maneuver their output. This new paradigm would modify the reactor's load factor and,

[4] Residual demand is defined as the electricity demand minus fatal generation

thus, may endanger the reactors' profitability in the current market environment. It is important to note that, as described in [7], nuclear power plants' capacity to operate flexibly is highly dependent on regulatory aspects such as the national nuclear energy commission's approbation, grid system constraints, and even the operator's own employees' training. Those factors that are uncorrelated with technical constraints or economic considerations may prohibit power plant maneuverability. Although using other generating technology like hydro or batteries storage units may prove to be cost-efficient, it is necessary to include the possibility to use nuclear flexibility capacities as we aim to build comprehensive modeling of a renewable-driven electric system.

In the first part of this paper, we will recall some considerations on electric systems modeling with a high share of renewables found in the literature. The second part of the paper aims to describe the actual flexibility potential of nuclear power plants and review the different modeling approaches of nuclear flexibility found in the literature. This part does not aim to exhaustively describe every technical constraint that determines the range of nuclear flexibility but highlights the main aspects of nuclear operations that affect this range. The third part discusses whether the modeling approaches found in the literature may misestimate nuclear flexibility. By highlighting these approaches' potential flaws, one can assess the robustness of the papers from the literature regarding the share of flexibility provisions by a nuclear fleet, the optimal mix of installed capacities found in those papers, but also the need for new storage units, the level of renewables curtailment, and even the optimal level of variable renewables that the electric system can fit in. Finally, the last part will conclude.

1 Specifics considerations on modeling with a high share of renewables

The current evolution of the electricity generation capacity mix toward VRE has led to the constitution of a rich modeling literature around integrating a higher share of variable renewable sources. As mentioned previously, we limit our analysis to models aiming to represent the electric system exclusively. We do not account for the numerous interactions between electricity and other energy sectors[5]. In the following section, we point out critical characteristics found repetitively in the existing literature, such as [13], [15]–[19], that should be included in any comprehensive models. We should mention that this literature is diverse and relies on different models (e.g., Antares-Simulator (RTE), GenX (MIT), PyPSA (KIT), EOLES (CIRED)…) serving different final purposes (industrial, academic or prospective …). As pointed by [20], modeling approaches regarding flexibility in electric systems "can be divided into static (dispatch only) and dynamic (dispatch and investment) analyses.". The difference between those two approaches revolves around whether they rely on capacity mix scenarios or capacity mix trajectories based on investment optimization criteria. Despite those differences, they both aim to replicate electric system operations and, as such, share numerous vital characteristics.

1.1 Electric systems key characteristics and market structure

The modeling approaches must represent the electric system's key characteristics correctly, meaning that models try to replicate the current liberalized market conditions or justify any changes

[5] Such interactions should be included as much as possible, for example through the electricity demand for domestic heating or electric vehicles. However, those issues are not to be included in the models but can rather be determined beforehand. Nonetheless, our following remarks hold true for larger scale energetic models including electric systems with high shares of renewables.

through their assumptions. Those conditions include technical constraints like the prominent place of fatal generation (variable renewables, run-of-the-river hydro) and the need to equalize supply and demand always. It also comprehends market design specificities like the "merit order" method that currently shapes the residual demand dispatch between producers. Regulatory aspects regarding competition and environmental impact are also crucial. In the literature, to simplify the representation, electricity markets are supposed to be perfect even if, in practice, abuse of dominant position could be determinant for system operations. Other aspects may depend on system specificities, for example, hydraulic resources management. As hydraulic generation has negligible variable costs and high maneuverability, it can either be used as baseload generation or marginal generation, providing balancing services to the system. Although maximizing hydraulic generation is beneficial to both the system's costs and its carbon footprint, the hydroelectricity balancing services ensure supply security. Stakes surrounding aspects of the electric system such as storage facilities use, ancillary services rules, sector-coupling potential (electric vehicle fleet, H2 generation through electrolysis....), and other critical parameters of the studied system also need to be addressed. Any change of assumptions regarding those aspects has to be explicit as they could greatly influence results.

1.2 The objective function and main constraints

The goal of operations and capacity expansion models is to determine both environmental and economical optimal dispatch of generation. The objective function then consists of minimizing global costs of the system during a specified period. It includes fixed costs of installed capacity and resulting variable costs from each generating unit. The main difference between the two families of models is that capacity expansion models include optimizing investment in new capacities in the objective function. The installed capacity mix approaches economic optimality in capacity expansion models such as [16], whereas operations models' mix relies on predetermined scenarios like [13].

The environmental aspect can be implemented directly into the objective function, notably through a carbon tax or price that affects each technology's variable cost depending on its carbon footprint [19]. Otherwise, the modelers can also implement a carbon constraint that limits the carbon level that the electric system can emit, as in [16]. The other main constraints focus on supply-demand equilibrium, as electricity generation and consumption should always be equal.

1.3 Renewables and demand variability

As VRE generation is highly volatile due to its dependency on weather, its output can vary significantly quickly. On the other hand, the electricity load is usually highly volatile, the daily, weekly, and seasonal variations observed in many countries defining demand. Combining these two variabilities is fundamental to the residual demand profile that the other generation units and storage facilities meet to keep the supply-demand equilibrium (see §1.4 below). As mentioned before, the residual demand variability should increase as the share of variable renewables grows, which exacerbates the need to take those fluctuations into account. It is then crucial to transcribe those fluctuations correctly into the model by adopting a detailed temporal resolution. The literature is evolving in this direction.

The review done in [21] notes that analyzing some aspects of renewables integration needs a sub-hourly temporal resolution, 30 or even 15 minutes timesteps. Moreover, the assumptions related to the potential levers used to frame this variability have to be explicit. We refer here to the curtailment of excess renewable generation and demand-side management practices development. As mentioned in §1.1, those levers are part of the flexibility mechanisms and have to be modeled accurately.

1.4 Dynamic constraints and unit-commitment models

As thermal generating units and storage facilities ensure most of the residual demand, they are the ones that change their output to keep the equilibrium between supply and demand. Technical constraints affect those units' operation, restraining their ability to start-up/shut-down, modify their output levels, and the time required to complete those maneuvers. The behavior of each generating or storage unit at a specific time step influences its near-future behavior. One of the most prominent examples is the time necessary to start-up a thermal generating unit after being shut-down. The time to "heat-up" the plant before electricity generation is exploitable creates a potential cost to the plant and the electric system. The decision to shut-down a plant must be optimized beforehand, considering the potential inter-temporal effects. The set of inter-temporal constraints, which comprehend ramping constraints, minimum up/downtimes, transients, is referred to in [22] as dynamic constraints. Dynamic constraints are the key determinants of plants' short-term flexibility. It is important to note that each technology possesses different dynamic constraints, resulting in baseload technology (such as coal, nuclear…) being less flexible, whereas peak technology (gas, oil, hydro, batteries…) can rapidly maneuver their output.

Representing accurately dynamic constraints permits differentiation of technologies' operation in the model and discriminates them based on their technical capacities. This enhancement also permits to economically discriminate technologies by including some additional costs such as start-up costs. As intertemporal constraints do condition operational flexibility, it calls for multi-temporal optimization modeling practices and a detailed temporal resolution.

Some of the literature has reviewed the potential impacts on neglecting the detail of both temporal resolution and technological constraints on the models' results. [23] and [24] have assessed that low temporal resolution may overestimate VRE uptake in dispatch systems. On the other hand, investment optimization also needs a detailed temporal resolution, as noted by [25], [26], and [27]. A low temporal resolution in the model favors investment in baseload and VRE technologies while underestimating flexible technologies' needed capacity. In the context of modeling variable renewables in the electric system, a sufficiently detailed temporal resolution is then crucial.

Regarding the implementation of technical constraints, [28] shows that neglecting unit-commitment constraints in capacity expansion models results in a sub-optimal capacity mix that heightens operational costs and carbon emissions. [29] also notes, in an Irish case-study, that the omission of flexibility constraints significantly impacts the optimal generation portfolio. If [30] highlights that part of the technical constraints may be omitted in order to shorten computational length and model complexity, it also underlines that this does not apply to models focused on high-share of renewables integration and flexibility. [31] reviews more literature about the impact of temporal resolution and technical constraints on models' results.

The literature has been evolving towards a more-comprehensive approach of dynamic constraints through the adoption of Mixed-Integer Programming (MIP) methods. As noted by [16], the previous literature has traditionally used Merit Order/Screening Curve models. Although these allow a more straightforward computational problem, they cannot comprehensively represent all dynamic constraints. Screening curves models usually prohibit inter-temporal considerations. Unit commitment models became more frequent in the literature as they overcome most of the limitations of the former modeling approach, formulated as linear programming (LP) [13] or including non-linearity through Mix-Integer Linear Programming (MILP) or dynamic programming. Using LP, the relaxed integer nature of power plants dramatically reduces the number of variables considered, easing the model resolution. However, this deteriorates the accuracy of the results. For example, using LP makes it impossible to include unit-commitment variables such as start-up/shut-down decision variables.

We can conclude that models related to the electric system's flexibility issues should prioritize MILP or dynamic approaches.

2 Nuclear power plants flexibility: definition and modeling

Although a baseload generation profile is economically optimal and technically easier for nuclear technology, it can perform flexible maneuvers, as seen in France, Germany, Belgium, Slovakia, Canada, and Sweden [10]. Different reactor designs are used in those countries, whether their type is BWR (Boiling Water Reactor), CANDU (Canadian Deuterium Uranium), or PWR (Pressurized Water Reactors). As the latter design consists of most of the currently installed capacity and is technically similar to the up-coming 3rd generation reactors, this paper will focus on PWRs.

This section of the paper aims to present the main drivers of those nuclear power plants' flexibility. We classify these drivers according to the three broad categories of flexibility services, and requirements pointed out in [32]; short-term (sub-hour, hour…), medium-term (hours to days), and long-term flexibility (weeks to months).

2.1 Short-term flexibility: definition and modeling

PWRs can modify their output either through changing the boric acid concentration, a neutron absorber, in the primary coolant or by changing neutron-absorbing control rod insertion levels. As noted in [33], operation modes have evolved significantly over the last 30 years, boric acid regulation being progressively less used for short-term variations as the achievable rate of power change is lower. Control rods movement allows faster and more precise power management, but it creates thermal and mechanical strains on the reactor's fuel. Indeed, the thermal variations induced by the rods' movements influence fuel pellets volume and their surrounding claddings. When inserting control rods, the temperature drops locally in the reactor's core and part of the pellets, and their claddings contract. Reversely, when withdrawing control rods, the temperature rises locally, and part of the pellets and their claddings dilate. The problem lies in the fact that they have different thermal expansion coefficients, creating mechanical stress, which may cause themselves cracking of the cladding. Corrosion effects due to corrosive fission products may exacerbate this problem.

Fast variations of temperature due to control rods movement may create pellet-cladding interaction phenomena that endanger the claddings' integrity, corresponding to a breach of the first containment barrier of PWRs. Although such breaches do not incapacitate the reactor generation capacity, it is common practice not to carry out flexible maneuvers after that, according to [10]. The aim is to limit the occurrence of cladding failures. The overall effect of the mechanical constraints related to control rods' movements is the limitation of the maximum power ramping rate of PWRs. The level of this ramp (up or down) ranges from 2% Pnom per minute (nominal power in a minute) to 5% Pnom per min, and even 10% Pnom per min for German PWRs [32]. The level of maximum ramping depends on the type of reactor, its irradiation cycle advancement, its operating mode, and the depth of the load-following maneuver [15], [34], [35].

It is important to note that, due to requirements for frequency control (minimum 2% Pnom per min), prospects regarding the profile of residual demand and the growing frequency nuclear maneuvers, 3rd generation reactors (EPR, AP1000…) should be capable of ramping up/down rates ranging from 3% to 5% Pnom per min [6], [36].

Regarding short-term concerns for modeling, the principal limit relates to ramping constraints. They frame the speed at which each plant may modify its output while functioning. Although the underlying phenomena defining the rate PWRs can change their outputs are specific to nuclear, it is possible to synthesize those constraints like any other "dispatchable" generation technology. Limiting short-term flexibility to ramping constraints then consists of a fair compromise between model accuracy and simplicity. It is safe to assume that even though the nature of short-term constraints differs significantly between nuclear and other generation means, the integration of those constraints in models should nevertheless be similar. Hence, as in [13] or [15], the literature clusters short-term flexibility requirements into a unique ramping constraint that frames the plants' overall flexibility.

The impact of the short-term constraints on reactors' flexibility is highly dependent on the time step chosen by modelers. The shorter the time step, the more impactful ramping constraints are on nuclear operations in models. It may then be necessary to adopt a sub-hour time step to assess the impact of those constraints, as one hour allows reactors to ramp up/down from nominal to minimal power even with a conservative ramping assumption of 2% Pnom per minute. Consequently, an insufficiently detailed time step may undermine the impact of short-term constraints, even though the model includes short-term constraints.

It is important to note that some models such as [17] resolve this issue of insufficient temporal resolution by implementing hourly ramping constraints – 25% Pnom per hour in this case. It refers to more conservative assumptions on ramping rates of reactors, originating from the fact that future PWRs design specification documents foresee ramping rates ranging from 17% to 30% Pnom per hour [37].

2.2 Medium-term flexibility: definition and modeling

A component that frames PWR flexibility on a broader time scale is Xenon transients in the reactor core. As noted in [15], Xenon-135 influences both ramping rates of nuclear reactors and their minimum stable power throughout the cycle. Xe-135 is a strong neutron absorber that mainly originates from the decay of Iodine-135 (fission product with a 6.7h half-life). The production rate of I-135 in the core is proportional to the reactor output. Parallelly, Xe-135 production evolves according to the concentration of I-135 in the core and "disappears" either by neutron capture or by decay (with a 9.2h half-life) –see Fig 1.

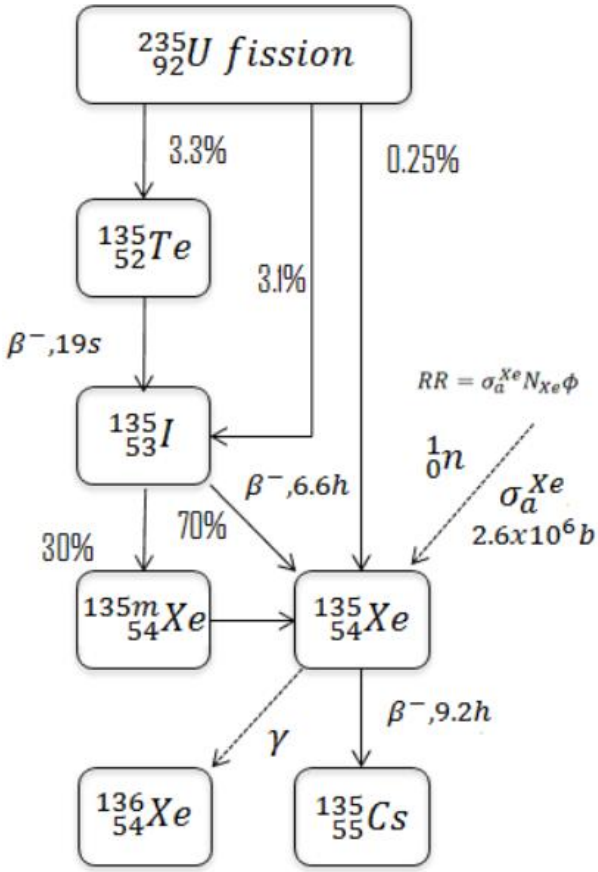


Fig 1: Xenon 135 evolution chain, www.nuclear-power.net, Data: JANIS 4.0/NEA

There is then a temporal lag between power output and Xe-135 concentration in the core. As the reactor power rises, the I-135 concentration heightens until the reactor's new equilibrium state is reached. Xe-135 concentration lessens because of increased neutron flux, reaching a minimum of 3 hours after the maneuvers' start, then goes back to an equilibrium state due to the accumulated I-135 in the core. Reversely, as the reactor power decreases, the I-135 production rate reduces, but the Xe-135 concentration heightens as it is still generated from the accumulated I-135. Because Xe-135 is a strong neutron absorber, Xenon transients' management is a significant challenge to maneuverability, especially regarding large power variations. After an output change, the effect on ramping constraints is that the nuclear reactor has to maintain a stable output to compensate for reactivity variations from Xenon transients. It is done by changing the primary circuit's boric acid concentration after control rods movements, diluting boric acid after control rods insertion to balance the augmenting Xe-135 concentration, and inversely concentrating boric acid after control rods extraction. PWRs then alternate between flexible maneuvers and stable power periods when load cycling (as seen in Fig 2). Similarly, Xenon transients force PWRs to either function or remain inactive after starting up/shutting down, resulting in mandatory minimum up/downtimes constraints that limit reactors' ability to maneuver.

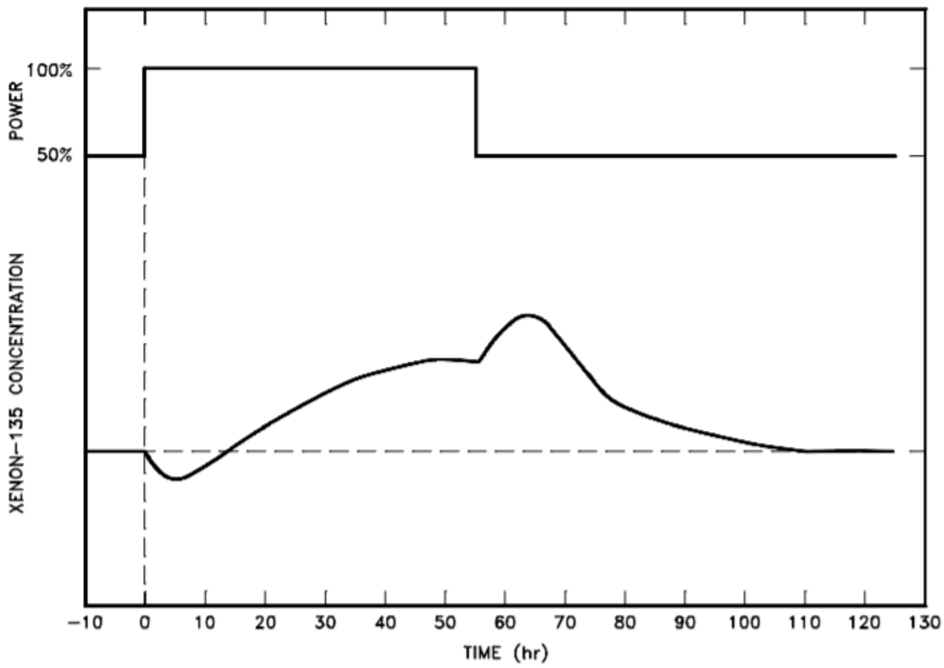
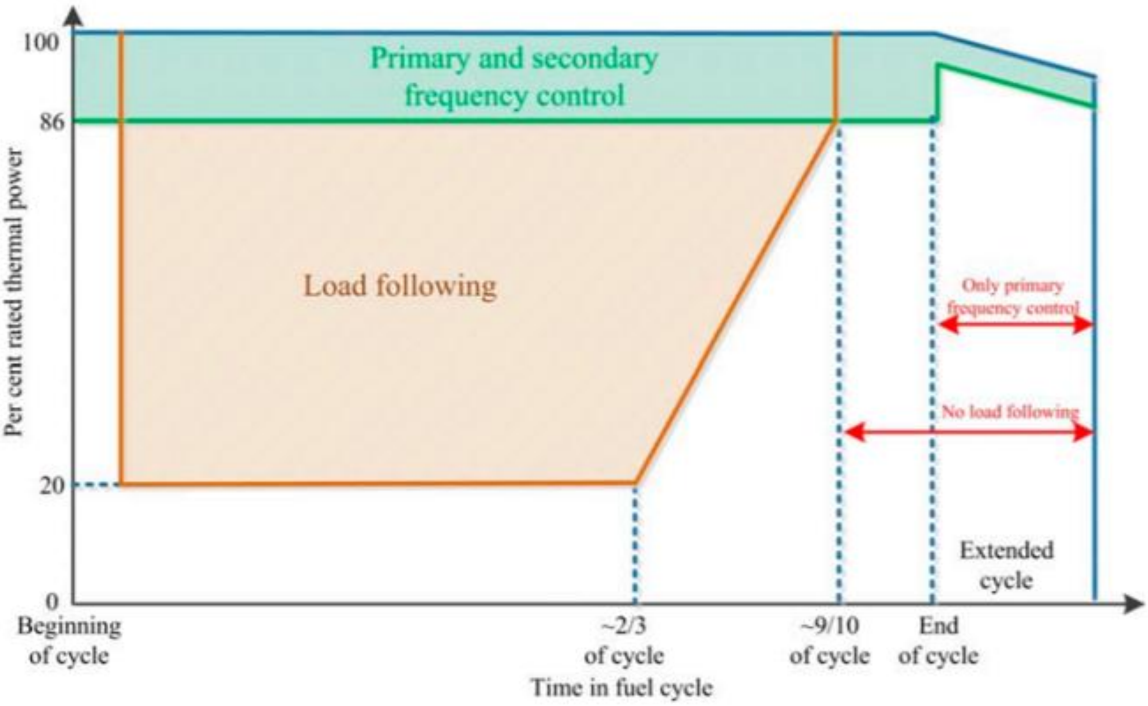


Fig 2: Xenon 135 variations during power changes [38]

The other effect that frame nuclear flexibility in the medium-term is the depleting boric acid concentration in the primary circuit at the end of the irradiation cycle. As boric acid concentration in the primary circuit decreases, it is more challenging to maneuver the reactor power by changing the boric acid concentration or moving control rods into the core. Thus, the achievable scope of maneuverability is higher at the start of the irradiation cycle and starts decreasing after two-thirds of the fuel cycle until the boric acid concentration reaches zero at the end of the irradiation cycle. It is then impossible to maneuver the reactor's output without shutting-down the reactor. The PWR enters an "extended-cycle" phase, allowing it to operate at a slowly decreasing nominal power and non-existent maneuverability. Fig 3 [39] illustrates a typical minimal power evolution in PWRs.



Legend: During the first two-thirds of the cycle, reactors can flexibly maneuver between 100% and 20-25% of their nominal power, depending on technology. From 65% to 90% of the cycle duration, boron concentration decreases, limiting quick variations of this concentration and preventing flexibility.

Fig 3: Flexible operation limits during a fuel cycle in a French PWR [7] *(reproduced from* [39]*)*

The evolution of a plant's minimum stable power through its cycle is primordial to its capacity to maneuver. In the context of VRE–nuclear coexistence and high volatility of residual demand, each plant's ability to perform deep load cycling is crucial to the electric system's stability.

Other components of the reactor's design do influence medium-term flexibility. For example, steam generators' designs may create thermal perturbation that affects the core reactivity, prohibiting fast ramps and forcing the reactor output to remain stable at least one hour before ramping back up. A PWR's flexibility also depends on the operator's operating mode (e.g., Mode A, G, and T for French PWRs). More information on medium-term flexibility is present in [14].

The implementation of medium-term flexibility constraints (related to Xenon transients) varies across the literature. [14] introduces "physics-induced operational constraints" for nuclear operations, allowing representation of both power stabilization after output changes and minimal operating power evolution in the model. Its companion paper, [15], also integrates those constraints to nuclear operations in order to determine the potential benefits of nuclear flexibility in renewables-driven power systems. Those two papers do simplify medium-terms technical constraints as they implement them in their case study. For example, the Xe-135 reactivity defects following a power output drop are all of the same magnitudes as long as this power drop is higher than 10% of the reactor's nominal power. Apart from these two papers, the vast majority of the literature over-simplify medium-term constraints on nuclear flexibility. About minimal power evolution through the irradiation cycle, the conventional approach is to fix the minimal power output that reactors can operate under, as seen in [10], [13], [16]. Although the level of this achievable minima power output may vary – 50% in [16], 40% in [13] -, it mostly refers to current requirements for newly built reactors, as seen in [36], that recommend an available 50% minimal power. An essential consequence of this modeling choice is that the minimal stable level remains stable through the irradiation cycle.

As for necessary power stabilization following output maneuvers due to the previously mentioned Xenon transients, there is no implementation of the related constraints that would limit consecutive power variations while functioning in most of the literature – the only exception being [14] and [15]. Minimum up/downtimes constraints induced by Xenon transients after starting-up/shutting-down are exclusive to MILP models, as in [14]–[18].

2.3 Long-term flexibility: definition and modeling

Each nuclear power plant alternate between generation phases and planned outage phases linked to 1) the need to recharge fuel assemblies after each irradiation cycle, 2) the need for maintenance of components, and 3) security inspections to ensure that the reactor can operate safely. Those three elements are crucial for available flexibility capacity at the plant level throughout the year. The generation phase duration depends on the reactor type and its fuel cycle, ranging from 12 to 24 months, depending on the fuel cycle's utilities' strategy. The duration of planned unavailability phases is variable depending on the nature of the outage. It ranges from one month if the outage is a simple refueling to two months for substantial maintenance and even five to six months for a potential decennial safety inspection. This alternation between availability and unavailability is optimized beforehand to maximize the available generation through peak residual demand and the plants' load factor. The resulting schedule influences flexibility at two levels; the plant and the overall nuclear fleet. At the plant level, because of outages or fuel burn-up, there are some periods where generation and participation in flexibility requirements are impossible. At the fleet level, the addition of the combined electric system's reactors availability and flexibility capacities define the fleet's overall generation capacity and maneuverability. There is a varying nuclear generation availability but also flexibility capacity depending on the time of year. Then, each power plant's schedule is in line with the rest of the fleet's schedule. This optimized schedule is the primary driver of long-term flexibility.

Although fundamental to available nuclear power capacity and flexibility in the electric system, long-term flexibility components are not implemented in the models. [10] thoroughly describes the stakes surrounding the operational schedule of reactors and its optimization (to either maximize plant profits or minimize load-shedding/black-outs) but does not implement in its model. The underlying hypothesis is that reactors are available continuously throughout the considered years.

Both [14] and [15] partially raise this issue. In their respective case studies, the authors consider only one 18-month irradiation cycle for their hypothetical plant. [15] focuses on one simulation year following the start of the reactor, meaning that it remains within the first two-thirds of its cycle, and depleting boric acid concentration does not affect its operation. Additionally, [14] focuses on the end of its irradiation cycle, highlighting the effects of physics-induced constraints on the model results. These two papers then evoke the influence of a reactor's schedule on its flexibility capacity but do not consider a fleet perspective.

3 Potential effects on renewables-driven models' results

The objective of this section is to point out the potential impacts of modeling assumptions linked to nuclear flexibility made in the literature on models' results, ranging from generation dispatch and capacity mix between generation technologies to economic outcomes of such mix.

3.1 Short-term modeling assumptions effects

Short-term flexibility constraints limiting nuclear operations are well implemented in the relevant literature. The omission of such constraints allows nuclear generation in models to ramp-up or ramp-down without limitations. It would greatly overstretch the nuclear fleet's ability to compensate for the variability of residual demand originating from renewables generation and electric load profile, especially in highly detailed temporal resolution models. Regarding nuclear alone, this may misestimate PWRs generation and, consequently, its profitability and installed capacity. Their inability to maneuver quickly may force costly nuclear generation shedding as residual demand decreases and limit the reactors' ability to ramp-up as it increases. This lack of short-term flexibility can be economically detrimental for nuclear power plants, with irreducible generation during low market price periods (i.e., residual demand decreases) and limited generation as market price increases (i.e., residual demand augments). The depleting effect of a lack of flexibility on reactors' profitability would then deepen as the installed capacity of VRE evolves, as seen in [2]. The optimal installed capacity of nuclear reactors would then reduce compared to a model ignoring ramping constraints. From the overall model perspective, short-term nuclear operations constraints may benefit more flexible technologies such as batteries and gas-fired power plants with Carbon Capture and Storage (CCS) to ensure the electric system's flexibility requirements. Omitting short-term constraints or over-estimating nuclear technology's ramping capacity may then underestimate the need for flexible means of generation and storage. Consequently, it can underestimate the technical and economic challenges linked to integrating high shares of VRE capacity in the future electricity mix.

It is important to note that, as ramping constraints range from 2% to 5% Pnom/min, short-term flexibility limitations moderately affect maneuvering capacity at an hourly resolution. As such, the ramping constraints' influence on the models' results may be non-existent when considering large enough temporal resolution, which highlights the stakes surrounding the models' temporal resolution.

3.2 Medium-term modeling assumptions effects

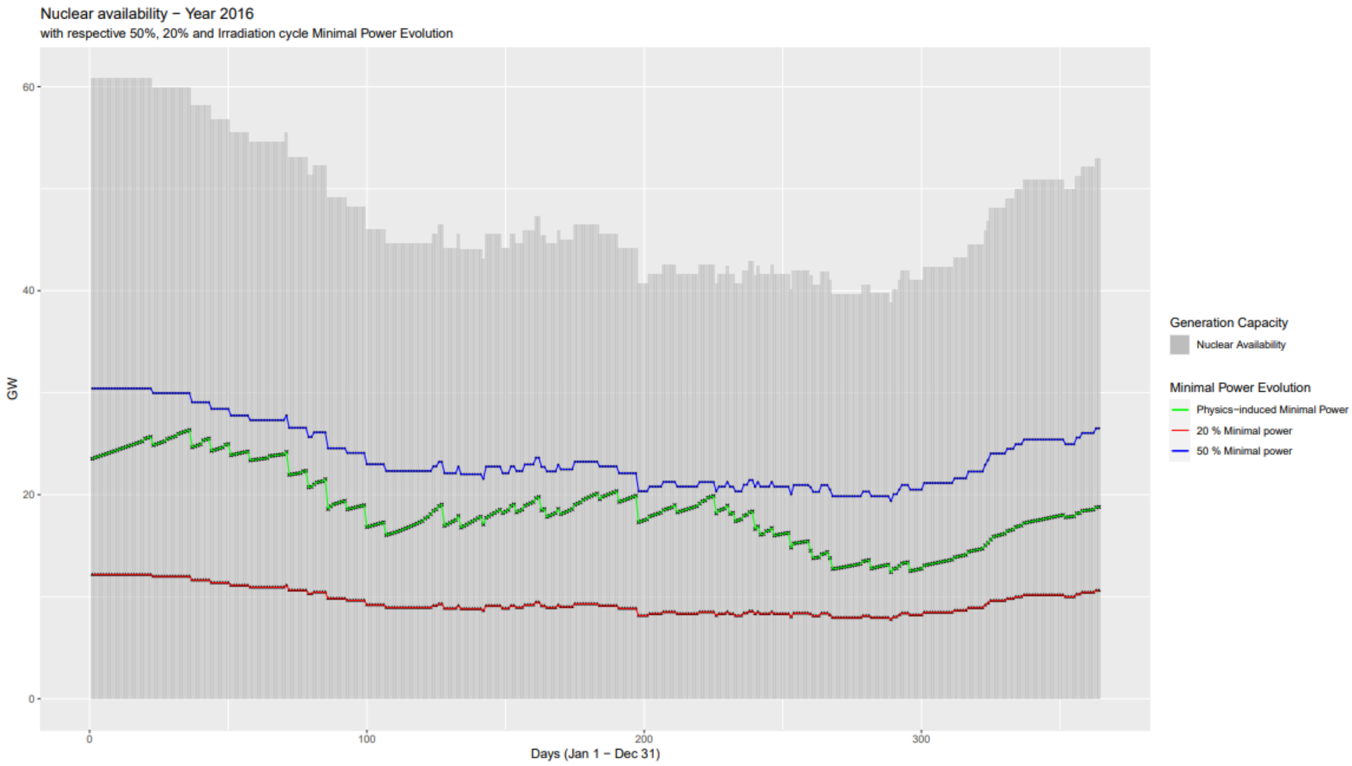
Medium-term flexibility assumptions also have an impact on model results. Like ramping constraints, reactors' need to maintain a stable output following a flexible maneuver limits their ability to adapt to the residual demand's fast-level changes. This constraint, if implemented, forbids reactors from performing several maneuvers successively. The omission of this constraint may over-estimate PWR's maneuverability in models, as reactors may consecutively ramp down (inv. up) then ramp up (inv. down) -even though physics-induced models would prohibit it. Regarding minimal power evolution through the irradiation cycle, it frames the potential maneuvers achievable by reactors. The effect on the estimation of achievable flexibility varies throughout the irradiation cycle of each PWR. At the beginning of the irradiation cycle, a 50 % minimal stable power assumption would under-estimate the reactor's maneuverability potential as minimal achievable power is around 20% of nominal power. Inversely, as minimal achievable power rises at the end of the irradiation cycle, a 50% minimal stable power assumption would be an over-estimation of a PWR maneuverability potential.

Consequently, the modeling assumption of a constant minimum stable power throughout the irradiation cycle is bound to both over and underestimate achievable maneuverability of PWRs depending on the period. In the context of high renewable penetration in future electric systems, the variability of residual demand and seasonality makes it crucial to estimate the achievable maneuverability of nuclear technology accurately. A fixed and constant minimal power assumption may be a hurdle to the accuracy of such models.

3.3 Long-term modeling assumptions effects

As we have seen before, the nuclear fleet's operational schedule is not implemented in the models. It is a gross simplification of the characteristics of nuclear technology. When neglecting the importance of the nuclear fleet schedule, models do not consider critical factors such as nuclear availability seasonality. The French example is a good illustration of this seasonality, as this country's operational schedule is optimized to maximize nuclear generation during high residual demand periods such as winter. It is the economically optimal utilization of a nuclear fleet both for plant owners and system planners as it heightens PWR's load factor and its revenues due to high residual demand periods. It also limits the need for other back-up technologies, demand-side management, or potential loss of load during those high residual demand periods. Neglecting nuclear availability seasonality may misestimate available nuclear generation and flexibility throughout the year and thus impact the models' results regarding the security of supply, costs of dispatch, and the system's carbon footprint. A constant nuclear availability assumption can be valid if the system's residual demand remains relatively constant throughout a year; however, this is a rare situation in reality.

The operational schedule of reactors also impacts the achievable flexibility of the nuclear fleet. As reactors do not start their irradiation cycle at the same time of the year, the evolution of their minimal stable power is also different. The fleet's overall minimal power is then the sum of each reactor's minimal power, meaning that its value depends on progress into irradiation of each reactor's cycle, strongly linked to their operational schedule. In the following Fig.4, we extracted the French nuclear fleet's operational schedule in 2016 from the Transparency platform of the European Network of Transmission System Operators for Electricity (ENTSO-E) and Agence de Sureté Nucléaire (ASN). We recreated this fleet's minimal power evolution based on the length of each reactor's irradiation cycle. We then compared the fleet's minimal power evolution to two constant minimal power hypotheses indexed on the French fleet's actual availability in 2016 – 50% constant minimal power (low-flexibility case) and 20% constant minimal power (high-flexibility case).



Note: The green line represents a fleet's minimal power based on each reactor's irradiation cycle. The authors built each reactor's schedule from ENTSO-E and ASN's data related to each reactor's outage. The minimal power evolution of each reactor was then built according to [39]. *We assumed that fuel-burnup was proportional to the advancement of each reactor's irradiation cycle, which is an approximation. It allows us to establish the shape of the fleet's minimal power evolution.*

Fig 4: French nuclear fleet generation capacity (2016) and minimal power (constant vs. "physic-induced")

Fig.4 highlights that both constant minimal power assumptions do not accurately represent the fleet's actual minimal power based on the reactor's irradiation cycle. Moreover, the shape of the "physics-induced" minimal power evolution is different from constant minimal power evolutions. Models using a constant minimal power assumption for nuclear flexibility may then misestimate this generating technology's flexibility potential. Added to the fact that the fleet's seasonality is not implemented in models, nuclear flexibility in models could differ significantly from a "realistic" physics-induced nuclear flexibility. Such considerations are crucial when assessing nuclear technology's role in responding to flexibility requirements induced by introducing a large VRE share into the capacity mix.

It is important to note that the absence of modeling assumptions may impact the models' results varyingly depending on the nuclear fleet's size present in the electric system studied. The case of the operational schedule of reactors is an obvious example. The higher the number of installed reactors in the electric system, the easier it is to mitigate planned outages' adverse effect on the total available nuclear generation. Additionally, the operational schedule differs according to the number of reactors installed, their cycle length, and the system's residual demand. Thus, even though we did not raise the stakes surrounding the nuclear fleet's size, such considerations should be considered when modeling.

Concluding remarks

It seems that current nuclear modeling in the literature does not fundamentally differ from conventional thermal generation modeling. We argue that this is a valid assumption only in a low variable renewable environment, where the need for flexibility from thermal generation remains negligible. However, in the context of the capacity development of variable renewables throughout the electricity mix, flexibility will be crucial in determining the future environmentally and economically optimal capacity mix. Although considered "baseload", nuclear has a real flexibility potential that needs to be accounted for and has already been partially implemented in some current models. The mechanisms underlying this flexibility potential are specific to this generating technology and depend on the reactors' type (BWR, PWR, SMR…), operation mode, and regulatory regulations. Regarding PWRs that constitute most of the installed nuclear capacity, Xenon transients and the operational schedule of power plants seem to be a blind spot in the literature. Models that, for example, do not implement Xenon transients may over-estimate nuclear flexibility, as reactors can successively perform maneuvers, which would be prohibited in "physics-induced" models.

We argue that such assumptions influence nuclear flexibility in models and should be better implemented in future works to increase accuracy. Such omissions may indeed misestimate available nuclear generation and flexibility in the model results. Eventually, those misestimations potentially influence electric systems' key aspects such as operational costs, the security of supply, and carbon footprint. As nuclear technology with low variable costs holds a primary place in the economic merit-order, misestimating nuclear flexibility could affect the expected optimal peak-generation capacity, storage facilities, demand-side response, and especially the optimal share of variable renewable capacity in electric systems. Those elements combined are crucial to the economic and environmental competitiveness of nuclear technology in renewable-driven electric systems. Only by correctly assessing the optimal nuclear ratio in the capacity mix and its corresponding load factor can we conclude nuclear technology's viability in the future renewables-driven mix. We hope that this paper may contribute to the literature by highlighting the stakes surrounding nuclear flexibility modeling in renewables-driven simulation and capacity expansion models.

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