Nuclear operations with a high penetration of renewables: the case of France*

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Abstract

A carbon-free electricity industry may rely on renewables, nuclear or both. This paper explores the latter option. We study empirically how nuclear power plants may adjust their operations in the face of growing wind and solar generation. Our analysis focuses on France, a country with a legacy nuclear capacity of 61 GW, as well as significant and steadily growing renewable generation. We first document that, in contrast to widely held beliefs, nuclear units can be operated flexibly: an additional 1 MWh of domestic wind and solar generation is on average associated to a 0.6 MWh decrease in nuclear output. However, we find evidence that fuel management constraints and, to a lesser extent, grid congestion are putting increasingly binding bounds on the "supply response" provided by nuclear units.

Keywords: nuclear, renewables, operating constraints, market power

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1 Introduction

Many power systems around the world are transitioning away from fossil fuels. Existing scalable and mature technologies available to reach this outcome consist of intermittent renewables (wind and solar) and nuclear power.[1] So far, most public policies have favored the former: given the escalation in the cost of building new nuclear plants and the decreasing costs of renewables, the share of nuclear in the global electricity mix has been declining, a trend that gained momentum after the Fukushima disaster of 2011.

In recent years, however, we observe a renewed interest in nuclear power. Indeed, the rise of both geopolitical tensions and global temperatures calls for diversifying energy sources and speeding up decarbonation. Therefore, the future carbon-free electricity mix of a number of developed countries may include large amounts of both nuclear and renewables.

Yet, from economic and technical standpoints, nuclear and renewables have characteristics that should somewhat limit the extent of their synergies. From a long run perspective, both families of technologies have high fixed costs and low variable costs, which tends to make them substituable in an optimal electricity mix (Green and Léautier, 2015; Holland et al., 2022). From a short run perspective, renewables produce electricity intermittently, requiring other generation technologies to fill the gaps. Nuclear power plants, however, face limitations in the extent to which they can quickly adjust their output (OECD, 2021). The practical stringency of these latter constraints, both today and in a future with a higher penetration of renewables, is however largely unknown.

To which extent will nuclear and intermittent renewable power plants be able co-exist at a large scale in future power systems? Which challenges are likely to arise in such systems?

This paper leverages detailed public data on the French power system between 2012-2023 to provide empirical answers to these questions. With 61 GW of installed nuclear capacity, and a total capacity of wind (resp. solar) which grew from 6.7 GW (resp. 2.5 GW) to 23 GW (resp. 19 GW) between the end of 2011 and the end of 2023, France provides a (so far) somewhat unique case study.

Our main findings are threefold. First, in contrast to widely held beliefs, we observe that

[1] Indeed, developed countries are usually considered to have exhausted the locations suitable for large-scale hydropower.

nuclear power plants can be operated very flexibly. On average, one additional MWh of wind or solar generation is associated with a 0.6 MWh decrease in nuclear output. This decrease is achieved through "load following", that is, short-duration decreases in the output of a subset of nuclear units. Second, the flexibility of nuclear units faces some limits that are becoming more and more stringent. On the one hand, in recent years, the occurrence of "minimum output constraints" follows a mildly increasing trend, more so for installations that have a higher "exposure" to renewable output. On the other hand, the average capacity factor of the nuclear fleet conditional on spot prices being low or negative remains fairly high. This observation is partly driven by the fact that nuclear units can no longer be operated flexibly in the few weeks preceding a shut down for refueling. Third, the length of fuel cycles and the duration of planned outages appears to be heterogeneous, and therefore possibly endogenous and strategically chosen. In this context, there exist scope for strategic responses by the nuclear operator beyond the well-known exercise of short-run market power.

The rest of the paper is organized as follows. Section 2 provides some relevant background. Section 3 describes our sources of data and the French power system. Section 4 documents the observed flexibility in nuclear operations. Section 5 shows, however, that there exist limits to this "supply response". Finally, Section 6 explores the scope for strategic responses by the monopoly operator of the nuclear fleet. Section 7 concludes.

2 Decarbonation, Nuclear and Renewables

This section provides some background on the envisioned role of nuclear energy in the decarbonation of electricity supply, as well as some of the main associated challenges that have been discussed in the literature.

2.1 Role of Nuclear Energy in Decarbonizing Electricity Supply

Most of the electricity consumed worldwide is generated from fossil fuels, such as coal or natural gas. Decarbonizing electricity supply therefore requires to decommission many fossil fuel power plants and generate instead electricity from less carbon-intensive energy sources. As a result, in recent years, many countries have strongly supported the development of

wind and solar energy and, since the mid-2010s, global yearly newly commissioned capacity have been higher for wind and solar than for fossil fuels (IRENA, 2022).

However, in contrast to fossil-fueled thermal power plants, which are "dispatchable" (i.e., can produce electricity on demand), wind and solar facilities are intermittent and only generate electricity when the wind blows or the sun shines. Therefore, a large literature explores how intermittency affects optimal policy design (e.g. Ambec and Crampes (2019) and Pommeret and Schubert (2022), among many others). In practical terms, the main challenge that arises is to maintain the system operator's ability to balance supply and demand in real time (a physics-induced constraint in electricity markets) with little to no fossil-fueled assets remaining and given the inherent variability of wind and solar output.

Besides hydropower, whose installed capacity is constrained by the limited number of suitable sites, nuclear is the only mature, carbon-free and "dispatchable" technology readily available today. However, in the past couple of decades, the share of nuclear energy in the global electricity mix has been *decreasing*.

This puzzle largely stems from the observed difficulty to build cost-competitive nuclear power plants. Indeed, while many countries launched or ramped up nuclear programs after the oil shock of the early 1970s, the Three Mile Island accident of 1979 and, most importantly, the Chernobyl disaster of 1986 have stopped this momentum through two main and related channels. First, the public acceptability of nuclear dropped significantly in many countries. Second, in order to address this lower acceptability, many layers of safety regulations have been added over time. This latter consequence magnified the intrinsic engineering challenges that building a nuclear plant entails, and ultimately translated into a very large cost escalation. This phenomenon has been showcased as an example of "negative learning-by-doing" (Grubler, 2010; Boccard, 2014). This expression has, however, raised some debates since, within a given model of nuclear reactor, some (modest) level of positive learning-by-doing can be observed (Rangel and Lévêque, 2015). Building on this observation, and given the rising concerns about climate change, the early 2010s saw a renewed interest in nuclear power. This "renaissance", however, was short-lived, especially after the disaster of Fukushima in March 2011 (Davis, 2012; Joskow and Parsons, 2012).

A decade later, *ex post* evaluations of the closure of nuclear plants, for example in Germany

or the U.S., have revealed some (perhaps) under-appreciated benefits of this technology. Besides positive spillovers for the local economy (Bauer et al., 2017), the health benefits in terms of air pollution when nuclear substitutes for coal power have been found to be very substantial (Severnini, 2017; Adler et al., 2020; Jarvis et al., 2022). In addition, local disamenities raised by the fear of a nuclear accident (Coulomb and Zylberberg, 2021) need not necessarily outweigh the smaller but more widespread disamenities induced by wind and solar projects (Jarvis, 2025). A couple of recent studies even revisit nuclear programs as examples of successful industrial policies (Andersson and Finnegan, 2024), and their demise in democracies after the Chernobyl accident as a missed opportunity (Makarin et al., 2024). In parallel, large government programs and private investments are being dedicated to develop so-called "small modular reactors" as an attempt to increase the cost-competitiveness of nuclear energy.

If it is too early to assess whether a nuclear "enlightenment" age is emerging, it now seems likely that nuclear energy will play a significantly role in decarbonizing the electricity mix of at least some countries. For example, France has committed to maintain its existing nuclear fleet for as long as technically possible, and has started to plan for its partial renewal by launching studies for six new nuclear units of 1.6 GW each. In such countries, the future carbon-free electricity mix will consist of both wind and solar on the one hand, and nuclear energy on the other hand.

2.2 Some Challenges Associated with Nuclear Energy

As the installed capacity of wind and solar increases significantly, dispatchable power plants with low carbon-intensity will become more and more valuable to address the challenge of managing intermittency. The extent to which nuclear power may benefit from these new economic conditions is, however, an open question.

First, nuclear units are complex units to maintain and operate. Therefore, they inevitably operate in a context where asymmetric information is unavoidable (e.g. Amore et al. (2024)), and the incentives faced by their owners can have a large influence on the competitiveness of nuclear energy. For example, in the United States, available evidence suggest that the deregulation of electricity generation has increased both the cost-efficiency (Davis and

Wolfram, 2012) and safety (Hausman, 2014) of nuclear operations.

If market incentives mitigate the costs of informational rents, the sheer size of nuclear units obviously raises market power concerns. Such market power may be exercised at different time horizons. In the short run, pivotal producers may bid strategically to influence spot prices. For example, Davis and Hausman (2016) document how the closure of a nuclear power plant in California has changed the incentives of other generators to exercise market power. In the medium term, the placement and duration of outages may be chosen in order to push up average price levels (Lundin, 2021). However, given the very high capital costs of nuclear units, their average utilization rate once commissioned, called "capacity factor", is – at least for a social welfare perspective – a key determinant of the competitiveness of this technology (Joskow and Rozanski, 1979). In that regard, the reasons underlying the low capacity factor of the French nuclear fleet (about 75% on average over the past couple of decades) may deserve a careful investigation (Boccard, 2014; Lynch et al., 2022). Finally, in the long term, entry and exit decisions (or announcements) can shape competitors' expectations, possibly favoring market concentration (Liski and Vehviläinen, 2018).

Most closely related to this paper, "dispatchable" power plants must meet the "residual" electricity demand, that is, gross consumption minus the output from zero-variable-cost renewables (mostly wind and solar). As the penetration of intermittent renewables increases, so does the volatility of the residual demand. The extent to which nuclear units can cope with this increased volatility is a critical and open question.

Indeed, given their very high capital costs, nuclear units are most profitably run steadily at their maximum output, a mode of operations known as "baseload" operations. However, nuclear units have some ability to vary their output level (Lokhov, 2011), for example to adapt the level of residual demand. Such "load following" operations, which we describe in more detail in the next Section, are for example widely used in France (Morilhat et al., 2019) and were also used in Germany (Grünwald and Caviezel, 2017).

However, little is known about the limits and economic consequences of operating nuclear units flexibly. First, although related evidence is scarce (Bruynooghe et al., 2010), load-following operations may accelerate wear and tear. Second, nuclear units face a number of technical operating constraints, which will bind more and more frequently as the penetration

of intermittent renewable generation increases. Utilities are in turn likely to implement adaptation strategies,[2] as a response to both changing technical challenges and evolving economic incentives. While the former may be captured to some extent through *ex ante* engineering approaches (e.g. Jenkins et al. (2018)), anticipating the full range of consequences that a power system with large shares of both nuclear and intermittent renewables entails is a daunting task.

In this paper, we instead rely on *ex post* econometrics analyses by leveraging the fact that France is a jurisdiction where large amounts of nuclear and renewable capacities already co-exist. This country indeed hosts 56 nuclear units split across 18 locations,[3] totally 61 GW of installed capacity, as well as over 40 GW of intermittent renewables (wind and solar) as of 31 December 2023. We next provide some background specific to the French context and to nuclear operations in the country.

3 Data on the French Power System

This section describes our main data sources and provides relevant background on both the French power system and nuclear operations.

3.1 Electricity Generation Fleet

Since 2017, the French government maintains a public inventory listing all electricity generation units.[4] Among other information, this inventory provides, for each unit, (i) its installed capacity, (ii) its technology (hydro, non-renewable thermal, nuclear, renewable thermal, solar, wind), (iii) the municipality where it is located,[5], and (iv) its commissioning date. In particular, knowing the installed capacity, municipality and commissioning date of each unit allows us to compute municipality-level time series of installed capacity, broken down by technology. For privacy reasons, however, small PV installations (lower than 36 kW of capacity) are aggregated at the municipality or departement level (see Astier et al. (2023)

[2]For example, Le Billon (2016) mentions that EDF has been increasing the number of units that can perform load following simultaneously.

[3]Each nuclear power plant hosts between 2 and 6 units.

[4]For example, the inventory as of 31 December 2023 is available at `https://odre.opendatasoft.com/explore/dataset/registre-national-installation-production-stockage-electricite-agrege-311223`, last accessed on 15 December 2024.

[5]Mainland France is divided into 30,000+ such municipalities, which therefore represent a very granular spatial unit.

for more details). Because they only represent 3.6 GW out of over 19 GW installed solar capacity as of 31 December 2023, we aggregate for simplicity small PV installations at the departement level.[6] To retrieve a time series of small PV installations, we use public data from the French Department of Energy[7], which notably provides total departement-level solar capacity as of 31 December of each year.[8]

Electricity generating technologies in France may be divided in 5 broad categories: nuclear, hydropower, fossil-fueled thermal plants, wind and solar. In what follows, we follow focus attention on the period 2012-2023. Over this time window, the installed capacities of these technologies have exhibited different trends.

First, nuclear represents the largest share of both installed capacity and generated electricity. The fleet, operated by the incumbent utility, consisted in 2012 of 19 nuclear power plants (Figure 1). These power plants are composed of two to six units, for a total of 58 units. The majority of them have a nameplate capacity of around 900 MW, while most remaining units have a nameplate capacity of around 1300 MW. Only the 4 most recent units (nuclear plants of Chooz and Civaux), which where commissioned in the early 2000s, have a higher nameplate capacity of around 1500 MW. The technical characteristics of each unit (nominal capacity, commissioning date, minimum output level, etc.) are publicly available from Électricité de France (EDF), the International Atomic Energy Agency or other data sources. Importantly, no nuclear unit was commissioned during our period of interest, while two 900 MW units (Fessenheim power plant) were decommissioned in 2020, leaving a remaining fleet of 18 plants composed of 56 units.

Similarly, the installed capacity of hydropower has been largely constant, with nonetheless a mildly increasing trend driven by the commissioning of small-scale run-of-the-river units. Fossil-fueled thermal capacity also followed an almost flat trajectory to reach about 18 GW in 2013, the closure of coal power plants being more than compensated by the opening of a few gas-fired power plants. Finally, the installed capacities of wind and solar have been growing significantly at a steady pace. Installed wind capacity increased from 9 GW as of

[6] Mainland France has 94 such departement.

[7] `https://www.statistiques.developpement-durable.gouv.fr/tableau-de-bord-solaire-photovoltaique-troisieme-trimestre-2023-0`, last accessed on 22 February 2024.

[8] Specifically, subtracting the installed capacity of solar units we observe individually to total installed capacity allows us to recover an estimate of the departement-level installed capacity of small installations ($\leq$36 kW) as of 31 December of each year. We interpolate these estimates linearly to proxy for the daily departement-level time series of these installations.

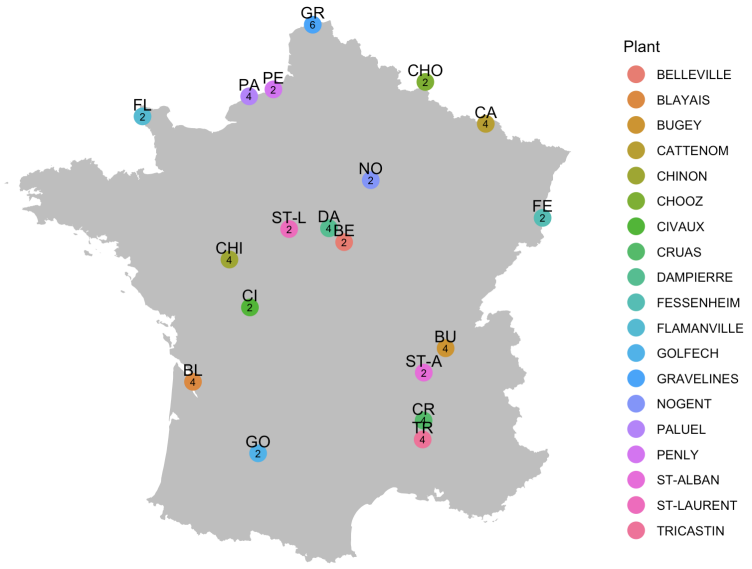


Figure 1: Location of the 19 nuclear power plants in our dataset. The figures in the circles indicate the number of units that compose each power plant.

31 December 2014 to about 23 GW as of 31 December 2023. Solar photovoltaic capacity increased from about 5 GW to 19 GW over the same time window.

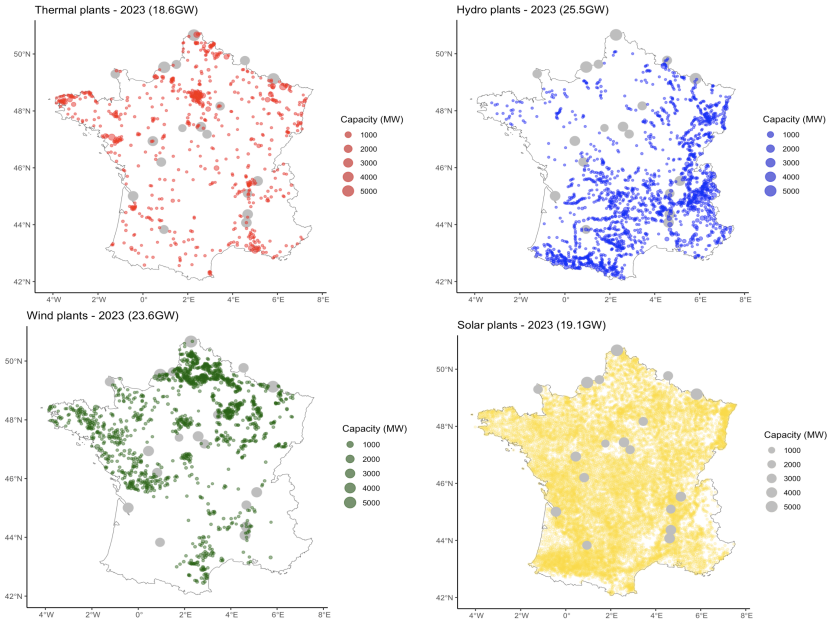


Figure 2: Locations of non-renewable thermal, hydro, wind and photovoltaic capacities as of 31 December 2023. Nuclear plants are located with gray circles.

Figure 2 shows where the installed capacities of the four main non-nuclear technologies (non-renewable thermal, hydro, wind and photovoltaic) are located as of 31 December 2023.

Importantly, the spatial distribution of power plants differs significantly by technology. Thermal power plants tend to be located close to the main cities, while hydro facilities are in the main mountain areas and along rivers. Wind power plants were predominantly installed in the North. Although somewhat spread out across the territory, solar installations have been more intensively deployed in the South. Overall, Figure 2 illustrates that the different nuclear power plants are "exposed" differently to other generating technologies, at least in a spatial sense.

3.2 Aggregate Consumption and Generation

Country-level outcomes for the power system are publicly available at a (sub)hourly time scale from both the transmission system operator[9] and Entso-e.[10] From these data sources, we retrieved or computed hourly electricity consumption, generation by technology and net imports/exports for the period 2012-2023.

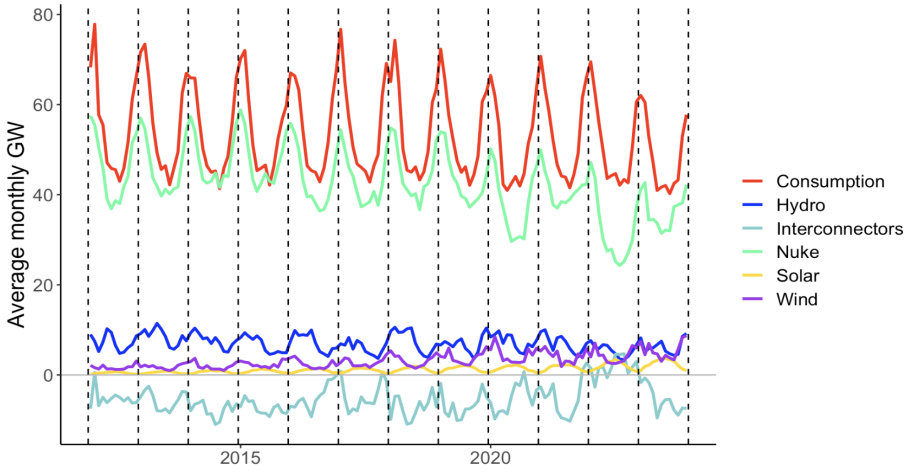


Figure 3: Monthly electricity consumption, generation by main technology and commercial exchanges over 2012-2023. Dashed vertical lines indicate the beginning of each year.

Figure 3 shows the corresponding time series aggregated at the monthly level. Several observations are worth making. First, France is a so-called "winter peak" system, meaning that electricity consumption is highest in during cold months (December, January and February). Indeed, given the high penetration of electric heating and the lack of widespread air conditioning, typical electricity demand during the winter is 1.5 to 2 times higher than

[9] From 2012 onward at `https://www.rte-france.com/eco2mix`, last accessed on 16 December 2024.
[10] From 2015 onward at `https://transparency.entsoe.eu/`, last accessed on 16 December 2024.

during the summer. Second, nuclear is by far the dominant technology in the electricity mix, representing three quarter of domestic generation and an even larger fraction of domestic consumption. Third, the fleet-level output of nuclear power plants is far from exhibiting a flat "baseload" pattern. Instead, nuclear generation follows very closely, at the aggregate level, domestic consumption, a except for the Covid-19 lock down period and the years 2022 and (to a lesser extent) 2023, when a generic default was discovered and induced many long-duration outages (Astier, 2024).

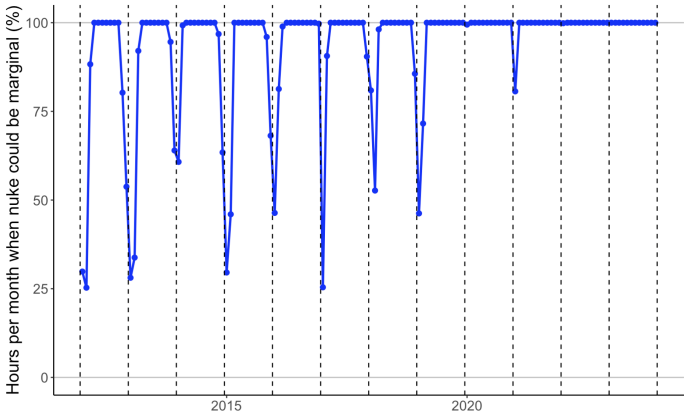


Figure 4: Percentage of hours in each month when nuclear would be the marginal technology in an hypothetical situation where all the nuclear units would be available.

Finally, the generation from wind and solar has been steadily growing from negligible amounts in 2012, to a combined output comparable to hydropower in 2023. While this increase in renewable output may seem relatively small, it actually precisely corresponds to the increase necessary to reach a power system that could, at least in theory, exclusively rely on nuclear and renewables. This crucial point is illustrated in Figure 4. Specifically, we computed, for each hour in our sample, the "residual demand" defined as gross electricity consumption (including water pumping) plus (net) exports minus must renewable generation (wind, solar, hydro and biomass). In other words, the residual demand represents the remaining electricity load that must be supplied by "dispatchable" assets, such as nuclear or fossil-fueled power plants. For each hour, we then compare the level of residual demand to installed nuclear capacity. If the latter exceeds the former, the nuclear fleet is sufficient to balance supply and demand under the hypothetical scenarios where all nuclear units would be available. Figure 4 plots, for each month in our sample, the percentage of hours where

such a "theoretical marginality" of nuclear occurs. We observe that, over the past three years, the increase in wind and solar (combined with the decrease in gross consumption and changes in imports/exports patterns) has been sufficient to make nuclear "theoretically marginal" in all hours. Therefore, our case study is particularly relevant to explore how power systems evolve as they approach a mix relying exclusively on nuclear and renewables.

3.3 Unit-Level Nuclear Operations

Unit-level hourly output of nuclear units is publicly available from the transmission system operator (TSO) from 2012 onward.[11] Over the period 2012-2023, the hourly output of 56 (after 2020) to 58 units (before 2020) represents about 6 million observations. Episodes of missing or erroneous data are therefore inevitable.

Because our later analysis predominantly relies on hourly unit-level output time series, we perform very extensive data cleaning and sanity checks. First, we flag obvious outliers[12] and interpolate them, as well as missing data, at the average value of the previous and next available observation.[13] Second, we cross-validate the data from the French TSO with the same data from Entso-e, available from 2017 onward. Specifically, we rely on Entso-e data for days when data quality issues are suspected in the French TSO data. Third, we aggregate unit-level output at the fleet level and compare it with the reported hourly aggregate nuclear output (see previous paragraph). At the end of our data cleaning procedure, the mean absolute value difference between the two time series is 0.5%, with only 7 hours (out of 105,192) where it exceeds 5% (maximum of 7.7%). Finally, we plotted and visually inspected all 58 time series, leading to a (relatively small) number of manual corrections. Besides consistency with fleet-level output, these manual corrections were informed, when relevant, by public information on outages, which we now describe.

We indeed also leverage three public sources of data on unit-level outages. First, the nuclear safety agency publishes on its website notifications of events when a nuclear unit is switched off and needs the authorization of the agency to be turned on again.[14] These

[11] `https://www.services-rte.com/fr/visualisez-les-donnees-publiees-par-rte/production-realisee-par-groupe.html`, last accessed on 23 February 2024.

[12] For example, a few observations per unit have a reported output is equal to 120% or more of nominal capacity.

[13] This interpolation is refined in the next steps of the data cleaning procedure.

[14] `https://www.asn.fr/l-asn-controle/actualites-du-controle/installations-nucleaires/arret-de-reacteurs-de-centrales-nucleaires`, last accessed on 23 February 2024.

outages usually correspond to planned outages for refueling and maintenance. We retrieve the dates of these outages, and whether or not refueling operations were performed, through a mix of web scrapping and manual searches.[15] This data is available for our full sample.

Second, transparency regulations force the incumbent utility, which operates all nuclear units, to declare planned and forced outages. These notifications are published by both the TSO[16] and the incumbent utility.[17] Besides an identifier of the outage, each notification consists of a publication date, a version (i.e., the number of updates about this outage that have been published to date), and information on the event (start, end, available capacity and, possibly, some – usually very minimal – description). Although both data sources agree most of the time, their overlap is far from perfect. We therefore build a merged dataset that keeps track of the latest notification about each event from either data source.

3.4 Market Prices

Finally, we will also make use in what follows of both French hourly day-ahead, as well as monthly and quarterly future prices. The former is publicly available, for example on Entso-e Transparency Platform.[18] The latter can be purchased from various stock exchanges trading the corresponding products.

4 Flexibility of Nuclear Operations

This section provides both qualitative and quantitative evidence that French nuclear units are operated flexibly.

4.1 Flexible Operations and Operating Constraints

Because this mode of operations is both the simplest and (usually) profit-maximizing, it is widely believed that nuclear units can only provide "baseload" power. This production

[15] We complement information on refueling events by looking manually, for each unit, at all several-week shut-down periods. Over a dozen suspected refueling events could not be found on the nuclear safety agency website and have been added manually.

[16] `https://www.services-rte.com/fr/telechargez-les-donnees-publiees-par-rte.html?category=generation&type=unavailabilities`, last accessed on 23 February 2024.

[17] `https://www.edf.fr/groupe-edf/ambition-neutralite-co2-pour-edf-a-l-horizon-2050/optimisation-et-trading/listes-des-indisponibilites-et-des-messages/liste-des-indisponibilites`, last accessed on 16 December 2024.

[18] `https://transparency.entsoe.eu/`, last accessed on 23 February 2024.

profile corresponds to a steady output at (or close to) nominal capacity, as illustrated in the left panel of Figure 5.

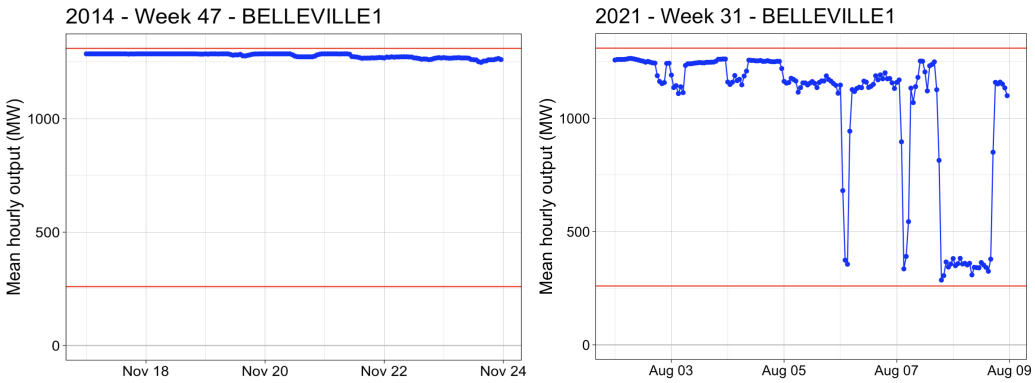


Figure 5: Hourly output of the unit "Belleville 1" for two different weeks. Left panel: example of baseload operations. Right panel: example of flexible operations. The upper red horizontal line represents nominal capacity, and the lower red horizontal line minimum output level.

However, nuclear units have the ability to be operated somewhat flexibly (OECD, 2021). First, they can participate in the provision of ancillary services, that is, quick short-duration variations in output to maintain the real-time balance between supply and demand within seconds or minutes. Such variations are limited in range and capped at $\pm 7\%$ of nominal capacity (Morilhat et al., 2019). Because of their small amplitude and short time-scale, ancillary service actions are hard to detect precisely from hourly output data. We therefore do not consider them in what follows.

Second, nuclear units can engage in "load following", as illustrated in the right panel of Figure 5. Specifically, during the nights of Thursday 6 and Friday 7 August 2021, as well as during most of the following weekend, the unit of "Belleville 1" is observed to decrease its output to less than 500 MW, that is, way below its nominal capacity of 1310 MW. Two important observations are also worth making. On the one hand, there exists a technical limit to how much a unit can decrease its output. This limit, typically around 20% of nominal capacity, is called "minimum output constraint" and is represented by the bottom horizontal line in Figure 5. To decrease output further, the operator must perform a "hot shut down", that is, stop the power plant completely for a few hours or days. While technically feasible, and indeed observed many times in the data, hot shut downs entail further costs. On the other hand, the unit is observed to change its output fairly quickly. Indeed, although nuclear

plants of course face limits regarding how fast they can vary their output, called "ramping constraints", they are technically able to safely change their electricity generation at a rate of about 5% of nominal capacity per minute. In other words, it is feasible for units to change their output from nominal capacity to minimum output level within 30 minutes. Therefore, because we observe unit-level output at an hourly granularity, we do not consider ramping constraints in what follows.

4.2 Aggregate Substitution between Nuclear and Renewables

Since we observe that nuclear units engage in load-following, we start by asking whether and, if so, to which extent, load-following operations of nuke units aim at accommodating intermittent output from renewables.

To do so, we rely on the aggregate hourly data described in paragraph 3.2 and use the standard approach of the literature (e.g. Adler et al. (2020)). Specifically, we estimate several models of the following form:

$$N_h = \alpha + \beta RES_h + \gamma RD_h + \delta_{h \in t} + \epsilon_h \tag{1}$$

where, for a given hour h, N_h denotes the output of the nuclear fleet, RES_h the combined output of wind and solar and RD_h the residual demand except for wind and solar, that is, gross consumption (including pumping) plus net exports minus hydro and must-run biomass output. We estimate different models that differ by the set of time fixed-effects $\delta_{h \in t}$ included in the specification: year, month-of-year, day-of-week, and/or day-of-sample.

Table 1 reports the obtained results. Consistently across specifications, we find that an additional MWh of wind or solar is associated with a 0.6 MWh decrease in nuclear output. In other words, the short-term substitution between wind/solar and nuclear is substantial. If anything, this substitution is potentially under-estimated. Indeed, by taking hydro output as exogenous (when computing hourly residual demand), we shut down the possibility that hydro reservoirs may endogenously reduce output during high renewable hours and substitute for nuclear output in a latter hour.

Interestingly, enriching Equation (1) to estimate year-specific substitution coefficients

	Dependent variable: N_h				
	(1)	(2)	(3)	(4)	(5)
RES_h	-0.812	-0.626	-0.602	-0.625	-0.592
	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)
RD_h	0.776	0.722	0.685	0.718	0.585
	(0.003)	(0.003)	(0.005)	(0.006)	(0.007)
Year FE	N	Y	Y	Y	N
Month-of-year FE	N	N	Y	Y	N
Day-of-week FE	N	N	N	Y	N
Day-of-sample FE	N	N	N	N	Y
Observations	105,180	105,180	105,180	105,180	105,180
R^2	0.925	0.954	0.960	0.962	0.994

Table 1: Obtained results for different specifications of Equation (1). Robust standard errors are clustered by day-of-sample.

between nuclear and renewable output yields results that depend more strongly on which time fixed effects are included in the specification. The coarsest specification without any time fixed effect suggests, consistently with Figure 4, that substitution has been increased over time, from about -0.3 to about -0.8. However, richer specifications including at least year fixed effects yield a roughly constant substitution coefficient over the years of our sample.

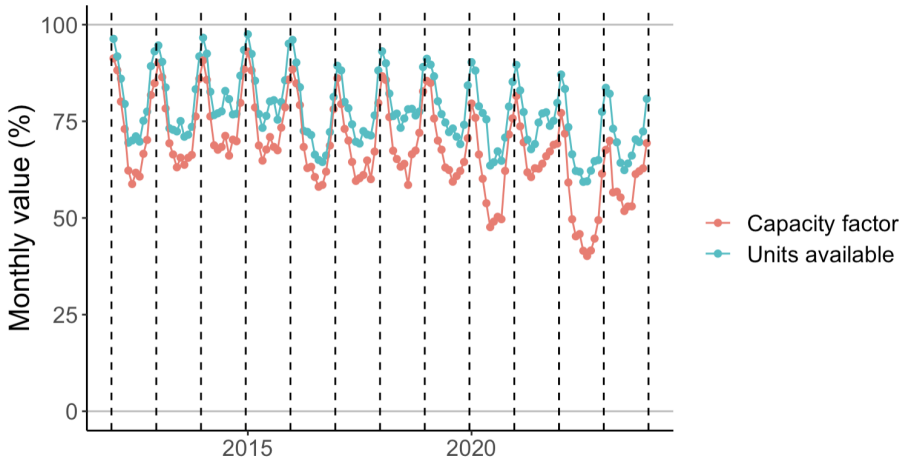


Figure 6: Monthly fleet-level capacity factor (%) and proportion (%) of the available unit-hour, that is, hours where a given unit had a non-zero capacity available to generate electricity (but possibly lower than nominal capacity for partial outages).

This discrepancy can be explained by a degradation of the availability of the nuclear

fleet over our time window. Figure 6 plots the evolution of the fleet level capacity factor (realized output as a percentage of maximum theoretical output), as well as the percentage of unit-hour in each month during which units had a positive available capacity. Both metrics exhibit a significant downward trend, with particularly low values during the Covid-19 lock down and in 2022-2023 where a serial outage was detected and led to the temporary shut down of a large share of the nuclear fleet (Astier, 2024).

Figure A.12 in Appendix A reproduces Figure 4, but replaces the nominal capacity of the nuclear fleet by its realized available capacity. This realized capacity takes into account units' unavailability due to observed outages and refueling operations. Interestingly, we observe that, once outages are taken into account, the realized marginality of the nuclear fleet has actually been stable or, if anything, slightly decreasing.

5 Operating Constraints and Renewables

In this Section, we leverage data on unit-level hourly output to explore technical operating constraints in more detail. Unfortunately, we do not observe these constraints directly. Instead, we must infer them from observed hourly output. This data limitation leads us to restrict attention to (i) the occurrence of minimum output constraints and (ii) the period 2015-2023.

First, as discussed in Section 4, besides available capacity, the two main operating limits faced by thermal power plants are ramping and minimum output constraints. Because the former cannot be reliably inferred from hourly output data, we focus on the latter.[19] Second, we are interested in operating constraints that bind in the context of "normal" operations. Therefore, when we observe a unit with a low output level, we must be able to confidently rule out that this situation may arise because of a partial outage. Although we do observe refueling outages for the whole period 2012-2023, information about other outages occurring before 2015 is only available from the TSO.[20] Upon inspection, we found that this data is very likely incomplete for 2012-2014. As a result, we restrict in this Section the sample to

[19] Hourly output data also allows to detect "hot" shut downs. However, such events are relatively rare and can be more easily confounded with forced outages that the utility may have failed to report. We therefore do not discuss them in what follows.

[20] In contrast, such data is provided by both the TSO and the incumbent utility for 2015-2023.

the period 2015-2023.

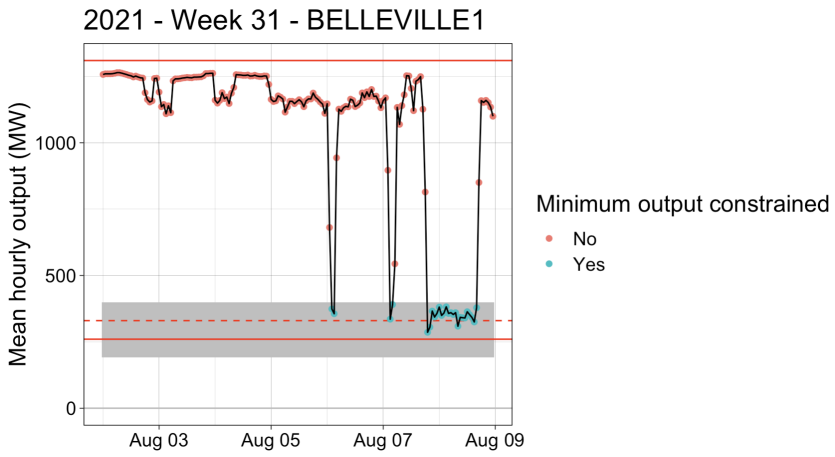


Figure 7: Illustration of how we label non-outage hours as "minimum output constrained". The bottom red horizontal line represents the minimum output level and the dashed red horizontal line this minimum output level plus the maximum capacity reserved for ancillary services. An hour is considered as "minimum output constrained" if hourly output is within a buffer of 5% of nominal capacity around those two lines.

To label a given unit-hour as "minimum output constrained", we retrieve from public data published by EDF unit-specific minimum-output level, which amount to about 20% of nominal capacity. We also retrieve the maximum capacity reserved to provide ancillary services, typically 2 to 5% of nominal capacity. These two values define a range of output values below which the unit cannot produce electricity and is obliged to shut down completely.

However, minimum output constraints are instantaneous *power* constraints. In contrast, our data consist of hourly *energy* output, that is, average power over the course of one hour. As a result, the minimum output constraint may bind within a given hour even though the average power during this hour is higher than this lower bound. Therefore, we define a "minimum output level region" as a buffer around the above range, with a width arbitrarily set at 5% of the nominal capacity of the unit. This buffer is materialized with a gray rectangle on Figure 7. Our first step to detect minimum output constraints is to label hours with an output within the "minimum output level region" as "minimum output constrained" (see Figure 5).

Finally, we want to capture minimum output constraints in the context of load-following, not hours during which the unit is constrained by an outage, or when it enters the minimum output level region as it is ramping down/up before/after a shut down. For long-duration

outages, we therefore exclude from eligible "minimum output constrained" hours the set of contiguous hours around the zero-output period where output is below 90% of nominal capacity. We then look at each remaining "minimum output constrained" hour and retrieve the three closest hours before and three closest hours after that are not in the minimum output level region. If at least one of these six hours correspond to an outage (whose publicly reported duration may be erroneous) or to a zero-output hour ("hot" shut down), we remove the considered unit-hour from the set of "minimum output constrained" hours.

5.1 Country-level Analysis

We first report in Figure 8, for each month of 2015-2023, how often minimum output constraints are detected. Two interesting patterns emerge. First, we observe a spike during the Covid-19 lock down, during which gross electricity consumption decreased sharply (Buechler et al., 2022). Second, the years 2022 and 2023, during which consumption was lower than usual (conservation efforts, mild winters) and the installed capacity of renewables increased sharply, seem to experience an increase in the occurrence of minimum output constraints.

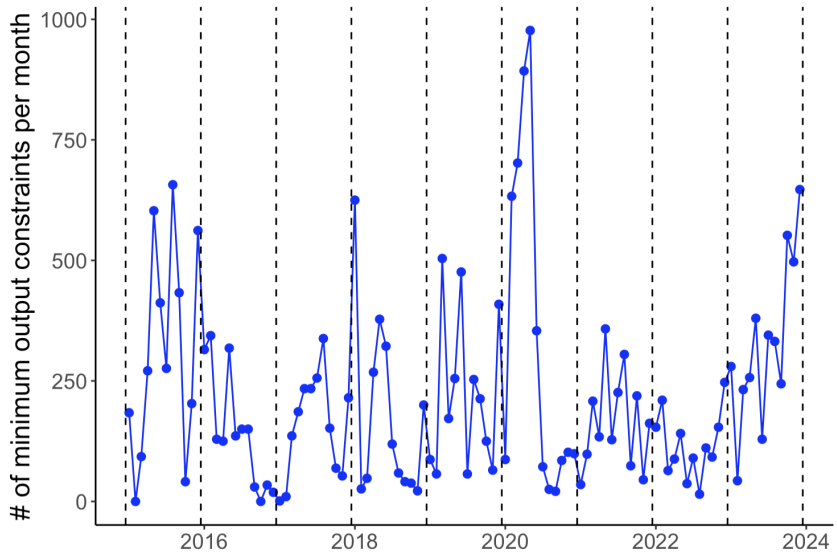


Figure 8: Occurrences of minimum output constrained hours (#/month) over 2015-2023.

Figure A.13 in the Appendix shows the histogram of the hours of the day during which minimum output constraints are inferred to bind. Consistently with the hypothesis that

wind and solar may play a role in triggering these constraints, the obtained distribution exhibits two modes: one during the night (2-6 am) and one during the afternoon (2-5 pm). In order to further test this hypothesis, we replace in Equation (1) the dependent variable with the number of units for which the minimum output constraint is binding in a given hour.

	Dependent variable: # of constrained units in hour h				
	(1)	(2)	(3)	(4)	(5)
RES_h (GWh)	0.061	0.086	0.122	0.118	0.251
	(0.004)	(0.005)	(0.005)	(0.005)	(0.007)
RD_h (GWh)	-0.020	-0.029	-0.099	-0.093	-0.241
	(0.001)	(0.002)	(0.004)	(0.004)	(0.007)
Year FE	N	Y	Y	Y	N
Month-of-year FE	N	N	Y	Y	N
Day-of-week FE	N	N	N	Y	N
Day-of-sample FE	N	N	N	N	Y
Observations	78,879	78,879	78,879	78,879	78,879
R^2	0.074	0.116	0.246	0.259	0.625

Table 2: Relationship between wind and solar output and the occurrence of minimum output constraints. Robust standard errors are clustered by day-of-sample.

All specifications suggest that a higher generation from wind and solar in a given hour is associated with more units reaching their minimum output constraint during this hour (Table 2), and that this relationship is statistically significant. The magnitude of the relationship is, however, less stable across specifications than in Table 1. Indeed, the extent to which some nuclear units must ramp down in the face of a low residual demand also depends on how many nuclear units are actually running during a given hour. Only specification (5), which includes day-of-sample fixed effects, controls for such unit commitment decisions. According to this specification, on average for a given hour, 1 nuclear unit is reaching its minimum output constraint for every 4 GWh of additional wind and solar output.

5.2 Grid Congestion

Because wind and solar power plants are not spread uniformly across space (Figure 2), different nuclear units have been differently "exposed" to the increase in installed renewable capacities. In this paragraph, we explore whether such spatial considerations have had a measurable impact on which nuclear units are facing binding minimum output constraints.

Consider indeed a given renewable power plant that produces 1 MWh of electricity. The "closer" this power plant is to a nuclear unit, the more substitutable this MWh may be to a MWh generated by the nuclear unit. Ideally, the proximity between the nuclear unit and the renewable facility should be measured with "electrical distance", that is by modeling power flows in a way that accounts for the topology of the power grid, electrical losses, and grid congestion. This exercise, however, requires very detailed information about the power system at every point in time. Unfortunately, some of the needed information is not publicly available (e.g. load at demand buses, grid topology and admittance matrix, transmission capacity constraints accounting for $N-1$ contingencies, etc.). We therefore leave the computation of "electrical distances" for further work and compute in what follows an "exposure" metric that can be derived from pubblicly available data.

Specifically, we rely on "spatial" rather than "electrical" distance. Consider a given date t and a given nuclear unit n. Let $i \in I_{t,\tau}$ index all the power plants of technology τ (e.g. wind) that have been commissioned by date t, and denote with K_i the installed capacity of unit i. We consider units to be located at the centroid of the municipality where they sit[21] and denote with $d(i,n)$ the as-the-crow-flies distance between unit i and nuclear unit n. Figure 10 illustrates these notations in a simple case where $I_{t,\tau} \equiv \{1,2,3\}$.

We then define the "exposure" $X_{n,t,\tau}$ of nuclear unit n to technology τ at date t as:

$$X_{n,t,\tau} \equiv \sum_{i \in I_{t,\tau}} \left(\frac{\max(d(i,n), d_0)}{d_0}\right)^{-\gamma} K_i$$

where γ and d_0 are (positive) tuning parameters. In what follows, we set $d_0 = 1$ km (to avoid giving an infinite weight to units located in the same municipality as a given nuclear unit), and use $\gamma = 0.5$ as our main specification.[22]

[21] Centroid of the departement for the small ($\leq$36 kW) solar units that are not listed individually.

[22] Although the value $\gamma = 0.5$ is somewhat arbitrary, qualitatively similar results are obtained by setting instead $\gamma = 0.25$ or $\gamma = 0.75$.

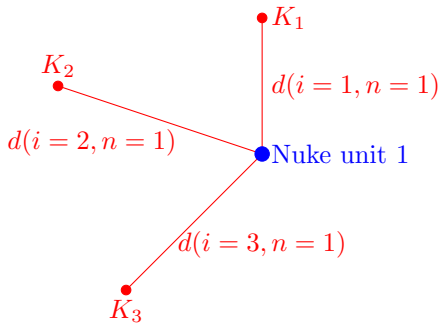


Figure 9: Construction of our "exposure" metric.

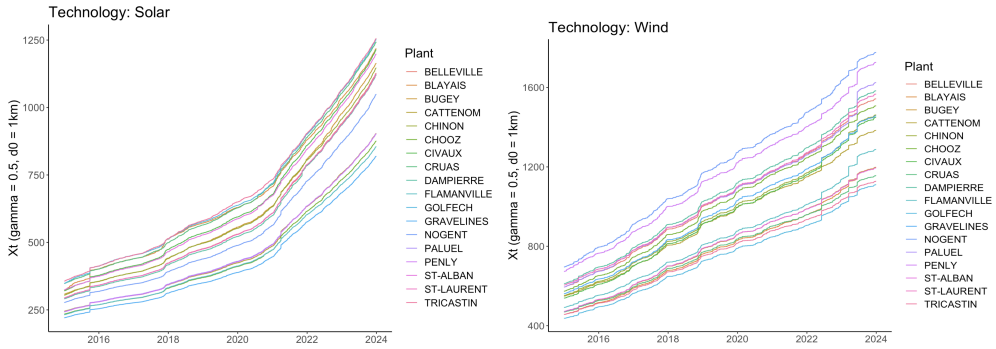


Figure 10: Obtained exposure metric (in MW) to solar (left panel) and wind (right panel) for the 18 nuclear plants between 1 January 2015 and 31 December 2023 ($d_0 = 1$ km and $\gamma = 0.5$).

Figure 10 shows the obtained "exposure" metric (in MW) to wind and solar for the 18 nuclear plants.[23] We observe a significant amount of both temporal and cross-sectional variation. Quite intuitively, nuclear plants in the Southern part of the country are mostly exposed to solar, those in the Northern part mostly exposed to wind and those in the center exposed to both wind and solar.

We then estimate the following models, restricting the sample to "normal" operation unit-hours (i.e. removing refueling, planned and forced outages):

$$Y_{h,n} = \sum_{\tau} \beta_{\tau} X_{\tau,h,n} + \mu_n + \delta_{h \in t} + \epsilon_{h,n} \tag{2}$$

where $Y_{h,n}$ is a dummy variable taking the value 1 is the minimum output constraint is binding for unit n during hour h, $X_{\tau,d,n}$ (for $\tau \in \{$solar, wind, fossil thermal, hydro$\}$ denotes

[23] For simplicity, we restrict the sample to the balanced panel of nuclear plants that were in operations during the whole period. Specifically, we exclude the plant of Fessenheim, which closed in 2020, from the data used for this analysis.

our technology-specific "exposure" metric, μ_n denotes unit fixed effects, and $\delta_{h\in t}$ refers to various combinations of time fixed effects. The error term $\epsilon_{h,n}$ is assumed either i.i.d. normal (linear probability model) or i.i.d. Gumbel (logit).

	Dependent variable: Is minimum output constraint binding for unit n in hour h?								
	Linear probability model					*Logit*			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
X_PV	0.0026	0.0094	0.011	0.044	0.046	0.30	1.1	1.3	6.3
	(0.0004)	(0.0007)	(0.0008)	(0.002)	(0.003)	(0.040)	(0.084)	(0.089)	(0.261)
						[0.002]	[0.009]	[0.01]	[0.05]
X_Wind	0.0033	0.0075	-0.0035	0.015	0.0017	0.41	0.87	-0.4	2.1
	(0.0003)	(0.0005)	(0.0007)	(0.002)	(0.002)	(0.034)	(0.060)	(0.078)	(0.218)
						[0.003]	[0.007]	[-0.003]	[0.02]
X_Hydro				0.039	-0.095				9
				(0.008)	(0.012)				(1.178)
									[0.07]
X_Therm				-0.016	0.017				-3.9
				(0.002)	(0.004)				(0.266)
									[-0.03]
Unit FE	N	N	Y	Y	Y	N	N	Y	Y
Year FE	N	Y	N	Y	N	N	Y	N	Y
Month of year FE	N	Y	N	Y	N	N	Y	N	Y
Day of week FE	N	Y	N	Y	N	N	Y	N	Y
Hour of day FE	N	Y	N	Y	Y	N	Y	N	Y
Day of sample FE	N	N	N	N	Y	N	N	N	N
Observations	2,877,240	2,877,240	2,877,240	2,877,240	2,877,240	2,877,240	2,877,240	2,877,240	2,877,240
R^2	0.0002	0.013	0.006	0.019	0.050				
Log Likelihood						−134,996	−119,492	−127,245	−111,234
Note:									Robust (HC1) standard errors

Table 3: Obtained results when estimating Equation (2) with different sets of fixed effects. Robust standard errors (HC1) are reported in parenthesis. For logit specifications, average marginal effects (i.e., the derivative of the probability that the minimum output constraint binds with respect to $X_{\tau,h}$) are reported in squared brackets. Exposure metrics are in GW and computed with $\gamma = 0.5$.

Table 3 reports the obtained results. For specifications with both cross-sectional and granular time fixed effects (Specifications (4), (5) and (9)), they suggest that increasing "exposure" to PV may be associated with more frequently binding minimum output constraints. Specifically, a 1 GW in increase in our exposure metric to PV is on average associated with a 4-5% increase in the frequency of occurrence of the minimum output constraint. Because our exposure metric (when normalized in GW) spans from 0.22 to 1.26, this effect is relatively small. Nonetheless, it does suggest that transmission grid congestion is likely to have an increasingly significant influence on the dispatch of nuclear units as solar PV penetration increases.

6 Economic Incentives

A large penetration of wind and solar resources transforms the distribution of electricity prices, for example increasing the number of hours with low (or negative) prices (Mallapragada et al., 2021) or, for solar PV, exacerbating the seasonality of residual demand (and therefore prices) in a winter-peak system. This Section discusses how the operator of nuclear units may respond to such changes.

6.1 Short-term Response to Day-ahead Prices

Textbook analysis of power markets (e.g. Léautier (2019)) suggests that, absent market power or technical constraints, a power plant should generate electricity in a given hour if, and only if, the spot price for this hour is higher than its marginal cost. Even when market power is a relevant concern, the operator of the plant generally still has strong incentives to reduce output when spot prices fall below marginal cost, at least down to the minimum output level (complete shut downs entailing additional costs).

To assess to which extent these theoretical insights indeed match empirical observations, we again restrict attention in this paragraph to the period 2015-2023. We retrieve hourly day-ahead prices that we group into 10 different bins, and compute the observed capacity factor of the nuclear fleet over different sets of hours for each of these price bins.

First, purple crosses in Figure 11 report the observed capacity factor in non-outage unit-hours, that is, all unit-hours for which the unit is not shut down for refueling and has not declared a planned or a forced outage. As expected, the observed capacity factor is lower during hours with low or even negative day-ahead prices, especially below 10-15€/MWh, which corresponds to typical reference values for the variable fuel cost of nuclear power plants. However, even when prices are *negative*, the observed conditional capacity factor remains higher than 75%, that is, far above the capacity factor of 20-25% that would be observed if all running nuclear units were decreasing generation to minimum output levels.

One explanation for this puzzle may be that, even in non-outage running hours, nuclear units cannot always be operated flexibly. In particular, nuclear units are operated according to fuel cycle sequences. Such a sequence starts with a refueling outage where a fraction (typically a third) of the uranium in the core is replaced, after which the plants ramps up

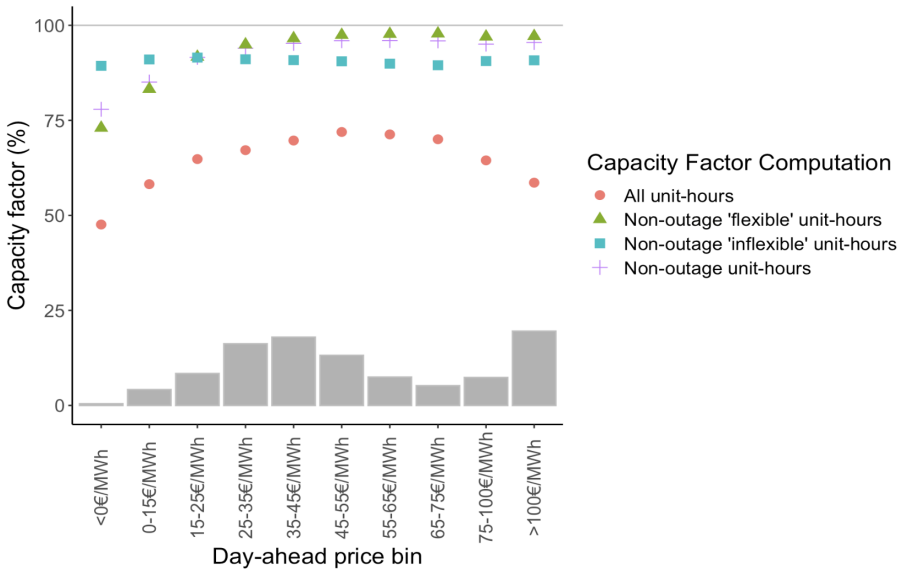


Figure 11: Average capacity factor by day-ahead price bins for different subsets of unit-hours: (i) all hours in 2015-2023 (red circles); (ii) non-outage (planned, forced, refueling) unit-hours (purple crosses); (iii) non-outage unit-hours when the unit has ramped up after a shut down and has not reached 80% of the fuel cycle (green triangles); (iv) non-outage unit-hours during ramping up and the last 20% of the fuel cycle (blue squares). The bottom gray bars represent the frequencies of each price bin.

and produces electricity until the next refueling outage. Figure A.14 shows an example of such a "fuel campaign" for the unit Blayais 1. Importantly, one may notice that the unit tends to vary its output much less towards the end of the fuel cycle. Indeed, because of the physics of the nuclear core, French nuclear units can no longer be operated flexibly when they are reaching the end of their fuel campaign (OECD, 2021).

Therefore, we next divide non-outage unit-hours into two mutually exclusive subsets: the first 80% of the fuel cycle on the one hand,[24] and the initial ramping up and last 20% of the fuel cycle on the other hand. In Figure 11, conditional capacity factors for the former subset are represented by green triangles, and conditional capacity factors for the latter subset are represented by blue squares. As expected, the average capacity factor of nuclear units during "inflexible" hours is found to be roughly constant independently of day-ahead prices. However, even if the average capacity factor during "flexible" hours is found to drop significantly for low day-ahead prices, it remains far above the capacity factor that would be obtained if all units were decreasing supply to their minimum output level.

[24]We measure the length of the fuel cycle as the total amount of electricity generated during the campaign. We exclude from the "flexible" hours the ramping up period at the beginning of the fuel cycle.

At least a couple of reasons might explain this last observation. First, day-ahead prices do not properly capture the private opportunity cost of ultimately running a nuclear unit. Indeed, changes between day-ahead forecasts and actual real-time system conditions may trigger opposite signals in intraday and reserve mechanisms. However, in the absence of transparent real-time markets, such incentives cannot be retrieved from public data. Second, transmission grid congestion is not internalized in day-ahead markets but is later accounted for in balancing mechanisms. A number of unit may therefore be "constrained on" by the system operator, although such constraints are equally hard to observe precisely given the absence of transparent locational price signals. We leave the exploration of both channels to further research.

Finally, the red circles in Figure 11 shows the obtained average capacity factors conditional on each price bins when considering all hours, including outages. They exhibit an inverted U-shape, with both low and high price levels being associated with lower capacity factors. While the latter likely reflects situations where the low availability of the nuclear fleet triggered high prices (Astier, 2024), the former may instead reflect situations where available capacity is (at least partly) adjusted to expected prices. Consistently, Figure A.15 shows that planned outages and refueling events occur more often during low-price hours. In addition, in other jurisdictions (Lundin, 2021), the availability of nuclear units has been shown to be strategically adjusted. The next paragraph explores this possibility in more detail.

6.2 Medium-term Response and Outage Scheduling

Although the increasing penetration of wind and solar should have made nuclear units more and more marginal (Figure 4), this evolution was not observed in practice (Figure A.12). Indeed, the decreasing availability and capacity factor of the nuclear fleet (Figure 6) has been commensurable with the rise in wind and solar output. The degradation of the capacity factor of the nuclear fleet can be, at least partly, attributed to two large exogenous shocks: the Covid-19 lock-down and a serial outage in 2022-23 following the discovery of stress corrosion cracking. Whether these shocks are sufficient to fully explain the plummeting capacity factor of the nuclear fleet from an already low baseline level is, however, an open question.

In this section, we provide preliminary evidence that the decrease in capacity factors might be in parts endogenous. Specifically, we discuss the length of fuel cycles.

After retrieving (and manually checking) all refueling events over our period 2012-2023, we fully observe 469 fuel campaigns (see Figure A.14 for an example). These campaigns correspond to the period of time between two refueling outages.[25] Besides their duration, we can retrieve how much electricity (in TWh) was produced during each campaign, which is the outcome we focus on in this paragraph.

During each refueling outage, a constant fraction (typically a third) of the fuel is renewed. Therefore, for a given unit, we expect the amount of electricity generated during each campaign to be very stable, if not constant. Consistently, when regressing the amount of electricity generated during a campaign on unit fixed effects, we obtain an R-squared of almost 0.9. The remaining 10% of "unexplained" variance may arise because some cycles have been stopped earlier than initially planned (e.g. due to a long forced outage) and/or because the length of the fuel cycle may be adjusted endogenously at the margin. The latter explanation would imply that the operator is likely to respond to the increasing share of renewables by adjusting how fuel cycles are optimized.

To test this hypothesis, we retrieve, for each fuel cycle, the price of future "base" products traded one month before the start of the cycle. From the products Q+1 to Q+4, as well as M+1 and M+2, we compute an estimate of the future price of delivering 1 year of constant output with a delivery starting at the beginning of the fuel cycle.[26] We then estimate:

$$Y_{i,c} = \beta P_c + \delta_i + \epsilon_{i,c} \tag{3}$$

where $Y_{i,c}$ denotes the electricity generated by unit i during cycle c (in TWh), P_c denotes our measure of the future price of baseload electricity based on prices quoted one month before the start of the cycle and δ_i denotes unit fixed effects. A positive value for our coefficient of

[25] We of course also observe the duration of refueling outages. Because the amount of maintenance performed during these outages is very heterogeneous (from virtually no maintenance to a full retrofit of the unit), and sometimes involves large unforeseen issues, their duration spans from one month (28.5 days) to three years (with a median of 11 weeks and a mean of 15 weeks). The full extent of what can be inferred from these durations is therefore uncertain and left for further research.

[26] When the front month matches a quarter product, we simply average the prices of Q+1 to Q+4. Otherwise, we use either (M+1, Q+1, Q+2, Q+3, Q+4) with weights (1/12, 1/4, 1/4, 1/6) or (M+1, M+2, Q+1, Q+2, Q+3, Q+4) with weights (1/12, 1/12, 1/4, 1/4, 1/12), depending on how far the start of the fuel cycle is from the delivery period of Q+1.

interest, denoted with β, means that an increase in expected electricity prices is associated with an increase in how much electricity is produced during the subsequent cycle.

Table 4: Electricity generated during a fuel cycle (TWh) regressed against the (resp. logarithm of) future price for the year of the cycle, from quotations one month before the start of the cycle.

	Dependent variable:			
	Output during the cycle (TWh)			
	(1)	(2)	(3)	(4)
future price (€/MWh)	2e-04		0.014	
	(0.0005)		(0.008)	
log(future price)		0.1		0.6
		(0.086)		(0.336)
Units FE	Y	Y	Y	Y
Observations	469	469	418	418
R^2	0.896	0.896	0.896	0.896

Table 4 shows the obtained estimates. Columns (1) and (2) use the full sample, while columns (3) and (4) restrict attention to fuel cycles that started before July 1st 2021, that is, before the start of the energy crisis. Although somewhat under-powered, our results do suggest a positive relationship between forward electricity prices and the length of fuel cycles. This relationship is significant at the 10% level for specifications (3) and (4). However, statistical significance is not robust to adding dummies for the month during which the fuel cycle starts. Although we cannot pin down the exact underlying mechanism (e.g. loading slightly more fuel *ex ante* vs burning the fuel longer if realized spot prices are indeed high *ex post*), these results suggest that fuel cycles are likely to be at least partly endogenous, and therefore to strategically respond to the increasing penetration of wind and solar.

7 Conclusion

This paper studies empirically the behavior of a carbon-free electricity system that relies on both renewables and nuclear. Our analysis focuses on France, a country with a legacy nuclear capacity of 61 GW as well as significant and steadily increasing renewable generation.

Specifically, we explore how French nuclear power plants have adjusted their operations in

the face of growing wind and solar generation. We first document that, in contrast to widely held beliefs, nuclear units can be in practice operated very flexibly: an additional 1 MWh of domestic wind and solar generation is on average associated to a 0.6 MWh decrease in nuclear output. However, we find evidence that fuel management constraints and, perhaps, grid congestion are putting binding bounds on the "supply response" provided by nuclear units. In particular, the minimum output constraint of nuclear units is found to be bidding more frequently over time, especially for the units most "exposed" to solar PV.

Finally, we observe that, although the decrease in residual demand should have made nuclear possibly marginal in virtually every hour, the realized marginality of nuclear did not change in practice due to a large decrease in the observed capacity factor of the nuclear fleet. While idiosyncratic outages are the leading explanation for the plummeting availability of nuclear units, we show that the operator enjoys some amount of flexibility regarding fuel management and planned outages, which might be leveraged for strategic purposes.

Subsequent iterations of this work will add the year 2024, during which renewable penetration increased substantially, to our sample. In addition, we will expand our analysis of both operating constraints and (possible) strategic behaviors.

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Appendices

A Supplementary Figures and Tables

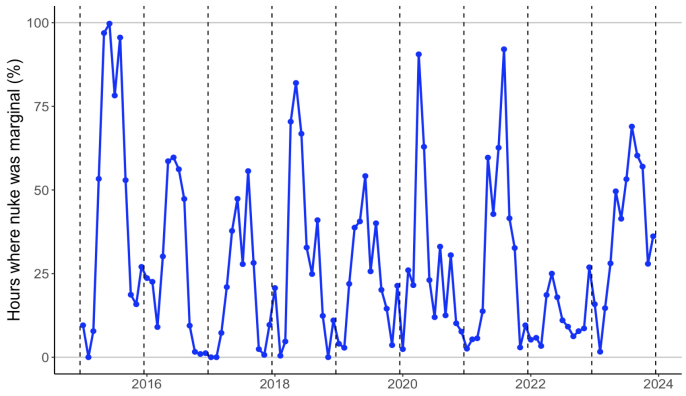


Figure A.12: Percentage of hours in each month when nuclear would be the marginal technology given the generation capacity actually available (i.e. accounting for refueling, forced and planned outages). The time series only start in 2015 because our data on outages other than refueling pre-2015 was found to be not as reliable as post-2015.

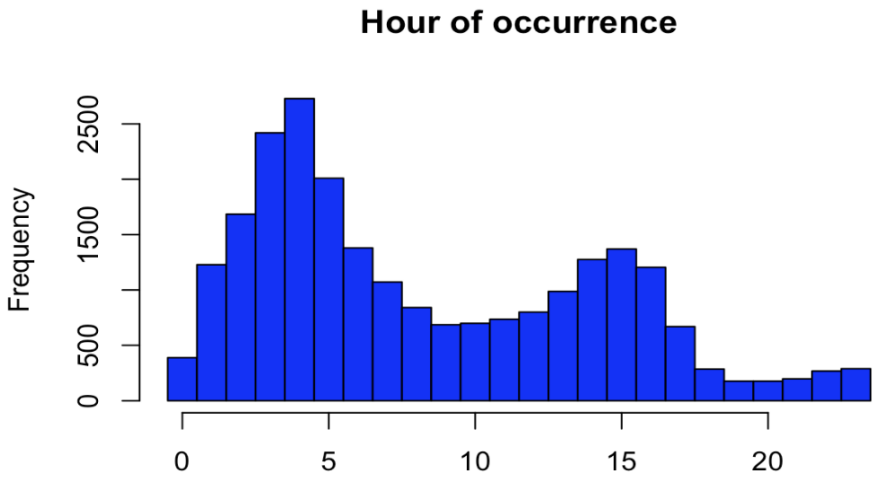


Figure A.13: Histogram of the hours of the day when the minimum output constraint is inferred to bind.

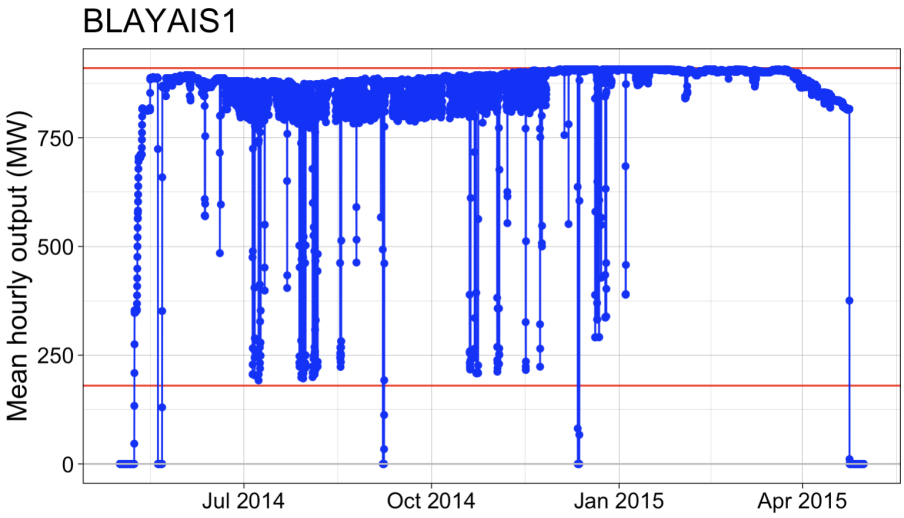


Figure A.14: Example of a fuel cycle.

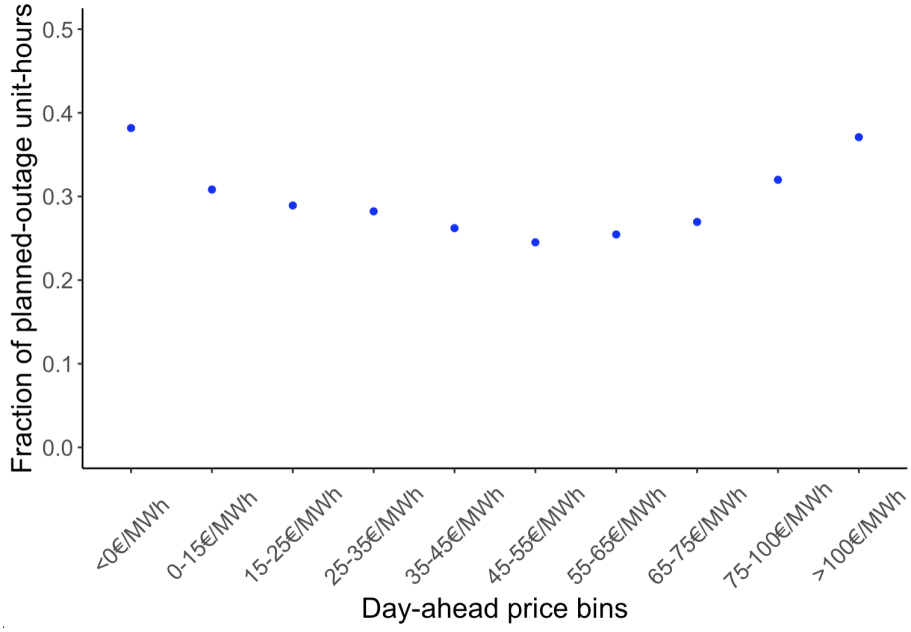


Figure A.15: Fraction of unit-hours that correspond to planned and refueling outages, broken down by price bins.