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

Preliminary

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Abstract

A carbon-free electricity mix may consist of 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 nuclear capacity of 63 GW and a total capacity of wind and solar of almost 50 GW as of 2025. In this context, the (lack of) ability of nuclear units to adjust output in the short-run can have a significant impact on electricity prices, and therefore on the long-term profitability of various investments. We show that French nuclear units are in practice operated very flexibly but that (nominal) minimum output constraints are binding more frequently as wind and solar generation increases. More generally, fuel management (and possibly grid) constraints are putting increasingly binding bounds on the available "flexibility" of the nuclear fleet: in 2024, hours during which available nuclear flexibility was exhausted are strongly associated with zero or negative prices.

Keywords: nuclear, renewables, operating constraints, electricity prices

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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 governments have favored the former option: given the escalating costs 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 in 2011 (Davis, 2012; Joskow and Parsons, 2012).

In recent years, however, we observe a renewed interest in nuclear power. Indeed, the increases in both geopolitical tensions and global temperatures call for diversifying energy sources and speeding up decarbonation. Several countries, such as France, the United Kingdom or Poland have announced plans to build new nuclear reactors. Therefore, the future carbon-free electricity mix of a number of developed countries will very likely include large installed capacities of both nuclear and renewables.

Yet, from both 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 substitutable in a steady-state optimal electricity mix (Green and Léautier, 2015; Holland et al., 2022). From a short-run perspective, wind and solar 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 and safely adjust their output (OECD, 2021). The practical stringency of these latter constraints, both today and in a future with a very high penetration of renewables, is however largely unknown.

This paper aims at addressing this gap. Specifically, it seeks to answer the following research questions: to which extent can (short-run) nuclear operations cope with large amounts of wind and solar generation? Which challenges are likely to arise in such electricity systems?

Although somewhat technical in appearance, these questions have first-order economic

[1] Developed countries are usually considered to have exhausted the locations suitable for large-scale hydropower. In addition, the cost-effectiveness and/or technological feasibility of alternative (possibly) carbon-free generation technologies, such as hydrogen or nuclear fusion, remains to be shown.

implications. Indeed, consider an electricity generation mix exclusively composed of wind and solar on the one hand, with a marginal production cost of zero, and nuclear on the other hand, with a positive marginal production cost. Figure 1 illustrates the corresponding supply function, although known as the "merit order" in the electricity industry. The horizontal green segment represents the total output from wind and solar in a given hour, and the horizontal orange segment the total capacity of nuclear units that are up and running during that hour. Further assume that (residual) electricity demand (in blue on Figure 1) is lower that the sum of renewable output and available nuclear capacity.

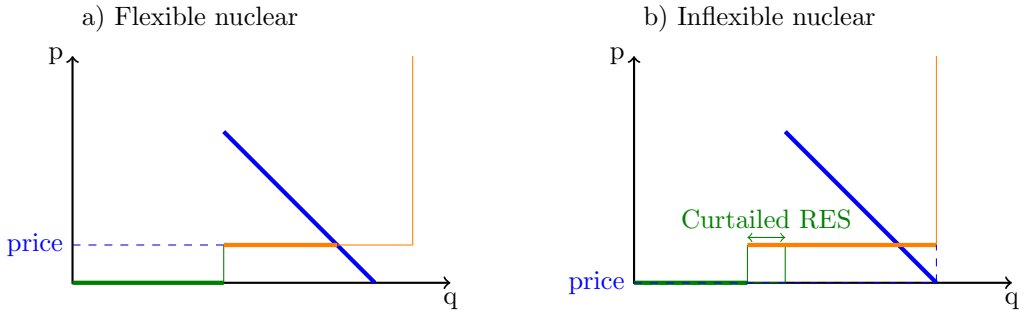


Figure 1: Market-clearing equilibrium prices when the nuclear fleet in either flexible (left panel) or inflexible (right panel) in the short run.

Two very different situations may then arise. On the one hand, if the nuclear fleet is "flexible" in the short run (left panel on Figure 1), it will decrease its output. The competitive market price will then be the marginal cost of nuclear and no renewable output will be curtailed. On the other hand, if the nuclear fleet is "inflexible" (right panel on Figure 1), the nuclear fleet will not ramp down. Renewables will then need to be curtailed, bringing the competitive market price down to zero.[2] Whether or not nuclear operations are flexible in the short run therefore has first-order implications for equilibrium market prices, and thus for the long-term profitability of the different production technologies as well as other investments (batteries, electric vehicles, etc.). In addition, in this example, flexible short-run operations increase total surplus by avoiding renewable output curtailments. On the flip side, however, operating nuclear units in a flexible manner may increase the probability of outages and thus decrease overall reliability.

This paper leverages detailed hourly public data on the French power system for 2012-2024

[2]Or even negative prices if renewable support schemes imply that renewable producers incur a positive (private) opportunity cost for not generating electricity.

to shed some light on these questions. With 63 GW of installed nuclear capacity, and a total capacity of wind (resp. solar) that grew from 6.7 GW (resp. 2.5 GW) to 24 GW (resp. 24 GW) between the end of 2011 and the end of 2024, France provides a somewhat unique case study (so far).

Our preliminary findings are threefold. First, in contrast to widely held beliefs, we observe that nuclear power plants are operated very flexibly, even on a short-run notice. When controlling for day-of-sample fixed effects (thus accounting for the nuclear capacity actually available on a given day), one additional MWh of wind or solar generation is on average 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, when engaging in load following, a nuclear unit has to produce a minimum level of output to maintain stable operations. In other words, it faces a "nominal" minimal output constraint (MOC).[3] We find that nominal MOCs are binding more and more often as the penetration of wind and solar increases. In addition, we provide qualitative evidence that this trend may be exacerbated by grid constraints in the case of solar generation. Third, in any given hour, nuclear plant operators can face minimum output constraints that are actually higher than the nominal MOC because of other factors, such as end-of-fuel-cycle rigidities or grid stability constraints. Such minimum output constraints driven by other factors, which we call "other MOCs", are found to bind much more frequently than nominal MOCs. When accounting for both nominal and other MOCs, we show that, in 2024, hours during which available nuclear flexibility was exhausted are strongly associated with zero or negative day-ahead prices.

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 short-run nuclear operations. Section 5 shows, however, that there exist limits to the short-run flexibility of the nuclear fleet. In particular, increasing wind and solar generation induces nominal MOCs to bind more frequently. In addition, we observe that other MOCs are significantly more prevalent, although for reasons not directly related to short-run variations in renewable generation. Section 6 shows that, in 2024, hours during

[3]Alternatively, the unit may stop producing for a short amount of time, an operation known as "hot shut down". This possibility, which entails significantly higher costs, will be discussed in later iterations of the paper.

which the remaining flexibility of the nuclear fleet was exhausted strongly correlate with hours with zero or negative day-ahead prices. This section also discusses areas for further research. Finally, section 7 concludes.

2 Decarbonation, Nuclear and Renewables

This section provides some background on the role that nuclear energy has been envisioned to play over time in the decarbonation of electricity supply, as well as some of the 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, many countries have been supporting the development of wind and solar energy. In the mid-2010s, global yearly newly commissioned capacity of wind and solar has for the first time exceeded that of 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 is blowing or the sun is shining. Therefore, a large literature explores how intermittency affects optimal policy design (e.g. Ambec and Crampes (2019); 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) in a power system where little to no fossil-fueled assets remain.

Besides hydropower, whose total installed capacity is constrained by the limited number of suitable sites and therefore not expected to grow significantly in developed countries, nuclear is the only mature, carbon-free and dispatchable technology readily available today. However, over 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, many layers of safety regulations have been added over time, partly as an endogenous response to this lower acceptability. This latter consequence magnified the intrinsic engineering challenges that building a nuclear plant entails, and ultimately translated into a 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 exists (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 because of 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 to the local economy (Bauer et al., 2017), the health benefits in terms of air pollution (when nuclear displaces 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 very successful green industrial policies (Andersson and Finnegan, 2024), and their demise in democratic countries 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 address the challenge of making nuclear energy cost-competitive.

If it is too early to say whether this renewed interest in nuclear power will again prove short-lived or whether a nuclear "enlightenment" age is instead emerging, it nonetheless

seems very likely that nuclear energy will play a significantly role in decarbonizing the electricity mix of at least some countries. For example, France is committed to maintain its existing nuclear reactors for as long as safely and technically possible, and has started to plan for their partial renewal by launching studies for almost 10 GW (six 1.6 GW units) of new nuclear capacity. 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, dispatchable power plants will become more and more valuable to address the challenge of intermittency. The extent to which nuclear power can represent an adequate response to these new economic conditions is, however, an open question.

First, nuclear units are complex to maintain and operate. In this context, asymmetric information is unavoidable (e.g. Amore et al. (2024)), and the incentives faced by plant owners can have a large impact 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 can raise market power concerns. Such market power may be exercised at different time horizons. In the short term, 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). Finally, in the long term, entry and exit announcements and/or decisions can shape competitors' expectations, possibly favoring market concentration (Liski and Vehviläinen, 2018).

Second, and more closely related to this paper, dispatchable power plants must meet the "residual" electricity demand, that is, gross consumption minus the total output from zero-variable-cost renewables. As the penetration of intermittent renewables increases, so does the volatility of the residual demand. Little is known about the extent to which nuclear

units can cope in practice (that is, based on empirical evidence from actual operations) with this increased volatility. 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". However, nuclear units do have the ability to vary their output level even on a short-run notice (Lokhov, 2011), for example to adapt their production to the level of residual demand. Such "load following" operations, which we describe in more detail in the next section, are for example routinely used in France (Morilhat et al., 2019) and were also used in Germany prior to the nuclear phase out (Grünwald and Caviezel, 2017).

However, little is known about the actual 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, to an even larger extent than fossil-fuel thermal plants (Jha and Leslie, 2025), 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,[4] 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. This paper instead relies on *ex post* econometric analyses by leveraging the fact that France is a jurisdiction where large amounts of both nuclear and renewable capacities already co-exist.

3 Data and Background 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.

[4]For example, Le Billon (2016) mentions that EDF has been increasing the number of units that can perform load following simultaneously, although the couple of simplistic investigations we ran so far failed to clearly detect this change.

3.1 French Electricity Generation Fleet

Electricity generating technologies in France may be divided into 5 broad categories: nuclear, hydropower, fossil-fueled thermal plants, wind and solar. Our study focuses attention on 2012-2024. Over this period of time, the installed capacities of these technologies have exhibited very different trends.

First, nuclear represents the largest share of both installed capacity and generated electricity. As of 2012, the nuclear fleet, operated by the incumbent utility, consisted of 19 power plants (Figure 2). These power plants are composed of two to six units, for a total of 58 units between 2012 and 2020. The majority of units 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, nominal minimum output level, etc.) are publicly available from Électricité de France (EDF), the International Atomic Energy Agency or other data sources. During our period of interest, two 900 MW units (Fessenheim power plant) were decommissioned in 2020 and one 1600 MW unit (Flamanville 3) was commissioned in December 2024.[5] The current fleet therefore consists of 18 plants composed of 57 units, for a total capacity of 63 GW.

To track the evolution of the other technologies, we rely on a yearly public inventory published by the French government since 2017. This inventory lists all electricity generation units as of 31 Deccember[6] and provides for each unit, among other information, (i) its installed capacity, (ii) its technology (hydro, non-renewable thermal, nuclear, renewable thermal, solar, wind), (iii) the municipality where it is located,[7], 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.[8]

[5] We do not include this unit in our dataset since it had not started commercial operations as of 31 December 2024.

[6] For example, the inventory as of 31 December 2024 is available at `https://www.data.gouv.fr/fr/datasets/registre-national-des-installations-de-production-et-de-stockage-delectricite-au-31-12-2024-1/`, last accessed on 9 April 2025.

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

[8] 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) for more details). Because they represent

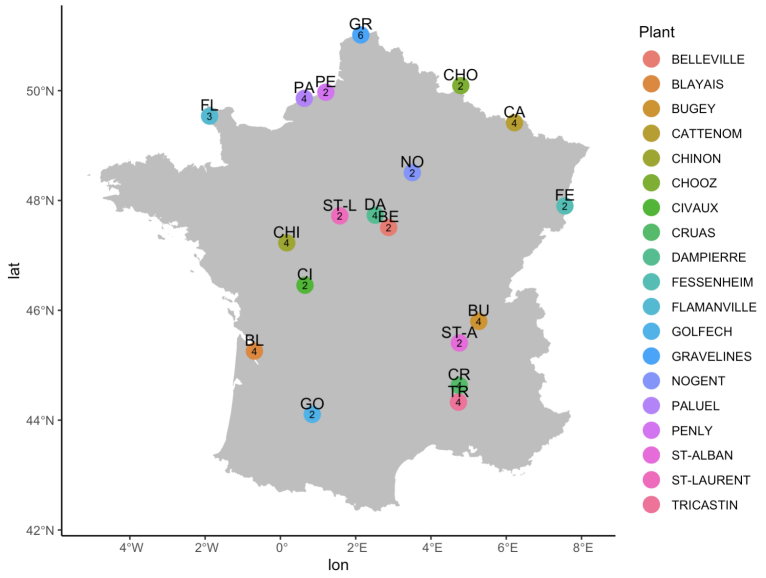


Figure 2: Location of the 19 nuclear power plants in our dataset. The figures in the circles indicate the number of units that compose each power plant (as of today for Flamanville).

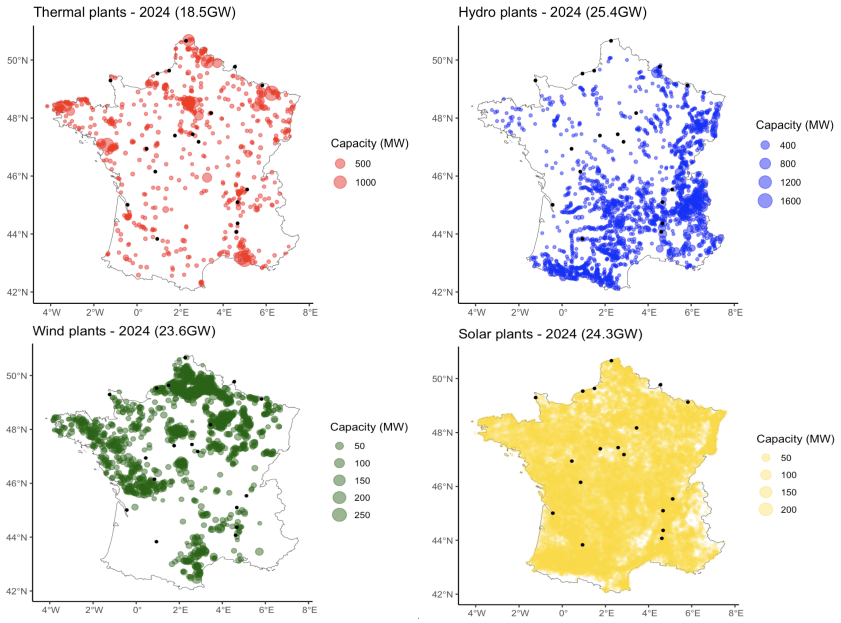


Figure 3: Locations of non-renewable thermal, hydro, wind and photovoltaic capacities as of 31 December 2024. Nuclear plants (operational as of 31 December 2024) are represented with black circles.

We observe that 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-

a small fraction of total installed solar capacity (less than 5 GW out of 24 GW as of 31 December 2024), we aggregate for simplicity small PV installations at the departement level (mainland France has 94 such departements). We interpolate these estimates linearly to proxy for the daily departement-level time series of these installations.

river units. Fossil-fueled thermal capacity also followed an almost flat trajectory to reach about 18 GW in 2024, 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 steadily. Installed wind capacity increased from 6.7 GW as of 31 December 2011 to about 24 GW as of 31 December 2024. Solar photovoltaic capacity increased from about 2.5 GW to 24 GW over the same time window.

Figure 3 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 2024. Importantly, the spatial distribution of power plants differs significantly across technologies. Thermal power plants tend to be located close to the main cities, while hydro facilities locate near the main mountain areas and along rivers. Wind power plants were predominantly installed in the North. Although somewhat spread out across the whole territory, solar installations have been more intensively deployed in the South. Overall, Figure 3 illustrates that the different nuclear power plants are "exposed" differently to other generation technologies, at least in a spatial sense.

3.2 Aggregate Consumption and Generation

Country-level information about the power system is publicly available at a (sub)hourly time scale from both the transmission system operator[9] and Entso-e.[10] We retrieve from these data sources hourly electricity consumption, aggregate generation by technology and net imports/exports for the period 2012-2024.

Figure 4 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 during cold winter months (December, January and February). Indeed, given the high penetration of electric heating and the lack of widespread adoption of air conditioning, typical electricity demand during the winter is 1.5 to 2 times higher than 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

[9] From 2012 onward at `https://www.rte-france.com/eco2mix`, last accessed on 9 April 2025.
[10] From 2015 onward at `https://transparency.entsoe.eu/`, last accessed on 9 April 2025.

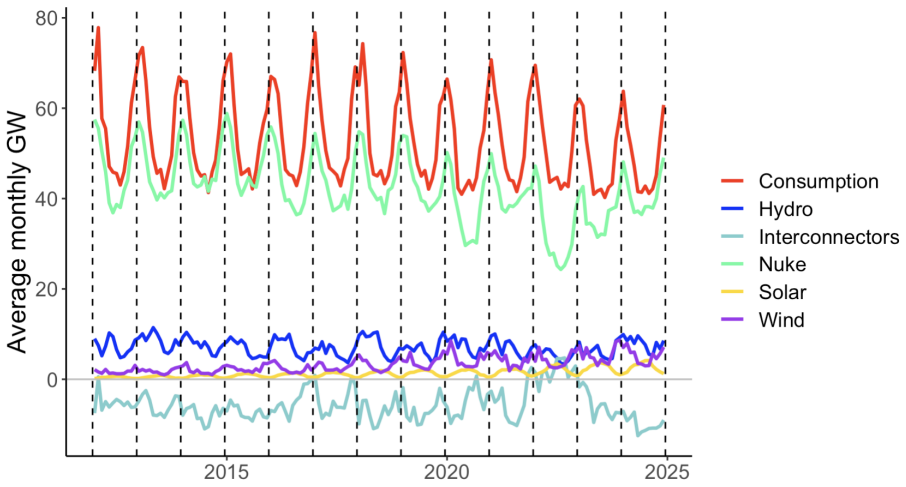


Figure 4: Monthly electricity consumption, generation by main technology and commercial exchanges over 2012-2024. Dashed vertical lines indicate the beginning of each year.

exhibiting a flat "baseload" pattern. Instead, nuclear generation follows very closely, at the aggregate level, domestic consumption, 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, 2025). This "seasonal" load-following is mostly achieved through the scheduling of refueling outages (Lynch et al., 2022).

Finally, the generation from wind and solar has been steadily growing from negligible amounts in 2012, to a combined output comparable to hydropower towards the end of the sample period. While this increase in renewable output may seem relatively small, it is actually sufficient to reach a power system that could, at least in theory, exclusively rely on nuclear and renewables. This point is illustrated in Figure A.1 in the Appendix. Therefore, our case study is particularly relevant to explore how power systems may behave as they approach an electricity mix relying exclusively on nuclear and renewables, revealing the associated challenges that may arise.

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 2012-2024, the hourly output of 56 (after 2020) to 58 units (before 2020) represents over 6 million observations. Episodes of

[11] `https://www.services-rte.com/fr/visualisez-les-donnees-publiees-par-rte/production-realisee-par-groupe.html`, last accessed on 9 April 2025.

missing or erroneous data are therefore impossible to avoid.

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,[14] 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 country-level time series is 0.57%, with only 24 hours (out of 113,976) where it exceeds 5%. Finally, we plotted and visually inspected all 58 time series, leading to a small number of manual corrections. Besides consistency with fleet-level output, these manual changes were informed, when relevant, by public information on unit-level 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 a notification whenever a nuclear unit is switched off and needs the authorization of the agency to be turned on again.[15] These 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.[16] This data is available for our full sample. Second, transparency regulations require the incumbent utility, which operates all nuclear units, to declare planned and forced outages. These notifications are published by both the TSO[17] and the incumbent utility.[18] 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

[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://transparency.entsoe.eu/`, last accessed on 9 April 2025.

[15] `https://www.asn.fr/l-asn-controle/actualites-du-controle/installations-nucleaires/arret-de-reacteurs-de-centrales-nucleaires`, last accessed on 9 April 2025.

[16] We complement information on refueling events by looking manually, for each unit, at all shut-down periods lasting more than a couple of weeks. Over a dozen very likely refueling events (based on typical fuel cycle lengths) could not be found on the nuclear safety agency website and have been added manually.

[17] `https://www.services-rte.com/fr/telechargez-les-donnees-publiees-par-rte.html?category=generation&type=unavailabilities`, last accessed on 9 April 2025.

[18] `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 9 April 2025.

have been published to date), and information on the event (start, end, available capacity and, possibly, some minimal description). Although both data sources agree most of the time, their overlap is not perfect. We therefore build a merged dataset that keeps track of the latest notification about each event from either data source. The obtained dataset on outages is only available for the period 2015-2024.

3.4 Additional Sources of Data

Since June 2021, the outage data published by the incumbent utility also include information about "dynamic" unit-level minimum output constraints. Specifically, due to transparency obligations, the utility must disclose the actual MOC enforced at a given unit at a given point in time whenever its value is at least 100 MW larger than the nominal MOC. We leverage these disclosure messages to build unit-level hourly time series of the actual minimum output constraint ("other MOC") from June 2021 to December 2024.

Finally, we will also make use in what follows of French hourly day-ahead prices. This data is publicly available, for example on Entso-e.

4 Flexibility of Nuclear Operations

This section provides both qualitative and quantitative evidence that French nuclear units exhibit very flexible short-run operations.

4.1 Example of Flexible Operations

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

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, short-duration (seconds or minutes) variations in output to maintain the real-time balance between supply and demand. In France, such variations are limited to a range of $\pm 7\%$ of nominal

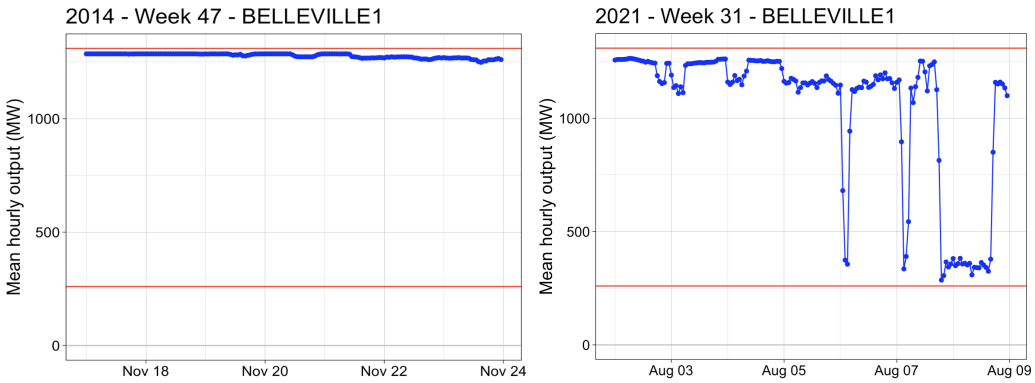


Figure 5: Hourly output of the unit "Belleville 1" for two different weeks. Left panel: example of baseload operations. Right panel: example of flexible operations. The upper red horizontal line represents nominal capacity, and the lower red horizontal line minimum output level.

capacity (Morilhat et al., 2019). Because of the small amplitude and short time-scale of the corresponding variations in output, the provision of ancillary services is hard to detect reliably from hourly output data. We therefore do not consider this dimension 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. This specific week was not hand-picked: such flexible short-run operations are widely observed across our whole dataset.[19] The next paragraph assesses to which extent their are used to accommodate wind and solar generation.

4.2 Aggregate Substitution between Nuclear and Renewables

To quantify the extent to which load-following operations of the nuclear fleet aim at accommodating intermittent output from renewables, we rely on country-level hourly data and use a standard approach in the literature (e.g. Adler et al. (2020)). Specifically, we estimate several models of the following form:

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

[19] Figure A.2 in the Appendix provides an even more extreme example.

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.

	Dependent variable: N_h (period 2012-2024)				
	(1)	(2)	(3)	(4)	(5)
RES_h	-0.77	-0.65	-0.63	-0.65	-0.63
	(0.0063)	(0.0061)	(0.0065)	(0.0067)	(0.0076)
RD_h	0.77	0.725	0.698	0.728	0.61
	(0.0034)	(0.0027)	(0.0047)	(0.0053)	(0.0068)
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	113,963	113,963	113,963	113,963	113,963
R^2	0.923	0.953	0.959	0.960	0.993

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

Table 1 reports the obtained results. Consistently across specifications, we find that an additional MWh of wind or solar generation is associated with a 0.6 MWh decrease in nuclear output.[20] Note that this estimate is robust even in specification (5), which includes day-of-sample fixed effects. Because such fixed effects capture the daily availability of the nuclear fleet (i.e., how many units are actually turned on), we interpret our estimate as short-run flexible operations. If anything, the estimated short-term substitution between nuclear and renewables is likely to be 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.

[20] An heterogeneity analysis estimating separate substitution coefficients by year-of-sample suggests that its value remained fairly consistent across years, ranging from -0.57 to -0.74.

5 Operating Constraints and Renewables

In this section, we first discuss the main operating constraints faced by nuclear units. We next leverage unit-level hourly output data to analyze the frequency of occurrence of the most relevant constraints, as well as their relationship with aggregate wind and solar generation. Finally, we implement an original empirical strategy to assess whether power grid congestion plays a role when deciding which nuclear unit(s) is operated flexibly.

5.1 Operating Constraints of Nuclear Units

While they can be operated flexibly even in the short run, nuclear units nonetheless face a number of operating constraints.

First, there exists an intrinsic technical limit to how much a unit engaging in load-following can decrease its output. This limit is called the nominal minimum output constraint (MOC). Figure 6 shows that, for French nuclear units, the nominal MOC is typically 20% of the nominal capacity of the unit. 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. Such operations entail significantly higher costs than load following.[21]

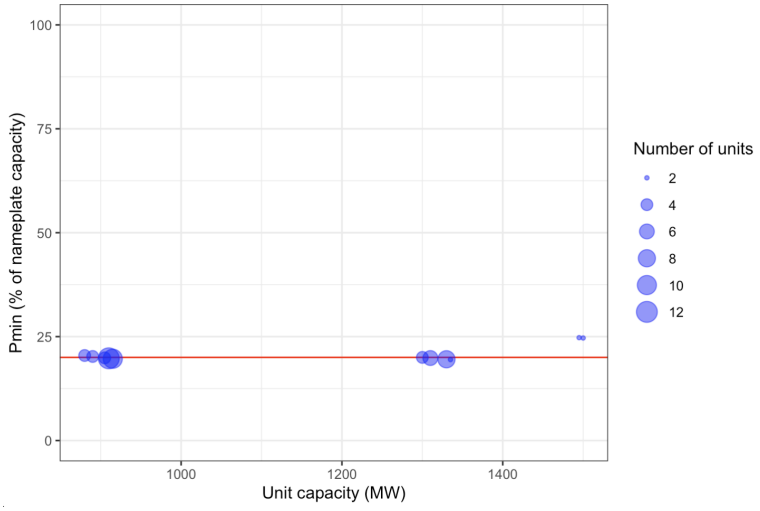


Figure 6: Units' minimum output level (expressed as a percentage of nominal capacity) as a function of nominal capacity. The red horizontal line corresponds to 20% of nominal capacity.

[21] While technically feasible, and indeed observed several times in the data, hot shut downs may be more easily confounded with unobserved forced outages. We therefore leave a detailed analysis of hot shut downs for further research.

Second, nuclear units face limits regarding how fast they can vary their output, called "ramping constraints". However, a nuclear unit is actually able to safely change its output at a rate of up to 5% of nominal capacity per minute. In other words, it is feasible for units to decrease their output from nominal capacity to nominal MOC within 30 minutes. Because we observe unit-level output with an hourly granularity, we therefore do not consider ramping constraints in what follows.

Finally, at a given point in time, the actual minimum output constraint faced by a given unit may be higher than its nominal MOC. For example, a minimum level of output may be needed to maintain a high enough voltage in some part of the power grid. Since June 2021, the incumbent utility publicly reports such other MOCs whenever they exceed the nominal MOC by at least 100 MW. Figure 7 illustrates both types of MOCs. The bottom red line corresponds to the nominal MOC of the unit (Figure 6) and the orange line corresponds to hours where the MOC is actually higher.

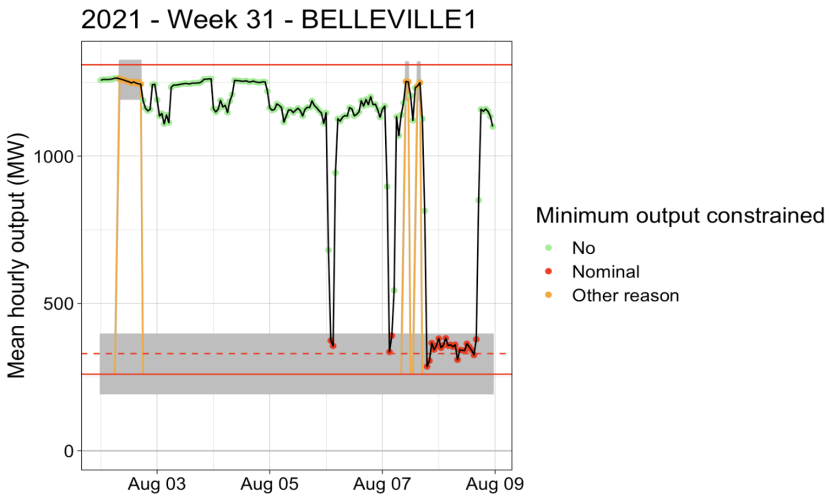


Figure 7: Illustration of how we label (non-outage) hours as "minimum output constrained", either due to the nominal MOC (red) or a MOC driven by other factors (orange). The bottom red horizontal line represents the nominal MOC and the dashed red horizontal line this minimum output level plus the maximum capacity reserved for ancillary services. The nominal MOC is assumed to bind in a given hour if hourly output is within a buffer of 5% of nominal capacity around those two lines. Similarly, the other MOC is assumed to bind if observed hourly output is with 5% of nominal capacity around this value.

Although we observe unit-level nominal MOCs (static values) and other MOCs (time series for June 2021-2024), *we do not directly observe whether the constraints are actually binding at any given point in time.* Indeed, 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 MOC may bind within a given hour even though the average power during this hour is higher than this lower bound.

To infer whether a MOC was (likely) binding within a given non-outage hour, we proceed as follows (see Figure 7 for a graphical illustration). First, because we are interested in operating constraints that bind in the context of normal operations, we must be able to confidently rule out that an observed low output level is not the consequence of a (partial) outage. Although we do observe refueling outages for the whole period 2012-2024, information about other outages occurring before 2015 is only available from the TSO.[22] Upon inspection, we found that this data is very likely incomplete for 2012-2014. As a result, we restrict in what follows the sample to the period 2015-2023. Then, to assess whether the nominal MOC was binding within a given hour, we retrieve, besides nominal MOCs (Figure 6), the maximum capacity each unit may commit to provide ancillary services (typically 2 to 5% of nominal capacity). We define a (nominal) "minimum output level region" as a buffer (with a width equal to 5% of the nominal capacity) around the nominal MOC and the nominal MOC plus the maximum capacity commited to ancillary services. Similarly, for other MOCs, we consider that the minimum output constraint is binding within a given hour whenever the observed hourly output is within a buffer of 5% of nominal capacity around the other MOC in that hour. Finally, the nominal MOC should not pick up hours when the unit enters the minimum output level region as it is ramping down/up before/after a long-duration outage. We therefore exclude from eligible nominal MOC hours the set of contiguous hours before/after of a long outage where output remains below 90% of nominal capacity.[23]

5.2 Country-level Analysis

Figure 8 reports, for each month in 2015-2024, the frequency with which minimum output constraints are detected (aggregating data observed at the unit-hour level).

First, we find that other MOCs are much more frequent than nominal MOCs. Conditional

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

[23] In addition, to avoid "false positives" due to transient states before/after a forced or planned outage, we retrieve the three closest hours before and three closest hours after a MOC is inferred to bind. 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.

on the unit not being in a refueling outage state, nominal MOCs occur less than 1% of hours while binding MOCs due to other factors occur more than 50% of hours.

Second, we observe frequently binding nominal MOCs during the Covid-19 lock down (spring 2020), a period when gross electricity consumption decreased sharply (Buechler et al., 2022). Similarly, the years 2022 to 2024, during which consumption was lower than usual (due to consumption savings and mild winters) and/or the installed capacity of renewables increased sharply, exhibit a sharp increasing trend in the occurrence of nominal MOCs. In contrast, the frequency of other MOCs remains fairly constant over 2021-2024, except for the year 2022, during which a large number of nuclear units have been outaged because of an unexpected generic failure (Astier, 2025).

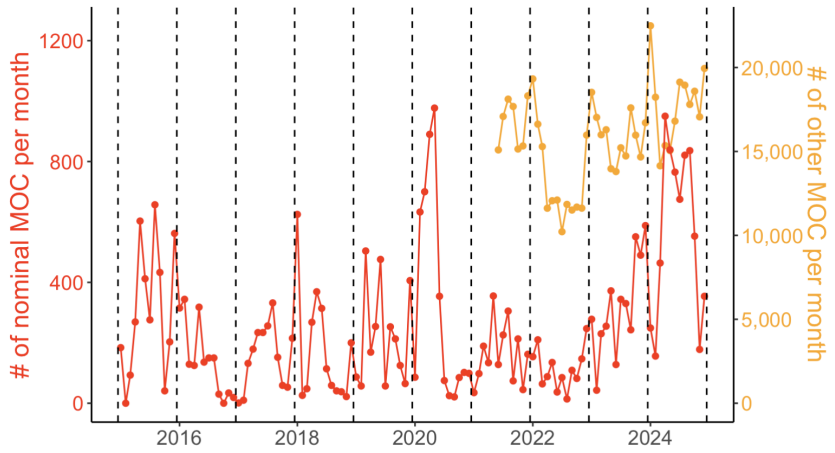


Figure 8: Occurrences of minimum output constrained hours (# unit-hour/month) over 2015-2024.

We next explore, both qualitatively and quantitatively, whether the occurrence of binding MOCs is related to wind and solar generation.

Figure A.3 in the Appendix shows the histogram of the hours of the day during which minimum output constraints are inferred to bind. For nominal MOCs, the obtained distribution exhibits two modes: one during the night (2-6 am), when gross demand is low and wind generation is often high, and one during the afternoon (2-5 pm), when solar generation is high (Figure A.4 shows the average aggregate generation of each technology for each hour of the day). Figure A.5 further reveals that the magnitude of these modes has increased significantly over the period 2022-2024. In contrast, for other MOCs, hours of occurrence are spread more uniformly across the hours of the day.

Although we do not observe the reason(s) that led the plant operator to declare a temporary MOC higher than the nominal MOC, there are well-known reasons why, even outside of outage 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 and produces electricity until the next refueling outage. Figure A.6 in the Appendix shows an example of such a fuel cycle. Importantly, because of the physics and chemistry of the nuclear core, French nuclear units can no longer be operated flexibly when they are reaching the end of a fuel cycle (OECD, 2021; Lynch et al., 2022).

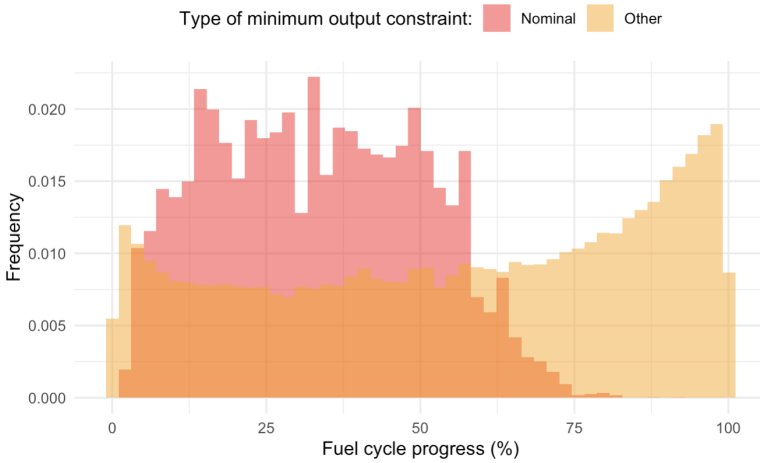


Figure 9: Occurrences of minimum output constraints (unit-hour observations) as a function of the position of the hour within the fuel cycle of the unit.

Figure 9 shows the observed frequency of nominal and other MOCs as a function of the position of the hour within the fuel cycle of the unit, which we are able to compute by manually retrieving all refueling outages. We observe that virtually all hours during which the nominal MOC binds take place during the first two thirds of the fuel cycle. In contrast, other MOCs bind relatively more frequently at the very beginning and during the last third of the fuel cycle.

Overall, the previous stylized facts suggest that wind and solar generation are likely to trigger the nominal MOC to bind, but not necessarily other MOCs. In order to test this hypothesis, we replace in Equation (1) the dependent variable with the number of units for which a minimum output constraint is inferred to bind in a given hour. Table 2 reports the

	Dependent variable: # of constrained units in hour h								
	Nominal MOC (2015-2024)			Other MOC (Jun 2021-2024)			Either MOC (Jun 2021-2024)		
	(1)	(2)	(3)	(4)	(5)	(6)	(6)	(7)	(8)
RES_h (GWh)	0.081	0.30		-0.14	0.00		-0.03	0.34	
	(0.004)	(0.0078)		(0.023)	(0.0172)		(0.023)	(0.023)	
RD_h (GWh)	-0.026	-0.28	-0.28	0.44	0.35	0.34	0.40	0.02	0.01
	(0.0014)	(0.0071)	(0.0072)	(0.013)	(0.019)	(0.018)	(0.014)	(0.026)	(0.024)
$Solar_h$ (GWh)			0.31			0.06			0.41
			(0.0082)			(0.017)			(0.022)
$Wind_h$ (GWh)			0.27			-0.32			0.00
			(0.0076)			(0.029)			(0.034)
Day-of-sample FE	N	Y	Y	N	Y	Y	N	Y	Y
Num.Obs.	87,662	87,662	87,662	31,437	31,437	31,437	31,437	31,437	31,437
R2	0.108	0.656	0.658	0.358	0.838	0.845	0.321	0.822	0.830

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

obtained results, including one additional specification where the output from renewables is split into solar generation on the one hand, and wind generation on the other hand.

The quantitative results confirm the above hypothesis. First, controlling for the level of residual demand (except for wind and solar) and day-of-sample fixed effects, a higher generation from wind and solar in a given hour is associated with more units reaching their nominal MOC during this hour. On average in a given hour, 1 additional nuclear unit is reaching its nominal MOC for every 3.3 GWh of additional wind and solar output. Estimating separate relationships for wind generation on the one hand and solar generation on the other hand yields similar estimates. In contrast, the occurrence of other MOCs is not associated with intraday variations in renewable generation: we estimate the corresponding coefficient to be a statistically precise zero. If anything, wind generation may be associated with a *decrease* in the occurrence of other MOCs (specification (6)).

5.3 Differential Spatial Exposure of Nuclear Units to Renewables

The previous results provide strong evidence that, at the national level, increasing generation from wind and solar triggers nominal MOCs to bind more often. However, wind and solar power plants are not spread uniformly across space (Figure 3). Therefore, different nuclear units may be differently "exposed" to the observed 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 nominal MOCs.

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 and Kirchhoff laws. This exercise, however, requires very detailed information about the power system at every point in time. Unfortunately, most of the information needed is not publicly available.[24] Instead, we compute in what follows an "exposure" metric that can be derived from publicly 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[25] and denote with $d(i,n)$ the as-the-crow-flies distance between unit i and nuclear unit n. Figure 11 illustrates these notations in a simple case where $I_{t,\tau} \equiv \{1,2,3\}$.

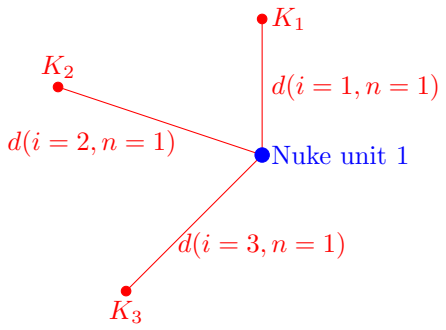


Figure 10: Construction of our "exposure" metric.

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 $\gamma = 0.5$ for our main specification.

Figure 11 shows the obtained "exposure" metric (in MW) to wind and solar for the

[24] Examples of missing data include the topology of the grid and its admittance matrix, transmission capacity constraints accounting for engineering margins (e.g. $N-k$ operations), load at demand buses, etc.
[25] Centroid of the departement for the small ($\leq$36 kW) solar units that are not listed individually.

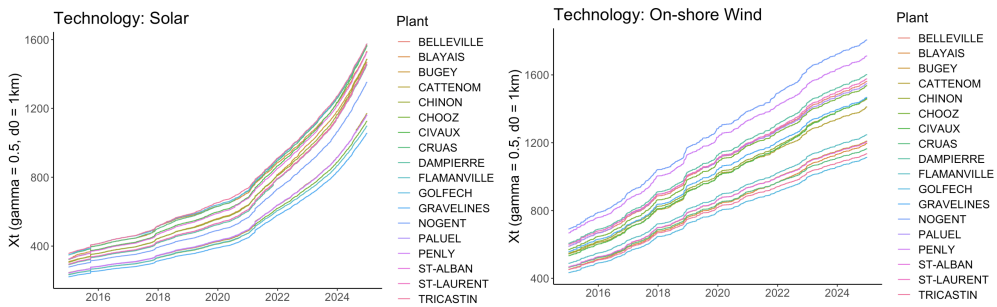


Figure 11: Obtained exposure metric (in MW) to solar (left panel) and wind (right panel) for the 18 nuclear plants between 1 January 2015 and 31 December 2023 ($d_0 = 1$ km and $\gamma = 0.5$).

18 nuclear plants.[26] 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. Note that, for this spatial analysis, "wind" only refers to on shore installations. Indeed, France currently only hosts 1.5 GW of off-shore wind (vs. 22.5 GW of on shore wind), and the corresponding plants were commissioned during the very end of our sample period (late 2023 and 2024).[27] Adding off-shore wind as an additional technology does not alter the obtained results.

For wind and solar, we then compute the "share" $W_{\tau,h,n}$ (in GWh) of the aggregate national output $S_{\tau,h}$ of technology τ in hour h that is "assigned" to unit n as follows. First, we retrieve, for hour h, the set M of running nuclear units, that is, the units that are neither stopped for refueling nor because of an outage. Second, we use the vector of exposures as a sharing key for $S_{\tau,h}$ and define:

$$W_{\tau,h,n} \equiv \frac{X_{\tau,h,n}}{\sum_{m \in M} X_{\tau,h,m}} S_{\tau,h} \tag{2}$$

Purposely, this definition ensures that:

$$\sum_{m \in M} W_{\tau,h,m} = S_{\tau,h} \tag{3}$$

[26] 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.

[27] The above country-level analysis does, however, include off-shore wind output in aggregate wind generation.

Our empirical strategy is then to estimate, on the sample of running (neither outaged nor refueling) unit-hour observations, linear probability models of the form:

$$Y_{h,n} = \alpha + \beta_1^{solar} Solar_h + \beta_1^{wind} Wind_h + \beta_2^{solar} W_{solar,h,n} + \beta_2^{wind} W_{wind,h,n} + \eta RD_h + \delta_{h\in D} + \lambda_n + \epsilon_{h,n} \quad (4)$$

where $Y_{h,n}$ is a dummy variable taking the value 1 if the nominal minimum output constraint is assessed to be binding in hour h for unit n, λ_n denotes unit fixed effects, and $\delta_{h\in D}$ refers to day-of-sample fixed effects.

The rationale behind Equation 4 is to nest the specification whose results are reported in Table 2. Specifically, if we remove the terms $W_{\tau,h,n}$ from Equation 4, we obtain the same specification as before, except that it is estimated on an unbalanced panel of unit-hour observations, rather than on a time series that aggregates the cross-sectional dimension. Adding the terms $W_{\tau,h,n}$ can then be seen as a sort of "horse race" specification. Specifically, it asks the question: controlling for aggregate residual demand and renewable output, does the "exposure" of a nuclear unit to a given renewable technology nonetheless still positively correlates with the occurrence of nominal MOCs?

Conveniently, because residual demand includes net exports, this approach allows to control (at least in parts) for any "exposure" to foreign generating units (whose location is not observed). A specification adding $X_{solar,h,n}$ (resp. $X_{wind,h,n}$) instead of $W_{solar,h,n}$ (resp. $W_{wind,h,n}$) would be an alternative approach, that was found to yield qualitatively similar insights.

Table 3 reports the obtained estimation results. The first and third columns correspond to the counterpart of the results shown in Table 2: 1 additional GWh of renewable output increases the probability that a unit available to ramp down reaches its nominal MOC by 0.007 to 0.008. Because there are on average 38 such units in a given hour, this estimate closely matches the previous estimate from aggregated data ($0.008 \times 38 = 0.3$), which is a mechanical result. Adding the combined exposure to renewable output ($W_{RES,h,n} \equiv W_{solar,h,n} + W_{wind,h,n}$) as a co-variate (specification (2)) yields a statistically insignificant coefficient. However, when exposures to wind and solar enter separately, a statistically significant relationship between exposure to solar generation and binding nominal MOCs is detected. In contrast, no robust effect is estimated for wind, and exposure to hydro and

Dependent Variable:	Is nominal MOC binding? ($\gamma = 0.5$, sample = non-outage hours)				
Model:	(1)	(2)	(3)	(4)	(5)
RES_h (GWh)	0.0078	0.0077			
	(6.4e-05)	(0.00012)			
RD_h (GWh)	-0.00707	-0.00707	-0.00716	-0.00715	-0.00730
	(5.5e-05)	(5.5e-05)	(5.6e-05)	(5.6e-05)	(5.7e-05)
$W_{RES,h,n}$ (GWh)		0.004			
		(0.0038)			
Solar$_h$ (GWh)			0.0082	0.0080	0.0081
			(0.00007)	(0.00015)	(0.00015)
Wind$_h$ (GWh)			0.0069	0.0071	0.0069
			(6.8e-05)	(0.00017)	(0.00017)
$W_{solar,h,n}$ (GWh)				0.008	0.011
				(0.0048)	(0.0049)
$W_{wind,h,n}$ (GWh)				-0.006	0.005
				(0.0058)	(0.0059)
$X_{hydro,h,n}$					-0.42
					(0.036)
$X_{therm,h,n}$					-1.0
					(0.09)
Num.Obs.	3,370,555	3,370,555	3,370,555	3,370,555	3,370,555
R2	0.064	0.064	0.064	0.064	0.064

Table 3: Obtained results when estimating Equation (4). Robust standard errors (HC1) clustered by unit and day-of-sample are reported in parenthesis. Exposure metrics are computed with $\gamma = 0.5$.

thermal technologies (measured with $X_{\tau,h,n}$ for simplicity) is, quite intuitively, negatively associated to binding nominal MOCs.

Tables A.1 and A.2 in the Appendix report the obtained results for alternative values of γ ($\gamma = 0.25$ and $\gamma = 0.75$ respectively). Consistently with the hypothesis that solar generation may induce local grid constraints, a larger coefficient for $W_{solar,h,n}$ is estimated when closer solar units are given a higher weight ($\gamma = 0.75$) than when they are given a lower weight ($\gamma = 0.25$). Overall, our analysis supports the hypothesis that the increasing penetration of solar generation may induce grid constraints that impact the ability of the nuclear fleet to accommodate renewable generation.

6 Nuclear Flexibility and Day-ahead Prices

This section first shows that the "exhaustion" of the short-run flexibility of nuclear operations was associated in 2024 with a sharp increase in the occurrence of non-positive day-ahead

prices, confirming quantitatively the illustrative example of section 1. We next discuss areas for further investigation.

6.1 Remaining Flexibility and Non-positive Day-ahead Prices

A large penetration of wind and solar resources is expected to transform the distribution of electricity prices, the most noticeable impact being an increasing number of hours with low (or negative) prices (Mallapragada et al., 2021).

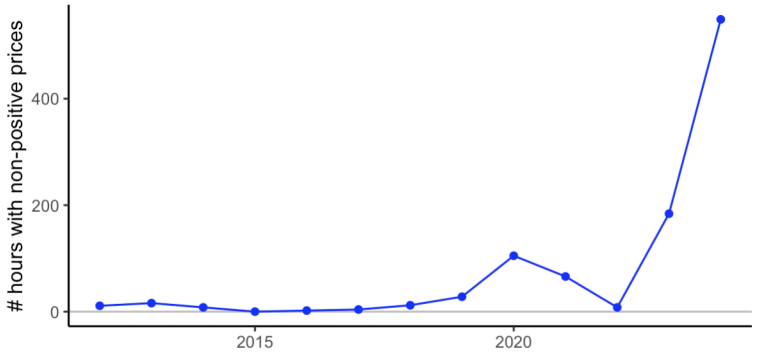


Figure 12: Number of non-positive hourly day-ahead prices per year in France.

Figure 12 shows that, in the case of France, zero or negative day-ahead prices were relatively rare until 2019. The year 2020 saw a large increase in their occurrence, which decreased back to almost zero in 2022. In 2023 and 2024, however, the frequency of non-positive prices skyrocketed, reaching 549 hours in 2024, that is, about 6% of hours. In addition, in 2024, the day-ahead market cleared at prices below 10€/MWh, that is, very likely below the mere variable cost of nuclear power, during more than 15% of hours.

In this paragraph, we thus explore to which extent this sharp change in the distribution of spot prices may reflect increasingly binding limits to the short-run flexibility of the nuclear fleet. In other words, we take to the data the simple example discussed in section 1.

Specifically, we note that, at any given point in time, a given unit must be in one of three possible states. First, the unit may be in an "outage" state (planned or forced outages, refueling) or have a zero output (hot shut down). In such situations, it cannot provide any downward flexibility. Second, the unit may be producing at its minimum output level, either nominal or driven by other factors. Again, such units can hardly decrease their output further, except for shutting down completely. Third, the unit may be running above its

minimum output constraint. We denote $\mathcal{F}_h$ (for "flexible") the set of units that fall within this latter category in hour h. Figure A.7 in the Appendix shows how the units are split across these different categories for the sample period for which we observe all possible categories (June 2021-2024).

We denote with RF_h the remaining (downward) flexibility of the nuclear fleet in hour h, defined as:

$$RF_h \equiv \sum_{n \in \mathcal{F}_h} (P_{n,h} - MOC_{n,h}) \tag{5}$$

where $P_{n,h}$ is the observed output of unit n during hour h, and $MOC_{n,h}$ is the minimum output constraint of this unit for this hour (either nominal or driven by other factors). Figure 13 shows the evolution of the (monthly) distribution of RF_h between June 2021 and December 2024. Although its median value seems to have remained fairly constant (after accounting for a strong seasonal pattern), the lower tail of the distribution (first percentile and below) has been significantly shifting to the left.

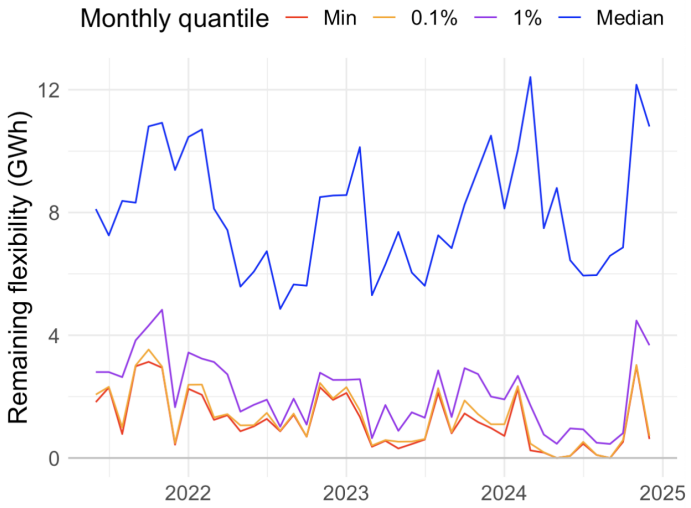


Figure 13: Summary statistics of the monthly distributions of hourly remaining flexibility: minimum, quantile 0.001, first percentile and median.

Therefore, we next investigate whether this shift can be directly related to the observed evolution of the left tail of day-ahead prices (Figure 12). Figure 14 shows a binscatter plot of the remaining flexibility RF_h against hourly day-ahead prices. We restrict attention to the year 2024, both to discard the very high spot prices observed during the energy crisis, and to have more density in the left tail of the distribution of RF_h. In addition, we censor

the sample to hours with 10 GWh or less of flexibility to increase readability.

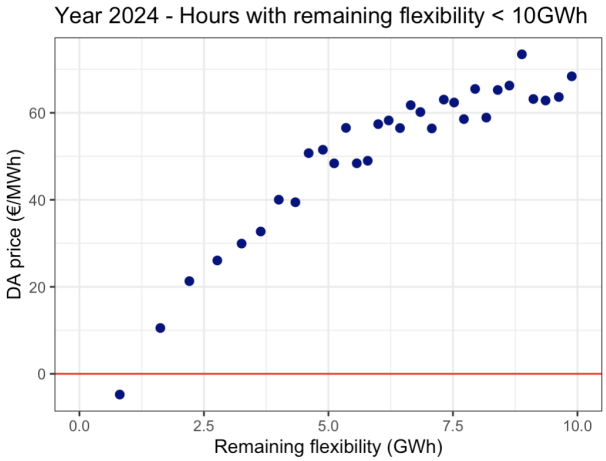


Figure 14: Binscatter plot of hourly day-ahead prices against remaining nuclear flexibility (drawn with the R package binsreg by Cattaneo et al. (2024)). The sample is restricted to hours in 2024 with a remaining flexibility lower than 10 GWh.

Overall, although a more structured econometric analysis remains to be done, Figure 14 strongly suggests that hours with non-positive prices typically corresponds to episodes where the short-run flexibility of the nuclear fleet is exhausted. In addition, the patterns observed in Figures 12 and 13 seems to imply that the years 2023 and, mostly, 2024 may have experienced a structural change in the French electricity mix in the sense that such situations are now occurring a non-negligible fraction of the time.

Once the flexibility of the nuclear fleet is exhausted, renewables become the marginal technology (see right panel in Figure 1), meaning that some wind and/or solar production must be curtailed.[28] Although, at least to the best of our knowledge, no detailed data on renewable curtailments is publicly available for France, the 2024 edition of the French Transmission System Operator (TSO) is the first to explicitly discuss, although briefly, such curtailments (RTE, 2025). Specifically, the TSO estimates that about 0.9 TWh of wind and 0.8 TWh of solar output have been curtailed, representing 2.4% of the total production of wind and solar in 2024.

[28]We do not discuss here the role of battery storage, whose installed capacity is growing but remains small as of 31 December 2024, with 1.1 GW.

6.2 Discussion

A number of areas of investigation remains to be explored. First, one may wonder to which extent flexible short-run nuclear operations increase wear and tear, and therefore may compromise reliability or even safety. This question is particularly critical in a context where the fleet experienced a generic outage in 2022 (Astier, 2025). While we observe public outage notices for 2015-2024, these messages unfortunately most often include little to no information about the exact nature of the outage. In addition, the distinction made between "forced" and "planned" outages is not very informative in the sense that a 2-hour forced outage leading to one week of maintenance is generally classified as two distinct outages: a 2-hour forced outage and a 1-week planned outage. However, a deeper analysis of available information, for example leveraging the publication dates of the various updates of the messages relating to the same outage, may enable us to partly circumvent this limitation.

Second, the extent to which the non-nominal MOCs are completely exogenous is an open question. While some aspects, such as end-of-fuel-cycle rigidities, seem largely exogenous, other MOCs might reflect endogenous dispatch decisions by the plant operator. For example, the incumbent utility may decide to avoid flexible operations in the fuel cycle that precedes a large-scale maintenance outage. More generally, looking more closely at the distribution of various types of flexible operations within each fuel cycle might reveal the existence of different operating modes.

Third, the incumbent utility may take fleet-level decisions about flexible operations (e.g. how many units may be ramped up or down simultaneously), and such policies may have evolved over time in order to increase the feasible operating range.

Finally, the placement and duration of refueling outages are endogenous medium-term decisions with a subsequent impact on the flexibility available in the short-run. For example, Figure 4 shows a clear seasonal pattern by which most if not all nuclear units are operating during the winter, while maintenance and refueling outages occur predominantly outside of the winter months, entailing a loss in the capacity factor of the fleet (Lynch et al., 2022). A follow-up study will therefore study such medium-term choices in more detail.

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 whose generation fleet includes, as of 31 December 2024, 63 GW of nuclear capacity and 48 GW of cumulated wind and solar capacity.

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 possibly grid congestion, are putting increasingly binding bounds on the "supply response" that nuclear units can provide. In particular, the nominal minimum output constraint of nuclear units is found to be bidding more frequently over time, especially for the units most "exposed" to solar generation.

Over the past couple of years, the large increase in the occurrence of very low or even negative prices is found to be strongly associated with episodes where the remaining downward short-run flexibility of the nuclear fleet was exhausted.

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Appendices

A Supplementary Figures and Tables

To draw Figure A.1, 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 A.1 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.

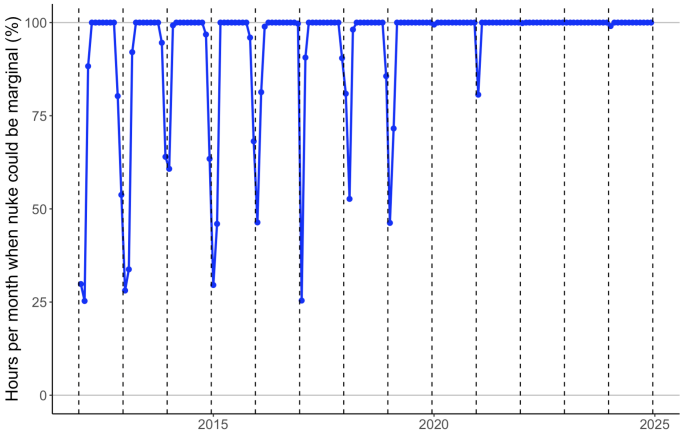


Figure A.1: Percentage of hours in each month when nuclear would be the marginal technology in an hypothetical situation where all the nuclear units would be available all the time.

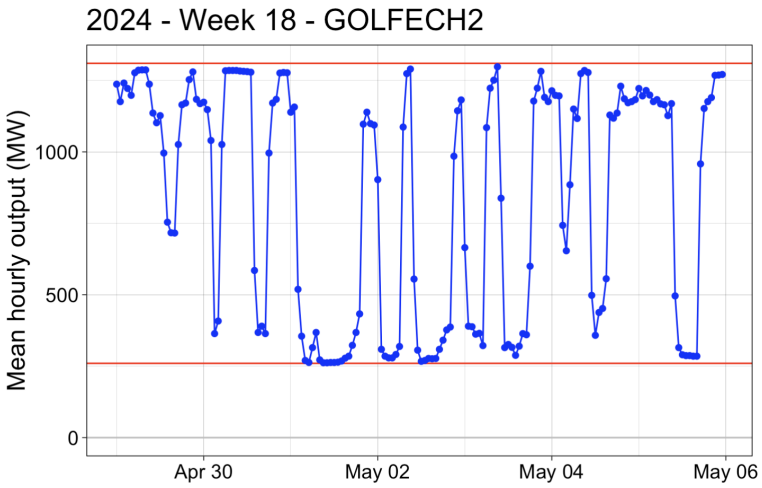


Figure A.2: Hourly output of the unit "Golfech 2" for one week in 2024.

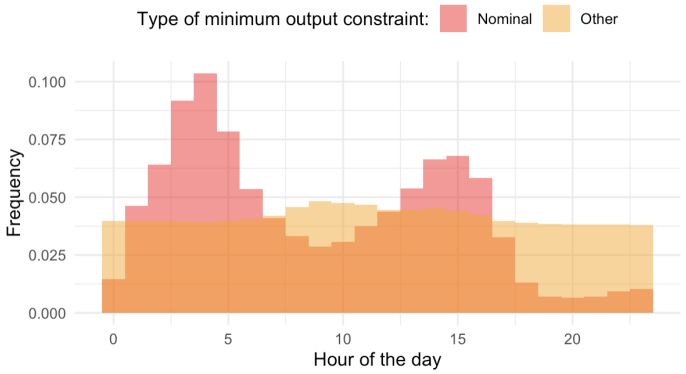


Figure A.3: Histogram of the hours of the day when the minimum output constraint is inferred to bind.

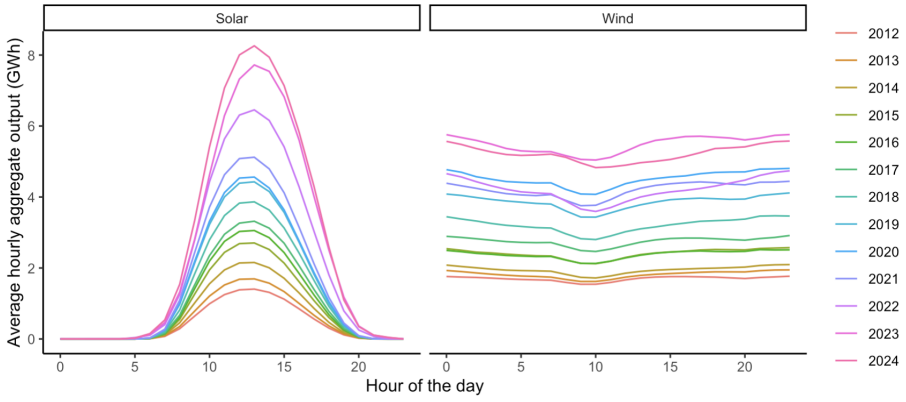


Figure A.4: Average hourly aggregate generation (GWh) from wind and solar for each year in our sample period.



Figure A.5: Histogram of the hours of the day when the nominal minimum output constraint is inferred to bind, broken down by year.

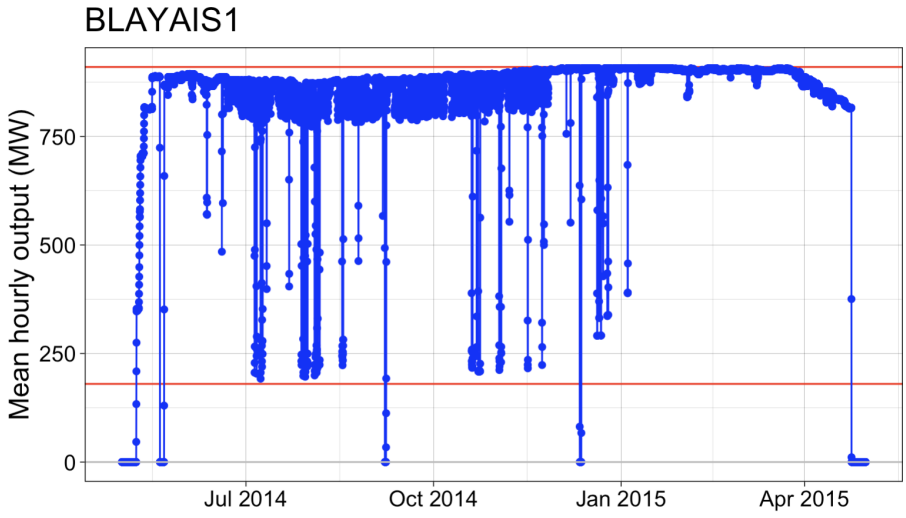


Figure A.6: Example of a fuel cycle.

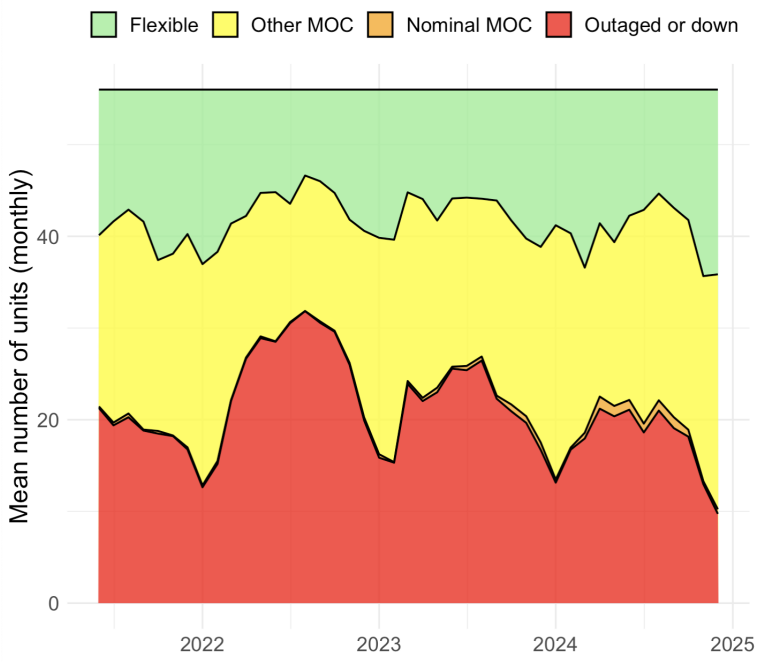


Figure A.7: Monthly average number of unit-hour in mutually exclusive statuses with respect to available downward flexibility.

Dependent Variable:	Is nominal MOC binding? ($\gamma = 0.25$, sample = non-outage hours)				
Model:	(1)	(2)	(3)	(4)	(5)
RES_h	0.0078	0.0075			
	(6.4e-05)	(0.00015)			
RD_h	-0.00707	-0.00706	-0.00716	-0.00716	-0.00730
	(5.5e-05)	(5.5e-05)	(5.6e-05)	(5.6e-05)	(5.7e-05)
$W_{RES,h,n}$		0.014			
		(0.005)			
$Solar_h$			0.0082	0.0085	0.0085
			(0.00007)	(0.00018)	(0.00018)
$Wind_h$			0.0069	0.0065	0.0059
			(6.8e-05)	(0.00024)	(0.00024)
$W_{solar,h,n}$				-0.009	-0.004
				(0.0058)	(0.0058)
$W_{wind,h,n}$				0.01	0.04
				(0.0089)	(0.0091)
X_hydro, h, n					-0.3
					(0.067)
X_therm, h, n					-1.2
					(0.12)
Num.Obs.	3,370,555	3,370,555	3,370,555	3,370,555	3,370,555
R2	0.064	0.064	0.064	0.064	0.064

Table A.1: Obtained results when estimating Equation (4). Robust standard errors (HC1) clustered by unit and day-of-sample are reported in parenthesis. Exposure metrics are computed with $\gamma = 0.25$.

Dependent Variable:	Is nominal MOC binding? ($\gamma = 0.75$, sample = non-outage hours)				
Model:	(1)	(2)	(3)	(4)	(5)
RES_h	0.0078	0.0078			
	(6.4e-05)	(9.8e-05)			
RD_h	-0.00707	-0.00707	-0.00716	-0.00715	-0.00726
	(5.5e-05)	(5.5e-05)	(5.6e-05)	(5.6e-05)	(5.6e-05)
$W_{RES,h,n}$		0.001			
		(0.0027)			
$Solar_h$			0.0082	0.0079	0.0079
			(0.00007)	(0.00013)	(0.00013)
$Wind_h$			0.0069	0.0071	0.0071
			(6.8e-05)	(0.00012)	(0.00013)
$W_{solar,h,n}$				0.012	0.015
				(0.0038)	(0.0038)
$W_{wind,h,n}$				-0.007	-0.005
				(0.0040)	(0.0041)
X_hydro, h, n					-0.39
					(0.025)
X_therm, h, n					-0.72
					(0.06)
Num.Obs.	3,370,555	3,370,555	3,370,555	3,370,555	3,370,555
R2	0.064	0.064	0.064	0.064	0.064

Table A.2: Obtained results when estimating Equation (4). Robust standard errors (HC1) clustered by unit and day-of-sample are reported in parenthesis. Exposure metrics are computed with $\gamma = 0.75$.