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# French Market Design in Practice: Some Lessons from the 2022 Energy Crisis

Nicolas Astier<sup>1</sup>

## Abstract

Between 2005 and 2021, France has generated more electricity from fossil-free resources (491 TWh/year on average) than its gross domestic consumption (481 TWh/year). Therefore, in terms of total surplus, the French electricity sector should have been barely hit, if at all, by the surge in fossil fuel prices during the 2022 energy crisis. In practice, however, the French government spent billions of euros in subsidies to electricity consumers, the incumbent utility – who operates the whole nuclear fleet – recorded its worst yearly financial result to date, and total electricity imports exceeded exports for the first time in more than 40 years. Although these outcomes can largely be attributed to bad luck, the extent to which they could have been mitigated through better market design and public policies is an open question. This article argues that existing policies, through their implied incentives to share and manage long-term risks, played a critical role in how France navigated the energy crisis. Consistently, reforming long-term risk-sharing mechanisms has emerged as the most pressing issue to address. Looking forward, however, updating short-term wholesale market design so as to better support a low-cost and reliable energy transition will likely prove increasingly important.

Keywords: market design; energy crisis; risk management; incentives

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## 1. Introduction

When it comes to electricity, it is fair to say that French engineer-economists have been pioneers in characterizing how to efficiently manage a vertically-integrated industry (Drèze, 1964). Their contributions include a general theory of peak-load pricing (Boiteux, 1949) and the computation of optimal linear taxes to meet a budget constraint (Boiteux, 1956), among many others (Morlat and Bessière, 1971). As a testimony to the ground-breaking nature of their work, most of which was written in French, James R. Nelson, professor of economics at Amherst College in the United States, published in the mid 1960s an entire book composed of English translations of seminal articles by employees of the incumbent utility Électricité de France (EDF). This book was titled “*Marginal Cost Pricing in Practice*” (Nelson, 1964).

Quite understandably, when the European Union started reforming the electricity sector in the 1990s, France showed some reluctance to fully embrace electricity markets (Hansen and Percebois, 2017). On the supply side, no significant divestment took place so that the Herfindahl-Hirschman index (HHI) in the early 2000s was above 9,000 (CRE, 2005), reflecting a very high level of market concentration. Grid activities were unbundled, but with a single Transmission System Operator (TSO) and one major Distribution System Operator (DSO) operating 95% of distribution grids, both companies being owned at 100% by the incumbent utility. On the demand side, residential customers were left on regulated tariffs. Retail competition was only enforced for large consumers, among which the market share of EDF at the end of 2004 was 99.5% (CRE, 2005). In this context, a simplified market design was implemented, which essentially allowed to maintain pre-existing operating practices.

Twenty years later, this legacy persists to a large extent in French electricity markets. Although a few reforms took place, they were, however, incremental and generally tried to address a specific issue in isolation, with little impact on the intensity of market competition. As a result, production assets are still highly concentrated, with a generation HHI above 6,000 (CRE, 2021),<sup>2</sup> and so are retail segments (HHI > 2000). In addition, EDF, which reverted back to being fully publicly owned in 2023, is still the majority shareholder of the TSO and the unique shareholder of the main DSO.

Given the dominant position of the incumbent utility, a number of *policy interventions* have been implemented over the years. On the retail side, for example, administratively-set rates have not been phased out. Almost two thirds of residential customers are still on a regulated tariff (CRE, 2024a), an option that was recently re-introduced for small C&I customers. On the supply side, the absence of divestments made it necessary to implement financial remedies in the early 2010s (see below). These policies may interact with, but are distinct from, the market rules that govern which power plants end up being dispatched, along with (short-term) revenue streams, which we refer to as wholesale *market design* in what follows.

Ultimately, the outcomes reached by the electricity sector are jointly determined by wholesale market design and policy interventions. In particular, the impacts of any market design reform will be dependent on, and might be muted by, public policies. The nature of these interactions

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<sup>2</sup> In addition, a large fraction of the decrease in the generation HHI is coming from subsidized intermittent renewables, most of which receive feed-in-tariffs and are therefore not active in spot markets.

is of course evolving with underlying market conditions, such as fossil fuel prices or the penetration of intermittent renewables.

When electricity prices skyrocketed in Europe towards the end of 2021 and in 2022, heated debates emerged about short-term market design (e.g. Fabra, 2023), which was accused by some observers of exacerbating the magnitude of the crisis. In contrast, the role played by existing policies received much less attention. These debates were particularly vivid in France. Indeed, because the domestic electricity generation mix is already almost carbon-free, the French electricity sector as a whole should not have been significantly exposed to fossil fuel prices. In practice, however, it suffered massive financial losses. In the end, the debates concluded that, if anything, short-term wholesale markets helped attenuating the price shock (e.g. through cross-border trade). As a result, post-crisis discussions are no longer focused on (short-term) market design reforms, but rather consist of policy proposals.

This article explores the respective roles of public policies and market design in France from two distinct perspectives. Looking backward, what role did public policies, and in particular risk-sharing mechanisms, play in the 2022 energy crisis? Looking forward, could some market design reforms prove helpful to support the energy transition?

We focus on these two research questions for several reasons. First, the complementary perspectives, that is, the role of market design during the energy crisis and of public policies to support the energy transition, have already received considerable attention. Second, in the French context, policy failures, and in particular badly designed risk-sharing mechanisms, played a very prominent role during the energy crisis. As a result, fixing these mechanisms is currently the most pressing issue faced by policymakers. In this context, discussions about market design reforms might be perceived as being of second-order importance in the short-run. In other words, because large redistributive shocks usually trigger political interventions and some instability, efficient mechanisms to manage long-term risks might represent a prerequisite for credible short-term market design reforms. Third, a deep dive into short-term market design in France is currently hampered by the lack of granular data enabling detailed studies of strategic behaviors. Nonetheless, looking forward, available experience from other jurisdictions points to a number of areas where the current market design seems unlikely to support a low-cost and reliable energy transition.

The rest of the paper is organized as follows. Section 2 provides further background on the French electricity sector and its sensitivity to fuel cost shocks. Section 3 discusses the 2022 energy crisis and shows how its impacts were exacerbated by the overarching policy framework. Section 4 explores a number of areas where, looking forward to a European electricity mix with larger shares of wind and solar energy, the existing short-term market design seems unlikely to support a low-cost and reliable energy transition. Finally, Section 5 concludes.

## **2. Background**

This section starts with a description of the French electricity mix. We then show that, because domestic generation almost exclusively relies on carbon-free technologies, a cost shock following a surge in fossil fuel prices has a negligible impact on overall welfare, but entails large

redistributive transfers in the absence of any hedging. Finally, we sketch how financial forward contracts may drastically reduce the magnitude of these transfers while embedding powerful incentives to attenuate the impacts of a short-term price shock.

*A. The French Electricity Mix*

In the wake of the oil shocks in the 1970s, France decided to invest massively in nuclear power (Boiteux, 1993). Over 30 years, more than 60 GW of nuclear generation capacity was installed, split into 58 units located at 19 distinct facilities. As a result, the electricity industry in France is, as a whole, almost perfectly physically hedged against variations in fossil fuel prices, a feature that is only shared by a handful of hydro-rich countries, such as Iceland or Norway.

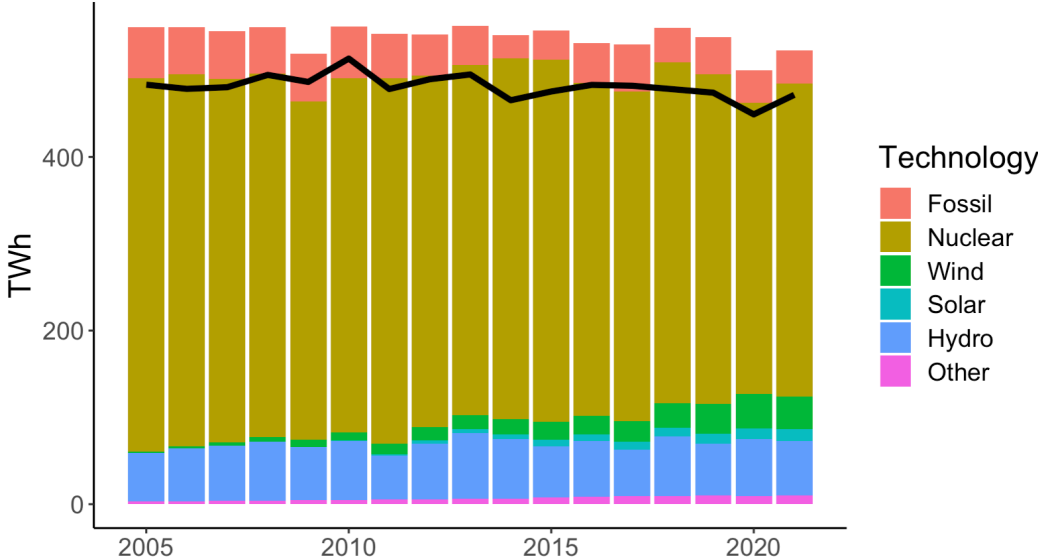


Figure 1. French domestic yearly gross consumption (black line) and domestic generation by technology (stacked colored columns) in TWh between 2005 and 2021 (data sources: Bilans électriques, RTE).

Figure 1 illustrates this situation for the period 2005-2021. The black line represents realized domestic gross electricity consumption (in TWh), which includes the electricity consumed for enriching uranium and is not adjusted to filter out deviations due to temperature anomalies. Yearly gross consumption has been very stable, with a mean of 481 TWh/year, a minimum of 449 TWh during the Covid-19 pandemic of 2020, and a maximum of 513 TWh in 2010, the coldest year within the considered time window. The stacked colored columns show total annual domestic electricity generation (in TWh), broken down by technology. In particular, the red boxes at the top of the stacks represent annual generation by fossil fuel thermal power plants (coal, oil and natural gas). Although significant amounts of electricity were still generated from coal and oil in the mid 2000s, the vast majority (85%) of fossil-fired electricity in 2021 was generated from natural gas. The other generation technologies include, from top to bottom, nuclear, wind, solar, hydroelectricity and other technologies (mostly renewable thermal plants fueled with biomass or waste).

Quite remarkably, in all years but three (2009, 2010 and 2017), the red boxes in Figure 1 lie above the black line representing gross domestic consumption. In all other years, the total electricity generated from fossil-free resources was higher than annual domestic consumption.

Over the full period 2005-2021, annual generation from all technologies but fossil-fueled thermal plants averaged 491 TWh/year, that is about 2% more on average than gross domestic electricity consumption (481 TWh/year).

*B. Impacts of a Shock in Fuel Prices*

The previous aggregate yearly values mask, however, considerable hourly variations. In some hours, total generation from fossil-free power plants exceeds domestic demand, and France is a net exporter of electricity. In other hours, domestic fossil-fueled power plants and/or imports are necessary to meet domestic consumption. Because spot prices are set by the most expensive unit called to produce electricity, as they are in any other market and would also be in an optimally-managed vertically-integrated utility, they are very sensitive to fossil fuel prices. Indeed, during hours where domestically-generated fossil-free electricity is lower than domestic demand, the residual demand will often be met by fossil-fueled power plants, either domestic or foreign.<sup>3</sup> Conversely, when France has excess fossil-free electricity, the marginal generator will often be a foreign fossil-powered unit.<sup>4</sup> Therefore, day-ahead prices in France over 2005-2021 are highly correlated with natural gas prices (Figure 2).

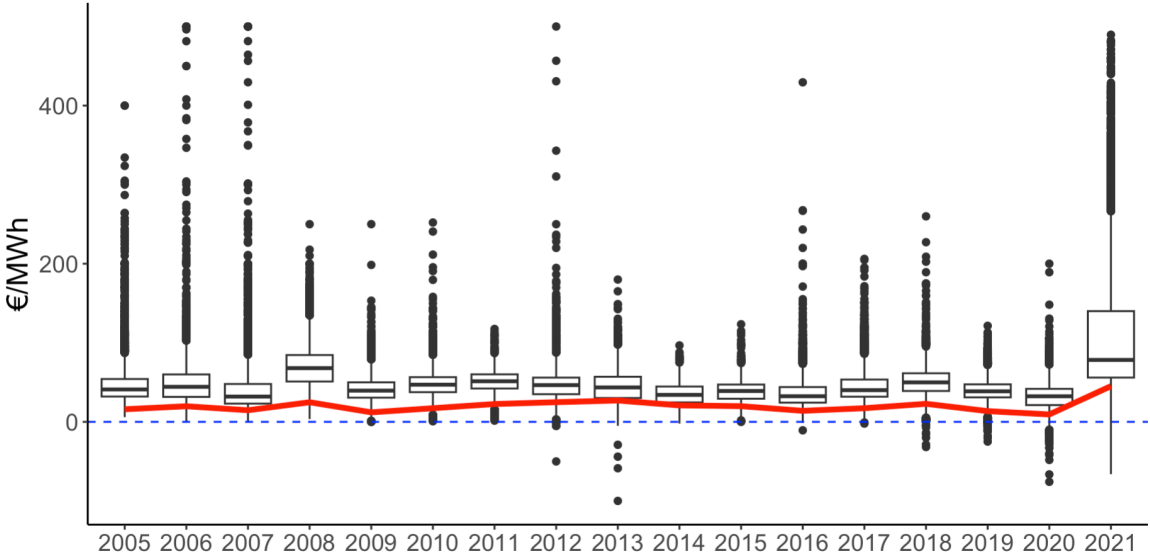


Figure 2. Annual distributions of hourly day-ahead prices (nominal €/MWh) in France for 2005-2021 (data retrieved from ENTSO-E and EPEX Spot). Boxes display the 25<sup>th</sup> (top bar), 50<sup>th</sup> (middle bar) and 75<sup>th</sup> (bottom bar) percentiles of the distributions, and whiskers extend to 1.5 times the interquartile range. The thick red line reports average natural gas prices (Netherlands TTF) in nominal €/MWh (data sources: Our World in Data for prices in \$/MWh and INSEE for currency exchange rates).

However, because electricity is domestically produced, contracts settling against electricity prices are to some extent of zero-sum nature. As a result, despite the high correlation between natural gas and electricity spot prices, the French electricity sector as a whole is actually barely

<sup>3</sup> The other situation that may arise corresponds to hours when France imports excess wind and solar electricity from neighbor countries.

<sup>4</sup> Or a domestic hydro-electric power plant with limited storage capacity and whose opportunity cost is also often pinned down by the variable cost of a fossil-fueled power plant.

exposed to variations in fossil fuel prices. In economics terms, the total domestic social surplus of the electricity industry is close to being insensitive to natural gas prices.

Figure 3 illustrates graphically the economic intuition behind this statement. First, the left panel represents a given hour where (i) available domestic fossil-free generation is lower than domestic consumption, and (ii) residual demand must be supplied by natural-gas-fired power plants, either domestic or foreign. A positive shock to the cost of natural gas induces a sharp increase in the electricity price from  $P_{normal}$  to  $P_{shock}$ . However, most of this increase represents a transfer from domestic consumers to domestic producers (rectangle B). The actual loss in total domestic social surplus is restricted to rectangle C. Conversely, the right panel represents a given hour where (i) available domestic fossil-free generation is higher than domestic consumption, and (ii) the exports are large enough so that the price of electricity is set by a natural-gas-fired plant, either domestic or foreign. In this situation, a positive shock to the cost of natural gas again induces a transfer from domestic consumers to domestic producers (rectangle E). However, it also generates higher revenues from electricity exports, represented by the rectangle F. Although the price shock induces large transfers from domestic consumers to domestic producers (rectangles B and E), its net impact in terms of total domestic surplus will be the average, across all hours, of the increased costs when fossil-free generation falls short of domestic demand (rectangle C) and the increased revenues from exports when it does not (rectangle F). Intuitively, the overall net impact is likely to be small.

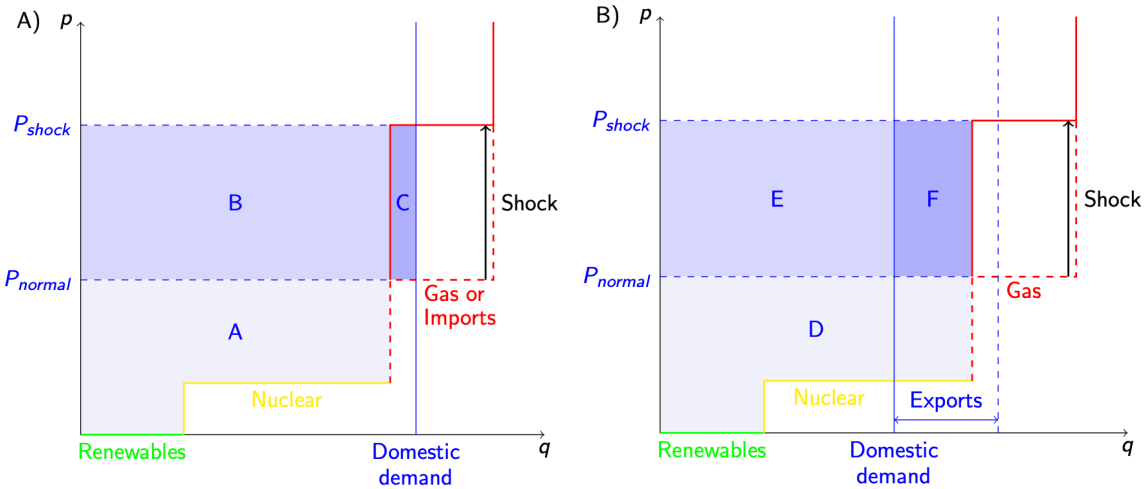


Figure 3. Impact of a positive shock in the price of natural gas when France is a net importer (left panel) versus a net exporter (right panel) of electricity.

In fact, under some simplifying assumptions, the average net impact of the natural gas price shock is exactly equal to zero when aggregate yearly domestic consumption is the same as aggregate yearly generation from domestic fossil-free power plants. To see this, assume for simplicity that (i) domestic demand  $q_h$  in hour  $h$  is perfectly inelastic; (ii) natural gas is the only fossil-fuel technology and has a marginal cost  $c_g$  which is identical across countries; (iii) the transmission grid is a copper plate; and (iv) the two situations depicted in Figure 3 are the only

two configurations that may arise.<sup>5</sup> In this very stylized framework, the French spot price of electricity under perfect competition is equal to  $c_g$  in all hours.<sup>6</sup>

We denote with  $s_{h, \text{clean}}$  the quantity of electricity generated in hour  $h$  from domestic fossil-free resources, and with  $C_h$  the corresponding total supply cost of fossil-free power plants in that hour. Because demand is assumed to be perfectly inelastic, the average domestic total surplus over the course of the year is equal, up to a constant, to minus the domestic cost of electricity, adjusted for net revenue from trade. From Figure 3, this total cost  $TC$  is equal to:

$$TC = \underbrace{\sum_{h, s_{h, \text{clean}} \geq q_h} [C_h - c_g(s_{h, \text{clean}} - q_h)]}_{\text{Exporting hours (Figure 3, panel A)}} + \underbrace{\sum_{h, s_{h, \text{clean}} < q_h} [C_h + c_g(q_h - s_{h, \text{clean}})]}_{\text{Importing hours (Figure 3, panel B)}} \quad (1)$$

which simplifies to:

$$TC = \sum_h C_h + c_g \left( \underbrace{\sum_h q_h}_{\text{Domestic cons.}} - \underbrace{\sum_h s_{h, \text{clean}}}_{\text{Domestic fossil-free gen.}} \right) \quad (2)$$

In particular, when annual domestic consumption is equal to annual generation from domestic fossil-free resources, aggregate total cost, and therefore total domestic surplus, does not depend on the marginal cost  $c_g$  of gas-fired power plants. Although obviously very stylized, these derivations illustrate why the French electricity sector as a whole should be, in theory, very resilient to a surge in fossil fuel prices.

### C. Hedging and Incentives

Two main takeaways emerge from the previous discussion. First, in France, spot electricity prices represent a very poor proxy for total domestic surplus: the former are equal to  $c_g$ , and therefore entirely determined by fossil fuel prices, while the latter can either increase or decrease with  $c_g$ . The high sensitivity of policy-makers to spot prices is therefore to a large extent misguided, and can even motivate inefficient policy interventions (Astier and Lambin, 2019). Second, a shock in fossil fuel prices can nonetheless have tremendous redistributive consequences. In our simple example, large transfers take place from consumers to producers (rectangles B and E).

<sup>5</sup> This latter assumption neglects situations where neighbor countries have an excess of zero marginal cost generation that is exported to France as a substitute to nuclear generation. If such situations were accounted for, the net impact of a natural gas price shock under assumptions (i)–(iii) when aggregate yearly domestic consumption is the same as aggregate yearly generation from domestic fossil-free power plants would be an increase in total surplus.

<sup>6</sup> In a long-term equilibrium, allowing for a small number of hours with load curtailments (and corresponding high prices) would be necessary to enable gas-fired power plants to recover their fixed investment costs. Such an extension would not alter our conclusions.



In practice, however, the actual redistributive implications of an increase in spot markets prices will depend on pre-existing financial positions. Given the historical stability of the ratio of domestic consumption and domestic fossil-free generation (Figure 1), risk-sharing mechanisms can (and, arguably, should) be used to reduce significantly the variability of both producers' revenues and consumers' bills.

As an illustration, let us assume that, prior to the (short-term) price shock depicted in Figure 3, producers have sold to consumers fixed-volume standardized forward contracts for a volume equal to the realized domestic demand  $q_h$  at a strike price equal to  $P_{normal}$ . In hour  $h$ , the settlement of financial positions would then entail a transfer  $(P_{shock} - P_{normal}) q_h$  from producers to consumers. As a result, consumer surplus (which can be measured as minus consumers' bills when demand is perfectly inelastic) would be identical with and without the shock. Similarly, producer surplus would be much less volatile than in the absence of hedging.

Besides financial transfers, forward contracts also induce strong incentives for producers to mitigate the magnitude of short-term price shocks. Consider indeed a given hour where their available generation capacity is lower than their contracted capacity, for example due to a forced outage. Producers are then exposed to spot prices for the volume contracted beyond their available capacity. For example, if they sold forward a volume  $q_h$ , as in the previous example, domestic producers must pay the counterparts of their contracts an amount corresponding to rectangle C in Figure 3. This exposure induces strong incentives to make sure that units are available to generate during short-term price spikes.

Unfortunately, first-best risk-sharing mechanisms, that is, well-regulated, competitive and liquid financial markets for standardized derivatives, rarely emerge by themselves. Indeed, market participants often find it more appealing to lobby to socialize the costs of their own risks. For example, it is frequently argued that feed-in-tariffs for renewables are cost-effective because they decrease the risk-premium paid by investors, a statement that typically omits to mention that the corresponding financial risk is simply transferred to end-consumers and/or taxpayers.

Consistently, when the energy crisis struck, long-term risk-sharing in France was, for the most part, taken care of through *ad hoc* mechanisms established by policy interventions. The next section shows that these mechanisms had a first-order influence on how the country navigated the crisis.

### **3. Looking Backward: the Role of Public Policies in the Energy Crisis**

This section addresses our first research question, that is, what role did public policies play in the 2022 energy crisis in France?

We first provide some background on the main exogenous drivers of the crisis. We then argue that these exogenous drivers are not sufficient to rationalize the timing of the initial intervention by the government. Instead, the overarching policy framework, and in particular the implied sharing of long-term risks and the incentives to manage them, was of first-order importance. Finally, we discuss other policies with redistributive implications.

## A. The 2022 Energy Crisis in France

### Shocks to Fuel Costs

In 2022, Europe arguably experienced its worst energy crisis since the oil shocks in the 1970s. Figure 4 shows the evolution of electricity day-ahead prices in France for 2021-2023. From an historical average (2005-2020) of 45€/MWh, spot prices averaged 109€/MWh in 2021, with a sharp increase in November and December. In 2022, prices averaged 276€/MWh, that is, a six-fold increase relative to the historical mean. If electricity were only sold on spot markets, the increase in total consumers' bills would have been about 30 billion euros in 2021 and 110 billion euros in 2022.<sup>7</sup>

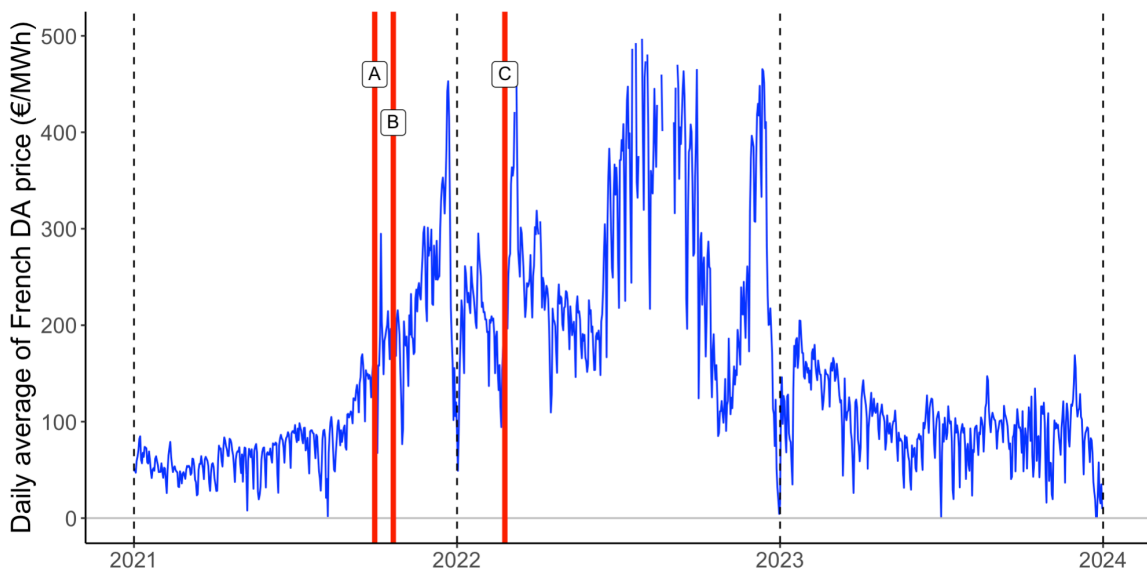


Figure 4. Daily average of French day-ahead prices (€/MWh) between 1 January 2021 and 31 December 2023. The vertical lines are discussed in Section 4 and indicate respectively (A) government's announcement to freeze regulated residential electricity rates; (B) the date at which anomalies in the nuclear unit Civaux 1 (not yet characterized as stress corrosion cracking) were reported to the nuclear regulation agency; and (C) launch of Russia's invasion of Ukraine.

The main driver of this unprecedented increase in electricity prices was a surge in natural gas prices, which started with the boom in economic activity in the post-Covid-19 recovery period (second half of 2021) and peaked when Russia launched its invasion on Ukraine at the end of February 2022 (vertical line C in Figure 4).

As discussed above, a large increase in electricity prices can, in theory, translate into a mild or even positive impact of the total surplus derived by the French electricity sector as a whole. In practice, however, the incumbent utility EDF reported its worst financial year to date (EBITDA of -5 billion euros) and billions of euros of public funds were spent to offset what would have been a massive increase in regulated residential tariffs. Why did both the incumbent utility and end-consumers/tax-payers have to bear such huge costs?

<sup>7</sup>  $480 \text{ TWh} \times (109 - 45) \text{ €/MWh} = 30 \text{ billions €}$  and  $480 \text{ TWh} \times (276 - 45) \text{ €/MWh} = 111 \text{ billions €}$ .

## Shocks to Available Fossil-free Generation

Two large and independent exogenous explanations strongly contributed to these outcomes. First, available renewable resources were lower than their historical average (RTE, 2023). The realized capacity factor of wind power plants was only 21.6%, its lowest value in 10 years.<sup>8</sup> More importantly, due to exceptional drought conditions at the end of 2021, hydro power plants only produced 49.6 TWh in 2022, their lowest output in almost fifty years (20% lower than their average output over 2005-2021). Second, the annual output from nuclear units was only 279 TWh, that is, 30% lower than the 2005-2021 average of 400 TWh. Because a large number of units were scheduled to have long planned outages in 2021-2022, both structurally and as a result of the Covid-19 pandemic having disorganized maintenance schedules, lower production levels than usual were expected. However, after a planned maintenance visit at the nuclear unit Civaux 1, EDF reported on 21 October 2021 (vertical line B in Figure 4) unexpected anomalies to the nuclear safety agency.<sup>9</sup> After further investigations, the incumbent utility reported in mid-December 2021 that these anomalies were due to stress corrosion cracking, a phenomenon that was subsequently found in all four units of the same technology (Civaux 1 and 2, Chooz 1 and 2). These 1,500 MW units, which are the most recent of the fleet, were shut down as a result during all of 2022. Stress corrosion cracking was subsequently also found in one unit of the previous technology of nuclear plants (Penly 1), which raised the concern that a serial failure might be impacting up to twelve additional units. Overall, the availability of the nuclear fleet in 2022 was historically low. As an illustration, on 28 August 2022, 65% of the capacity of the nuclear fleet was offline (RTE, 2023).

Because of the low availability of both hydro and nuclear, realized total generation from domestic fossil-free power plants was, in 2022, 57 TWh (12.6%) lower than domestic electricity consumption. If valued at the average spot price of 276 €/MWh in 2022,<sup>10</sup> this represents a gross revenue shortfall of about 13 billion euros. As a result, for the first time since the roll out of its nuclear program, France was a net importer of electricity, with annual imports exceeding exports by 16.5 TWh.

### *B. Public Policies and the Onset of the Crisis*

From the previous discussion, one may conclude that bad luck fully explains why the French electricity sector took such a big hit from the 2022 energy crisis. Such a conclusion, however, is inconsistent with how the crisis unraveled in practice.

To see this, consider the timeline of the three main events discussed above: an exceptional drought, forced outages of nuclear units, and a spike in natural gas prices. First, the extreme magnitude of the drought and its consequences for the year 2022 was only fully known towards the end of 2021, when the absence of large precipitations during the Fall had materialized. Second, the technical anomaly in the nuclear unit Civaux 1 was detected at the end of October 2021 (vertical line B in Figure 4), and characterized as stress corrosion cracking

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<sup>8</sup> The average capacity factor of wind power over 2014-2021 has been 23.5% (RTE, 2023).

<sup>9</sup> <https://www.asn.fr/l-asn-informe/actualites/corrosion-detectee-sur-le-circuit-ris-du-reacteur-1-de-la-centrale-de-civaux>

<sup>10</sup> This back-of-the-envelope calculation represents a lower bound since the covariance between hourly generation shortfalls and spot prices is positive.

only by mid-December. Third, although natural gas prices had started to increase in the second half of 2021, they only reached extreme values at the onset of Russia's attack on Ukraine in February 2022 (vertical line C in Figure 4).

However, the French Prime Minister announced a freeze of residential electricity rates on 30 September 2021 (vertical line A in Figure 4), that is, *before* the three shocks fully materialized. Why did the government intervene so early given that events such as future rainfalls, an unexpected mechanical failure, and a war, were arguably quite impossible to perfectly anticipate?

The answer to this puzzle lies into the adverse interaction between two public interventions: regulated residential tariffs and an *ad hoc* mechanism implemented to mitigate the monopoly position of EDF on nuclear operations.

### **Regulated Tariffs for Residential Consumers**

First, although the European Union has been advocating for a complete phase out of regulated tariffs, the French government has consistently maintained such tariffs for residential consumers. As evidenced by the public intervention of 30 September 2021, a regulated tariff implicitly benefits from some form of public insurance in times of crisis. Because private contracts cannot rely on this insurance, the existence of a regulated tariff limits the ability of retailers to offer competitive alternative tariffs, for which they have to bear a risk premium when privately hedging through long-term contracts.<sup>11</sup> As a result, as of 2021, the vast majority of residential consumers were either on the regulated tariff, which can only be offered by the incumbent utility, or on a tariff that replicated the financial structure of the regulated tariff (possibly with a small discount), which can be offered by any retailer. In other words, the financial risk faced by residential customers regarding their electricity bill was almost exclusively managed through the methodology used to compute the regulated rate.

To make the existence of a regulated tariff, which can only be offered by EDF, compatible with retail competition, the French government had to compute it in a way that does not provide an unfair advantage to the incumbent utility. Therefore, a major obstacle to maintaining such a tariff was that EDF is *de facto* the monopoly operator of the nuclear fleet, which is able to produce electricity at a cost that cannot be replicated by new entrants. In other words, the incumbent utility benefits from a “nuclear rent” that they could be tempted to dissipate, for example to block new entry (Champsaur, 2009).

### **“ARENH” Mechanism**

To address the previous concerns, the government implemented in July 2011 a centralized contracting mechanism to (financially) divest a fraction of nuclear power. This mechanism, called ARENH (for “*Accès Régulé à l'Electricité Nucléaire Historique*”), is administratively setting

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<sup>11</sup> In this environment, retailers may choose not to hedge at all and to exert their limited liability option if wholesale prices increase significantly above the rate they offered to their customers. This strategy was famously used by the Texan retailer “Griddy”. However, while also present in France, this strategy did not play a major role in the 2022 energy crisis (mostly because French retailers hedged most of their supply at attractive prices via regulated access to nuclear power).

both a price and a volume cap, and is therefore poorly suited to manage risks in a flexible manner. Specifically, it gives retailers a free call option for a constant supply of electricity at a regulated price (in €/MWh) up to a given volume computed, for each retailer, from the realized consumption of their portfolio of customers.<sup>12</sup> The strike price of this option was set using a cost-based approach at 42 €/MWh on 1 January 2012 and was not updated since then. Concretely, in November of each year, retailers can file a request to the regulator to receive their estimated allowance<sup>13</sup> of “ARENH rights” for the coming year, that is, the right to pay 42 €/MWh for a given volume of energy allocated uniformly across all hours of the year. The total volume that can be claimed by retailers was capped to 100 TWh/year, a cap that was initially non-binding given the low market share of entrant retailers.

### **Interaction between Regulated Tariffs and ARENH before the Crisis**

Once the ARENH mechanism was established, the administrative formula setting the level of the regulated tariff for residential consumers explicitly made the assumption that baseload electricity was supplied from it. Specifically, assuming for simplicity that the front-year baseload forward prices can be perfectly foreseen, the assumed procurement cost for baseload electricity was 42 €/MWh, as long as the 100 TWh cap was not bidding.

This formula guaranteed that an entrant retailer could compete with the regulated tariff. Consistently, the market share of non-incumbent retailers increased steadily over time. As a result, when forward baseload electricity prices went above 42€/MWh, in November 2018, about 133 TWh of ARENH options were exercised for delivery in 2019. Because this quantity exceeded the cap of 100 TWh, a uniform rationing rule was applied: each retailer was allocated only 75% (100/133) of its requested volume. In order to set the level of the regulated tariff, an additional assumption was needed to capture how the curtailed 25% of baseload energy would (supposedly) be procured. In such cases, the administrative formula considered that this energy was procured at the front-year forward baseload prices that are prevailing in December. Such prices were around 60€/MWh in December 2018, so that the regulated tariff for 2019 only increased by a small amount.

In 2020 (resp. 2021), the 100 TWh cap was also binding with a total demand of 147 TWh (resp. 146.2 TWh). Once again, however, front-year forward baseload prices were reasonably low in December 2019 (resp. 2020) at around 45€/MWh (resp. 49€/MWh), so that the bidding cap on the volume of ARENH rights only had a minor impact on the level of regulated tariffs. Therefore, policymakers did not intervene.

### **Interaction between Regulated Tariffs and ARENH at the Onset of the Crisis**

The situation, however, looked very different in September 2021. Front-year baseload forward prices were higher than 100€/MWh and following an increasing trend. One could therefore forecast that the demand for ARENH rights in November 2021 would again exceed the cap of

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<sup>12</sup> Note that hydro-electric power plants also benefit from similar Ricardian rents as historical nuclear units. However, they were excluded from the ARENH mechanism on the rationale that they were supposed to be auctioned to possibly different operators in the near future.

<sup>13</sup> At the end of the delivery year, this estimated allowance is cleared against the actual allowance, computed from the realized consumption of the portfolio of eligible customers of each retailer.

100 TWh. Assuming this demand would be about 150 TWh (it actually reached 160 TWh) and that front-year baseload forward prices would remain above 100€/MWh in December (they actually exceeded 200€/MWh), the government could already anticipate in September, from the formula used to compute regulated rates, that – absent any intervention – these rates would experience a substantial increase.<sup>14</sup> The Prime Minister therefore decided to cap to 4% the upcoming increase in regulated tariffs.

It is worth stressing that the decision to cap the increase in regulated rates occurred *before* the full magnitude of the three supply shocks materialized: natural gas prices were high but Russia’s attack on Ukraine was months away, water stocks were very low but very high levels of rainfalls in Oct-Dec were still possible, and the availability of the nuclear fleet was expected to be low but stress corrosion cracking was not discovered yet.

Instead, the intervention of the government in September 2021 was a consequence of the implicit risk-management strategy implemented on behalf of residential customers. Indeed, the formula for regulated tariffs acted as a focal point that most retailers replicated to procure electricity for their consumers. However, the regulated tariff was only hedging a fraction of residential consumers’ bills: whenever the 100 TWh cap of ARENH rights was binding, the curtailed fraction of baseload electricity was deemed to be purchased at the “last minute” (i.e., in December for delivery from January to December of the following year). Of course, by construction, the 100 TWh cap is binding when forward baseload prices are greater than 42€/MWh (the strike price of the call option). Therefore, residential consumers were most exposed to spot electricity prices precisely when such prices were high. In other words, although the baseload electricity procured by retailers was around 150-160 TWh, residential rates were implicitly only hedging the procurement of 100 TWh: about one third of residential customers’ baseload consumption was left fully exposed to the volatility of the last month’s quotation price of the front-year baseload forward contract for electricity.

If residential tariffs had implemented a larger hedging ratio, for example spreading procurement over several years ahead of delivery, the level of residential consumers’ bills would have been much less sensitive to the realized wholesale front-year forward baseload prices in December 2021: financial contracts would have automatically redistributed significant amounts of money to consumers and, as a result, the government may not have intervened so early, if at all.<sup>15</sup> However, because retailers were (rationally) offering rates indexed on the regulated tariff, and they had little to no incentive to hedge their residual short-position.

Therefore, even before the exogenous drivers of the 2022 energy crisis fully materialized, the existing policy framework would have induced very large transfers from end-consumers to

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<sup>14</sup> Instead of 42€/MWh, the baseload price assumed by the regulated tariff formula would have been  $(100 \cdot 42\text{€/MWh} + 50 \cdot 100\text{€/MWh}) / 150 = 61.3\text{€/MWh}$ , that is, a 45% increase. Of course, regulated tariffs also include grid access fees and taxes so that the actual percentage increase of the regulated tariff would have been lower. However, a 45% increase applied to about one third of the tariff means an overall increase of about 15%, which was unlikely to be deemed politically acceptable.

<sup>15</sup> For example, the 5-year average forward prices for baseload power did not exceed 120 €/MWh in 2022-2023, to be compared to the energy supply of the regulated tariffs level, including ARENH, exceeding 200 €/MWh (without government intervention) in January 2022. See: [https://www.cre.fr/fileadmin/Documents/Deliberations/import/230119\\_2023-17\\_TRVE.pdf](https://www.cre.fr/fileadmin/Documents/Deliberations/import/230119_2023-17_TRVE.pdf)

other market participants. We next discuss how the government attempted to attenuate the magnitude of these transfers.

### C. Public Policies during the Crisis

In a nutshell, government's interventions during the crisis were aimed at creating transfers to end-consumers. We first discuss a couple of existing policies that should have induced such transfers but fell short of doing so. The government also attempted to tax *ex post* the infra-marginal rents of fossil-free power plants (rectangles B and E on Figure 3), a move whose ultimate redistributive consequences are hard to assess.

#### Capacity Mechanism and Non-compliance "Penalties"

France does have an existing *ex ante* mechanism that induce transfers between producers and consumers. Specifically, the country launched in November 2016 a capacity mechanism. Although there are many shades of such mechanisms (e.g. Holmberg and Ritz, 2021), their stated goal is to limit the risk of generation shortages by creating an *ex ante* transfer from consumers to producers. The transfer received by a given producer depends on its certified "firm capacity", that is, the assessed available generation capacity that he will be able to provide in times of "stressed conditions". This mechanism is supposed to address a missing money and/or a missing market problem that, especially in the presence of regulated price caps, may induce socially-inefficient power plant closures (or inefficiently low entry) in the absence of capacity payments (Newbery, 2016).

Of course, because "stressed conditions" are impossible to perfectly anticipate, properly defining "firm capacity" is a very challenging endeavor. This issue is particular acute for intermittent renewable resources which, because they tend to produce electricity with a high degree of contemporaneous correlation within a given technology, are by construction generating less electricity than average during stressed conditions, at least once they reached a sufficient level of penetration (Wolak, 2022).

The serial failure of nuclear units in 2022 in France provides another illustration of the limited ability of capacity mechanisms to protect end-consumers in practice, at least financially speaking. Between 23 April 2020 and 9 December 2021, auctions for capacity certificates for delivery in 2022 settled at prices between 16.6€/kW and 39€/kW, with a price of 23.9€/kW for the last auction.<sup>16</sup> At the beginning of the auctioning period, the fleet of nuclear units was eligible for 53.6 GW worth of capacity certificates. However, as the planned availability to nuclear units plummeted towards the end 2021, the updated quantity of capacity certificates decreased to 42.1 GW.

As EDF lost the corresponding "physical" capacity certificates, the utility could either buy other certificates in auctions or pay an "imbalance price" equal to the realized price of the last auction (without any additional explicit penalty). In other words, if we focus attention to the 10+ GW of nuclear capacity certificates that ended being canceled because of outages, EDF sold these certificates at a price between 16.6€/kW and 39€/kW, and bought them back at

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<sup>16</sup> <https://www.edf.fr/entreprises/electricite-gaz/electricite-offres-de-marche/mecanisme-de-capacite-explications-et-prix-des-encheres> (last accessed on 16 July 2024).

23.9€/kW, likely incurring no substantial financial penalty (if any). Of course, the extent to which the clearing price of the last auction reflected a competitive price for capacity certificates might be worth investigating.

In the end, French end-consumers paid in 2022 over 1 billion euros<sup>17</sup> to nuclear units for their “capacity benefits”, and received no compensation for the fact that the realized availability of the fleet was actually historically low, and insufficient to guarantee adequacy, as evidenced by very high-risk premia on the forward market.<sup>18</sup>

### **Revenues from Support Mechanisms to Renewables**

Public policies supporting renewables in France provide a financial hedge to producers but also to end-consumers and taxpayers. Indeed, the vast majority of wind and solar PV installations in France were still selling their output under a feed-in-tariff regime. As a result, when spot prices exceed the unit-specific prevailing tariff, renewable producers had to pay the difference back to the government. Anticipating this revenue stream, the government cut, in February 2022, the tax mainly dedicated to fund subsidies for renewable electricity production. Its level was decreased to less than 1€/MWh, from a prevailing level of 22.5€/MWh.

In practice, however, because feed-in-tariffs were not binding private contracts, a large number of renewable producers exercised their implicit option to exit the tariff to instead sell their output directly on wholesale markets. A law was subsequently passed to tax the “super profits” that some energy companies made during the crisis. A thorough evaluation of how much revenue the government could ultimately retrieve remains to be done.

### **Ex post Taxation of the Nuclear Rent**

Finally, in January 2022, the government increased the volume of ARENH rights for the delivery year 2022 from 100 to 120 TWh, with a strike price of 46.2€/MWh for the additional 20 TWh of electricity. Because the prevailing front year baseload forward electricity price was around 250€/MWh during the last days before delivery in December 2021, the implied direct transfer from EDF to end-consumers amounted to a few billion euros.<sup>19</sup>

It is worth noting that the *ex post* nature of the government’s intervention had important but hard-to-measure redistributive implications. Indeed, putting aside the subsequent unplanned outages due to stress corrosion cracking, let us denote  $Q_{\text{nuke}}$  the expected (as of, say, mid-2021) available output for 2022 from nuclear units, and  $Q_{\text{demand}}$  the aggregate expected demand for baseload electricity from all consumers. For simplicity, let us assume that  $Q_{\text{nuke}} = Q_{\text{demand}}$ . We denote with  $F_i$  the forward sales of market participant  $i$ ,<sup>20</sup> which are such that:

$$F_{\text{nuke}} + F_{\text{retailers}} + F_{\text{others}} = 0$$

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<sup>17</sup> 24€/kW x 42.1 GW = 1 billion euros

<sup>18</sup> The forward baseload price for the 1<sup>st</sup> quarter of 2023 reached 1,840 €/MWh on 26<sup>th</sup> August 2022.

<sup>19</sup> 20,000,000 MWh \* (250 – 46.2) €/MWh = 4.1 billion euros.

<sup>20</sup>  $F_i < 0$  when market participant  $i$  is a net buyer.



Finally, let  $P_{\text{forward}}$  be the price of forward baseload electricity contracts for delivery in 2022, which we assume for simplicity to be constant, for example to capture quotation periods far ahead before the start of the delivery period.

In a counterfactual world where retailers would have had (by assumption) incentives to hedge a 100% of their expected consumption well before delivery, one would have expected that, by January 2022, financial positions would have been such that:

$$F_{\text{retailers}} = -Q_{\text{demand}} = -Q_{\text{nuke}} \quad \text{and} \quad F_{\text{nuke}} = (1-x) Q_{\text{nuke}}$$

where  $(1-x)$  denotes the share of expected nuclear output sold forward by EDF. When a spot price  $P_{\text{spot}} \gg P_{\text{forward}}$  realizes in 2022, retailers are fully hedged and face a procurement cost of  $P_{\text{forward}}Q_{\text{demand}}$ , and EDF makes an additional profit  $xQ_{\text{nuke}} (P_{\text{spot}} - P_{\text{forward}})$  whose overall cost is borne by other forward market participants (who sold in aggregate  $F_{\text{others}} = xQ_{\text{nuke}}$  at  $P_{\text{forward}}$  which they have to buy back at  $P_{\text{spot}}$ ).

In reality, because of the incentives conveyed by the regulated tariff, retailers have likely only hedged a fraction  $y < 1-x$  of their expected demand. Assuming that the hedging strategy of EDF remains unchanged (selling a share  $(1-x)$  of the nuclear output forward), the actual financial position of retailers at the end of 2021 was:

$$F_{\text{retailers}} = -yQ_{\text{demand}} = -yQ_{\text{nuke}}$$

Therefore:

$$F_{\text{others}} = - (1-x-y) Q_{\text{nuke}} < 0$$

meaning that other market participants are net buyers in forward markets. When a spot price  $P_{\text{spot}} \gg P_{\text{forward}}$  realizes in 2022, retailers are exposed to a loss  $(1-y) Q_{\text{demand}} (P_{\text{spot}} - P_{\text{forward}})$  relative to the previous scenario. Other participants in the forward market, however, now make an aggregate profit  $(1-x-y) Q_{\text{nuke}} (P_{\text{spot}} - P_{\text{forward}})$  for having purchased the residual nuclear output that EDF was willing to sell forward. Therefore, requiring EDF to compensate retailers' losses now has a direct financial cost for the electricity sector as a whole. Implementing *ex post* transfers to restore the previous situation would require to unwrap the financial positions of all other market participants, an impossible endeavor in practice.<sup>21</sup>

#### D. Some Lessons from the Energy Crisis in France

A few takeaways emerge from the French experience during the 2022 energy crisis.

First, although a lot of political attention in Europe was directed to short-term market design, one may argue that public policies played a much greater role in France. In particular, the overarching policy framework forced the government to intervene *before* the main exogenous shocks underlying the crisis fully materialized. Because credibly-stable market rules are a key pre-requisite for market incentives to deliver the full range of their intended benefits, a well-

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<sup>21</sup> However, it is worth noting that the trading branch of EDF made a net profit of about 5 billion euros in 2022.

designed policy framework represents a critical complement to a sound wholesale market design. While the 2022 energy crisis in France is a somewhat extreme illustration of this observation, it may also resonate in other jurisdictions. For example, the province of Alberta in Canada has both a short-term market design that assumes away grid congestion and an overarching policy framework stating that grid upgrades will be made whenever significant congestion levels are observed. As a result, the case for a market design reform implementing locational price signals is difficult to make, despite the large benefits it could entail in the context of the energy transition (Brown et al., 2025).

Second, the government intervened because the short-term price shock would have induced large financial transfers from end-consumers to other market participants. This outcome is somewhat puzzling given the fact that, at least in expectation, domestic carbon-free electricity generation exceeds domestic consumption. Indeed, this latter observation implies that electricity consumers could have been relatively easily hedged against short-term price shocks. The policy failures in France therefore highlight the practical importance of long-term risk-sharing mechanisms to avoid large swings in consumers' bills.

Third, risk-sharing mechanisms that credibly rule out *ex post* government interventions would also provide strong incentives to maintain resource availability in times of scarce supply. In contrast, the French capacity mechanism failed to reflect the social opportunity cost of the low availability of nuclear units in 2022, which was enormous in the midst of the crisis. Indeed, when the daily average of spot prices exceeded 300€/MWh (Figure 4), the market value of the output of a single 1,500 MW unit was worth 10 million €/day.<sup>22</sup> The unit of Civaux 1, where stress corrosion cracking was first discovered, was shut down between 21 August 2021 and 1 February 2023, that is, 17 months. Therefore, whether more efficient responses to both the impact of Covid-19 on maintenance schedules and the discovery of stress corrosion cracking would have been possible is an open question that could deserve further investigation.<sup>23</sup>

In the aftermath of the energy crisis, policy debates in the European Union have understandably focused on implementing more efficient long-term risk-sharing mechanisms, an issue that virtually all electricity markets around the world are struggling with. In France, this debate revolves around the end of the ARENH mechanism, which will phase out on 31 December 2025. Because this mechanism was precisely introduced to keep nuclear operations into the hands of a single firm, any alternative set of policies faces the challenge of accommodating the dominant position of the incumbent utility into a market environment.

Policy discussions are currently exploring the possibility of enforcing a much higher hedging ratio on retailers (CRE, 2024c), while jointly intervening to create liquid and competitive financial markets for standardized electricity derivatives. Such an approach may also alleviate to some extent legitimate concerns about the exercise of market power by producers in spot markets (Allaz and Villa, 1993).

In this overall context, proposals of short-term wholesale market design reforms are receiving little attention, if at all. Yet, failing to include short-term market rules in current policy

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<sup>22</sup>  $1500 \text{ MW} \times 24 \text{ h} \times 300 \text{ €/MWh} = 10.8 \text{ M€}$

<sup>23</sup> For example, the repair of stress corrosion cracking failures was slowed down by a shortage of high-skilled welders. This issue had, however, already been raised before the energy crisis (Folz, 2019).

discussions may represent a missed opportunity to possibly prevent, or at least attenuate, the next crisis of the electricity sector. Indeed, there exist ample international evidence that the prevailing short-term market design has a number of shortcomings which may hamper its ability to support a low-cost and reliable energy transition. The next section discusses some of these limitations and associated challenges.

#### **4. Looking Forward: Market Design Supporting a Cost-effective Energy Transition**

Following the energy crisis, revisiting the overarching policy framework, and in particular long-term risk-sharing mechanisms, has emerged as the main priority in the French electricity policy space. While they represent a necessary condition, nothing guarantees, however, that such reforms will prove sufficient to prevent future crises and support a cost-effective energy transition. In particular, international experience suggest that the existing short-term market design is subject to a number of shortcomings, and that the inefficiencies these limitations induce are likely to amplify in the future.

This section first briefly provides some relevant background on short-term market design in France. It then discusses a number of areas where prevailing market rules may struggle to support the energy transition.

##### *A. Background on Short-term Wholesale Electricity Markets in France*

Short-term electricity markets in France consist of a complex set of rules and financial transfers. We refer readers to Graf (2025) for a detailed discussion about European-style short-term market design, as well as some of the well-known challenges and shortcomings they entail.

In a nutshell, an artificial distinction is made between “market” operations, that are for the most part intermediated by power exchanges, and “grid” operations, that are supervised by system operators. The former, which typically prevail until one hour before delivery, consist of financial commitments that are not tied to any specific physical asset. The latter, however, have to make sure that physics constraints are not violated. To do so, they prescribe asset-specific actions which are associated to additional financial transfers.

For the purpose of “market” operations, wholesale market participants are bundled into balancing responsible parties (BRPs), who are supposed to maintain a “balanced perimeter”, that is, to try to ensure that their total net withdrawals from the grid (irrespective of the nature and location of the corresponding physical assets) are matched with equivalent contractual positions. BRPs can trade electricity on voluntary “zonal” day-ahead markets, as well as in intraday markets.

When it comes to “grid” operations, the transmission system operator (TSO) collects asset-specific bids for both ancillary services (used for primary and secondary reserves) and a balancing mechanism (mostly used for restoring reserves and managing grid congestion). When such bids are activated, the corresponding energy is adjusted in the perimeter of the relevant BRP, effectively linking the economic incentives of market participants across “market” and “grid” operations.

## *B. Some Challenges facing the French Electricity Sector*

Assessing the performance of any electricity market design requires detailed information about market participants' actions and payoffs. Unfortunately, such information is particularly hard to retrieve in the European context. Assume, for example, that one is interested in retrieving the profit derived by a given generation unit in a given hour. Leaving aside financial forward contracts, a starting point would be to proxy revenue with the (observed) realized output of the unit times the (observed) day-ahead market price. To make further progress, however, at least two important pieces of information are very hard to retrieve. First, one needs an estimate of the production cost of the unit. Day-ahead markets, even if they were perfectly competitive, would not provide this information. Indeed, the bids in these markets are attached to the perimeter of a BRP, not a specific generating unit. Therefore, little no information is revealed about the marginal cost of inframarginal units. Second, the unit may derive additional revenue from balancing mechanisms, for which bidding data is not publicly available and very hard to access. In addition, whether a given unit is asked to perform some action in balancing mechanisms will depend on the planned generating profile that the unit communicated to the TSO on the day before delivery. A well-known caveat of so-called "zonal" market designs is that this information can be strategically manipulated (Graf et al., 2020).

Overall, the information necessary to quantify short-run incentives and payoffs is split across multiple TSOs, power exchanges and generators. Improving data access and the transparency of short-term markets and balancing mechanisms therefore represent a critical pre-requisite to enable informed debates about market design. Rather than attempting to evaluate the performance of the French wholesale market design without such data, the remainder of this section instead highlights, based on international experience, a couple of challenges faced by the electricity sector in France for which market design seems likely to be of first-order importance.

First, the capacity factor of the fleet of nuclear reactors, that is, the amount of electricity produced relative to the theoretical maximum output that the fleet could generate, has been very low in recent years: 60% in 2020, 65% in 2021, 50% in 2022 and 57% in 2023. Although disorganized maintenance schedules due to the Covid-19 pandemic (2020-21) and the generic stress corrosion cracking failure (2022-23) played a significant role in these outcomes, the pre-existing average capacity factor over 2012-19 was only 72%. In contrast, the observed capacity factor of the fleet of nuclear reactors in the United States, which is on average slightly older than the French fleet, is above 90%.<sup>24</sup> This difference might be rationalized, at least to some extent, by the large size of the nuclear fleet relative to domestic demand, as well as the strong seasonal consumption pattern, which provides incentives to maximize availability during winter months (Lynch et al., 2022). If so, one should expect the on-going increase in the interconnection capacity between France and its neighbors to trigger a significant increase in the utilization of the French nuclear units.

Second, the cost of these new interconnectors is substantial, and has reached values as high as 1 billion euros per GW for the most recent projects. For example, the construction cost of a

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<sup>24</sup> For example, Constellation Energy, the largest nuclear power operator in the U.S., has achieved an average nuclear capacity factor of 94.6% for the period 2022-2023.

2 GW interconnection under construction between France and Spain is currently estimated at around 3 billion euros (CRE, 2023). Similarly, the construction cost of a 700 MW interconnection under construction between France and Ireland is currently estimated at around 1.5 billion euros (CRE, 2022). More generally, overall spendings in the transmission grid are following a sharply increasing trend. In 2024, the French Transmission System Operator is planning to spend almost 2 billion euros in grid investments, the highest yearly budget in at least fifty years. Looking forward, transmission grid capital expenses may exceed 3.5 billion euros in 2027 (CRE, 2024b) and may reach 100 billion euros from 2025 to 2040, that is, more than 6 billion euros per year.<sup>25</sup>

In this context, exploring approaches that optimize the use of the existing transmission grid infrastructure, which may in turn increase the available capacity for cross-border trading, would be a worthwhile endeavor. For example, spatially more granular pricing in day-ahead markets may help manage more efficiently grid congestion and renewable curtailments, while limiting the arbitrage opportunities between day-ahead markets and balancing mechanisms (Graf et al., 2020). In addition, in France, the vast majority of the installed capacity of wind and solar generation connect to the distribution grid (Astier et al., 2023). Therefore, deriving precise forecasts of power flows in the distant future, which to assess whether the benefits of a given grid upgrade outweigh its costs, is particularly challenging.

When exploring possible market design reforms, extensive experience may be drawn from other jurisdictions. For example, the previous discussion obviously raises the question of the benefits of transitioning European markets to a so-called “nodal” system, which has been consistently both advocated by most scholars and lobbied against by most of the industry (Eicke and Schittekatte, 2022). However, the actual implementation of nodal pricing differs from jurisdictions to jurisdictions to some remarkable extent. In Australia for instance, although locational marginal prices (LMPs) are computed and published by the system operator, financial settlements are performed against the price of a single node, effectively creating similar – albeit slightly different – perverse incentives as the ones prevailing in a zonal system (Billimoria and Leslie, 2025). Similarly, the example of New Zealand shows that short-time wholesale electricity markets can rely on LMPs even in a market design where generators are free to decide whether or not to turn on their units in day-ahead. However, the lack of centralized day-ahead auctions and dispatch orders may deteriorate the reliability of the system as the penetration of intermittent renewables increases (McRae, 2025).

## 5. Conclusion

Having paved the way on how to efficiently manage a vertically integrated electricity utility, France has been reluctant to fully embrace electricity markets at the end of the 1990s. Instead, a large number of incremental reforms were implemented, somewhat leaving the country halfway between a regulated vertically-integrated monopoly and well-designed competitive markets. This uncomfortable position left end-consumers much more exposed to the 2022 energy crisis than they might have been under either regime.

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<sup>25</sup> <https://assets.rte-france.com/prod/public/2024-03/SDDR2024-volet-mise-en-oeuvre-doc-C.pdf>

In particular, the interaction between regulated tariffs and an *ad hoc* mechanism implemented to maintain the monopoly of EDF on nuclear operations left residential consumers significantly exposed to the price shock of the energy crisis. Consistently, French policymakers are currently working on designing more efficient long-term risk-sharing mechanisms.

Although rethinking the overarching policy framework rightly emerged as the most pressing issue to address, nothing guarantees that the associated reforms will prove sufficient to prevent future crises, which may be of a different nature. In particular, short-term wholesale market design in Europe faces a number of relatively well-known limitations, whose associated inefficiencies are likely to grow over time as the energy transition unfolds. Therefore, the on-going policy discussions could also represent an opportunity to explore avenues to improve short-term wholesale market design in France, but also – and ideally – in Europe. Indeed, the magnitude of cross-border flows make European countries largely interdependent, both in terms of their exposure to short-term shocks – as evidenced by the 2022 energy crisis – and in terms of their ability to ensure long-term generation adequacy (Astier and Ovaere, 2022).

An objective and informed debate about market design can hardly take place without transparent information on critical economic and operational dimensions. As of today, such data tend to be scattered around between system operators (grid congestion and redispatch), nominated electricity market operators (day-ahead and intraday auctions) and large generators (who self-dispatch and do not have to disclose the underlying composition of their portfolio bids). Future market design reforms should therefore seek to improve information collection and access, both through the empowerment of regulatory agencies and market design evolutions that elicit such information.

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