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The Price and Emissions Effects of Extending Nuclear Lifetimes:
Evidence from Spain

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As Spain approaches the first scheduled nuclear retirements —most notably, Almaraz in 2027— the debate over the implications of delaying the nuclear phase-out has reopened. This paper uses detailed simulations of the Iberian electricity market to assess the consequences of postponing Almaraz's closure on wholesale electricity prices, renewable and storage profitability, and power-sector CO_2 emissions. We test the robustness of our findings to alternative investment targets, electricity demand paths, and gas marginal costs. We caution against a purely static assessment: while extending Almaraz, holding everything else equal, lowers prices and emissions by displacing gas, it also depresses renewables' captured prices and increases curtailment, weakening incentives to invest in renewables and storage. If the investment response is large enough, a delayed nuclear phase-out may ultimately lead to higher prices and higher emissions.

Keywords: energy transition, electricity markets, renewable energies, nuclear power, electricity prices, carbon emissions, simulations.

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1 Introduction

The role of nuclear power in the energy transition remains controversial. On the one hand, as a source of carbon-free electricity, nuclear features in decarbonization pathways that are consistent with climate goals (International Energy Agency, 2023).[1] On the other hand, nuclear power is widely perceived as risky (Goebel et al., 2015), and the challenge of long-term radioactive waste management remains unresolved (Fowlie, 2026). Recent experience with new nuclear construction in several countries has been marked by delays and overruns,[2] and cost comparisons with other carbon-free alternatives —such as renewables complemented by storage— are not always favorable (Lazard, 2024).[3]

Beyond the question of investing in new nuclear capacity, policymakers also face the decision of whether to extend the operating lifetimes of existing reactors. This issue is also contentious. Lifetime extensions can strain public acceptance, given concerns about accident risk, increase the volume of radioactive waste associated with prolonged operation, and require substantial capital outlays for upgrades and retrofits needed to comply with evolving safety standards. At the same time, delaying the closure of nuclear plants is often viewed as a release valve for the growing pressure on power systems as the economy electrifies —for example, through the expansion of data centers, electrified industrial processes, and green hydrogen production.

Spain is among the countries facing the question of whether to keep its nuclear plants running longer than planned. In 2019, as most reactors neared the end of their 40-year design life, the government and plant owners agreed on a gradual phase-out that would close the entire fleet by 2035, starting with Almaraz in 2027. By late 2025, however, utilities formally signaled their intention to extend Almaraz's operation until 2030, opening a heated public debate over the pros and cons of delaying the nuclear phase-out.

In this paper, we run detailed hourly simulations of the Iberian wholesale electricity market under a range of future supply and demand scenarios to quantify the effects of a potential delay in Almaraz's closure. In particular, we focus on key electricity market outcomes: wholesale prices, profitability of renewable and storage investments, and power-sector CO_2 emissions. Our analysis uses two baselines for assessing the effects of the delayed closure: either Spain's National Energy and Climate Plan targets (*PNIEC* baseline) for 2030, or less ambitious targets informed by conversations with industry professionals about the investments that are realistically achievable by 2030 (*Feasible* baseline).

[1] Reflecting this view, the European Union has recently classified certain nuclear activities as aligned with its taxonomy for sustainable activities (European Commission, 2022).

[2] See, for instance, the examples provided by Hinkley Point C in the UK, or Flamanville-3 in France.

[3] As Fowlie (2026) puts it: *"The growing availability of low-cost renewables and storage, together with an increasingly flexible demand-side, complicates the claim that nuclear power is some kind of moral climate necessity. There are cheaper ways to decarbonize the grid."*

A central takeaway of the analysis is that the effects of delaying nuclear retirement cannot be evaluated through purely static lenses. If all renewable and storage investments proceed as planned, extending the operation of Almaraz mechanically increases low-marginal-cost supply, lowering wholesale prices and reducing emissions by displacing gas-fired generation. Relative to the baselines with a 2027 closure, our simulations indicate that prices would fall by either 4–8% (relative to the *PNIEC* baseline) or 5–11% (relative to the *Feasible* baseline) over 2028–2031. Also, power-sector CO_2 emissions would decline by roughly 14–20% or 16–23%, respectively.

However, this static *ceteris paribus* approach fails to capture key dynamic effects. A delayed closure depresses the prices captured by renewables and raises curtailment in hours when nuclear and renewable availability jointly exceed demand. In our simulations, solar captured prices fall by about 12–18% (*PNIEC* baseline) or 16–23% (*Feasible* baseline) in 2028–2031, while curtailment increases sharply (by roughly 30–60%), pushing the profitability of new investments into negative territory. These effects weaken incentives to deploy the renewable and storage capacity on which Spain's transition pathway relies. If the resulting investment shortfall is sufficiently large, a delayed phase-out may ultimately lead to higher prices and higher emissions both while the plant remains online and, even more markedly, after it closes.

Determining the equilibrium investment response to a delayed phase-out is inherently challenging. Methodologically, it would require a structural model of dynamic investment to endogenize the post-delay investment mix, i.e., to identify the portfolio of new capacity under which all entrants break even given the new set of market prices, which are also endogenous to the scale and type of entry.[4] Such an exercise lies beyond the scope of this paper. In any event, such an approach may be of limited validity to the extent that investment decisions depend on future price expectations and, hence, on the credibility of the policy path, which could be weakened by a decision to delay the nuclear phase-out. Such regulatory uncertainty would plausibly raise investors' required risk premia, increasing the cost of capital, and providing an additional channel through which clean investment could be scaled back.

To get a sense of how important the investment-response channel might be, we have re-computed the effects of the delayed closure under a set of potential reductions in renewable and storage deployment. Quantitatively, we find that if an extension to 2030 is accompanied by a 25% shortfall in renewable and storage deployment relative to the baseline trajectory, average wholesale prices increase by 4,5–7,2% (*PNIEC* baseline) or 1,6–2,4% (*Feasible* baseline) over 2028–2030 and by 10-11% in 2031 — although this latter increase could be partly mitigated if investments in renewables and storage resume

[4] Such an approach is used by Elliott (2025) to assess the impact of combining carbon taxes and capacity subsidies on the equilibrium generation mix in Western Australia.

after the 2030 closure of Almaraz.[5] Power-sector emissions over the period 2028–2030 fall under some scenarios, but increase when the investment response is sufficiently large. In 2031, they unambiguously rebound sharply, reflecting the smaller stock of clean capacity once Almaraz closes — again, depending on whether investment resumes or not.

Inevitably, these results depend not only on the equilibrium response of investment, but are also subject to substantial uncertainty about future demand and supply conditions. To assess the robustness of our findings, we also conduct a set of sensitivity analyses and obtain similar qualitative conclusions under alternative demand paths and plausible variation in gas and carbon prices.

In sum, the impact of extending nuclear operations depends on how the delay affects the roll-out of renewables and storage. Keeping nuclear plants online longer may lower prices and emissions at first, but it can also dampen clean-investment incentives and lead to higher prices and emissions later on. Beyond these direct profitability effects, revising the closure calendar may also undermine policy credibility, shifting expectations and increasing risk premia for clean projects. Taken together, these considerations call for a dynamic assessment, rather than the static partial-equilibrium logic that often dominates the public debate.[6]

Beyond Spain, these lessons also matter for other countries that have fully phased out nuclear power (e.g., Germany and Taiwan),[7] those that have adopted and later revised phase-out policies (e.g., Switzerland, Belgium, and South Korea), those considering a return to nuclear generation (e.g., Italy) or those that are increasing it (e.g., Poland, Czech republic, and the UK).

Germany's experience has attracted the most attention, given the scale of the nuclear closure and the abrupt policy shift following the Fukushima accident.[8] Recently, Jarvis, Deschenes, and Jha (2025) have studied the electricity market consequences of Germany's 2011 phase-out, finding increases in electricity prices and CO_2 emissions, with social costs outweighing the benefits of reducing nuclear risks.[9] Yet the German episode differs in important ways from the Spanish case. In Germany, roughly two-thirds of its 12 GW of nuclear capacity were withdrawn within months in 2011, with the remaining reactors shut

[5] Yet, an investment rebound is unlikely if delaying Almaraz's closure also leads to postponements in the retirement of the next two reactors scheduled to shut down, Ascó I and Cofrentes. While our main simulations keep the shutdown schedule for the remaining reactors unchanged, Section 6.3 examines scenarios in which the closure of these two units is delayed beyond 2030.

[6] See, for instance, Rodríguez (2025), and the related press coverage.

[7] Liski and Vehviläinen (2018) conduct a numerical analysis of the impacts of a potential nuclear phase-out in the Nordic countries. In line with our results, holding other factors constant, retiring nuclear capacity raises wholesale prices by shifting generation toward higher–marginal-cost technologies, whereas expanding wind capacity lowers prices by displacing those same technologies. Their focus, however, is on the effect of cross-ownership on firms' voluntary exit decisions.

[8] Previous papers focused on the shutdown of a small number of nuclear plants in the United States; see Davis and Hausman (2016), Severnini (2017) and Adler, Jha, and Severnini (2020).

[9] See also Grossi, Heim, and Waterson (2017), who analyze the 2011 nuclear shutdown over a 3-year window, between 2009 and 2012.

down by 2022, a period that overlapped with the European energy crisis and Germany's high exposure to Russian gas. By contrast, Spain's 7 GW nuclear fleet is scheduled to retire gradually over an eight-year window. The starting energy mix also differs markedly. In Germany, coal accounted for a large share of generation at the time of the nuclear phase-out,[10] which explains why lost nuclear output was largely replaced by fossil-fired production, pushing prices and emissions up. In Spain, coal has already exited, and renewables account for a much larger —and rising— share of generation, making it more plausible that reductions in nuclear output can be absorbed by renewables and storage rather than by increased fossil generation.

The Spanish–German comparison suggests that the effects of nuclear phase-out policies are highly time- and context-dependent. Accordingly, the likely consequences of future phase-out decisions —or of reversing existing plans— should be evaluated case by case, taking into account each country's generation mix, system constraints, and policy environment.

The remainder of the paper is organized as follows. Section 2 describes Spain's energy transition, including the planned phase-out of nuclear power and the scale-up of renewable generation and storage. Section 3 reviews the design and performance of the Iberian electricity market and discusses how the transition may affect key market outcomes. Section 4 presents the simulation methodology and the scenarios considered, and Section 5 reports the results. Section 6 provides sensitivity analyses to assess the robustness of the main findings. Section 7 concludes. The Appendix contains additional results and further details on the simulations.

2 The Energy Transition in Spain

Spain's energy transition is framed by the *Plan Nacional Integrado de Energía y Clima 2023–2030* (*PNIEC*),[11] which constitutes the main policy instrument to align national energy and climate objectives with the European Union's decarbonization agenda. The plan sets ambitious targets for emissions reductions, renewable energy deployment, and electrification, with the power sector playing a central role in the transition.

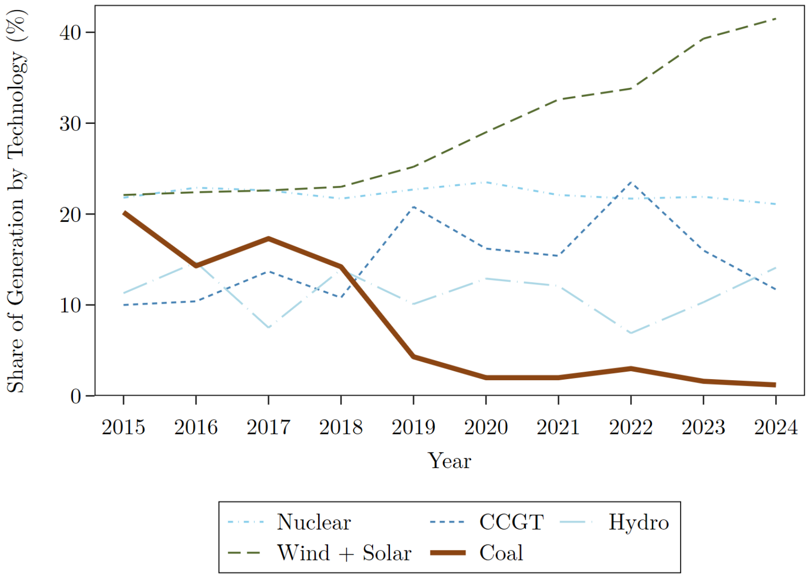
Yet, Spain's energy transition was already well underway before the formal approval of the *PNIEC*. In the years leading up to its adoption, the power sector saw a rapid build-out of renewable generation —especially wind and solar PV— driven by declining technology costs, favorable financing conditions, and abundant natural resources (wind, sunshine, and available land). At the same time, coal-fired generation was progressively

[10] Still today, coal represents roughly one-fifth of total electricity generation in Germany, while gas-fired generation provides slightly above one-tenth.

[11] See MITECO (2024). The *Plan* was originally designed to cover the period 2021–2030 and was first approved in 2020. Its current version dates from 2023, following a formal revision that updated the targets and measures in light of evolving market conditions and European climate commitments.

phased out, with most coal plants closing between 2019 and 2021 in response to tighter environmental regulation and increasing CO_2 prices. As a result, the electricity mix entering the *PNIEC* period already reflected a substantial shift away from fossil fuels and toward low-carbon technologies (Figure 1), providing the foundation on which the current transition strategy builds.

Figure 1: Evolution of electricity generation by technology in the Spanish power sector



Notes: This figure shows the evolution of the market shares of the main generation technologies in the Spanish electricity market since 2015 (peninsular generation). Source: REE (2025).

By 2030, the *PNIEC* targets a reduction in greenhouse gas emissions of approximately 32% relative to 1990 levels, alongside a substantial increase in the share of renewable energy in final energy consumption. The electricity sector is expected to lead this transformation: renewables are projected to account for around 81% of total electricity generation by 2030, up from roughly 50% in recent years. Achieving this objective requires a large expansion of renewable generation capacity, as well as significant investments in storage and system flexibility.

2.1 The Phase-Out of Nuclear Power Plants

Spain's first commercial nuclear reactor (José Cabrera/Zorita) began operating in 1968. Since then, nuclear capacity expanded mainly in the late 1970s and 1980s, when most of today's fleet was commissioned; Trillo, which entered commercial operation in 1988, was the last reactor to come online in Spain. Over these past decades, nuclear power has remained a central component of the Spanish generation mix, supplying roughly one-fifth of the total electricity (Figure 1).

Table 1: 2030 targets for the Spanish power sector

Indicator	**Actual** 2024	***PNIEC*** 2030	***Feasible*** 2030
Share of renewables in electricity generation (%)	58,8	81	73
Total installed generation capacity (GW)	127	203	176
Wind capacity (GW)	31,5	60,5	45
Solar PV capacity (GW)	31,7	72,1	65
Solar thermal capacity (GW)	2,3	4,8	2,3
Nuclear capacity (GW)	7,1	3,0	3,0
CCGTs (GW)	24,5	24,5	24,5
Hydro (GW)	14,6	14,6	14,6
Installed storage capacity (GW)	3,4	17,6	15,4
Hydrogen electrolyzers (GW)	–	12	12

Notes: The first column of this table reports electricity generation and capacity in the Spanish peninsular electricity system as of 2024, as reported in REE (2025). The second column shows the *PNIEC* 2030 targets reported in MITECO (2024), Table D.5 (p. 627, Peninsular Adaptado). The third column reports what we refer to as *Feasible* targets regarding the 2030 targets. Under both *PNIEC* and *Feasible*, nuclear capacity declines progressively as reactors close between 2027 and 2035, as detailed in Table 2.

In 2019, as most Spanish reactors approached the end of their 40-year operating life,[12] the Spanish government and the plant owners (Iberdrola, Endesa, and Naturgy) agreed on a gradual phase-out schedule that envisaged the complete shutdown of all reactors by 2035. This agreement was reflected in the *PNIEC* and later incorporated into the *Seventh General Radioactive Waste Plan* (PGRR), approved in 2023.

The nuclear phase-out follows a staggered schedule, with individual reactors closing between 2027 and 2035, starting with the Almaraz plant in 2027 (Table 2). The total installed nuclear capacity, currently around 7,1 GW,[13] is therefore expected to decline progressively over the next decade.

Yet, at the end of 2025, the electricity companies informed the Spanish government of their intention to extend the operating life of the Almaraz nuclear power plant until 2030, as part of a broader strategy for the phased closure of Spain's nuclear power plants. The government refused to grant concessions, stating that any extension of nuclear plants' operating lifetimes would have to meet nuclear-safety requirements and safeguard security of supply and must not impose additional costs on consumers (and, by implication, on public finances/taxpayers).[14] At the time of writing, the decision is still pending official

[12]The Nuclear Safety Council (CSN) refers to this as the plants' "vida de diseño". In 2019, it clarified that the start date is tied to first grid connection.

[13]Beyond the reactors currently in operation, Spain has also had several nuclear plants that have since shut down or never entered service: José Cabrera (Zorita), which was disconnected in 2006; Santa María de Garoña, which ceased operation in 2012; and Vandellós I, which was shut down in 1989 following a fire. In addition, the Lemóniz and Valdecaballeros projects never entered commercial service.

[14]A press coverage of these issues can be found at El País (2025b) and El País (2025a), respectively.

approval.

Table 2: Existing Spanish nuclear power plants, start of commercial operations, and planned closure dates

Nuclear plant	Unit	Capacity (MW)	Start of operation	Planned closure
Almaraz I	Reactor 1	1.049	1983	2027
Almaraz II	Reactor 2	1.044	1984	2028
Ascó I	Reactor 1	1.032	1984	2030
Cofrentes	Single reactor	1.092	1985	2030
Ascó II	Reactor 2	1.027	1986	2032
Vandellós II	Reactor 2	1.087	1988	2035
Trillo	Single reactor	1.066	1988	2035

Notes: This table reports Spain's currently operating nuclear reactors, including capacity, start year of commercial operation, and planned closure date. Source: Foro Nuclear (2025).

2.2 The Scale-Up of Renewable Energies and Storage

The decline in nuclear generation is to be offset primarily by a massive expansion of renewable energy sources, particularly solar photovoltaic and wind power. According to the *PNIEC* (MITECO, 2024), total installed electricity generation capacity is expected to reach approximately 214 GW by 2030, compared to around 120 GW in 2024. Solar photovoltaic capacity alone is projected to more than double, reaching over 76 GW by 2030, while wind capacity is expected to increase to around 60 GW (Table 1).

In addition to renewables, the *PNIEC* places strong emphasis on electricity storage and flexibility. Installed storage capacity (including pumped hydro and batteries) is projected to rise from about 3,5 GW in 2024 to more than 20 GW by 2030. Gas-fired power plants are expected to remain in the system as a source of dispatchable capacity and balancing services, although their utilization is projected to decline as renewable penetration increases.

Overall, the *PNIEC* envisions a power system characterized by high renewable penetration, declining reliance on conventional baseload technologies, and increased dependence on flexibility mechanisms. The nuclear phase-out is therefore an integral element of a broader structural transformation of the Spanish electricity market, with important implications for electricity prices and investment incentives, which is the focus of the current article.

3 The Electricity Market: Design, Performance and Impacts of the Energy Transition

Understanding competition in wholesale electricity markets is essential for assessing the potential effects of the nuclear phase-out. This section briefly reviews the main institutional features of these markets and highlights a set of stylized facts that are relevant for the subsequent analysis.

3.1 Electricity Market Design

Wholesale electricity markets are organized institutions governed by well-defined rules that map firms' price–quantity offers into market-clearing prices and dispatch decisions. In the Iberian Peninsula, wholesale electricity trading takes place through a sequence of centralized markets, of which the day-ahead market is the most important.[15] The day-ahead market is organized as a uniform-price auction. For each trading period,[16] generators submit bids specifying the quantities they are willing to supply at different minimum prices, while consumers submit bids indicating the maximum prices they are willing to pay for given quantities.

The Market Operator aggregates all supply and demand bids to construct hourly supply and demand curves for each trading period. Their intersection determines both the market-clearing price and the set of generating units dispatched to produce electricity. All units with bids at or below the market-clearing price are dispatched and receive the same price, equal to the bid of the marginal generating unit. Units with lower bids are referred to as inframarginal.

In addition to the day-ahead market, a sequence of markets allow participants to adjust their positions as new information becomes available. These include discrete intraday auctions as well as a continuous intraday market, known as Single Intraday Coupling (SIDC), which enables market participants to manage imbalances closer to real time and to access liquidity across European markets, subject to available cross-border transmission capacity. Trading in the continuous market is possible until one hour before delivery.

Figure 2 illustrates aggregate demand and supply curves in the day-ahead market for a representative trading period. All bids to the left of the intersection are accepted and settled at the market-clearing price, which corresponds to the price offer of the last accepted unit.

After market clearing, the System Operator evaluates the technical feasibility of the resulting dispatch and, if necessary, intervenes through balancing and redispatch markets

[15] The Spanish wholesale electricity market was established in 1997. In July 2007, the Spanish and Portuguese markets were integrated, giving rise to the Iberian electricity market (MIBEL).

[16] Up to September 2025, trading took place on an hourly basis. Since then, quarter-hourly markets have been introduced.

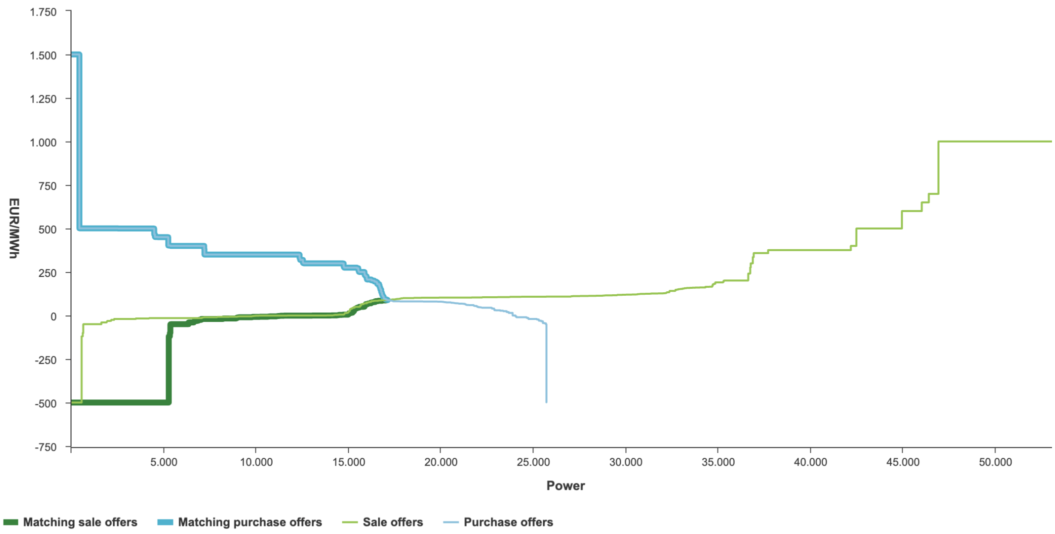


Figure 2: Aggregate demand and supply curves in the Iberian day-ahead wholesale electricity market

Notes: The figure depicts supply and demand in the Iberian day-ahead electricity market for a given hour of a representative day. The market-clearing price is determined at the intersection of the two curves. The solid green line indicates dispatched supply offers, and the solid blue line indicates dispatched demand offers. Source: OMIE (2025).

to ensure the real-time balance of supply and demand and the secure operation of the network. The importance of these markets has increased substantially with the growing penetration of intermittent renewable generation.

3.2 Electricity Market Performance

For the market to deliver efficient outcomes, generation technologies should be dispatched in increasing order of their marginal costs —commonly referred to as the *merit order*— regardless of their investment costs. In some cases, however, their technical characteristics (e.g., ramping constraints) may introduce intertemporal opportunity costs that should also be taken into account. Such an efficient dispatch is achieved only in the absence of market power, i.e., when generators have the incentives to bid at marginal cost (or at the relevant opportunity cost, when applicable) (Borenstein, 2000).

The distribution of demand over time shapes generation patterns across technologies, with higher-demand hours requiring the activation of progressively more expensive and flexible units. Nuclear and renewable technologies, which have very low operating costs, are typically dispatched first, either until demand is met or until their available capacity is exhausted. However, when their combined available capacity exceeds demand, the limited ability of nuclear power plants to ramp down output can lead to the curtailment of renewable generation, despite renewables having lower marginal costs. If demand exceeds the available capacity of nuclear and renewable energies, the residual demand is met by thermal technologies, most notably gas-fired power plants, whose marginal costs are substantially higher and, often, highly volatile due to variation in gas and CO_2 prices.

Reservoir hydroelectric plants and pumped storage facilities play a key role in covering demand peaks, when their value —and hence the prices they can capture— are highest. More generally, technologies with high operational flexibility —such as gas-fired, hydroelectric units and batteries— are particularly well suited to provide ancillary services that help the System Operator maintain system balance across time and network locations.[17]

Figure 3 illustrates how electricity demand is covered by different generation technologies over a representative day. Nuclear generation appears relatively flat, reflecting both its low marginal cost and its limited ability to ramp output in response to fluctuations in demand and renewable generation. In contrast, gas-fired and hydroelectric generation vary substantially over the day, adjusting to changes in residual demand and providing peak-shaving generation. Net imports play a relatively limited role, reflecting the historically low level of interconnection between the Iberian Peninsula and the rest of Europe.

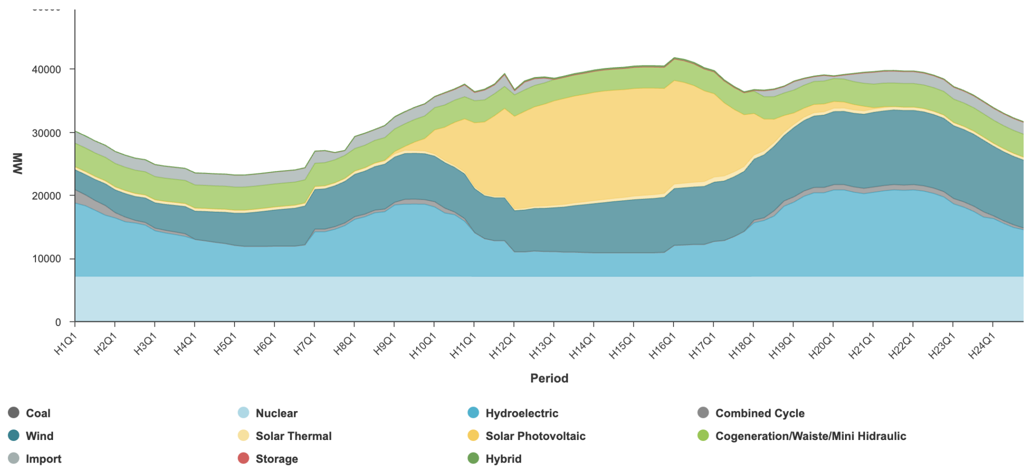


Figure 3: Generation patterns over a representative day in the Iberian day-ahead wholesale electricity market

Notes: The figure shows the generation mix in the Iberian day-ahead electricity market over a representative day. The upper contour traces total electricity demand, while the colored areas represent the contributions of different generation technologies used to meet that demand. Source: OMIE (2025).

[17]Transmission congestion can disrupt the merit order. When network constraints bind, the System Operator may need to dispatch higher-cost units located in congested areas instead of lower-cost plants in zones with surplus generation.

3.3 Electricity Market Impacts of the Energy Transition

The energy transition is expected to affect the performance of electricity markets through several interacting channels, as renewable penetration increases, nuclear capacity is progressively withdrawn, storage expands, interconnection capacity rises, and electricity demand grows. These developments affect prices, investment incentives, and emissions in ways that depend on the relative timing and scale of each component of the transition.

The expansion of renewable generation increases the share of inframarginal technologies with very low marginal costs. Holding demand fixed, this shifts the aggregate supply curve outward in many hours, reducing the frequency with which high-cost thermal units set the market-clearing price. This mechanism generates a well-documented price-depressing effect (Fabra, 2021), particularly in periods of high renewable availability. Lower prices reduce the profitability of renewable generation and may weaken incentives for new investments, unless low prices are offset by complementary developments such as the expansion of storage capacity, the phase-out of baseload technologies such as nuclear power, increased interconnection capacity, or higher electricity demand driven by electrification.[18]

The deployment of storage introduces intertemporal arbitrage into the market. Storage tends to absorb electricity during periods of low prices —typically associated with high renewable output— and release it during periods of higher prices (Andrés-Cerezo and Fabra, 2023; Andres-Cerezo and Fabra, 2025; Gowrisankaran, Reynolds, and Svento, 2025). This behavior modifies the effective demand profile faced by generators, reduces renewable curtailment, and smooths price fluctuations over time. By increasing the value of electricity during high-renewable periods and reducing scarcity during peak demand, storage affects both the price patterns over time as well as the distribution of revenues across technologies. For instance, Andres-Cerezo and Fabra (2025) show that in electricity markets with high solar penetration, an expansion of storage capacity may increase the profitability of solar generators while reducing that of wind generators. This occurs because storage raises prices during periods of high solar availability, when it charges, but depresses prices during periods in which wind generation is relatively more abundant. Storage is also expected to erode the market profits of gas-fired generators, as it competes with them in supplying electricity during peak-demand hours.

The phase-out of nuclear generation introduces additional interactions in electricity markets. Nuclear power plants combine low marginal costs with limited operational

[18] Additionally, the auctioning of regulator-backed Contracts for Differences (CfDs) for new renewable investments may decouple investment decisions from expected wholesale market prices, thereby promoting renewable projects that might not have been undertaken in the absence of such contracts. See Fabra and Llobet (2025).

flexibility,[19] which restricts their ability to adjust output in response to fluctuations in demand and renewable generation. In systems with high renewable penetration, this inflexibility may contribute to renewable curtailment when aggregate low-cost supply exceeds demand. A reduction in nuclear capacity relaxes this constraint and can increase the share of renewable generation absorbed by the system. At the same time, withdrawing nuclear capacity reduces the availability of carbon-free baseload generation, potentially increasing reliance on other polluting technologies, depending on demand conditions and the availability of flexibility resources. The resulting effects on market prices and carbon emissions, therefore, depend on how the loss of nuclear output is offset by renewable generation, storage, interconnection capacity, and thermal generation.

Delaying the closure of nuclear power plants would tend to operate in the opposite direction — as illustrated in Figure 4. Holding investment plans fixed, the continued operation of low-cost nuclear capacity would exert downward pressure on market prices and reduce the utilization of other technologies. This includes not only thermal generation, but also renewable generation, as the limited flexibility of nuclear plants may increase renewable curtailment. Lower prices and reduced renewable output can, in turn, weaken the profitability of renewable investments and potentially affect the scale and timing of future capacity deployment. If this dynamic response occurs, the net effect of the delayed closure can be a price reduction (if the response is weak) or a price increase (if it is strong). Consequently, the net comparison between the planned nuclear phase-out and alternative scenarios involving delayed closures depends on the relative strength of these opposing mechanisms, which cannot be determined unambiguously ex ante and must be assessed quantitatively.

Greater interconnection capacity further shapes these outcomes by expanding the relevant market over which supply and demand are balanced. Cross-border trade allows excess renewable generation to be exported and scarcity to be mitigated through imports, affecting both price levels and volatility. Interconnections also influence investment incentives by linking domestic prices to price conditions in neighboring markets (Gonzales, Ito, and Reguant, 2023).

Finally, increasing electricity demand, driven by electrification of final energy uses, shifts the demand curve outward and raises the utilization of generation assets. Higher demand may counteract some of the price-depressing effects of the renewable expansion and affect the relative profitability of baseload, flexible, and peaking technologies. From an emissions perspective, the impact of demand growth depends on the composition of marginal generation and the extent to which additional consumption is met by low-carbon sources (Holland, Mansur, and Yates (2025) and Steinberg et al. (2017)).

[19] Whereas nuclear power plants are often viewed as inflexible, Astier and Wolak (2026) document that French reactors can perform "load-following" in response to short-run fluctuations in wind and solar output. This capability, however, depends on the specific reactor technology and operational design.

Overall, the energy transition modifies electricity market outcomes through changes in the composition, flexibility, and scale of supply, as well as through evolving demand patterns. The effects on prices, investment incentives, and emissions are theoretically ambiguous and depend on the interaction between renewable deployment, nuclear phase-out, storage capacity, interconnection, and demand growth. Understanding these interactions requires a quantitative framework capable of replicating electricity market outcomes under alternative scenarios. This motivates the simulation analysis that follows.

4 Electricity Market Simulations

This section describes the approach for simulating the Iberian day-ahead wholesale electricity market under several scenarios for future electricity supply and demand conditions. The ultimate goal is to quantify the effects of delaying the closure of the Almaraz nuclear plant by comparing a baseline scenario that follows the planned phase-out with counterfactual scenarios that differ in how the delay affects investment in other carbon-free technologies.

4.1 Methodology

Simulations are conducted with an algorithm that mimics the actual functioning of the Iberian electricity market, assuming competitive supply.[20] All simulations are performed at the hourly level over the 35,064 hours spanning the sample period from 1st January 2028 to 31th December 2031.

On the supply side, the model draws on granular data describing the technical characteristics of actual power plants operating in the Spanish electricity market —including their capacity, thermal efficiency, and emissions rates (Global Energy Monitor, 2025) for gas plants; and hourly availability for renewable resources. These inputs are combined with assumed prices for gas and EU-ETS CO_2 allowances, which might differ across scenarios (as detailed below).

Equipped with this information, we estimate marginal generation costs following standard methodologies (see, for example, Fabra and Imelda, 2023). For a thermal plant i, marginal costs in period t are characterized as follows:

$$c_{it} = \frac{p_t^G + \tau_t \epsilon^G}{e_i} + om_i,$$

where p_t^G denotes the price of gas, ϵ^G denotes its CO_2 emission factor; τ_t is the CO_2 price; e_i is the plant-specific efficiency rate in converting fuel into electricity; and om_i stands

[20] The software that has been used for the simulation is ENERGEIA (Fabra and Toro, 2025). This software also computes the market outcomes under strategic bidding, modeled following the framework in de Frutos and Fabra (2012). The results, which are available upon request, remain quantitatively similar.

for the plant's operation and maintenance costs.

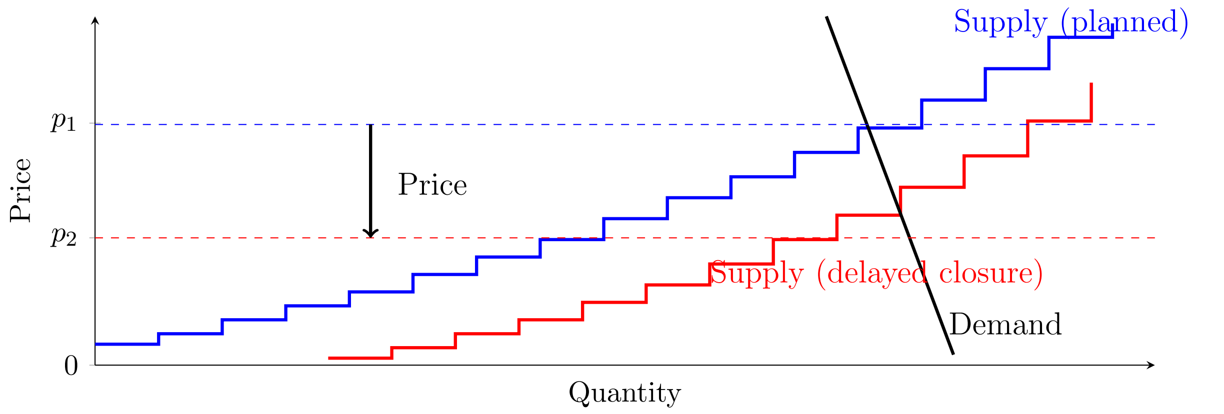
The marginal costs of renewable generators and storage assets are driven by operation and maintenance costs. For nuclear plants, we also account for start-up costs, which can make them willing to continue producing even at negative prices in order to avoid shutting down and incurring restart costs.

The industry's hourly competitive supply curve is constructed by stacking generating units in increasing order of marginal cost (or, when relevant, opportunity cost). Hydro output is allocated to shave the peaks of net demand, i.e., demand after accounting for available renewable generation. The intersection of this competitive supply schedule with demand (net of the hydro allocation) determines the market-clearing prices and quantities in every hour. These outcomes are then updated iteratively to account for storage operations. In particular, storage is assumed to arbitrage intraday price differences by charging in low-price hours and discharging in high-price hours up to their capacity limits, with a 10% energy loss during charge/discharge cycles (i.e., a 90% round-trip inefficiency).

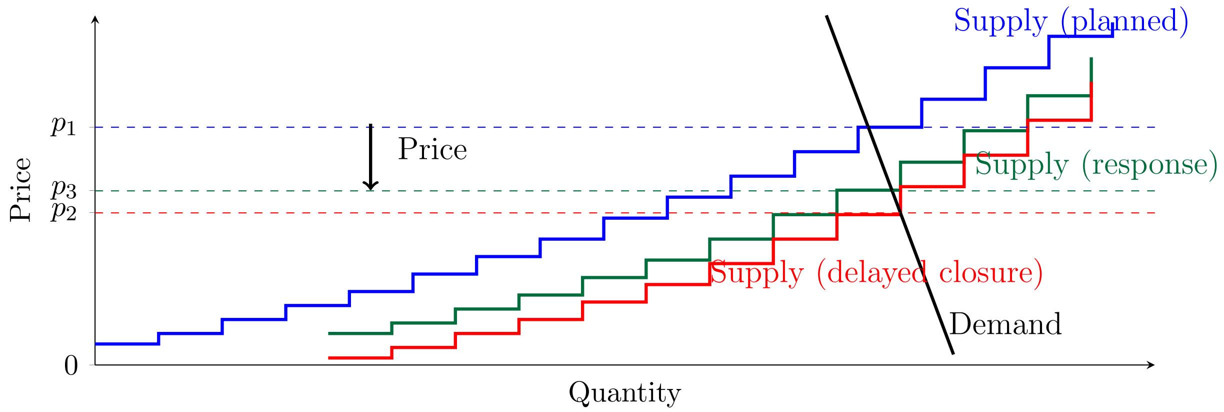
Finally, since the Iberian electricity market is interconnected with France, French electricity prices affect supply and demand conditions in Iberia, depending on whether France is importing from or exporting to the region.[21] To approximate French prices, we have applied the same simulation methodology used for Spain with French data. Cross-border flows are determined endogenously by price differentials, with Spain exporting to France when Spanish prices are lower and importing otherwise, subject to interconnection limits.

To assess the model's performance, we have run simulations using actual 2024 market data. Figure 5 compares the resulting simulated prices for the Iberian electricity market with observed prices. The model reproduces average price levels closely: the mean simulated hourly price is 65,153 €/MWh, compared with an observed average of 65,135 €/MWh. The correlation between observed and simulated daily average prices is also very high, as evident from the figure. Likewise, nuclear, hydro, and renewable generation in the simulations match the observed production levels, resulting in the same thermal gap. Overall, the close match in both price levels and their time variation, and the generation mix, supports the model's suitability for performing future projections and counterfactual analyses.

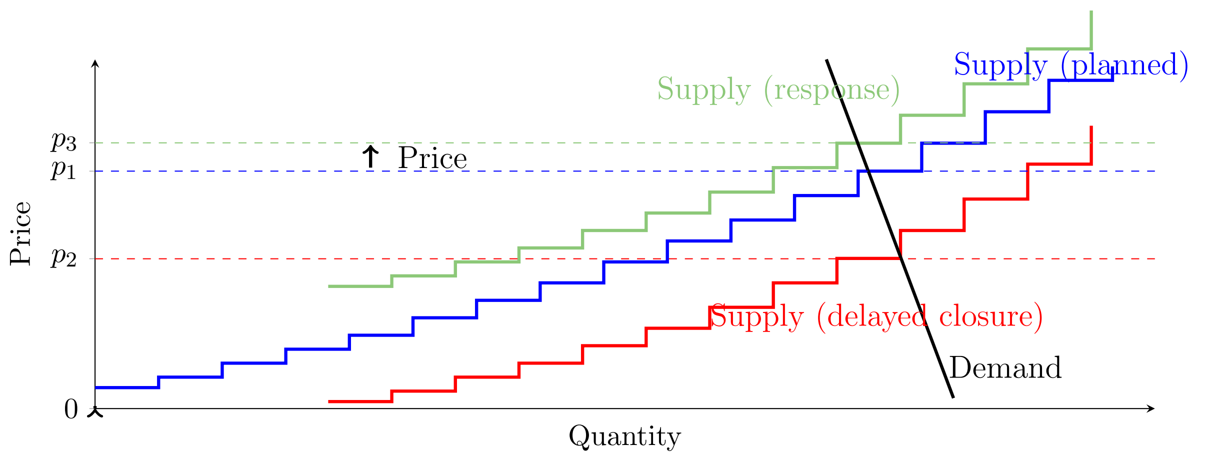
[21] The Spanish market is closely linked to the Portuguese market, together forming the Iberian electricity market. This interconnection is rarely congested, resulting in nearly identical prices in Spain and Portugal. Accordingly, we treat the Spanish and Portuguese markets as fully coupled throughout the analysis.



(a) Static effect



(b) Weak dynamic effect

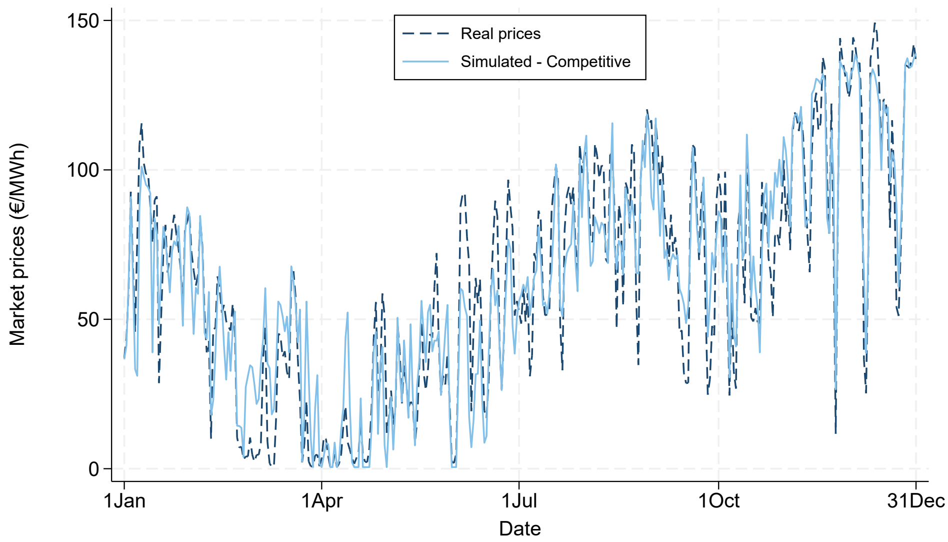


(c) Strong dynamic effect

Figure 4: Expected effects of a delayed nuclear phase-out: static and dynamic effects.

Notes: These figures illustrate the potential impact of a delayed nuclear phase-out. The upper panel shows the static effect only: the delayed closure keeps additional low-marginal-cost capacity in the market, shifting the supply curve outward (red supply curve) and lowering prices. The middle and lower panels also incorporate a dynamic effect, whereby the delayed closure crowds out investment in renewables and storage, shifting the supply curve inward (green supply curve). With a weak dynamic response (middle panel), prices still fall, but by less. With a strong response (lower panel), the dynamic effect fully offsets the static effect and prices increase.

Figure 5: Validating the Model: Simulated versus Realized Wholesale Prices (2024)



Notes: The figure shows daily average electricity prices in Spain in 2024 (light purple) and their simulated counterparts (dark purple).

4.2 Scenarios

This paper assesses the impact of extending the operation of the Almaraz nuclear power plant in Spain until 2030 through a set of baseline and counterfactual simulations, accompanied by a sensitivity analysis. The scenario design focuses on alternative assumptions regarding nuclear availability, renewable and storage investment paths, electricity demand growth, and key fuel and carbon prices (Table 3). All simulations cover the years 2028–2031.

Baseline Scenarios: *PNIEC* and *Feasible*. We consider two baseline scenarios, *PNIEC* and *Feasible*, which differ in their 2030 targets for investment and demand. The *PNIEC* baseline assumes full compliance with Spain's National Energy and Climate Plan targets for renewable generation and storage by the end of 2030,[22] and projects electricity demand of 344 TWh in 2030 (MITECO, 2024). Given demand of 232 TWh in 2024 (REE, 2025), this implies an average annual growth rate of 6,77% over 2024–2030.

However, several factors could prevent full attainment of the *PNIEC* deployment targets. Beyond financing, renewable and storage build-out is increasingly constrained by slow permitting and environmental assessments, land and social-acceptance limits, shortages of specialized labor and equipment, supply-chain disruptions, and grid bottlenecks — a challenge seen across Europe (Financial Times, 2026). Macroeconomic conditions also matter: higher interest rates and risk premia raise funding costs, while market dynamics can compress revenues through price cannibalization for renewables and narrower arbitrage margins for storage. Together, these considerations motivate benchmarking our results against more conservative deployment paths.

Accordingly, we have constructed a *Feasible* baseline reflecting less ambitious targets, informed by conversations with industry professionals about what is realistically achievable by 2030. In this scenario, investment targets are lower for wind (45 GW instead of 60,5 GW), solar (65 GW instead of 72,1 GW), and storage (15,3 GW instead of 17,6 GW). Demand growth is also more moderate: 2,7% in 2025,[23] and 4% per year thereafter, rather than 6,77%.

Beyond these differences, the two baseline scenarios share similar assumptions. In particular, both reflect the currently planned nuclear phase-out schedule. Nuclear units retire according to the agreed calendar: Almaraz I is assumed to close in 2027 and Almaraz II in 2028 (Table 2). Installed capacities of all other technologies start from their observed 2024 levels and increase linearly to reach the baseline targets by the end of 2030. Hourly availability of variable renewables is represented using the average hourly

[22] In more detail, since the *PNIEC* objectives are assumed to be reached by the end of 2030, the target capacities become operational on January 1st, 2031 and remain at that level throughout the year.

[23] This was the actual demand growth rate in 2025.

capacity factors observed over 2020–2024.[24] CCGT and hydro capacities remain constant over the period, and coal-fired generation is fully phased out by 2028.

Interconnection capacity with France evolves in line with *PNIEC* assumptions: the Bay of Biscay interconnection is assumed to enter operation in 2029, increasing the Spain–France transfer capacity from 2.800 to 5.000 MW.[25]

Finally, under both baseline scenarios, we assume a natural gas price of 30 €/MWh and a price of EU ETS allowances of 80 €/tCO_2, in line with current and future prices.

Counterfactual Closure Scenarios. To assess the effects of extending the operation of the Almaraz nuclear plant, a set of counterfactual scenarios is constructed in which both Almaraz I and II remain operational until 2030 (and all other reactors close as planned). These scenarios differ only in the extent to which the baseline target investments materialize as planned (either relative to the *PNIEC* or to the *Feasible* baselines). The motivation for this design is that prolonged nuclear availability may reduce wholesale prices and, consequently, weaken investment incentives for renewables and storage. The counterfactuals, therefore, capture alternative investment responses to the delay of the nuclear closure. Three counterfactual investment paths are considered: whether 100%, 75% or 50% of the renewable and storage capacity additions to reach the 2030 baseline are realized. All other elements of the simulations are kept identical to the baseline scenarios.[26]

[24] Capacity-factor data are computed using production and capacity data from Redeia (2025).

[25] The Galicia–Portugal reinforcement is also expected to be operational by 2028, raising transfer capacity to 4.200 MW from Spain to Portugal and 3.500 MW from Portugal to Spain. However, this has no material effect on the simulation results, as the assumption is that the two markets are always coupled.

[26] In the sensitivity analysis conducted in Section 6, we consider lower demand growth rates, and higher and lower marginal costs for gas-fired generation relative to the *PNIEC* scenario.

Table 3: Simulation Scenarios

	Almaraz's Closure	Annual Demand Growth	Gas Price	CO_2 Price	Renewables and Storage (since 2024)
Baselines					
PNIEC: Closure 2027 + 100% inv.	2027	6,76%	30 €/MWh	80 €/Ton	100% *PNIEC*
Feasible: Closure 2027 + 100% inv.	2027	2,7% (realized in 2025); 4% (2026-2031)	30 €/MWh	80 €/Ton	100% *Feasible*
Counterfactuals					
Closure 2030 + 100% Baseline inv.	2030				100% Baseline
Closure 2030 + 75% Baseline inv.	2030				75% Baseline
Closure 2030 + 50% Baseline inv.	2030				50% Baseline
Sensitivity					
Medium demand growth		3,38%			
Low demand growth		1,69%			
High marginal costs (gas)			50 €/MWh	80 €/Ton	
Low marginal costs (gas)			30 €/MWh	60 €/Ton	
Delayed closure of Ascó I and Cofrentes					

Notes: This table summarizes the assumptions underlying the two baselines considered and the counterfactual scenarios, as well as the sensitivity analyses. The installed capacity targets are reported in Table 1. Blank entries indicate that the corresponding assumption is unchanged relative to the baseline. All scenarios, except for the last, keep the shutdown schedule for the other reactors unchanged.

5 Simulation Results

5.1 Effects on Electricity Prices

Figure 6 reports simulated annual average wholesale electricity prices for 2028–2031 under the *PNIEC* and *Feasible* baselines and under counterfactual scenarios in which the closure of Almaraz is delayed until 2030. These counterfactuals differ in the assumed impact of the delay on the trajectory of renewable and storage deployment. Table 4 reports the corresponding price effects (in percent) relative to the two baselines.

When the delayed closure is assumed not to affect renewable and storage investment (i.e., deployment still reaches 100% of the baseline targets), wholesale prices fall (by about 4–8% using the *PNIEC* baseline, or by about 5–11% using the *Feasible* baseline). These price declines are mechanically driven by the additional low-marginal-cost nuclear output, which relaxes scarcity and reduces the frequency with which gas-fired plants set the marginal price —as illustrated in panel (a) of Figure 4.

The ranking reverses, however, once the delay is assumed to crowd out clean investment. A reduction in deployment to 75% of the 2030 targets is already sufficient to overturn the baseline effect. Under the *PNIEC* baseline, prices rise by roughly 4,5–7,2% in 2028–2030 and by 11,1% in 2031; under the *Feasible* baseline, prices increase by 2,4% in 2028, 2% in 2030, and 9,4% in 2031, but fall by 1,5% in 2029. The price increases become progressively larger as the investment shortfall deepens to 50% target achievement.

In sum, under both baselines, the qualitative predictions are the same: delaying the phase-out lowers prices through the static effect, but prices can increase once the investment response is sufficiently strong. Nonetheless, there are slight differences in the quantitative predictions under the *PNIEC* and *Feasible* baselines, both in price levels (which mechanically affect percentage changes) and in investment targets (which shape how consequential a given investment shortfall is). In particular, under the *Feasible* baseline, the early closure of Almaraz tends to generate larger price reductions and smaller price increases than under *PNIEC*, because baseline prices are lower and the implied investment contraction is less pronounced.

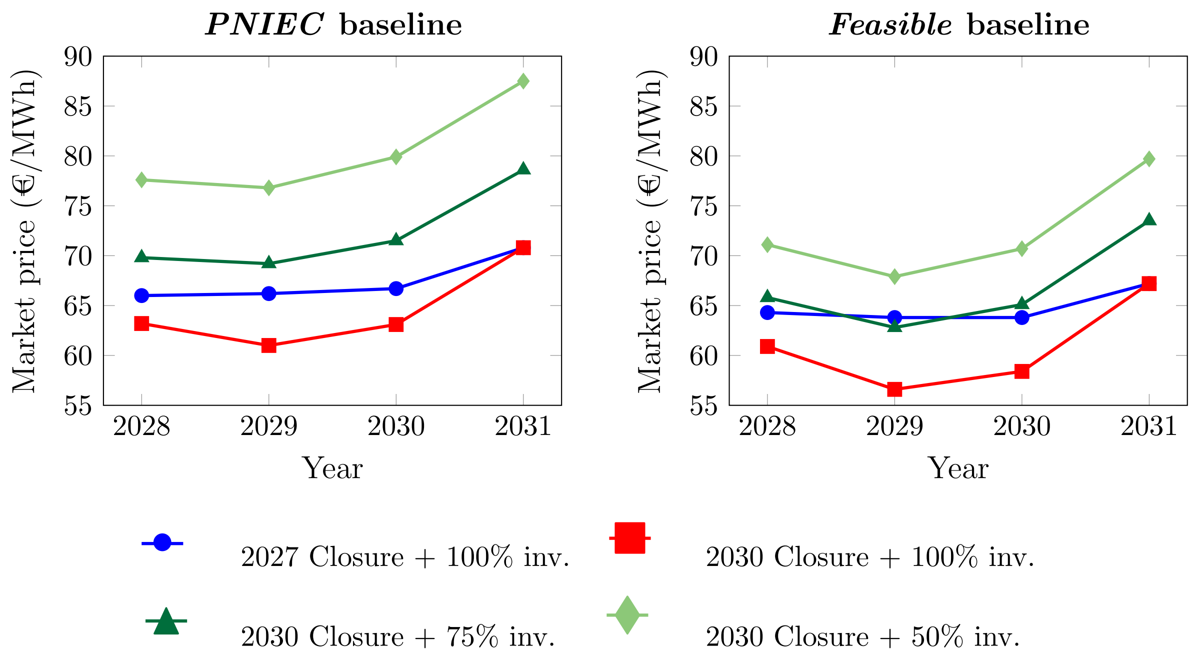


Figure 6: Evolution of annual average wholesale electricity prices under the *PNIEC* baseline (left) and the *Feasible* baseline (right), 2028–2031.

Notes: These figures report annual average wholesale electricity prices under the *PNIEC* baseline (left panels) and *Feasible* baseline (right panels). Table A.1 in the Appendix reports the actual price figures.

Table 4: Price effects of delaying the nuclear phase-out (%)

	Market prices (%)			
	2028	**2029**	**2030**	**2031**
***PNIEC* baseline**				
Closure 2030 + 100% inv.	-4,27%	-7,99%	-5,38%	—
Closure 2030 + 75% inv.	5,76%	4,48%	7,24%	11,11%
Closure 2030 + 50% inv.	17,63%	15,97%	19,70%	23,60%
***Feasible* baseline**				
Closure 2030 + 100% inv.	-5,20%	-11,30%	-8,40%	—
Closure 2030 + 75% inv.	2,38%	-1,55%	1,98%	9,40%
Closure 2030 + 50% inv.	10,61%	6,52%	10,86%	18,64%

Notes: Percentage effects are computed relative to the baseline in each panel. Dashes indicate years in which market prices coincide with the corresponding baseline. Table A.1 in the Appendix reports the actual price figures.

5.2 Effects on Renewable Energies

Figure 7 provides evidence consistent with the concern that delaying Almaraz's closure could affect investment incentives for renewable energies. The figure reports technology-specific captured prices for solar and wind using both the *PNIEC* as well as the *Feasible* baselines. Under the counterfactual in which the delayed closure does not affect the deployment path (i.e., renewable and storage investment still follows the baseline trajectory), captured prices decline relative to the *PNIEC* baseline by about 12–18% for solar, and 5–9% for wind; the price declines relative to the *Feasible* baseline are even more pronounced, reaching 22% for solar and 13% for wind. Cutting down on investments would restore their profitability.

For solar, captured prices are already low along the baseline paths and fall further to roughly 20-22 €/MWh during the years in which Almaraz remains online, potentially below the levels required for profitable new investment, especially for projects with substantial merchant exposure. Captured prices recover only once Almaraz is assumed to close, rising to around 25-30 €/MWh by 2031 under the baseline scenarios (when Almaraz, Ascó I, and Cofrentes have closed down). Wind captured prices are substantially higher —around 55-70 €/MWh during 2028–2030 in the delayed-closure scenarios, also below the captured prices under the planned closure scenarios.

Table 5: Effects of the delayed closure on solar and wind market profits per MW

	Solar prices (%)				**Wind prices (%)**			
	2028	**2029**	**2030**	**2031**	**2028**	**2029**	**2030**	**2031**
***PNIEC* baseline**								
Closure 2030 + 100% inv.	-12%	-18%	-13%	—	-5%	-9%	-6%	—
Closure 2030 + 75% inv.	26%	24%	32%	49%	5%	4%	7%	10%
Closure 2030 + 50% inv.	87%	70%	93%	121%	17%	16%	19%	21%
***Feasible* baseline**								
Closure 2030 + 100% inv.	-14%	-22%	-16%	—	-6%	-13%	-9%	—
Closure 2030 + 75% inv.	15%	10%	16%	42%	2%	-3%	1%	9%
Closure 2030 + 50% inv.	52%	41%	57%	93%	10%	5%	10%	17%

Notes: The table reports percentage changes in market revenues per unit of installed solar and wind capacity relative to the corresponding baseline in each panel. Dashes indicate that the outcome coincides with the baseline. Tables A.2 and A.3 in the Appendix report the actual price figures under both baselines.

Beyond the effects on wholesale prices, delaying the closure of Almaraz has substantial implications for renewable curtailment —particularly for those plants located near the nuclear power plant. Under the counterfactual in which renewable and storage deployment still reaches 100% of *PNIEC* targets, curtailment increases sharply —by 28%, 52%, and 62% in 2028, 2029, and 2030, respectively. Using the *Feasible* baseline, curtailment increases even more so —by 31%, 58%, and 58% in 2028, 2029, and 2030, respectively. Curtailment declines only when the clean-capacity build-out is scaled back.

Higher curtailment reduces realized renewable output and captured revenues, thereby amplifying the profitability pressures already induced by lower market prices. Indeed, as shown in Table 5, the combined effects of reduced captured prices plus increased curtailment unambiguously give rise to reduced profitability, providing additional support to the concern that a delayed nuclear phase-out could translate into slower renewable and storage deployment

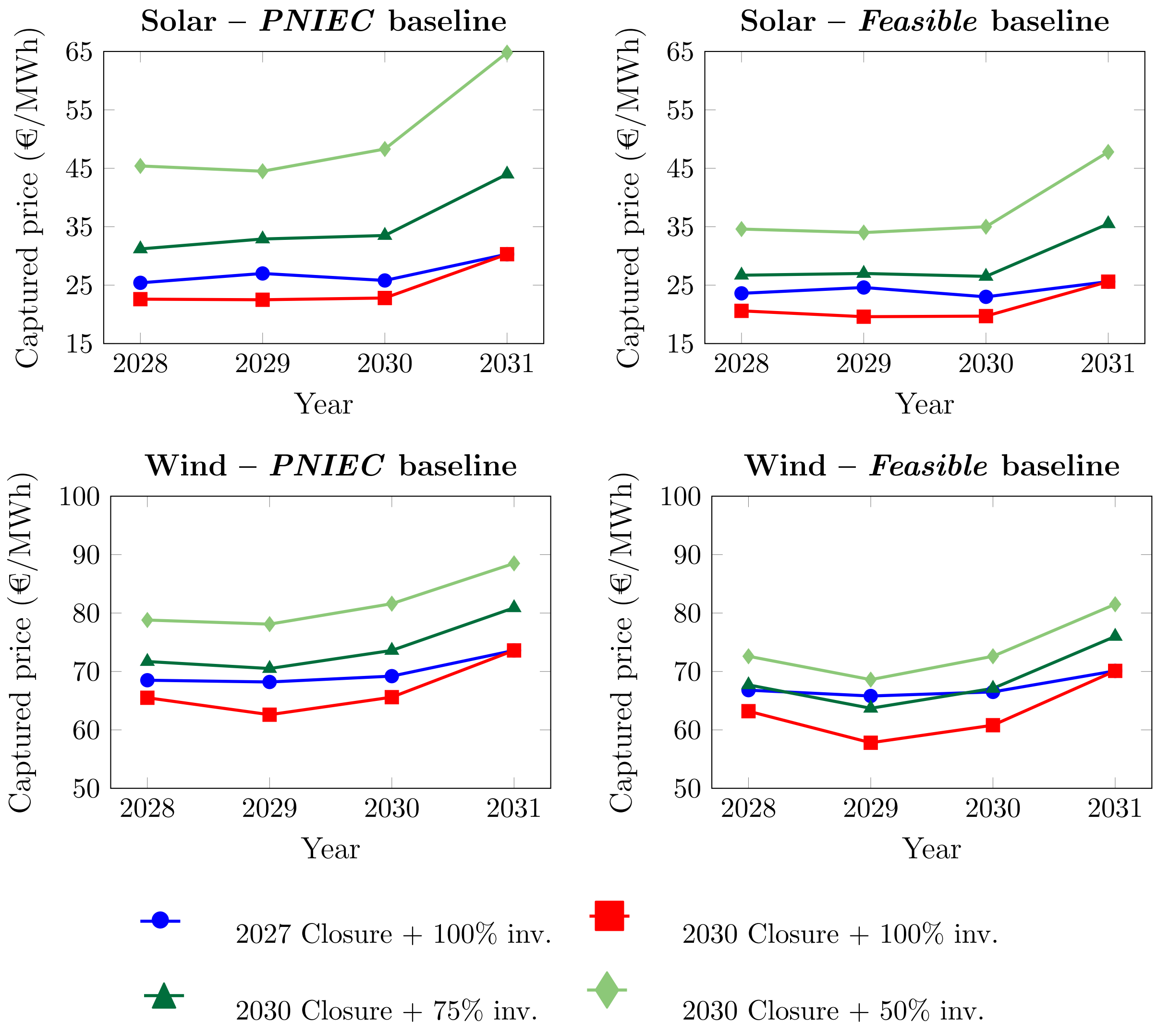


Figure 7: Evolution of captured prices for solar and wind under PNIEC and feasible-investment baselines, 2028–2031.

Notes: These figures report the captured prices by solar (upper panels) and wind (lower panels) under the *PNIEC* baseline (left panels) and the *Feasible* baseline (right panels). Table A.2 in the Appendix reports the actual price figures.

5.3 Effects on Energy Storage

The results regarding renewable curtailment help explain why a delayed nuclear phase-out can be beneficial for storage when renewable investments are preserved, or detrimental otherwise.

Two mechanisms initially operate in opposite directions. Under the scenario in which the baseline deployment targets are fully met, keeping Almaraz online tends to compress intraday price spreads by reducing the number of high-priced hours as gas-fired units are displaced from the margin. Consequently, the price differentials available for arbitrage fall.[27] However, this reduction in spreads is more than offset by the increase in the storage capacity factor, consistent with higher volumes of excess renewable output available for charging when Almaraz remains in operation. Overall, as reported in Table 6, storage profits rise (by 1,5–3,6% under the *PNIEC* baseline and 2,1–3,4% under the *Feasible* baseline), indicating that the utilization effect dominates despite some margin compression.

However, when renewable and storage deployment falls short of the baseline targets, the ranking of these effects reverses. With fewer renewables, storage cycles less frequently and the capacity factor declines sharply, while arbitrage spreads increase only modestly (or not enough to compensate). Storage profitability therefore falls under the 75% deployment scenario, and by progressively larger amounts as investment is reduced further (Table A.4).

These dynamics become more pronounced after 2030, once Almaraz closes (along with Ascó I and Cofrentes). In low-renewables scenarios, renewables are less frequently price-setting, so low-price hours become scarcer: the price floor rises, intraday spreads compress, and storage profitability deteriorates beyond what is implied by lower utilization alone. For example, under an investment freeze, arbitrage price differences in 2031 fall by 11,6% and the storage capacity factor drops by 82,8%; together, these effects translate into a roughly 90% decline in storage profits relative to the baseline with a 2027 closure.

These patterns highlight that a key determinant of storage profitability is the availability of low-cost renewable electricity (Andres-Cerezo and Fabra, 2025): if delaying nuclear retirement weakens incentives to invest in renewables, it can indirectly depress incentives to invest in storage. In that case, capacity payments for storage would need to increase substantially to offset the loss in market-based revenues.

5.4 Effects on Carbon Emissions

Table 7 reports the implications of delaying the closure of Almaraz for power-sector carbon emissions. Mirroring the price results, when the delay does not affect the renew-

[27] Table A.4 in the Appendix decomposes the effects on storage market profits under the *PNIEC* baseline.

Table 6: Effects of the delayed closure on storage market profits (%)

	Storage market profits (%)			
	2028	**2029**	**2030**	**2031**
***PNIEC* baseline**				
Closure 2030 + 100% inv.	3,57%	3,30%	1,47%	—
Closure 2030 + 75% inv.	-8,37%	0,37%	-3,16%	-18,69%
Closure 2030 + 50% inv.	-29,42%	-10,86%	-19,73%	-46,44%
***Feasible* baseline**				
Closure 2030 + 100% inv.	3,39%	2,14%	-0,11%	—
Closure 2030 + 75% inv.	-1,71%	3,38%	2,21%	-8,91%
Closure 2030 + 50% inv.	-11,03%	7,55%	-2,44%	-20,71%

Notes: Entries report changes in market profits made by storage units relative to the corresponding baseline in each panel. Dashes indicate that the outcome coincides with the baseline.

able and storage deployment path (i.e., investment still reaches 100% of baseline targets), total emissions fall because additional nuclear output displaces gas-fired generation at the margin. In this case, emissions decline relative to both baselines, as reported in Table 7.

The picture changes once the delayed phase-out weakens investment incentives and part of the planned renewable and storage build-out fails to materialize. With a moderate shortfall —achieving 75% of the targets— emissions rise relative to the *PNIEC* baseline: by about 5% in 2028, are essentially unchanged in 2029, and increase by roughly 8% in 2030. Under the *Feasible* baseline, instead, emissions reductions still obtain in 2028–2030 even when only 75% of the *Feasible* targets are met, because these targets are less ambitious and a 25% shortfall implies a smaller absolute reduction in renewable and storage deployment. Larger investment shortfalls, however, lead to emissions increases also under the *Feasible* baseline, as reported in Table 7.

Under both baselines, the increases in emissions persist beyond the period in which Almaraz remains online. Once the plant closes, the system is left with a smaller carbon-free capacity stock, which raises reliance on gas-fired generation and leads to a substantial rebound in emissions. In 2031, emissions are 24% (under the *PNIEC* baseline) or 17% (under the *Feasible* baseline) higher than in the no-delay baseline under the 75% deployment scenario. These results underscore that the net climate impact of extending nuclear operation depends critically on its interaction with the pace of clean-capacity deployment.

Table 7: Effects under the *PNIEC* and *Feasible* baselines (%)

	Emissions (%)			
	2028	**2029**	**2030**	**2031**
***PNIEC* baseline**				
Closure 2030+ 100% inv.	-15,55%	-20,17%	-13,89%	—
Closure 2030+75% inv.	5,01%	-0,38%	8,27%	24,34%
Closure 2030+50% inv.	29,41%	25,33%	35,52%	53,69%
***Feasible* baseline**				
Closure 2030+100% inv.	-18,48%	-23,42%	-16,41%	—
Closure 2030+75% inv.	-5,08%	-11,58%	-2,19%	16,92%
Closure 2030+50% inv.	9,26%	2,77%	14,66%	37,23%

Notes: This table reports changes in power-sector emissions between each baseline and the corresponding closure scenarios. Dashes indicate that the outcome coincides with the baseline.

6 Sensitivity Analysis

To assess robustness, this section presents sensitivity analyses that examine how extending Almaraz's lifetime interacts with alternative trajectories for Spanish electricity demand and with uncertainty in fuel-market conditions. We also consider a broader nuclear phase-out delay —postponing not only Almaraz, but also Ascó I and Cofrentes, which are currently scheduled to close by 2030.[28]

6.1 Electricity Demand Growth

Future electricity demand is subject to substantial uncertainty due to several interacting structural and policy-driven factors. First, the pace and scale of electrification of final energy uses —particularly in transport, residential heating, and parts of industry— remain highly uncertain. While policy targets foresee rapid penetration of electric vehicles, heat pumps, and electrified industrial processes, actual adoption depends on technology costs, infrastructure deployment, consumer behavior, and regulatory stability.

Second, electricity demand growth is closely linked to overall economic activity, which is itself uncertain in the medium to long run. Spain's economic growth prospects are exposed to global macroeconomic conditions, fiscal consolidation paths, and sectoral transformations, particularly in tourism, manufacturing, and energy-intensive industries. These factors directly affect both aggregate electricity consumption and load profiles.

Third, energy efficiency improvements introduce additional ambiguity. Continued efficiency gains in appliances, buildings, and industrial processes may partially or fully

[28] For brevity, we report results under the *PNIEC* baseline; the corresponding analyses under the *Feasible* baseline lead to similar qualitative conclusions.

offset demand increases from electrification. However, the magnitude and timing of these efficiency gains depend on building renovation rates, enforcement of efficiency standards, and technological progress, all of which are difficult to forecast.

Fourth, climate and weather variability add further uncertainty to electricity demand. Rising temperatures and more frequent extreme weather events increase cooling demand, while milder winters may reduce heating needs. At the same time, year-to-year weather fluctuations affect peak demand levels, which are particularly relevant for system adequacy assessments.

Finally, policy and regulatory uncertainty play a central role. Changes in support policies for electrification can significantly alter consumption incentives. In addition, the interaction between electricity demand and the deployment of distributed generation, self-consumption, and storage remains uncertain and may reduce net demand from the grid, as has been the case in recent years.

Taken together, these factors imply that long-term electricity demand projections for Spain should be interpreted with caution and motivate the use of alternative demand growth scenarios in quantitative analyses. For this reason, and considering that the *PNIEC* demand projections are very ambitious, we have assumed alternative scenarios in which electricity demand grows at either half or one fourth of the *PNIEC*-implied rate, corresponding to annual growth rates of 3,38% and 1,69%, respectively.

Results. The qualitative conclusions regarding the price effects of delaying Almaraz are unchanged. As expected, lower demand growth reduces the level of wholesale prices in all scenarios. However, conditional on a given demand path, the differences across the baseline and the closure scenarios remain of similar magnitude.

Figure 8 illustrates this pattern by reporting annual average prices for 2028–2031 under the three demand-growth assumptions.[29] In every year, delaying the closure while maintaining the *PNIEC* investment trajectory lowers prices relative to the baseline phase-out schedule. By contrast, if the delay is accompanied by an investment shortfall — illustrated by the 75% *PNIEC* deployment case— prices are higher than in the baseline. Across demand scenarios, the size of these effects is comparable to the percentage changes reported in Figure 6 and its demand-sensitivity counterpart, indicating that our main conclusions are robust to slower electrification dynamics.

Nevertheless, a key distinction across demand-growth scenarios concerns the captured prices of renewables. Under more conservative demand trajectories, captured prices decline substantially and can fall below plausible break-even levels, thereby weakening investment incentives. For example, in the 100% investment scenario, solar captured prices drop to roughly 10,6–12,4 €/MWh under the medium-demand-growth assumption and further to about 7,4–8,6 €/MWh under low demand growth. These results reinforce

[29]For completeness, all the prices for all scenarios are reported in Tables A.5 and A.6 of the Appendix.

the notion that, when demand growth is weaker than implied by the *PNIEC*, delaying the closure of Almaraz can substantially exacerbate already thin renewable profitability, potentially making continued investment in new renewable capacity unsustainable.

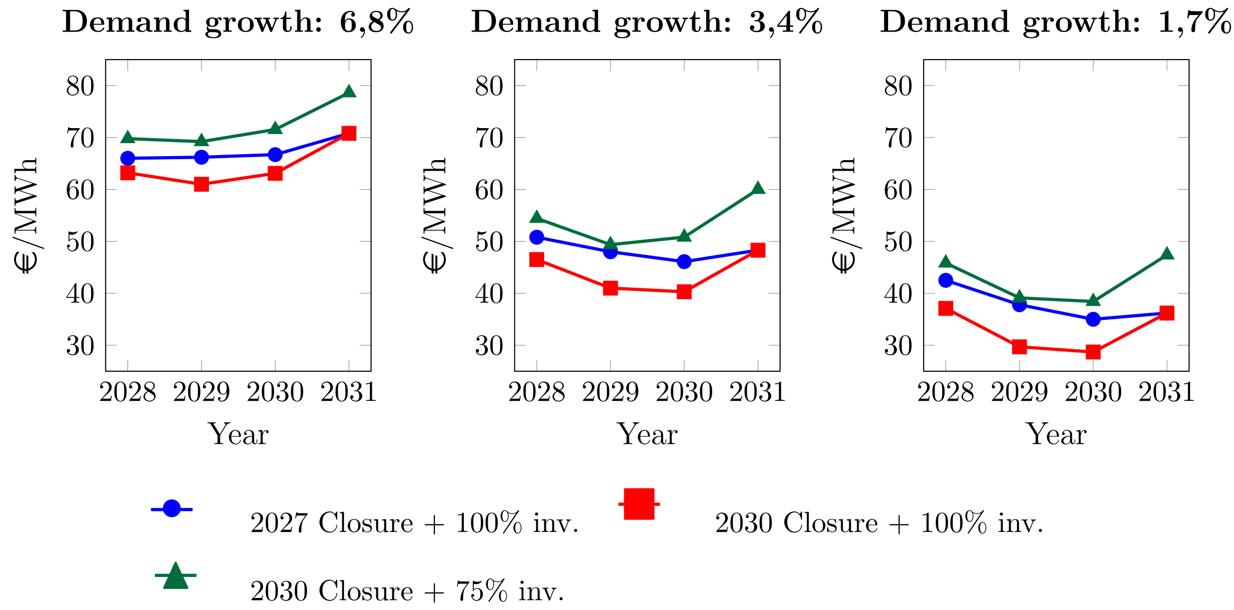


Figure 8: Annual average wholesale electricity prices across demand-growth assumptions and *PNIEC* investment scenarios, 2028–2031.

Notes: The figures report annual average wholesale electricity prices under three electricity-demand trajectories: the baseline demand path (6,8% annual growth), a medium-growth scenario (3,4%), and a low-growth scenario (1,7%). For each demand trajectory, results are shown for the *PNIEC* baseline (dark blue) and for the counterfactual delayed-closure scenarios with either 100% (medium blue) or 75% (light blue) of the *PNIEC* investment targets.

6.2 Gas and CO_2 Prices

Wholesale electricity prices are still strongly influenced by natural gas and CO_2 prices, as these jointly determine the marginal cost of gas-fired generation. Gas plants continue to set the market-clearing price in many hours, even as renewable penetration increases, because they often provide the residual supply and flexibility required to balance the system. While prevailing gas and CO_2 prices are broadly consistent with the assumptions in our baseline scenario, substantial uncertainty remains over their future trajectories.

On the gas side, European prices remain sensitive to global LNG market conditions — new liquefaction capacity coming online, Asian demand growth, and potential shipping or infrastructure disruptions— as well as to weather-driven variability in heating and power demand (itself affected by the degree of renewable energy penetration), storage levels, and geopolitical risks affecting pipeline flows or LNG supply routes.

On the CO2 side, EUA prices depend on EU ETS policy and market fundamentals: reforms that tighten or loosen the cap, changes to the Market Stability Reserve, the pace of coal-to-gas switching and renewable deployment, and macroeconomic conditions that affect industrial output and emissions. Uncertainty around electrification, hydrogen uptake, and the cost/availability of abatement technologies can further alter allowance demand.

We therefore assess the sensitivity of our results to alternative assumptions for gas and CO_2 prices. Specifically, we consider (i) a *high-cost* scenario in which the marginal cost of gas-fired generation increases due to a higher gas price (50 €/MWh instead of 30 €/MWh in the baseline), and (ii) a *low-cost* scenario in which the marginal cost of gas-fired generation decreases due to a lower CO_2 price (60 €/tCO_2 instead of 80 €/tCO_2 in the baseline).

Results. Figure 9 illustrates the effects of delaying the closure of Almaraz under these alternative marginal cost assumptions for gas-fired generation.[30] As expected, wholesale prices are higher when gas-fired marginal costs are high and lower when they are low. Importantly, however, the relative price differences between the planned closure versus the Almaraz-delayed closure scenarios are broadly preserved: changing the gas marginal cost mainly shifts the overall price level rather than altering the ranking of scenarios.

The main margin through which the gas-cost environment matters is the profitability of renewables, as reflected in their captured prices. As argued above, the delayed closure becomes more consequential when renewable profitability is already tight. This is precisely the case in the low gas marginal cost scenario (here driven by a lower CO_2 price), where the delayed closure combined with full *PNIEC* deployment pushes solar captured prices down to around 21 €/MWh. By contrast, in the high gas marginal cost scenario (here driven by a higher gas price), captured prices for solar remain materially higher —around 27–28 €/MWh even under delayed closure with 100% achievement of *PNIEC* investment targets— making the extension less problematic from an investment-incentives perspective.

However, it is unlikely that high renewable penetration is associated with higher gas marginal costs in equilibrium: as renewables and storage expand, they reduce gas burn and emissions, which tends to weaken demand for gas and EU ETS allowances and, in turn, depress both gas and CO_2 prices absent major external supply disruptions. This consideration suggests that the low gas marginal cost environment may be particularly relevant when assessing the interaction between a delayed nuclear phase-out and renewable investment incentives in high renewable energy penetration scenarios.

[30] For completeness, Tables A.7 and A.8 in the Appendix report all the prices under the scenarios with low and high marginal cost of gas-fired generation.

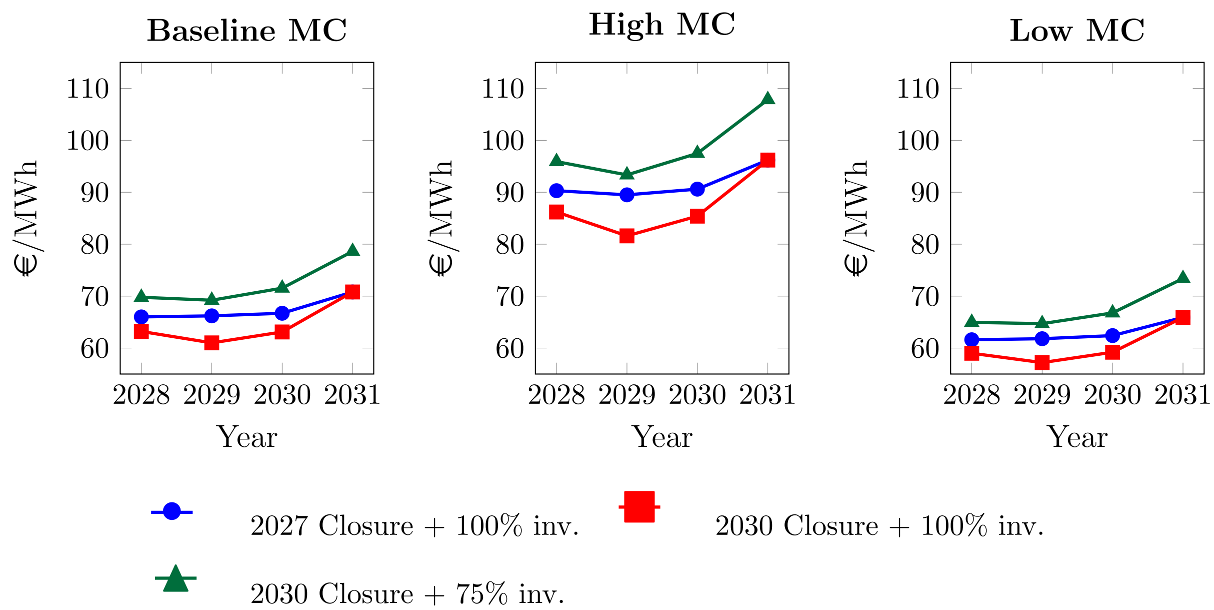


Figure 9: Annual average wholesale electricity prices under alternative gas and CO_2 price assumptions, 2028–2031.

Notes: The figures report annual average wholesale electricity prices under the baseline assumptions, a high-gas-price scenario with a gas price of 50 €/MWh instead of 30 €/MWh (resulting in a high marginal cost of gas-fired generation), and a low-CO_2-price scenario with an EU ETS allowance price of 60 €/tCO_2 instead of 80 €/tCO_2 (resulting in a low marginal cost). For each marginal cost scenario, results are shown for the *PNIEC* baseline (blue) and for the counterfactual delayed-closure scenarios with either 100% (red) or 75% (dark green) of the *PNIEC* investment targets.

6.3 Beyond Almaraz: Delayed Nuclear Phase-Out

One additional concern with delaying the closure of Almaraz is that it may undermine the credibility of the entire nuclear phase-out calendar. In particular, a revision of the 2027 Almaraz's deadline could raise expectations that the closures of Ascó I and Cofrentes —also scheduled for 2030— might be postponed as well, especially given the operational and political difficulty of managing the simultaneous retirement of four reactors in the same year. Such a shift would extend the period of additional low-marginal-cost nuclear supply beyond 2031, further depressing wholesale prices and captured revenues, and thereby deepening the scale-back in renewable and storage investment incentives.

These effects were not incorporated in our main analysis, which considered the delayed closure of Almaraz in isolation. In this section, we have extended the simulations for 2031 under scenarios in which Ascó I and Cofrentes have not yet retired. We compare these outcomes to the corresponding *PNIEC* and *Feasible* baselines, where Ascó I and Cofrentes do retire in 2030 and are therefore not available in 2031.

Table 8 reports expected wholesale prices in 2031 under alternative assumptions about whether Ascó I and Cofrentes retire as scheduled or remain online, allowing for the associated reduction in renewable and storage investment. Consistent with our main results, we find a static effect: if investment is unaffected, keeping the reactors online lowers prices by about 4–6%. Once investment responds, however, a dynamic effect emerges: prices increase by roughly 4–7% when 25% of baseline investment fails to materialize, and by about 13–20% when the shortfall rises to 50%. The effects on all other metrics are similar to the ones reported in the main analysis.

Table 8: 2031 Wholesale electricity prices if the closures of Ascó I and Cofrentes are also delayed beyond 2030

	2031 Prices (€/MWh)	
	***PNIEC* baseline**	***Feasible* baseline**
Ascó & Cofrentes offline + 100% inv.	70,8	67,2
Ascó & Cofrentes online + 100% inv.	67,7	63,2
Ascó & Cofrentes online + 75% inv.	75,7	69,7
Ascó & Cofrentes online + 50% inv.	84,7	75,9
Price effects of keeping Ascó and Cofrentes online (%)		
Ascó & Cofrentes online + 100% inv.	-4,41%	-5,91%
Ascó & Cofrentes online + 75% inv.	6,85%	3,71%
Ascó & Cofrentes online + 50% inv.	19,60%	12,90%

Notes: The upper panel reports annual average wholesale electricity prices in 2031 under the *PNIEC* and Feasible baselines. The lower panel reports percentage effects relative to the corresponding baseline with Ascó I and Cofrentes *offline*.

7 Conclusions

Spain's National Energy and Climate Plan (*PNIEC*) envisaged a coordinated energy transition, involving a gradual phase-out of coal and nuclear generation alongside the expansion of renewable capacity and energy storage. Under this design, new renewables and storage would progressively displace thermal generation, providing the flexibility required to accommodate electrification-driven demand growth. By 2030, coal would be fully phased out, roughly half of the nuclear fleet would remain in operation, and renewables would account for about 81% of total electricity generation, which would rise substantially to meet economy-wide decarbonization objectives.

As the scheduled retirement of the first nuclear units approaches —most notably, the agreed shutdown of Almaraz, starting in 2027— the plant's owners have requested an extension of operations until 2030. This request has reopened the policy debate on the role of nuclear power in the transition and, in particular, on the market and emissions consequences of a delayed nuclear phase-out, including the knock-on effects on other clean generation technologies.

This paper has used detailed electricity-market simulations to quantify the impacts of delaying the phase-out of Almaraz from 2027 to 2030 over the 2028–2031 period on three key outcomes: wholesale electricity prices; the profitability conditions for renewable energies and energy storage; and power-sector CO_2 emissions.

A central message of the paper is that the nuclear retirement decision cannot be evaluated in a purely static manner. While extending Almaraz would mechanically add low-cost supply —reducing prices and emissions by displacing gas— it can also depress renewables' captured prices and raise curtailment, weakening incentives to invest in renewables and, as a consequence, storage. If this investment response is large enough, the static price and emissions gains can reverse, and a delayed phase-out may ultimately lead to higher prices and higher emissions.

Determining the endogenous investment response is challenging, not least because it may depend not only on profitability but also on expectations about future prices — expectations that could themselves be undermined by the decision to delay the nuclear phase-out. As a consequence, the risk premia required by investors in renewables and energy storage might go up and, thus, raise financing costs, adding another channel for the potential slowdown of the clean-capacity deployment.

To obtain some orders of magnitude of the investment-response channel, we have computed the effects on prices and emissions under a range of plausible investment responses. Our simulations indicate that if the delayed closure reduces renewable and storage deployment by 25% relative to the *PNIEC* path —so that only 75% of the 2030 targets are achieved— average wholesale electricity prices increase by roughly 4,5–7,2% in 2028–2030 and by about 11,1% in 2031. Power-sector emissions rise by around 5% in 2028 and about 8% in 2030, with a pronounced rebound thereafter: emissions in 2031 are approximately 24% above the no-delay baseline once Almaraz closes and the system operates with a reduced clean-capacity stock. Using the *Feasible* 2030 baseline —based on less ambitious targets than the *PNIEC*— yields slightly more muted effects, but the qualitative conclusions remain broadly unchanged.

These conclusions are robust to alternative demand trajectories and to plausible variation in the marginal cost of gas-fired generation, driven by different realizations of gas prices and EU ETS allowance prices. They also remain robust when considering scenarios in which delaying Almaraz's closure triggers delays in the retirement of the next two reactors scheduled to shut down, Ascó I and Cofrentes.

Overall, the results underscore that the net consequences of extending nuclear operations depend critically on the response of the clean-capacity deployment. Policies that delay the nuclear phase-out may lower prices and emissions in the short run, but they can also slow the renewable and storage build-out and, thereby, worsen market outcomes and emissions in subsequent years.

The impact of the nuclear phase-out on security of supply is beyond the scope of this paper. However, it is relevant to remark that Spain has a large fleet of combined-cycle gas turbines (CCGTs) operating at low capacity factors:[31] there are 26 GW of CCGT capacity in Spain (or 24,5 in Peninsular Spain) —almost four times the existing nuclear fleet— providing ample flexibility to absorb any unreplaced nuclear output as well as future increases in electricity demand. In none of the simulations reported in this paper is there a shortage of generation capacity to meet demand.[32]

A decision on whether to allow extended nuclear lifetimes also has broader economic implications beyond the wholesale-price and emissions effects quantified here. Persistent changes in electricity prices and price volatility affect firms' input costs and investment incentives —particularly in electricity-intensive industries— and, through supply-chain linkages, the wider economy. These effects impact their competitiveness, influence output and employment in industrial clusters, and shape the attractiveness of Spain as a destination for investment in low-carbon technologies and in electrification-dependent activities (e.g., data centers, electrified industrial processes, and green hydrogen production), for which abundant low-cost clean electricity is increasingly a key locational factor. Quantifying these broader macroeconomic and distributional effects is beyond the scope of this paper, but they underscore the importance of assessing nuclear lifetime decisions using more than the static partial-equilibrium lenses that often dominate the public discourse.

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[31] In 2024, the average capacity factor of CCGTs was 15.5%. Peak demand occurred on 9 January at 9 p.m., reaching 38,3 GW. At that time, CCGTs were generating 14 GW, implying around 12 GW of spare CCGT capacity.

[32] Security-of-supply concerns could arise for other reasons, such as voltage and frequency control. However, as the blackout of April 28, 2025, showed, CCGTs are particularly well suited to addressing these issues.

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Online Appendix

A Additional Results and Details

Table A.1: Wholesale electricity prices under the *PNIEC* and *Feasible* baselines

	Market prices (€/MWh)			
	2028	**2029**	**2030**	**2031**
***PNIEC* baseline**				
Closure 2027 + 100% inv.	66,0	66,2	66,7	70,8
Closure 2030 + 100% inv.	63,2	61,0	63,1	70,8
Closure 2030 + 75% inv.	69,8	69,2	71,5	78,6
Closure 2030 + 50% inv.	77,6	76,8	79,9	87,5
***Feasible* baseline**				
Closure 2027 + 100% inv.	64,3	63,8	63,8	67,2
Closure 2030 + 100% inv.	60,9	56,6	58,4	67,2
Closure 2030 + 75% inv.	65,8	62,8	65,1	73,5
Closure 2030 + 50% inv.	71,1	67,9	70,7	79,7

Notes: The table reports annual average wholesale electricity prices (€/MWh) under the two baselines.

Table A.2: Captured prices by solar and wind under the *PNIEC* baseline and counterfactual scenarios

	Captured prices by solar (€/MWh)			
***PNIEC* baseline**	**2028**	**2029**	**2030**	**2031**
Closure 2027 + 100% inv.	25,4	27,0	25,8	30,3
Closure 2030 + 100% inv.	22,6	22,5	22,8	30,3
Closure 2030 + 75% inv.	31,2	32,9	33,5	44,0
Closure 2030 + 50% inv.	45,4	44,5	48,3	64,8
	Captured prices by wind (€/MWh)			
Closure 2027 + 100% inv.	68,5	68,2	69,2	73,6
Closure 2030 + 100% inv.	65,5	62,6	65,6	73,6
Closure 2030 + 75% inv.	71,7	70,5	73,6	80,9
Closure 2030 + 50% inv.	78,8	78,1	81,6	88,5

Notes: The table reports annual average captured prices (€/MWh) for solar PV (upper panel) and wind (lower panel) in the wholesale electricity market under the baseline *PNIEC* scenario and the counterfactual delayed-closure scenarios.

Table A.3: Captured prices by solar and wind under the *Feasible* baseline and counterfactual scenarios

	Captured prices by solar (€/MWh)			
Feasible Baseline	**2028**	**2029**	**2030**	**2031**
Closure 2027 + inv.	23,6	24,6	23,0	25,6
Closure 2030 + 100% inv.	20,6	19,6	19,7	25,6
Closure 2030 + 75% inv.	26,7	27,0	26,5	35,5
Closure 2030 + 50% inv.	34,6	34,0	35,0	47,8
	Captured prices by wind (€/MWh)			
Closure 2027 + inv.	66,8	65,8	66,5	70,1
Closure 2030 + 100% inv.	63,2	57,8	60,8	70,1
Closure 2030 + 75% inv.	67,7	63,7	67,1	76,0
Closure 2030 + 50% inv.	72,6	68,6	72,6	81,5

Notes: The table reports annual average captured prices (€/MWh) for solar PV (upper panel) and wind (lower panel) in the wholesale electricity market under the baseline *Feasible* scenario and the counterfactual delayed-closure scenarios.

Table A.4: Changes in storage outcomes under alternative *PNIEC* investment scenarios

	Change in storage profits (%)			
Baseline: PNIEC	**2028**	**2029**	**2030**	**2031**
Closure 2030 +100% inv.	3,57	3,30	1,47	—
Closure 2030 +75% inv.	-8,37	0,37	-3,16	-18,69
Closure 2030 +50% inv.	-29,42	-10,86	-19,73	-46,44
	Change in the capacity factor (%)			
Closure 2030 +100% inv.	8,14	7,37	6,77	—
Closure 2030 +75% inv.	-10,41	2,93	-3,24	-17,55
Closure 2030 +50% inv.	-30,09	-11,95	-18,61	-44,57
	Change in arbitrage spreads (%)			
Closure 2030 + 100% inv.	-4,21	-4,55	-5,34	—
Closure 2030 +75% inv.	3,07	-0,44	2,11	1,03
Closure 2030 +50% inv.	3,29	3,84	3,02	1,23

Notes: The top panel reports the change in storage arbitrage profits per MW relative to the *PNIEC* baseline. The decomposition highlights two drivers: the capacity factor (middle panel) and the average arbitrage spread (bottom panel). The capacity factor is computed as total annual energy charged divided by installed capacity. The arbitrage spread is the difference between the discharge-price average and the charge-price average, with each price weighted by the corresponding discharged/charged energy.

Table A.5: Wholesale electricity prices and effects of delaying the closure of Almaraz — Medium Demand Growth (3,4%)

	Market prices (€/MWh)			
	2028	**2029**	**2030**	**2031**
PNIEC Baseline	50.8	48.0	46,1	48,3
Closure 2030 + 100% PNIEC inv.	46,5	41,0	40,3	48,3
Closure 2030 + 75% PNIEC inv.	54,4	49,4	50,8	60,0
Closure 2030 + 50% PNIEC inv.	63,4	59,5	61,3	70,9
	Price effect of the delayed closure (%)			
Closure 2030 + 100% PNIEC inv.	-8,44	-14,52	-12,65	—
Closure 2030 + 75% PNIEC inv.	7,10	2,88	10,29	24,32
Closure 2030 + 50% PNIEC inv.	24,79	24,03	33,09	46,80

Notes: Market prices are annual average wholesale prices assuming an expected demand growth of 3,383% year-on-year, using 2024 actual hourly demand values. Percentage price effects are computed relative to the *PNIEC* baseline with closure according to the original schedule. The effect for 2031 under full *PNIEC* investment is not reported because market prices coincide with the baseline.

Table A.6: Wholesale electricity prices and effects of delaying the closure of Almaraz — Low Demand Growth (1,7%)

	Market prices (€/MWh)			
	2028	**2029**	**2030**	**2031**
PNIEC Baseline	42,5	37,8	35,0	36,2
Closure 2030 + 100% *PNIEC* inv.	37,1	29,7	28,7	36,2
Closure 2030 + 75% *PNIEC* inv.	45,8	39,1	38,4	47,4
Closure 2030 + 50% *PNIEC* inv.	54,0	48,7	49,2	59,7
	Effect of the delay on market prices (%)			
Closure 2030 +100% *PNIEC* inv.	-12,77	-21,49	-18,01	—
Closure 2030 +75% *PNIEC* inv.	7,76	3,41	9,86	30,88
Closure 2030 +50% *PNIEC* inv.	27,02	28,76	40,74	64,87

Notes: The table reports annual average wholesale electricity prices assuming low electricity demand growth (1,69% per year). Percentage effects are computed relative to the *PNIEC* baseline with nuclear phase-out according to the original schedule. Dashes indicate years in which prices coincide with the baseline.

Table A.7: Wholesale electricity prices and effects of delaying the closure of Almaraz — High marginal cost of gas-fired generation

	Market prices (€/MWh)			
	2028	**2029**	**2030**	**2031**
PNIEC Baseline	90,3	89,5	90,6	96,2
Closure 2030 + 100% PNIEC inv.	86,2	81,6	85,4	96,2
Closure 2030 + 75% PNIEC inv.	95,9	93,3	97,5	107,8
Closure 2030 + 50% PNIEC inv.	107,7	105,7	109,8	120,5
	Effect of the delay on market prices (%)			
Closure 2030 +100% *PNIEC* inv.	-4,51	-8,89	-5,79	—
Closure 2030 +75% *PNIEC* inv.	6,46	4,70	8,02	12,07
Closure 2030 +50% *PNIEC* inv.	18,09	17,32	19,68	22,55

Notes: The table reports annual average wholesale electricity prices assuming all the baseline assumptions, except for the price of gas, which is assumed to be 50 €/MWh instead of 30 €/MWh, giving rise to a higher marginal cost of gas-fired generation.

Table A.8: Wholesale electricity prices and effects of delaying the closure of Almaraz — Low marginal cost of gas-fired generation

	Market prices (€/MWh)			
	2028	**2029**	**2030**	**2031**
PNIEC Baseline	61,6	61,8	62,4	65,9
Closure 2030 + 100% *PNIEC* inv.	59,0	57,2	59,2	65,9
Closure 2030 + 75% *PNIEC* inv.	65,0	64,7	66,8	73,4
Closure 2030 + 50% *PNIEC* inv.	72,1	71,4	74,3	81,5
	Effect of the delay on market prices (%)			
100% *PNIEC* inv.	-4,16	-7,35	-5,07	—
75% *PNIEC* inv.	5,71	5,16	7,43	11,40
50% *PNIEC* inv.	16,17	14,93	17,88	21,31

Notes: The table reports annual average wholesale electricity prices assuming all the baseline assumptions, except for the price of $C0_2$, which is assumed to be 60 €/Ton instead of 80 €/Ton, giving rise to a lower marginal cost of gas-fired generation.