Iberian Peninsula Blackout: A Trade-Off Between Operational Risk and Consumer Cost*

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Abstract

Ensuring sufficient energy availability to meet demand—while operating resources within their own physical constraints and those of the grid—is fundamental to the secure and reliable functioning of any power system. Under the European short-term wholesale market design, system operators must reactively adjust (redispatch) market schedules originating from an assumed unconstrained ("copper plate") network. This sequential market-clearing approach can complicate real-time operations and may increase the operational risk. We perform an event study analysis using hourly market and system data from 2019–2025. We find that after the 2025 Iberian Peninsula Blackout the Spanish system operator responded by prioritizing reliability, procuring greater volumes of gas-fired generation and reducing anticipated real-time output from wind and solar resources. However, this more conservative approach to operational risk, focused on ensuring secure and reliable real-time operations, has also led to higher redispatching costs.

Keywords: Congestion Management; Physically Feasible Schedules; Redispatch Market; Renewable Energy Curtailment; System Security

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1 Introduction

Electricity blackouts are rare but potentially catastrophic events, posing serious risks to safety, economic stability, and public trust. At the same time, they offer valuable opportunities to extract lessons and identify systemic weaknesses across the entire power system. In recent years, large-scale outages around the world (Hawker et al., 2024) including prominent ones in the U.S.—such as Winter Storm Uri in Texas (2021)[1] and Winter Storm Elliott in the Eastern U.S. (2022)[2]—have highlighted how extreme weather events can lead to resource adequacy failures, where available generation is insufficient to meet sudden surges in demand.

In contrast, the April 2025 blackout in Spain and Portugal, one of the most significant in recent European history, appears to stem from different causes. Known as the 2025 Iberian Peninsula Blackout, this event has attracted international attention,[3] particularly because Spain is a global leader in the deployment of renewable energy sources (RES), especially wind and solar. While many countries await the full analysis and lessons learned, the official report from the Spanish government points to a chain of events that led to voltage instability, exacerbated by the automatic disconnection of large RES installations (CSN, 2025). Initial findings suggest that, unlike recent blackouts in the U.S. driven by resource adequacy challenges, the Iberian blackout was primarily an operational reliability event.

In this paper, we analyze the Iberian Peninsula Blackout through the lenses of electricity market design.[4] In the current design of the European short-term wholesale electricity market, markets are cleared sequentially: energy is first traded assuming an unconstrained ("copper plate") grid,[5] after which system operators make reactive adjustments—typically through redispatch or congestion management—to ensure secure system operation.[6] In recent years, the growing fre-

[1]See, e.g., `https://www.naesb.org/pdf4/ferc_nerc_regional_entity_staff_report_feb2021_cold_weather_outages_111621.pdf`.

[2]See, e.g., `https://www.ferc.gov/sites/default/files/2024-02/24_Winter-Storm_Elliot_0207_UPDATE.pdf`.

[3]For example, the Federal Energy Regulatory Commission (FERC) in the U.S., discussed the incidence in one of their open meetings, see `https://ferc.gov/news-events/news/presentation-iberian-peninsula-blackout-april-2025`.

[4]The intention of this paper is *not* to blame certain technologies, market participants, system operators, regulators, or other relevant entities but to discuss paths forward to balance operational security against the need to decarbonize the electric system.

[5]Zonal congestion between bidding zones is accounted for but not within bidding zones. With a few exceptions, the bidding zones are mostly defined by national borders, which includes fairly large bidding zones/countries such as Germany, France, or Spain.

[6]The E.U. regulation considers redispatching actions essential to ensure that certain security conditions relevant for

quency of binding system constraints has driven an increase in redispatch volumes across Europe (Bundesnetzagentur, 2024; ACER, 2025b).

In 2024, for instance, the Spanish and German system operators were required to activate 17.1 TWh (6.9% of total electricity demand) and 8.3 TWh (1.9% of total electricity demand) from fossil-fuel generating units through redispatching, respectively. Moreover, in Spain, 10.6 TWh,[7] and in Germany, 5.9, TWh[8] of RES sold in the unconstrained markets had to be curtailed. In 2024, the total redispatching costs in Spain amounted to €2.5B, representing approximately 16% of the annual wholesale energy procurement costs, assuming all real-time market demand was priced at the day-ahead market price.[9]

An analysis of hourly data spanning from January 2019 to June 2025, including market volumes from the day-ahead and intraday segments, redispatching mechanism, and real-time generation aggregated by technology, yields several important findings. First, we find that the current European market design does not provide adequate operational incentives for the generating units that are essential for maintaining secure system operation. For example, in the spring of 2024, one year prior to the Iberian Peninsula Blackout, virtually no combined cycle gas (CC) and coal generation was scheduled in the day-ahead and intraday markets, despite approximately 1.43 GWh and 0.33 GWh operating in real time.[10] Second, the Spanish system operator appears to have responded to the blackout by enhancing system security through increased redispatch of CC and other synchronous generators, while simultaneously reducing scheduled output from RES. This more conservative approach to operational risk has also led to higher redispatching costs in the aftermath of the blackout. Third, we observe a reversal in the temporal pattern of redispatch: the pre-blackout trend toward interventions closer to real time has shifted toward earlier action,

a secure real-time operation of the electric system (thermal transmission limits, voltage, frequency, inertia, and others) are met at all times.

[7] In 2024, the Spanish system operator activated (increased net output) equals to 15.0 TWh from combined cycle gas (CC) and 2.1 TWh from coal. Sold RES in the unconstrained markets that was curtailed in real-time: 6.8 TWh (wind), 2.4 TWh (photovoltaics), and 1.4 TWh (thermosolar). Total electricity demand in Spain was 248 TWh in the same year (REE, 2025c).

[8] German operations data is available from `www.pv-magazine.com/2025/04/03/pv-curtailment-jumps-97-in-germany-in-2024/`. Total electricity demand in Germany was 429 TWh (Bundesnetzagentur, 2025).

[9] The average Spanish day-ahead market price was €63/MWh in 2024 and total real-time market demand was 248 TWh. Aggregate hourly wholesale energy procurement costs, measured as real-time market demand multiplied by the corresponding day-ahead prices, amounted to approximately €16B.

[10] Average scheduled energy from CC and coal in the day-ahead markets was 0.049 GWh and 0 GWh between March and May 2024 (9 a.m. to 8 p.m.). After redispatching by the system operator net schedules were, on average, 1.2 GWh for CC and 0.33 GWh for coal.

with a greater share of redispatch occurring during the day-ahead stage after the blackout. Yet another indication of efforts to reduce operational risks. Finally, a comparative analysis of recent capacity developments in Spain, California, and Texas reveals that, although Spain has significantly expanded RES particularly from solar photovoltaics in recent years, it has seen negligible investment in battery storage. This stands in contrast to the substantial growth in storage capacity observed in both U.S. markets over the same period.

Batlle et al. (2025) discusses the Iberian blackout through the lenses of European institutions. They argue that an institutional unbundling between transmission ownership and system operation would align short-term operational needs with long-term planning goals, and ultimately improve the integration of RES in Europe.

We focus on the role of short-term wholesale markets, showing that the current market design does not provide sufficient operational incentives (mostly because of depressed unconstrained market prices) in line with secure grid operation. For instance, the Spanish government (CSN, 2025) pointed out that the Spanish system operator attempted to start up an additional natural gas power plant on the operating day of the blackout. However, the attempt came too late, as this type of plant requires lead time to become fully capable of supplying energy and grid services. In our analysis, we show that after the blackout, the Spanish system operator increased its focus on operational reliability by dispatching more natural gas units earlier on. An electricity market design that supports secure system operation from the outset—rather than completely relying on system operators to address security reactively—may offer significant benefits, particularly during the energy transition period.

This paper is organized as follows. Section 2 introduces the Spanish short-term wholesale market design, including institutional details and the approach to managing risk to ensure secure real-time system operation. Section 3 describes what is known to date about the 2025 Iberian Peninsular blackout. Section 4 provides descriptive evidence on redispatching actions and costs over time with a focus on pre- and post-blackout periods. Section 5 quantifies the effect of post-blackout redispatching volumes for CC, synchronous generation, and wind and solar photovoltaics, as well as redispatching costs using an econometric analysis. Section 6 concludes.

2 Market Description and Institutional Framework

In this section, we describe the Spanish overall short-term wholesale electricity market design including institutional details. Furthermore, we discuss the role of system operators and their strategies to maintain real-time operational reliability and system security.

In any electricity market the effective competition takes place through the actual, potentially constrained, network (Graf and Wolak, 2024). In the current Spanish overall electricity market design, in line with the simplified European market design, market participant trade energy based on an (unconstrained, "copper plate") "market." However, because market participants' "market" decisions may not be always compatible with a secure operation of the grid, the system operators must reactively adjust those market schedules through what is commonly known as redispatching or congestion mangement.[11] Therefore, the overall short-term wholesale market includes not only the designated day-ahead and intraday markets, but also the redispatching process, which interacts with the former.

2.1 Day-Ahead and Intraday Markets

The Spanish day-ahead and intraday markets are part of the pan-European day-ahead and intraday market framework, where market participants can trade energy day-ahead and on the operating day (intraday) until close-to-real-time. The European market is partitioned into fairly large pre-defined market areas, or bidding zones, which are typically defined by national borders and the whole Spanish peninsula (mainland Spain) is treated as a single bidding zone.[12] In the European market framework energy is traded across Europe accounting only for congestion between bidding zones, but not within bidding zones (ENTSO-E, 2025b,c). Resulting marginal clearing prices in the day-ahead and intraday auction markets are uniform within each bidding

[11] Market participants operating in these markets are likely to understand (or at least be able to predict) the real-time system security needs. If the short-term market design is agnostic toward these realities, it will create incentives to under- or over-sell the output of certain generating units in the initially unconstrained market and wait until the system operator is forced to make changes to ensure the secure operation of the grid. These arbitrage games constitute what is called the "INC/DEC-Game" and it has been theoretically shown that it leads to inefficient market outcomes (see, e.g., Dijk and Willems, 2011; Holmberg and Lazarczyk, 2015; Ehrhart et al., 2022, 2025). There is also increasing empirical evidence of these inefficiencies from real-word electricity markets (see, e.g., Hirth and Schlecht, 2019; Graf et al., 2020b, 2021; Davi-Arderius and Schittekatte, 2023; Brown, 2024). Furthermore, there are simulation studies aiming to identify strategic offer behavior in simplified markets (see, e.g., Sarfati et al., 2019; Sarfati and Holmberg, 2020) or counterfactual system simulations (see, e.g., Green, 2007; van der Weijde and Hobbs, 2011; Grimm et al., 2022; Knörr et al., 2024; Thomassen et al., 2024). Holmberg (2024) discusses measures that may mitigate INC/DEC Gaming.

[12] Portugal, part of the Iberian peninsula, is a separate bidding zone.

zone.

The Spanish day-ahead market involves clearing a single auction each day, setting marginal prices and cleared quantities[13] for all hours of the next operating day.[14] The intraday markets consist of a combination of auctions and continuous trading, and give market participants the flexibility to update their day-ahead market positions until close-to-real-time.[15]

The only operational system security constraint reflected in the day-ahead and intraday markets is the balance between aggregate offered supply and demand within each bidding zone, with resulting interzonal imports and exports subject to the available transmission corridor capacity constraints between zones.

2.2 Redispatch and Real-Time Operations

Operating a power system securely and reliable requires certain conditions to be met at all times: (i) the sum of generation must be equal to the sum of consumption, (ii) the energy flows across all networks and transformers must respect their technical limits, and (iii) specific operational criteria (voltage,[16] frequency,[17] and inertia[18]) should not deviate from their security levels. Moreover, maintaining a minimum level of operating or balancing reserves—i.e., having enough resources available with the capability to quickly ramp up and down their production (or consumption)—allows the system operator to be able to effectively manage real-time contingencies, i.e., unforeseen loss of equipment or resources, real-time deviations from load forecasts, and real-time deviations from weather-dependent generation forecasts (predominately hydro, so-

[13]The Spanish wholesale market has adopted a combination between "unit-level bidding" and "portfolio bidding." The former applies to generation and storage units larger than 100 MW. Other units can be grouped into a portfolio if they belong to the same technology category and meet certain characteristics (see Annex II in MITECO (2025b) for more details).

[14]Market participants in the Spanish day-ahead and intraday markets have the option to submit complex offers and bids that allow them to trade groups or blocks of several hours rather than only single hours. For more details, see OMIE (2025a,b) or, e.g., Reguant (2014) and Hübner and Hug (2025).

[15]We refer to Ito and Reguant (2016) for a discussion of auction intraday markets in Spain and to Graf et al. (2024) for a discussion of continuous trading intraday markets in Europe.

[16]Electricity must be delivered at consistent voltage for all levels of the grid, i.e., from household level (low voltage distribution grid) to ultra high voltage transmission grid level. Voltage regulation can be provided by various devices (for instance, synchronous generation, static synchronous compensators (STATCOMs), synchronous condensers, or newer generations of inverter-based resources (IBR)) through their reactive power output (Davi-Arderius et al., 2023).

[17]Frequency regulation requires to maintain the system frequency within a specified range (50 Hz in Europe and 60 Hz in the U.S.). It is controlled by real-time adjustments of the output from resources.

[18]Inertia is the tendency of rotating masses, such as synchronous generators, to resist against changes in frequency. Low levels of inertia, for instance, increase the risk that the system becomes unstable under any significant variations in generation or demand (Tielens and Van Hertem, 2016).

lar, and wind).[19]

From the perspective of the grid, the set of market schedules, commercial schedules, or operational plans (for each generation, consumption, and storage unit for the operating day) emerging from the day-ahead and intraday markets are not necessarily compliant with all the security conditions described before (Davi-Arderius et al., 2025). Hence, system operators in each member state (country) operate their own redispatching mechanisms to securely operate the system. This mechanism transforms market schedules (anticipated real-time operation of generation, storage, and flexible demand) into schedules that are compliant with a secure operation of the grid (Graf, 2025). Redispatch was originally considered a last-resort tool with the intent of being rarely used, but in recent years it has become the de facto centralized market clearing in many E.U. member states: redispatching volumes and costs grow year-on-year (ACER, 2024).

As shown in Figure B.2, the Spanish redispatching process is staged with redispatchig taking place right after the day-ahead market has cleared (day-ahead redispatch)[20] and then also during the operating day closer to real time (real-time redispatch). Only qualified units can participate in the redispatch mechanism which makes it a less competitive market place. The Spanish system operator runs the paid-as-offered and pay-as-bid redispatch process to adjust generation and consumption schedules up (INCrease) or down (DECrease). A peculiarity of the Spanish redispatch process is that phase 1 of the day-ahead redispatching stage is regulated for generation units getting DECed and for consumption units getting INCed. The regulated price for those schedule INCs and DECs is the corresponding hourly day-ahead market price (see Table B.1 for more details on the redispatching framework). The costs of redispatching are added to the energy costs and are not recovered through the network tariff structure (ACER, 2025a).

[19]There might be additional security conditions. Among others, N-1 security criteria to ensure the system operates in the event of a network element failure, minimum short-circuit currents to minimize voltage dips when a line disconnection occurs (Schlabbach, 2005), or minimizing *power system oscillations* (cyclical variations in voltage, current, or power flow within an electrical power system, typically caused by interactions among generators, loads, and control systems (Kundur et al., 2007; Shao et al., 2023)).

[20]The day-ahead redispatch stage is split into two phases in which first technical constraints are resolved (phase 1) followed by phase 2 redispatch actions to ensure generation and consumption is balanced after changes made in phase 1.

2.3 Strategies to Mitigate Operational Risks

In the day-ahead timeframe, both market participants and the system operator make decisions under uncertainty. Specifically, market participants formulate their day-ahead offer curves based on expectations of other market participants' behavior (Graf and Wolak, 2024) and also factor in the revenue stream from all segments of the market including redispatching opportunities (Graf et al., 2020b).

In response to the market schedules originating from the day-ahead market, the system operator redispatches at the unit-level if the units committed by the market participants in the day-ahead market are not in line with an expected secure operation of the system in real time. Specifically, a redispatch need arises when the set of market schedules (i) does not align with the network's expected real-time capabilities and (ii) lacks robustness to withstand a range of credible contingencies.

In case of anticipated security violations, the system operator can either "wait and see," i.e., taking a reactive stance, waiting for more information to unfold before taking redispatching actions, or to decide "here and now," i.e., redispatch on the spot which could turn out to be a wrong decisions in hindsight. Waiting can pay off, as market and system conditions may shift and anticipated real-time security violations may resolve on their own. However, if those violations persist or worsen, the system operator may face challenges securing sufficient reliability resources on short notice. This challenge is compounded by the fact that many conventional power plants cannot generate power instantaneously if they are not turned on already (O'Neill et al., 2005; Graf et al., 2020a; Jha and Leslie, 2025). Hence, the "wait and see" strategy carries the risk of not being able to commit conventional units in time. Furthermore, since the pool of potential reliability resources shrinks as real-time approaches, the cost of procuring reliability services may increase too.

The pay-as offered/bid redispatching process can be costly and in 2020 the Spanish regulator introduced economic incentives for the system operator, requiring it to pay a penalty if annual redispatching volumes increased relative to the average of the previous five years, or to receive a premium if they decreased (CNMC, 2019). These economic incentives, along with the mandate set in European Union (2019) to limit RES curtailment to 5% of annual generation, create a tension between ensuring operational security—often requiring increased redispatch—and avoiding penalties or lost incentives tied to minimizing such interventions.

3 Iberian Peninsula Blackout

In this Section, we discuss what is known to date about the Iberian blackout. It occurred on April 28, 2025, at 12:33 p.m. and left 60 Million customers located in Spain, Portugal, and a small area in France close to the Spanish border, without power supply. The blackout lasted many hours: half of the demand was restored at 10:30 p.m. and 99.95% of the demand at 7:00 a.m. the next day (CSN, 2025). At the time of the blackout, the day-ahead market price was $-€0.01$/MWh. Non-positive day-ahead market prices in the Spanish bidding zone have been frequent during March and April right before the blackout (occurring in 8.2% of the hours or in 231 hours out of 2819 hours). While solar availability is already strong during that season, electricity demand is typically relatively low because of the mild weather with limited demand for heating or air conditioning. On the day of the blackout, three out of seven nuclear plants were offline (Trillo, Almaraz I, and Cofrentes). Almost two thirds of the total generation (64%) came from inverter based resources (IBR),[21] primarily solar photovoltaics, and Spain was exporting more than 4 GWh to neighboring countries (see Table B.2). Redispatching volumes at the time of the blackout reported by the Spanish system operator are shown in Table B.3. The Spanish government estimated the economic cost of the blackout between €400M and €800M, but some stakeholder estimated an economic cost up to €1,600M.[22]

According to CSN (2025) and ENTSO-E (2025a), a concatenation of facts led to the blackout.

[21] RES (as well as battery storage) are so-called IBR because they rely on inverters to convert direct-current power to alternating-current power that can be transmitted on the electric grid. The North American Electric Reliability Corporation (NERC) defines IBRs as a plant/facility consisting of individual devices that are capable of exporting real power through a power electronic interface(s) such as an inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. Examples include, but are not limited to, plants/facilities with solar photovoltaic, certain wind plants, battery energy storage systems, and fuel cell devices. See https://www.nerc.com/pa/Stand/Project_2020_06_Verifications_of_Models_and_Data_f/2020-06_IBR_Definitions_Clean_final.pdf.

[22] See https://www.infobae.com/espana/2025/04/30/el-gobierno-rebaja-las-perdidas-economicas-por-el-apagon-las-cifra-en-800-millones-frente-a-los-1600-que-dicen-los-empresarios. In addition, legal disputes are expected to determine who will assume responsibility for the legal claims, which could involve significantly higher costs, see, e.g., https://aelec.es/alertamos-de-imprecisiones-y-omisiones-en-el-informe-de-entso-e-y-publicamos-un-analisis-de-expertos-independientes-sobre-el-apagon-del-28-de-abril and https://www.20minutos.es/noticia/5722855/0/las-electricas-anticipan-un-largo-camino-judicial-recurriran-las-reclamaciones-por-apagon-insisten-apuntar-red-electrica.

The non-exhaustive list of facts reported to date[23] contains overvoltages in the whole national system; the presence of inter-area oscillations (power, voltage, and frequency swings) in the Continental Europe Synchronous Area; the cascade trip of RES (IBR), and the disconnection of the France and Spain interconnector. Unfortunately, load shedding could not automatically recover the nominal frequency. The Spanish system operator reported that some gas-fired generators did not provide voltage control as planned (REE, 2025a). As acknowledged by the Spanish government in CSN (2025), unlike recent blackouts driven by resource adequacy challenges, the Iberian blackout was a "systemic overvoltage situation" that produced a cascade tripping of generators, i.e., an operational reliability event.

The Spanish government has also released a list of recommendations to be implemented in the national electrical system:

- Reassessing the security criteria used by system operators for redispatching units. The Spanish government questions whether the system operator activated enough gas-fired plants through redispatching before the blackout for voltage control.
- Enabling the participation of IBR (RES) for voltage control with reactive energy. Until to date, RES operated at fixed power factor and the main sources to provide voltage control were static synchronous compensators (STATCOMs) owned by the transmission system operator and conventional synchronous generation.[24]
- Incentivizing consumption from large consumers.[25]
- Developing terms and conditions for market participation of independent aggregators (virtual power plants).
- Accelerating additional cross-border capacity with Europe (France), removing regulatory barriers for storage, and installing grid devices to minimize future power system oscillations.

[23] The final report from ENTSO-E has not been published yet.

[24] When market schedules from synchronous generation and existing STATCOM capacity were not enough to control voltages, the system operator typically relied on specific conventional plants to be operated at their minimum operating level. A month after the blackout, the Spanish Regulator approved a new voltage control system under which RES (IBR) should actively provide reactive energy for voltage control. See https://www.cnmc.es/prensa/po-control-tension-20250617.

[25] Power system overvoltages decrease when electricity consumption increases. This phenomena is explained by the surge impedance loading (SIL) effect (Ghassemi, 2019).

4 Descriptive Evidence

In this section, we present descriptive evidence on how technology-aggregated net market and redispatch volumes, as well as redispatch costs, have evolved between 2019 and 2025 in Spain. We show that the current E.U. short-term electricity market design does not provide incentives for CC units to sell energy in the day-ahead market although the *current* system almost always needs them for secure real-time operation.

We furthermore show changes in volumes of CC and total redispatch costs right before and after the 2025 Iberian Peninsula blackout. We will provide descriptive evidence that the blackout has increased the demand for redispatch of CC units at the expense of curtailing RES that was sold in the unconstrained day-ahead and intraday markets. These changes are likely driven by a revised assessment of operational risk tolerance made by the system operator.

Spanish wind generating capacity increased from 23.4 GW (2019) to 32.1 GW (2024) and front-of-meter photovoltaic capacity increased from 4.8 GW (2019) to 32.4 GW (2024). However, unlike other regions with significant wind and solar investment, Spain has not yet incorporated meaningful levels of battery storage. We refer to Appendix A for more details on long-term trends including a cross-region comparison with California and Texas.

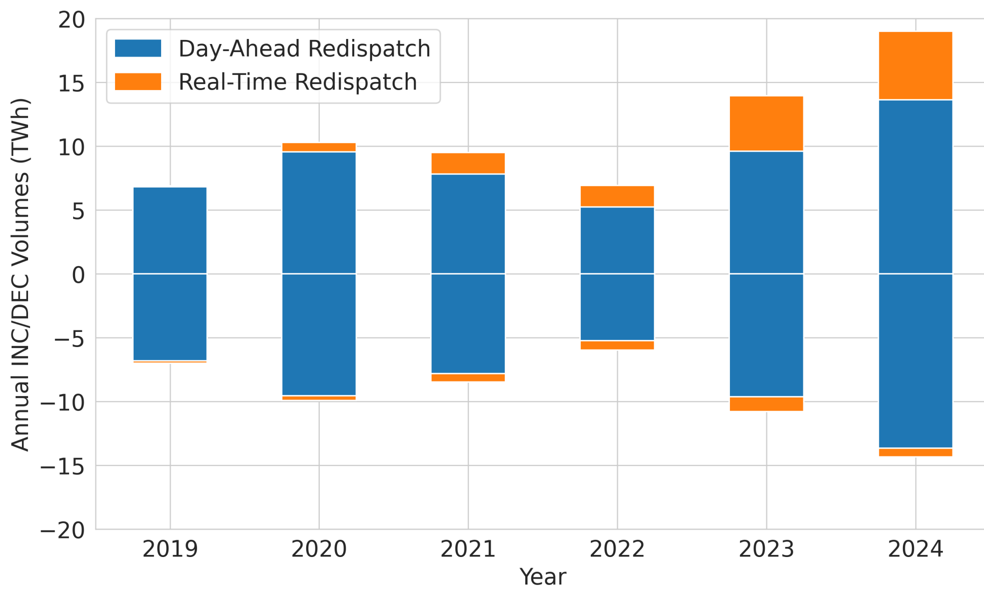
The changes in the capacity mix has resulted in increasing costs and volumes of redispatched energy year-over-year. Figure 1, Panel (a), illustrates the evolution of annual redispatching volumes. While in 2019 the total absolute volumes for INC and DEC were about 14 TWh per year, these volumes have more than doubled by 2024 (about 13% of annual electricity demand in 2024).[26] While in 2019 virtually all redispatch was still carried out day-ahead, i.e., after the day-ahead market has cleared, there is a recent trend to redispatch closer to real-time, i.e., on the operating day.

Consistent with the higher redispatch volumes also annual total redispatch costs, defined as the INC redispatch costs net of DEC redispatch costs, have increased substantially as shown in Figure 1, Panel (b). While the total redispatch cost was under €0.25B in 2019, it has increased

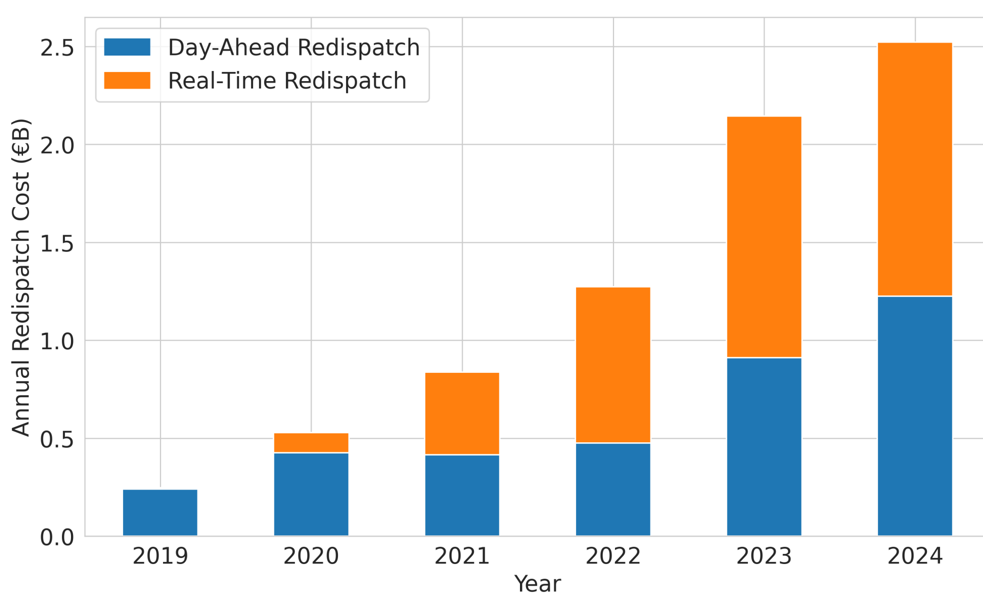
[26] In 2024, INC redispatch was 13.6 TWh and 5.4 TWh after the day-ahead markets and during intraday markets (real-time redispatch), respectively. DEC redispatch was 1.7 TWh and 0.7 TWh after the day-ahead markets and during intraday markets (real-time redispatch), respectively. Total electricity demand was 248 TWh. Graf et al. (2021) and Davi-Arderius et al. (2025) find that redispatching volumes increase with the scheduled volumes of IBRs (wind and photovoltaic) in the day-ahead markets, or when the electricity demand decreases.

tenfold to approximately €2.5B by 2024 and is expected to continue growing (Davi-Arderius et al., 2024). Furthermore, it appears that moving redispatch from day-ahead to real-time is more costly, at least on a per MWh of redispatch cost comparison.

Figure 1: Annual Redispatching Costs and Volumes



(a) Volumes



(b) Costs

Notes: Positive volumes in Panel (a) represent INC redispatch and negative volumes represent DEC redispatch. Annual total redispatch costs in Panel (b) are calculated by subtracting the DEC redispatch costs from the INC redispatch costs. Positive DEC redispatch costs are payed to the system operator and hence reduce total redispatch costs. Source: REE (2025c).

4.1 Market, Redispach, and Real-Time Schedules

Under the current Spanish market design, the short-term markets are to a large extent agnostic to the many physical constraints necessary to securely operate the electric system in real-time. Given a fixed network topology and accompanying security limits, the unit level outputs and locational demands will determine the risk of security constraint violations. From an operational perspective, units vary by location and type (quality).[27] Resolving anticipated security or reliability constraints can be achieved by adjusting (redispatching) outputs of those generating and storage units as well as demands.

We first show how schedules of different technologies by market segment, i.e., day-ahead and intraday markets as well as redispatching markets, have evolved over time. In Figure 2, we break down hourly average net CC and IBR (wind and front-of-meter solar photovoltaics) schedules. Panel (a) shows that in 2019 most of the generated energy in real-time from CC was sold through the day-ahead market. In 2024, this was not the case anymore (Panel b) and most of the real-time energy output from CC was procured through redispatch (INC). Over the same time more volumes from IBR have been sold through the day-ahead market which eventually could not be delivered securely because of constraints in the transmission system (see negative values in panels (c) and (d) corresponding to average net DEC redispatch).

In Figure B.3, we compare distributions of hourly day-ahead market and real-time schedules of aggregated CC gas generation. In Panel (a) we compare hourly schedules between 2019 and 2023 and in Panel (b) for 2024. In about 20% of the hours between 2019 and 2023 no CC schedules emerged from the day-ahead market. By 2024, this share exceeds 60%, primarily due to increasing RES capacity, which outcompetes fuel-based technologies on a variable cost basis. However, in real-time it is virtually impossible to operate the *current* system without CC generation as can be seen from the real-time schedule distributions. Even though the amount of RES has increased substantially between 2019 and 2024, the maximum real-time demand for CC in 2024 is only slightly lower (16.1 GWh) than their maximum real-time demand between 2019 and 2023 (17.7 GWh in

[27] For example, a battery storage unit is an energy limited resource and can thus only supply energy as long as its battery is not empty. A wind generation unit's maximum available capacity (potential) depends on the wind speed and direction. And most conventional units have non-convex operational constraints such as minimum stable generation limits and other physical constraints which makes them sluggish to respond to changed market/system conditions. Technologies also differ in their contribution to grid services as discussed in Section 2.2.

2022).

Finally, we focus on hour-by-hour schedules between May and June, 2024, i.e., covering about a month before and after the blackout, based on data from one year prior. Under the current short-term market design, late spring/early summer is typically a challenging time for system operations in many European countries because of low demand conditions (many holidays and cooling season not yet beginning) and excess RES. Because excess RES can be sold in the unconstrained day-ahead and intraday markets, system operators often need to curtail RES while ramping up dispatchable synchronous generation to ensure a secure operation of the system. In Figure 3, we show hourly schedules for CC that originated from the day-ahead and intraday markets as well as the schedule changes from redispatch. Almost all CC generation during that time is procured through the redispatch market rather than through the day-ahead or intraday markets.

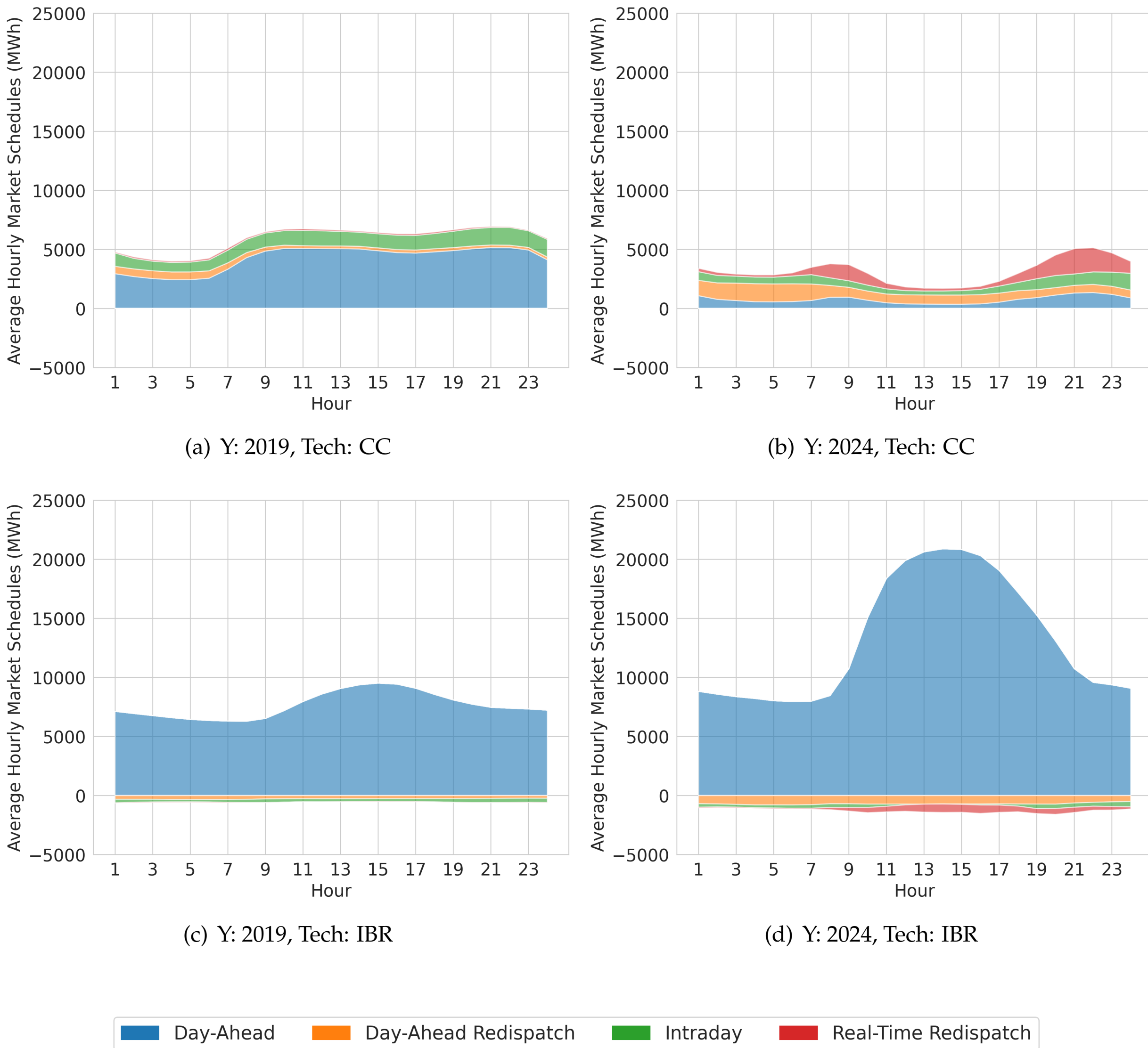
4.2 Pre- and Post-Blackout Redispatch Outcomes

The 2025 Iberian Peninsula blackout occurred on April 28, 2025, at around noon. In Figure 4, we show CC net redispatch volumes before and after the blackout (blue line) as well as range and average net redispatch volumes from prior years (black line and gray-shaded area). In Panel (a) we show daily average net redispatch volumes and in Panel (b) we show daily average total redispatch cost. The figure in Panel (a) suggests that CC redispatch volumes substantially increased after the blackout relative to before the blackout but also relative to even the most extreme redispatch levels in prior years.

The Spanish system operator is likely to have implemented a safer mode of operation after the blackout, redispatching (INCing) rotating synchronous generators more aggressively, e.g., CC units, which provide higher contribution to grid stability, voltage control, and inertia. In exchange, higher volumes of sold RES in the day-ahead markets were curtailed to keep the system balanced. This may point to the dilemma of system operators with RES curtailment caps: maximizing RES output (minimizing carbon emissions) or maximize operational security which increases redispatching costs and carbon emissions. Solving this dilemma is not straightforward and may put pressure on system operators.

In Figure 5, we compare average hourly (net) redispatching volumes by technology before

Figure 2: Average Hourly Combined Cycle (CC) and Inverter-Based Resources (IBR) Incremental Schedule by Market Segment for the Years 2019 and 2024



(a) Y: 2019, Tech: CC

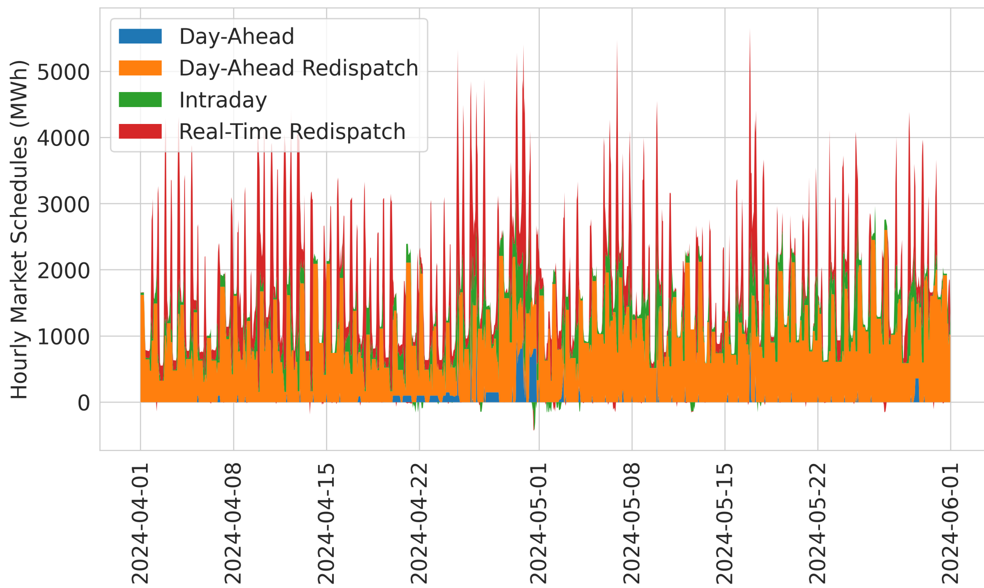
(b) Y: 2024, Tech: CC

(c) Y: 2019, Tech: IBR

(d) Y: 2024, Tech: IBR

Notes: Each panel represent a year (Y)-technology (Tech) combination of average hourly net energy schedules by market segment. Day-Ahead represents net energy schedules from the day-ahead markets. Intraday represent net schedules increases (positive) and decreases (negative) after the day-ahead markets. Day-Ahead Redispatch and Real-Time Redispatch represent net schedule increases (positive) and decreases (negative) by the system operator after the day-ahead and intraday markets, respectively. Inverter-Based Resources (IBR) contain wind and front-of-meter solar photovoltaics.

Figure 3: Hourly Aggregate Combined Cycle (CC) Schedules by Market Segment in April and May 2024



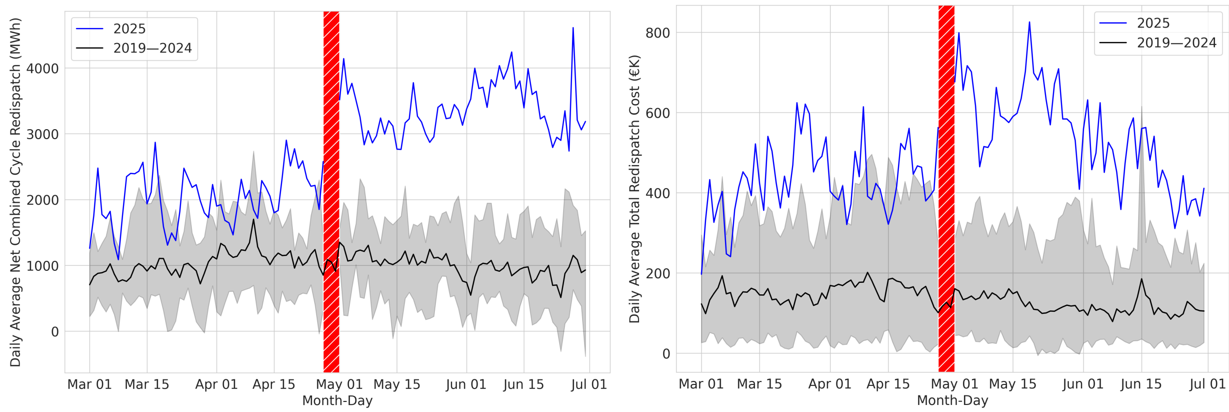
and after the blackout for the day-ahead and real-time redispatching stage. In Panels (a) and (b), we show that day-ahead redispatch has increased considerably after the blackout, mainly from CC. Furthermore, those net CC schedules reached their maximum at night hours. Hourly average net CC redispatch has increased in all hours after the blackout, but particularly during hours that coincide with solar photovoltaic generation (between hours 10 a.m. and 6 p.m.). Solar photovoltaic generation has been DECed more frequently during the day-ahead stage after the blackout (negative values in Panel b).

In Panels (c) and (d) of Figure 5, we show that real-time redispatch has decreased after the blackout, indicating a strategy change by the system operator, likely aimed at increasing operational security. Specifically, the Spanish system operator tends to resolve operational constraint earlier on (day-ahead redispatch) after the blackout.

5 Econometric Analysis

In this section, we use an event study model (Miller, 2023) to estimate the effect of the blackout on: (i) net CC redispatching volumes, (ii) net synchronous generation redispatching volumes, (iii) net IBR redispatch volumes, and (iv) total redispatching costs. The changes after the blackout hints

Figure 4: Daily Average Net Redispatch Outcomes Pre- and Post-Blackout



(a) CC Volumes

(b) Cost

Notes: Panel (a) shows daily average combined cycle gas (CC) net redispatch volumes (positive values represent net INC redispatch and negative values net DEC redispatch). Volumes are aggregated across CC units. Panel (b) shows daily average total redispatching costs. The 2025 Iberian blackout occurred on April 28, 2025, at around noon (red bar). We skip observations between April 28, 2025 and April 30, 2025. Daily averages for volumes (in MWh) and prices (in €K) are calculated across all hourly intervals. The black line represents the average value for each day across the years 2019–2024, while the contours of the gray shaded area indicate the minimum and maximum daily averages within that same period.

at the system operator's reassessment of risk by activating more CC and reducing anticipated real-time IBR output that was sold in the unconstrained market.

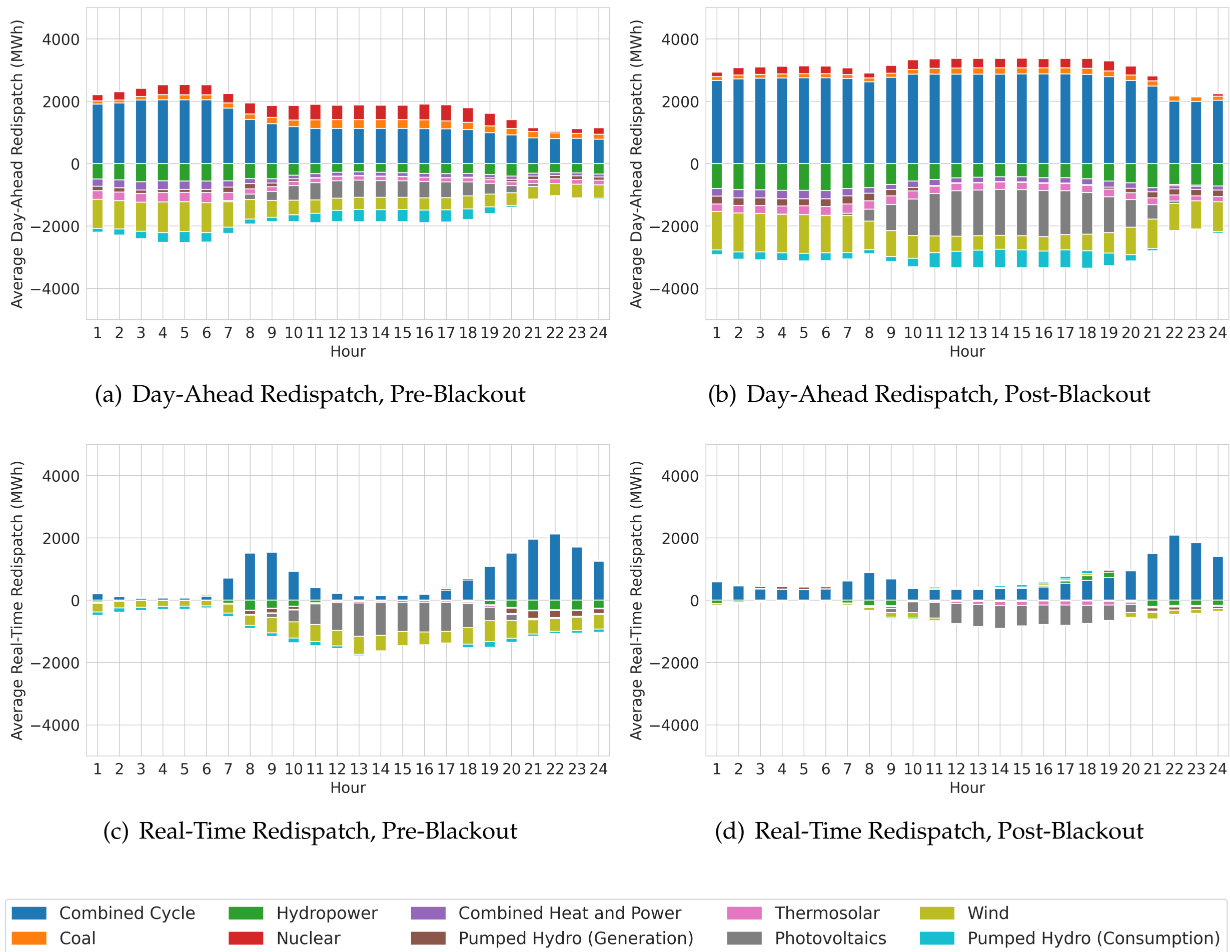
We estimate the following equation for outcome variable Y_{yh}, where the subscripts refer to year (y) and hour-of-year (h):

$$Y_{yh} = \alpha_y + \delta \text{post}_{yh} + \beta X_{yh} + \gamma F_{yh} + \epsilon_{yh}. \tag{1}$$

We include year of the sample fixed effects (α_y) and X_{yh} is a vector of control variables. post_{yh} is an indicator that equals 1 for all post-blackout observations and is 0 otherwise. Note that for non-blackout years the indicator variable is 0. We flexibly control for day-ahead forecasts of the net load (nl-fc), including their squared and cubic terms, i.e., $X = \left[\text{nl-fc}, \, (\text{nl-fc})^2, \, (\text{nl-fc})^3\right]$. The nl-fc is defined as the day-ahead load forecast net of the forecasted available generation from IBR (wind and front-of-meter photovoltaics).[28] We also control for calendar fixed effects—including

[28]Because energy from IBR has variable cost close to zero, the nl-fc indicates the forecasted energy needed to fill in from rotating synchronous generators, i.e., nuclear, combined cycle gas, coal, combined heat and power, hydropower, pump storage (generation), and thermosolar. Note that nl-fc can also be negative if the forecasted IBR potential exceeds forecasted demand. As explained previously, contribution of IBR to inertia, voltage control, and grid stability is currently more limited than that of synchronous generation. Hence, the nl-fc levels give a good indication of how much

Figure 5: Net Hourly Average Redispatch Volumes Technology Pre- and Post-Blackout



(a) Day-Ahead Redispatch, Pre-Blackout

(b) Day-Ahead Redispatch, Post-Blackout

(c) Real-Time Redispatch, Pre-Blackout

(d) Real-Time Redispatch, Post-Blackout

Notes: The 2025 Iberian Peninsula blackout occurred on April 28, 2025. Pre-blackout (Panels a and c) contains hourly data from March 1, 2025 to April 27, 2025. Post-blackout (Panels b and d) contains hourly data from May 1, 2025 to June 30, 2025. Day-ahead redispatch (Panels a and b) takes place after the day-ahead market has cleared but still day-ahead of the operating day. Real-time redispatch redispatch (Panels c and d) takes place on the operating day. Hourly averages are in MWh (see Appendix B.1 for further details on how we calculate redispatching volumes).

business day, month of the year, and hour of the day—which are captured in the vector F_{yh}. The error term is ϵ_{yh}.

Our dataset includes hourly scheduled energy in the wholesale markets (day-ahead and intraday), the redispatching mechanisms, and real-time netted at the technology level, between January 1, 2019 and June 30, 2025. For this analysis, we focus only on the months March to June which captures about two months before and after the blackout.[29] We refer to Section B.1 for more details on the dataset. Summary statistics of the main variables, disaggregated by year, are reported in Table B.4.

Table 1 summarizes our main results. The coefficient of interest is δ, i.e., the effect of the post-blackout period on the net CC redispatching volumes (cc), net synchronous generation redispatching volumes (sync), net IBR redispatch volumes (ibr), and redispatching costs (cost). The statistically significant estimate in column (1) suggests that, following the blackout, CC net redispatching volumes increased by an average of 1.4 GWh per hour. To put this number in context, the hourly average CC net redispatching volume during the same period one year prior to the blackout has been 1.6 GWh (see Table B.4). Hence, this is a substantial and highly significant increase consistent with the graphical analysis shown in Figure 4.

If we aggregate all the synchronous generation, we again find a highly significant and positive post-blackout coefficient (Column (2) in Table 1). Note that the schedules are netted and hence underestimate the true INC and DEC volumes as discussed earlier. The column (3) estimate suggest that IBR have been DECed more frequently after the blackout. Specifically, the net redispatch volumes decreased by an average of 0.4 GWh per hour. Finally, following the blackout, the estimated total redispatching cost increase is €142K per hour on average. A significant increase relative to the hourly average cost in 2024 of €321K (see Table B.4) during the same period prior to the blackout.

The redispatching mechanism is a sequential process which starts day-ahead and ends in real-time. Table B.5 reports the results of estimating the same four specifications used in Table 1 but restricts the dependent variables to day-ahead redispatching volumes only. Consistent with the data presented in Figure 5, Panels (a) and (b), we find that the estimates of the post-blackout

synchronous generation is likely sold and scheduled through the day-ahead and intraday markets.

[29]We removed observations from April 28, 2025 (the day of the blackout) and two days after blackout because the system was operating under very particular conditions at that time.

Table 1: Main Regression Results

	(1) cc	(2) sync	(3) ibr	(4) cost
post	1,358.73	779.68	−397.51	142,063.78
	(23.49)	(28.15)	(23.89)	(4,898.68)
nl-fc/1000	60.52	18.19	338.30	−7,980.06
	(7.38)	(8.85)	(7.51)	(1,539.26)
$(\text{nl-fc}/1000)^2$	−1.72	−1.19	−15.94	133.62
	(0.52)	(0.62)	(0.53)	(108.57)
$(\text{nl-fc}/1000)^3$	0.02	0.04	0.27	6.89
	(0.01)	(0.01)	(0.01)	(2.36)
Business day FE	Yes	Yes	Yes	Yes
Year-of-sample FE	Yes	Yes	Yes	Yes
Month-of-year FE	Yes	Yes	Yes	Yes
Hour-of-day FE	Yes	Yes	Yes	Yes
Obs.	20,396	20,396	20,396	20,396
Adj. R^2	0.64	0.35	0.54	0.64

Notes: Hourly data covering approximately two months before and after the blackout (March–June) for each year of the sample (2019–2025). Standard errors are reported in parentheses.

coefficients are more pronounced, i.e., more net CC and SYNC generation INCs (columns (1) and (2)), more IBR DECs (column (3)), and higher estimated redispatching costs (column (4)). All coefficients are statistically highly significant.

In contrast, Table B.6 reports the results of estimating the same four specifications used in Tables 1 and B.5, but restricts the dependent variables to real-time redispatching volumes only. Consistent with the data presented in Figure 5, Panels (c) and (d), we find that the estimates of the post-blackout coefficients have the opposite sign and are less statistically significant. Specifically, the estimated post-blackout effect on net real-time CC and SYNC redispatch is slightly negative (columns (1) and (2)), the estimated post-blackout effect on net real-time IBR redispatch is positive (column (3)), and the the estimated post-blackout effect on real-time redispatching costs is negative (column (4)).

The regression results support the hypothesis that the Spanish system operator has increased redispatch (INC) from SYNC and from CC in particular which also increased the total redispatching costs.[30] Furthermore, the redispatching strategy has changed from redispatching more day-ahead rather than in real-time which does not follow the annual trend of recent years (see Figure 1).

In summary, the evidence suggests that the Spanish system operator likely implemented a safer operational mode following the blackout. All our estimates show a statistically significant increase of net CC and SYNC redispatch volumes post-blackout, while IBR net volumes decreased. The post-blackout changes primarily took place in the day-ahead redispatch stage. The increased redispatch volumes (INC and DEC) also increased hourly average total redispatch cost significantly post-blackout.

6 Discussion and Conclusion

The European short-term wholesale market is designed to operate on the premise that physical network constraints, such as transmission and other system constraints, hardly ever bind. This fiction has never been true and it is becoming less true by the day, especially with large amount of RES that can be sold in the "unconstrained" markets but face real-time integration challenges. As a result, redispatch—a centralized, supposedly last-resort, tool used by system operators to correct market schedules incompatible with secure grid operation—is increasingly being deployed.

Relying on redispatch for operational reliability may increases system risks for several reasons: (i) redispatching is always conducted after the fact, rather than through the upfront enforcement of system constraints during market clearing, (ii) system operators must forecast real-time energy flows based also on day-ahead and intraday market schedules and make decisions within very short timeframes, (iii) system operators do not have complete oversight of market schedules of all individual units (under the "portfolio bidding" approach for small or medium-sized units), and (iv) system operators may face regulatory pressure to reduce redispatching volumes and costs.

Our results suggest that, following the blackout, the Spanish system operator increased its emphasis on operational reliability and security by committing more gas-fired units and reducing the anticipated real-time output from wind and solar resources. Although security criteria should be determined in accordance with the level of risk deemed acceptable to regulators, system operators,

[30] In Tables C.7–C.9, we replicate the regressions above using average daily values rather than hourly values. The qualitative interpretation of our results is unchanged as a result of this robustness check.

and the public, it is important to recognize that their derivation necessarily relies on probabilistic models and that a zero-failure rate is not achievable in practice.

Efforts to enhance operational reliability and security through redispatch are inherently associated with increased redispatch volumes and corresponding costs. In the case of Spain, the topic has become controversial because it is affecting the entire energy system value chain: (i) increases the total energy costs paid by all consumers, both large industrial and domestic, (ii) leads to larger amounts of unused RES, particularly in a system with limited storage capacity, and (iii) places the Spanish system operator at the center of the challenge. In contrast, U.S. short-term wholesale electricity markets transitioned two decades ago from a simplified sequential design to one that incorporates system constraints directly into market clearing,[31] thereby supporting secure real-time operations and reducing the need for reactive adjustments to infeasible market outcomes.

On a longer time horizon, however, there are more options that can mitigate future short-term operational challenges and reduce redispatching volumes. These could be, for instance, more grid/equipment of the right size/type at the right location (coordinated resource and grid planning). But also incentives to better site new generation (including RES) and storage capacity, considering existing and future network capacity and their impact on system security.

Optimal power system planning frameworks can be complex and challenging to implement, as they require aligning the interests of a wide range of stakeholders. Hence, additional flexibility may be needed—supported by consistent market design and policies—to attract a diverse portfolio of resources that complement each other well. Locational marginal pricing, or more broadly, a market framework that dynamically supports secure system operation, can help guide investment in generation, storage, and demand-side resources.

[31] Several authors found improvements in market efficiency (see, e.g., Hogan, 1998; Alaywan et al., 2004; Wolak, 2011; Triolo and Wolak, 2022) after transitioning from a simplified market mechanism to an integrated market mechanism. See also Eicke and Schittekatte (2022) and Neuhoff et al. (2025) for a debate of more granular network pricing in Europe.

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_ , _ , and _ , "The effect of intermittent renewables on the electricity price variance," *OR Spectrum*, 2016, *38* (3), 687–709.

A Long-Term Trends in Spain within the International Context

In this section, we show recent market trends in Spain which experienced substantive RES capacity additions in recent year, particularly solar photovoltaics.[32] Unlike other strong renewable energy markets such as California or Texas, there has been almost no investment in battery storage yet.

A.1 Market Trends

The Iberian power system (Spain and Portugal) has very limited interconnection with the rest of Europe and Africa. The cross-border capacity with France and Morocco is 4 GW and less than 1 GW, respectively. Since 2019, renewable energy capacity has increased substantially in Spain: wind generating capacity increased from 23.4 GW (2019) to 32.1 GW (2024), and front-of-meter photovoltaic capacity increased from 4.8 GW (2019) to 32.4 GW (2024).[33] Moreover, annual market demand for electricity, i.e., total demand net of behind-the-meter self-consumption, has decreased from 269 TWh (2019) to 248 TWh (2024), partially explained by an increase in behind-the-meter photovoltaic capacity (REE, 2025d). Spain, unlike other regions with significant wind and solar investment, has not incorporated meaningful levels of battery storage—an issue we discuss in detail below.

A.2 Comparing Spain's Energy Transition to Global Trends

We compare the generation mix and storage capacities between Spain, California, and Texas. All three regions are leaders in RES deployment, predominantly wind and solar. Total in-region electricity generation in 2024 was about 465 TWh in Texas, 248 TWh in Spain, and 216 TWh in California. Texas can be considered an energy island, a characterization that also applies to Spain (or more specifically to the Iberian peninsula which includes mainland Spain and Portugal) given its limited interconnection capacity with Portugal (5 GW), France (4 GW), and Morocco (less than 1 GW).[34] California, however, imports about 30% of its electricity from out-of-state.[35]

In Figure A.1, we show relative generation shares for California, Spain, and Texas. Spain has seen considerable RES investment in recent years predominately in solar. In 2019 the annual generation from wind and solar was about 25% of the total annual generation this share has increased to almost 45% in 2024. California and Texas, the top wind and solar markets in the U.S., had similar combined wind and solar shares in 2019 (both slightly above 20% but California being solar dominated and Texas being wind dominated), but have not caught up with Spain. California's

[32] The real-time potential, or maximum available capacity, of wind and solar resources vary by season. Solar has a concentrated diurnal shape. Both resource types are also intermittent, which increases the need for backup capacity and operating reserves. During the initial development of RES, these topics were widely discussed in the academic literature (Luickx et al., 2008; Liu et al., 2020; Graf et al., 2020a, 2021; Wozabal et al., 2013, 2016).

[33] Photovoltaic capacity does not include behind-the-meter photovoltaics, i.e., self-consumption. With no official data available, the Spanish renewable energy trade group, APPA (Asociación de Empresas de Energías Renovables), estimates behind-the-meter photovoltaics capacity being around 8.5 GW in 2024. This might partially explain why the market demand for electricity (total demand net of behind-the-meter self-consumption) has decreased in Spain during the last years (see, e.g., APPA, 2025).

[34] See `https://www.sistemaelectrico-ree.es/es/informe-del-sistema-electrico/intercambios/capacidad-intercambio`.

[35] See `https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-electrical-energy-generation`. In 2023 this share fell to 23%.

wind and solar generation share was about 30% in 2024 and Texas' about 35%.[36]

Although the share of combined wind and solar generation is substantially less in California and Texas compared to Spain, both U.S. markets have seen significant growth in storage capacity. For example, utility-scale battery storage capacity in California has increased from only 0.3 GW (power) in 2019 to 12.5 GW in 2024.[37] In Texas, battery storage has increased from below 0.3 GW until 2021 to 9.5 GW by the end of 2024.[38] Spain has not seen any material utility-scale battery storage investments. By the end of 2024, legacy (pumped hydro) storage capacity was 3.4 GW (power) and between 2019 and 2024 only 0.025 GW (power) of battery storage capacity was added to the system (REE, 2025b). A few weeks after the Iberian Peninsula blackout, the Spanish government approved a new Royal Decree Law 7/2025, a post-blackout action plan that included, among many other things, amendments on basic regulations to enable a fast development of battery storage. However, this new Royal Decree Law was not finally validated by Congress and became void.[39]

B Additional Material

This section provides further background on the data used in this study. Furthermore, we include additional figures and tables.

B.1 Data Provenance

Data used in this analysis was downloaded from the ESIOS website operated by the Spanish system operator on July 7, 2025 (REE, 2025c). Data includes: (i) the scheduled energy by technology from the day-ahead markets before redispatching actions from the system operator (PDBF or Programa Diario Base de Funcionamiento), (ii) the scheduled energy by technology from the day-ahead markets including all the redispatching actions from the system operator in the day-ahead (PDVP or Programa Diario Viable Provisional), (iii) the scheduled energy by technology from the all the intraday markets (PHFC or Programa Horario Final Continuo), (iv) final delivered energy by technology, which includes all the redispatching actions made in real-time as well as the balancing services made by the system operator (P48 or Programa Operativo) (MITECO, 2025b). Day-Ahead Redispatch volumes used in this paper are calculated as the difference between PDVP and PDBF. Changes in market schedules made in the intraday markets are calculated as the difference between PHFC and PDVP. Real-Time Redispatch volumes are calculated as the difference between P48 an PHFC. The approach is consistent with previous studies (Davi-Arderius et al., 2024, 2025).

Our dataset further includes day-ahead forecasts of: (i) total electricity demand, (ii) photovoltaic potential or maximum available capacity, and (iii) wind potential or maximum available capacity. The data is published by the Spanish system operator and defined in REE (2025c) as; "the demand forecast takes into account the consumption values registered in precedent similar

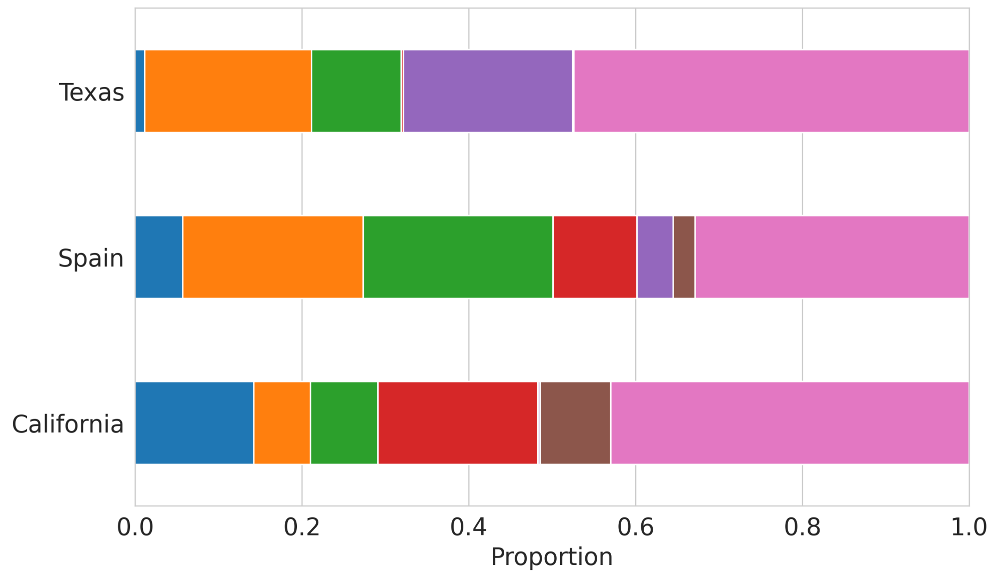
[36]Note that total generation between 2019 and 2024 grew substantially in Texas (+21%), moderately in California (+8%), and negligibly in Spain (+1%). See Figure B.4 for absolute annual generation values by technology and region.

[37]See `https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey`. California has also legacy pumped hydro storage capacity as well as residential and commercial battery storage.

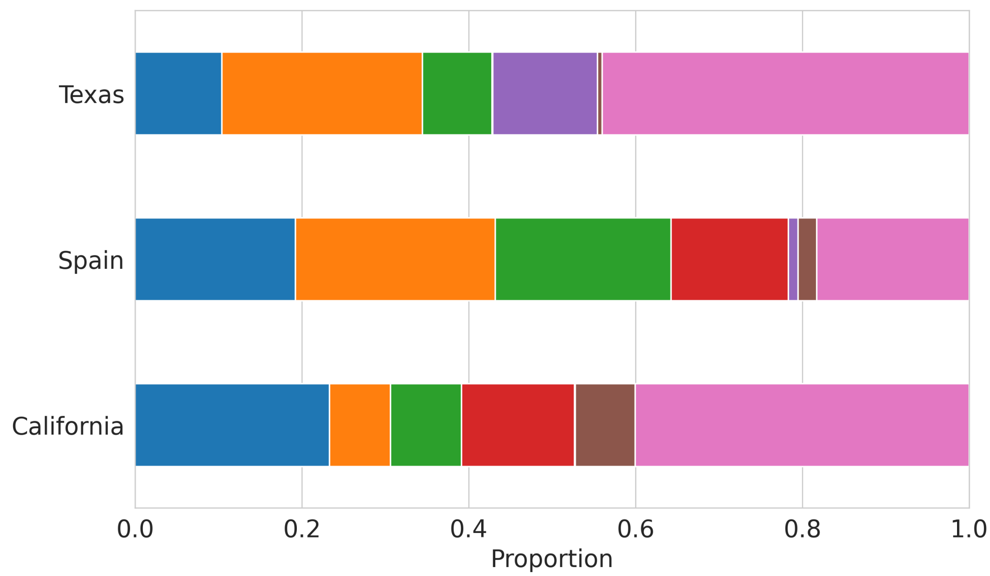
[38]See `https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-State-of-the-Market-Report.pdf`.

[39]For more details see, Real Decreto-ley 7/2025, de 24 de junio, "por el que se aprueban medidas urgentes para el refuerzo del sistema eléctrico" (`https://www.boe.es/eli/es/rdl/2025/06/24/7/con`).

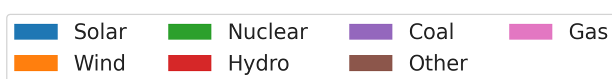
Figure A.1: Relative Annual In-Region Generation Mixes for 2019 and 2024



(a) Y: 2019



(b) Y: 2024

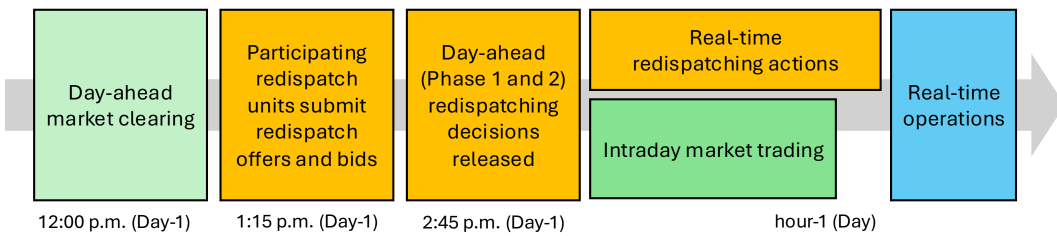


Notes: Each panel corresponds to generation mixes for a particular year (Y). Category "Other" contains renewable (e.g., geothermal) and non-renewable sources (e.g., oil). Annual Spanish (peninsula) generation data from Red Electrica de España (`https://www.ree.es`), Texas generation data from ERCOT (`https://www.ercot.com`), and California generation data from the California Energy Commission (`https://www.energy.ca.gov/`).

periods, as well as other factors with influence in the electrical consumption as the labour, the climatology and the economical activity;" "wind power hourly forecast is calculated according to the Wind Power Forecasting Model of the System Operator;" and "hourly generation Solar PV forecast received from the forecast models."

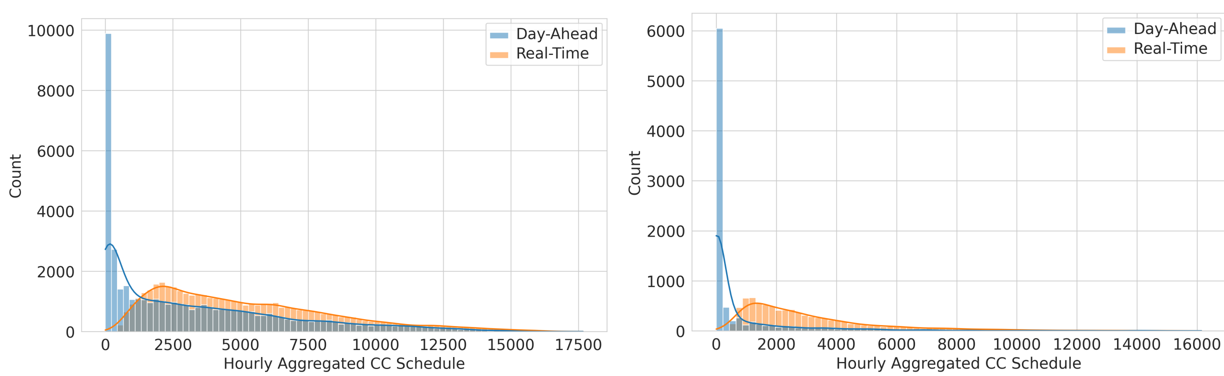
B.2 Figures

Figure B.2: Timeline of the Spanish Short-Term Wholesale Markets and Redispatching Processes



Notes: Own elaboration based on MITECO (2025b,c).

Figure B.3: Distributions of Hourly Day-Ahead and Real-Time Aggregated Combined Cycle (CC) Gas Schedules



(a) 2019–2023 (b) 2024

B.3 Tables

C Robustness checks

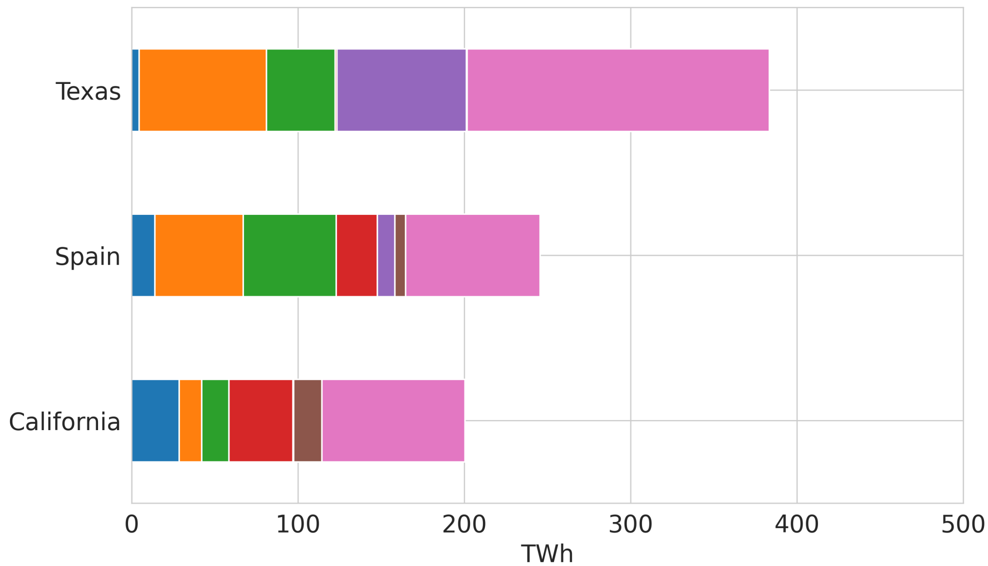
In this section, we provide additional regression analyses. Specifically, we replicate the regressions in Section 5 using average daily values rather than hourly values. In Tables C.7, C.8, and C.9 we report regression results analogue to the estimations reported in Tables 1, B.5, and B.6.

Table B.1: Spanish Redispatching Market Framework

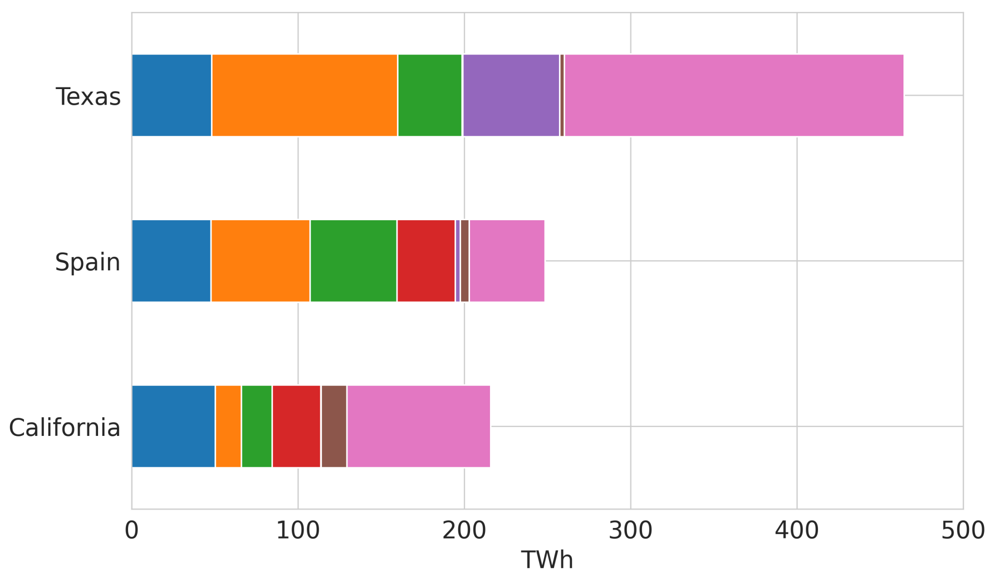
Market Stage	Market Side	INC	DEC
Day-Ahead (Phase 1)	Generation	System operator pays market participant as-offered	System operator gets paid day-ahead market price from market participant
	Consumption	System operator pays market participant day-ahead market price	System operator gets paid as-bid from market participant
Day-Ahead (Phase 2)	Generation	System operator pays market participant as-offered	System operator gets paid as-bid from market participant
	Consumption	System operator pays market participant as-offered	System operator gets paid as-bid from market participant
Real-Time	Generation	System operator pays market participant as-offered	System operator gets paid as-bid from market participant
	Consumption	System operator pays market participant as-offered	System operator gets paid as-bid from market participant

Notes: Day-Ahead (Phase 1) corresponds to the actions in day-ahead to solve operational constraints. Day-Ahead (Phase 2) corresponds to actions ensuring generation and consumption is balanced after changes made in phase 1. Real-Time corresponds to all actions made after Day-Ahead (Phase 2)—in parallel and after the intraday markets—until up to real-time. Offers and bids can also be negative when the prices of the day-ahead or intraday markets are below €1/MWh. Hence, a generation unit could also be paid for reducing its output. Storage units participate on the generation and consumption side. See MITECO (2025a) and MITECO (2025c) for further details.

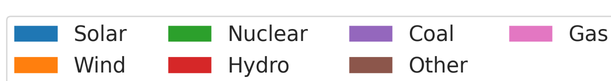
Figure B.4: Annual In-Region Generation Mixes for 2019 and 2024



(a) Y: 2019

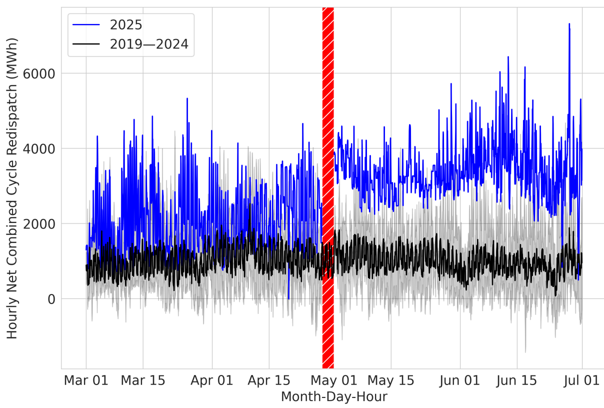


(b) Y: 2024

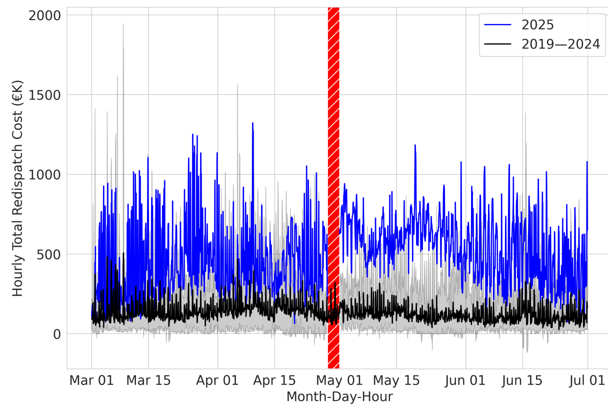


Notes: Each panel corresponds to generation mixes for a particular year (Y). Category "Other" contains renewable (e.g., geothermal) and non-renewable sources (e.g., oil). Annual Spanish (peninsula) generation data from Red Electrica de España (`https://www.ree.es`), Texas generation data from ERCOT (`https://www.ercot.com`), and California generation data from the California Energy Commission (`https://www.energy.ca.gov/`).

Figure B.5: Hourly Net Redispatch Outcomes Before and After the Blackout (April 28, 2025)



(a) CC Volumes



(b) Cost

Notes: Panel (a) shows hourly combined cycle gas (CC) net redispatch volumes (positive values represent net INC redispatch and negative values net DEC redispatch). Volumes are aggregated across CC units. Panel (b) shows hourly total redispatching costs. The 2025 Iberian blackout occurred on April 28, 2025, at around noon (red bar). We skip observations between April 28, 2025 and April 30, 2025. Volumes are in MWh and costs in €K. The black line represents average values for each hour across the years 2019–2024, while the contours of the gray shaded area indicate the minimum and maximum averages within that same period.

Table B.2: Generation Mix in Spain and Cross-Border Flows (April 28, 2025 at 12:30 p.m.)

Technology	GWh	Share of total generation
Photovoltaics	18.1	53%
Wind	3.6	11%
Nuclear	3.4	10%
Hydropower	3.2	9%
Combined cycle	1.6	5%
Combined heat and power[1]	1.4	4%
Thermosolar	1.5	4%
Others[2]	0.8	2%
Coal	0.2	1%
Pumped hydro (generation)	0.03	0%
Total Generation	33.9	100%
Exports to Portugal	2.7	
Exports to France	0.9	
Exports to Marocco	0.8	
Pumped hydro (consumption)	3.0	

[1] Includes electricity generation from waste.

[2] Includes generation from biofuel, diesel engines, gas turbines, and vapor turbines.

Source: `https://demanda.ree.es/visiona/peninsula/nacionalau/tablas/2025-04-28/2`.

Table B.3: Volumes of Redispatching Actions (April 28, 2025 at 12 p.m.–1 p.m.)

Stage	Direction	GWh
Day-ahead	Upwards (INC)	1.9
Day-ahead	Downwards (DEC)	1.9
Real-time	Upwards (INC)	0
Real-time	Downwards (DEC)	0.6

Source: REE (2025c).

Table B.4: Summary Statistics

Variable	Definition	Unit	Year	Obs.	Mean	Std. Dev.	Min	Max
cost	Total hourly costs of redispatching actions	€	2019	2,927	34,027	27,163	−8,530	526,995
			2020	2,927	70,168	37,890	11,050	222,905
			2021	2,906	61,337	50,287	−50,651	457,260
			2022	2,927	116,370	164,609	−117,972	1,944,526
			2023	2,927	204,599	146,482	−16,310	1,411,926
			2024	2,927	320,514	158,193	42,593	1,013,727
			2025	2,855	489,508	209,328	62,617	1,322,087
cc	Hourly net redispatching volumes of CC	MWh	2019	2,927	514	476	−1,095	2,452
			2020	2,927	1,062	656	−689	3,329
			2021	2,906	992	517	−724	3,178
			2022	2,927	780	608	−1,432	3,200
			2023	2,927	1,166	635	−634	5,092
			2024	2,927	1,576	770	163	4,790
			2025	2,855	2,724	1,042	−11	7,318
synch	Hourly net redispatching volumes of all synchronous generators	MWh	2019	2,927	649	528	−838	3,420
			2020	2,927	1,184	619	−695	4,151
			2021	2,906	948	661	−1,404	4,047
			2022	2,927	878	721	−1,744	4,160
			2023	2,927	1,148	671	−980	5,686
			2024	2,927	1,811	886	−335	5,066
			2025	2,855	2,027	931	−557	6,941
ibr	Hourly net redispatching volumes of all IBR	MWh	2019	2,927	−326	244	−2,093	405
			2020	2,927	−821	431	−3,756	376
			2021	2,906	−567	302	−3,216	1,627
			2022	2,927	−341	407	−3,355	968
			2023	2,927	−806	704	−5,144	519
			2024	2,927	−1,391	1,150	−7,274	3,832
			2025	2,855	−1,717	1,157	−7,115	728
nl-fc	Hourly day-ahead forecast of net load	MWh	2019	2,927	20,471	4,223	9,194	32,081
			2020	2,927	17,145	4,084	5,224	31,776
			2021	2,906	18,193	4,939	4,203	32,026
			2022	2,927	16,346	5,017	2,057	30,152
			2023	2,927	13,147	5,817	−555	29,937
			2024	2,927	12,934	6,089	−3,640	31,587
			2025	2,855	13,943	6,418	−3,788	30,477

Notes: Synchronous generation includes nuclear, combined cycle gas (CC), coal, combined heat and power, hydropower, pumped hydro (generation), and thermosolar. Generation from IBR include wind and front-of-meter photovoltaics. The net load day-ahead forecast is calculated by subtracting the forecasted available generation from IBR from the day-ahead demand forecast.

Table B.5: Regression Results with Day-Ahead Redispatch

	(1) cc^{DA}	(2) $sync^{DA}$	(3) ibr^{DA}	(4) $cost^{DA}$
post	1,439.14	846.86	−733.20	202,228.76
	(15.62)	(16.54)	(14.29)	(2,911.70)
nl-fc/1000	34.36	−36.77	66.97	−12,092.70
	(4.91)	(5.2)	(4.49)	(914.91)
$(\text{nl-fc}/1000)^2$	−3.13	−1.4	−3.13	−0.75
	(0.35)	(0.37)	(0.32)	(64.53)
$(\text{nl-fc}/1000)^3$	0.04	0.04	0.07	5.66
	(0.01)	(0.01)	(0.01)	(1.40)
Business day FE	Yes	Yes	Yes	Yes
Year-of-sample FE	Yes	Yes	Yes	Yes
Month-of-year FE	Yes	Yes	Yes	Yes
Hour-of-day FE	Yes	Yes	Yes	Yes
Obs.	20,396	20,396	20,396	20,396
Adj. R^2	0.74	0.62	0.55	0.73

Notes: Hourly data covering approximately two months before and after the blackout (March–June) for each year of the sample (2019–2025). Standard errors are reported in parentheses.

Table B.6: Regression Results with Real-Time Redispatch

	(1) cc^{RT}	(2) $sync^{RT}$	(3) ibr^{RT}	(4) $cost^{RT}$
post	−80.41	−67.18	335.69	−60,164.98
	(19.31)	(23.21)	(17.82)	(4,695.72)
nl-fc/1000	26.16	54.97	271.34	4,112.64
	(6.07)	(7.29)	(5.6)	(1,475.48)
$(\text{nl-fc}/1000)^2$	1.41	0.21	−12.81	134.37
	(0.43)	(0.51)	(0.39)	(104.08)
$(\text{nl-fc}/1000)^3$	−0.03	0	0.2	1.24
	(0.01)	(0.01)	(0.01)	(2.26)
Business day FE	Yes	Yes	Yes	Yes
Year-of-sample FE	Yes	Yes	Yes	Yes
Month-of-year FE	Yes	Yes	Yes	Yes
Hour-of-day FE	Yes	Yes	Yes	Yes
Obs.	20,396	20,396	20,396	20,396
Adj. R^2	0.41	0.29	0.40	0.42

Notes: Hourly data covering approximately two months before and after the blackout (March–June) for each year of the sample (2019–2025). Standard errors are reported in parentheses.

Table C.7: Regression Results using Daily Average Values

	(1) cc	(2) sync	(3) ibr	(4) cost
post	1,342.72	783.88	−383.58	144,145.78
	(70.01)	(81.99)	(81.1)	(12,300.04)
nl-fc/1000	185.03	51.36	335.98	5,371.71
	(64.21)	(75.2)	(74.39)	(11,281.89)
$(\text{nl-fc}/1000)^2$	−7.58	−2.53	−14.86	−584.47
	(4.25)	(4.97)	(4.92)	(745.91)
$(\text{nl-fc}/1000)^3$	0.07	0.04	0.24	13.8
	(0.09)	(0.10)	(0.10)	(15.64)
Business day FE	Yes	Yes	Yes	Yes
Year-of-sample FE	Yes	Yes	Yes	Yes
Month-of-year FE	Yes	Yes	Yes	Yes
Obs.	851	851	851	851
Adj. R^2	0.81	0.59	0.64	0.86

Notes: Daily average data covering approximately two months before and after the blackout (March–June) for each year of the sample (2019–2025). Standard errors are reported in parentheses.

Table C.8: Regression Results with Day-Ahead Redispatch using Daily Average Values

	(1) cc^{DA}	(2) sync^{DA}	(3) ibr^{DA}	(4) cost^{DA}
post	1,430.63	851.24	−731.14	204,774
	(58.46)	(61.20)	(53.04)	(10,758.19)
nl-fc/1000	142.61	−24.28	94.32	−1,817.77
	(53.62)	(56.13)	(48.65)	(9,867.67)
$(\text{nl-fc}/1000)^2$	−9.64	−1.65	−3.82	−1,079.73
	(3.55)	(3.71)	(3.22)	(652.4)
$(\text{nl-fc}/1000)^3$	0.16	0.05	0.06	35.22
	(0.07)	(0.08)	(0.07)	(13.68)
Business day FE	Yes	Yes	Yes	Yes
Year-of-sample FE	Yes	Yes	Yes	Yes
Month-of-year FE	Yes	Yes	Yes	Yes
Obs.	851	851	851	851
Adj. R^2	0.81	0.69	0.66	0.81

Notes: Daily average data covering approximately two months before and after the blackout (March–June) for each year of the sample (2019–2025). Standard errors are reported in parentheses.

Table C.9: Regression Results with Real-Time Redispatch using Daily Average Values

	(1) cc^{RT}	(2) $sync^{RT}$	(3) ibr^{RT}	(4) $cost^{RT}$
post	−87.91	−67.36	347.56	−60,628.21
	(48.3)	(62.37)	(51.8)	(9,963.24)
nl-fc/1000	42.42	75.64	241.67	7,189.48
	(44.3)	(57.21)	(47.51)	(9,138.53)
$(\text{nl-fc}/1000)^2$	2.06	−0.87	−11.04	495.27
	(2.93)	(3.78)	(3.14)	(604.2)
$(\text{nl-fc}/1000)^3$	−0.09	0.00	0.17	−21.42
	(0.06)	(0.08)	(0.07)	(12.67)
Business day FE	Yes	Yes	Yes	Yes
Year-of-sample FE	Yes	Yes	Yes	Yes
Month-of-year FE	Yes	Yes	Yes	Yes
Obs.	851	851	851	851
Adj. R^2	0.55	0.35	0.47	0.65

Notes: Daily average data covering approximately two months before and after the blackout (March–June) for each year of the sample (2019–2025). Standard errors are reported in parentheses.