Network Operation and Constraints and the Path to Net Zero

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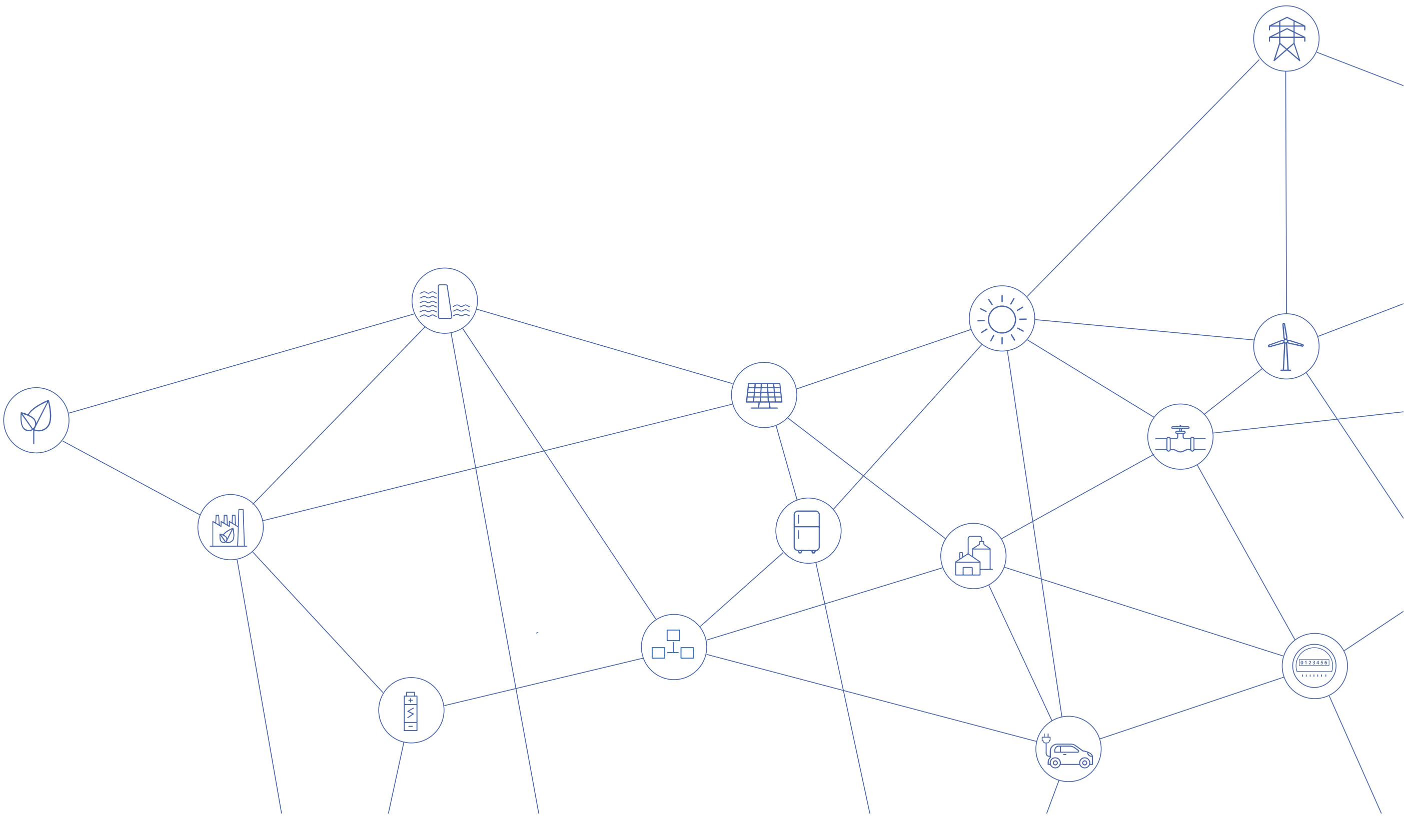

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Abstract

Operating a reliable power system requires respecting strict safety and security criteria such as avoiding grid congestion, minimum levels of inertia, maintaining voltage levels, and having minimum adequacy reserves. However, large scale integration of intermittent renewables is transforming grid operation by creating new operational challenges. When operational security criteria are not met in parts of the network, system operators use ancillary services (redispatching) to activate or curtail specific generation units to manage the flows. In Spain, the volumes and costs of redispatching have multiplied by two and nine times between 2019 and 2023, respectively. In 2023, volumes peaked at 16.5TWh and the costs to 2.1b€. A similar picture is emerging in other countries. We investigate the determinants of network constraints associated with redispatched volumes after the day-ahead and intraday markets. To our knowledge, this is the first study to examine this topic in detail at national level. We use the seasonal autoregressive ARIMA time-series estimator method with hourly operational and market data (2019-2023). We find that actions to alleviate network congestion represent one-third of the redispatched volumes, though increasing every year. After day-ahead markets, most redispatched volumes are aimed at voltage problems, which aggravates when demand decreases, or generation from wind and photovoltaics (power electronics generation) increases. After intraday-markets, two thirds of the redispatched volumes were related to insufficient adequacy reserves, which calls for backup fossil fuel plants. We provide operational and regulatory recommendations aimed at minimizing volumes of these network constraints and the need for corrective actions.

Keywords: Network operation, renewable integration, redispatching, synchronous generation, power electronics, network congestion, voltage issues, reliability criteria.

1. Introduction

Renewable energy sources (RES) are essential for decarbonizing power systems and achieving climate change targets. Transmission and distribution grids are the backbone of the electricity system and transport the renewable energy from production to consumption areas. IEA (2023) states that countries need to pay more attention to grids to support large scale integration of RES to connect the anticipated large amount of them. They estimate that achieving current environmental targets it is essential to add or refurbish over 80 million kilometers of grids until 2040. In many countries, the lack of hosting capacity is constraining the connection of new RES and estimates 3TW of RES are waiting in grid connection queues. IEA emphasizes the need to improve grid operation to accommodate the intermittent generation sources. Grid investments needed to achieve the clean energy transition targets in Europe account for 584 billion of € European Commission, 2023a).

Efficient integration of RES requires enough grid hosting capacity to avoid congestion and bottlenecks while respecting other operational constraints such as minimum grid reserves, voltage constraints, or minimum adequacy reserves. This is essential for a reliable and safe grid operation that minimizes the risk of blackouts and their economic impact (Andrersen et al., 2023). When one of these constraints is not respected, system operator activates or curtails some generators through ancillary services, referred to as redispatching in Europe.[1] Davi-Arderius et al. (2024) analyze the volumes of energy activated by system operators to ensure network operational safety after the day-ahead markets in Spain (2019-2022) and observe an increasing replacement of RES by pollutant synchronous generators to avoid network constraints. They conclude that focusing on grid congestions is necessary, but not a sufficient condition to efficiently integrate RES in the power system. Davi-Arderius et al. (2023c) find that volumes redispatched by system operator accounted for 6-11% of all emissions from the power system in Spain (2019-2021), which reduced the environmental benefits from replacing pollutant technologies by RES. Moreover, these volumes amounted to curtailment of up to 8% of all the wind scheduled production.

System operators need to replace RES -wind or photovoltaics- by combined cycle or coal plants after the day-ahead markets more frequently because of two main reasons. First, a lack of grid capacity to export RES output, which used to be concentrated in specific regions with optimal weather conditions. Second, RES are made of power electronics converters, whose operational and dynamic response to control frequency or voltage differs from those of synchronous fossil fuel plants. Thus, higher volumes of RES might affect network security criteria, and complicate grid operation in decarbonized power systems (Chamorro et al., 2016; Davi-Arderius et al., 2023b).

The aim of this paper is to analyze the determinants of network operational constraints in the day-ahead and real-time in a highly decarbonized power system, namely Spain. We study the 2019-2023 and combine market data from the Spanish Nominated Energy Market Operator (NEMO) with operational data from the Spanish Transmission System Operator (TSO) (OMIE, 2024; REE, 2024).[2] We use the hourly scheduled energy by

[1] In this paper we use the term system operator to refer either to Transmission System Operator (TSO) or Distribution System Operator (DSO).

[2] The Nominated Electricity Market Operator (NEMO) corresponds to the entity designated by the competent authority to perform tasks related to single day-ahead or single intraday market coupling. Link: https://www.nemo-committee.eu/

technology in the day-ahead spot and intraday markets in the Spanish bidding zone. The market data is merged with operational data made of hourly volumes after day-ahead and intraday markets and classified by the network operational constraint. These volumes are known as 'redispatching' in the European Regulation. The combination of market and operational data is another contribution of this analysis. We use the seasonal ARIMA time-series estimator (SARIMA) method, where variables are differentiated to ensure their stationarity (Dickey et al, 1979). A lagged endogenous variable and seasonal components capture the time dynamics.

The impact of RES on network operational constraints has been widely analyzed in many theoretical studies (Tielens et al., 2016; Gu et al., 2017; Bialek, 2020; Denholm et al., 2020; Makolo et al., 2021). Moreover, most studies of efficient integration of RES in the power systems focus on potential grid bottlenecks through planning models. In the energy economics literature, these studies can be classified into techno-economic models (Fraunholz et al., 2021; Skolfield et al., 2022), economic models (Hancevic et al., 2022; Gutierrez-Meave et al., 2023) and incentive regulation models (Zenón et al., 2017; Hesamzadeh et al., 2018). Some studies also quantify the need to build new grid infrastructure (Costa-Campi et al., 2020; Davi-Arderius et al., 2023b). However, to our knowledge, the impact of RES on network security criteria at a highly decarbonized power system national level has not been empirically assessed. This analysis has general relevance since our results also shed light on future operational constraints in other countries with high levels of RES. Solving operational constraints requires a combination of inter-related long-term solutions. These include requesting additional technical capabilities for new RES, limiting excessive concentration of RES in some grid areas, defining an optimal combination of different RES technologies across the system, setting specific tariffs to incentivise demand in certain hours or regions, implementing ancillary services, or boosting investments in grid digitalization to anticipate network constraints and set the most optimal solution.

The remainder of the paper is organized as follows. Section 2 reviews the literature about the integration of RES. Section 3 describes the Spanish case. Section 4 outlines the methodology and empirical strategy. Section 5 describes the data used. Section 6 presents the results. Finally, Section 7 is conclusions.

2. Integrating RES in the Power System

2.1. Grid planning

The energy planning and potential impacts of RES on the electricity flows, congestion and future grid investments have attracted the attention of many scholars. The decarbonization of the power system substantially changes the electricity flows. In many cases, the optimal areas for new RES -considering maximum annual production- does not match with the location of the replaced polluting plants or with the available grid capacity (Costa-Campi et al., 2021; Goke at al., 2022). In recent years, the limited grid capacity to connect new installations is one of the main barriers to connect new RES as they also require additional grid investments.[3]

[3] https://www.iea.org/reports/is-the-european-union-on-track-to-meet-its-repowereu-goals.

In energy economics literature, there are mainly three types of models about the grid planning. First, the techno-economic models are related to the energy system optimization models and provide results on economic variables. They complement the traditional optimal power flow models used in the assessment of the potential transition to nodal pricing or splitting bidding zones, (Kunz et al., 2016; Fraunholz et al., 2021; Skolfield et al., 2022). In terms of transmission grids, techno-economic models use exogeneous assumptions on capacity expansion. Sarmiento et al. (2019) applies GENeSYS-MOD models to the Mexican power system, while Oei et al (2020) applies the same models on regional characteristics for high renewable configurations to China, India, South-Africa, Mexico, Europe, Germany, and Colombia. Sarmiento et al. (2021) apply GENeSYS-MOD, ReEDS 2.0, urbs-MX and NANGAM models to examine the impact of natural gas prices on the power systems of Mexico and the US. Rahdan et al., (2024) quantify the potential impacts of distributed generation on distribution costs and electricity losses at European level through the PyPSA-EurSec open model. Costa-Campi et al., (2020, 2021) and Davi-Arderius et al. (2023b) study the Spanish transmission grid with gravity models and quantify potential grid investments related to different location for new RES. Conlon et al. (2019) uses a Renewable Target Model (RTM) to evaluate the transmission grid investments related to different scenarios of RES penetration in New York State's grid and use an optimization software over the 2007-2012 period to find optimal level of investments.

The second type are economic models that analyze the input and outputs of the energy markets in the economy, and economic variables such as prices, elasticities, gross domestic product, employment, or CO2 emissions. Transmission network is considered as an input, and results are obtained for different assumptions and scenarios made on the grid capacity investment. For instance, Hancevic et al. (2022) develop an economic framework to provide insights into the economic and environmental effects of promoting the renewable energy industry in Mexico. Gutierrez-Meave et al. (2023) analyze the potential economic effects of accelerated electrification and decarbonization in selected Latin American countries with an economic equilibrium model.

In the third type of models, incentive-based regulatory models bi-level programming combine a power-flow model (lower-level) with an incentive-regulatory model (upper-level) that incentivize and efficiently expansion of the transmission grid. Hogan et al. (2010) study the regulatory approaches to transmission expansion compatible with merchant investment in the context of price-taking generators and loads. Zenón et al. (2017) study transmission planning of the Mexican electricity market and analyze welfare-optimal network expansion with two modeling strategies: an incentive price-cap mechanism to promote the expansion of Mexican networks, and a centrally planned grid expansion by an independent system operator (ISO) within a power-flow model. Hesamzadeh et al. (2018) study electricity transmission pricing and investment with the HRGV approach, based on a bilevel optimization with the transmission company (Transco) at the top and the ISO at the bottom level. Varawala et al. (2023) considers an incentive-based market clearing mechanism using a power network representation with a distinctive feature of incomplete information regarding generation costs.

The outcomes of these models are used to set regulatory framework for an efficient grid expansion (Egerer et al., 2015; Hesamzadeh et al., 2020). In these models, grid investments are associated with potential congestions or grid bottlenecks. However, there are other operational constraints that limit the full operation of RES such as inertia or voltage control issues (Davi-Arderius et al., 2023c). These are known as operational security criteria.

2.2. Operational security criteria

A reliable operation of the power systems requires compliance with specific grid operation security criteria such as respecting thermal limits, maintaining flows, voltage and frequency within predetermined levels, and ensuring minimum capacity reserves. In the short-term, system operators must forecast energy flows and validate if these criteria are met for the next hours or days and, if needed, take corrective actions. In real-time, system operators must also validate these criteria with monitoring devices. The following are the main security criteria for a safe grid operation. Appendix A describes further details of these security criteria and potential mitigation measures that system operators might use.

- **Congestions**: Each element of the grid has a maximum capacity for energy flows, also known as thermal limit or maximum congestion. Congestion in parts of the grid, are expected to be positively correlated with the total electricity demand or higher volumes of RES production.
- **Grid reliability**: Relates to the redundant grid to assume the disconnection of a line or transformer without disrupting the electricity supply. They are also known as N-1 or N-2 security criteria if it refers to the disconnection of one or two grid assets, respectively. Grid reliability issues are expected to follow similar patterns as congestion.
- **Voltage**: An electrical parameter that must be within predetermined levels to ensure the safety conditions of the network and quality of supply. Voltage problems are more likely to happen during low demand times because of the surge impedance loading (SIL) effect: the load level determines whether a line behaves as a capacitor that injects reactive energy (and increases voltage), or as an inductance that consumes reactive energy (and reduces voltage).
- **Frequency**: Relates to the oscillation of voltage generated by rotating machines which corresponds to its nominal value (50Hz in Europe and 60Hz in the US) when generation and consumption are balanced. Thus, frequency stability issues are more likely to happen when volumes from synchronous generation decrease.
- **Adequacy reserves**: Relates to the volume of dispatchable (upward and downward) scheduled generation to immediately solve unbalances between generation and consumption. Deficit of adequacy reserves are more likely to happen when volumes of dispatchable technologies are low.

2.3. Technical solutions

Table 1 summarizes the technical solutions to deal with operational problems: thermal limits, voltage control and frequency (inertia). The table also identifies which regulatory instruments can be used for each technical solution. Below we describe them:

- **Operational rules**: refers to the criteria used to operate the transmission and distribution grids, which define situations under which grid should be reconfigured, i.e. transformers or lines should be switched.
- **Grid planning criteria**: means the criteria used by system operators to build new lines and transformers, or reinforce existing ones (Caputo et al., 2023).

- **RES requirements**: refers to the technical requirements that RES should fulfil when they connect. In Europe, they are set in the Grid Connection Codes and their national implementation rules (Schittekatte et al., 2021).
- **Ancillary or local services**: consists of services necessary for the operation of the power system, but not including congestion management. These services can or not be procured under market-based (Electricity Regulation (EU) 2019/943).
- **Hourly ToU tariffs**: include different hourly charges to incentivize consuming electricity on some periods over others. Tariffs might also be time-spatial dependent (Wang et al., 2023).
- **Locational incentives**: include different regional charges for consumers/generators, locational auctions for new RES (Davi-Arderius et al., 2023b).

3. Redispatching in Spain

The Electricity Directive (UE) 2019/944 mandates system operators to ensure secure operation of the grid and if some network operational constraint is not respected, they should take action. First, they should use (non-costly) solutions such as changing network configuration with the operation of lines. When these actions are not sufficient, they should reschedule production (or consumption) from specific generators (or consumers), namely redispatching actions in Europe.[4]

In transmission grid planning, operators use scenarios of future generation and consumption to identify potential grid investments. In some countries, the redispatching needs within a bidding zone are considered in a second stage and network expansion is made towards a congestion-free transmission network. Kemfert et al. (2016) show that considering the trade-offs between transmission expansion and generation dispatch minimizes grid investments and provides a higher welfare from transmission capacity expansion. However, redispatching needs might encourage some market participants to change their bidding strategy and capture these congestion rents. They state that the optimal transmission expansion is defined by the minimum level of congestion and network expansion cost. Strategic behavior in redispatching is mostly related to abuse of market power or inc-dec gaming (Palovic et al., 2022).

[4] In Electricity Regulation (EU) 2019/943, redispatching is defined as “a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security”.

Table 1. List of technical solutions and their potential impact on the three operational constraints. For details see Appendix A.
Source: ENTSOE (2021), Davi-Arderius et al. 23a) and own elaboration

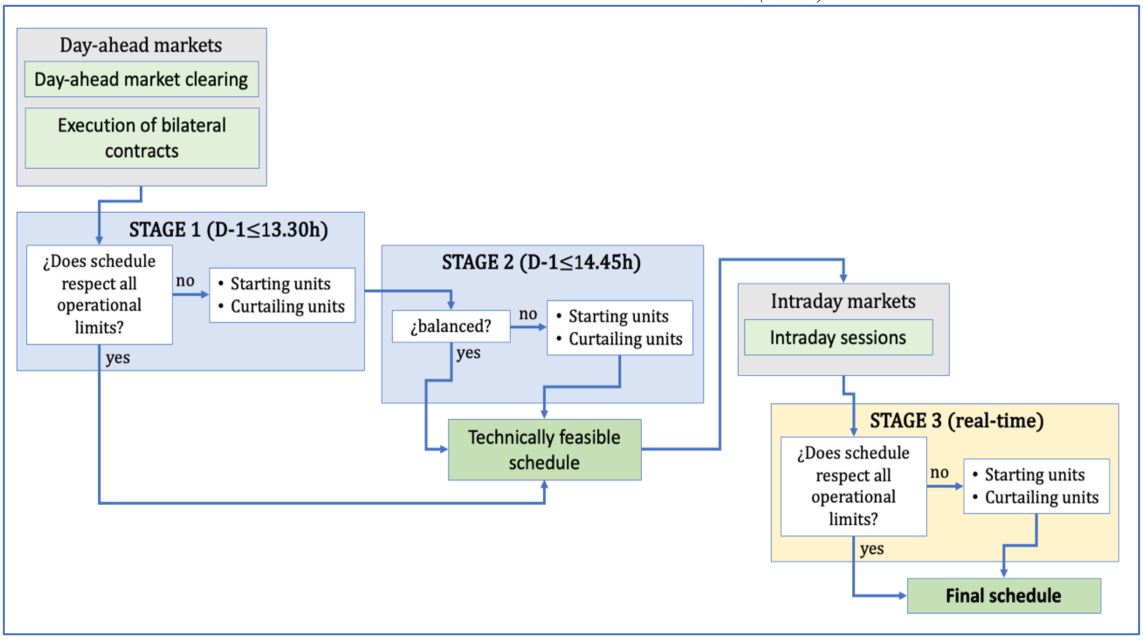
	Does the technical solution solve the operational constraint?				Regulatory instrument					
Technical solution	**Congestions & grid reliability** (need to curtail units)	**Voltage control** (need to replace RES by synchronous)	**Frequency (inertia)** (need to replace RES by synchronous)	**Adequacy reserves** (need to start thermal units)	*Operating rules*	*Grid planning criteria*	*RES requirements*	*Ancillary or Local Services*	*Hourly ToU tariffs*	*Locational Incentives*
Higher cross-border capacity	Yes	Yes, in the case of HVDC connections	Yes	Yes		X				
New lines and transformers	Yes	Yes, if loads in HV lines are above SIL	Yes, if interconnect different areas	No		X				
Switching lines and transformers	Yes	Yes, if loads in HV lines are above SIL	Yes, if interconnect different areas	No	X					
Dynamic Line Rating (DLR)	Yes	No	No	No	X	X				
Higher consumption in the affected nodes	Yes, if reduces need to transmit energy over long distances	Yes, if loads in HV lines are above SIL	Not clear (consumption reduces inertia)	No	X				X	X
New capacitors and reactances	No	Yes	No	No		X				
Storage in the RES curtailed plants	Yes,	Yes, for storage in GFM	Yes, for storage in GFM	No			X	X	X	
Virtual inertia in power electronics + battery	No	No	Yes	No			X	X		
Grid forming in RES power electronics	No	Yes	Yes	No			X	X		
Flywheels in RES	No	No	Yes	No		X	X	X		
Synchronous condensers	No	Yes	Yes	No		X	X	X		
Advanced power electronics in RES to control reactive energy	No	Yes	No	No			X	X		
Higher withstand capability of RES power electronics (RoCoF>1Hz/s)	No	No	Yes	Might reduce needs of reserves			X	X		
Static synchronous compensators (STATCOM), flexible AC transmission system (FACTS)	Yes, they can control flows in meshed grids	Yes, for STATCOM with batteries	Yes	No		X	X	X		

Note: Dispatchable energy reserves are not included in this table as they can only be solved through activating generators and consumers

In 2020, the costs of remedial actions in the European countries amounted to 3.6 billion Euros, and redispatching 2.3 billion Euros. ACER and CEER (2022) state that only 66% of all the remedial actions are related to congestion issues, while 26% are related to voltage issues. At the EU level, Germany, Poland, and Spain have the highest volumes of energy redispatching, while Italy, Spain and Germany have the highest costs. This highlights the impact of these actions in the costs for customers.

In Spain, redispatching processes are divided in three Stages (Figure 1) (Table 2). In the day-ahead (Stage 1), NEMO publishes the day-ahead market schedule per bidding zone for the next day every day before 13h30. This is the raw data and the sum of scheduled generation (+imports) equals to the scheduled consumption (+exports) (Schittekatte et al., 2021).

Figure 1. Flowchart describing the processes for remedial actions in the day-ahead (redispatching in Stages 1 and 2), and in the real-time (Stage 3). Source: Own elaboration based on MICT (2015)



In Stage 1, TSO and DSO carry out a security analysis of the day-ahead market schedule for the next hours, i.e. assess potential grid bottlenecks (congestions issues), the N-1 security criteria (grid reliability), frequency stability problems, inertia needs, reactive energy flows and voltage control issues, and adequacy reserve of upwards/downwards dispatchable units (MICT, 2016). If need, they should take (non-costly) remedial actions such as changing the network topology, changing the substation configuration, or switching reactances or capacitors. If these actions are not enough, TSO and DSO should act on specific generators or consumers, i.e. take redispatching actions.[5]

Once all redispatching actions are taken in Stage 1, the TSO must restore the system balance, i.e. the sum of the of generation (and imports) must equal to the sum of

[5] In Spain, owners of the market scheduled units provide two mandatory bids. First, a bid to increase its generation (or consumption) up to the maximum available production (or consumption) when the scheduled generation (or consumption) in the day-ahead does not match its maximum capacity. Second, a bid to decrease its generation (or consumption) when the scheduled generation (or consumption) in the day-ahead is not zero. TSO is the operator of the redispatching market and when DSO needs actions, TSO procures on behalf of DSO.

consumption (and exports). In the day-ahead, the system is balanced with volumes in Stage 2. At this moment, the day-ahead market schedule becomes a day-ahead feasible schedule, which should be published before 14h45 in the day-ahead.

Then, positions from generators and consumers are traded in the intraday markets. As before, the intraday-market schedule also published by NEMO should be assessed by TSO and DSO. The system balance is made with the activation of balancing reserves. Finally, unforeseen events might cause overloads, frequency stability problems, inertia needs or voltage control issues. In such cases, TSO and DSO should take remedial actions in real-time when they cannot be corrected with network reconfiguration or in the intraday markets. These actions are made in Stage 3 (MICT, 2015; CEER, 2021). Redispatching actions are economically compensated considering the criteria in Table 3. Precisely, non-compensating the curtailed generators in the Stage 1 is behind many complaints by RES owners.[6]

Table 2. Compensation scheme to the redispatched units in the Spanish Regulatory Framework Source: MITECO (2019b) and CNMC (2022b)

		Upward actions	**Downward actions (curtailment)**
Day-ahead	**Stage 1**	Compensated at bid prices	Not compensated
	Stage 2	Compensated at bid prices	Compensated at bid prices
Real-time	**Stage 3**	Compensated at bid prices	Compensated at bid prices

In Spain, the annual costs for volumes between 2019 and 2023 have multiplied by nine and amount to 2.15 b€ in 2023. In 2022 the annual volumes of activated energy in the day-ahead decreased from 8,042 GWh to 5,856 GWh (-27%), which coincides with the implementation of the new *Sistema Automático de Reducción de Potencia* (SARP).[7] Under this mechanism, generators -that voluntarily participate- must be tripped (in seconds) by the system operator when some security criteria are not respected. In consequence, system operators do not need to fulfill the N-1 security criteria and generators are not preventively curtailed. However, volumes in 2023 increase again. In the same period, volumes in day-ahead and real-time increased by 56 and 1797%, respectively. According to ACER and CEER (2022), 71% (300 M€) of the redispatched costs in the day-ahead in 2020 were used to solve voltage issues. This highlights that overloads were not the main problem in the day-ahead, which might be explained by the relevant investments made in the transmission grid during the last decade and its criterion of prudence in connection of new RES (MITECO, 2019a). In the Spanish regulatory framework, RES cannot be connected to the grid if the TSO or DSO identify a future grid bottleneck (Table 3).[8] In previous literature Davi-Arderius et al (2023c, 2024) focus on volumes activated in the day-ahead, while volumes activated on real-time have not been analyzed previously.

[6] https://www.elmundo.es/economia/empresas/2023/07/21/64ba9be9e9cf4a5e368b45a3.html
[7] https://www.cnmc.es/prensa/procedimiento-congestiones-20220125
[8] Between 2010 and 2020, the length of 400kV lines increased from 18,799 km to 21,764 km (+15.6%), and the length of 220kV lines increased from 17,755 km to 19,939km (+12.3%). Source REE (2024). In Spain, the assessment to connect RES includes avoiding grid congestions.

Table 3: Annual volumes and costs.
Source: REE (2024)

		Units	2019	2020	2021	2022	2023
	Annual demand	GWh	249.900	237.205	243.862	235.437	229.282
Day-ahead (Stages 1+2)	Volumes	GWh	7,058	9,979	8,042	5,856	11,030
	Economic cost	M€	239	423	443	473	912
Real-time (Stage 3)	Volumes	GWh	290	1,091	2,345	2,429	5,502
	Economic cost	M€	7.2	103	421	796	1,233
Total	**Volumes**	GWh (% annual demand)	**7,248**	**11,070**	**10,387**	**8,285**	**16,532**
			2.90%	4.67%	4.26%	3.52%	7.21%
	Economic cost	M€	**246**	**526**	**864**	**1,269**	**2,145**

Note: Redispatched energy corresponds to the sum of the upward and downward energy redispatched.

4. Empirical Approach

This section describes the empirical approach followed to analyze the determinants of the network operational constraints in the day-ahead and real-time in Spain (2019-2023).

In the Day-ahead Technology Model, we estimate how the volumes activated after the spot market gate closure are determined by the scheduled generation for each technology ($daTECHN_{i,t}$). The dependent variable is the activated energy associated with the following network constraints: voltage issues ($daVoltage$), congestions ($daCongestions$), grid reliability ($daReliability$), or others ($daOthers$). The scheduled technologies are nuclear (N), combined cycle (CC), coal (CO), hydropower (H), pumping generation (PG), combined heat and power (CHP), thermosolar (TS), photovoltaic (PV), wind (W), and cross-border flows (I). Equation 1:

$$daVolumes_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot daVolumes_{t-1} + \hat{\beta}_2 \cdot daTECHN_t + \hat{\beta}_3 \cdot m_t +$$

$$+\hat{\beta}_4 \cdot holiday_t + \widehat{\emptyset} \cdot \Delta daVolumes_{t-24} + \varepsilon_t \qquad (1)$$

$$daTECHN = \left[\begin{matrix} N, CC, CO, H, PG, CHP, TS, PV, W, I \\ daDEM, daRES \end{matrix} \right]$$

$$daVolumes_t = \begin{bmatrix} daVoltage \\ daCongestions \\ daReliability \\ daOthers \end{bmatrix}$$

In the Day-ahead Demand Model, we analyze how the volumes activated are determined by the total demand after the day-ahead markets ($daDEM$) and the percentage of power electronics in the scheduled generation ($daRES$). As before, the dependent variable is the activated energy associated with each network constraint. Equation 2:

$$daVolumes_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot daVolumes_{t-1} + \hat{\beta}_2 \cdot daDEM_t + \hat{\beta}_3 \cdot daRES_t$$

$$+\hat{\beta}_4 \cdot m_t + \hat{\beta}_5 \cdot holiday_t + \widehat{\emptyset} \cdot \Delta daVolumes_{t-24} + \varepsilon_t \quad (2)$$

$$daVolumes_t = \begin{bmatrix} daVoltage \\ daCongestions \\ daReliability \\ daOthers \end{bmatrix}$$

In this case, the total scheduled demand after the day-ahead market ($daDEM$) and the rate of power electronics (non-synchronous) in the total demand ($daRES$) is calculated as shown in Equations 2 and 3.

$$daDEM_t = N_t + CC_t + CO_t + H_t + PG_t + CHP_t + TS_t + PV_t + W_t + I_t \quad (3)$$

$$daRES_t = \frac{PV_t + W_t}{daDEM_t} \quad (4)$$

In the Intraday Technology Model, we analyze how the volumes activated after the intraday gate closure are determined by the scheduled generation for each technology ($idTECHN_{i,t}$). The dependent variable is the activated energy associated with the same network constraints as in Equation 1 but adding adequacy reserves. Equation 5:

$$idVolumes_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot idVolumes_{t-1} + \hat{\beta}_2 \cdot daTECHN_t + \hat{\beta}_3 \cdot m_t +$$

$$+\hat{\beta}_4 \cdot holiday_t + \widehat{\emptyset} \cdot \Delta idVolumes_{t-24} + \varepsilon_t \quad (5)$$

$$idTECHN = [\begin{matrix} N, CC, CO, H, PG, CHP, TS, PV, W, I \\ daDEM, daRES \end{matrix}]$$

$$idVolumes_t = \begin{bmatrix} idVoltage \\ idCongestions \\ idReliability \\ diAdequacy \\ idOthers \end{bmatrix}$$

In this model, network constraints are related to voltage issues ($idVoltage$), congestions ($idCongestions$), grid reliability issues ($idReliability$), insufficient adequacy reserves ($idAdequacy$), or others ($idOthers$). Scheduled technologies correspond to nuclear (N), combined cycle (CC), coal (CO), hydropower (H), pumping generation (PG), combined heat and power (CHP), thermosolar (TS), photovoltaic (PV), wind (W), and cross-border flows (I).

In the Intraday Demand Model, we analyze how the volumes activated after the intraday gate closure are determined by total demand after the day-ahead markets ($idDEM$) and the percentage of power electronics in the scheduled generation ($idRES$). The dependent variable is the activated energy associated with each network constraint. Equation 6:

$$idVolumes_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot idVolumes_{t-1} + \hat{\beta}_2 \cdot idDEM_t + \hat{\beta}_3 \cdot idRES_t$$

$$+\hat{\beta}_4 \cdot m_t + \hat{\beta}_5 \cdot holiday_t + \hat{\emptyset} \cdot \Delta idVolumes_{t-24} + \varepsilon_t \qquad (6)$$

$$idVolumes_t = \begin{bmatrix} idVoltage \\ idCongestions \\ idReliability \\ diAdequacy \\ idOthers \end{bmatrix}$$

In this case, the total scheduled demand after the intraday market ($idDEM$) and the rate of power electronics in the total demand ($idRES$) is calculated as shown in Equations 7 and 8.

$$idDEM_t = N_t + CC_t + CO_t + H_t + PG_t + CHP_t + TS_t + PV_t + W_t + I_t \quad (7)$$

$$idRES_t = \frac{PV_t + W_t}{idDEM_t} \qquad (8)$$

In all models, seasonality is controlled by several dummy variables: m_t, a dummy variable for each month, while $holiday_t$ equals to 1 in weekends and national holidays. ε_t corresponds to the error term.

In the models, the estimated $\hat{\beta}_2$ represents the short-run effect of technologies or demand, i.e. the effect on the next hour.[9] In order to compare the contribution of each technology in different network constraints, we calculate the long-run effect, i.e. the average impact of each coefficient in each year. Equation 9:

$$Long\ run\ effect = \frac{\hat{\beta}_2}{(1-\hat{\beta}_1-\hat{\emptyset})} \qquad (9)$$

We cannot use the ordinary least square estimations because we include the lagged endogenous variable. This could lead to biases problems related to potential autocorrelation of residuals (Keele and Kelly, 2006). Instead, we use maximum likelihood estimators that have been utilised in studies that use similar estimates (Costa-Campi et al., 2018; Davi-Arderius et al., 2023c). We use a SARIMA time-series estimator, including the first lagged endogenous variable as an independent variable to capture its dynamics. Moreover, we include the lags of 24 endogenous variable as another independent variable to capture the daily seasonal patterns. Moreover, we differentiate all estimates to ensure their stationarity. The coefficients are estimated for the activated or curtailed volumes associated with each network operational problem in the day-ahead.

[9] Our models include the AR1 and AR24 estimates. Thus, a change in one hour "has some memory" and affect the next hours and days. This effect is solved when we calculate the long-term effect that considers both AR1 and AR24 coefficients (Equation 9).

In all cases, we perform five estimations, one per year (2019, 2020, 2021, 2022 and 2023) as there are notable differences during this period. First, the generation mix significantly changed between 2019 and 2023: photovoltaics capacity increases +144% up to 26.951MW, wind capacity increases +20% up to 30,718MW, and coal capacity decreases -64% up to 3.464MW (REE, 2024). Second, 2020 includes the covid lockdown and a major paralysis of the economic activity: in Spain the interannual GDP decreased -11.3% (INE, 2023), with a clear impact on the total electricity demand (Santiago et al., 2021). Third, the average wholesale price differs from one year to another (47,78€/MWh in 2019, 33,95€/MWh in 2020, 111,93€/MWh in 2021, 167,53€/MWh in 2022, and 87,69€/MWh in 2023 which might significantly affect the technologies operating in each year (OMIE, 2024). Finally, there is an ongoing process to commission new lines, cables, substations, and reactive compensation equipment by the TSO and DSO.

5. Data

Our data includes hourly data from the Spanish bidding zone between 2019 and 2023. The dataset used combines the operating data published by the Spanish TSO and market data published by the Spanish NEMO (REE, 2024; OMIE, 2024).

5.1. Scheduled energy

We use the day-ahead and intraday market schedule made after the day-ahead markets and after the intraday markets published by the Spanish NEMO. Tables 5 and 6.[10]

Table 5. Summary statistics the scheduled energy for each technology in the day-ahead $(daTECHN_t)$ *(N=43,795)*

Variable	Technology	Units	Mean	St.Dev.	Min	Max
CC_t	Combined cycle	MWh	3,291	3,435	0	15,666
CO_t	Coal	MWh	450	733	0	6,530
H_t	Hydropower	MWh	3,013	1,802	456	10,264
N_t	Nuclear	MWh	6,341	855	2,683	7,151
PG_t	Pumping Generation	MWh	270	459	0	2,649
PV_t	Photovoltaic	MWh	2,570	3,690	0	16,359
TS_t	Thermosolar	MWh	595	681	0	2,186
CHP_t	Combined Heat and Power	MWh	3,671	741	1,034	4,865
W_t	Wind	MWh	7,258	3,889	392	21,620
I_t	Cross-border flows	MWh	-516	2,457	-8,371	6,525
$daDEM_t$	Total demand	MWh	26,944	4,322	14,013	40,491
$daRES_t$	Generation from power electronics (PV + wind)	%	36.31	16.67	3.49	89.16

[10] Intraday schedule includes the energy scheduled after closing the last intraday session in each hour.

Table 6. Summary statistics the scheduled energy for each technology after the intraday markets $(idTECHN_t)$ *(N=43,795)*

Variable	Technology	Units	Mean	St.Dev.	Min	Max
CC_t	Combined cycle	MWh	4,891	3,219	165	16,111
CO_t	Coal	MWh	733	713	0	6,677
H_t	Hydropower	MWh	2,901	1,794	367	9,909
N_t	Nuclear	MWh	6,309	874	3,242	7,129
PG_t	Pumping Generation	MWh	266	464	0	2,656
PV_t	Photovoltaic	MWh	2,499	3,626	0	16,071
TS_t	Thermosolar	MWh	565	679	0	2,186
CHP_t	Combined Heat and Power	MWh	3,499	778	1,028	4,727
W_t	Wind	MWh	6,678	3,888	353	20,803
$idDEM_t$	Total demand	MWh	27,826	4,206	16,870	40,763
$idRES_t$	Generation from power electronics (PV + wind)	%	32.70	16.36	2.67	89.29

5.2. Network constraints

We use the network constraints in the day-ahead and real-time published by the Spanish TSO. Table 7 provides the summary statistics. The following are the type of network constraints we analyse (see Appendix A for details):

- **Voltage problems**: situations where voltage in the grid is out of the nominal parameters and system operators should activate and curtail generation units to control reactive power flows.
- **Congestion**: situations with grid bottlenecks (N security) at transmission and distribution grid level.
- **Reliability**: situations where the grid reliability criteria (N-1) at transmission grid level is not respected.
- **Adequacy reserve**: situations where volumes of very fast dispatchable generation in both directions (upwards and downwards is below the security level).
- **Others**: refers to other situations.

In the day-ahead processes, voltage problems are behind most of the dispatched volumes, while congestion and reliability problems account for less than one-third of the volumes. In real-time processes, the need to solve adequacy reserves represents the highest volumes.

Table 7. Volumes of energy activated and classified by network constraint (N=43,804).

Network Constraint	**Variable**	**Units**	**Mean**	**St.Dev.**	**Min**	**Max**
Voltage	$daVoltage_t$	MWh	550	512	0	3615
Congestions	$daCongestion_t$	MWh	189	174	0	891
Reliability	$daReliability_t$	MWh	183	366	0	3625
Others	$daOther_t$	MWh	35	114	0	1988
Voltage	$idVoltage_t$	MWh	44	129	0	1766
Congestions	$idCongestion_t$	MWh	2	19	0	898
Reliability	$idReliability_t$	MWh	53	185	0	4161
Reserves	$idReserves_t$	MWh	161	413	0	3376
Others	$idOther_t$	MWh	5	65	0	1852

Figures 2 and 3 show the annual volumes related to each of the above network constraints. In day-ahead, volumes in 2020 and 2023 peaked to 10TWh of energy and voltage problems were the main network constraints, while congestions and reliability problems hardly accounted for a third of volumes. In real-time processes, volumes increased exponentially between 2019 and 2023: from 43 TWh (2019) to 3391 TWh (2023). Moreover, ensuring adequacy reserves is the reason behind most of the actions.

Figure 2: Annual redispatched energy (Stage 1) by network constraint (2019-2023).

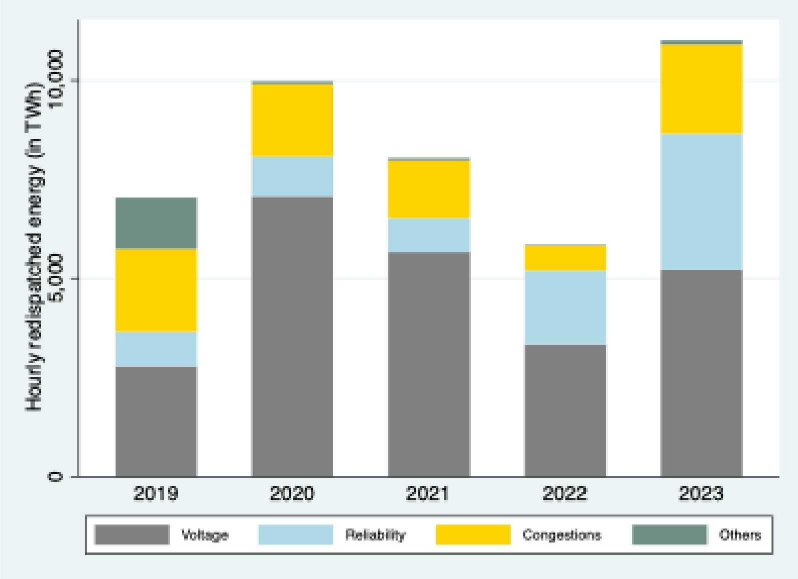
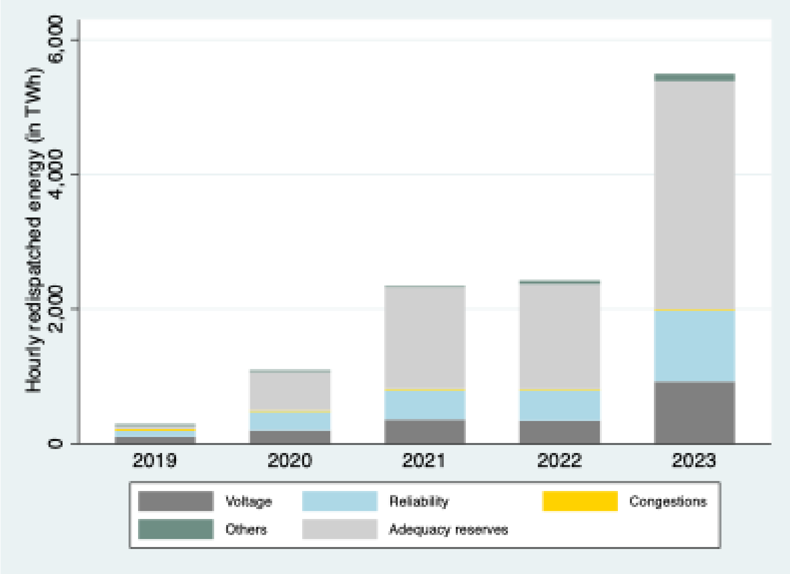


Figure 3: Annual redispatched energy (Stage 3) by network constraint (2019-2023).



In Appendix B, Figures B.1 to B.5 show the hourly activated energy by operational constraints and year after the day-ahead (Stage 1). The figures show some interesting results. First, total volumes peaked at the off-peak hours (night), while the opposite after the intraday markets and voltage constraints were the highest at this time. Second, congestion and grid reliability problems are higher during the peak demand period. Third, volumes of curtailed generation due to grid reliability problems are at a maximum in 2023.

Figures B.6 to B.12 in Appendix B show the hourly activated energy by operational constraints from 2019 and 2023 respectively after the intraday (Stage 3). As before, the figures show some noteworthy results. First, total activated volumes are at maximum at peak time and most were related to insufficient adequacy reserves. Second, volumes related to grid reliability were at maximum at peak time, almost all corresponded to curtailment of units. Third, very few volumes were used to solve congestion problems.

6. Results

6.1. Network Operational Constraints

This section describes the main results and a discussion of them. The estimates from our four models are shown in Appendix D and E: Day-ahead Technology, Intraday Technology, Day-ahead Demand and Intraday Demand. We present tables with the average coefficient of each determinant in each year using Equation 9, i.e. how each coefficient contributes to the redispatched volumes to solve each type of network operational constraint. The technology coefficients represent the additional volumes of redispatched energy (in MWh) associated with each additional scheduled MWh for each technology.

The coefficients for demand (Demand) represent the additional volumes of redispatched energy (in MWh) associated with each additional scheduled MWh after the day-ahead or intraday markets. Finally, coefficients for RES corresponds to the additional volumes of redispatched energy (in MWh) associated with percentual point of RES made of power electronics in the scheduled energy. Positive values are in red, while the negative values are in black. The colors of the cells compare the values: the highest numbers are in red, while the lowest ones are in green and the intermediate ones in yellow. Cells for values corresponding to RES do not have color as these coefficients are in different units.

First, determinants of voltage problems are shown in Table 8. After the day-ahead markets, almost all technologies show reduced voltage issues, except for nuclear in some years. In this case, coefficients for total demand are negative, meaning that total demand reduces the volumes for voltage issues. This is explained by the Surge impedance loading or SIL effect introduced in Section 2.2 and further developed in Appendix A.3: the load level determines whether a line behaves as a capacitor that injects reactive energy, or as an inductance that consumes reactive energy. However, coefficients associated with the rate of scheduled power electronics in the mix (RES) are positive for all years, which implies that voltage problems become greater when the scheduled power electronics increase.

Table 8. Annual determinants of volumes activated by voltage issues by the scheduled technologies.

	After Day-ahead					After Intraday				
Voltage	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
CC	-0.133	-0.208	-0.207	-0.151	-0.268	-0.005	-0.009	-0.036	-0.019	-0.029
Coal	-0.027	0.917	-0.254	-0.248	1.178					-0.066
Hydro	-0.081	-0.080	-0.076	-0.096	-0.122	-0.003	-0.007	-0.018	-0.012	-0.023
Nuclear		-0.122	-0.089					0.035		-0.027
Pumping	-0.063	-0.074	-0.097	-0.108	-0.166				-0.018	-0.024
Photovoltaics	-0.089	-0.076	-0.097	-0.082	-0.128	-0.004	-0.006	-0.014	-0.013	-0.013
Thermosolar	-0.078	-0.105	-0.115	-0.093				-0.016		-0.024
CHP	-0.214	-0.575	-0.377	-0.562	-0.872					-0.051
Wind	-0.062	-0.074	-0.064	-0.057	-0.085	-0.007	-0.007	-0.020	-0.018	-0.014
Imports	-0.044	-0.052	-0.084	-0.063	-0.101	-0.006	-0.003	-0.014	-0.012	-0.008
Demand	-0.082	-0.103	-0.107	-0.093	-0.146	-0.004	-0.005	-0.018	-0.014	-0.018
RES	5.569	3.008	8.468	12.336	12.026					1.002

Note: Missing values corresponds to non-significant coefficients in estimations from Appendix B and C.

A combination of the two effects (on total demand and rate of power electronics) are behind the coefficients associated to individual technologies: coefficients for some synchronous generators (combined cycle, coal and CHP) are much smaller than generators made of power electronics (photovoltaic and wind). After the intraday markets, some technologies are not associated with voltage problems, but the rest of coefficients follow similar patterns: those associated with synchronous generators are smaller than wind or photovoltaics. These results highlight the added value of synchronous generation associated to system voltage.

The results for network voltage constraints shed light on a challenge related to the decarbonization of the power systems; increasing production from photovoltaics or wind, both made of power electronics, requires solving new operational needs. As shown in Figures C.1 to C.5, solving voltage issues after the day-ahead is only related to starting new units. As shown in Figures D.1, D.3, D.5, D.7 and D.9, all activations after the day-ahead are coal and combined cycles. Thus, voltage problems are solved by the replacement of generators made of power electronics by combined cycle or coal plants.

Second, determinants of congestion are shown in Table 9. After the day-ahead markets, almost all technologies increase congestion, except for coal. This is confirmed by the coefficients associated to total demand, all positive, which means that overload problems are associated with higher demand and production from each technology, as is obvious. However, the table depicts another pattern: volumes associated to CHP, photovoltaics and thermosolar are higher than the rest of technologies, which might be explained because plants from these technologies are not all connected to the transmission grids, and photovoltaics and thermosolar are highly correlated. These results show that an efficient integration of RES needs assessing grid investments to minimize grid bottlenecks. After the intraday markets, very few coefficients are significant, which might be explained by the fact that almost all these problems are solved before starting intraday markets.

Table 9. Annual determinants of volumes activated by congestion issues by the scheduled technologies.

	After Day-ahead					After Intraday				
RTD	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
CC	0.036	0.028	0.011	0.002	0.007		0.001			
Coal	-0.051	-0.512	-0.382	-0.153	-0.684		0.002	0.003	0.001	
Hydro	0.021	0.016	0.011	0.006	0.014	-0.000				
Nuclear	0.080									
Pumping	0.036	0.002	0.011	0.006	0.020					
Photovoltaics	0.032	0.035	0.027	0.010	0.021			0.001		
Thermosolar	0.041		0.021	0.028						
CHP	0.113	0.181	0.093	0.095	0.064			0.008	0.004	
Wind	0.020	0.009						0.001		0.000
Imports	0.013	0.008	0.007	0.005	0.005			0.000		
Demand	0.024	0.023	0.012	0.006	0.010	0.000		0.000		
RES	-0.199	1.383	1.780	1.316	3.102				0.036	

Note: Missing values corresponds to non-significant coefficients in estimations from Appendix B and C.

Third, determinants of grid reliability are shown in Table 10. After the day-ahead markets, the scheduled production from almost all technologies increases grid reliability problems, except for coal. A similar pattern is found with positive coefficients associated with total demand, which means that grid reliability problems are clearly related to higher demand and production from each technology. However, this Table depicts another pattern: needs from thermosolar and CHP are substantially higher than the rest of technologies, which highlight the lack of grid capacity when scheduled. In Figures D.7 and D.9, the curtailment of photovoltaics and thermosolar scheduled production after the day-ahead market is noteworthy. After the intraday markets, photovoltaics, wind and thermosolar positively contributes to these problems. These results complement the determinants of congestion and confirm that decarbonizing the power system creates congestion problems.

Table 10. Determinants of volumes activated by grid reliability issues by the scheduled technologies.

	After Day-ahead					After Intraday				
SC	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
CC	0.015	0.010	0.005		-0.018			-0.004		-0.017
Coal	0.011	-0.080	-0.060	-0.034	-0.310		0.041			
Hydro	0.019	0.020	0.016	0.038	0.047				-0.004	
Nuclear			0.064	-0.160						0.043
Pumping	0.021	0.036			0.056	-0.007				
Photovoltaics	0.016	0.016		0.067	0.054				0.004	0.018
Thermosolar		0.084		0.236	0.181		0.025		0.016	0.030
CHP	0.187	0.181	0.110		0.202			0.030		
Wind	0.012	0.014	0.025	0.040	0.048	0.011	0.014	0.021	0.030	
Imports	0.006			0.052		0.002			0.011	
Demand	0.016	0.019	0.007	0.047	0.039	-0.001	0.001	0.000	0.001	0.011
RES	-0.003	0.011	-0.003	0.043	0.043	0.001	0.007	0.006	0.007	0.017

Fourth, determinants of solving deficits of adequacy reserves are shown in Table 11, which are only made after intraday markets. The table shows interesting patterns: the need to activate volumes and solve adequacy reserves decrease with the scheduled combined cycle or coal. Coefficients associated with photovoltaics are negative, but close to zero. On the contrary, volumes increase with the rest of technologies with extreme contribution from Hydro, Pumping Generation, Thermosolar and CHP plants. As shown in Figures D.6, D.8 and D.10, important volumes from combined cycle units are activated after the intraday markets. In conclusion, the power system needs always minimum volumes of combined cycle and coal to provide adequacy reserves, and when sufficient volumes of these are no scheduled in the market, they should be activated through redispatching processes. Finally, the determinants of solving other constraints are shown in Table F.6. After both the day-ahead and intraday, few technologies explain these constraints and there are not common patterns among them.

Table 11. Determinants of volumes activated by insufficient adequacy reserves by scheduled technologies.

	After Intraday				
RS	**2019**	**2020**	**2021**	**2022**	**2023**
CC	-0.003	-0.176	-0.145	-0.088	-0.158
Coal	-0.019			0.122	-0.499
Hydro	0.012	0.131	0.197	0.184	0.390
Nuclear			0.082		
Pumping	0.049	0.349	0.316	0.313	0.363
Photovoltaics			-0.014	-0.027	-0.016
Thermosolar			0.068	0.127	0.322
CHP		0.150	0.161	0.330	0.883
Wind		0.039	0.047	0.019	0.062
Imports	-0.003	0.028	0.056	0.044	0.088
Demand	0.002	0.051	0.078	0.069	0.182
RES	-0.899	-8.099	-22.645	-26.092	-52.160

6.2. Discussion of results

As shown in Figures 2 and 3, volumes associated with grid bottlenecks – congestions and grid reliability – are not behind most of the redispatched volumes. On the contrary, they are explained with voltage problems after the day-ahead and a deficit of adequacy reserves after intraday-markets. Thus, the statement that grid bottlenecks are the main problem in the operation of power system with high shares of RES does not seem to hold, at least in Spain. These results might be explained because system operators only connect a new unit if there is enough grid hosting capacity and non-firm connection agreements are not implemented in Spain, yet. In these cases, there is a firm capacity for 24/365 and a non-firm capacity during some hours a year when the grid hosting capacity is limited (CEER, 2023). Thus, non-firm connections or alleviating the current criteria to connect new RES could result in higher volumes associated with congestions, which must be assessed prior to its implementation to identify all costs and benefits and avoid concerns about additional volumes.

Electricity markets can make an efficient assignment of resources -generators and consumers- to minimize spot prices, but they do not necessarily provide technically feasible schedules. At this point, should we change the current European market design to also include these network constraints? A bold solution could be to implement nodal prices in Europe, but they are only useful for network constraints related to grid bottlenecks. In our study, we find that most volumes are activated for other operational constraints, i.e. voltage or capacity reserves. Moreover, it has been widely demonstrated that marginal prices and the current market design provides efficient outcomes and guarantees the demand coverage even under extreme shocks scenarios (Jamasb et al., 2024). Thus, it seems reasonable that solutions to minimize these volumes do not consider changes in the fundamentals of the current European market design.

When considering solutions to decrease these volumes, there are several recommendations. First grid planning models made in advance and used for identifying efficient grid expansion related to new RES should go beyond the assessment of only grid bottlenecks as they don't explain the full picture. We find that complex operational constraints are limiting a higher integration of RES in the power systems. They should also forecast operational issues such as voltage, inertia or adequacy reserves. However, this requires performing advanced dynamic simulations, which need more advanced software, grid structural data such as the resistances and impedances of the grid elements, and the dynamic models of the generators and consumers. In many cases, this information is not public. Related to the dynamic models of generators, some manufacturers are reluctant to make them public arguing for copyright issues (Manfren et al., 2020; Tao et al., 2022).[11] In this context, "digital twins" of real processes emerge as a feasible alternative solution and study like this, based on the past data, seems a good starting point.[12] Results from grid planning models should provide sufficient data to identify regulatory recommendations, some of which are described below.

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[11] Some manufacturers are reluctant to show the issues from their units to other manufacturers. Dynamic models show all detailed operation characteristics and technical capabilities of power electronics. In many cases, solutions implemented by them require costly research+development+innovation (R+D+I) processes and are part of property patents. In some Member States, dynamic models of generators are directly provided by manufacturers to the TSO and generators do not have access to them (MITECO, 2019c).

[12] Digital twin is a virtual model used to accurately reflect physical objects. This is a technology used to monitor, simulate, predict and optimize (Tao et al., 2022).

Second, implementing locational incentives in the long-term grid planning to limit the concentration of new RES, which includes moving from the unique (postal) tariff scheme to different regional tariffs (Morell-Dameto et al., 2024), implementing regional auctions for new RES (Davi-Arderius et al., 2023b), publishing grid capacity maps, defining conditions under which specific anticipatory grid investments for RES shall be granted, or accelerating permitting and administrative processes related to new grids (European Commission, 2023a). However, defining quotas for RES at regional level might become a controversial political issue between central, regional, and local administrations.

Third, the decision to phase out technologies in the climate change plans should go beyond the simple replacement of a MWh produced by combined cycles or coal by RES. We find that synchronous generators, specially combined cycles, are behind most of the solutions for the network constraints, especially to solve voltage problems and insufficient adequacy reserves. Davi-Arderius et al (2023c; 2024) highlight this problem for volumes of after day-ahead, but in this study, we find this effect is aggravated with volumes of after intraday-markets. Moreover, the costs for activating combined cycles could be procured through a capacity market and their economic conditions could be set in advance. This could reduce potential gaming or market power from owners of combined cycle if they know in advance that they will be regularly activated.

Fourth, implementing an efficient incentive to the system operators to optimize the volumes activated. Spanish TSO has an economic incentive to annually reduce the volumes of activated energy and their costs (CNMC, 2019). Currently, this incentive is capped to ±5% the base remuneration.[13] However, incentivizing system operators to reduce curtailment could however internalize the problem. Under this incentive, how could we be sure that 'network benefits' don't over-shadow the 'whole-system benefits'? Another possibility would be to assess whether the current criteria used by system operators to activate synchronous generators are not overly conservative. The Spanish Regulator approved a mechanism to not fulfill several security criteria such as N-1 in exchange of tripping the generator in seconds or minutes after an unforeseen event. This is known as Sistema de Reducción Automática de Potencia (CNMC, 2022b) and the participation of units to this service is not mandatory. However, this mechanism might not be useful for situations where a high concentration of scheduled RES might affect dynamics or produce network stability problems.

In the same context, Regulators must overview if the hourly adequacy reserves used by TSO are optimal or excessively conservative. These reserves are calculated by the TSO considering its forecasts (Appendix A.5). Thus, more biased estimates from TSO can result in higher volumes of reserves with corresponding higher costs for customers. In the Spanish Regulatory framework, TSO have another economic incentive and penalty if their forecasts are biased, but they are capped to ±5% of base remuneration. Reducing these reserves could increase the risk of ending with important grid stability problems due to imbalances between demand and generation, but these trade-offs should be regularly analyzed as scenarios might change.

Fifth, promoting smart grids and specific digitalization investments to increase grid capacity through mechanisms such as DLR. Regulators have several instruments to

[13] According to CNMC (2019), the "base remuneration" includes incomes for CAPEX and OPEX for the operating activities. In the proposed remuneration published by the Spanish Regulation for 2042, "base remuneration" accounts 77M€ and incentives +1.5M€ (CNMC, 2023a).

promote them: approving these investments over others or incentivizing digitalization investments (Llorca et al., 2024). Traditional solution to deal with these volumes of energy is investing in new lines, cables, transformers, STATCOM, FACTS, etc. However, these investments incur costs for customers and the social resistance to building new lines or substations in increasing. Therefore, alternative solutions should be found and implementation of grid innovative technologies or local flexibility services might be a solution (European Commission, 2023a; Jamasb et al., 2024).

Sixth, implementing long-term local flexibility services to deal with structural or repetitive operational limits during peak RES production. These services might be procured one or two years in advance and would reduce the need for redispatching volumes after the day-ahead or intraday markets (European Commission, 2023b). They might include a capacity compensation for being available and another compensation for the energy curtailed or activated. This mechanism would also provide efficient economic incentivize to install storage devices in RES to store the curtailed production. A complementary recommendation could be using utility scale combined solar-storage and some countries are making this a requirement for solar auctions (Toba et al., 2023). However, this entails challenges if the stored production is later exported to the grid with the same generation technology than RES, i.e. power electronics. This is the case with traditional storage batteries. Alternatively, storage should be performed through pumping consumption whose output is from pumping generators, which are synchronous generators with all their benefit capabilities compared to RES.

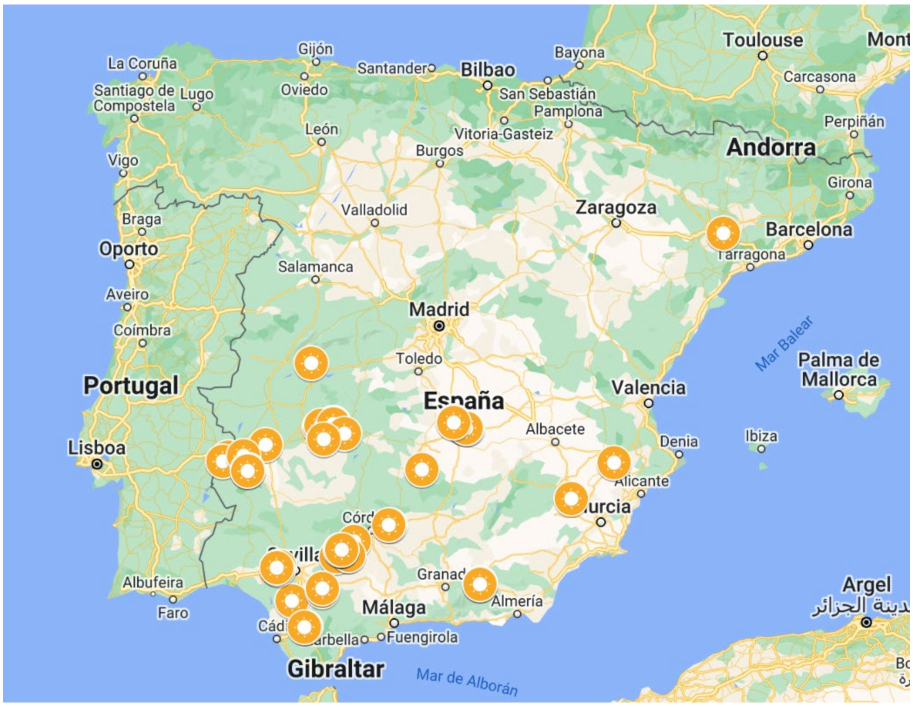
Seventh, implementing more demanding capabilities for power electronics in new RES such as grid forming (GFM) technologies introduced in Section 2. However, there are some implications related to the implementation of GFM to RES: (i) this is not mature and commercial technology; (ii) this would increase the Levelized Cost of Energy (LCOE) associated to new RES with the corresponding negative impact on the wholesale prices; (iii) this might be discriminatory if it is required RES sited to specific areas. Moreover, there are not deep experiences with the implementation of GFM to all RES regardless its size and capacity and, especially at the distribution grid level with highly resistive lines. As a complementary solution, implementing specific ancillary or local services to incentivize specific RES units to have more robust dynamic capabilities related to the voltage or inertia services. This mechanism would avoid the discriminatory effect related with the establishment of mandatory requirements for all new RES. Moreover, the economic compensation to providers would be defined efficiently through the ancillary service markets. However, the procurement of these services should be done in the long term, for instance a year-ahead, to provide efficient incentives to retrofit specific RES.

Related to the growing concern of the curtailment of RES made in 2022 and 2023, we cannot identify specific locations of all curtailed photovoltaics plants, but we know that many thermosolar productions were curtailed at the same time. Precisely, 99% of all thermosolar capacity is concentrated and sited in the mid-south of the Iberian Continental as is shown in the Figure 4.[14] Thus, it is very likely that many of these photovoltaics plants could be in the mid-South area of Spain.

[14] The installed capacity of thermosolar plants was 2,300MW in 2023, of which only 25MW were in the North-West of Spain (Catalonia), representing only 1% of the capacity.

Eighth, implement regulatory instruments to foster the consumption on specific regions during the peak solar production. For instance, defining a specific bidding zone for the mid-South area in Spain. However, splitting bidding zones would require deep analysis of the structural congestions to identify if grid bottlenecks are associated to the transmission lines that connect the North to the South or are more related to local transmission lines. In this last case, defining a new bidding zone won't be an efficient solution.

Figure 4. Map of the thermosolar plants in Spain.
Source: Prothermosolar (2023).



Nineth, enabling the possibility that the demand and consumption participates in the redispatching process and in the provision of adequacy reserves. The possibility of demand participation instead of using pollutant combined cycles should be explored. Moreover, this would ensure technological neutrality as the participation of demand in balancing services should be made on equal footing than generation.

Finally, accelerating the implementation of projects of common interest to increase the cross-border capacity and improve the power system dynamics and share potential adequacy reserves between different countries. A more interconnected power system can host higher volumes of RES made of power electronics. However, sharing adequacy reserves between different countries would require closer operation coordination between TSO from different countries. This recommendation is included in the EU Grid Action Plan (European Commission, 2023a).

In summary, our results show that the transmission grid planning should consider the potential redispatching needs within a bidding zone in an integrated way in line with Kemfert et al., (2016). Redispatching needs are relevant enough and clearly constraint the operation of a high share of RES.

7. Conclusions

This analysis highlight some of the relevant operational challenges related with the decarbonization of the power system, which trade-off some of the expected benefits of the replacement of traditional pollutant plants -made of synchronous generators- by RES -made of power electronics. When redispatching services should be activated after day-ahead and intraday markets means that there are relevant inefficiencies and room for improvement. All these actions result in additional costs for customers and trade-offs some of the potential benefits from RES, when their scheduled should be replaced by other pollutant technologies.

Up to now, grid planning models have been focused to identify future grid bottlenecks and quantify grid investments needed to connect new RES. As we find, these models should evolve and study potential network operational constraints beyond grid congestions. However, requirements on grid data models are relevant and some information barriers should still be addressed.

Related to the curtailment of RES in these processes, some technological advances are still necessary to make RES capabilities much more robust and closer to those from replaced synchronous generators. However, this also requires its fast adoption in the current regulatory framework and TSO and DSO should be incentivized to exploit their new RES capabilities. This might imply reducing some of the actual security of supply levels used by TSO, but this should be deeply assessed, and different operational solutions should be considered. Otherwise, new capabilities won't be never fully exploited.

Future research lines from our analysis are related with a further exploration with a power-flow model the trade-off among redispatch, transmission-capacity expansion and voltage control when renewable generation is integrated. This implies adding in the TSO´s objective function terms for transmission-capacity costs and for voltage control costs that the TSO is going to minimize. Under a change of demand, or an increase in renewable output, the TSO would choose either to redispatch in favor of fossil fuels, increase network capacity, increase voltage controls, or a combination of the three.

Moreover, the empirical trade-off between transmission capacity expansion and redispatching, due to voltage control issues, would be interesting to explore also at regional level.

Disclaimer: The opinions expressed within the contents are solely the authors' and do not reflect the opinions of the institutions or companies with which they are affiliated. Daniel Davi-Arderius works at e-Distribucion Redes Digitales, SLU and is part of the EU DSO Entity.

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Appendix A – Technical appendix

A.1. Congestions

When energy flows through the grid elements e.g. transformers, overhead lines, etc., power losses turn into heat and electricity losses (Costa-Campi et al., 2018). The higher these flows, the higher is the heat dissipated in each element. Therefore, each element of the grid has a maximum capacity for energy flows, also known as thermal limit or maximum congestion. This leads system operators to forecast congestions and identify potential grid investments several years ahead. The same procedure is followed when system operators assess the connection of a new consumer or generator: they simulate flows under the operation of this new unit. These grid investments are part of the network development planning processes (Batalla et al., 2023).

In the long-run, congestions are forecasted in scenarios that consider the most likely future situations. However, these scenarios do not consider all the possible futures mainly due to the variability of RES production. Therefore, system operators need to forecast energy flows for the next days and hours to anticipate potential grid bottlenecks, i.e. congestion above the maximum capacity of grid elements. In these forecasts, system operators use reliable information such as historical data on flows in the past hours, or the scheduled generation or consumption from the day-ahead markets.[15] In real-time, system operators monitor flows in its network through digital devices installed on the lines and transformers.

The first and easiest solution for congestion management is to change the grid topology, i.e. switching lines or transformers. However, the potential for these measures is limited. Complementary solutions are Dynamic Line Rating (DLR) or setting maximum allowable current-carrying capacity on the lines depending on the weather conditions along the lines. For instance, setting a higher maximum capacity of lines on winter than in summer. However, DLR requires advanced monitoring and digitalized tools (Douglass et al., 2019; Lawal et al., 2022). Another solution to grid congestions is grid reinforcements or new electrical infrastructure such as transmission lines, substations, transformers, etc. In the future, procurement of flexibility services by system operators will be a complementary measure to alleviate congestions by changing the consumption or generation profiles (Jamasb et al., 2024).

A.2. Grid reliability

Grid reliability refers to the redundant grid to assume the disconnection of a line or transformer without creating any losses in the electricity supply. They are also known as N-1 or N-2 security criteria if it refers to the disconnection of one or two grid assets, respectively.[16] This security criteria provides grid reliability as an unforeseen disconnection of any element can be solved by system operators. The higher is the grid voltage, the higher is the need for grid reliability. It requires complex iterative calculation processes of resultant flows when a grid element is disconnected, either for scheduled maintenance works or protection tripping in case of faults, lighting strikes or overloads. Grid reliability is considered in the same calculation process as congestion: in the grid

[15] Schedules from day-ahead market are commitment with an associated financial compensation.
[16] N-1 security criteria means that the power system operates in normal conditions when there is the disconnection of a grid element such as line or transformer.

planning process (long-term) and in the grid operation (short or real-time). Moreover, the solutions useful for congestions can also be applied to grid reliability needs.

A.3. Voltage

Voltage is an electrical parameter that must be always within predetermined levels to ensure the safety conditions of the network and the quality of supply.[17] Operating a power system outside these levels is risky: electrical equipment -transformers or lines- can be damaged, and some loads or generators could not remain coupled to the grid. Ultimately, lines, transformers or generators might be disconnected by protection devices.

In High Voltage grids, voltage is managed through the control of the reactive energy flows, traditionally by synchronous generators.[18] The replacement of synchronous generators by RES entails that power electronics should provide a similar response to voltage control as the replaced synchronous generators. However, this is not straightforward for several reasons. First, reactive energy from power electronics is constrained to the primary resource availability, i.e. sun or wind. Second, power electronics should include specific and expensive devices. Third, the provision of voltage control services by RES needs cooling converters, which means additional electricity consumption in ancillary services, thus affecting their economic feasibility of the plant. Fourth, large RES plants might have many kilometers of underground cables between the point of connection to the grid and the furthest windmills or photovoltaic panels scattered across the service area, which behaves like a large capacitor and injects reactive power flows. Fifth, the decarbonization of the system has coincided with the burying of many overhead High Voltage lines that behave as natural capacitors, aggravating the need for voltage control. Finally, some equipment might also be useful for controlling reactive flows: Static synchronous compensators (STATCOM), flexible AC transmission system (FACTS), synchronous condensers, capacitors or reactances (Anaya et al., 2020; Davi-Arderius et al., 2023a).[19]

In the UK, the transmission system operator (TSO) has identified important regional overvoltages under two complementary situations: (i) long or underground HV lines whose load is below its surge impedance loading (SIL), which is very common when the demand is low;[20] (ii) absence of synchronous generators in the area to consume reactive energy. In these cases, system operators must make actions such as starting specific synchronous generators or disconnect some underground cables (National Grid ESO, 2022). At present, there are few experiences with the procurement of voltage services through market based ancillary services (Anaya et al., 2022).

The Spanish regulator launched two regulatory sandboxes to trial a new ancillary service for provision of voltage control services by RES and consumers (CNMC, 2020, 2023b). In particular, to take advantage of the voltage control capacities already required in the

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[17] Each electrical equipment has its own nominal voltage.

[18] High Voltage lines have a lower R/X ratio, where R is the resistance and X the impedance (Davi-Arderius et al., 2023a).

[19] Most of these points might also apply to synchronous generators. In RES, these reasons are relevant since the connection of many RES is made under auctions that aim to minimize their LCOE costs (Davi-Arderius et al., 2023b).

[20] Surge impedance loading or SIL corresponds to the load to determine whether a line behaves as a capacitor that injects reactive energy, or as an inductance that consumes reactive energy. SIL depends on the physical characteristics of the line, as well as on their voltage.

national implementation of the Regulation (EU) 2016/631 (MITECO, 2020). The regulator justifies the sandbox with the increasing need to start specific synchronous generators for redispatching or to disconnect HV lines to control reactive flows. There are few empirical studies of the potential impacts of voltage control on the power system at national level. Davi-Arderius et al., (2023c) find that the emissions from the day-ahead market schedule are downward biased between +0.00391 and +0.0145 tn of CO2 for each additional MWh of scheduled wind or photovoltaics. This is a consequence of the need to replace power electronics (wind and photovoltaics) by synchronous generators (combined cycle and coal) in the day-ahead scheduling.

A.4. Frequency

In Altern Current, frequency relates to the oscillation of voltage generated by rotating machines. Nominal frequency in Europe is 50Hz, or 60Hz in The United States and other countries. Frequency is controlled through inertia. This is the stored kinetic energy in rotating synchronous generators that gives the tendency to remain rotating and set the immediate frequency response when there is a power generation and demand unbalance. They are usually a consequence of tripping of a large generator, a large consumer or a disconnection of electrical areas (Tielens et al., 2016).[21] Under low levels of inertia, frequency disturbances become more abrupt and frequency changes increase.[22] In these disturbances, some generators or loads might disconnect, further aggravating the initial frequency oscillation. In other words, this is a looping process that might put at risk the overall stability of the power system stability and with a blackout (Gu et al., 2017; Bialek, 2020; Makolo et al., 2021).

The connection of RES might affect power system stability since inertia and short-circuit current might decrease because the dynamic response of power electronics used in wind or photovoltaics differs from synchronous generators used in nuclear, hydropower, combined cycle, or coal plants (Zografros et al., 2018; Denholm et al, 2020; Mehigan, 2020; Meegahapola, 2020; ENTSOE, 2023). In synchronous plants, rotating generators are directly coupled to the grid providing their rotational energy when there is a disturbance. In RES, power electronic converters are coupled with the grid, and they may provide virtual or synthetic inertial response through the activation of its power electronics.[23] However, implementing virtual inertia requires installing some battery or storage device in the generator (Xing et al., 2021). Moreover, the provision of inertia might suffer from some delay since the power control system needs to identify the need and react[24]. This might pose a problem when the share of RES based on power electronics in the grid is very high. In the UK, Homan et al., (2021) analyze historic frequency data and assess the future frequency response requirements in 2030. They find that the frequency response needs to be fast acting to address lower levels of inertia.

[21] The disconnection of electrical areas might be related, for instance, to tripping a High Voltage cross-border line. If a country is importing energy, the impact of this disconnection equals to tripping a large generator and equals to the disconnection of a large consumer if the country is exporting energy.
[22] Rate of Change of Frequency (RoCoF) is measured as the time derivative of the frequency in Hz/second (ENTSOE, 2020).
[23] Some wind turbines might have some kinetic energy stored in their blades, gearbox or generators, which is not possible in photovoltaics where there are no rotating parts.
[24] Full activation times to provide inertia for technologies vary: 4 ms for flywheel inverters, 100-200 ms for photovoltaics, 0.5 to 5 s for wind turbines (Miller et al., 2017).

There are other technical solutions to provide inertia. First, inertial response from power electronics might evolve with a combination of grid forming (GFM) power electronics and storage devices such as batteries, capacitors, or flywheels (ENTSOE, 2021).[25] However, GFM are not fully commercial solutions. Third, flywheels storage devices provide fast dynamic response and inertia to the system. They are made of a synchronous generator, a bidirectional power converter, a flywheel, and a bearing system (Zhang et al., 2022). Similarly, synchronous condensers are synchronous generators coupled to the grid to maintain a spinning mass that provide the same inertial response as a synchronous generator during a disturbance.[26] Fourth, fast frequency response services include the response from generators for fast increase/decrease of net supply of energy. For instance, the Electric Reliability Council of Texas (ERCOT) implemented this service in non-critical loads to respond to changes in the frequency (Denholm et al., 2020). Fifth, building new lines to increase the interconnection capacity between different areas or countries, might reduce impedance and increase the inertia of the system.

There are many theoretical studies on the impact of high shares of non-synchronous generation in the system. ENTSOE (2021) study the cases that might cause a Rate of Change of Frequency (RoCoF) higher than 1 Hz/second due to its high potential risk of leading to a blackout. Johnson et al. (2020) analyze the ERCOT to assess safe inertia levels under different levels of RES. They find that addressing low inertia levels increases the system costs by about 2% and CO_2 emissions by 3.4% above the baseline scenario in 2030. As solution for the low inertia levels, they propose complementary mechanisms such as price signals to procure inertia contributions, plants retirements or fast frequency response services.

A.5. Adequacy reserves

A TSO calculates the daily minimum volume of dispatchable (upward and downward) scheduled generation in the day-ahead markets and after the intraday markets, namely dispatchable reserve capacity.[27] These reserves are in addition to the procurement of balancing services. In Spain, the upward and downward dispatchable capacity reserves are calculated considering the following parameters: (i) the difference between the scheduled demand forecasted by TSO and the final demand in the day-ahead and intraday markets; (ii) the difference between the scheduled wind and photovoltaic production made by TSO and the final scheduled wind production; (iii) situations with a risk of coupling delay or load increasing combined cycles (CNMC, 2022a). In the Spanish regulatory framework, a TSO has economic incentives to improve the accuracy of

[25] There are two main power electronics technologies for RES: grid following (GFL) and grid forming (GFM). GFL is the most used technology, while GFM is in a nascent stage. GFL behave as a controlled current source with a high parallel impedance, while GFM is represented as a voltage source with low series impedance. Hence, GFL regulates its voltage or current by controlling the injected current, while GFM regulates the power by controlling the voltage. Under no-load conditions, GFM provides a reference voltage, while GFL requires an external voltage for current injection. Accordingly, dynamics and response of GFM are closer to a synchronous generator than GFL (Rosso et al, 2021; ENTSOE, 2023).

[26] There are some studies related to the retrofit of synchronous generators from phased-out pollutant plants and transform them into synchronous condensers. However, this is not straightforward and requires an exhaustive analysis case by case (Deecke et al., 2015).

[27] "Enough upward reserve capacity" means there are enough dispatchable generators not operating at their nominal load, and with the capability to increase production quickly. For each unit, these reserves are calculated as the difference between scheduled production and nominal capacity. On the contrary, "Enough downward reserve capacity" means enough dispatchable generators able to reduce production quickly.

demand and renewable forecasts and if the forecasts are biased, the incentive becomes a penalty (CNMC, 2019, 2023a).

Appendix B – Hourly demand of electricity

Figure B.1: Average hourly scheduled energy in 2019. Source: own calculations

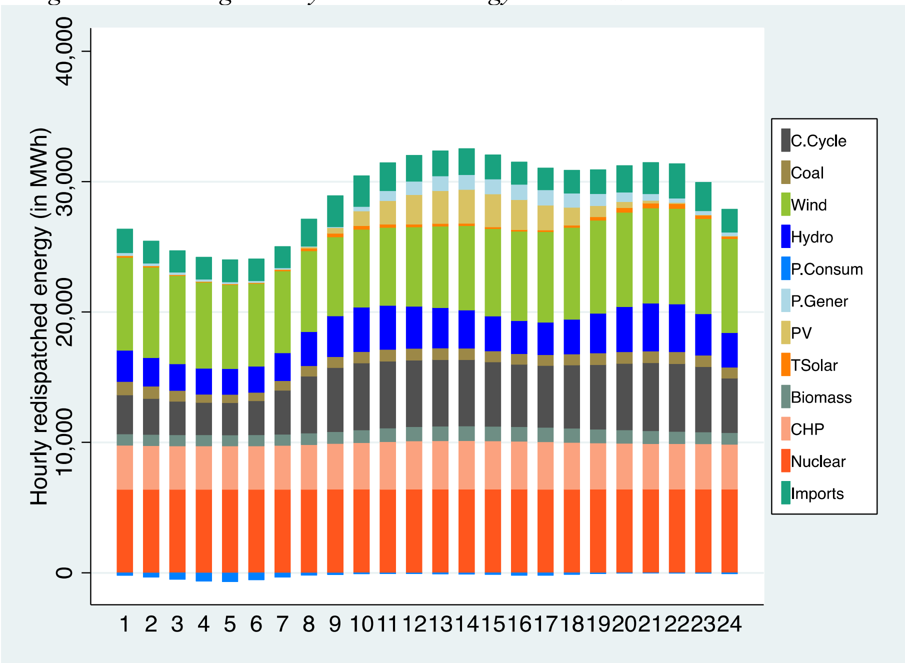


Figure B.2: Average hourly scheduled energy in 2020. Source: own calculations

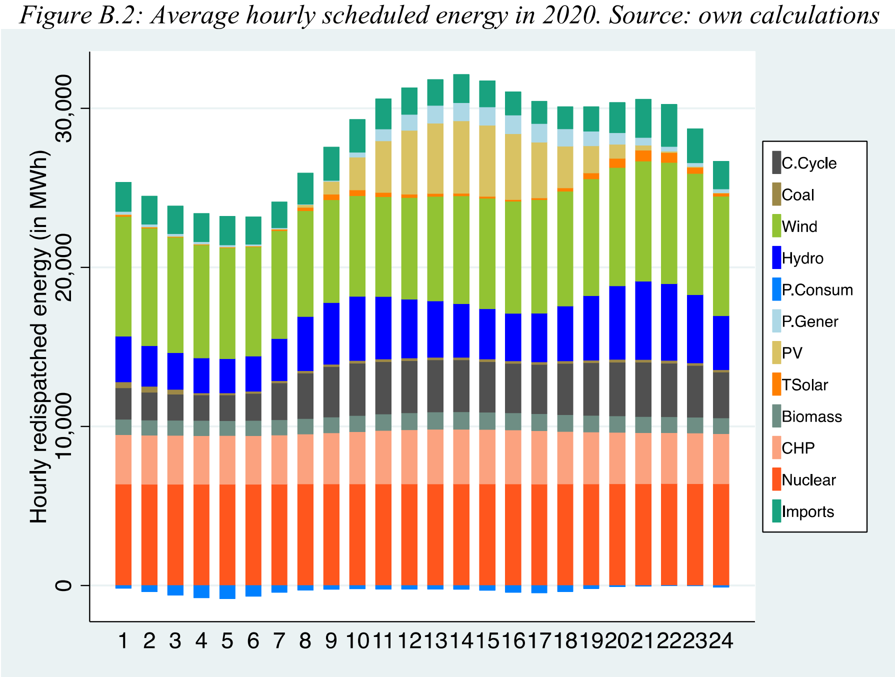


Figure B.3: Average hourly scheduled energy in 2021. Source: own calculations

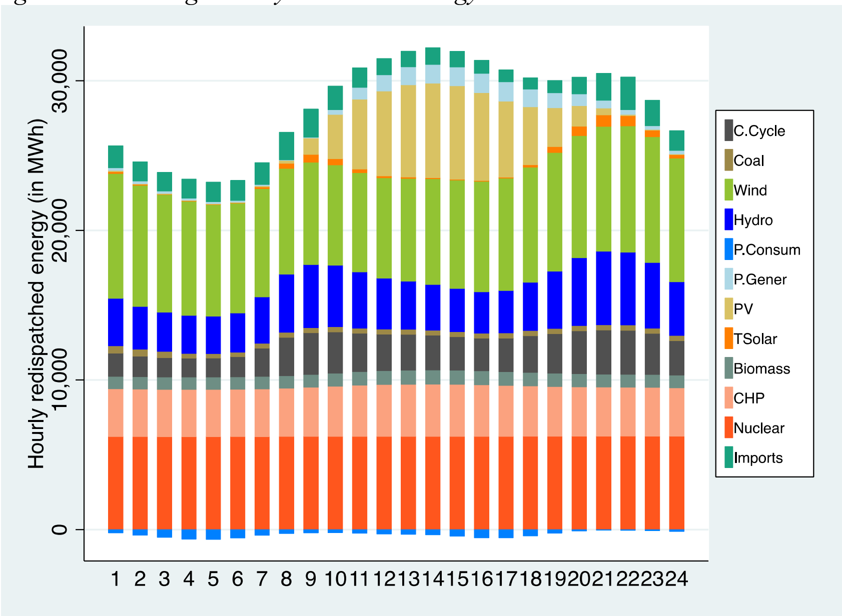


Figure B.4: Average hourly scheduled energy in 2022. Source: own calculations

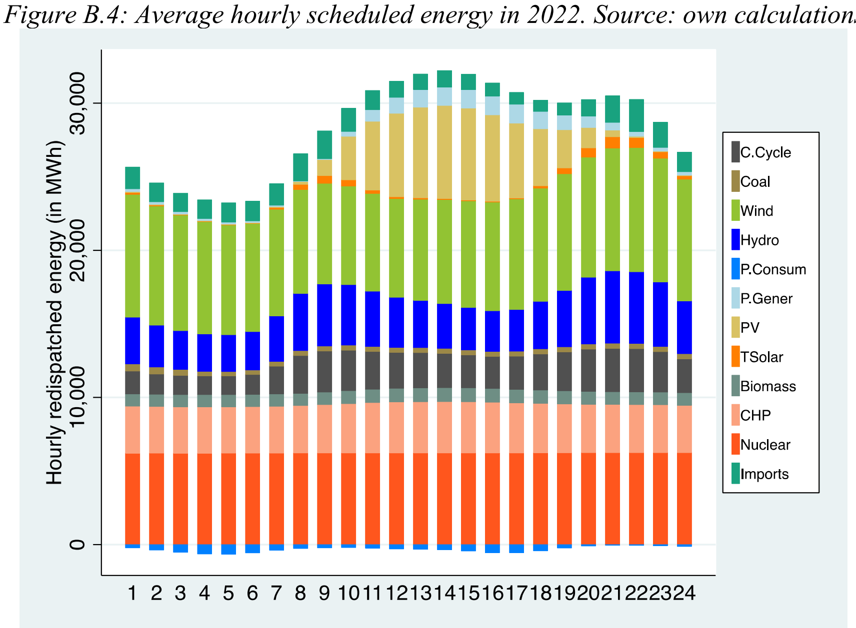
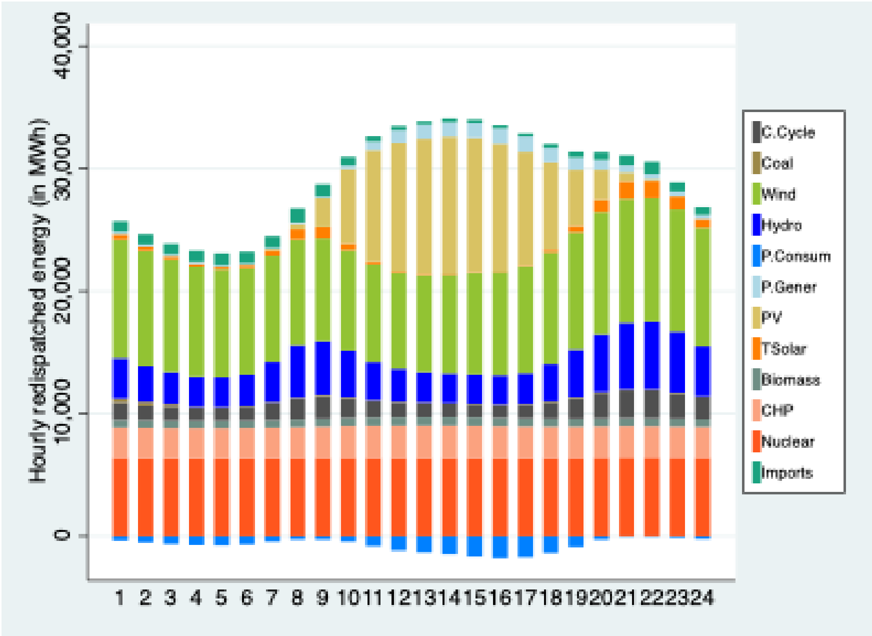


Figure B.5: Average hourly scheduled energy in 2023. Source: own calculations



Appendix C – Hourly volumes of AS by network constraint

In all the graphs, positive values in vertical axis correspond to upward redispatched energy, while negative values show downward redispatch energy.

Figure C.1: Average hourly redispatched energy (Stage 1) by technology in 2019. Source: own calculations.

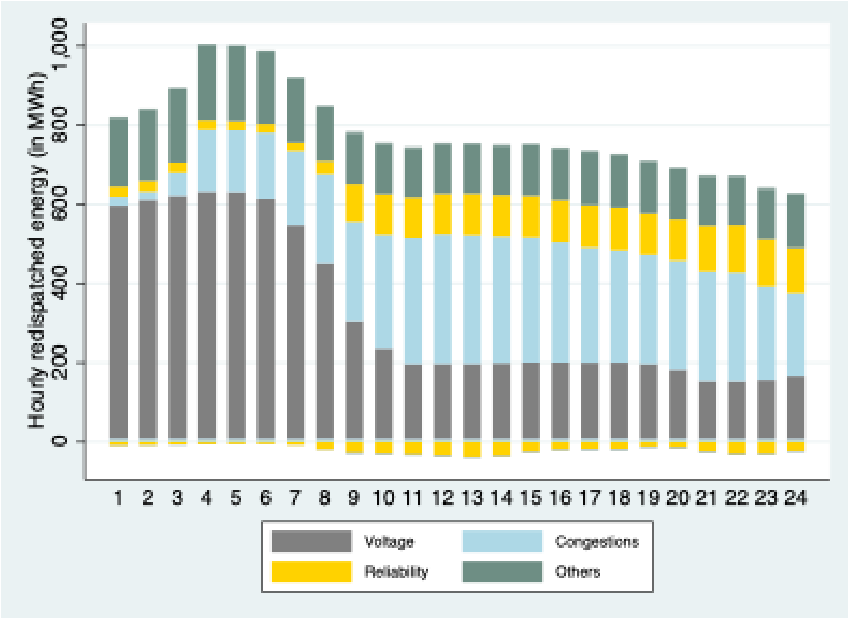


Figure C.2: Average hourly redispatched energy (Stage 1) by technology in 2020. Source: own calculations.

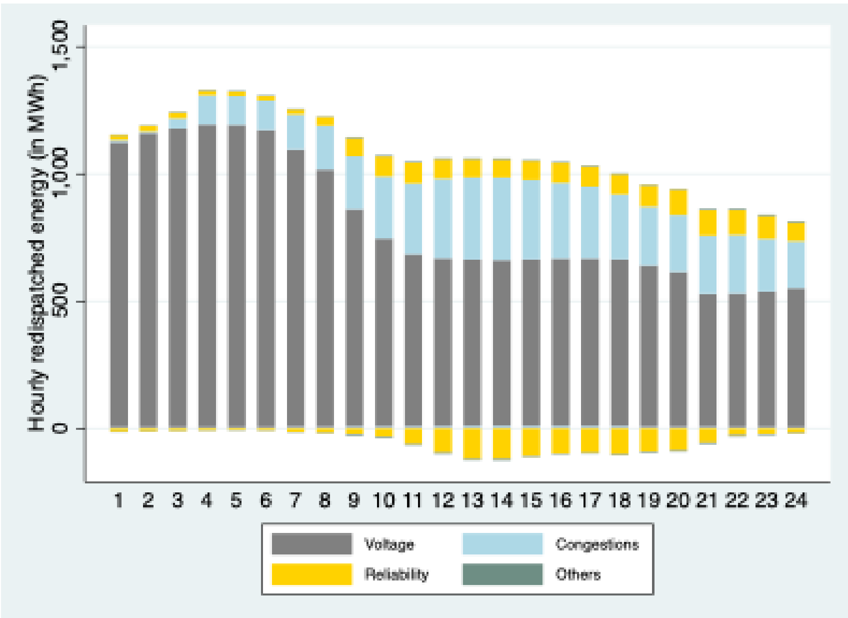


Figure C.3: Average hourly redispatched energy (Stage 1) by technology in 2021. Source: own calculations.

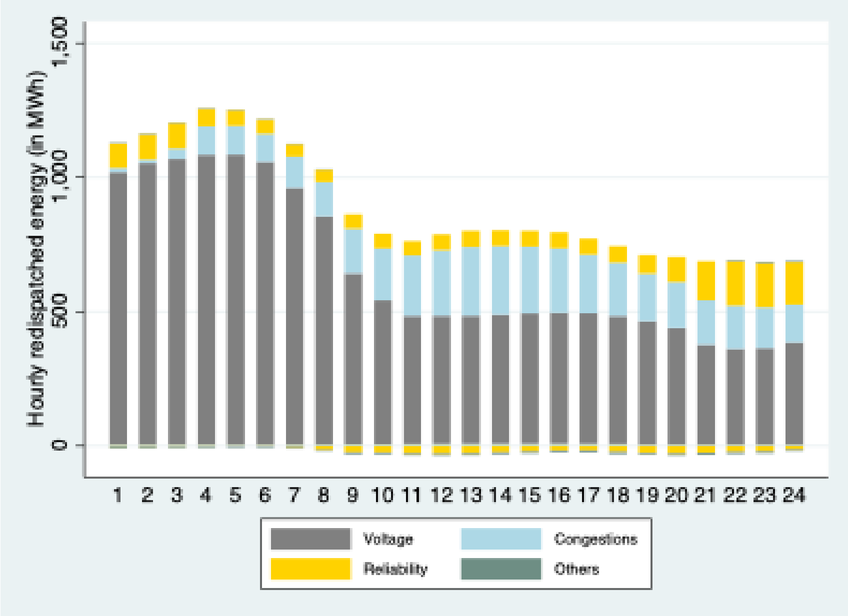


Figure C.4: Average hourly redispatched energy (Stage 1) by technology in 2022. Source: own calculations.

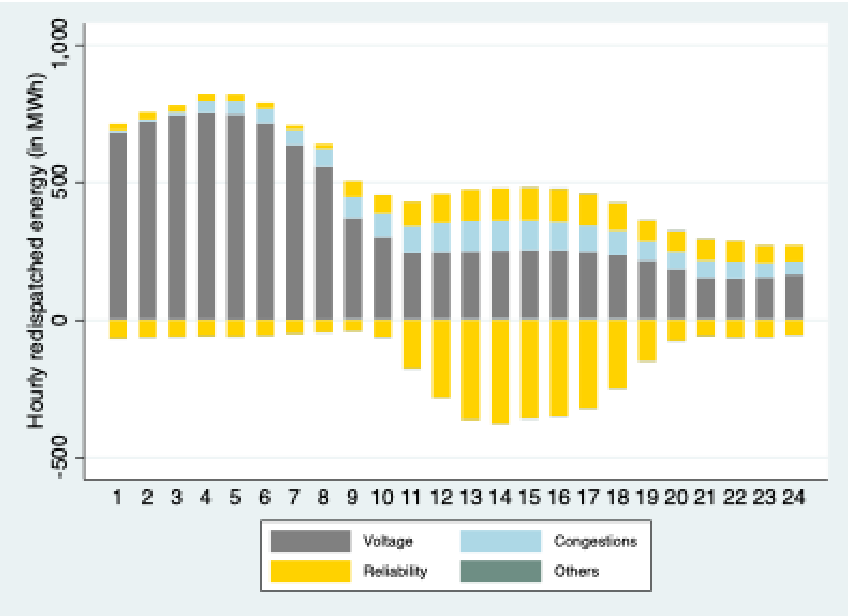


Figure C.5: Average hourly redispatched energy (Stage 1) by technology in 2023.

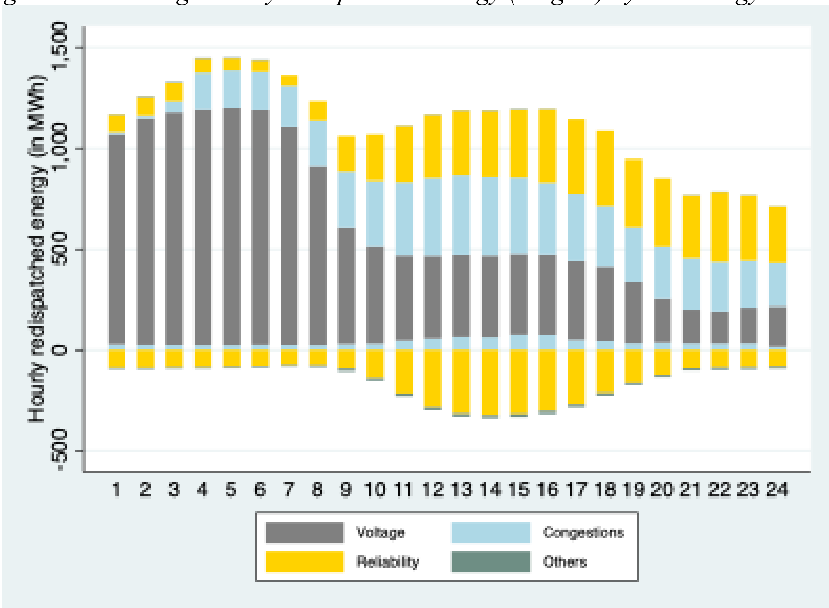


Figure C.6: Average hourly redispatched energy (Stage 3) by technology in 2019.

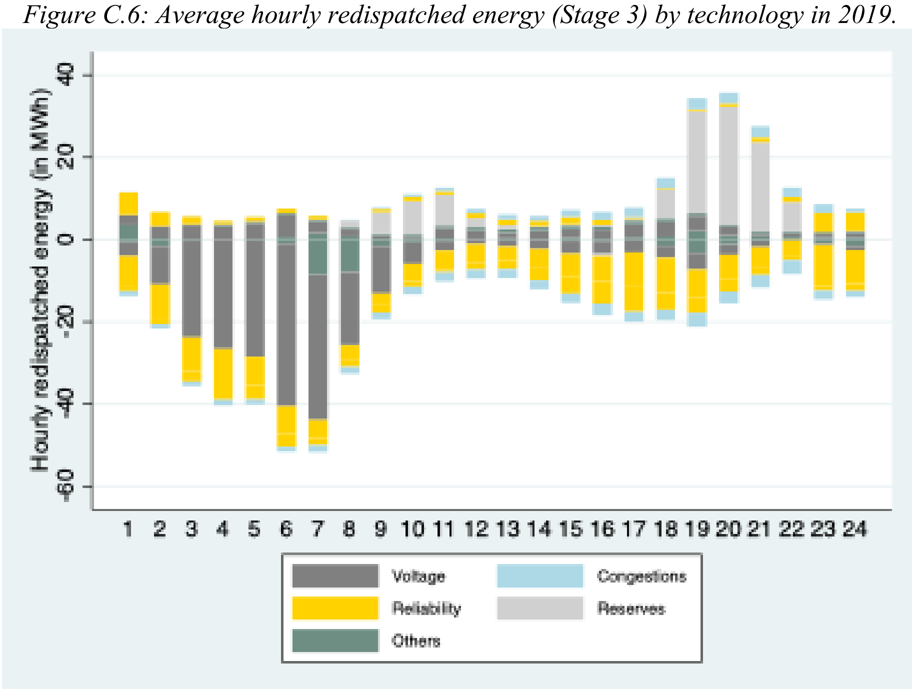


Figure C.7: Average hourly redispatched energy (Stage 3) by technology in 2020.

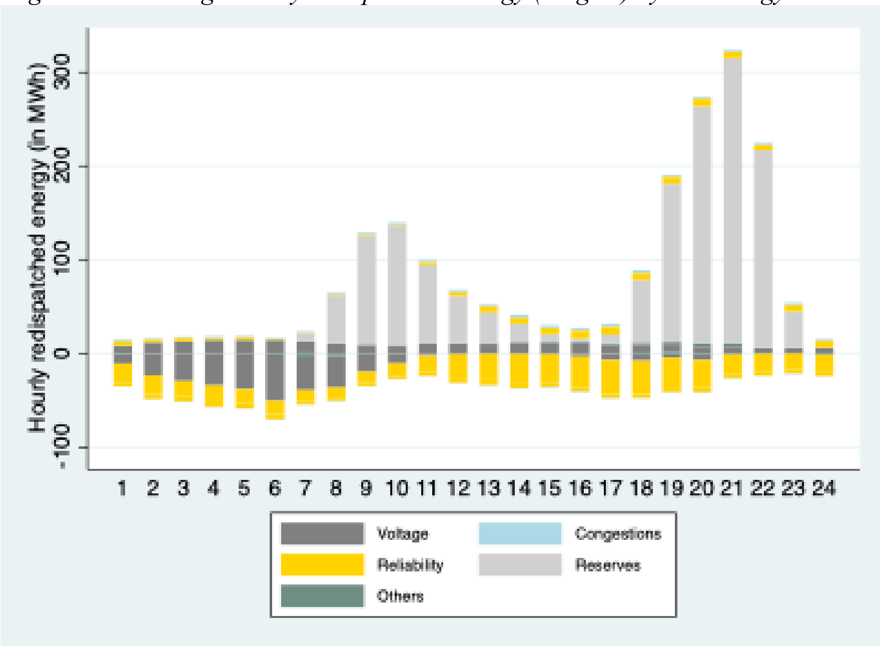


Figure C.8: Average hourly redispatched energy (Stage 3) by technology in 2021.

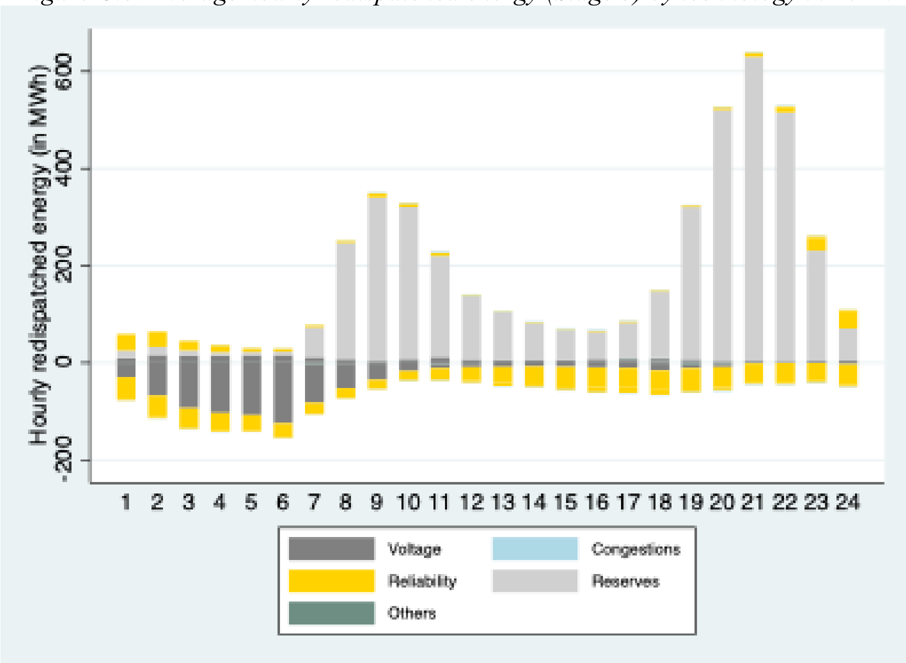


Figure C.9: Average hourly redispatched energy (Stage 3) by technology in 2022.

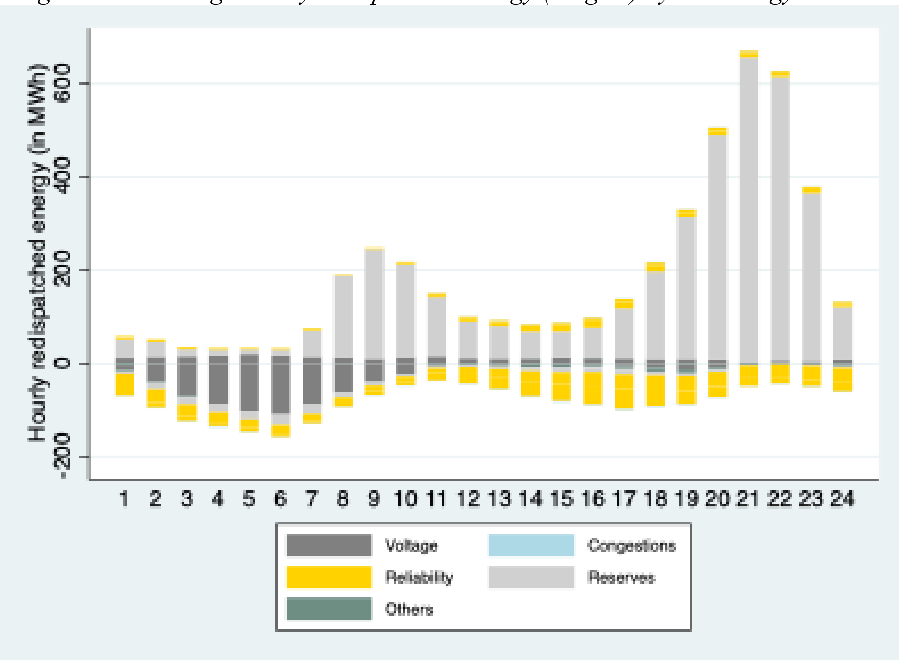
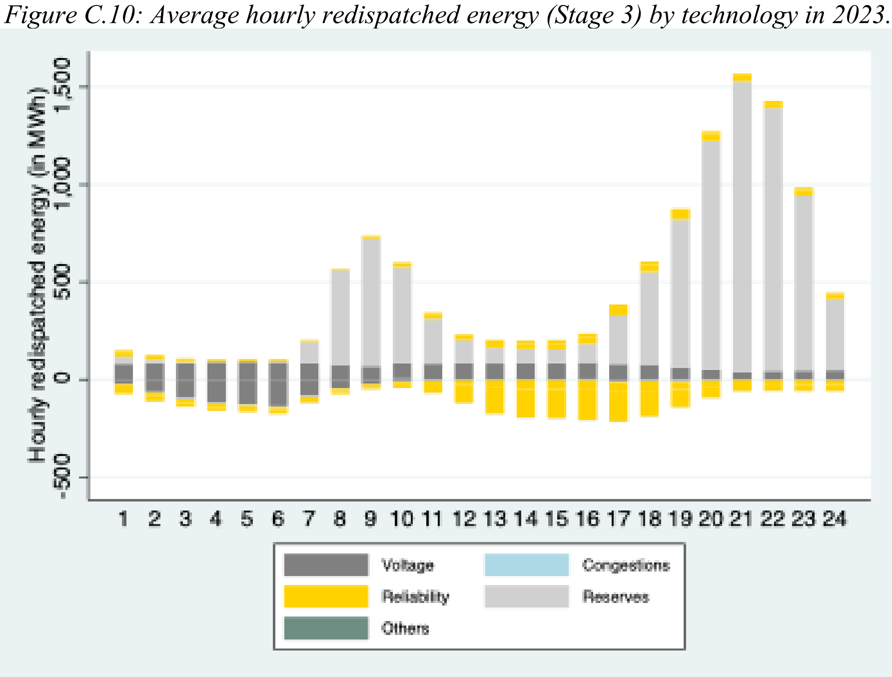


Figure C.10: Average hourly redispatched energy (Stage 3) by technology in 2023.



Appendix D – Hourly volumes of AS by activated technology

In all the graphs, positive values in vertical axis correspond to upward redispatched energy, while negative values show downward redispatch energy.

Figure D.1: Average hourly redispatched energy (Stages 1 and 2) by technology in 2019. Source: own calculations

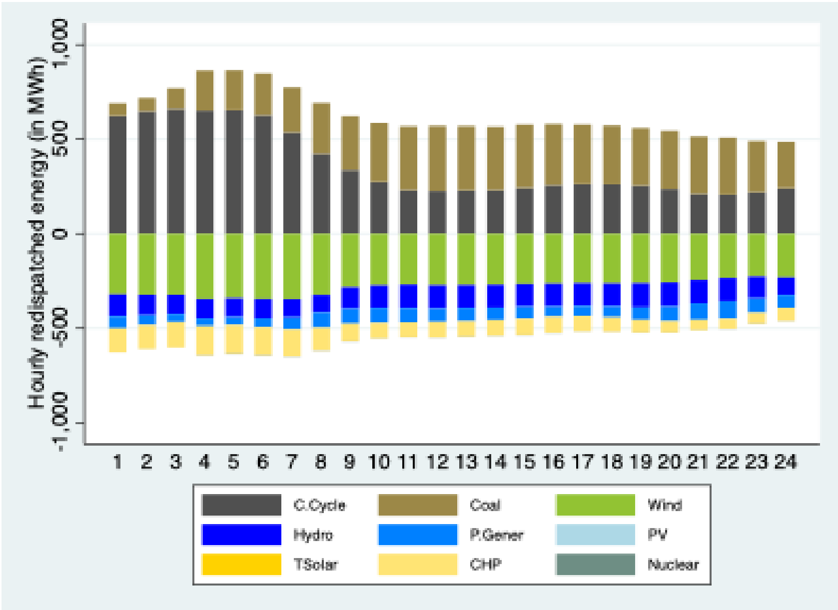


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Figure D.2: Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2019.

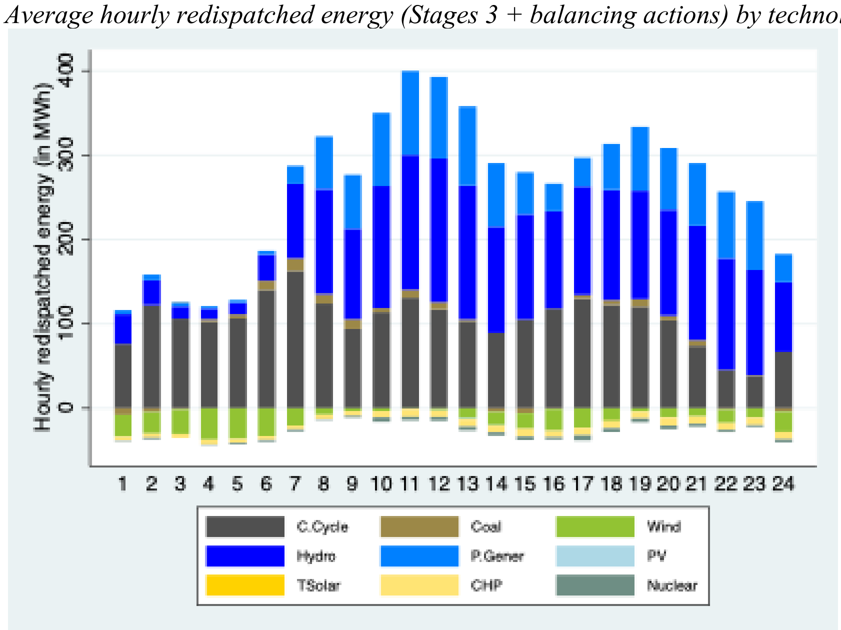


Figure D.3: Average hourly redispatched energy (Stages 1 and 2) by technology in 2020. Source: own calculations.

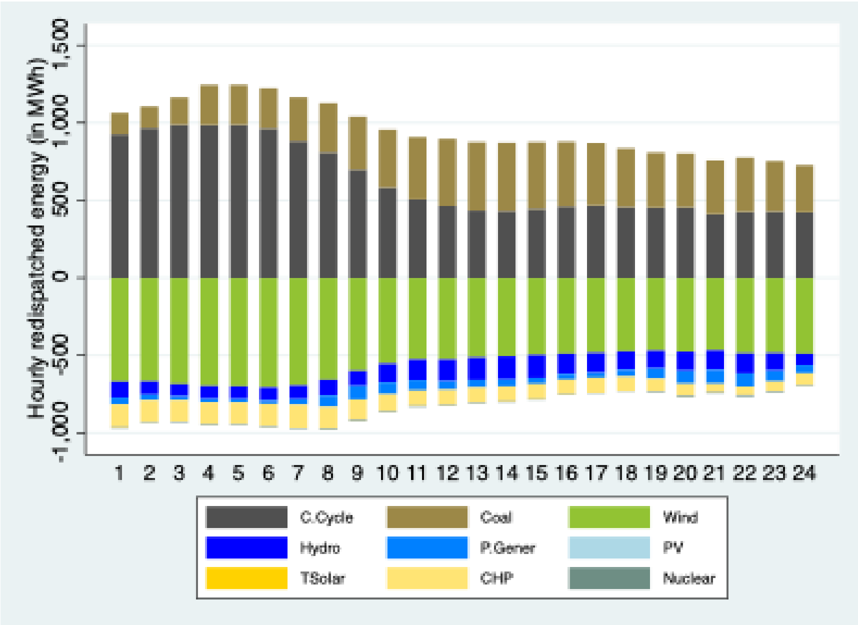


Figure D.4: Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2020.

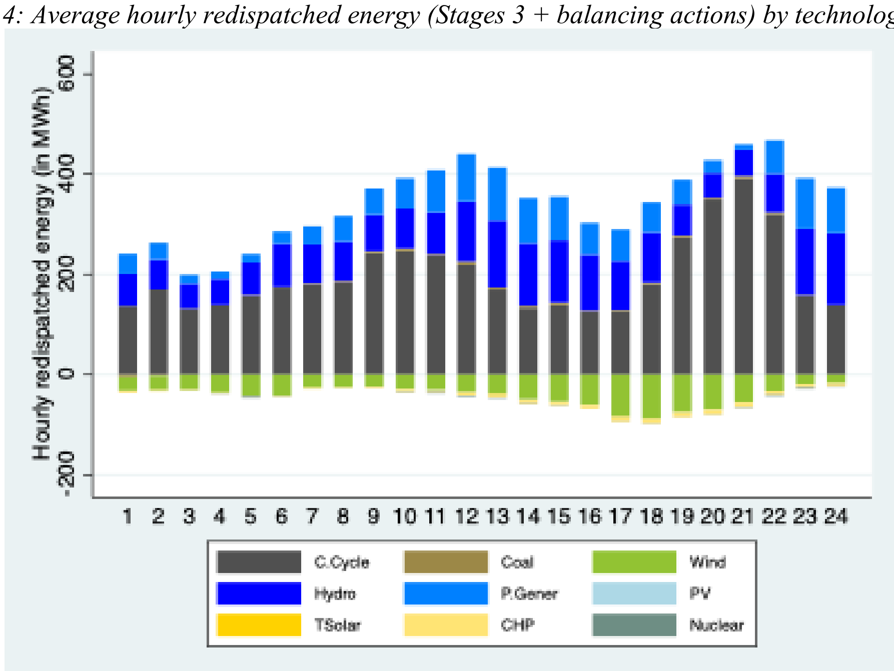


Figure D.5: Average hourly redispatched energy (Stages 1 and 2) by technology in 2021.
Source: own calculations.

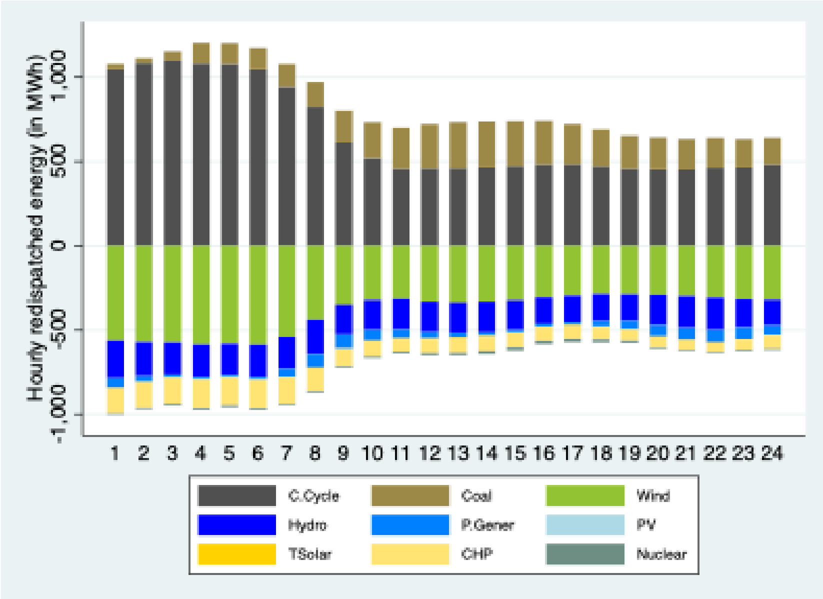


Figure D.6: Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2021.

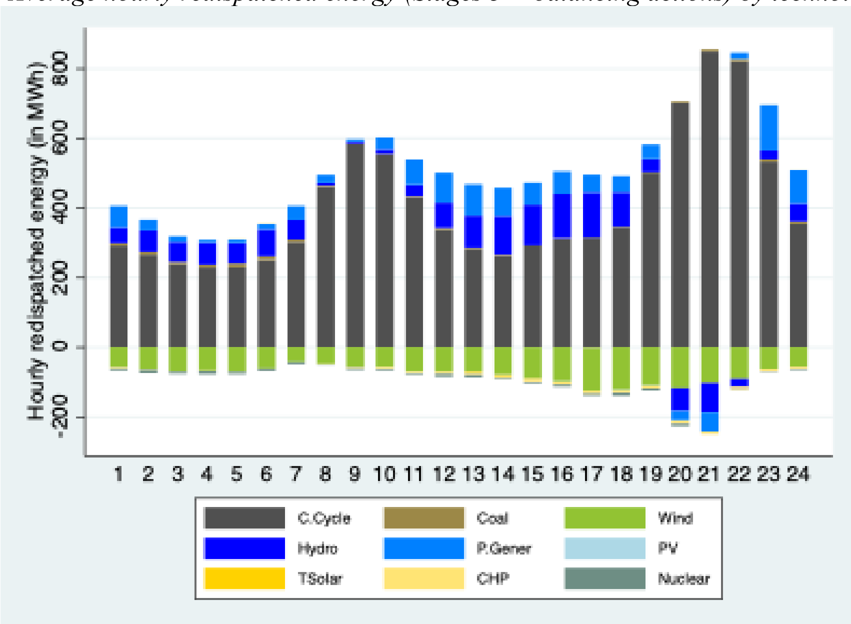


Figure D.7: Average hourly redispatched energy (Stages 1 and 2) by technology in 2022.
Source: own calculations.

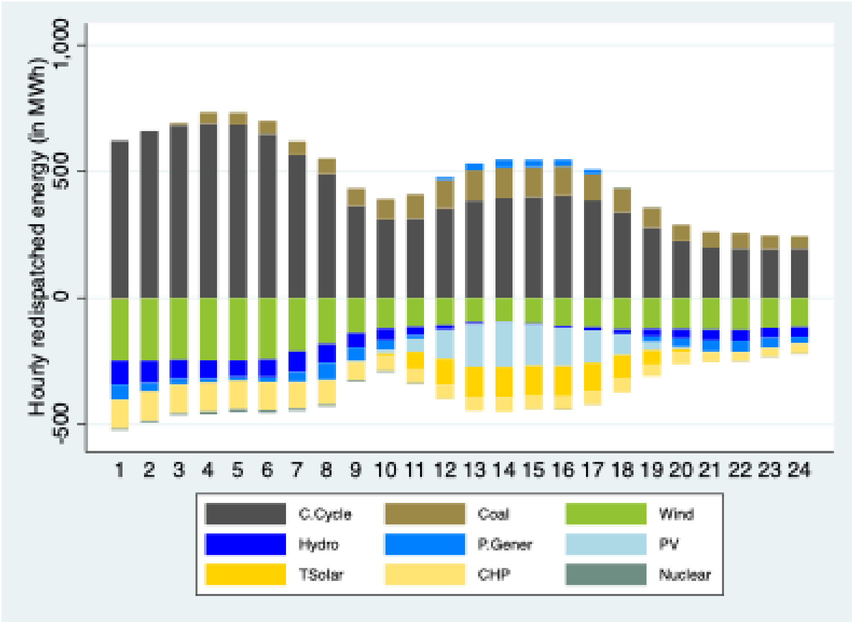


Figure D.8: Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2022.

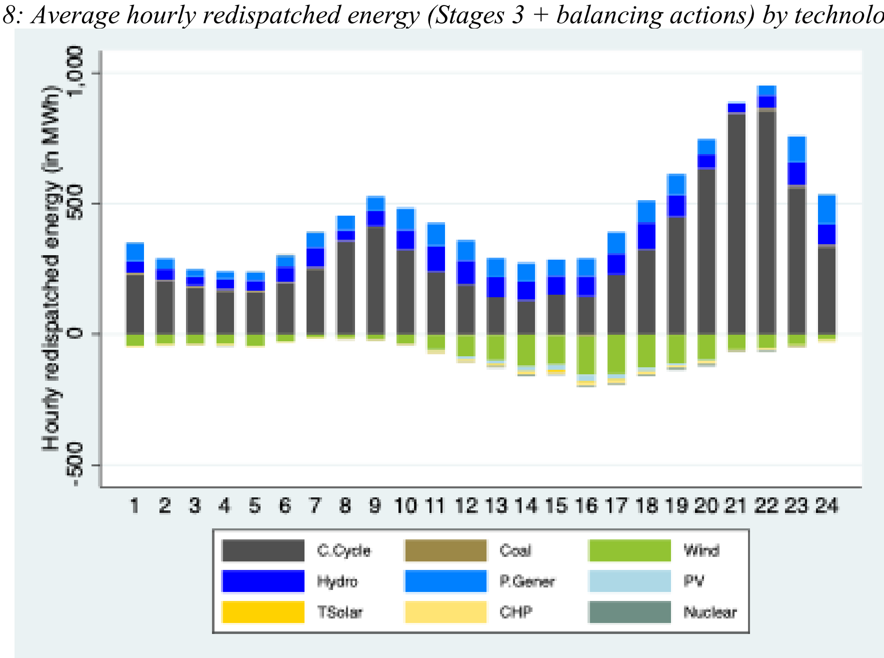


Figure D.9: Average hourly redispatched energy (Stages 1 and 2) by technology in 2023. Source: own calculations.

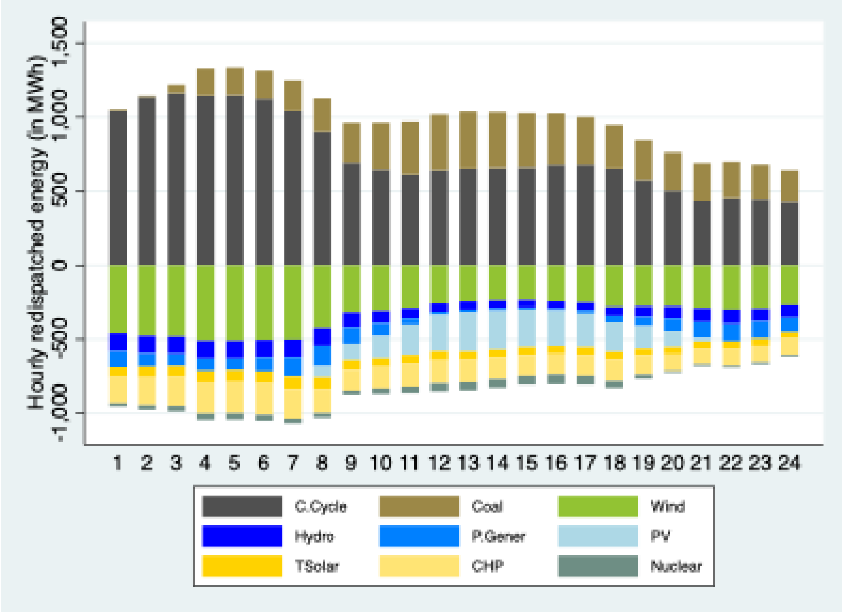
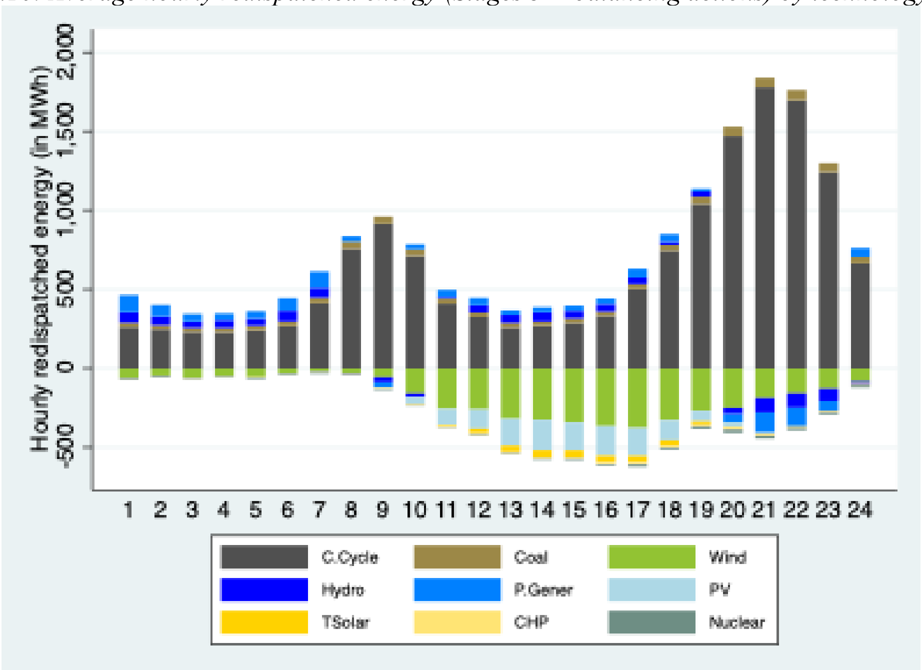


Figure D.10: Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2023.



Appendix E - Estimates for the technology model:

Table E.1. ML estimations for voltage constraints after the day-ahead markets.

	(2019) $\Delta daVoltage_t$	(2020) $\Delta daVoltage_t$	(2021) $\Delta daVoltage_t$	(2022) $\Delta daVoltage_t$	(2023) $\Delta daVoltage_t$
Comb. Cycle (ΔCC_t)	-0.0580****	-0.0869****	-0.101****	-0.0700****	-0.120****
	(0.00144)	(0.00253)	(0.00169)	(0.00159)	(0.00259)
Coal (ΔCO_t)	-0.0117****	0.383****	-0.124****	-0.115****	0.528****
	(0.00318)	(0.0186)	(0.00850)	(0.00847)	(0.0225)
Hydropower (ΔH_t)	-0.0352****	-0.0336****	-0.0370****	-0.0444****	-0.0547****
	(0.00198)	(0.00227)	(0.00266)	(0.00272)	(0.00240)
Nuclear (ΔN_t)	-0.00771	-0.0508****	-0.0433****	0.0160	-0.0156
	(0.00613)	(0.0104)	(0.0120)	(0.0148)	(0.0123)
Pumping gen. (ΔPG_t)	-0.0275****	-0.0309****	-0.0471****	-0.0502****	-0.0742****
	(0.00442)	(0.00437)	(0.00403)	(0.00347)	(0.00403)
Photovoltaics (ΔPV_t)	-0.0389****	-0.0318****	-0.0474****	-0.0382****	-0.0572****
	(0.00691)	(0.00538)	(0.00393)	(0.00265)	(0.00243)
Thermosolar (ΔTS_t)	-0.0341****	-0.0437***	-0.0559****	-0.0432****	-0.0224
	(0.00934)	(0.0137)	(0.0133)	(0.0126)	(0.0146)
CHP (ΔCHP_t)	-0.0934****	-0.240****	-0.184****	-0.261****	-0.391****
	(0.0138)	(0.0195)	(0.0206)	(0.0197)	(0.0208)
Wind (ΔW_t)	-0.0272****	-0.0310****	-0.0312****	-0.0265****	-0.0379****
	(0.00220)	(0.00270)	(0.00255)	(0.00294)	(0.00308)
Imports (ΔI_t)	-0.0191****	-0.0216****	-0.0408****	-0.0292****	-0.0453****
	(0.00146)	(0.00182)	(0.00185)	(0.00171)	(0.00224)
AR1	-0.0818****	-0.0687****	-0.134****	-0.0885****	-0.0882****
	(0.00815)	(0.00764)	(0.00709)	(0.00755)	(0.00802)
AR24	0.646****	0.651****	0.646****	0.624****	0.640****
	(0.00322)	(0.00312)	(0.00373)	(0.00330)	(0.00395)
Constant $(\widehat{\beta_0})$	88.21****	119.3****	124.2****	123.4****	157.0****
	(0.268)	(0.338)	(0.429)	(0.384)	(0.528)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.2. ML estimations for congestion issues after the day-ahead markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$
Comb. Cycle (ΔCC_t)	0.0177****	0.0210****	0.00628****	0.000963*	0.00495****
	(0.00101)	(0.00142)	(0.00119)	(0.000512)	(0.000970)
Coal (ΔCO_t)	-0.0252****	-0.385****	-0.222****	-0.0691****	-0.464****
	(0.00233)	(0.00755)	(0.00395)	(0.00211)	(0.00436)
Hydropower (ΔH_t)	0.0104****	0.0120****	0.00631****	0.00273***	0.00928****
	(0.00146)	(0.00120)	(0.00102)	(0.000878)	(0.000870)
Nuclear (ΔN_t)	0.0398****	0.00287	-0.00562	0.00866	0.00165
	(0.0104)	(0.00568)	(0.00454)	(0.00649)	(0.00475)
Pumping gen. (ΔPG_t)	0.0181****	0.00143	0.00616****	0.00271***	0.0136****
	(0.00331)	(0.00289)	(0.00166)	(0.000901)	(0.00145)
Photovoltaics (ΔPV_t)	0.0158****	0.0260****	0.0154****	0.00444****	0.0144****
	(0.00402)	(0.00168)	(0.00133)	(0.000684)	(0.000621)
Thermosolar (ΔTS_t)	0.0203***	0.00784	0.0120**	0.0128****	-0.00149
	(0.00632)	(0.00556)	(0.00521)	(0.00315)	(0.00414)
CHP (ΔCHP_t)	0.0564****	0.136****	0.0539****	0.0428****	0.0437****
	(0.0105)	(0.0112)	(0.00740)	(0.00701)	(0.00760)
Wind (ΔW_t)	0.00976****	0.00701****	0.000212	0.000750	0.000232
	(0.00157)	(0.00147)	(0.00107)	(0.000739)	(0.00101)
Imports (ΔI_t)	0.00650****	0.00573****	0.00430****	0.00214****	0.00330****
	(0.00103)	(0.000972)	(0.000781)	(0.000564)	(0.000771)
AR1	-0.107****	-0.154****	-0.105****	-0.0399****	-0.0658****
	(0.00843)	(0.00969)	(0.00782)	(0.00722)	(0.00949)
AR24	0.609****	0.402****	0.524****	0.589****	0.387****
	(0.00484)	(0.00609)	(0.00465)	(0.00298)	(0.00582)
Constant $(\widehat{\beta_0})$	54.93****	58.23****	48.79****	30.78****	45.91****
	(0.193)	(0.255)	(0.161)	(0.0777)	(0.180)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.3. ML estimations for grid reliability issues after the day-ahead markets.

	(2019) $\Delta daReiability_t$	(2020) $\Delta daReiability_t$	(2021) $\Delta daReiability_t$	(2022) $\Delta daReiability_t$	(2023) $\Delta daReiability_t$
Comb. Cycle (ΔCC_t)	0.0111****	0.00770***	0.00365*	-0.00316	-0.0109***
	(0.00131)	(0.00287)	(0.00191)	(0.00278)	(0.00346)
Coal (ΔCO_t)	0.00832***	-0.0594**	-0.0447****	-0.0153	-0.193****
	(0.00291)	(0.0235)	(0.00917)	(0.0134)	(0.0272)
Hydropower (ΔH_t)	0.0147****	0.0147****	0.0120****	0.0168****	0.0294****
	(0.00197)	(0.00261)	(0.00250)	(0.00496)	(0.00332)
Nuclear (ΔN_t)	-0.0235	-0.0186	0.0475****	-0.0712**	0.0144
	(0.0145)	(0.0194)	(0.0140)	(0.0312)	(0.0252)
Pumping gen. (ΔPG_t)	0.0160***	0.0268****	0.00161	0.00939	0.0348****
	(0.00541)	(0.00509)	(0.00409)	(0.00667)	(0.00503)
Photovoltaics (ΔPV_t)	0.0119***	0.0122****	0.00260	0.0296****	0.0337****
	(0.00456)	(0.00334)	(0.00198)	(0.00237)	(0.00215)
Thermosolar (ΔTS_t)	0.00317	0.0625****	-0.00826	0.105****	0.113****
	(0.00768)	(0.00923)	(0.00744)	(0.0111)	(0.0117)
CHP (ΔCHP_t)	0.142****	0.135****	0.0815****	-0.00499	0.126****
	(0.0130)	(0.0272)	(0.0247)	(0.0333)	(0.0274)
Wind (ΔW_t)	0.00880****	0.0101***	0.0185****	0.0177****	0.0298****
	(0.00227)	(0.00319)	(0.00258)	(0.00426)	(0.00408)
Imports (ΔI_t)	0.00462***	0.00275	0.00151	0.0229****	0.00188
	(0.00151)	(0.00168)	(0.00164)	(0.00270)	(0.00246)
AR1	-0.0172**	0.0179****	-0.0235****	0.213****	0.0543****
	(0.00697)	(0.00471)	(0.00617)	(0.00506)	(0.00750)
AR24	0.256****	0.235****	0.284****	0.343****	0.323****
	(0.00404)	(0.00376)	(0.00393)	(0.00409)	(0.00443)
Constant $(\widehat{\beta_0})$	76.21****	108.1****	97.13****	129.2****	171.0****
	(0.169)	(0.150)	(0.197)	(0.300)	(0.429)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.4. ML estimations for other issues after the day-ahead markets. Note: Estimations for 2023 are not converging

	(2019) $\Delta daOthers_t$	(2020) $\Delta daOthers_t$	(2021) $\Delta daOthers_t$	(2022) $\Delta daOthers_t$
Comb. Cycle (ΔCC_t)	-0.0196****	0.000270	0.000786*	-0.000208
	(0.000485)	(0.000821)	(0.000415)	(0.000609)
Coal (ΔCO_t)	-0.0462****	-0.0102**	-0.00610***	-0.00142
	(0.000870)	(0.00450)	(0.00226)	(0.00191)
Hydropower (ΔH_t)	0.00417****	0.00123	-0.000233	0.000467
	(0.000833)	(0.000935)	(0.000424)	(0.000694)
Nuclear (ΔN_t)	-0.0331****	-0.00174	-0.00547***	-0.00202
	(0.00454)	(0.0232)	(0.00181)	(0.00963)
Pumping gen. (ΔPG_t)	-0.000779	0.00123	0.000714	0.000380
	(0.00220)	(0.00195)	(0.000838)	(0.00155)
Photovoltaics (ΔPV_t)	0.000282	0.00113	-0.0000789	0.000296
	(0.00182)	(0.000712)	(0.000369)	(0.000288)
Thermosolar (ΔTS_t)	-0.000543	-0.00241	-0.00136	-0.0000566
	(0.00327)	(0.00226)	(0.00152)	(0.00162)
CHP (ΔCHP_t)	-0.00198	-0.00419	-0.0000383	-0.00381
	(0.00581)	(0.0139)	(0.00550)	(0.00565)
Wind (ΔW_t)	0.00285***	0.000141	0.00113	0.000731
	(0.000978)	(0.00119)	(0.000711)	(0.000566)
Imports (ΔI_t)	0.000860	0.000318	0.000401	0.000301
	(0.000675)	(0.000768)	(0.000389)	(0.000334)
AR1	-0.0163**	-0.0218****	0.0449****	0.133****
	(0.00718)	(0.00297)	(0.00276)	(0.00282)
AR24	0.152****	0.0231****	0.376****	-0.0226****
	(0.00422)	(0.00456)	(0.00112)	(0.00563)
Constant $(\widehat{\beta_0})$	34.81****	22.76****	13.49****	10.83****
	(0.0839)	(0.0204)	(0.0130)	(0.00793)
N	8732	8780	8756	8756

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.5. ML estimations for voltage constraints after the intraday markets.

	(2019) $\Delta idVoltage_t$	(2020) $\Delta idVoltage_t$	(2021) $\Delta idVoltage_t$	(2022) $\Delta idVoltage_t$	(2023) $\Delta idVoltage_t$
Comb. Cycle (ΔCC_t)	-0.00488****	-0.0101****	-0.0314****	-0.0183****	-0.0268****
	(0.00108)	(0.00159)	(0.00147)	(0.00191)	(0.00189)
Coal (ΔCO_t)	-0.00388	-0.0125	-0.0235	-0.0197	-0.0612****
	(0.00382)	(0.0215)	(0.0196)	(0.0164)	(0.0159)
Hydropower (ΔH_t)	-0.00341**	-0.00731****	-0.0159****	-0.0112****	-0.0212****
	(0.00173)	(0.00134)	(0.00187)	(0.00235)	(0.00149)
Nuclear (ΔN_t)	-0.00496	-0.00646	0.0307***	-0.0368	-0.0247***
	(0.0162)	(0.0387)	(0.0107)	(0.0264)	(0.00950)
Pumping gen. (ΔPG_t)	-0.00498	-0.00234	-0.00660	-0.0169****	-0.0221****
	(0.00386)	(0.00338)	(0.00465)	(0.00402)	(0.00260)
Photovoltaics (ΔPV_t)	-0.00465**	-0.00653****	-0.0126****	-0.0125****	-0.0123****
	(0.00198)	(0.00150)	(0.00169)	(0.00132)	(0.00100)
Thermosolar (ΔTS_t)	-0.00328	0.00289	-0.0139*	-0.0120	-0.0220****
	(0.00451)	(0.00651)	(0.00816)	(0.00733)	(0.00590)
CHP (ΔCHP_t)	0.0227	0.0108	0.00783	-0.00364	-0.0472***
	(0.0162)	(0.0184)	(0.0175)	(0.0187)	(0.0164)
Wind (ΔW_t)	-0.00740****	-0.00725***	-0.0179****	-0.0168****	-0.0129****
	(0.00183)	(0.00265)	(0.00261)	(0.00288)	(0.00262)
Imports (ΔI_t)	-0.00633****	-0.00277**	-0.0124****	-0.0118****	-0.00763****
	(0.000962)	(0.00113)	(0.00126)	(0.00159)	(0.00148)
AR1	-0.0868****	-0.112****	-0.0252****	0.0108**	-0.0530****
	(0.00311)	(0.00294)	(0.00368)	(0.00445)	(0.00468)
AR24	0.0316****	0.0477****	0.144****	0.0315****	0.132****
	(0.00470)	(0.00592)	(0.00394)	(0.00586)	(0.00616)
Constant $(\widehat{\beta_0})$	44.39****	57.21****	78.14****	82.58****	81.82****
	(0.0637)	(0.0842)	(0.183)	(0.167)	(0.222)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.6. ML estimations for congestion issues after the intraday markets.

	(2019) $\Delta idCongestion_t$	(2020) $\Delta idCongestion_t$	(2021) $\Delta idCongestion_t$	(2022) $\Delta idCongestion_t$	(2023) $\Delta idCongestion_t$
Comb. Cycle (ΔCC_t)	0.000169	0.000631*	0.000314	-0.0000836	-0.0000797
	(0.000603)	(0.000348)	(0.000329)	(0.000402)	(0.000221)
Coal (ΔCO_t)	-0.00158	-0.0145****	-0.0222****	-0.00525****	0.0000101
	(0.00217)	(0.00196)	(0.00169)	(0.00108)	(0.00137)
Hydropower (ΔH_t)	0.00101**	-0.00000868	0.0000982	-0.0000306	0.0000796
	(0.000404)	(0.000336)	(0.000242)	(0.000349)	(0.000170)
Nuclear (ΔN_t)	-0.00240	0.000167	0.00167	0.00749****	-0.000588
	(0.00935)	(0.0395)	(0.00247)	(0.00115)	(0.00290)
Pumping gen. (ΔPG_t)	-0.000133	-0.000445	0.000301	0.0000707	-0.0000695
	(0.000844)	(0.000493)	(0.000470)	(0.000511)	(0.000373)
Photovoltaics (ΔPV_t)	-0.000367	0.000495	0.000732****	0.0000295	0.000184
	(0.000585)	(0.000312)	(0.000159)	(0.000155)	(0.000123)
Thermosolar (ΔTS_t)	0.00167	-0.000981	-0.000573	0.00123	-0.000758
	(0.00117)	(0.000903)	(0.000762)	(0.000903)	(0.000915)
CHP (ΔCHP_t)	0.00141	0.00443	0.00788****	0.00428**	-0.000993
	(0.00616)	(0.00420)	(0.00175)	(0.00188)	(0.00210)
Wind (ΔW_t)	0.0000763	-0.000115	0.000582**	0.000443	0.000401*
	(0.000377)	(0.000697)	(0.000256)	(0.000328)	(0.000209)
Imports (ΔI_t)	0.000178	0.000168	0.000361*	-0.0000434	0.000146
	(0.000234)	(0.000250)	(0.000189)	(0.000231)	(0.000223)
AR1	0.212****	-0.00248	-0.0985****	-0.0442****	-0.158****
	(0.00144)	(0.00237)	(0.00304)	(0.00230)	(0.00158)
AR24	0.0159*	-0.00000937	-0.0432****	-0.0248****	0.178****
	(0.00883)	(0.105)	(0.00342)	(0.00348)	(0.00150)
Constant $(\widehat{\beta_0})$	9.728****	9.390****	8.610****	7.473****	7.457****
	(0.00939)	(0.00826)	(0.0138)	(0.00731)	(0.00529)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.7. ML estimations for grid reliability issues after intraday markets.

	(2019) $\Delta idReiability_t$	(2020) $\Delta idReiability_t$	(2021) $\Delta idReiability_t$	(2022) $\Delta idReiability_t$	(2023) $\Delta idReiability_t$
Comb. Cycle (ΔCC_t)	-0.00337***	-0.0992****	-0.101****	-0.0533****	-0.101****
	(0.00105)	(0.00291)	(0.00295)	(0.00323)	(0.00429)
Coal (ΔCO_t)	-0.0185****	0.000839	0.0572	0.0737***	-0.319****
	(0.00340)	(0.0241)	(0.0371)	(0.0263)	(0.0341)
Hydropower (ΔH_t)	0.0112****	0.0737****	0.137****	0.111****	0.249****
	(0.000974)	(0.00247)	(0.00282)	(0.00361)	(0.00361)
Nuclear (ΔN_t)	-0.0112	-0.0141	0.0575*	0.0536	0.0308
	(0.0102)	(0.0480)	(0.0338)	(0.0366)	(0.0376)
Pumping gen. (ΔPG_t)	0.0472****	0.197****	0.220****	0.189****	0.232****
	(0.00135)	(0.00323)	(0.00419)	(0.00487)	(0.00601)
Photovoltaics (ΔPV_t)	-0.00188	-0.00712	-0.00995***	-0.0162****	-0.0103****
	(0.00157)	(0.00448)	(0.00317)	(0.00281)	(0.00284)
Thermosolar (ΔTS_t)	0.00292	0.00887	0.0474****	0.0767****	0.206****
	(0.00364)	(0.0128)	(0.0134)	(0.0166)	(0.0192)
CHP (ΔCHP_t)	0.00144	0.0843**	0.112****	0.199****	0.564****
	(0.0217)	(0.0362)	(0.0321)	(0.0382)	(0.0326)
Wind (ΔW_t)	0.000653	0.0219****	0.0326****	0.0114**	0.0397****
	(0.00155)	(0.00432)	(0.00456)	(0.00480)	(0.00541)
Imports (ΔI_t)	-0.00265****	0.0159****	0.0389****	0.0268****	0.0563****
	(0.000759)	(0.00205)	(0.00229)	(0.00303)	(0.00352)
AR1	-0.0329****	0.0532****	0.0308****	0.0278****	-0.0230***
	(0.00732)	(0.00708)	(0.00812)	(0.00718)	(0.00830)
AR24	0.0622****	0.383****	0.272****	0.369****	0.384****
	(0.00360)	(0.00472)	(0.00688)	(0.00558)	(0.00682)
Constant $(\widehat{\beta_0})$	37.58****	121.2****	152.9****	164.7****	227.0****
	(0.0729)	(0.410)	(0.668)	(0.627)	(1.039)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.8. ML estimations for insufficient adequacy reserves after the intraday markets.

	(2019) $\Delta idAdequacy_t$	(2020) $\Delta idAdequacy_t$	(2021) $\Delta idAdequacy_t$	(2022) $\Delta idAdequacy_t$	(2023) $\Delta idAdequacy_t$
Comb. Cycle (ΔCC_t)	-0.00337***	-0.0992****	-0.101****	-0.0533****	-0.101****
	(0.00105)	(0.00291)	(0.00295)	(0.00323)	(0.00429)
Coal (ΔCO_t)	-0.0185****	0.000839	0.0572	0.0737***	-0.319****
	(0.00340)	(0.0241)	(0.0371)	(0.0263)	(0.0341)
Hydropower (ΔH_t)	0.0112****	0.0737****	0.137****	0.111****	0.249****
	(0.000974)	(0.00247)	(0.00282)	(0.00361)	(0.00361)
Nuclear (ΔN_t)	-0.0112	-0.0141	0.0575*	0.0536	0.0308
	(0.0102)	(0.0480)	(0.0338)	(0.0366)	(0.0376)
Pumping gen. (ΔPG_t)	0.0472****	0.197****	0.220****	0.189****	0.232****
	(0.00135)	(0.00323)	(0.00419)	(0.00487)	(0.00601)
Photovoltaics (ΔPV_t)	-0.00188	-0.00712	-0.00995***	-0.0162****	-0.0103****
	(0.00157)	(0.00448)	(0.00317)	(0.00281)	(0.00284)
Thermosolar (ΔTS_t)	0.00292	0.00887	0.0474****	0.0767****	0.206****
	(0.00364)	(0.0128)	(0.0134)	(0.0166)	(0.0192)
CHP (ΔCHP_t)	0.00144	0.0843**	0.112****	0.199****	0.564****
	(0.0217)	(0.0362)	(0.0321)	(0.0382)	(0.0326)
Wind (ΔW_t)	0.000653	0.0219****	0.0326****	0.0114**	0.0397****
	(0.00155)	(0.00432)	(0.00456)	(0.00480)	(0.00541)
Imports (ΔI_t)	-0.00265****	0.0159****	0.0389****	0.0268****	0.0563****
	(0.000759)	(0.00205)	(0.00229)	(0.00303)	(0.00352)
AR1	-0.0329****	0.0532****	0.0308****	0.0278****	-0.0230***
	(0.00732)	(0.00708)	(0.00812)	(0.00718)	(0.00830)
AR24	0.0622****	0.383****	0.272****	0.369****	0.384****
	(0.00360)	(0.00472)	(0.00688)	(0.00558)	(0.00682)
Constant ($\widehat{\beta_0}$)	37.58****	121.2****	152.9****	164.7****	227.0****
	(0.0729)	(0.410)	(0.668)	(0.627)	(1.039)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table E.9. ML estimations for other issues after the intraday markets.

	(2019) $\Delta idOthers_t$	(2020) $\Delta idOthers_t$	(2021) $\Delta idOthers_t$	(2022) $\Delta idOthers_t$	(2023) $\Delta idOthers_t$
Comb. Cycle (ΔCC_t)	0.000597	0.000112	0.000698	-0.000158	0.00488***
	(0.000987)	(0.000820)	(0.000618)	(0.000718)	(0.00153)
Coal (ΔCO_t)	-0.000999	-0.00660	-0.000272	0.00812	-0.0478****
	(0.00247)	(0.00817)	(0.00899)	(0.00688)	(0.0106)
Hydropower (ΔH_t)	-0.00119	-0.00144*	-0.000382	-0.000159	0.00138
	(0.00126)	(0.000770)	(0.000672)	(0.00120)	(0.00142)
Nuclear (ΔN_t)	0.00146	-0.00126	-0.00396	-0.00266	0.322****
	(0.0190)	(0.0277)	(0.00392)	(0.0262)	(0.00206)
Pumping gen. (ΔPG_t)	-0.00133	0.00512****	-0.00233**	0.000330	0.00100
	(0.00187)	(0.00151)	(0.00113)	(0.00162)	(0.00220)
Photovoltaics (ΔPV_t)	-0.00207*	-0.000283	-0.000749*	0.000392	0.00147**
	(0.00110)	(0.000830)	(0.000419)	(0.000608)	(0.000630)
Thermosolar (ΔTS_t)	0.00223	0.00154	0.00239	0.00231	0.00617*
	(0.00296)	(0.00392)	(0.00246)	(0.00270)	(0.00362)
CHP (ΔCHP_t)	-0.0136	-0.00223	0.00200	0.00148	-0.0148
	(0.00832)	(0.00675)	(0.00599)	(0.00704)	(0.0112)
Wind (ΔW_t)	-0.000818*	0.000373	0.0000782	0.000730	0.00185
	(0.000433)	(0.00112)	(0.000468)	(0.00102)	(0.00158)
Imports (ΔI_t)	-0.000175	-0.0000256	-0.000284	-0.000984	0.000451
	(0.000475)	(0.000551)	(0.000451)	(0.000730)	(0.00109)
AR1	-0.428****	-0.219****	-0.318****	-0.156****	-0.223****
	(0.000717)	(0.00161)	(0.00146)	(0.00181)	(0.00164)
AR24	0.0565****	0.00145	0.0306****	0.0494****	0.0151****
	(0.00565)	(0.0105)	(0.00803)	(0.00513)	(0.00334)
Constant $(\widehat{\beta_0})$	27.65****	25.21****	26.80****	35.45****	53.11****
	(0.0203)	(0.0351)	(0.0185)	(0.0442)	(0.0558)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Appendix F - Estimates for the demand model

Table F.1. ML estimations for actions made after day-ahead

	(2019) $\Delta daVoltage_t$	(2020) $\Delta daVoltage_t$	(2021) $\Delta daVoltage_t$	(2022) $\Delta daVoltage_t$	(2023) $\Delta daCongestion$	(2019) $\Delta daCongestion$	(2020) $\Delta daCongestion$	(2021) $\Delta daCongestion$	(2022) $\Delta daCongestion$	(2023) $\Delta daCongestion$
Demand (ΔTED_t)	-0.0343****	-0.0376****	-0.0503****	-0.0418****	-0.0531****	0.0111****	0.0135****	0.00565****	0.00262****	0.00340****
	(0.00100)	(0.00147)	(0.00131)	(0.00138)	(0.00143)	(0.000656)	(0.000697)	(0.000549)	(0.000389)	(0.000530)
RES ($\Delta sRES_t$)	2.339****	1.097**	3.997****	5.518****	4.374****	-0.0932	0.819***	0.840****	0.553****	1.035****
	(0.499)	(0.536)	(0.517)	(0.402)	(0.434)	(0.358)	(0.301)	(0.238)	(0.112)	(0.154)
AR1	-0.0860****	-0.0697****	-0.129****	-0.0853****	-0.0837****	-0.106****	-0.157****	-0.101****	-0.0381****	-0.0397****
	(0.00791)	(0.00751)	(0.00719)	(0.00758)	(0.00763)	(0.00835)	(0.00927)	(0.00739)	(0.00702)	(0.00865)
AR24	0.666****	0.705****	0.657****	0.638****	0.720****	0.637****	0.565****	0.629****	0.618****	0.706****
	(0.00306)	(0.00277)	(0.00368)	(0.00321)	(0.00328)	(0.00456)	(0.00536)	(0.00374)	(0.00274)	(0.00428)
Constant ($\widehat{\beta_0}$)	89.24****	122.1****	126.8****	125.0****	161.9****	55.39****	60.85****	50.49****	31.33****	50.12****
	(0.265)	(0.339)	(0.430)	(0.388)	(0.513)	(0.184)	(0.246)	(0.140)	(0.0658)	(0.168)
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table F.2. ML estimations for actions made after day-ahead

	(2019) $\Delta daReliability_t$	(2020) $\Delta daReliability_t$	(2021) $\Delta daReliability_t$	(2022) $\Delta daReliability_t$	(2023) $\Delta daReliability_t$	(2019) $\Delta daOthers_t$	(2020) $\Delta daOthers_t$	(2021) $\Delta daOthers_t$	(2022) $\Delta daOthers_t$	(2023) $\Delta daOthers_t$
Demand (ΔTED_t)	0.0118****	0.0142****	0.00528****	0.0196****	0.0232****	-0.00474****	0.000649**	0.000240	0.000225	
	(0.000753)	(0.00122)	(0.00105)	(0.00178)	(0.00160)	(0.000297)	(0.000277)	(0.000208)	(0.000164)	
RES ($\Delta sRES_t$)	-0.653	2.215****	-0.512	4.768****	6.605****	2.232****	-0.0131	-0.0584	0.0330	
	(0.487)	(0.487)	(0.338)	(0.517)	(0.379)	(0.215)	(0.0932)	(0.0690)	(0.0602)	
AR1	-0.0183***	0.0180****	-0.0187***	0.227****	0.0604****	-0.0131*	-0.0219****	0.0456****	0.134****	
	(0.00695)	(0.00465)	(0.00606)	(0.00495)	(0.00731)	(0.00713)	(0.00290)	(0.00268)	(0.00169)	
AR24	0.266****	0.248****	0.294****	0.359****	0.352****	0.162****	0.0239****	0.379****	-0.0231****	
	(0.00393)	(0.00353)	(0.00373)	(0.00391)	(0.00416)	(0.00376)	(0.00304)	(0.000978)	(0.00318)	
Constant ($\widehat{\beta_0}$)	76.49****	108.8****	97.59****	130.5****	173.5****	36.17****	22.78****	13.51****	10.84****	
	(0.167)	(0.149)	(0.177)	(0.277)	(0.431)	(0.0827)	(0.0149)	(0.00858)	(0.00664)	
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table F.3. ML estimations for actions made after day-ahead

	(2019) $\Delta idVoltage_t$	(2020) $\Delta idVoltage_t$	(2021) $\Delta idVoltage_t$	(2022) $\Delta idVoltage_t$	(2023) $\Delta idCongestion_t$	(2019) $\Delta idCongestion_t$	(2020) $\Delta idCongestion_t$	(2021) $\Delta idCongestion_t$	(2022) $\Delta idCongestion_t$	(2023) $\Delta idCongestion_t$
Demand (ΔTED_t)	-0.00456****	-0.00566****	-0.0151****	-0.0131****	-0.0159****	0.000244*	0.0000997	0.000313***	0.0000286	0.0000932
	(0.000457)	(0.000553)	(0.000786)	(0.000964)	(0.000833)	(0.000128)	(0.000109)	(0.0000967)	(0.000111)	(0.0000809)
RES $(\Delta sRES_t)$	-0.432	-0.393	0.305	-0.0270	0.902****	-0.0755	-0.00539	0.0396	0.0380*	0.0207
	(0.307)	(0.251)	(0.343)	(0.182)	(0.163)	(0.0881)	(0.0499)	(0.0373)	(0.0229)	(0.0169)
AR1	-0.0864****	-0.111****	-0.0184****	0.0123***	-0.0471****	0.213****	-0.00136	-0.0995****	-0.0434****	-0.158****
	(0.00292)	(0.00273)	(0.00354)	(0.00436)	(0.00467)	(0.00104)	(0.00205)	(0.00287)	(0.00204)	(0.00126)
AR24	0.0307****	0.0491****	0.160****	0.0335****	0.147****	0.0170**	-0.00181	-0.0425****	-0.0262****	0.178****
	(0.00456)	(0.00577)	(0.00375)	(0.00573)	(0.00599)	(0.00826)	(0.121)	(0.00312)	(0.00300)	(0.00144)
Constant $(\widehat{\beta_0})$	44.41****	57.30****	78.62****	82.66****	82.50****	9.735****	9.412****	8.666****	7.489****	7.460****
	(0.0594)	(0.0806)	(0.179)	(0.157)	(0.224)	(0.00768)	(0.00500)	(0.00884)	(0.00508)	(0.00467)
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table F.4. ML estimations for actions made after day-ahead

	(2019) $\Delta idReliability_t$	(2020) $\Delta idReliability_t$	(2021) $\Delta idReliability_t$	(2022) $\Delta idReliability_t$	(2023) $\Delta idReliability_t$	(2019) $\Delta idAdequacy_t$	(2020) $\Delta idAdequacy_t$	(2021) $\Delta idAdequacy_t$	(2022) $\Delta idAdequacy_t$	(2023) $\Delta idAdequacy_t$
Demand (ΔTED_t)	-0.000558	0.00101*	0.000312	0.000794	0.00776****	0.00152***	0.0247****	0.0490****	0.0382****	0.0970****
	(0.000397)	(0.000522)	(0.000785)	(0.000811)	(0.00136)	(0.000521)	(0.00207)	(0.00192)	(0.00208)	(0.00286)
RES $(\Delta sRES_t)$	0.315	1.532****	1.287****	1.661****	3.248****	-82.08**	-392.3****	-1429.8****	-1452.8****	
	(0.257)	(0.206)	(0.289)	(0.191)	(0.282)	(33.40)	(88.25)	(80.38)	(60.12)	-2775.3****
AR1	0.0519****	0.128****	0.110****	0.146****	0.157****	-0.00889	0.0696****	0.0256***	0.0472****	0.000928
	(0.00202)	(0.00350)	(0.00278)	(0.00360)	(0.00452)	(0.00650)	(0.00620)	(0.00827)	(0.00701)	(0.00811)
AR24	0.0594****	0.0544****	0.0614****	0.0440****	0.136****	0.0957****	0.446****	0.343****	0.396****	0.467****
	(0.00496)	(0.00660)	(0.00355)	(0.00655)	(0.00579)	(0.00347)	(0.00411)	(0.00647)	(0.00535)	(0.00645)
Constant $(\widehat{\beta_0})$	36.28****	45.07****	69.35****	65.18****	124.4****	38.64****	139.4****	180.0****	179.6****	271.2****
	(0.0394)	(0.0631)	(0.0833)	(0.112)	(0.299)	(0.0388)	(0.345)	(0.719)	(0.622)	(1.227)
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table F.5. ML estimations for actions made after day-ahead

	(2019) $\Delta idOthers_t$	(2020) $\Delta idOthers_t$	(2021) $\Delta idOthers_t$	(2022) $\Delta idOthers_t$	(2023) $\Delta idOthers_t$
Demand (ΔTED_t)	-0.000620****	-0.000141	-0.000356	0.0000399	0.00104**
	(0.000184)	(0.000282)	(0.000223)	(0.000433)	(0.000490)
RES $(\Delta sRES_t)$	-0.0511	0.00735	0.0433	0.275***	0.0176
	(0.124)	(0.131)	(0.0623)	(0.0852)	(0.111)
AR1	-0.427****	-0.218****	-0.318****	-0.156****	-0.231****
	(0.000684)	(0.00144)	(0.00132)	(0.00167)	(0.00137)
AR24	0.0593****	0.000756	0.0317****	0.0496****	0.0117****
	(0.00526)	(0.0100)	(0.00763)	(0.00475)	(0.00304)
Constant $(\widehat{\beta_0})$	27.66****	25.24****	26.82****	35.46****	56.40****
	(0.0190)	(0.0154)	(0.0175)	(0.0366)	(0.0323)
N	8732	8780	8756	8756	8757

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table F.6. Determinants of volumes activated by other issues by the scheduled technologies.

	After Day-ahead					**After Intraday**				
SC	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
CC	-0.023		0.001							0.004
Coal	-0.053	-0.010	-0.011							-0.040
Hydro	0.005							-0.001		
Nuclear	-0.038		-0.009							0.267
Pumping								0.004	-0.002	
Photovoltaics							-0.002		-0.001	0.001
Thermosolar										0.005
CHP										
Wind	0.003						-0.001			
Imports										
daDemand	-0.006	0.001				-0.000				0.001

daRES	0.009							0.002	