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Environmental and Welfare Effects of Large-Scale Integration of Renewables in the Electricity Sector

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Abstract

The 2022 energy crisis highlighted the dependence of the Europe electricity sector on imported natural gas and the need to accelerate the adoption of renewables to the power system. However, operating a reliable power system with high share of renewables might require curtailing some renewables and activating conventional generators not scheduled in the day-ahead markets to ensure system reliability. These actions can result in environmental impacts, higher system costs and welfare impacts for customers. We use a novel high-granularity data from the Spanish power system for the period 2019–2022 to estimate the effects of these actions and forecast future impact of implementing ambitious targets of the European Gas Reduction Plan. We show that reliance on conventional generators will sharply increase with the addition of renewables. However, higher electricity consumption reduces the negative welfare impacts of integrating renewables. Until renewables and storage technologies advance further, conventional generators are needed for reliable operation of the systems.

Keywords Renewables · Decarbonization · Generation mix · Redispatching · Curtailment · Inverter-based resources · Synchronous generators · Day-ahead market · Network constraints · Gas crisis · System operator

JEL Classification L51 · L94 · Q41 · Q42

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1 Introduction

The European Green Deal is the EU's long-term growth plan to make Europe climate neutral by 2050. This target is enshrined in the European Climate Law, as well as the legally binding commitment to reduce net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels (European Commission 2019b; Borghesi et al. 2022). In July 2021, the Commission presented its 'Fit for 55' package of legislation to achieve these targets. The proposals would reduce natural gas consumption by 30% by 2030, with more than one-third of the savings coming from meeting the EU energy efficiency target (European Commission 2019b). In response to the energy market disruption by the Russia-Ukraine war, the European Commission presented the REPower EU Plan and the European Gas Reduction Plan to reduce gas consumption for the winter (European Commission 2022a, b). In consequence, many countries increased the climate ambition of their national energy plans, which translated into greater volumes of renewable energy sources (RES) to reduce dependence on gas fueled technologies, i.e. combined cycles.

However, the practical implementation of these ambitious environmental targets also requires addressing relevant operational challenges: wind and photovoltaics generators are inverted-based resources (IBR) with limited operation compared to rotating synchronous generators used in conventional plants (Hirth et al. 2018a; Davi-Arderius et al. 2024). Consequently, not all scheduled RES production in the markets is finally delivered, and some are replaced by conventional generators to ensure system reliability minimize the risk of blackouts (Andresen et al. 2023). In other words, large-scale integration of RES might increase the need for fossil-fuel sources with the associated social costs (emissions), loss of consumer welfare (higher costs) and loss of efficiency in general (wasting clean production).¹ This inefficiency might also constrain assessments of power system resource adequacy of highly decarbonised systems, which describes the expected level of security of supply for a ten-year horizon (ENTSOE 2024).

In countries with high shares of RES, volumes of activated energy to ensure system security peaked in 2020: 21.1 TWh in Germany, 11.1 TWh in Spain and 9.3 TWh in Italy. Its annual costs range from 1.47b€ for Italy, 0.43b€ for Spain and 0.25b€ for Germany in the same year. In 2022, volumes of activated energy were: 27.2 TWh in Germany, 11.0 TWh in Poland and 8.2TWh in Spain. During the covid lockdown in Spain, these actions produced more than 11% of the CO₂ emissions of the power sector as most of them were related activation of coal and combined cycle plants (ACER 2024; Davi-Arderius and Schittekatte 2023). This highlights that the allocation of generation and consumption in electricity markets might be economically efficient, but it does not minimize the risk of blackouts, with welfare implications for customers and the curtailed RES.

The literature on welfare effects of RES can be divided in the following groups: assessments of impacts on carbon pricing mechanisms or taxes (e.g., Best et al. 2020); welfare assessments and efficiency of programs aimed to promote and subsidise RES (e.g., Lehman et al. 2018; Alolo et al. 2020; Rövekamp et al. 2021); assessment of impacts of RES on electricity prices (e.g., Trujillo-Baute et al. 2018; Gambardella et al. 2020); contribution of

¹ In Europe, all these actions are known as redispatching. Art. 2 (26) of the Electricity Regulation (EU) 2019/943 defines redispatching 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, to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security*' (European Commission 2019a).

RES to reduce CO₂ emissions (e.g., Saidi and Omri 2020; Rehman et al. 2022); impact of RES on the network costs (e.g., Liu et al. 2021; Davi-Arderius et al. 2023); assessments of savings on gas imports (e.g., Runhau et al. 2023; Chyong et al. 2024); finally, assessment of welfare implications related to the power system integration of RES, e.g., Thomassen et al., (2024) estimate curtailment of 310 TWh of RES in Europe by 2040 and Davi-Arderius et al. (2023) find that low electricity demand during the covid lockdown peaked the actions to ensure system reliability, which produced 11% of CO₂ emissions from the power system. However, to our knowledge, the forecast of potential welfare implications of ambitious RES plans and measures to reduce gas imports on electricity networks has not been empirically assessed.

This paper aims to analyze welfare implications related to the connection of RES and how they could evolve with ambitious decarbonization targets in the national energy plans. These targets affect the generation mix and the consumption profile, i.e., installation of RES, energy efficiency programs and charging of electric vehicles (EVs). Welfare implications are related to higher revenues for owners of activated units, additional cost for consumers or higher CO₂ emissions. Moreover, we provide an assessment of future volumes in line with the Electricity Market Design (EMD) reform to improve the EU's electricity market design, which states that National Regulatory Authorities should report on the "estimated needs for flexibility" for a period of at least the next 5–10 years at national level (European Commission 2024). These results are relevant for minimizing potential welfare impacts of policies to decarbonize economies. They range from subsidies to promote installation of small RES in households or replacing fueled cars by EV, charges or Time-of-Use Tariffs (ToU) to incentivize electricity consumption in some hours, or peak shaving programs to consumption at peak hours.

Our hypothesis is that greater integration of RES has welfare implications and these will increase over time. We aim to answer the following research questions:

- What are the short-term implications of rescheduling RES in the day-ahead?
- What are the long-term effects of RES and electricity demand on carbon emissions, consumer welfare and efficiency of the sector?

The methodology consists of two stages. First, we assess how the total electricity demand and the rate of RES in the mix determine volumes of energy activated at the day-ahead markets and their costs in the (2019–2022). Second, using empirical estimates from the first stage we quantify how these volumes, costs and CO₂ emissions could evolve under different programs (scenarios), most of them related to the implementation of the European Gas Demand Reduction Plan. Precisely, this plan aimed to reduce gas consumption -reducing the electricity consumption and increasing the share of RES.

Our results help to assess the future efficiency implications of electricity markets and regulatory instruments to minimize potential negative welfare implications. The Spanish case anticipates similar challenges in other countries that are making heavy investments in RES and electricity use. The magnitude of the challenge aggregated across the EU is much larger and regulatory frameworks should provide the right incentives to minimize future inefficiencies. To our knowledge, this question has not been addressed in literature so far.

Spain has a high share of RES in gross electricity consumption (42.9% in 2021). Moreover, the Iberian Peninsula is an "energy island" because the cross-border capacity with France and Morocco is limited (IEA 2021) and far from the 15% requirement by the European Commission (2018). The case of Spain is relevant for other systems that implement similar policies. In 2021, the (net) actions of combined cycle plants in Spain amounted to

5.7TWh and increased its gas consumption by 30%. We use hourly data from the Spanish Nominated Electricity Market Operator (NEMO) and the Spanish Transmission System Operator (TSO), namely OMIE and REE, between 2019 and 2021. We use a Seasonal Autoregressive Integrated Moving Average time-series estimator (SARIMA), where variables are differentiated to ensure their stationarity and lagged endogenous variables capture the time dynamics (Dickey and Fuller 1979; Kwiatkowski et al. 1992).

The remainder of the paper is organized as follows. Section 2 describes network operation and RES. Section 3 describes the data. Section 4 presents the empirical approach. Section 5 presents the results. Finally, Sect. 6 is conclusions and regulatory recommendations.

2 Economic and Technical Integration of RES

Integration of RES in the electricity system and market requires economic allocation of generation and consumption as well as technical validation by system operators to ensure that the scheduled supply and demand is reliable, i.e. minimizes the risk of blackouts. Here we describe these processes. In competitive day-ahead electricity markets, the supply curve is made of the generation bids, while the demand curve is made of the consumption bids. In both cases, bids are sorted in ascending order. A particular feature of electricity markets, as opposed to many commodities, is that the clearing price applies to all cleared units irrespective of their bidding prices. In other words, all customers pay a uniform price, and all generators receive the same price. This mechanism is known as marginal pricing.

Under this scheme, generators have incentive to bid prices at their variable (marginal) costs. Moreover, this is useful to schedule non-dispatchable generation technologies whose production cannot be modulated each hour, i.e. nuclear or flowing hydropower. In these cases, nuclear plants have incentive to submit bids at zero prices to be always scheduled because they will receive the market clearing price which will be higher than their bid price. Owners of RES have similar incentives to submit bids at zero prices when they do not have storage devices for their output. These incentives shape the supply curve in the electricity markets.

Prior to the large-scale connection of RES, the closing technology in the electricity market tended to be a dispatchable conventional technology such as coal, fuel, or combined cycle plants.² These technologies can quickly adapt their production to the hourly demand. Thus, clearing prices were set at the variable costs of these technologies. In recent years, the large-scale connection of RES has transformed the market supply curve, i.e. in hours with peak solar production, the supply curve becomes flat, and the resultant clearing price becomes zero or even negative.³ Moreover, dispatchable conventional technologies (coal, fuel or combined cycle plants) are not always scheduled through the day-ahead markets (Jamasp et al. 2024). See Fig. 1.

In Europe, day-ahead markets consist of three different steps. First, all supply and demand curves from each bidding zone (country) are aggregated, which provides a

² Hydropower is a dispatchable technology, but its marginal production costs for run-of-the-river plants are close to zero.

³ In the electricity markets, negative prices might arise in hours with peak scheduled RES production and low consumption. In this case, generators may submit bids with negative prices when their units cannot stop their production (nuclear or flowing hydropower) or the RES might incur financial losses if they do not meet minimum annual production commitments.

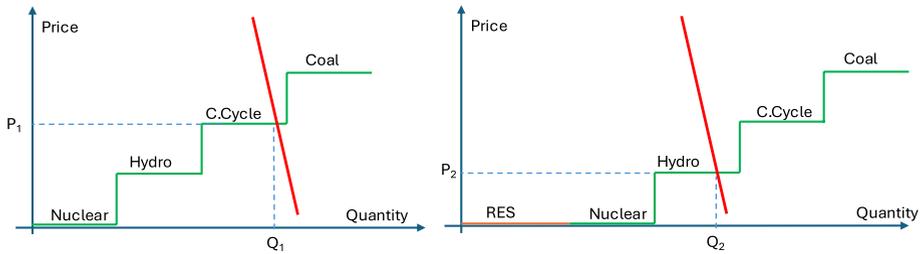


Fig. 1 Electricity market supply and demand curves. Left: represents equilibrium before introduction of RES (P_1 , Q_1). Right: represents equilibrium after introduction of RES (P_2 , Q_2). *Source:* Own elaboration

common European day-ahead spot price. Second, TSOs assess if the dispatching of the day-ahead market schedule of generation and consumption would overload some interconnection capacity between bidding zones or cross-border capacity between countries. If so, some generators and consumers are activated (or curtailed) in the affected bidding zones, which results in different (spot) prices for the affected bidding zones.⁴ This explains why European countries do not always have the same hourly spot price in the day-ahead markets. Third, system operators must ensure that the market schedule of generation and consumption from the day-ahead markets in each bidding zone is technically feasible, i.e. the operational constraints in their network are respected.⁵ When this is not the case, system operators must activate plants not cleared in the day-ahead markets and/or curtail other generators scheduled within the same bidding zone. These actions are known as ‘redispatching’ and might involve financial compensations to the activated and curtailed units, which should be paid by all customers in the corresponding bidding zones.

The financial flows from customer to generators have welfare impact: the additional costs reduce the consumer surplus. Generators’ profits may be affected depending on the compensation arrangements for their activation or curtailment. The compensation mechanism for generators is decided at national level. In some cases, not all curtailed generators are compensated, while in others they receive a predetermined compensation, which might be less or more than the agreed price with their supplier. Finally, these actions might imply additional CO₂ emissions when scheduled RES are replaced by conventional fossil fuel plants. The day-ahead market schedule of generation and consumption minimizes the risk of blackout only when key reliability parameters are within certain predetermined thresholds. See Appendix 1 for further detail. In late 2023, the EU Action Plan for Grids defines several priorities to achieve 1,000 GW of solar and up to 317 GWh of offshore wind until 2030. The actions include the need for grid investments improving the long-term transmission and distribution planning to efficiently connect more RES (European Commission 2023).

In the United States, Australia or Chile, electricity markets are not organized in bidding zones, but in locational marginal pricing (LMP) mechanisms, where there is a different price in each location of the country, namely nodes. Under this mechanism, the price is not only based on the generation technology and consumption, but also on the cost of grid

⁴ In Europe, day-ahead spot markets operate under the copper plate principle, which means that potential grid constraints within each bidding zone are not considered when the market is cleared.

⁵ A market schedule of units includes detailed assignment of generators or consumers, with their corresponding energy to generate or consume, respectively.

congestion. This provides locational economic incentives to consume (or generate) when is needed according to the network capacity. However, LMP does not provide outcomes that also respect all the operational security parameters, e.g. frequency or voltage (Eicke and Schittekatte 2022).

The literature on the actions used to ensure system reliability and security can be divided into two groups. First, theoretical studies. Hirth et al. (2018b) develop a zonal wholesale market with a locational market to identify optimal bidding strategies and determine Nash-equilibrium prices. Poplavskaya et al. (2020) develop a methodology to increase cross-border exchanges through preventive activation of units. Schermeyer et al. (2018) develop a congestion management scheme at distribution grid level considering the flexibility options to avoid curtailing RES. Grimm et al. (2022) compare the cost and market-based procurement of actions from RES and conventional generation to assess its overall welfare. Concerns for gaming related to these actions has been analyzed: Hirth et al. (2020) identify potential gaming related to market procurement of actions, Palovic et al. (2022) study potential strategic behavior by generators and consumers between electricity markets and these processes. Ehrhart et al. (2024) assess a potential mechanism where market participants are compensated for their availability to be activated when required.

Second, empirical studies. Joos and Staffell (2018) find that costs of actions to solve grid bottlenecks in the UK and Germany peaked since 2010, resulting in curtailment rates of 5% for wind farms in both countries. Petersen et al (2023) assess the welfare impact of intermittent wind power in Spain (2009–2018) and find that an additional GWh of wind increases the cost of action up to 0.19 Euro/MWh. Davi-Arderius and Schittekatte (2023) estimate that the actions in Spain lead to a reduction between 0.93 and 6.2% of the maximum potential CO₂ savings from RES. Finally, Thomassen et al. (2024) study potential curtailed RES in Europe in 2040 with actions to ensure system security and find annual curtailments might peak up to 310 TWh. However, the forecast of potential welfare implications from implementing ambitious national energy plans and measures to reduce gas imports has not been empirically assessed yet.

3 Data

The data used in this study combines operating data published by the Spanish TSO and market data published by the Spanish NEMO (REE 2024; OMIE 2024). They include hourly data between 2019 and 2022 and corresponds to the Spanish bidding zone. Figure 2 shows the hourly electricity generated by technology between 2019 and 2022. The Spanish hourly demand follows two peaks, one at 12–13 h and another at 20–21 h. Wind production is relatively constant throughout the hours of the day, while photovoltaics produce between 8 and 21 h.

Table 1 shows the summary statistics of the remedial actions by technology. They can be classified in two groups of plants: those whose volumes activated are higher than curtailed during this (combined cycle, coal, and pumping consumption), and those whose activated volumes are lower than curtailed during this (wind, photovoltaics, thermosolar, CHP, hydropower, and pumping generation). Table 2 shows the summary statistics of total electricity demand, and share of RES.

Figure 3 shows the hourly (net) activated volumes in the day-ahead and differentiating between synchronous generation (Eq. 2), IBR (Wind and Photovoltaics) and Pumping Consumption.

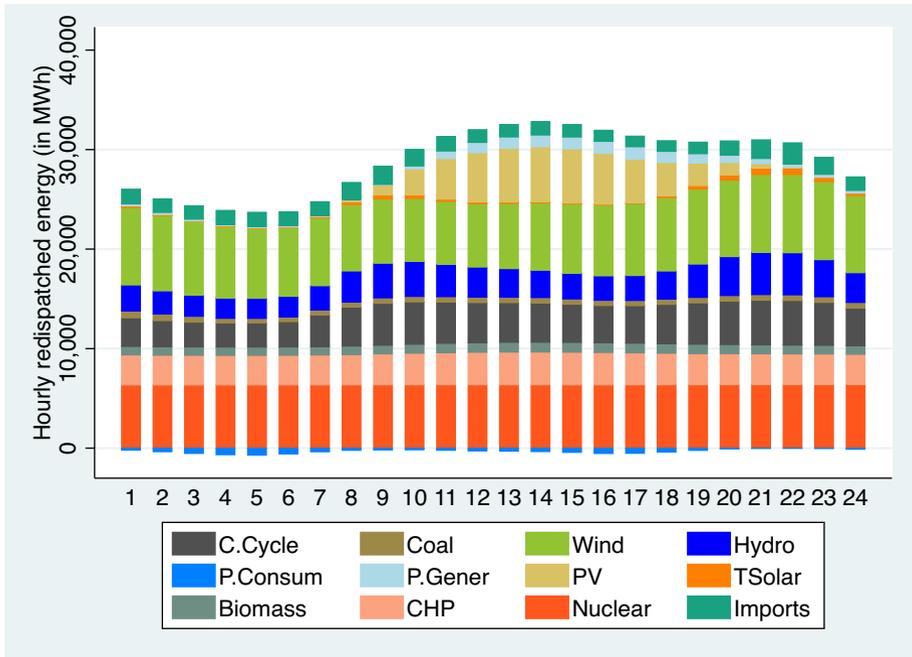


Fig. 2 Total Electricity demand by technology. Source: Own elaboration based on OMIE (2024)

Table 3 shows the annual volumes of activated and curtailed energy in the day-ahead by technology, as well as the annual costs paid by customers. The annual volumes of curtailed wind and photovoltaic production peak at 4,953 and 405 GWh, respectively. In the case of wind, this equals to 8% of the annual scheduled production in the day-ahead. In synchronous generation, mostly combined cycle and coal plants are activated, while hydropower, CHP and pumping generators are curtailed. This shows that network operational constraints are time and spatial dependent, and the locations of combined cycle and coal plants might fit better with the location of grid network constraints than other synchronous sources.

Table 4 summarizes the annual scheduled production from combined cycle plants in the day ahead, as well as the activated energy with the corresponding gas consumption. It should be noted that the activated energy in this technology due to remedial actions exceeds 22% of all their scheduled energy in 2020 and 2021.

Figure 4 plots how the (net) volumes of synchronous generation evolve with the total demand (TED_t) for each year. We find a negative correlation between the two variables, showing that volumes of activated energy at night are higher when the load levels of lines are lower.⁶ Figure 5 shows how the (net) energy activated from synchronous generators evolve with the RES ($sRES_t$).

⁶ See the surge impedance loading (SIL) effect described in Appendix 1.

Table 1 Summary statistics of net volumes (redispatched energy) by technology in the day-ahead

Variable	Definition	Units	Mean	St. Dev	Min	Max
$r_{CC,t}$	(Net) volumes from combined cycle plants	MWh	507.64	495.10	-2,436.50	3,022.30
$r_{CO,t}$	(Net) volumes from coal plants	MWh	210.89	213.40	-567.00	1,215.00
$r_{W,t}$	(Net) volumes from wind plants	MWh	-349.21	312.27	-2,207.80	658.10
$r_{PV,t}$	(Net) volumes from PV plants	MWh	-11.83	93.51	-2,375.00	34.90
$r_{TS,t}$	(Net) volumes from thermosolar plants	MWh	-11.03	64.96	-940.80	24.50
$r_{CHP,t}$	(Net) volumes from CHP plants	MWh	-74.32	90.70	-868.90	81.60
$r_{H,t}$	(Net) volumes from hydropower plants	MWh	-110.85	146.33	-1,504.00	1,160.40
$r_{PG,t}$	(Net) volumes from pumping plants when generating	MWh	-44.63	106.78	-1,360.00	1,198.20
$r_{PC,t}$	(Net) volumes from pumping plants when consuming	MWh	-103.62	226.37	-2,456.10	800.00
$r_{SYNCH,t}$	(Net) volumes from synchronous generators	MWh	472.15	398.53	-658.1	3,176.2
$r_{COST,t}$	Hourly costs	€	40,817	47,035	-47,409	738,436
$Auction_{gas,t}$	Gas price	Eur/MWh	43.25	43.54	4.17	246.25
$Price_{CO_2,t}$	CO2 auction price	Eur/tn	45.71	24.35	14.6	97.51

Positive values mean starting units (higher generation), negative means curtailing units (lower production) (N = 38,663)

The (net) volumes from synchronous generation ($r_{SYNCH,t}$) is calculated using Eq. 2. In generation technologies, positive values mean starting units during redispatching, negative values mean curtailing in the day-ahead. In pumping generators when consuming, positive values mean curtailing consumption, while negative values mean the opposite. Negative costs mean savings for customers, e.g. when activated energy is related to pumping consumption

Table 2 Summary statistics of the total electricity demand and the share of wind and photovoltaics in Total Electricity Demand (TED_t). (N = 38,663)

Variable	Definition	Units	Mean	St. Dev	Min	Max
TED_t	Total (scheduled) demand in the day-ahead	MWh	28,820.9	4,473.2	17,161.7	42,064.5
PV_t	Scheduled photovoltaic in the day-ahead	MWh	2,132.2	3,066.9	0	15,053.8
W_t	Scheduled wind in the day-ahead	MWh	7,306.3	3,794.5	477.6	21,545.0
$sRES_t$	Share of IBR (wind and photovoltaics) in TED	%	31.12	12.72	3.48	72.73

The share of IBR ($sRES_t$) is calculated using Eq. 4

4 Empirical Approach

4.1 Analysis

First, we analyze the energy activated from all conventional generators in the dispatch model. Endogenous variable is the hourly (net) activated energy of synchronous generation ($r_{SYNCH,t}$) and corresponds to energy activated from nuclear, combined cycle, coal, hydropower, pumping generation, CHP, biomass and thermosolar plants. This variable is positive if the sum of activated energy is higher than the curtailed energy and is negative in the opposite case. Explanatory variables include hourly total electricity demand (TED_t) and percentage of IBR ($sRES_t$) in total demand. Seasonality is controlled by

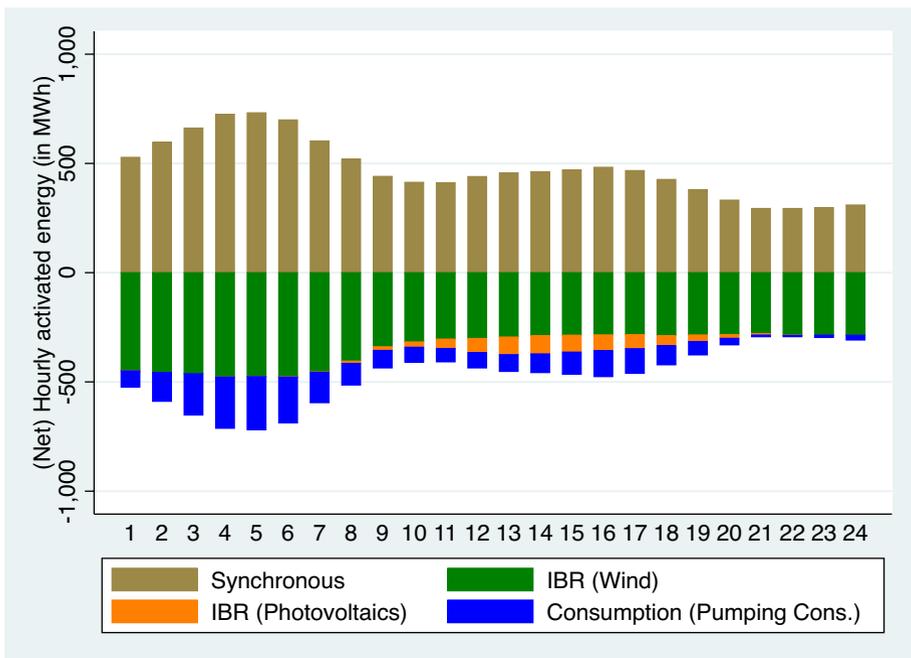


Fig. 3 Average hourly (net) activated energy in the day-ahead by technology (2019–2022). Note: Positive values mean activated energy, while negative means curtailment. Pumping in negative values means higher activated. Source: Own elaboration based on OMIE (2024) and REE (2024)

Table 3 Annual volumes of actions (redispached energy) in the day-ahead and costs for customers *Source:* REE (2024) and own calculations

	Units	2019	2020	2021	2022
Annual electricity demand	GWh	249.9	237.2	244.0	235.4
Scheduled production from wind plants	GWh	58,454.3	61,797.6	66,170.4	63,667.5
Scheduled production from photovoltaic plants	GWh	7,583.6	13,667.3	19,399.2	27,211.1
Scheduled production from combined cycle plants	GWh	37,505.7	24,591.8	19,472.3	46,950.8
Scheduled production from coal plants	GWh	7,330.1	1,568.5	3,106.9	7,188.5
(Net) volumes from combined cycle plants	GWh	+ 3,019.5	+ 5,361.2	+ 5,767.8	+ 3,639.0
(Net) volumes from coal plants	GWh	+ 2,321.6	+ 2,899.8	+ 1,560.9	+ 607.4
(Net) volumes from CHP plants	GWh	- 622.1	- 695.6	- 775.9	- 510.8
(Net) volumes from hydropower plants	GWh	- 947.5	- 972.1	- 1,579.8	- 384.8
(Net) volumes from pumping generation plants	GWh	- 572.6	- 458.2	- 372.3	- 160.6
(Net) redispached energy from thermosolar plants	GWh	- 0.7	- 2.8	- 29.4	- 353.6
(Net) volumes from plants made of synchronous generators	GWh	+ 3,083.9	+ 5,973.0	+ 4,373.1	+ 2,715.1
(Net) volumes from Wind plants	GWh	- 2,479.2	- 4,952.7	- 3,451.4	- 1,352.8
(Net) volumes from Photovoltaics plants	GWh	- 0.7	- 0.7	- 405.1	- 219.3
Economic cost	M€	239	423	443	473

In (net) volumes, positive values mean higher activated than curtailed energy, while negative means the opposite

Table 4 Main data associated to the combined cycle plants in Spain in the day-ahead (2019–2022) *Source:* Own elaboration based on REE (2024) and OMIE (2024)

	Units	2019	2020	2021	2022
Scheduled generation					
Energy	GWh	37.51	24.59	19.47	46.95
Gas	Mm3 gas	4,567.65	2,994.93	2,371.44	5,717.94
Remedial actions					
Energy	GWh	3.02	5.36	5.77	3.64
Gas	Mm3 gas	367.74	652.92	702.44	443.18
Remedial actions versus scheduled generation	%	8%	22%	30%	8%
Costs paid by customers	M€	239	423	443	473

Gas consumption is calculated using Eq. 7. Mm3 means Million of m3

several dummy variables: M_t , a dummy variable for each month, while $holiday_t$ equals to 1 in weekends and national holidays. See Eq. 1:

$$\Delta r_{SYNCH,t} = \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta r_{SYNCH,t-1} + \hat{\beta}_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot \Delta sRES_t + \sum_{m=1}^{11} \hat{\delta}_m \cdot M_t^m + \hat{\beta}_4 \cdot holiday_t + \hat{\theta} \cdot \Delta r_{SYNCH,t-24} + \varepsilon_t \tag{1}$$

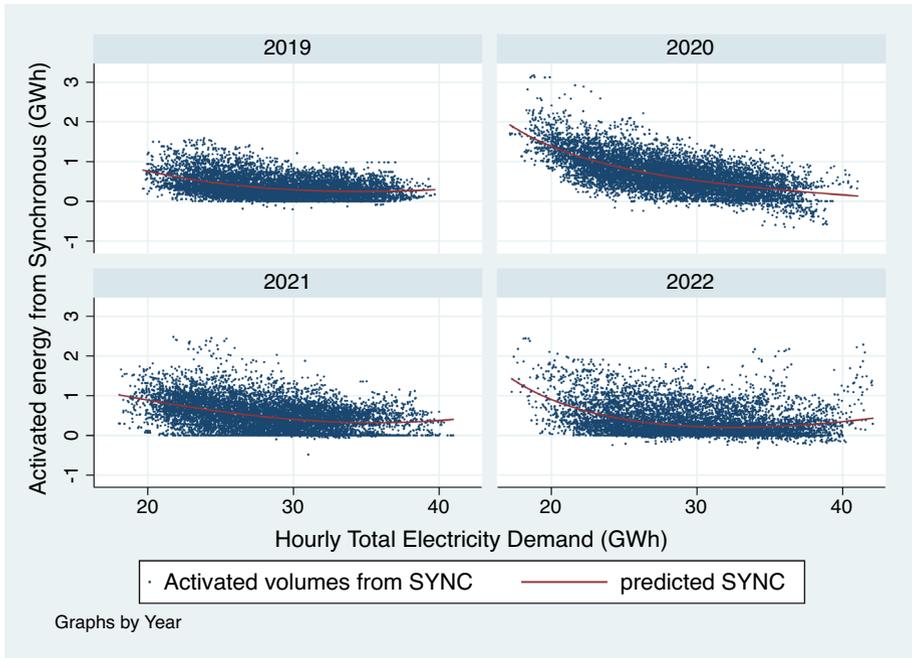


Fig. 4 Annual (net) volumes of energy activated from Synchronous generation ($r_{SYNCH,t}$) in vertical axis versus total demand (TED_t) in horizontal axis. Red line is the fitted trend line. *Source:* Own elaboration

$r_{SYNCH,t}$ is the sum of the (net) hourly activated energy from each synchronous technology in the day-ahead and is calculated in Eq. 2:

$$r_{SYNCH,t} = \sum_{i=N,CC,CO,H,PG,CHP,B,TS} r_{i,t} \tag{2}$$

where N corresponds to nuclear, CC for combined cycle, C for coal, H for hydropower, PG for pumping generation, CHP for CHP, B for biomass and TS for thermosolar plants.

The hourly share of RES ($sRES_t$) corresponds to the share of IBR (wind and photovoltaic) scheduled in the day ahead. This is calculated as the sum of wind (W_t) and photovoltaics (PV_t) over total demand as in Eq. 3.

$$sRES_t = \frac{W_t + PV_t}{TDEM_t} \cdot 100 \tag{3}$$

Second, we study the activated energy only from combined cycle, coal, and CHP plants in the technology model. In this case, endogenous variable corresponds to the hourly (net) activated energy for combined cycle ($\Delta r_{CC,t}$), coal ($\Delta r_{CO,t}$) and CHP plants ($\Delta r_{CHP,t}$). As in the dispatch model, these variables are positive if the sum of activated energy is higher than the curtailed energy, while the negative is the opposite. See Eqs. 4, 5 and 6.

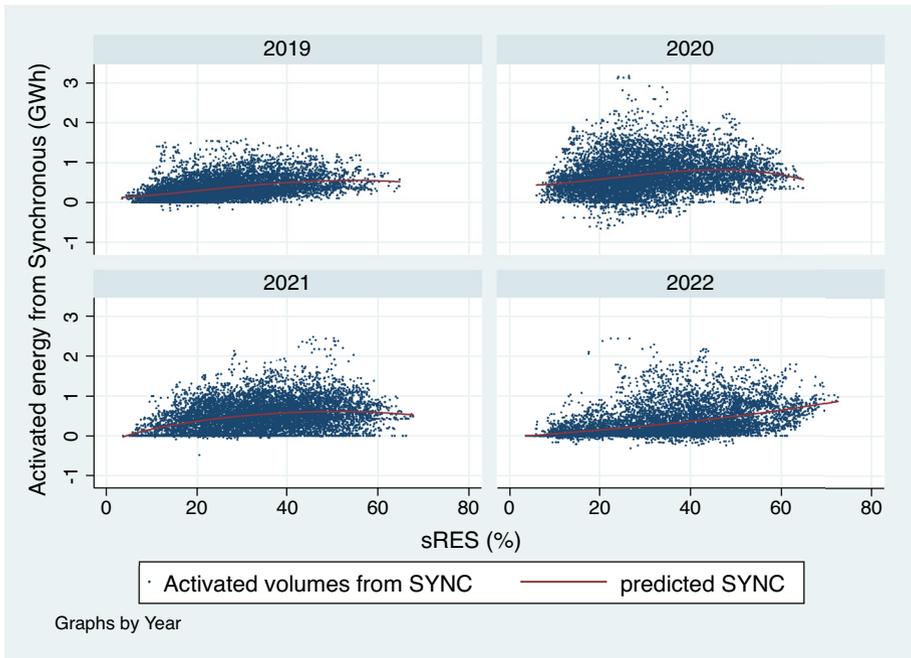


Fig. 5 Annual (net) volumes of energy activated from synchronous generators ($r_{SYNCH,t}$) in vertical axis versus share of RES ($sRES_t$) in horizontal axis for each year (2019–2022). Red line shows the fitted trend line. *Source:* Own elaboration

$$\begin{aligned} \Delta r_{CC,t} = & \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta r_{CC,t-1} + \hat{\beta}_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot \Delta sRES_t + \sum_{m=1}^{11} \hat{\delta}_m \cdot M_t^m + \hat{\beta}_4 \cdot holiday_t \\ & + \hat{\theta} \cdot \Delta r_{CC,t-24} + \varepsilon_t \end{aligned} \tag{4}$$

$$\begin{aligned} \Delta r_{CO,t} = & \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta r_{CO,t-1} + \hat{\beta}_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot \Delta sRES_t + \sum_{m=1}^{11} \hat{\delta}_m \cdot M_t^m + \hat{\beta}_4 \cdot holiday_t \\ & + \hat{\theta} \cdot \Delta r_{CO,t-24} + \varepsilon_t \end{aligned} \tag{5}$$

$$\begin{aligned} \Delta r_{CHP,t} = & \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta r_{CHP,t-1} + \hat{\beta}_2 \Delta TED_t + \hat{\beta}_3 \cdot \Delta sRES_t + \sum_{m=1}^{11} \hat{\delta}_m \cdot M_t^m + \hat{\beta}_4 \cdot holiday_t \\ & + \hat{\theta} \cdot \Delta r_{CHP,t-24} + \varepsilon_t \end{aligned} \tag{6}$$

Third, we analyze the hourly costs of the activated energy in the cost model. These costs are paid by all the customers through a specific charge on energy consumed. Endogenous

variable is the hourly cost ($r_{COST,t}$). Explanatory variables include the hourly total demand (TED_t) and percentage of IBR ($sRES_t$) in total demand. See Eq. 7:

$$\begin{aligned} \Delta r_{COST,t} = & \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta r_{COST,t-1} + \hat{\beta}_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot \Delta sRES_t \\ & + \sum_{m=1}^{11} \hat{\delta}_m \cdot M_t^m + \hat{\beta}_4 \cdot holiday_t + \hat{\theta} \cdot \Delta r_{COST,t-24} + \varepsilon_t \end{aligned} \quad (7)$$

Regarding the empirical approach, the ordinary least square estimations could lead to biases problems as we include the lagged endogenous variable (Keele and Kelly 2006). As a solution, we use maximum likelihood estimators, which have been used in similar analyses (Davi-Arderius and Schittekatte 2023).

In all cases, we perform four estimations, one per year (2019, 2020, 2021 and 2022) as there are notable differences between the years. First, the renewable capacity increases between 2019 and 2022: photovoltaics increases by 335% to 19,644 MW, wind increases by 29% to 29,643 MW. Moreover, coal capacity from these plants decreases by 66.3% to 3,223 MW (REE 2024). Second, demand decreased in 2020 due to the covid lockdown (Santiago et al. 2021). The interannual GDP decreased by 11.3% (INE 2024). Third, the average wholesale price notably differs in this period (47.8 €/MWh in 2019, 33.9 €/MWh in 2020, 111.9 €/MWh in 2021 and 167.5 €/MWh). This might affect the technologies operating in each period (OMIE 2024). Fourth, the annual price of CO2 on the EU ETS increases from 24.7 €/tn in 2019 to 80.2 €/tn in 2022 (EEX 2024). Lastly, TSOs and Distribution System Operators (DSOs) are always commissioning new lines, cables, substations, and reactive compensation equipment.

4.2 Simulations

In this section, we simulate how annual volumes and costs of activated energy could evolve in the future under different scenarios related with changes on the total energy consumption and share of RES:

- (a) *Photovoltaic*: Connection of + 10 GW of photovoltaics (RES) to the grid.
- (b) *Wind*: Connection of + 10 GW of wind (RES) to the grid.
- (c) *Generation behind the meter*: Installation of + 10 GW of photovoltaics generation behind the meter, namely self-consumption. This generation reduces consumption in the hours of photovoltaic production.
- (d) *Electric Vehicle at peak hours*: Charging EV during the peak hours (19–0 h), which means higher electricity consumption during these hours. We consider different additional consumption of + 10 GWh each peak hour.
- (e) *Electric Vehicle at off-peak hours*: Charging EV during the off-peak hours (0–5 h), which means higher consumption during these hours. We consider different additional consumption of + 10 GWh each off-peak hour/year.
- (f) *Energy Efficiency*: Implementation of energy efficiency programs to reduce consumption for each hour of the day by – 10 GWh.
- (g) *Higher Consumption*: Other electrification programs that would result in higher electricity consumption for each hour of the day. We consider different additional consumption of + 10 GWh each hour.

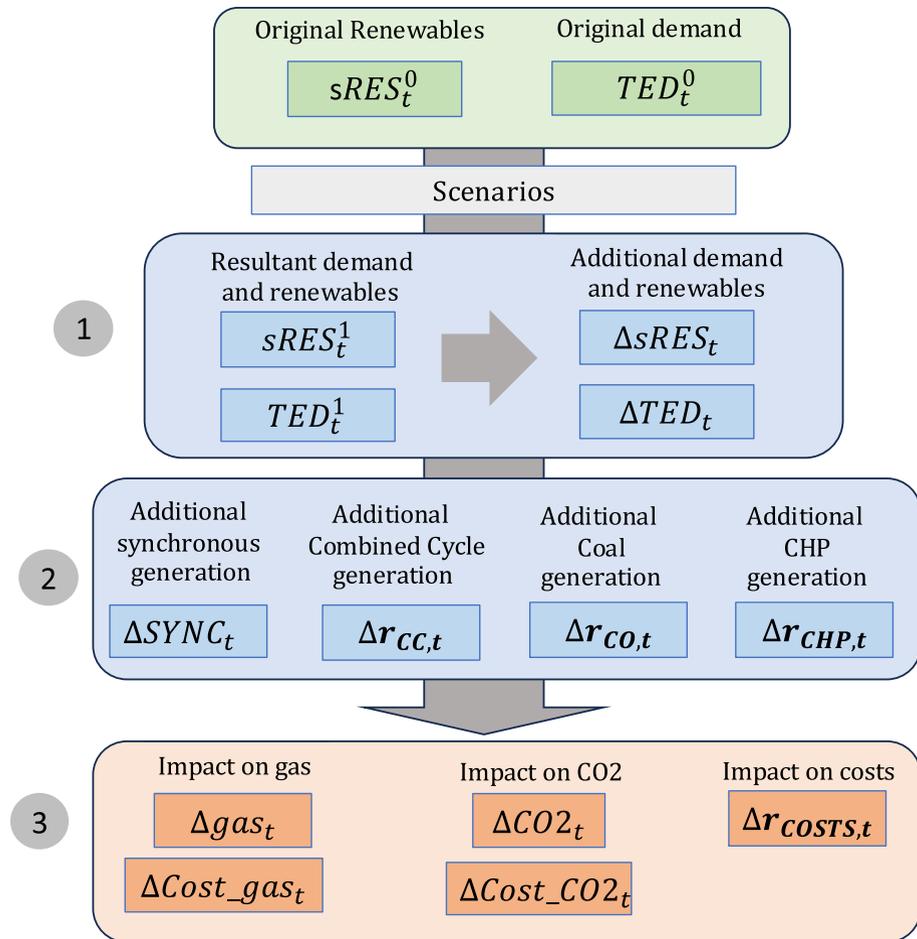


Fig. 6 Flowchart with the process followed to calculate the potential impacts of each scenario in actions to ensure system reliability

- (h) *Peak shaving products*: Implementation of peak shaving services to reduce 5% of national consumption during the four hours with the highest consumption in the year.⁷

In all the cases, we consider +10 GW or –10 GWh to make results easily comparable. Simulations are made of three steps, and we use the original dataset for 2022 as a starting point. First, we recalculate the new hourly dataset made of the resultant total electricity demand (TED_t^1) and share of RES ($sRES_t^1$) from each scenario. Second, we use the hourly changes on the total electricity demand (ΔTED_t) and the share of RES ($\Delta sRES_t$) for each scenario and calculate the resultant changes on the activated synchronous generation

⁷ <https://www.consilium.europa.eu/en/press/press-releases/2022/09/30/council-agrees-on-emergency-measures-to-reduce-energy-prices/#:~:text=Electricity%20demand%20reduction&text=Member%20states%20will%20identify%2010,both%20targets%20in%20this%20period.>

($\Delta SYNC_t$), activated energy for combined cycle ($r_{CC,t}$), coal ($r_{CO,t}$) and CHP plants ($r_{CHP,t}$). Finally, we calculate how all this activated energy impacts on the annual gas consumption (Δgas_t) and its costs ($\Delta Cost_{gas_t}$), on the annual CO₂ emissions ($\Delta CO_{2,t}$) and its costs ($\Delta Cost_{CO_{2,t}}$), and on the annual costs paid by customers ($\Delta r_{COSTS,t}$) (see Fig. 6). It is noteworthy that all these impacts are calculated using the empirical estimates and dataset from 2022.⁸ Detailed calculations are described in Appendix 2.

5 Results

5.1 Cost of Actions

In the Cost Model, we analyze the hourly costs of the actions in the day-ahead to answer our first research question, relating to the short-term welfare implications from scheduling RES in the day-ahead. Endogenous variables are the hourly costs paid by customers to compensate the actions. Hourly costs related to volumes activated in the day-ahead processes increase when the total demand decreases or the scheduled RES increase. In Table 5, each additional scheduled MWh in total demand (TED_t) reduces the costs of actions between 0.67€ and 2.63€. Moreover, one additional percentage point in the share of RES ($sRES_t$) increases the costs between 459.8€ and 1,854.2€. In Table 6, each scheduled MWh of RES (IBR) increases the costs between 1.63 €/MWh and 6.24 €/MWh in average.⁹ These costs include the activation of synchronous generators, and the curtailment of other generators keeps the system balanced. Note that the costs peaked during the 2022 gas crisis and were at their lowest during the covid pandemic, likely because of the minimum gas prices during this period.

In the Spanish regulatory framework, hourly action costs are added to the hourly wholesale price paid by all suppliers. Consequently, action costs increase the final price when the scheduled RES in the day-ahead increase, which might desincentivise consuming during the hours of maximum RES production.¹⁰ Thus, it is essential to deep dive into their determinants to minimize potential welfare impacts.

5.2 Activation of Synchronous Generation

In the Dispatch Model, we analyze the volumes of synchronous generation technologies activated in the day-ahead processes (Table 7). The activated energy from synchronous generators follows the same pattern for each year: they increase when total demand decreases or the share of RES increases. Each additional scheduled MWh in the total demand (TED_t) reduces the activated energy in synchronous generation between 0.018 and 0.034 MWh. Moreover, one additional percentage point in the share of RES ($sRES_t$) increases the activated energy in all synchronous generators between 9.82 and 13.36 MWh.

⁸ In our simulations, we are considering only data for 2022 as this year best reflects the reality of the current situation. For instance, data from the previous years does not consider the installed new RES made in 2022, or the new commissioned networks in 2022.

⁹ As robustness checks, for all the estimations we have performed the same estimations but using annual datasets from 1st October until 30th September. Results keep consistent.

¹⁰ The wholesale price use to be minimum or close to zero when the RES production is maximum (Jamash et al. 2024).

Table 5 Maximum likelihood estimations each year (costs of actions)

	2019	2020	2021	2022
	$\Delta r_{COST,t}$	$\Delta r_{COST,t}$	$\Delta r_{COST,t}$	$\Delta r_{COST,t}$
	(Eq. 1)	(Eq. 1)	(Eq. 1)	(Eq. 1)
Total demand ($\hat{\beta}_2$)	-0.671**** (0.137)	-0.722**** (0.0906)	-2.316**** (0.145)	-2.629**** (0.195)
Renewables ($\hat{\beta}_3$)	635.8**** (101.6)	459.8**** (51.06)	1,256.5**** (70.62)	1,854.2**** (76.55)
Holiday ($\hat{\beta}_5$)	-86.71 (328.6)	-27.59 (188.2)	191.7 (329.3)	110.0 (508.2)
Lagged ($\hat{\beta}_1$)	0.0138 (0.0122)	-0.0662**** (0.00757)	0.0607**** (0.00604)	0.107**** (0.00619)
Seasonality ($\hat{\varphi}$)	0.175**** (0.00166)	0.470**** (0.00377)	0.423**** (0.00452)	0.400**** (0.00319)
Constant ($\hat{\beta}_0$)	9,965.7**** (4.118)	9,235.1**** (24.66)	14,280.8**** (34.20)	20,857.0**** (40.55)
<i>N</i>	8,734	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends and National holidays	Yes	Yes	Yes	Yes

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

Table 6 Average action costs associated with scheduled volumes of RES

Year	(1) \overline{TED}_t (in MWh)	(2) 1% of \overline{sRES}_t (in MWh)	(3) $\Delta sRES_t$ coefficients from Table 5 (in Eur/% RES)	(4) Cost (in Eur/MWh RES)
2019	29,045.35	290.5	635.8	+ 2.19
2020	28,173.42	281.7	459.8	+ 1.63
2021	28,341.88	283.4	1,256.5	+ 4.43
2022	29,725.44	297.3	1,854.2	+ 6.24

Costs from column (4) represent the average costs for each year. They are calculated by dividing the coefficients from column (3) and column (2)

These results are very relevant because, as shown in Fig. 3, additional activated synchronous generation implies additional pumping consumption and curtailment of RES to keep balanced the power system, i.e. total demand equals total generation. In other words, the activated energy in synchronous generators show the potential curtailment of RES.

Table 7 Maximum Likelihood estimations each year (volumes for synchronous generation)

	2019	2020	2021	2022
	$\Delta r_{SYNCH,t_t}$	$\Delta r_{SYNCH,t_t}$	$\Delta r_{SYNCH,t_t}$	$\Delta r_{SYNCH,t_t}$
	(Eq. 2)	(Eq. 2)	(Eq. 2)	(Eq. 2)
Total demand ($\hat{\beta}_2$)	-0.0181**** (0.000902)	-0.0264**** (0.00131)	-0.0335**** (0.00122)	-0.0217**** (0.00129)
Renewables ($\hat{\beta}_3$)	9.824**** (0.641)	9.821**** (0.757)	13.360**** (0.604)	12.540**** (0.536)
Holiday ($\hat{\beta}_5$)	1.966 (2.031)	0.289 (3.061)	-0.150 (3.134)	0.530 (3.404)
Lagged ($\hat{\beta}_1$)	-0.0643**** (0.00764)	-0.0520**** (0.00861)	-0.0915**** (0.00831)	0.0385**** (0.00674)
Seasonality ($\hat{\omega}$)	0.302**** (0.00654)	0.350**** (0.00628)	0.301**** (0.00682)	0.246**** (0.00650)
Constant ($\hat{\beta}_0$)	94.3**** (0.374)	137.6**** (0.519)	143.2**** (0.583)	142.1**** (0.473)
N	8,734	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends and National holidays	Yes	Yes	Yes	Yes

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

In the Technology Model, we analyze the determinants of the activated energy for combined cycle, coal, and CHP plants, which are the synchronous technologies with the highest volumes of activated energy. In Table 8, the activated energy for combined cycle plants follows the same pattern as other synchronous generations (Table 7). The need for activating combined cycle plants ranges between 0.026 and 0.044 MWh for each MWh less of scheduled energy in the day-ahead. Related to the scheduled RES, they increase between 4.240 and 12.280 MWh for each additional percentage point of RES in the day-ahead mix.

In Table 9, activated energy for coal plants follows different patterns than other synchronous generations (Table 7) and combined cycle plants (Table 8). Coal plants are only activated when the total demand increases. This might be because in the peak hours many combined cycles plants are scheduled, and TSO opts for this technology as the second-best option. The coefficient of the share of RES is significant in 2021 and 2022, coinciding with higher RES connected to the grid.

In Table 10, activated energy from CHP increases with the total electricity demand, but decreases with the share of RES in the generation mix. This explains that this technology is mostly curtailed to allocate volumes of activated combined cycle and coal plants, which might be explained by locations of CHP plants are not optimal from the point of view of network operational needs.

Table 8 Maximum likelihood estimations for each year (volumes for combined cycle)

	2019 (Eq. 5)	2020 (Eq. 5)	2021 (Eq. 5)	2022 (Eq. 5)
	$\Delta r_{CC,t}$	$\Delta r_{CC,t}$	$\Delta r_{CC,t}$	$\Delta r_{CC,t}$
Total demand ($\hat{\beta}_2$)	-0.0294**** (0.00113)	-0.0260**** (0.00149)	-0.0443**** (0.00139)	-0.0321**** (0.00134)
Renewables ($\hat{\beta}_3$)	7.841**** (0.699)	4.240**** (0.843)	7.944**** (0.654)	12.280**** (0.511)
Holiday ($\hat{\beta}_5$)	3.136 (2.368)	4.615 (3.239)	3.319 (3.085)	2.128 (3.001)
Lagged ($\hat{\beta}_1$)	-0.0872**** (0.00918)	-0.0542**** (0.00760)	-0.0995**** (0.00922)	-0.0204** (0.00932)
Seasonality ($\hat{\omega}$)	0.480**** (0.00470)	0.563**** (0.00357)	0.562**** (0.00449)	0.511**** (0.00428)
Constant ($\hat{\beta}_0$)	112.8**** (0.393)	143.1**** (0.343)	144.8**** (0.506)	139.2**** (0.477)
N	8,735	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends and National holidays	Yes	Yes	Yes	Yes

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

5.3 Simulations for Different Scenarios

This section provides the results from the simulations detailed in Sect. 4.2 to answer the second research question, i.e. what the long-term effects of RES and demand are on carbon emissions, consumer welfare and efficiency of the sector. In all the simulations, calculations include future values: total demand in 2022 (TED^0), the share of renewables in 2022 (RES^0), additional renewable production (ΔRES), additional need of synchronous generation ($\Delta SYNC$), additional energy activated from combined cycle plants (ΔrCC), additional energy activated from coal plants (ΔrCO) and additional energy activated from CHP plants ($\Delta rCHP$). Positive values mean higher activated energy, while negative values mean less activated energy. Moreover, we calculate the CO₂ emissions associated with energy activated from combined cycle, coal and CHP plants, and the gas consumption associated with activation of combined cycle. Finally, we calculate the costs associated to these actions ($\Delta Cost$), but considering estimations from 2022.¹¹ These costs include both

¹¹ The spot prices in 2022 peaked and so could redispatching actions. However, we consider 2022 as the year reflects the last grid commissioned cables, generators, and consumers, which clearly constraints the need for redispatching actions. In Table 11, total redispatching costs ($\Delta Cost$) are mostly lower than the sum of the cost of gas (Δgas) and CO₂ emissions (ΔCO_2) in many cases. This is because since the Iberian exception was implemented during this period and the wholesale price was partially decoupled from gas prices in the international markets. The Iberian exception was a price cap mechanism to limit the impact of the gas on the electricity markets (Jamás et al. 2024).

Table 9 Maximum Likelihood estimations for each year (volumes for coal)

	2019 (Eq. 6)	2020 (Eq. 6)	2021 (Eq. 6)	2022 (Eq. 6)
	$\Delta r_{CO,t}$	$\Delta r_{CO,t}$	$\Delta r_{CO,t}$	$\Delta r_{CO,t}$
Total demand ($\hat{\beta}_2$)	0.00910**** (0.000750)	0.0101**** (0.000693)	0.00488**** (0.000587)	0.00301**** (0.000454)
Renewables ($\hat{\beta}_3$)	0.480 (0.434)	-0.630 (0.390)	0.709** (0.287)	0.974**** (0.172)
Holiday ($\hat{\beta}_5$)	0.0170 (1.411)	-1.751 (1.318)	0.412 (1.117)	1.249 (0.975)
Lagged ($\hat{\beta}_1$)	-0.0787**** (0.00992)	-0.118**** (0.00975)	-0.0671**** (0.00712)	-0.0682**** (0.00674)
Seasonality ($\hat{\omega}$)	0.516**** (0.00481)	0.511**** (0.00532)	0.570**** (0.00405)	0.450**** (0.00336)
Constant ($\hat{\beta}_0$)	66.28**** (0.192)	67.39**** (0.256)	54.99**** (0.130)	46.04**** (0.109)
<i>N</i>	8,735	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends and National holidays	Yes	Yes	Yes	Yes

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

the costs of gas and the corresponding CO2 emissions because the owners of non-scheduled generators in the day ahead should bid in the redispatching processes (MITECO 2019; CNMC 2022).

Table 11 shows the results for all the scenarios. Related to the connection of wind and photovoltaics, the additional RES production (ΔRES) are similar as the annual wind and photovoltaic production is nearly the same. However, the need for synchronous generation ($\Delta SYNC$) differs between 792 TWh for photovoltaic versus 928 TWh for wind. This is explained because photovoltaic production is made during the highest total electricity demand, while wind production is also important at night (off peak time) (see Fig. 2). These results are relevant and highlight that some RES used to replace pollutant technologies (and decrease gas consumption) should be later curtailed and replaced by these pollutant technologies to address network operational constraints. For wind, this effect is even higher as their production profile is not well correlated with total demand peaks. This also affects the resultant CO2 emissions and gas consumption. In terms of gas consumption, installing 10GW of photovoltaics and wind results in extra gas consumption of 81.89 and 95.94 Mm3/year, respectively. In terms of costs for customers, they increase with 117 M€/year for photovoltaic and 137 M€/year for wind. Cost of gas consumption increases with 98 M€/year for photovoltaic and 105 M€/year for wind.

It is noteworthy that these scenarios assume that technological development of future installed RES will remain constant, which seems very unlikely. Therefore, values from Table 11 should be considered as the most pessimistic solution. However, it is important to

Table 10 Maximum Likelihood estimations for each year (volumes for CHP)

	2019 (Eq. 7)	2020 (Eq. 7)	2021 (Eq. 7)	2022 (Eq. 7)
	$\Delta r_{CHP,t}$	$\Delta r_{CHP,t}$	$\Delta r_{CHP,t}$	$\Delta r_{CHP,t}$
Total demand ($\hat{\beta}_2$)	0.00713**** (0.000311)	0.00734**** (0.000397)	0.0119**** (0.000426)	0.00776**** (0.000335)
Renewables ($\hat{\beta}_3$)	-1.101**** (0.222)	-0.750**** (0.226)	-1.051**** (0.218)	-1.635**** (0.140)
Holiday ($\hat{\beta}_5$)	-0.490 (0.777)	-0.0492 (1.050)	-0.549 (1.194)	-0.323 (0.869)
Lagged ($\hat{\beta}_1$)	-0.125**** (0.00629)	-0.210**** (0.00581)	-0.187**** (0.00723)	-0.191**** (0.00647)
Seasonality ($\hat{\omega}$)	0.140**** (0.00529)	0.142**** (0.00638)	0.0884**** (0.00717)	0.141**** (0.00600)
Constant ($\hat{\beta}_0$)	37.62**** (0.113)	54.62**** (0.176)	60.83**** (0.242)	45.29**** (0.153)
<i>N</i>	8,735	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends and National holidays	Yes	Yes	Yes	Yes

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

consider that future technological developments will only benefit the future RES connected to the grid, while not the existing RES.

Related to the installation of generation capacity behind the meter also known as self-consumption, the total demand (TED^1) decreases, which implies a need for additional synchronous generation ($\Delta SYNC$) of 991 GWh/year. Moreover, most of the activated energy is combined cycle, while energy activated for coal and CHP plants decreases. This lower activated energy might be explained by less need for combined cycle plants in the day-ahead scheduled energy. In terms of CO2 emissions, installing RES generation behind the meter increases power system emissions of +292 kTn/year. In terms of gas consumption, there is a need for additional gas of 119 Mm3/year. In terms of costs to customers, they increase to 133 M€/year. In summary, a program aimed at reducing the CO2 emissions and gas imports also increases the issues related to network operational limits and their costs.

Related to charging the EV during the peak and off-peak hours, respectively. The positive impacts on synchronous generation, CO2 emissions and gas consumption are very similar. However, increasing the electricity demand in the peak time is less efficient than in the off-peak time: the need for synchronous generation decreases with 708 compared to 679 TWh/year. In terms of costs for customers, action costs are reduced by 92 M€/year compared to 88 M€/year, which represents another positive externality. All these results show that the performance of the power system is more optimal when the electricity demand is

Table 11 Results for each scenario

Scenario	TED^0 (TWh)	ΔTED (TWh)	RES^0 (TWh)	ΔRES (TWh)	$\Delta SYNC$ (GWh)	ΔrCC (GWh)	ΔrCO (GWh)	$\Delta rCHP$ (GWh)	ΔCO_2 (kTn)	ΔGas (Mm3)	ΔCO_2 (MEur)	ΔGas (MEur)	$\Delta Cost$ (MEur)
Photovoltaics (+10GW)	260.39	0	112.45	21.57	+792.12	+775.69	+61.52	-103.28	+282.93	81.89	+22.74	+97.80	+117.12
Wind (+10GW)	260.39	0	112.45	21.57	+928.04	+908.80	+72.08	-121.00	+331.48	+95.94	+26.42	+105.45	+137.22
Gen. behind meter (+10GW)	260.39	-23.48	236.91	-24.48	+991.45	+1,225.66	-33.36	-245.04	+291.91	+119.42	+23.47	+142.23	+132.99
EV (+10GW)	260.39	21.89	282.28	21.89	-679.44	-902.86	+50.12	+196.52	-184.68	-86.02	-14.77	-99.32	-87.78
EV (+10GW/h in peak hour)	260.39	21.89	282.28	21.89	-707.91	-930.73	+47.91	+200.23	-194.85	-88.96	-15.58	-102.19	-91.99
EV (+10GW/h in off-peak hour)	260.39	-87.6	172.79	-87.60	+3,882.17	+4,752.13	-110.23	-938.10	+1,154.53	+464.49	+92.19	+527.70	+523.25
Energy efficiency (-10GW/h)	260.39	87.6	347.99	87.60	-2,852.50	-3,743.81	+190.20	+803.85	-786.74	-358.05	-62.90	-412.27	-371.0
Peak shaving (-5% inpeak hour)	260.39	-2.49	257.91	-2.489	+97.43	+122.43	-4.13	-24.98	+28.21	+11.87	+2.26	+13.78	+12.96

made in the off-peak hours. These savings should be considered when countries design the time periods on ToU considering the operational needs.

Impacts associated to higher and lower demand during all hours of the day are not symmetric: the need of synchronous generation associated to a higher demand is $-2,853$ GWh/year, while $+3,882$ GWh/year for a lower demand. In terms of costs for customers, savings range up to -371 M€/year, while costs go up to $+523$ M€/year. These results complement the previous ones and highlight that decreasing the total electricity consumption is less efficient because of the need for more synchronous generation to solve network operational constraints. Indeed, the Spanish volumes of emissions related to actions peaked during the covid-19 lockdown (Davi-Arderius and Schittekatte 2023).

Finally, the implementation of peak shaving products to reduce 5% of the total demand for four hours reduces the annual demand by $-2,489$ GWh, but also increases the need of synchronous generation by $+97.43$ GWh for the same period. In terms of costs for customers, they increase up to $+13$ M€/year. All these results highlight that peak shaving products might not provide all the expected savings in gas consumption and these inefficiencies should be considered in their design. These additional costs are directly paid by customers and trade-off other expected potential savings.

6 Conclusions and Regulatory Recommendations

This paper shows that demand profiles and scheduled RES (wind and photovoltaics) can determine the welfare implications and loss of efficiency when implementing energy policy plans. Higher shares of RES (IBR) or lower electricity demand increases the actions, which implies relevant welfare impacts: costs for customers, subsequent curtailment of RES, and economic compensations to the activated plants. This shows that electricity markets by itself does not always provide an assignment of generation and consumption that minimizes the risk of blackout. Moreover, all these additional economic transactions between consumers and generators must be considered in the design of any program that might affect the demand profiles or promote RES.

When these results are used to simulate how future electricity demand and RES might affect the emissions, consumer welfare and efficiency, we find that changes in the hourly demand have a clear impact on them. In consequence, actual benefits from programs aimed at replacing pollutant technologies, reducing CO₂ emissions, or reducing gas imports might slightly differ from those expected in advance. In some cases, we find that programs -such as connecting generation behind the meter in households- might become regressive since specific customers with acquisitive power can afford the purchasing cost of these generation installations and reduce their electricity bills (due to lower consumption), while other customers face higher operational costs in their bills. These trade-offs must be in the design of future programs aimed at subsidizing the installation of small generation capacity behind the meter or the design of network charges.

In our analysis, we refer to RES as wind or photovoltaic plants primary source, while not to other RES technologies such as hydropower or pumping generators. This distinction is based on the kind of generator behind its plant: IBR or synchronous generator. This highlights a main conclusion from this analysis: countries that use RES made of synchronous generators -hydropower or thermosolar- would minimize the activation of non-cleared conventional generators on the day-ahead markets and their corresponding welfare implications. In this discussion, the role of nuclear technology becomes relevant since they are

synchronous generators that provide robustness to the system. Its added value to the system should also be considered in assessments prior to the disconnection of nuclear plants from the grid.

From our results and simulations, we are not suggesting that RES should not be implemented, but that some potential complementary recommendations should be considered to reduce these volumes and their corresponding welfare implications. Some studies defend the need to implement LMP in Europe to consider grid limitations in the electricity markets. However, most of the electricity needs behind these actions in Spain are not related to grid congestions, but to the need to have specific technologies running, which is not solved with LMP. Below we describe some complementary recommendations.

The first recommendation is related to the assessments of power system resource adequacy for the next years. Our results show a dependence on RES in conventional technologies. Thus, the increasing need of non-cleared technologies in the markets due to system reliability must be considered when assessing whether some combined cycle or coal plants can be disconnected from the system.

The second recommendation is related to the need to increase cross-border capacity between countries which enables that plants connected in a neighbor country become efficient solutions. Consequently, the need for activating non-cleared technologies in the day-ahead markets could decrease, which highlights a relevant and relatively unexplored positive externality from investments on cross-border capacity. This should be explored in depth in future empirical analysis and considered in assessments of European projects of common interest aimed to fund cross-border projects.

The third recommendation is related to the need to implement technological development of IBR. Innovative projects could be devised to test these impacts on a small scale. In this scenario, there is a dilemma between economically incentivizing advanced technological solutions now or waiting for the maturity of these technological developments. This requires advanced assessments of both operational and economic aspects. In any case, potential benefits from this recommendation might be limited to new RES since most of the currently installed RES are still non-amortized long-term investments.

The fourth recommendation relates to the implementation of ToU tariffs with low charges in off-peak hours to incentivize consuming electricity in these hours. However, most customers do not react to the hourly prices since the price elasticity of electricity consumption is small, especially because of the low volumes of installed storage devices. Moreover, efficiency of ToU and hourly spot prices might be neutralized when suppliers offer flat tariffs to customers, which means the same tariff regardless of time of consumption. As an intermediate solution, the potential benefits from considering different tariffs for each period should be assessed, i.e. peak/off-peak hours, or work/weekends. However, its social acceptance may be low, and decision-makers might be reluctant to implement it.

The fifth recommendation is related to system operators, which are the requesting operators of activating these plants non-cleared in the markets. They have deep knowledge on grid operation and data to perform complex analysis, which are essential to devise efficient grid operation strategies to predict future network operation constraints. The best approach is an efficient coordination of diverse actions in the long-term: grid planning criteria, technical requirements for IBR used in new RES, or setting optimal location of new RES in terms of network constraints. Grid planning analysis should assess the impact of the location for future RES on the volumes of activated energy. In some cases, concentrating RES only in the most optimal regions -in terms of wind or sun- might result in the highest volumes. In consequence, locational regulatory incentives for RES might be considered such as locational RES auctions or reinforcing the grid capacity for hosting new RES in some areas over others.

The sixth recommendation relates to the possibility to install grid devices to minimize the need for actions. This includes installing specific assets such as synchronous compensators, reactances, capacitors or others. Their installation might be done under two different schemes: by grid operators and funded by tariff charges or built by private investors and funded through procurement of ancillary services. If built by grid operators, they should be included in the grid investment plans. However, if built by private investors, their building costs might be lower. The procurement of these ancillary services should be under long-term procurement to provide efficient signals for long-term investments. Under short-term procurement, economic incentives to make these investments are lower. In any case, the decision to install these assets or procure long-term flexibility services should be taken in advance to prevent delays in the connection of new RES.

The last recommendation is related to the need to electrify the final energy consumption with hydrogen or ammonia, which would also be useful to make better use of potential surplus of RES in the mix. Hydrogen or ammonia can also be considered a storage technology when it can be produced in advance and stored in tanks. A similar benefit comes from the installation of household batteries, but their costs do not make them enough economically viable. In the next few years, future technological developments should improve efficiency of process used to produce hydrogen and ammonia from electricity and decrease the manufacturing costs of batteries.

The Spanish case anticipates similar scenarios in countries that are making efforts to decarbonize their mix. The magnitude of the challenge aggregated across the EU is much larger. Our main conclusion is that solving grid bottlenecks is a necessary, but not sufficient condition for an efficient integration of RES, which have an increasing dependence on replaced conventional technologies. Further research is needed to analyze the remedial actions discussed also in real-time. A more detailed analysis of the activated units could provide useful locational information on potential network operational constraints.

Appendix 1

A day-ahead market schedule of generation and consumption is reliable and minimizes the risk of blackout only when key reliability parameters across the network are within certain predetermined thresholds (Davi-Arderius et al. 2024):

Energy flows: These are related to the flow of energy flows through each network element, i.e. lines and transformers.¹² With an increasing concentration of RES, the patterns of energy flow through networks change and become more variable, often leading to grid congestions when they exceed the maximum network capacity. In many cases, RES are located far from the replaced conventional technologies or networks are not necessarily developed as rapidly as the RES are deployed (Janda et al. 2017; Davi-Arderius et al. 2023).

Frequency: When there is an imbalance between generation and consumption, frequency deviates from its nominal value, i.e. 50 Hz (in Europe). Each power system has a specific capacity to immediately recover the nominal frequency when there is a disturbance related to unbalance between generation and consumption, which is measured with inertia. Combined cycle or coal plants provide inertia with their stored kinetic energy. However, IBR (wind or photovoltaic) has much lower inertial response. Consequently, large scale

¹² These include the N-1 security criteria implying that the final dispatch should be robust against the failure of an N network element.

connection of IBR might decrease the inertia of the system in some areas, which in turn might compromise the ability of the system to recover from the generation and consumption imbalance (ENTSOE 2020; Matevosyan et al. 2021; Gu et al. 2022).

Voltage: This is an electrical parameter that must be always respected to ensure network security conditions and quality of supply.¹³ Traditionally, combined cycle or coal plants controlled the system voltage, while IBR have costly and limited capacity to perform a similar role (Anaya et al. 2020). When total demand decreases, load levels of lines are lower and voltage in the system increase due to the surge impedance loading (SIL) effect (Davi-Arderius et al. 2024).

Appendix 2

For each scenario, we calculate the activated energy from plants made of synchronous generation ($\Delta SYNC_t$), and activated energy for combined cycle ($\Delta r_{CC,t}$), coal ($\Delta r_{Co,t}$) and CHP plants ($\Delta r_{CHP,t}$). Moreover, we calculate the corresponding gas consumption (Δgas_t) associated with the activated energy for combined cycle and CHP plants. Finally, we find the (net) additional CO₂ emissions associated to these actions ($\Delta CO_{2,t}$) and their economic costs. The process consists of the next steps:

- *Step 0:* The starting point consists of the hourly total electricity demand (TED_t^0) and share of renewables made of IBR ($sRES_t^0$).¹⁴
- *Step 1:* For each hour, we calculate the new hourly total electricity demand (TED_t^1) and the change in the total electricity demand (ΔTED_t). This step is not followed in the scenarios related with the connection of photovoltaic and wind using Eq. 8.

$$\Delta TED_t = TED_t^1 - TED_t^0 \quad (8)$$

- *Step 2:* For each hour, we calculate the change on the share of renewables ($\Delta sRES_t$) made of IBR (wind and photovoltaic) using the Eq. 9:

$$\Delta sRES_t = RES_t^1 - RES_t^0 = \frac{RES_t^1}{TED_t^1} - \frac{RES_t^0}{TED_t^0} \quad (9)$$

where the new hourly share of renewables ($sRES_t^1$) is calculated as follows¹⁵:

- For scenarios photovoltaic and wind, $sRES_t^1$ corresponds to the new share of renewables considering the additional capacity. Therefore, $\Delta sRES_t > 0$
- For the other scenarios:

¹³ Each electrical equipment has its own nominal voltage.

¹⁴ In the scenario photovoltaic and wind, the assignment of additional RES production at each hour is made considering the hourly production profile and estimated annual production for each technology. For both technologies, we consider an annual production based on average production for Spain: 2.08 GWh by each installed MW for photovoltaics, and 2.16 GWh by each installed MW for wind (Davi-Arderius and Schittekatte 2023).

¹⁵ This criterion is based on the principles that photovoltaics and wind bid at very low marginal price. Therefore, they are always included in market clearing. For each hour, the new hourly share of RES ($sRES_t^1$) is calculated using the existing hourly RES production ($sRES_t^0$) for 2022.

- If $TED_t^1 > TED_t^0 \Rightarrow$ additional demand is covered by synchronous generators, thus $\Delta sRES_t < 0$
 - If $TED_t^1 < TED_t^0 \Rightarrow$ Lower total demand reduces production by synchronous generators, thus $\Delta sRES_t > 0$.
 - If $TED_t^1 = TED_t^0 \Rightarrow \Delta sRES_t = 0$.
- *Step 3:* For each hour, we calculate the changes on the activated energy for synchronous generation ($\Delta SYNC_t$) using the estimates $\hat{\beta}_2$ and $\hat{\beta}_3$ from Eq. 2 (2022) in Table 7. In other words, this additional synchronous generation means curtailing an equivalent production from IBR (wind and photovoltaics) to keep the system balanced.

$$\Delta SYNC_t = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{10}$$

- *Step 4:* For each hour, we calculate the activated energy for combined cycle ($r_{CC,t}$), coal ($r_{CO,t}$) and CHP plants ($r_{CHP,t}$) using the estimates $\hat{\beta}_2$ and $\hat{\beta}_3$ (2022) from Tables 8, 9 and 10, respectively. See Eqs. 11, 12 and to 13.

$$\Delta r_{CC,t} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{11}$$

$$\Delta r_{CO,t} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{12}$$

$$\Delta r_{CHP,t} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{13}$$

- *Step 5:* For each hour, we calculate the additional gas consumption (Δgas_t) associated to combined cycle and CHP actions and its cost. See Eqs. 14 and 15.

$$\Delta gas_t = \frac{\Delta r_{CC,t} + \Delta r_{CHP,t}}{0.7 \cdot 0.0117} \tag{14}$$

$$\Delta Cost_{gas,t} = Auction_{gas,t} \cdot \Delta gas_t \cdot 0.0117 \tag{15}$$

where 0.7 is the efficiency rate of the combined cycle and CHP technologies, and 0.0117 is the ratio (MWh/m3 of gas) (DGPEM 2022). $Auction_{gas,t}$ corresponds to the daily price of the Daily Product in the Spanish zone (Eur/MWh) (MIBGAS 2023).

- *Step 6:* For each hour, we calculate for the (net) additional CO2 emissions ($CO2_t$) related to the activated and curtailed generation from combined cycle, coal, and CHP plants. Clearly, $CO2_t$ can be positive or negative, depending on the activated and curtailed generation technologies in the hour.¹⁶ We also calculate the corresponding daily costs of the emission based on the CO2 auction ($Price_CO2_t$) (in Eur/tn) (EEX, 2024). See Eqs. 16 and 17.

$$\Delta CO2_t = 0.34 \cdot \Delta r_{CC,t} + 0.95 \cdot \Delta r_{CO,t} + 0.38 \cdot \Delta r_{CHP,t} \tag{16}$$

$$\Delta Cost_CO2_t = \Delta CO2_t \cdot Price_CO2_t \tag{17}$$

¹⁶ The CO₂ emission factors considered are 0.95 tn CO₂/MWh for coal, 0.37 tn CO₂/MWh for combined cycle, 0.38 tn CO₂/MWh for CHP and 0.24 tn CO₂/MWh for biomass plants. Source: REE (2021).

- *Step 7*: For each hour, we calculate the costs from activated energy ($r_{COSTS,t}$) using estimates from Equation Table 6. See Eq. 18.

$$\Delta r_{COSTS,t} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \quad (18)$$

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