Environmental Impacts of Redispatching in Decarbonizing Electricity Systems

A Spanish Case Study

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Abstract

In recent years, European system operators have been more frequently needing to redispatch generation, load, or both, after the day-ahead market clearing to ensure that the final dispatch schedule does not violate any network limit. In this paper, we focus on the environmental impact of redispatch processes. We use hourly data from the Spanish market operator and transmission system operator between 2019-2021 to analyze the emissions introduced by redispatch processes. We find that while redispatch energy accounts for about 2-4% of total annual electricity demand, it contributes to about 6-11% of the annual power sector's CO2 emissions. Upwards redispatch energy is nearly entirely provided by polluting power plants, while clean wind generation is by far the most downwards redispatched. We confirm that redispatch volumes increase when the share of intermittent renewables in the supply mix increases but, additionally, show that redispatch volumes also significantly increase during hours with low energy demand. The latter can indicate important inefficiencies in the integration of renewables in the power system, not only leading to higher costs but also emissions. Finally, we find that when considering the CO2 emissions from redispatch, the abated CO2 emissions resulting from marginally increasing renewable generation, substituting coal or gas in the day-ahead schedule, reduces by 0.7-4.5%. We offer several recommendations to reduce the need for redispatch actions and recommendations to make redispatch actions less polluting. A key point is the consideration of a specific ancillary service for voltage control.

Key words: renewables, redispatching CO2 emissions, power markets, power system operations, ancillary services

JEL classifications: L51, L94, Q41, Q42

1. Introduction

In many places around the globe the share of power generation by intermittent renewable energy sources (RES) is increasing. Merely connecting RES to the power grid does not always imply that all the generated clean electricity will finally be delivered to end consumers. The power grid, connecting generation and demand, is a complex system constraint by physical laws. A common feature of many power systems is that the replacement of conventional technologies by RES entails significant changes in the patterns of electricity flows through the grid. RES are often located relatively far away from load centers, have different production profiles than thermal generators and displace the production from synchronous generation traditionally used to support the voltage system (National Grid ESO, 2021). As often network development lags the deployment of RES, increasingly RES generation needs to be curtailed to avoid the violation of network elements and endanger the operation of the power grid (ACER and CEER, 2021).

There exist several power market design options to ensure that the scheduled electricity production does not violate limits of network elements. In the European Union (EU) a zonal pricing model is applied to wholesale electricity markets. Zonal pricing implies that when trading electricity, the network within a bidding zone is considered a copper plate; only thermal network congestions between bidding zones are considered when clearing the pan-European markets.[1] Bidding zones often coincide with the territory of a country. As the simplified representation of the network in the market clearing becomes harder to respect, transmission system operators (TSO) and the distribution system operators (DSO) (hereafter, SOs) increasingly require alterations of the dispatch after the day-ahead market clearing to avoid any security violation. This is especially true in the case of (often) large bidding zones. These measures are known as redispatching, and their costs are socialized over the customers within each bidding zone. An alternative to a zonal pricing model is a nodal pricing model, in which the network elements at transmission level are internalized in the day-ahead (and real-time) market clearing and, no, or at least a less, corrections of the dispatch after the market clearing are required.

In the academic literature, several theoretical and empirical analyses have been performed focused on the potential impact of new RES on the regional grid congestions within a bidding zone (Costa-Campi et al., 2020), the corresponding volume of redispatched energy (Staudt et al., 2018), and the redispatch costs (Joos and Staffell, 2018; Schermeyer et al., 2018). Another important literature stream focusses on market design questions related to zonal markets and the implications of redispatch on incentives of market participants. Stoft (1999) and, more recently, Hirth and Schlecht (2020) explain that organizing a (by nature) more local redispatch market after a zonal day-ahead market yields undue arbitrage opportunities that rational firms exploit, which is referred to as the inc-dec game. In this paper, we empirically assess CO2 emissions associated to redispatch processes for a case study of Spain between 2019 and 2021.

Savelli et al. (2022) is a recent work that is related to our paper. They show for a case study in Great Britain using data between August 2020 and January 2021 how the location of newly installed RES impact marginal redispatch costs and replaced emissions. They use a simulation model and focus on a proposal of improved long-term contracts for RES

[1] In case flow-based market coupling is implemented, as in the CORE region in the EU, also internal network elements which have a significant impact on cross-zonal trade (so-called critical network elements) are explicitly considered in the market clearing.

that better internalize redispatch and balancing costs. In contrast to that paper, we focus exclusively on redispatch-related emissions and study these in greater detail. Concretely, our research questions are:

(i) how much emissions would have been avoided in case the Spanish network would have been able to always accommodate the nation-wide welfare-maximizing dispatch schedule?
(ii) what are the drivers of emissions via redispatch processes?
(iii) how much CO2 is emitted via redispatch processes per MWh of increased RES production in the day-ahead schedule?

We do not want to imply that completely avoiding any RES curtailment is the most cost-efficient solution from a system perspective, but our analysis is relevant as it gives a more complete understanding about potential emission impacts that can inform trade-offs between mitigating grids constraints and curtailing RES.

The zonal setup of the power market in the EU allows us to answer our research questions without the need for any additional information other than the hourly day-ahead schedule of the Spanish bidding zone, the final physical schedule of the same bidding zone and market time unit, and the amount of CO2 emitted per MWh per power plant active in Spain. A similar analysis in a nodal system would be more complicated. We obtain this data from the Spanish market operator, namely OMIE, and the Spanish TSO, namely Red Eléctrica de España (REE), for the period between 2019 and 2021. To provide answers to the second and third research question our empirical approach is an ARIMA time-series estimator, where variables are differentiated to ensure their stationarity and a lagged endogenous variable is included to capture the time dynamics.

Spain is an interesting case study for two reasons. First, due to its high share of RES in the gross annual electricity consumption (48.4% in 2021) (REE, 2022). Second, due to the fact that the Iberian peninsula is an “energy island”; the commercial exchange capacity with France and Morocco is very limited and the interconnections between Spain and Portugal are rarely fully utilized (IEA, 2021).[2] As the whole territory of Spain is covered by one large bidding zone, the limited interconnection of the bidding zone across the Pyrenees makes it possible to isolate the impact of changes in the national generation mix on internal grid bottlenecks and subsequent redispatch actions, which are not aggravated by the need for redispatch to preserve cross-zonal exchanges. In that sense, the results for Spain can be of interest for other power systems that are being decarbonized but at a slower pace, especially when also having limited interconnections such as the UK.

The following of the paper is divided in five sections. In Section 2, we provide more technical background to redispatch procedures and discuss the current regulatory frame that is in place in the EU around redispatch. In Section 3, we introduce the dataset, provide descriptive statistics and describe the empirical approach. In Section 4, we provide the results and present a discussion. Finally, we end with a conclusion.

[2] The commercial capacity between Spain and France is 2,800 MW, interconnection capacity between Spain and Morocco is 900 MW in the Spain-Morocco direction and 600 MW in the Morocco-Spain direction. The interconnections with Portugal are rarely congested (5% as estimated by EIA (2021)). This is not necessarily because of the size (2,300 MW in 2019) but rather because of the coincidence of generation and demand patterns. In that sense, we similarly expect that few redispatch actions were needed to preserve cross-zonal exchanges.

2. Redispatching: Technical and Regulatory Background

This section is split in two parts. First, we provide a technical description of redispatching. After, we describe the current regulatory framework that is in place in the EU and Spain.

2.1 Technical background

Electricity systems are made of networks that connect generators with end consumers. Operating this system is particularly complex because several technical security constraints (TSC) must be always met: (i) the sum of the generated energy should be equal to the sum of the consumed energy at each time, while storage is (at least today) limited[3]; (ii) each network asset (cable, transformer, substation) should be operated under their thermal and voltage limits[4], while alternating current (AC) flows are hard to control, and; (iii) operational security criteria should be fulfilled. Security criteria include the reservation of a minimum of generators able to provide near real-time ancillary services such as balancing and the N-1 criteria implying that the final dispatch should be robust against the failure of a network element.

In AC systems, the total energy that travels through the grids is known as the apparent current (in MVA), which is made of active energy (in MWh) and reactive energy (in MVAr). The grid frequency is controlled by adjusting active power consumption or generation, while voltage is controlled by the reactive power flows, which is especially important in the High Voltage (HV) grids due to their high impedance.[5] In contrast to active power, reactive power is local and cannot be transmitted over long distances.

With an increasing penetration of RES, active energy flow patterns through networks change and become more variable within a day and between seasons, often leading to thermal congestions as networks are not necessarily as rapidly expanded as RES is deployed (Janda et al., 2017). Moreover, RES displace the production from synchronous generators, which historically provided the voltage support through the control of their reactive energy (National Grid ESO, 2021). In case a production schedule would violate a thermal limit of a network element, a generator/load upstream of the congestion needs to increase generation (or to lower consumption), while, to remain the power balance, a generator/load on the opposite side needs to decrease generation (or increase consumption).

Besides issues with thermal limits due to changes in the transmission and distribution of flows, regional imbalances in reactive power can also lead to the need for redispatch to respect voltage limits. A surplus of reactive power in some point of the grid can increase the voltage above the nominal operating rate of the relevant assets, while a deficit decreases the voltage and might compromise the grid stability. Table 1 gives an overview

[3] If supply does not match demand within a synchronous area, the frequency starts deviating from its reference value. Large frequency deviations can lead to the disconnection of generation and/or load further worsening the frequency with potentially a black-out as the outcome. Electricity can only be stored through the transformation in other energy sources, such as chemical energy in batteries or kinetic energy in pumping plants.

[4] The thermal limit corresponds to the maximum temperature that any electrical asset -cable or transformer- can operate under normal conditions. This operating temperature depends on the electricity flows through it, which heats the asset due to electricity losses, and its weather conditions. Voltage limit corresponds to the maximum operating voltage for any electrical asset.

[5] The impedance of the low voltage grids is very small. Consequently, reactive energy is poorly effective to control their voltage. Instead, voltage drops can be controlled by the active energy flows.

of the grid parameters related to the sources of reactive energy flows and potential mechanisms to control them.[6]

Table 1: Sources of reactive energy in the power systems and potential mechanisms to control reactive flows, i.e., voltage in the power system. Source: own elaboration based on National Grid ESO (2021)

	Asset	**Impact on the reactive energy flows**
Sources of reactive energy	Grids	HV grids generate more reactive energy than the low voltage (LV) grids due to their higher impedance
		Long underground cables act as a capacitor and generates more reactive energy than the aerial cables.
		Lightly loaded grids generate more reactive energy than the highly loaded grids.
Mechanisms to control reactive energy[7]	Reactive compensation equipment	Static synchronous compensator (STATCOM) can generate or consume reactive energy, while capacitors can inject reactive energy.
	Consumers	Generate or consume reactive energy depending on their consumption assets. Moreover, embedded generation decreases the minimum demand in the transmission grids.
	Synchronous generators	Traditionally, synchronous generators (combined cycle, fuel and coal plants) have had the most important role in actively controlling the reactive energy flows.
	Generators made of power electronics	Traditionally, power electronics have not made an active control of reactive energy flows. They should be operated in specific way to be actively controlling the reactive energy flows.

Under zonal pricing, the market clearing algorithm only considers thermal limits on network elements between bidding zones, and not potential thermal or voltage issues within a bidding zone resulting from the cleared schedule generation and load schedule. After the day-ahead market clearing, both the TSO and DSO (hereafter, all the SOs) validate whether the TSC within bidding zone are fulfilled. If this is not the case, SOs must resort to remedial actions of which the most prevalent are redispatch measures.[8]

Figure 1 provides an overview of the day-ahead scheduling process in Spain, in which redispatch plays an important role. This process is divided in three main stages. The exact timing of the different steps might slightly differ from one Member State to another. Stage 1 is the market clearing done at pan-European level and based on the existing bilateral contracts agreed between generators and consumers, and the outcomes from the Single Day-Ahead coupling (for more detail see Schittekatte et al., 2021). The aim of the Stage 1 is the provision of an economically efficient market schedule (EEMS) per bidding zone for each hour of the next day before 13h30. In the EEMS, the sum of energy generated

[6] National Grid ESO (2021) identifies several situations with potential voltage issues. Among others: (i) lightly loaded long transmission lines with limited local voltage support generation (West Mindlands); (ii) high gain from (underground) cable circuits, particularly overnight when the demand is low, in combination with reliance on synchronous generator (London); large penetration of small generation offsetting demand and higher reliance on synchronous generator (South West Peninsula).

[7] Traditionally, specific power factors (the ratio between the active energy and apparent energy) were fixed for consumers and generators, which ensured that some share of reactive energy is consumed or generated. Nowadays, power electronics implemented in RES and in some consumption, devices can provide an apparent energy (MWA) setpoint regardless the active energy (MWh) (Regulation (EU) 2016/631). However, power electronics might need cooling, which might result in some additional operational costs. This evolution opens the possibility to create ancillary service markets for voltage control.

[8] Art. 2 (26) of the Electricity Regulation (EU) 2019/943 formally 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).

equals to the sum of energy consumed.[9] In Stage 2.1, the SOs must validate whether the EEMS is also technically feasible, which means verifying whether all the previously explained TSC are respected. If not, the SOs must change their grid topology (so-called non-costly remedial actions), i.e., switch lines or transformers, and if that is not enough, then specific generators, consumers, or storage devices are redispatched. As the schedule of several grid users is altered in Stage 2.1 and the sum of supply and demand always needs to match, the energy gap, i.e., a deficit or surplus of generation, is addressed in Stage 2.2. Finally, in Stage 3 the economically and technically feasible schedule (EFTS) is obtained before 14h45. As intraday trading is allowed after the EFTS, unvoluntary deviations from the day-ahead positions are possible (which are solved via near real-time balancing markets), or unforeseen failures of lines can occur, there might be the need for additional redispatch after Stage 3. However, the volumes of additional redispatch are typically significantly lower than in Stage 3. REE reports that the redispatched energy in the real time accounted about 3.9%, 9.9% and 22.6% of the total redispatched energy in 2019, 2020 and 2021, respectively (REE, 2020, 2021a, 2022).[10]

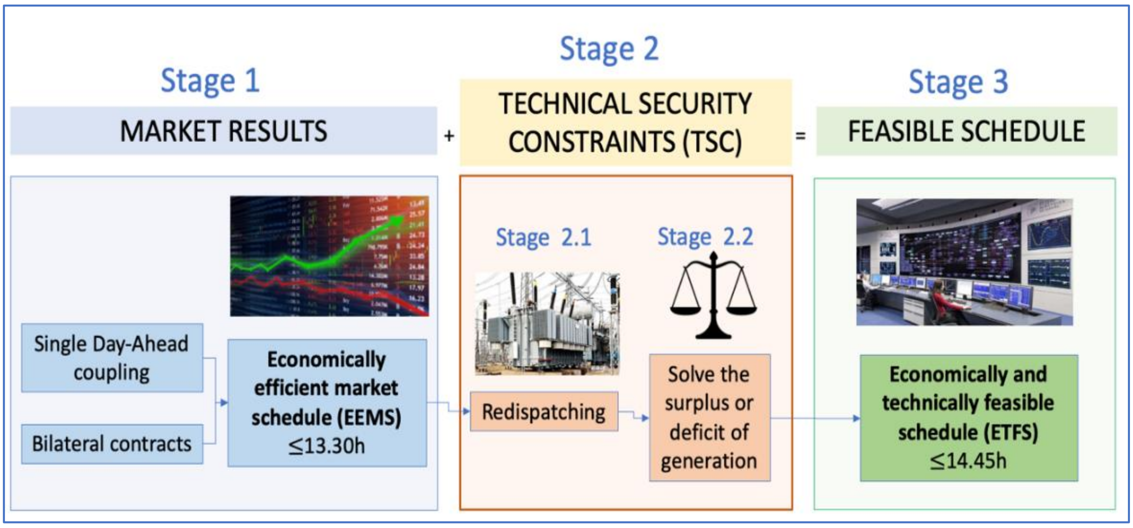

Figure 1: Sequential processes in the day-ahead market to have an economically and technically feasible schedule (ETFS) made of generation, consumption, and storage. Source: own elaboration.

In Spain, the TSC are defined in a specific national regulation (MICT, 2016). Table 1 shows the main data relevant to the redispatched energy from Stages 2.1 and 2.2 between 2019 and 2021. ACER and CEER (2021) report that in 2020 Spain had the third highest volume of redispatched energy in the EU after Germany and Poland. In terms of redispatching costs, as defined by ACER and CEER, Spain ranks second after Italy.[11]

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[9] Scheduled exports are considered as consumption, while the scheduled imports as generation.

[10] The Spanish TSO does not provide any explanation about this increasing redispatched energy in real time. However, the quality of supply in the transmission grid worsen in 2021 compared to 2020, which induces a higher number of unforeseen events that might require activating more redispatching energy in the real time. In this period, the non-supplied energy in the transmission grid increased from 95 to 188 MWh, and the average time of interruption increased from 0.21 minutes to 0.41 minutes.

[11] Please note that in terms of total costs for remedial actions Germany surpasses Spain. A significant amount of costs for remedial actions in Germany are classified as 'other costs' described as costs for network reserves (including both availability and activation payments) and RES curtailment compensations in the case of Germany.

Table 1: Redispatched energy and costs from the Stage 2 (Figure 1) in the Spanish electricity system. Source: Own calculations, based on our dataset and REE (2020, 2021a, 2022).

	Units	2019	2020	2021
Annual electricity demand	GWh	249,257	236,755	242,492
Redispatched Energy	GWh (% total)	7,058 (2.83%)	9,979 (4.21%)	8,042 (3.32%)
Costs from the redispatched energy	M€	239	423	443
	€/MWh	1.00	1.79	1.83

Note: Redispatched energy corresponds to the sum of the upward and downward energy redispatched in the Stage 2.1, while the costs include both the Stage 2.1 and 2.2. Redispatched energy in the real time is not included.

2.2 Regulatory framework

The Electricity Regulation (EU) 2019/943 mandates in Article 13 that the redispatching of generation or demand response should be based on objective, transparent and non-discriminatory criteria. Moreover, downward redispatch of RES or high-efficiency cogeneration should be as minimum as possible to limit costs and emissions. Importantly, in the same Article 13 it is also stated that the provision of redispatch shall be organized using market-based mechanisms, shall be financially compensated, and shall be open to all technologies, storage devices or demand response. Non-market based redispatching is only allowed in case not enough competition can be guaranteed.

Even though mandated by the Electricity Regulation (EU) 2019/943, as far as the authors are aware, market based redispatching is still not to the same extent applied in all EU Member States (European Commission, 2019a). A relevant paper in this regard is the work by Poplavskaya et al. (2020). In that paper the redispatching regimes of TSOs in three countries are compared: Germany, France, and the Netherlands. Poplavskaya et al. (2020) explain that there is not a universally established procurement mechanism for redispatch energy. Germany applies cost-based redispatch, France procures redispatch energy jointly with mFRR/RR balancing services, and in the Netherlands a separate redispatch market was created. The advantage of cost redispatch is that it can avoid gaming but hinders the provision of system services from most small market participants, such as flexible demand and storage, whose variable costs are difficult to determine administratively. In Spain, the procurement of redispatched energy in the Stage 2.1 is a hybrid mechanism (MICT, 2015)[12]:

- Downward redispatched energy: Generators receive the hourly wholesale price for curtailed production.
- Upward redispatched energy: At any given hour generators must bid a volume of upward redispatch that is equal the difference between their scheduled energy in the EEMS (Stage 1) and their maximum production. In the case of RES, the maximum productions should consider the maximum primary resource availability, i.e., sun or wind. Upward redispatch bids can be split between 10 different blocks with each a different price.

Recently the rise of “bottom-up” flexibility markets is witnessed in the EU. Flexibility markets are often referred to as markets set up at distribution-level to procure local system services from distributed energy resources (DERs). Flexibility markets are fostered due to provisions in the Electricity Directive (EU) 2019/944 stating in Art. 32 that distribution system operators shall procure services in a market-based manner from resources such as distributed generation, demand response, or storage when such services are cheaper than

[12] Pumping generators are treated differently. If pumping consumption is curtailed to provide upward redispatch, the non-consumed energy is not remunerated. To provide downwards redispatch, pumping generators must bid the difference between their scheduled (in the EEMS) and maximum consumption.

grid expansion (European Commission, 2019b). Valarezo et al. (2021), providing an overview of newly emerging system service markets, explain that several pilot projects are currently in place in Spain. As the volumes redispatched in these pilots is very limited for the time being, they do not interfere with our analysis. Importantly, as discussed in Schittekatte and Meeus (2020), in the future for several flexibility markets the idea is that they are jointly (or at least planned to) operated by DSOs and TSOs. As such, for instance resources connected at the distribution-level can more easily provide services to resolve congestion issues at transmission-level, or vice-versa. Such evolution is expected to be important to decarbonize redispatching.

3. Data and Empirical Approach

We start this section by explaining how we constructed the dataset, after we provide relevant descriptive statistics, finally, we describe the chosen empirical approach.

The answer to our first research question, i.e., the total CO2 emissions introduced due to redispatch processes, can directly be calculated from the resulting dataset. Answers to our second and third research questions, i.e., the drivers behind redispatch-related CO2 emissions and a quantification of the redispatch-related CO2 emissions associated with more RES generation, requires a deeper analysis that we conduct via descriptive statistics and the estimations of models based on the resulting dataset.

3.1. Constructing the dataset

The construction of our dataset consists out of two steps. First, the calculation of the hourly redispatched energy per technology. Second, the calculation of the hourly change in CO2 emissions due to the redispatched energy. All data is hourly and refers to the Spanish bidding zone. The necessary data is provided by Spanish nominated electricity market operator (NEMO), namely OMIE, and the Spanish TSO, being REE. The considered period covers from 2019 to 2021. Building this dataset requires merging several datasets from both the NEMO and the TSO.

3.1.1. Step 1: the calculation of the hourly redispatched energy per technology

In the first step of our data collection process, we need to obtain the economically efficient market schedule (EEMS) and the economically and technically feasible schedule (EFTS) per generation technology, i.e., the energy schedule after redispatch actions. Having obtained these two datasets, we can calculate the hourly redispatched energy per technology. The EEMS results from matching the outcome of the day-ahead market, a pan-European auction held at noon the day before delivery, and the data regarding the execution of bilateral contracts with physical dispatch of energy. The raw data is provided by the Spanish NEMO, but to have a useful dataset to perform our estimations requires complex data processing. Table 3 shows the summary statistics of the EEMS by technology. This data is used as exogeneous variables in the empirical analysis.

Table 3. Summary statistics of the EEMS by technology for 2019-2021(N=26,280)

Variable	Technology	Units	Mean	St.Dev.	Min	Max
CC_t	Combined cycle	MWh	3,103.9	3,141.6	0	14990.2
CO_t	Coal	MWh	376.7	726.2	0	5295
H_t	Hydropower	MWh	3,209.4	1,743.0	531.5	10,161.1
N_t	Nuclear	MWh	6,336.0	898.9	3,410.2	7,151.9
PG_t	Pumping	MWh	216.1	386.9	0	2,648.9
PV_t	Photovoltaic	MWh	1,546.8	2,107.0	0	8,638.7

TS_t	Thermosolar	MWh	553.8	653.5	0	2,184
CHP_t	Combined Heat and Power	MWh	3,230.3	259.1	2,278.6	3,878.1
B_t	Biomass and others	MWh	1,014.1	97.5	604.2	1,410.9
W_t	Wind	MWh	7,093.7	3,663.1	770.6	20,715.6

As explained in the previous section, based on the EEMS all the SOs evaluate whether the resultant electricity flows are also technically feasible, i.e., they do not violate congestion limits and fulfill the rest of security criteria. If not, SOs alter specific generation, load pattern, or both, to change the physical flows in the grid. In that regard, as we have access to the EFTS, i.e., the energy schedule after redispatch actions, we can calculate the redispatched energy for each i technology at each t hour using Eq. 1:

$$r_{i,t} = EEMS_{i,t} - EFTS_{i,t} \quad (1)$$
$$i = [CC, CO, H, N, PG, PV, TS, CHP, B, W]$$

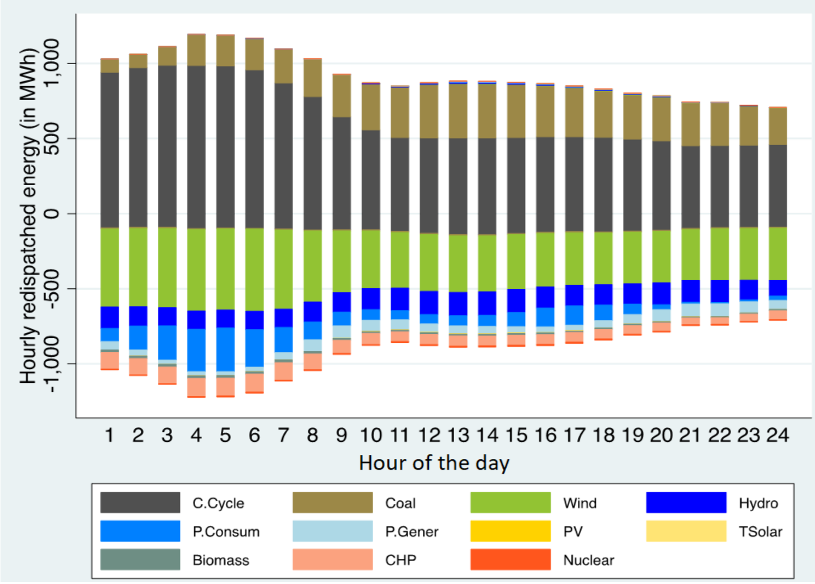
Table 4 shows the summary statistics of the net redispatched energy and -in brackets- the upwards redispatched energy (Stage 2.1) per technology. Combined cycle is the technology most often upward redispatched, while wind is the technology that is by far most downwards redispatched (curtailed). Note that the average downward redispatched photovoltaics is almost null. This is due to the fact that wind generators, at least in the considered period, are frequently relatively large plants connected to the transmission grid, while photovoltaics are smaller plants connected to the distribution grids. When comparing Table 3 and 4 note that the share of coal-fired generation in terms of redispatch energy is significantly higher than in terms of scheduled energy in the EEMS.

Table 4. Summary statistics of the net redispatched energy by technology for 2019-2021. Data for the upwards redispatched energy is provided in brackets.

Technology	Units	Mean	St.Dev.	Min	Max
CC_t	MWh	538.4 (647.3)	505.9 (461.0)	-2,436.5 (0)	3,022.3 (3,022.3)
CO_t	MWh	248.2 (264.9)	204.2 (208.2)	-399 (0)	1215 (1215)
H_t	MWh	-133.2 (3.1)	151.0 (16.5)	-1,450.7 (0)	559.6 (559.6)
N_t	MWh	-6.0 (0.0)	56.4 (0.8)	-1,113.2 (0)	90.1 (90.1)
PG_t	MWh	-53.4 (1.6)	102.0 (25.3)	-949.7 (0)	865 (865)
PV_t	MWh	-0.4 (0.0)	3.0 (0.3)	-58.6 (0)	15.1 (15.1)
TS_t	MWh	-1.3 (0.0)	7.35 (0.5)	-184 (0)	24.5 (24.5)
CHP_t	MWh	-79.2 (0.2)	96.0 (2.5)	-868.9 (0)	58.3 (58.3)
B_t	MWh	-12.1 (0.1)	17.5 (1.7)	-170.8 (0)	21.5 (43.4)
W_t	MWh	-414.1 (1.6)	312.7 (21.1)	-2,207.8 (0)	658.1 (668.2)

Figure 2 shows the average hourly upward and downward energy for each technology. Note that for instance, in the same hour a combined cycle unit can provide upward redispatch in one part of the grid, while in another part of the grid another combined cycle unit can provide downward redispatch. The redispatched energy in Table 4 shows the net difference between the upward and downward for each hour. We see the highest volumes of redispatch hours during the night. During these hours demand is typically low and high wind production, typically leading to voltage issues as discussed in more depth later.

Figure 2: Average hourly redispatched energy in Stage 2 (Figure 1) by technology (2019-2021). Source: own calculations *based on our dataset. Note: Positive values in vertical axis corresponds to upward redispatched energy, while negative downward redispatch energy. The negative coefficient for pumping consumption means a higher consumption of electricity*.



3.1.2. Step 2: calculation of the hourly impact of redispatch on CO2 emissions

In the second step, we calculate for each hour the total CO2 emissions related to the redispatched energy ($CO2_t$) considering the specific emissions per each technology (Eq. 2).[13] Obviously, $CO2_t$ can be either positive or negative, depending on the generation technologies that are upward and downward redispatched in the particular hour.

$$CO2_t = 0.34 \cdot r_{CC,t} + 0.95 \cdot r_{CO,t} + 0.38 \cdot r_{CHP,t} + 0.24 \cdot r_{B,t} \qquad (2)$$

Considering the technologies that are upwards and downwards redispatched (Figure 2), it is no surprise that the hourly change in CO2 emissions due to redispatch is in almost all hours positive. We estimate that on average an additional 401.9 ton of CO2 per hour was emitted due to redispatch needs for 2019-2021 (standard deviation: 214.1, minimum: -376.2, maximum: 1,634.34). Table 5 provides an answer to our first research question: the CO2 emissions associated to the redispatching energy. As we see, the upward redispatched energy, mostly from combined cycles and coal, represents about 10% of the total power system emissions, while the redispatched energy only represents 2.8% to 4.2% of the total power (see Table 2). In other words, redispatched energy is a lot more polluting than the average non-redispatched power production.

Table 5: CO2 emissions from the redispatched energy. Source: Own calculations and based on our dataset and REE (2020, 2021a, 2022). Note: Redispatched energy in the real time is not included.

	Units	2019	2020	2021
CO2 emissions from the redispatched energy	ktn of CO2 (% total)	3,142.68 (6.29%)	4,121.55 (11.41%)	3,297.37 (9.18%)
Total power sector CO2 emissions	ktn of CO2	50,000.0	36,130.9	35,906.6

3.2 Analysis of the resulting dataset

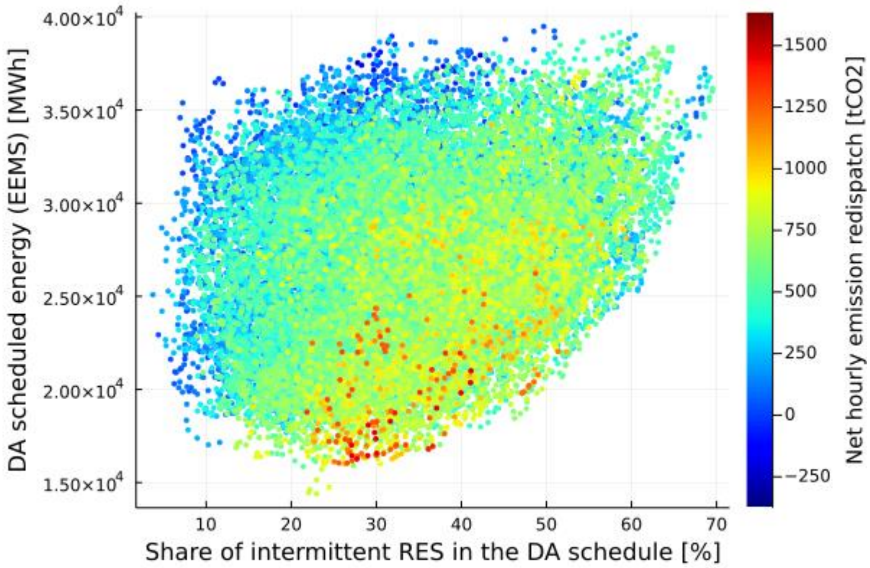
To provide an intuition behind the possible answers to our second and third research question, we need first analyze the resulting dataset in more depth before introducing the empirical approach.

[13] CO2 factor emissions 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 (REE, 2021b).

An important finding from Table 5 that is during the Covid-19 confinement (Spring-early summer 2020) the redispatched energy and accordingly the CO2 emission from redispatch actions were the highest, while there was an overall lower electricity demand compared to the other considered years. This might be counterintuitive on first sight but can be explain by the fact that in the Spanish power system, during low demand periods surpluses of reactive energy flows are more frequent and, at least currently, the only way to absorb these (local) surpluses is by having the TSO starting up some synchronous generators (combined cycle or coal) (Anaya et al., 2022). [14] ACER (2021) reports that in 2020, 71% of total redispatched energy in Spain was due to such voltage problems. From the data, we can identify this dynamic by noting the high volumes of upwards redispatch by thermal generators in Stage 2.1. ("the first redispatch action is the start-up of these units"). As these generating units require to run at minimum load levels that are higher than zero, other (scheduled) often non-synchronous generation (RES) needs to be redispatched downwards ("a second action" in Stage 2.2) to rebalance the system. Concretely, in 2020, a record of 8% of the scheduled wind production was downward curtailed in the redispatching process (Stage 2.2).[15] In other words, the current procedure to resolve voltage issues implies an important waste of clean resources.

Figure 3 provides more insight in this phenomena by showing the CO2 emissions from all the hourly redispatched actions in Spain for 2019-2021. The y-axis corresponds to the hourly day-ahead scheduled energy (EEMS) and x-axis the share of intermittent RES (solar PV and wind) in the EEMS. Green coloured dots represent lower CO2 emissions from redispatch (with as baseline the EEMS), while purple dots indicate high emissions.

Figure 3: Day-ahead scheduled energy (EEMS) vs share of renewable (wind and sun) in the EEMS for Spain from 2019-2021. Colors show the additional CO2.



A rather unexpected pattern appears. We do two observations. First, the hours with the highest hourly emissions due to redispatch actions occur when the share of RES as the total scheduled energy (% RES divided by EEMS) is relatively medium (between 20-

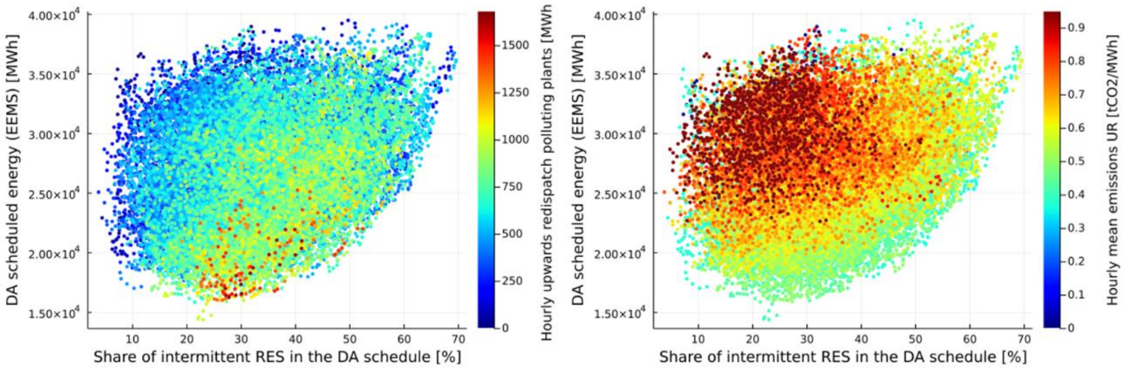
[14] As discussed in Section 4, wind and photovoltaics interface the grid via power electronics, which implies that the participation in voltage control services required different procedures than the synchronous generators, i.e. combined cycle, coal, hydropower or nuclear. hydropower.
[15] The average hourly wind scheduled production W_t was 6,691MWh (2019), 7,035MWh (2020), 7,554 MWh (2021) and the average hourly wind curtailed was 284MWh (2019), 564MWh (2020), 394MWh (2021), which represents a share of 4.2%, 8.0% and 5.2% respectively.

40% of the total supply), while at the same time the absolute hourly total scheduled energy (=demand) is low. For the same shares of RES in the day-ahead schedule, the emissions from redispatch are significantly higher with lower overall scheduled energy. When overall scheduled energy is relatively high, only under a significant share of RES production the CO2 emissions from redispatch increase. In Section 4, we investigate these relationships in more depth based on the empirical approach introduced in the next subsection. In Appendix I, we provide additional figures including the same figure per year. It can be seen that especially in 2020 during the Covid-19 confinement the highest emissions associated with redispatch were observed during the hours with the lowest total scheduled energy.

Second, another important observation is that the hours with very high shares of RES day-ahead scheduled production (>60%) occur only exclusively when the system demand is also relatively high. Under very high shares of RES, the CO2 from redispatch is relatively low. This can explained by two reasons that would require deeper analysis. First, correlation of high demand periods and high intermittent RES production. Second, at times with very high intermittent RES production, not necessarily all RES production is cleared in the day-ahead market even though the total hourly production of intermittent RES is less than 100% of the hourly demand. This happens for example because it is very costly to shut down for some generators for a brief period (e.g., nuclear is the prime example but this can also happen for coal). An "indicator" of this happening are day-ahead power prices being near or lower than zero.

Figure 4 shows two panels with data from Spain for 2019-2021 that further explain the dynamics displayed in Figure 3. In both graphs, similar as in Figure 3, the y-axis corresponds to the hourly day-ahead scheduled energy (EEMS) and x-axis to share of intermittent RES supply in EEMS. In the left panel, the colours of the dots represent the sum of the upward redispatched energy from combined cycle, coal, CHP and biomass, while in the right panel, the colours of the dots represent the average CO2/MWh emissions associated to the upwards redispatched energy from combined cycle, coal, CHP and biomass. In both cases, green indicates lower and purple indicate higher values.

Figure 4: Day-ahead scheduled energy (EEMS) vs share of renewable in the EEMS for Spain from 2019-2021. Left graph shows the sum of the upward redispatched energy from combined cycle, coal, biomass and CHP, while the right graph the average CO2 emissions from the same upwards redispatched energy.



We observe contrasting patterns when comparing these panels. First, the left panel shows that the highest hourly upwards redispatch energy from polluting power plants occurs when demand is low and the share of intermittent RES is average. This pattern is rather similar as the pattern in Figure 4. In other words, the absolute introduced hourly CO2 emissions due to redispatched energy seem to be strongly driven by the volume of upwards redispatch energy from polluting power plants in the same hour. However, a very different pattern appears on the right panel. Highest average CO2 emissions per MWh from the upwards redispatch energy occurs when the share of RES in the day-ahead schedule is relatively low and the overall schedule day-ahead energy is high. The main reason for this finding is that during those hours coal is providing most redispatch energy as typically many gas-fired generation has already been started up and is running near their maximum capacity. Gas is running near their maximum capacity to fullfill the high energy demand that can be only to a limited extent be fullfilled by RES generation (i.e., low share of RES in the EEMS). The least average CO2 emitted per MWh of redispatch energy occurs when the highest volume of redispatch occurs, when the share of RES is average and the overal day-ahead scheduled is low. In Section 4, we investigate these relationships in more depth based on the empirical approach introduced in the next subsection. In Appendix I, we provide the same figures per year. It can be seen that in the year 2021, the year in which the European energy crisis started, shows a different pattern for the average CO2 emissions per upwards redispatch energy.

3.3. Empirical approach

To investigate in more depth the patterns that are observed and discussed in the previous subsection, we employ an ARIMA time-series estimator, where variables are differentiated to ensure their stationarity and the lagged endogenous variable is included to capture the time dynamics.[16] We introduce four models. The first three models correspond with the panels shown in Figures 3 and 4 and relate to our second research question. The fourth model introduces new relationships in the dataset to provide an answer to our third research question.

In our first model, our endogenous variable is the hourly CO2 emissions associated to the sum of the upward and downward redispatched energy ($\Delta CO2$), while the explicative variables correspond to day-ahead energy schedule before redispatching (EEMS), and the share of wind and photovoltaics in the EEMS.

$$\Delta CO2_t = \beta_0 + \beta_1 \cdot \Delta CO2_{t-1} + \beta_2 \cdot \Delta EEMS_t + \beta_3 \cdot \Delta RES_t + \beta_4 \cdot m_t + \beta_5 \cdot holiday_t + \varepsilon_t \quad (4)$$

$$EEMS_t = \sum_{i=CC,CO,H,N,PG,PV,TS,CHP,B,W} EEMS_{i,t} \quad (5)$$

$$RES_t = \frac{\sum_{i=PV,W} EEMS_{i,t}}{EEMS_t} \cdot 100 \quad (6)$$

In our second model, our endogenous variable is the hourly upward redispatched energy associated to the pollutant technologies (Δur_t) -combined cycle, coal, biomass, and CHP-, while the explicative variables correspond to daily energy schedule before redispatching (EEMS), and the share of wind and photovoltaics production in EEMS.

$$\Delta ur_t = \beta_0 + \beta_1 \cdot \Delta r_{t-1} + \beta_2 \cdot \Delta EEMS_t + \beta_3 \cdot \Delta RES_t + \beta_4 \cdot m_t + \beta_5 \cdot holiday_t + \varepsilon_t \quad (7)$$

$$ur_t = \sum_{i=CC,CO,B,CHP} ur_{i,t} \quad (8)$$

In our third model, our endogenous variable is the average CO2 emissions associated to the upward redispatched energy from coal, combined cycle, biomass and CHP ($\Delta avCO2_t$)

[16] In the partial autocorrelation analysis, we find the first lag is significant as in other studies related with hourly scheduled generation or consumption (Costa-Campi et al, 2018). We provide the stationary tests for the variables in the Appendix II. Under the ADF test, we reject the null hypothesis that there is a unit root in both levels and differences. However, under the KPSS test, we only reject the null hypothesis that the series is stationary in levels, but not in differences. Therefore, in the empirical analysis we use variables in differences to ensure they are stationary.

and the explicative variables correspond to day-ahead energy schedule before redispatching (EEMS), and the share of wind and photovoltaics in EEMS.

$$\Delta avCO2_t = \beta_0 + \beta_1 \cdot \Delta avCO2_{t-1} + \beta_2 \cdot \Delta EEMS_t + \beta_3 \cdot \Delta RES_t + \beta_4 \cdot m_t + \\ + \beta_5 \cdot holiday_t + \varepsilon_t \quad (9)$$

$$avCO2_t = \frac{0.34 \cdot ur_{CC,t} + 0.95 \cdot ur_{CO,t} + 0.38 \cdot ur_{CHP,t} + 0.24 \cdot ur_{B,t}}{ur_{CC,t} + ur_{CO,t} + ur_{CHP,t} + ur_{B,t}} \quad (10)$$

In our fourth model, our endogenous variable is the hourly CO2 emissions associated to the sum of the upward and downward redispatched energy ($\Delta CO2$) and the explicative variables correspond to daily energy schedule per technology in the EEMS.

$$\Delta CO2_t = \beta_0 + \beta_1 \cdot \Delta CO2_{t-1} + \beta_2 \cdot \Delta CC_t + \beta_3 \cdot \Delta CO_t + \beta_4 \cdot \Delta H_t + \beta_5 \cdot \Delta N_t + \\ + \beta_6 \cdot \Delta PG_t + \beta_7 \cdot \Delta PV_t + \beta_8 \cdot \Delta TS_t + \beta_9 \cdot \Delta CHP_t + \beta_{10} \cdot \Delta B_t + \\ + \beta_{11} \cdot \Delta W_t + \beta_{12} \cdot m_t + \beta_{13} \cdot holiday_t + \varepsilon_t \quad (11)$$

Where the explicative variables correspond to scheduled energy in the EEMS. In all the equations, seasonality is controlled by m_t, a dummy variable for each month, while $holiday_t$ equals to 1 in weekends and national holidays.

We use maximum likelihood estimators to avoid potential biases that might arise with ordinary least square estimations in the presence of the lagged dependent variable. Further, we perform three different estimations, one per year (2019, 2020 and 2021) as there are relevant differences during this period (see also the figures in Appendix I). We enumerate four developments over the considered years. First, the generation mix changes between 2019 and 2021: photovoltaics capacity increases +212% up to 15.048MW, wind capacity increases +20% up to 28.175MW, and coal capacity decreases -62,5% up to 3.764MW (REE, 2022). Second, 2020 includes the pandemic containment and severe restrictions on movement during some months, which clearly affected the national electricity demand (Santiago et al., 2021). Third, the average wholesale price is quite different from one year to another (47,78€/MWh in 2019, 33,95€/MWh in 2020 and 111,97€/MWh in 2021), which might constraint the technologies operating in the particular year. Fourth and last, the TSO and DSOs are ongoing commissioning new grids, substations and reactive compensation equipment, precisely aimed to reduce redispatching.

4. Results and Discussion

In this section we first present results based on the dataset and models presented in the previous section. After, we discuss in more depth these results and provide regulatory recommendations.

4.1 Results

Table 6 displays the results for Eq. 4. Note that in all our estimations, both the endogenous and explicative variables are in differences. We have two observations from the table. First, there is no consistent relationship between the additional amount of CO2 emitted due to the redispatch process and a change in scheduled energy across years. For 2019 and 2020, an increase in the hourly demand leads to more CO2 emitted via redispatching, while the opposite is true for 2021. These results can be explained by the different roles of the upward redispatched of combined cycle and coal. In Appendix III, we show that when the scheduled energy increases, redispatch energy from combined cycle decreases, while redispatched energy from coal increases.[17] In 2019 and 2020, coal-fired generation was more expensive than gas-fired generation, combined cycles were less operated in the low demand periods and more available to provide upward redispatch.[18] However, in the high demand periods, generation from combined cycle generators are operating closer to their maximum capacity (as a fleet) and the TSO must opt for coal to provide upward redispatch.[19] Due to the rising gas prices from the summer of '21 onwards, gas and coal switched in the merit order which explains the change in sign for the relationship between CO2 emitted via redispatch and the scheduled energy for the year 2021.

Table 6: ML estimations for Eq. 4 per year

	2019	**2020**	**2021**
	$\Delta \boldsymbol{CO2_t}$	$\Delta \boldsymbol{CO2_t}$	$\Delta \boldsymbol{CO2_t}$
Scheduled Energy $(\Delta EEMS_t)$	0.00299^{****}	0.00203^{***}	-0.00899^{****}
	(0.000572)	(0.000657)	(0.000507)
Renewables (ΔRES_t)	1.693^{****}	1.976^{****}	5.203^{****}
	(0.429)	(0.376)	(0.258)
Holiday $(holiday_t)$	1.106	-0.183	1.295
	(1.596)	(1.889)	(1.627)
Lagged $(\Delta CO2_{t-1})$	-0.00893	-0.0235^{**}	-0.0336^{****}
	(0.00949)	(0.00990)	(0.00969)
Constant $(\widehat{\beta_0})$	68.31^{****}	81.95^{****}	70.82^{****}
	(0.261)	(0.274)	(0.276)
N	8,735	8,783	8,759
Seasonality			
Month	Yes	Yes	Yes
Weekends & Nat. holidays	Yes	Yes	Yes

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

The second observation is that higher participation of wind and photovoltaics in the EEMS results in higher CO2 emissions related to the redispatching processes. The impact of shares of intermittent RES grows across the period, which could be to some extent explained by the higher wind and solar capacity connected. The sudden increase in 2021 can also explained by the fact that the higher shares of RES in the day-ahead schedule, the higher the probability that coal is the marginal technology in the day-ahead market in the second part of 2021 and thus can provide a significant volume of the upwards redispatch energy.

In the next estimations we disentangle the previously described dynamics. Table 8 shows results from estimations based on Eq. 7 and 9 for the considered years. Overall, when

[17] In Appendix III, an additional MWh in the scheduled energy (ΔSE_t) entails the following redispatch of combined cycle: -0.0481MWh (2019), -0.0504MWh (2020) and -0.0618MWh (2021). Moreover, an additional MWh in the scheduled energy (ΔSE_t) entails the following redispatch of coal: +0.0182MWh (2019), +0.0188MWh (2020) and +0.0113MWh (2021). In Table 6, the positive CO2 emissions in columns 1, 3 and 5 are due to the higher CO2 emissions from coal (0.95tn/MWh) compared to combined cycle (0.37tn/MWh).

[18] In the Spanish regulation, the criteria defined by the NRA to choose technologies to upward redispatch are the following: (i) the cheapest bid to redispatch, (ii) RES technologies, (iii) high efficiency thermal installations, (iv) the rest. Source: *Boletin Oficial del Estado (21.10.2019)*

[19] In Figure 2, the upward redispatch energy in coal is higher at day. Moreover, the average EEMS for combined cycle in *holiday=1* is 2,829MWh (2019), 1,517MWh (2020), 1,022MWh (2021), in *holiday=0* is 4,927MWh (2019), 3,350MWh (2020) and 2,741MWh (2021). The average EEMS for coal in *holiday=1* is 376MWh (2019), 129MWh (2020), 277MWh (2021), in *holiday=0* is 730MWh (2019), 163MWh (2020) and 388MWh (2021).

comparing the results from Table 6 and 7, it can be said that when discussing the hourly net emissions due to redispatch (Eq. 4), the "volume effect", i.e., the MWh's redispatched in an hour by polluting technologies (Eq. 7), is significantly more important than the "supply mix effect", i.e., what polluting technologies are providing redispatch (Eq. 9).

Further we do two important observations from the results in Table 7. First, the results confirm that the sum of the upward redispatched energy from pollutant technologies is consistently inversely related with the hourly scheduled energy (grid congestions), and positively related with the share of RES (share of power electronics in the mix). Both indicate that a significant share of the need for redispatching is mostly likely due to reactive energy flows and voltage problems (Table 1). Second, the mean intensity of CO2/MWh associated to the previous upward redispatched energy from pollutant technologies in 2019 and 2020 is positively correlated with the hourly scheduled energy, and negatively related with the share of RES. This finding confirms that coal, the most pollutant technology, is more probably to be upward redispatched when the scheduled energy increases, but less probably when the participation of RES increases. In 2021, we do not see this effect on the intensity of CO2/MWh due to the coal-gas switch in the merit order around the middle of the year due to the energy crisis.

Table 7: ML estimations for Eq. 7 and 9 per year

	2019 (Eq. 7) Δur_t	**2020 (Eq. 7)** Δur_t	**2021 (Eq. 7)** Δur_t	**2019 (Eq. 9)** $\Delta avCO2_t$	**2020 (Eq. 9)** $\Delta avCO2_t$	**2021 (Eq. 9)** $\Delta avCO2_t$
Scheduled Energy ($\Delta EEMS_t$)	-0.0180**** (0.000864)	-0.0180**** (0.00118)	-0.0407**** (0.00103)	0.0000224**** (0.000000696)	0.0000142**** (0.000000475)	0.124 (0.340)
Renewables (ΔRES_t)	8.285**** (0.620)	10.68**** (0.637)	12.50**** (0.493)	-0.00761**** (0.000537)	-0.00338**** (0.000294)	-100.5 (105.8)
Holiday ($holiday_t$)	0.857 (2.479)	-0.592 (3.366)	2.089 (3.221)	0.000657 (0.00208)	-0.00116 (0.00154)	181.1 (589.1)
Lagged (Δur_{t-1})	0.00991 (0.00980)	-0.00940 (0.0103)	-0.0879**** (0.0106)			
Lagged ($\Delta avCO2_{t-1}$)				-0.119**** (0.00660)	-0.152**** (0.00424)	-0.458**** (0.000390)
Constant ($\widehat{\beta_0}$)	108.4**** (0.370)	148.3**** (0.415)	148.3**** (0.609)	0.0889**** (0.000244)	0.0713**** (0.000167)	25439.2**** (8.323)
N	8,735	8,783	8,759	8,735	8,783	8,759
Seasonality						
Month	Yes	Yes	Yes	Yes	Yes	Yes
Weekends & Nat. Holidays	Yes	Yes	Yes	Yes	Yes	Yes

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

Table 8 shows results from estimations based on Eq. 11 for the three years. In all the cases, we control seasonality by the inclusion of a dummy for each month, and another dummy for weekends or national holiday days out of weekends.

For our third research question, what we are mostly interested in from these results are the estimations of changes in emissions due to changes in wind and solar photovoltaics generation. As expected, when considering the previous results, we can see that higher production volumes of intermittent RES in the EEMS induce higher CO2 emissions from redispatched energy necessary for the ETFS. More specifically, we find that each additional MWh of wind increases redispatching emissions between +0.00570 and +0.00662tn of CO2, and each additional MWh of photovoltaics between +0.00666 and +0.0159tn of CO2. The positive correlations highlight that integrating RES might require addressing some operating challenges that should be solved to avoid the need for pollutant technologies.

Finally, in Table 9 we calculate the net CO2 emissions related to wind and photovoltaics, considering two different replaced technologies: coal and combined cycle. It is important to note that current redispatching processes reduce the potential CO2 savings between -1.6% and -4.5% for photovoltaics, and between -0.7% and 2.0% for wind. Up to our knowledge, such "emission reduction correction factors" due to operational issues in the integration of RES are not considered in emission-related assessments of RES technologies, which is a contribution of this paper.

Table 8. ML estimations for Eq. 11 per year

	2019 $\Delta \boldsymbol{CO2_t}$	**2020** $\Delta \boldsymbol{CO2_t}$	**2021** $\Delta \boldsymbol{CO2_t}$
Combined Cycle (ΔCC_t)	-0.00330**** (0.000953)	-0.00771**** (0.00158)	-0.0362**** (0.000986)
Coal (ΔCO_t)	-0.135**** (0.00257)	-0.192**** (0.00862)	-0.276**** (0.00492)
Hydropower (ΔH_t)	0.0178**** (0.00156)	0.00682**** (0.00138)	-0.00279** (0.00122)
Nuclear (ΔN_t)	0.0218** (0.0103)	-0.0189*** (0.00697)	-0.0471**** (0.00983)
Pumping generation (ΔPG_t)	0.0287**** (0.00407)	-0.00180 (0.00318)	0.00225 (0.00263)
Photovoltaics (ΔPV_t)	0.00666** (0.00329)	0.0159**** (0.00230)	0.00225* (0.00124)
Thermosolar (ΔTS_t)	0.0152*** (0.00584)	-0.0129** (0.00602)	-0.0135*** (0.00424)
Biomass (ΔB_t)	0.0318* (0.0183)	-0.0692** (0.0274)	0.221**** (0.0373)
CHP (ΔCHP_t)	-0.0376*** (0.0127)	-0.0534*** (0.0188)	-0.0487**** (0.0134)
Wind (ΔW_t)	0.00570**** (0.00166)	0.00721**** (0.00213)	0.00662**** (0.00152)
Holiday $(holiday_t)$	-0.900 (1.480)	-0.613 (1.825)	-0.742 (1.488)
Lagged $(\Delta CO2_{t-1})$	-0.0154 (0.00957)	-0.0422**** (0.00989)	-0.0786**** (0.00968)
Constant $(\widehat{\beta_0})$	64.13**** (0.254)	80.37**** (0.277)	66.70**** (0.283)
N	8,735	8,783	8,759
Seasonality			
Month	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes

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

Table 9. Net abated CO2 emissions from photovoltaics and wind, considering two replaced technologies (coal and combined cycle).

Renewable technology generating	Replaced technology	Savings on CO2 emissions			
		Day-ahead schedule	**Redispatching**	**Net CO2 emissions**	**Emission reduction correction**
		(tCO2/MWh)	(tCO2/MWh)	(tCO2/MWh)	%
Photovoltaics	Coal	-0.95	+0.01526	-0.93474	**-1.61%**
	Combined Cycle	-0.34	+0.01526	-0.32474	**-4.49%**
Wind	Coal	-0.95	+0.00692	-0.94308	**-0.73%**
	Combined Cycle	-0.34	+0.00692	-0.33308	**-2.03%**

Note: Redispatching emissions come from the maximum long-term CO2 emissions shown in Appendix IV.

4.2 Discussion and regulatory recommendations

Our analysis confirms, at least for the considered case study, that redispatched energy is on average more polluting than non-redispatched energy and that increasing shares of RES in the day-ahead schedule are leading to increased redispatch volumes. We estimate for the case of Spain, considering the period between 2019-2021, that the theoretical avoided emissions from the replacement of a MWh produced by fossil-fuel generation by a MWh produced by RES need to be reduced by 0.7-4.5% to account for operational issues in the delivery of the generated electricity by the RES. Such “emission reduction correction factors” might appear still relatively small but are not insignificant. Also, this issue, considering business-as-usual, is expected to increase steeply.

What our analysis has also shown is that the common idea that increasing volumes of redispatch, and hence increased emissions from redispatched energy, are solely driven by higher shares of RES production is an incomplete statement. Further, the common idea that redispatch volumes can be reduced by simply building more networks also requires rethinking. The exact drivers of emissions from upward redispatch, in most cases replacing curtailed renewables, and the most efficient solutions to reduce emissions from redispatch are a lot more complex. On top, it is hard to make any general statement about redispatch processes, and their associated additional emissions, as they are heavily impacted by “shocks” to the power system. Examples that have been illustrated in our analysis are the Covid-19 confinement, leading to a decrease in overall demand, and the ongoing EU energy crisis, leading to a switch between gas and coal-fired generation in the merit order underlying the day-ahead dispatch. In what follows, we first discuss how our analysis can inform potential solutions to reduce the need for redispatch. After, we discuss how our analysis can inform solutions to make redispatch processes less pollutant.

Our results have shown that the hours with the highest emissions from redispatch are also the hours with the highest volume of redispatch energy. We found that the volume of hourly redispatch energy increases with lower hourly scheduled energy, and higher shares of intermittent RES in the supply mix. The former factor indicates potential voltage issues as an important driver for redispatch, in line with the current voltage issues also identified in the UK (National Grid ESO, 2021).

Simply building more networks would not necessarily solve the voltage issues, instead more networks could even make them worse. Importantly, under the current zonal system in Spain no operational and siting incentives are provided to supply, demand, and storage via wholesale power prices.[20] The introduction of more granular locational prices,

[20] Eicke et al. (2020) study 2nd best mechanisms that introduce locational operation and siting incentives other than via wholesale electricity prices.

whether it being smaller zones or nodal pricing, would not necessarily directly solve all operational issues related to the delivery of clean electricity but at least can provide improved incentives that lead to a reduction in the need for redispatch in the short and longer run. Under more locational prices, spatially diverging day-ahead prices would make it more straightforward for resources, especially demand and storage, to react to local operational constraints; the threshold to participate in resolving local operation issues for storage and demand would be a lot lower in this way than via any post-market clearing redispatch mechanism whose costs are socialized across all the customers in a country (bidding zone). As such, also the need for redispatch would reduce.

Significant volumes of demand response and storage are active in existing nodal markets in the US (Eicke and Schittekatte, 2021). Vom Scheidt et al. (2022) studies the impact of more locational prices for the siting and operation of electrolyzers and show that passing spatially resolved electricity price signals leads to electrolyzers being placed at low-cost grid nodes, causing causes lower end-use costs for hydrogen, while at the same time substantially decreasing congestion management costs. At least for the case of Spain, not only thermal violations of network elements would need to be internalized in the market clearing algorithm but also voltage limitations. As far as the authors are aware, current nodal pricing systems do not, or at least not to a large extent, consider voltage limits in the market clearing. Nearly three decades ago, there has been a debate about the calculation and publication of reactive power prices, in additional to active power prices in nodal systems (Hogan, 1993). At that time the idea has finally been abandoned as the costs seemed higher than the benefits (Kahn and Baldick, 1994), but it might be revisited.

Our results have also shown that redispatched energy is a lot more polluting than the average non-redispatched power production. Nearly all upward redispatch is provided by polluting power plants, with an important role for coal generation, while mostly clean electricity, provided by wind, is curtailed to restore the energy balance. Further, the largest reductions of emissions from redispatch can obtained by replacing coal in the provision of redispatch (or reducing the need of redispatch) when the share of intermittent RES is low, and overall demand is high, in case the production prices of coal being higher than gas. In case gas-fired generation is more expensive than coal-fired generation, as is currently the case, this statement does not hold anymore. With the Clean Energy Package, published in 2019, the European Commission has introduced regulations to promote the participation of RES, demand, and storage in the provision of redispatch. So far, at least for the considered case study, very little progress seems to have been made in this respect. Full-fledged market-based redispatch systems would enable the participation of demand and storage which could lead to important cost reductions and the “greening” of redispatched energy. For example, Xiong et al. (2021) introduce Power-to-Gas as a redispatch option and apply their model to the German electricity system. They find that instead of curtailing RES, increased synthetic natural gas can be produced and injected into the gas grid for later usage. Their results show a reduction on curtailment of renewables by 12% through installing Power-to-Gas at a small set of nodes frequently facing curtailment. On the other hand, it is also well known that market-based redispatch can lead to serious gaming concerns (see e.g., Hirth and Schlecht, 2020).

Specifically with regards to mitigating voltage issues, there are two main instruments: (i) a traditional solution based on installing new reactive compensation equipment and, (ii) a more innovative solution based on better exploiting current and future RES. The Spanish TSO has planned to install new static synchronous compensators (STATCOMs) during the period 2021-2026 with an investment cost of more than 100M€ and an annual operating cost of more than 2M€, directly funded by electricity tariffs (MITECO, 2019). However, RES could take a similar role than the replaced synchronous generators in the voltage control. Nowadays, the participation of RES in the voltage control is limited up to now and in volume far from the voltage control capabilities that are currently being leveraged from synchronous generators that on the longer run are expected to be mothballed or at least reduce even more in operating hours (combined cycle and, especially, coal generators). In Spain as in many other countries, RES constantly follow a fixed power factor setpoint (peak/offpeak hours, working/holidays days). As these power factors are not changed for months,[21] the TSO should upward redispatched some coal or combined cycles plants to control the variable reactive energy needs, as has been shown in our analysis. The corresponding annual costs for consumers -in redispatching- range from 239M€ to 443M€ and lead to significant additional CO2 emissions. Alternatively, Regulation (UE) 2016/631 mandates new wind plants and photovoltaics to provide variable reactive energy also according to a voltage setpoint, which would enable an active participation of RES in the power system voltage control.[22] If this approach would become common practice, the need to upward redispatch combined cycle or coal (synchronous generators) would be reduced with the beneficial impact on the CO2 emissions and costs for consumers.[23]

However, the introduction of wide-spread voltage control by RES requires addressing three main economic issues. First, the oldest RES should be upgraded to implement this active participation in the voltage control. Second, RES providers of this service might face some operating costs as these plants will not be operating in their optimal conditions and face other additional operating costs (electricity losses and extra cooling to power inverters). Third, the reactive energy needs might differ across different regions within the same country. In economic regulation there are several mechanisms to deal with this: specific funding programs to upgrade the oldest RES and ruled-based or market-based compensation for the costs for the RES providers of the service. Regulation 2019/943 describes the introduction of in relation to non-discriminatory, transparent provision of non-frequency ancillary services, such as voltage control, as one of the areas for new network codes (Art. 59 (1.d)) (European Commission, 2019a). Further, also the framework guidelines of the new network code for demand-side flexibility discuss the introducing of long-term market-based procurement of voltage control, including at the distribution-level (ACER, 2022). Our analysis provides an argument for the urgence to go ahead with the implementation of a new ancillary service for the provision of voltage

[21] For the oldest RES, changing a power factor setpoint cannot be remotely done and requires moving a technician to the installation.

[22] When a generator follows a power factor setpoint, the provided reactive energy is always a share of the active energy and cannot inject reactive energy in some hours and consume in other ones. However, the system needs might be different across the day: in some hours there might be regional overvoltages (a surplus of reactive energy) and the generator should consume reactive energy, while in others there might be undervoltages (a deficit of reactive energy) and the generator should inject reactive energy. This can be solved if the generator implements a voltage control following a voltage setpoint: the provided reactive energy is proportional to the difference between the RES voltage setpoint and the voltage at the point of connection. This is mandatory for new RES. For further details, see Art. 21(3) in Regulation (EU) 2016/631.

[23] In Spain, power electronics of new wind and solar must have the capability to inject and consume some reactive energy in the absence of wind or sun (P=0). In the limit, power electronics of RES could also provide reactive energy flows in the absence of sun/wind, just with ancillary services to feed power electronics and cooling devices. For further details, see Figure 11 in MITECO (2020).

control.[24] Anaya and Pollitt (2020) do a review of current trends in the procurement of reactive power and confirm that currently market-based mechanisms are only to a very limited extent in place.

The novel service for the provision of voltage control must be technology agnostic, including the participation of demand. A final important point is how to implement a non-discriminatory market-based approach to this service when some assets already owned by the TSO -STATCOMs and capacitors- could compete in the provision of the same service. For the existing reactive compensation equipment, it could be considered a possibility to privatize these and move away from being a regulated asset (if competition and savings for consumers could be guaranteed). For those planned new reactive compensation equipments, a deeper analysis would be required to study in how far using the current resources (RES and consumption) could be an alternative to provide the same voltage control. Such approach would also release substation space for connecting new RES. In case the reactive energy needs would not be entirely met by existing resources, the installation of new reactive compensation equipment could be made with a tender process to third private parties to build and operate them during some years, in line with the current ancillary services aimed to provide inertia to the system (see e.g., National Grid ESO, 2022).

As an intermediate solution before implementing a new ancillary service, the curtailed RES could be reduced if all the consumption could participate in the redispatching processes, which is currently not possible in the Spanish regulatory framework. As we see in Figure 2, pumping consumption is a valid alternative to curtail schedule RES. However, note that higher consumption for redispatching purposes in some hours would lead to a decrease of the energy demand for the adjacent hours, the needs for upward redispatch pollutant technologies in those adjacent hours would slightly increase as we show in Table 7.

5. Conclusions

Connecting clean energy resources to the grid does not necessarily imply that each MWh produced from these resources will finally be delivered to end users, affecting the the power system economic efficiency. The power grid is complex system that is constraint by physical laws and complex technical constraints. In this paper we have studied the environmental impacts of redispatching processes for the case of Spain between 2019-2021 to identify some of these inefficiencies. Redispatching implies the alteration of generation, demand or storage after the day-ahead market clearing when the nation-wide welfare maximizing day-ahead production and consumption schedule violates grid-related security limits. We answered three research questions:

(i) how much emissions would have been avoided in case the Spanish network would have been able to always accommodate the nation-wide welfare-maximizing dispatch schedule?

(ii) what are the drivers of emissions via redispatch processes?

(iv) how much CO2 is emitted via redispatch processes per MWh of increased RES production in the day-ahead schedule?

[24] An alternative would be the direct integration of voltage limits in the market clearing algorithm. A separate ancillary service market for voltage control might be more realistic to implement in the short and medium term.

Regarding the first question, for Spain, when looking at the years 2019-2021, upward redispatched energy, nearly entirely provided by coal and combined cycle, represent about 10% of the total power system emissions, while the redispatched energy represents 2.8% to 4.2% of the total energy. In other words, redispatched energy to correct the day-ahead clearing schedule is considerably more polluting than the average non-redispatched power production.

Regarding the second question, we have shown that the hourly emissions from redispatching are rather driven by the volume of redispatch energy than the change in resources supplying redispatched energy in a given hour. Increasing hourly volumes of redispatch energy correlate not only with increasing shares of intermittent RES in the day-ahead schedule but also with decreasing hourly electricity demand, which was especially apparent during the period of the Covid-19 confinement. The latter clearly affects the efficiency of the power system and is an indication of the important role of voltage issues behind the high volumes of upward redispatch energy. Further, in case that the production costs of coal are higher than gas (as in the case of most of the considered periods), the largest average emissions per MWh of upwards redispatch energy typically occur when the share of intermittent RES is low, and overall demand is high. In case gas-fired generation is more expensive than coal-fired generation, as is the case since the onset of the European energy crisis in the summer of 2021, this statement does not hold.

Finally, regarding the third research question, we found that the abated emissions from the replacement of an additional MWh produced by fossil-fuel generation by a MWh produced by RES need to be reduced by 0.7-4.5% to account for operational issues in the delivery of the generated electricity by the RES. Such “emission reduction correction factors” might appear still relatively small but are not insignificant. Also, this issue, considering business-as-usual, can be expected to increase in the future with even high penetrations of intermittent RES.

Based on our findings, we ended the paper with regulatory recommendations to reduce the volume of redispatch energy and to make redispatch processes less emitting. The introduction of more spatially granular wholesale prices, preferably also internalizing voltage limits, are a recommendation for the former, while market-based redispatch and a specific new ancillary service for voltage control are recommendations for the latter. Such service would reduce the costs for consumers if the market procurement of this new ancillary service was cheaper than installing additional reactive compensation equipments. In that respect, a social cost benefit analysis of the introduction of the market-based procurement for the Power Potential project, a case study in the UK, indeed found significant savings for end consumers in the range from 8 to 21% of business-as-usual asset costs by 2050 (Anaya and Pollitt, 2022). It is important for regulators to make sure that the current regulatory framework of network operators provides the right incentives to explore such innovative solutions, e.g., rewarding reductions in redispatch volumes and the associated emissions. Important in that regard is that in May 2022, the Spanish Regulator opened a regulatory sandbox to trial an ancillary service for voltage control at the request of the Spanish TSO (CNMC, 2022).

We cannot say at this point whether all our findings can be generalized for other countries. There is a general trend in increasing redispatch volumes over the last decade for all EU countries with increasing penetration of intermittent RES (see e.g., the annual wholesale market monitoring reports by ACER) and we assume that it is highly likely that the redispatched energy could be also more pollutant than the non-redispatched energy in most other countries (with the possible exception of hydro-dominated countries). However, more detailed country case studies are needed to understand whether the drivers behind redispatch volumes and the associated emission are country-specific or can be generalized. Another important future revenue stream is to conduct spatially more granular analysis. The present paper utilized aggregated data for the entire country. However, some issues can be concentrated in specific locations, which would further extend the current analysis.

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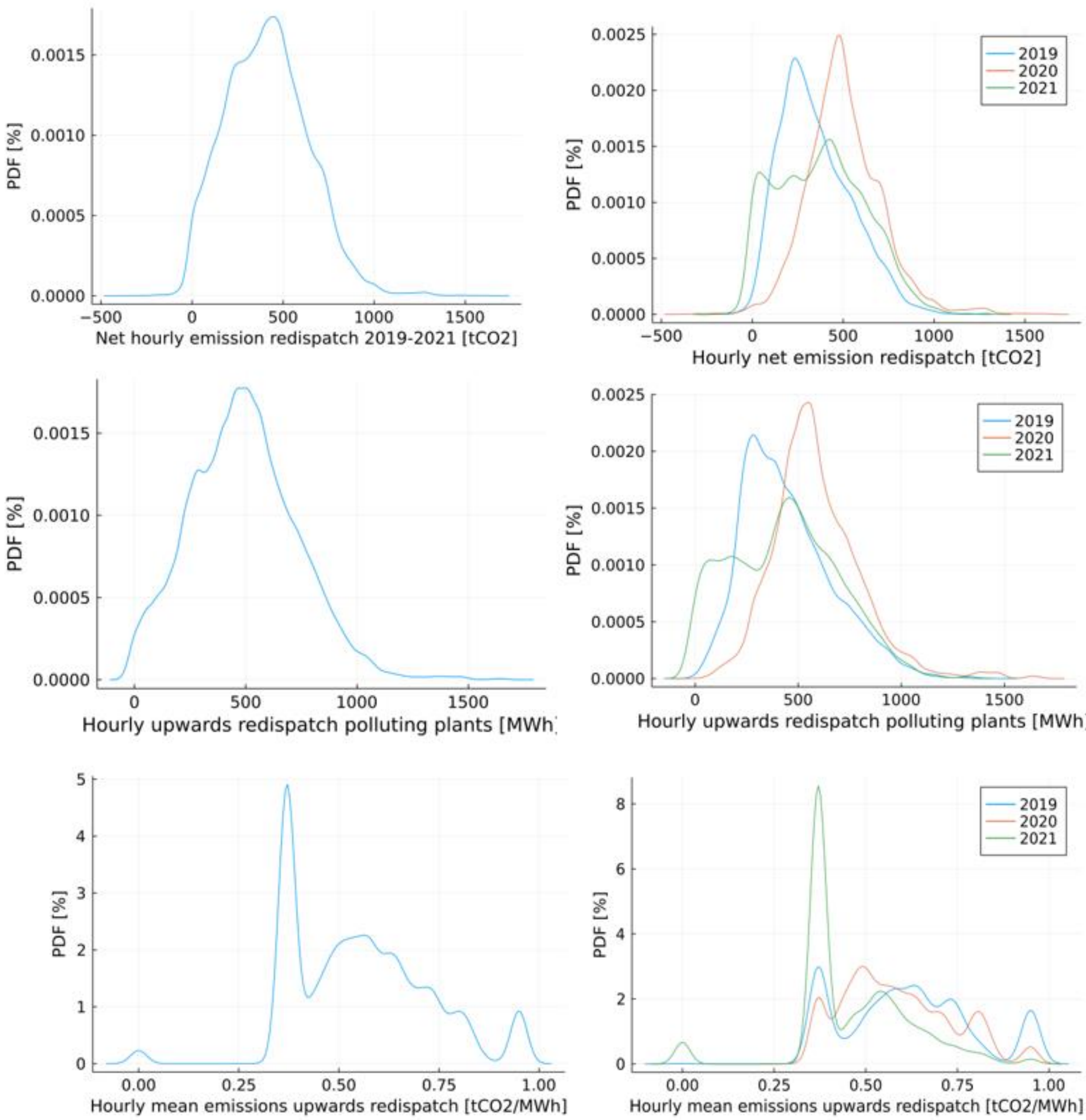
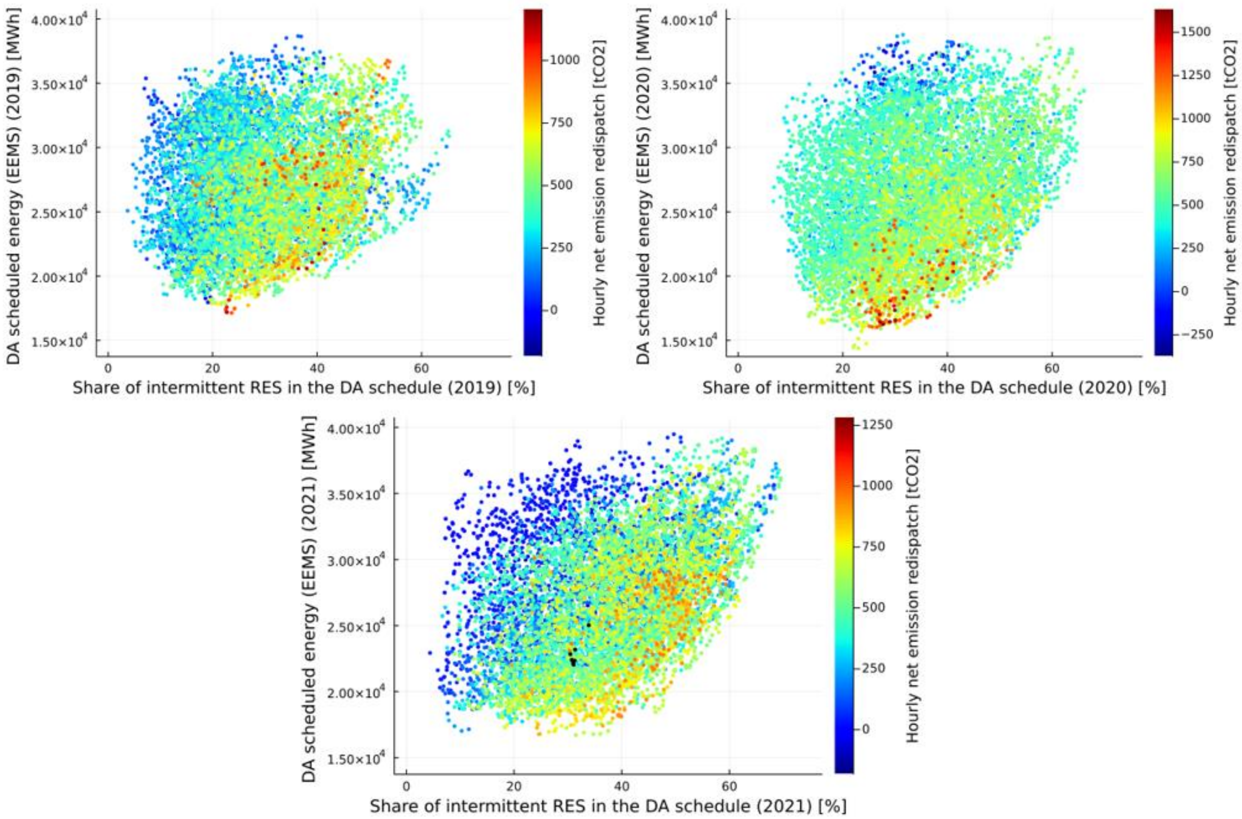
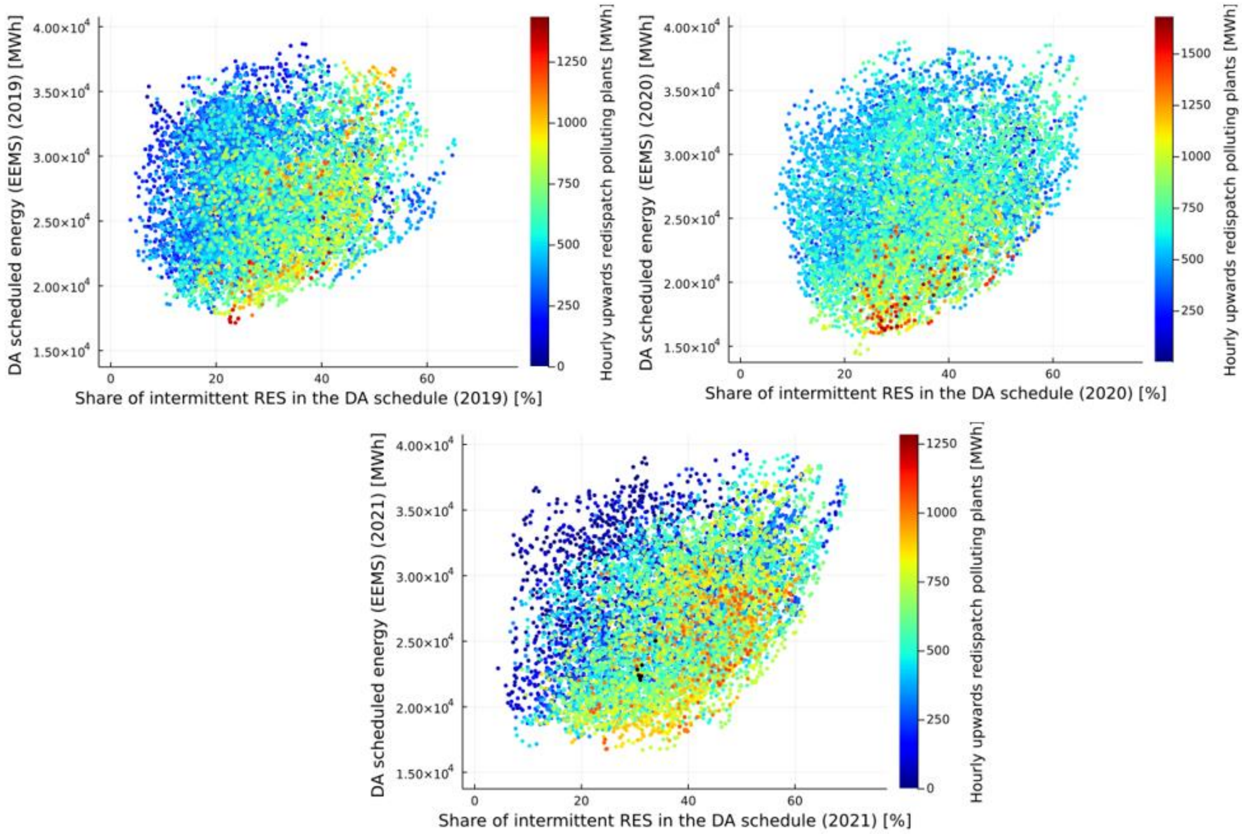
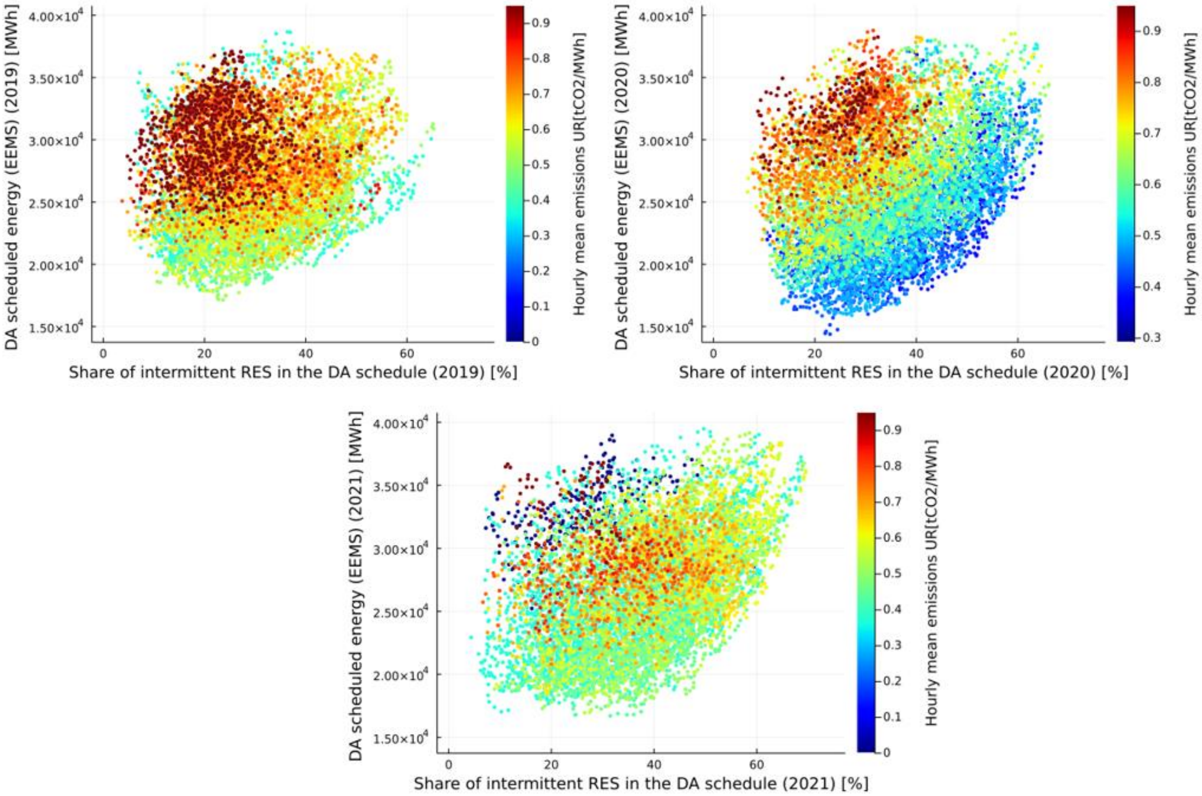
Appendix I: Additional Descriptive Statistics of the Entire Dataset and Yearly Series




DA scheduled energy (EEMS) (2019) [MWh]
Share of intermittent RES in the DA schedule (2019) [%]
Hourly net emission redispatch [tCO2]
DA scheduled energy (EEMS) (2020) [MWh]
Share of intermittent RES in the DA schedule (2020) [%]
Hourly net emission redispatch [tCO2]
DA scheduled energy (EEMS) (2021) [MWh]
Share of intermittent RES in the DA schedule (2021) [%]
Hourly net emission redispatch [tCO2]


DA scheduled energy (EEMS) (2019) [MWh]
Share of intermittent RES in the DA schedule (2019) [%]
Hourly upwards redispatch polluting plants [MWh]
DA scheduled energy (EEMS) (2020) [MWh]
Share of intermittent RES in the DA schedule (2020) [%]
Hourly upwards redispatch polluting plants [MWh]
DA scheduled energy (EEMS) (2021) [MWh]
Share of intermittent RES in the DA schedule (2021) [%]
Hourly upwards redispatch polluting plants [MWh]


DA scheduled energy (EEMS) (2019) [MWh]
Share of intermittent RES in the DA schedule (2019) [%]
Hourly mean emissions UR[tCO2/MWh]
DA scheduled energy (EEMS) (2020) [MWh]
Share of intermittent RES in the DA schedule (2020) [%]
Hourly mean emissions UR[tCO2/MWh]
DA scheduled energy (EEMS) (2021) [MWh]
Share of intermittent RES in the DA schedule (2021) [%]
Hourly mean emissions UR[tCO2/MWh]

Appendix II:

Stationarity Tests

As we are using hourly data, we perform two stationarity tests to our variables: the ADF test (Dickey and Fuller, 1979), and the KPSS tests (Kwiatkowski et al., 1992). Results are shown in Table 11.

Table 11. Stationarity tests of our variables

Variable	ADF test		KPSS test	
	Levels	**differences**	**Levels**	**differences**
$CO2_t$	-27.093***	-163.997***	96.2***	0.000529
$EEMS_t$	-20.640***	-66.817***	9.31***	0.000911
RES_t	-14.203***	-69.543***	9.45***	0.001190
ur_t	-27.965***	-156.431***	82.4***	0.000925
$avCO2_t$	-155.700***	-265.878***	0.0112	0.000020
CC_t	-27.748***	-148.660***	31.4***	0.000794
CO_t	-29.698***	-156.520***	58.3***	0.000269
H_t	-51.439***	-193.990***	39.8***	0.000145
N_t	-40.455***	-167.111***	1.12***	0.000162
PG_t	-58.101***	-185.605***	10.5***	0.000249
PV_t	-35.362 ***	-147.155***	12.6***	0.000213
TS_t	-45.840***	-171.590***	8.93***	0.000130
CHP_t	-50.415***	-187.209***	10.6***	0.000195
B_t	-54.269***	-201.732***	8.4***	0.000151
W_t	-32.430**	-173.341***	97.7***	0.000373

Note: * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Appendix III:

Redispatched Energy from Combined Cycle and Coal

In the Eq. 12 and 13, we calculate how the redispatched energy by combined cycle ($\Delta r_{CC,t}$) and coal ($\Delta r_{CO,t}$) evolve with the day-ahead scheduled energy ($\Delta EEMS_t$).

$$\cdot\, \Delta r_{CC,t} = \beta_0 + \beta_1 \cdot \Delta r_{CC,t-1} + \beta_2 \cdot \Delta EEMS_t + \beta_3 \cdot m_t + \beta_4 \cdot holiday_t + \varepsilon_t \quad (12)$$

$$\cdot\, \Delta r_{CO,t} = \beta_0 + \beta_1 \cdot \Delta EEMS_t + \beta_2 \cdot \Delta r_t + \beta_3 \cdot m_t + \beta_4 \cdot holiday_t + \varepsilon_t \quad (13)$$

Table 12 ML estimations for each year.

	2019 (Eq. 12) $\Delta r_{CC,t}$	**2019 (Eq. 13) $\Delta r_{CO,t}$**	**2020 (Eq. 12) $\Delta r_{CC,t}$**	**2020 (Eq. 13) $\Delta r_{CO,t}$**	**2021 (Eq. 12) $\Delta r_{CC,t}$**	**2021 (Eq. 13) $\Delta r_{CO,t}$**
Scheduled Energy ($\Delta EEMS_t$)	-0.0481****	0.0182****	-0.0504****	0.0188****	-0.0618****	0.0113****
	(0.00106)	(0.000664)	(0.00137)	(0.000650)	(0.00130)	(0.000604)
Holiday ($holiday_t$)	2.308	0.716	2.964	-0.590	4.250	0.680
	(2.799)	(1.758)	(3.973)	(1.698)	(3.910)	(1.596)
Lagged ($\Delta r_{CC,t-1}$)	-0.0470****		-0.0327***		-0.0669****	
	(0.0112)		(0.0103)		(0.0137)	
Lagged ($\Delta r_{CO,t-1}$)		-0.0159		-0.0515****		0.00864
		(0.0132)		(0.0126)		(0.0105)
Constant ($\widehat{\beta_0}$)	127.6****	74.97****	170.4****	76.67****	174.0****	66.24****
	(0.449)	(0.267)	(0.461)	(0.319)	(0.679)	(0.207)
N	8,735	8,735	8,783	8,783	8,759	8,759
Seasonality						
Month	Yes	Yes	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes	Yes	Yes

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

Appendix IV:

Long-Run CO2 Emissions:

The long-term effects for photovoltaics ($CO2_{PV,LT}$) and wind ($CO2_{W,LT}$) are calculated with Eq. 14 and 15, respectively.

$$CO2_{PV,LT=}\beta_7/(1-\beta_1) \qquad (14)$$

$$CO2_{W,LT=}\beta_{11}/(1-\beta_1) \qquad (15)$$

Table 13. Long-term CO2 emissions effects from each technology

	2019	**2020**	**2021**	**Maximum**
Photovoltaics ($CO2_{PV,LT}$)	0.00666	0.01526	0.00209	0.01526
Wind ($CO2_{W,LT}$)	0.00570	0.00692	0.00614	0.00692

For 2019, we consider $\beta_1 = 0$ as the lagged coefficient for this year is not significant at p=0.10 in the column 1 from Table 8.