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E-mail: francesco.colelli@unive.it**Keywords:** SARS-CoV-2, energy, renewable energy, climate changeSupplementary material for this article is available [online](#)**Abstract**

COVID-19 lockdowns make it possible to investigate the extent to which an unprecedented increase in renewables' penetration may have brought unexpected limitations and vulnerabilities of current power systems to the surface. We empirically investigate how power systems in five European countries have dealt with this unexpected shock, drastically changing electricity load, the scheduling of dispatchable generation technologies, electricity day-ahead wholesale prices, and balancing costs. We find that low-cost dispatchable generation from hydro and nuclear sources has fulfilled most of the net-load even during peak hours, replacing more costly fossil-based generation. In Germany, the UK, and Spain coal power plants stood idle, while gas-fired generation has responded in heterogeneous ways across power systems. Falling operational costs of generators producing at the margin and lower demand, both induced by COVID-19 lockdowns, have significantly decreased wholesale prices. Balancing and other ancillary services' markets have provided the flexibility required to respond to the exceptional market conditions faced by the grid. Balancing costs for flexibility services have increased heterogeneously across countries, while ancillary markets' costs, measured only in the case of Italy, have increased substantially. Results provide valuable evidence on current systems' dynamics during high renewables' shares and increased demand volatility. New insights into the market changes countries will be facing in the transition towards a clean, secure, and affordable power system are offered.

1. Introduction

Despite the increase in the residential electricity demand of nearly the entire world population spending more time at home, lockdown measures to cope with the COVID-19 pandemic have resulted in an unprecedented drop in total electricity demand (Buechler *et al* 2020, Prol and Sungmin 2020). Across European countries, electricity demand during the 1st lockdown phase has fallen on average by 10%–15% (Chen *et al* 2020, Cicala 2020, McWilliams and Zachmann 2020, Narajewski and Ziel 2020).

The shock induced by the governments' response to the pandemic has occurred at a time of struc-

tural transformation of national power systems. Since the 2008–2009 global financial crisis, variable renewable energy source (RES) capacities have been picking up, and today more than 50% of the newly installed capacity for electricity generation consists of RES (Figueres *et al* 2018). Newly installed RES capacity grew more than 200 GW in 2019, its largest increase ever (Murdock *et al* 2020).

The ongoing changes in electricity load and generation during COVID-19 have been documented, showing how all regions implementing lockdown measures have undergone a noticeable shift towards low-carbon sources (Bahmanyar *et al* 2020, IEA 2021, Prol and Sungmin, 2020). RES have gained a

higher share following the sudden fall in electricity demand.

These sources have near-zero marginal costs and, in Europe, are legally prioritized over fossil fuels thanks to priority dispatch connection terms⁶ (Oggioni *et al* 2014). As a result, the uptake of RES and the reduction in fossil-fuel-based generation have temporarily contributed to reducing emissions (Le Quéré *et al* 2020). The sudden decarbonization and the resulting reduction in carbon emissions from power generation experienced during the COVID-19 lockdowns is nevertheless a temporary phenomenon induced by the unprecedented fall in the net-load. It is unlikely for any country to fully decarbonize the power sector by simply reducing electricity demand, especially due to the trend of electrification that would potentially increase electricity demand in the future (Riahi *et al* 2017, Zhang and Fujimori 2020).

However, insights can be drawn from understanding how power systems have reacted under a generation mix composed predominantly by RES. Understanding the characteristics of power systems in which RES could easily account for 100% of the power demand in a given hour of the day may bring to the surface possible limitations of the current power systems, leading to volatility in power prices and possibly to higher costs for managing the grid. Furthermore, the high overcapacity experienced during the lockdowns can provide insight into the risks of business case deterioration of specific types of generation (fossil-based, dispatchable) and inform future systems' characteristics regarding flexible backup capacity mechanisms (Caldecott and McDaniels, 2014).

Our contribution advances the understanding of how different features of the power systems studied have shaped their reaction and performance during the COVID-19 lockdowns, as well as before and after the relaxation of the containment measures. The majority of the literature evaluating the impact of high RES penetration on the power systems are based on system modeling (Hammons 2008, van Hout *et al* 2014, Newbery *et al* 2018), inherently relying on assumptions and stylized mechanisms.

The contribution of this paper is built on a narrow but growing empirical literature assessing power systems' stability through the use of high frequency data collected during extreme conditions (Brijs *et al* 2015, Joos and Staffell 2018) and on the rapidly developing literature assessing the impacts of COVID-19 lockdowns through empirically grounded counterfactual scenarios (Graf *et al* 2020, Granello *et al* 2020).

We develop a suit of econometric models to represent different aspects of the power systems, exploiting the real data offered by the natural experiment of very high RES penetration collected by Transmission System Operators (TSOs) during the COVID-19 1st lockdown phase. Then, we use such models to reproduce power systems' characteristics in a business-as-usual scenario (counterfactual) during the 1st and 2nd quarter of 2020. Finally, we identify the causal effect of the lockdowns by computing the difference between the observed and counterfactual values (i.e. the prediction errors). We separately evaluate the ability of the models to predict our dependent variables in two out of sample periods: (a) in the months preceding the lockdowns and (b) in the months during, and following, the lockdowns. We analyze the five biggest European economies: France, Germany, Italy, Spain, and the UK, which have been heavily affected by the ongoing pandemic and account for two-thirds of installed renewable power capacity in the EU28 (IRENA 2020).

First, we focus our attention on how the combination of demand shocks and high RES generation reduced net-load demand and thus impacted on the generation schedule of dispatchable generation technologies⁷. COVID-19 lockdowns' influence on power markets' equilibrium results from the interaction between demand and the supply side, which is determined by the sequence in which power plants with different marginal costs contribute to generation (the merit order). When the demand curve shifted downwards during the lockdowns, the intersection between demand and supply shifted too, pushing power plants operating at a marginal cost above the new equilibrium price out of the market. This analysis allows us to investigate both the impact on hourly operations of power generators and the overall variation in the carbon intensity of the dispatchable generation mix.

Second, we investigate how electricity price fluctuations have reflected variations in the market equilibrium during COVID-19 lockdowns, as conventional generation technologies in Europe play a dominant role in setting wholesale prices as they meet the net-load, i.e. residual demand not satisfied by renewable sources (Weber 2006, Sensfuß *et al* 2008, Gelabert *et al* 2011, Pollitt and Chyong 2018). The lockdowns have remarkably reduced average wholesale electricity prices by as much as 45% in Italy (Graf *et al* 2020), while the pan-EU average of day-ahead baseload prices reached a low of 24 € MWh⁻¹ in the 2nd quarter of 2020, down 44% year-on-year (EC 2020). The reasons behind this fall are to be found in the contemporaneous occurrence of low fossil fuel and carbon allowance prices during the

⁶ The renewable energy directive 2009/28/EC lays down that member states shall ensure that, priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources shall be safeguarded.

⁷ Across the paper we use the concepts of demand, total load and transmission load interchangeably.

lockdowns (IEA 2020, Abadie 2021) as well as from the lockdown-induced demand fall. We quantify the impact of COVID-19 induced shocks on the day-ahead electricity markets by tracing the evolution of hourly wholesale electricity prices. We decompose the impact of COVID-19 on wholesale day-ahead prices between the shocks on (a) demand and (b) fossil generations' operation costs, a novel addition to the available literature.

Finally, we turn our attention to the balancing markets managed by TSOs. The fall in demand and the resulting change in the generation mix affected the task of balancing the electricity systems. In Italy, for instance, the weeks of lockdowns were associated with an increase in the costs incurred for ancillary operations (Graf *et al* 2020). During COVID-19 lockdowns, exceptional conditions were registered to accommodate the larger-than-usual demand forecast errors, that is the deviation between the day-ahead forecast and the actual demand. Both sources of uncertainty might have required more upward and downward flexibility. In particular, the occurrence of high demand forecast errors can be considered an interesting experiment comparable to a situation where shocks of similar magnitude would occur due to very high RES penetration, as both increase the size of the net-load forecast errors. In other words, we investigate whether TSOs are able to deal with an intensification of the existing demand/supply shocks when net-load becomes more difficult to predict and the errors become larger, both in absolute terms and in relative terms compared to the total net-load (i.e. experiencing more volatility due to the stochastic unpredictability of RES and demand). A comparison across countries is particularly informative as differences in the baseload mix may result in different levels of systems' incompressibility (i.e. lack of downward flexibility), due to the different start-up and ramping costs (Brijs *et al* 2015).

2. Methods

Containment measures have taken different degrees of stringency across Europe, sometimes with regional differentiations. For the purpose of cross-country comparability, we classify the nation-wide measures used at the time of writing in five categories ('school closure', 'domestic curfew', 'commerce halt', 'commerce halt—partial', 'non-essential activities halt', see supplementary table S1 (available online at stacks.iop.org/ERL/16/064018/mmedia)). We investigate the propagation of the shocks induced by the COVID-19 lockdowns to the power sectors with hourly data from the 1st of January 2017 to the 27th of July 2020. Our power sector data source is the European Network of TSOs for electricity (ENTSO-E 2021). We exclude weekends and bank holidays from the main analysis (supplementary figure S2 presents a

comparison of the demand shocks between weekends and weekdays).

We disentangle the contribution of factors contextual to the unprecedented shock by developing a set of econometric models that make it possible to estimate different counterfactual scenarios in which the COVID-19 induced shock does not occur for the: (a) electricity load and renewable generation's share in the power mix (b) the capacity factor of dispatchable technologies, their share in the dispatchable generation mix and the resulting carbon intensity of the dispatchable generation mix; (c) wholesale day-ahead prices (d) balancing markets' costs (see supplementary tables S2–S8). For each combination of dependent variable and country, we test alternative specifications based on polynomials of the key explanatory variables, and we select the best model based on the residual mean square error (RMSE) and the Akaike information criterion. We train the models on working days, hourly data from January 2017 to December 2019. We then assess the predictive power of the model by using out-of-sample data from January 2020 to July 2020. The out-of-sample period is further split between: (a) the observations preceding the lockdowns (January to March or April, depending on the country); (b) the days of lockdown as defined in supplementary table S1. We separately evaluate the ability of the models to predict hourly prices in the two out-of-sample periods by computing the RMSE (see supplementary results and supplementary table S9).

2.1. Electricity load and RES generation

The model adopted to study the behavior of electricity load and renewables' share in the generation mix is based on weather and other seasonal effects, such as the time of the day and day of the week. We isolate the effect of the co-occurrence of seasonal variations in the weather by using daily records of maximum temperature, solar irradiance, and wind speed (NOAA 2020a, 2020b). Actual total load is defined as the sum of power generated by plants on TSOs networks, from which the balance (export–import) of exchanges on interconnections between neighboring bidding zones and the power absorbed by energy storage resources is deduced. The total load represents the power demand on the transmission and distribution networks, while any power demand served by distributed networks is not included in the statistics. This aspect influences our measure of the total load, reducing it at times of high generation of renewables in distributed networks. We take such effect into account by performing a set of alternative econometric specifications of the power demand model including daily solar irradiance as a control for distributed energy.

2.2. Dispatchable generation

We construct a counterfactual scenario in which the COVID-19 induced net-load shock does not occur to

estimate: (a) the total capacity factor of dispatchable technology n at hour h ($CF_{h,n}$); (b) the share of technology n in the dispatchable generation mix ($S_{h,n}$):

$$CF_{h,n} = (G_{h,n}) / C_{y,n} \quad (1)$$

$$S_{h,n} = \left(G_{h,n} / \sum^n G_h \right) \quad (2)$$

where: C is capacity, G is generation of dispatchable technologies, n technology; h is hour, and y is year.

With the 1st variable we evaluate how the demand shock resulting from the COVID-19 lockdown impacts dispatchable technologies' absolute contribution to the power system. The variable measures the share of the total systems' capacity that is generating in each hour of the day over the total available capacity installed in a given year. With the 2nd variable we evaluate the impact of the demand shock on dispatchable technologies' relative contribution to the power system. We evaluate the share of each dispatchable technology in the dispatchable generation mix, as opposed to the total generation mix (including non-dispatchable technologies, amongst which RES), to focus on dispatchable technologies' contribution to system net-load.

The econometric model adopted to study the behavior of hourly dispatchable generation and day-ahead prices includes three explanatory variables: (a) the hourly non-dispatchable renewable generation available on the grid⁸; (b) a linear spline of maximum temperature bins to approximate seasonal demand; (c) a proxy measure of operative costs for fossil fuel generators (OC_d^{tech}). Further controls include calendar effects (see supplementary methods).

The OC_d^n are computed as the combination of the daily spot price of fossil fuels (p_d^n) and the daily European Emission Allowances' price (ets_d) multiplied by the country-specific power plants' emission intensity (eff^n). Our proxy measures the incentives for fossil fuel generators to bid in the day-ahead market, as this is the cost-component of the 'clean spark spread' for gas and 'clean dark spread' for coal, defined as the difference between market prices of

electricity ($p_h^{\text{ely,ahead}}$) and power plants' unitary operative costs (Abadie 2020):

$$OC_d^n = p_d^n + eff^n \times ets_d \quad (3)$$

$$SPARK_d^n = p_h^{\text{ely,ahead}} - OC_d^n \quad (4)$$

where d : day; h : hour; n : fossil fuel (gas, coal).

2.3. Wholesale electricity prices

Day-ahead prices result from the day-ahead auction markets, which host most of the electricity sale and purchase transactions (Gestore Mercati Elettrici—GME 2020). In these markets, hourly energy blocks are traded for the next day and offers are accepted based on the economic merit-order criterion and taking into account transmission capacity limits. Actual spot prices on the other hand result from the intraday market and are based on unit price differentials from the day-ahead price. In both cases the price is determined, for each hour, by the intersection of the demand and supply curves. The clearing prices are influenced by the bids of the thermoelectric plants that are selected as the marginal units. Furthermore, if the net-load is reduced (due to an increase in non-dispatchable renewable energy or to a demand reduction), the thermoelectric plants with higher marginal costs will be cut out from the market and consequently the clearing market prices will fall. Negative prices can arise under conditions of high supply from solar power plants or wind turbines, which have near-zero marginal costs, due to a combination of factors: while low-cost RES are typically not incentivized to reduce production as they receive a market premium in addition to the wholesale market price for each unit of electricity generated⁹, the most inflexible fossil-based generators accept negative prices due to the high costs of performing shutdown re-start sequences (Clò et al 2015, Fanone et al 2013).

The contemporaneous occurrence of (a) low fossil fuel prices and carbon allowance prices (IEA 2020, Abadie 2021), (b) variations in RES generation, and (c) lockdown-induced demand reductions requires a methodological framework that can disentangle the price effect (a) from the supply and demand effects (b + c). Methodologies that filter out the effect of the COVID-19 induced shock on fossil fuel prices would provide a more plausible counterfactual scenario to evaluate power systems' reactions to the extreme net-load variations¹⁰. We decompose the impact of

⁸ We assume that the quantity of non-dispatchable renewable generation available is unaffected by the lockdowns. Despite wind and solar generation being dictated by weather, our assumption may not hold if some projects might have been faced with curtailment due to the low demand and overcapacity. Furthermore, subsidy free merchant projects operating in the UK, Spain and Germany may have responded to the low prices and stopped operating. We use the forecasted renewables' generation rather than the actual generation in order to provide a robustness check to the exogeneity assumption. Given the relatively small share of subsidy-free projects on the overall installed non-dispatchable renewables' capacity, we assume that the displacement of non-dispatchable renewable generation is not sufficiently large to affect market prices.

⁹ The lack of incentives to turn down production is particularly relevant when periods of oversupply are of limited length. In order to introduce an incentive to react to market oversupply, in Germany the '6 h rule' stops support payments to wind farm operators if wholesale day-ahead electricity prices go negative for more than 6 h.

¹⁰ In doing so, we evaluate the market fundamentals rather than the system fundamentals, as we are not looking at the functioning of

COVID-19 on wholesale day-ahead prices between (a) demand shock and (b) fossil fuel price drops. While the intra-day spot prices may convey a clearer signal of market interactions, as it better reflects the tightness of the market (leading to higher highs and lower lows in the electricity price)¹¹, data availability constrains the analysis to the day-ahead price only (see supplementary methods)¹².

2.4. Balancing

Balancing systems are used to maintain and restore the short-term active power balance in integrated electricity systems. They are based on a balancing power market through which TSOs acquire balancing power and an imbalance settlement system that financially clears the imbalances (Gestore Mercati Elettrici—GME 2020). Balancing power is only demanded by the TSOs, hence it is a single-buyer market. The TSO acts in two steps: (a) it contracts reserve capacity from conventional power units in the day-ahead market; (b) it activates in real-time part of the contracted quantities to cover system imbalances. Upward reserves (due to power deficits) are purchased by the TSO at a given ‘upward price’ which is normally higher than the day-ahead market price, as it reflects not only the increasing marginal cost of production, but also a premium for the flexibility of the generators (Clò and Fumagalli 2019). Downward reserves (due to power surpluses) are activated when the TSOs sell back the excess of energy to flexible generators already sold in the market, at a price that represents the saved operating costs (and are therefore normally lower than the day-ahead market price). Nevertheless, under conditions of large scarcity of downward reserves, downward flexibility providers may bid positive activation prices in order to be paid for the service, leading to negative imbalance prices (Brijs *et al* 2015). Even in the case of downward reserve prices the market imbalances generate a ‘system cost’, as end-users are not made whole for the energy not consumed (Clò and Fumagalli 2019). Therefore, we consider both costs due to deficits and surpluses as positive ‘system costs’ and compute the

the market but the ability of the dispatchable capacity mix to adapt to the shock and how this impacts the market (prices). We are not looking at the functioning of the market under these circumstances (for example, whether the markets provide sufficient incentives to adapt to the net-load shock or to react to variable RES and forecast errors).

¹¹ Furthermore, spot prices in the five European countries considered are influenced by cross-border intraday trade, based on a common information technology system that allows orders entered by market participants in one country to be matched by orders similarly submitted by market participants in any other country within the project’s reach as long as transmission capacity is available (ENTS-E 2019).

¹² As the price within a country is differentiated from zone to zone, we adopt the average of the day-ahead prices of sub-national geographical zones, weighted for the quantities purchased in these zones, reported by national TSOs (ENTSO-E 2021).

overall total incurred for balancing purposes over the day.

Other ancillary services excluded from the balancing systems are reactive power compensation and transmission congestion management. These can constitute a large part of the grid costs related to the management of the volatility in RES supply (Hirth and Ziegenhagen 2015).

We gather data from ENTS-E and national TSOs for: (a) balancing markets in Germany, France, United Kingdom and (b) the expenses on the ancillary services’ markets in Italy¹³. Therefore, for Germany, France and the United Kingdom we consider only a part of the short-term integration costs of variable renewable energy, namely balancing costs, while we are able to include a larger set of grid management costs for Italy. The lack of data availability on the Spanish system’s hourly balancing costs in 2020 resulted in the exclusion of the country from the analysis. Our econometric model considers the daily balancing costs (BC_d), computed as the daily sum of all hourly expenses incurred in the real-time balancing market (BEX_d) over the daily total actual load (AL_d) as the dependent variable. The variable is therefore a direct measure of the balancing costs incurred by the consumers, expressed in € MWh^{-1} :

$$BC_d = \frac{\sum_h BEX_h}{AL_d}. \quad (5)$$

The explanatory variables include: (a) the quantities traded over the day in the balancing market (i.e. the total imbalance requirement); (b) the day-ahead wholesale prices; (c) the day-ahead net-load; (d) the capacity factor of each dispatchable generation technology (see supplementary methods). It is important to include day-ahead wholesale prices and the day-ahead net-load as controls as low prices influence market dynamics because thermal generation facilities may turn to the ancillary services instead of the day-ahead market (Graf *et al* 2020). Further controls include calendar effects. The same model is adopted to study the costs of balancing and ancillary services’. We test a set of alternative model specifications where the influence of the key dependent variables is assumed to be either linear, quadratic or cubic. The inspection of the difference between the model-based counterfactual estimates and the observed balancing costs provides an indication of how much the balancing markets have been affected by unusual market conditions which cannot be captured by the market-based variables we include in the econometric model. Our approach is motivated by recent empirical evidence on the Italian re-dispatch markets during COVID-19 lockdowns, showing that observed

¹³ Data provided by Terna. Data includes the expenses incurred by Terna on the Ancillary Services Market, including system relief of intra-zonal congestions, creation of energy reserve and real-time balancing.

ancillary services' costs during the lockdown have been higher than model-based estimations, likely due to new offer strategies or additional operating constraints (Graf et al 2020).

3. Results

3.1. Increase in RES penetration due to the fall in power load

The power system has rapidly responded to COVID-19 lockdowns, when electricity demand was plummeting with the intensification of restrictions' stringency across all countries. Compared to the counterfactual demand that would have occurred in the absence of the COVID-19 lockdowns, the drop in average daily transmission load has increased with the intensification of restrictions across all countries, but especially in Italy and Spain (supplementary figure S1, panel (a)). The 'commerce halt' and 'commerce halt-partial' policies reduced electricity load on average by 10%–15% across the five European countries analyzed. Further stopping all non-essential production activities, resulted in an average reduction of 25% in Italy (surpassing 30% at the onset) and of 22% in Spain (supplementary figure S1, panel (b)). Inspection of the hourly load profile (supplementary figure S1, panel (c)) reveals that all countries experienced a fall in demand from 5 am to 10 pm, with the highest negative spikes around the morning (7–8 am) and evening (6–7 pm) peaks. Higher-than usual domestic activities between 12am and 3pm have compensated the industrial and commercial drops to some extent, leading to smaller reductions. This effect is particularly strong in France, Spain and Italy, suggesting that sectoral responses have differed across countries, possibly depending on different production and consumption behaviors. Going beyond speculation, however, would require the analysis of more granular data, e.g. electricity demand by certain sectors (households, industrial, and commercial).

The fall in the power load has resulted in an upward shift of RES penetration rates in all countries, although the magnitude varies depending on the power system (figure 1). On average, RES have contributed up to 60% of total active generation in Germany (an additional 15% point increase compared to the counterfactual mean shares), around 50% in Italy and Spain (an additional 5%–10% point increase), up to 40% (an 8% point increase) in the United Kingdom and up to 20% in France (3%–5% point increase). A clearer picture of the remarkable increase in RES penetration can be assessed by inspecting the maximum share of RES generation observed during the lockdown phases: RES contributed a maximum of 76% of total active generation in Germany, 60%–70% in Spain, Italy and the United Kingdom and 40% in France.

Lockdowns have shifted the average contribution of solar energy up by 8%–15% points across all countries except in France (where they were up only by 2%–3% points), during the central hours of the day. As a result, the average hourly share in the mix has ranged from 20% in Spain to 40% in Germany. The impact on wind generation resulted in a smaller absolute change (with the exception of Germany), as wind contributed relatively little or during the hours in which net-load dropped less (night-time). The share of non-dispatchable hydropower has increased by roughly 5% points during evening peaks and night hours in all countries except the UK, where the technology's contribution to the mix is limited. The 1st direct impact of RES contributing up to 60%–70% in power generation due to the COVID-19 demand shocks can be assessed by looking at power generation's market equilibrium, resulting in a reduction of the dispatching of power plants operating at the margin, sharp modulations of the generation mix, and downward pressure on wholesale prices.

3.2. Changes in the profile of dispatchable generation

We compare the counterfactual capacity factor with the observed hourly mean values during the lockdown phase across countries (we focus our results on the two most stringent lockdowns, the 'commerce halt' lockdown phase in figure 2 and supplementary figure S5 and the 'non-essential activities halt' in supplementary figures S6 and S7). The difference between the observed and counterfactual mean hourly capacity factor of the technologies corresponds to the estimated impact of the net-load shock on the contribution of each technology to the power system in each country (supplementary figure S4). A negative (positive) estimated impact means that the total capacity factor has decreased (increased) with respect to the counterfactual scenario without the COVID-19 induced net-load shock. A decrease (increase) in the total capacity factor means that a smaller (larger) share of the technology's total available capacity contributed to the power system compared to the counterfactual scenario. The change in the curvature of the line through the hour of the day signals that the technology is ramped up/down for flexibility purposes and is used mostly to accommodate peak loads. The variation of the estimated impact on the capacity factor throughout the day is an indication of the extent to which the net-load shock influenced the ramping requirements of each technology. This can signal the extent to which technologies were able to adjust to the circumstances and contribute to the power system alongside a relatively high share of RES to fulfill load requirements. Such a time-varying capacity factor characterizes all technologies with the exception of nuclear-based generation, which exhibits a uniform shape through the hours.

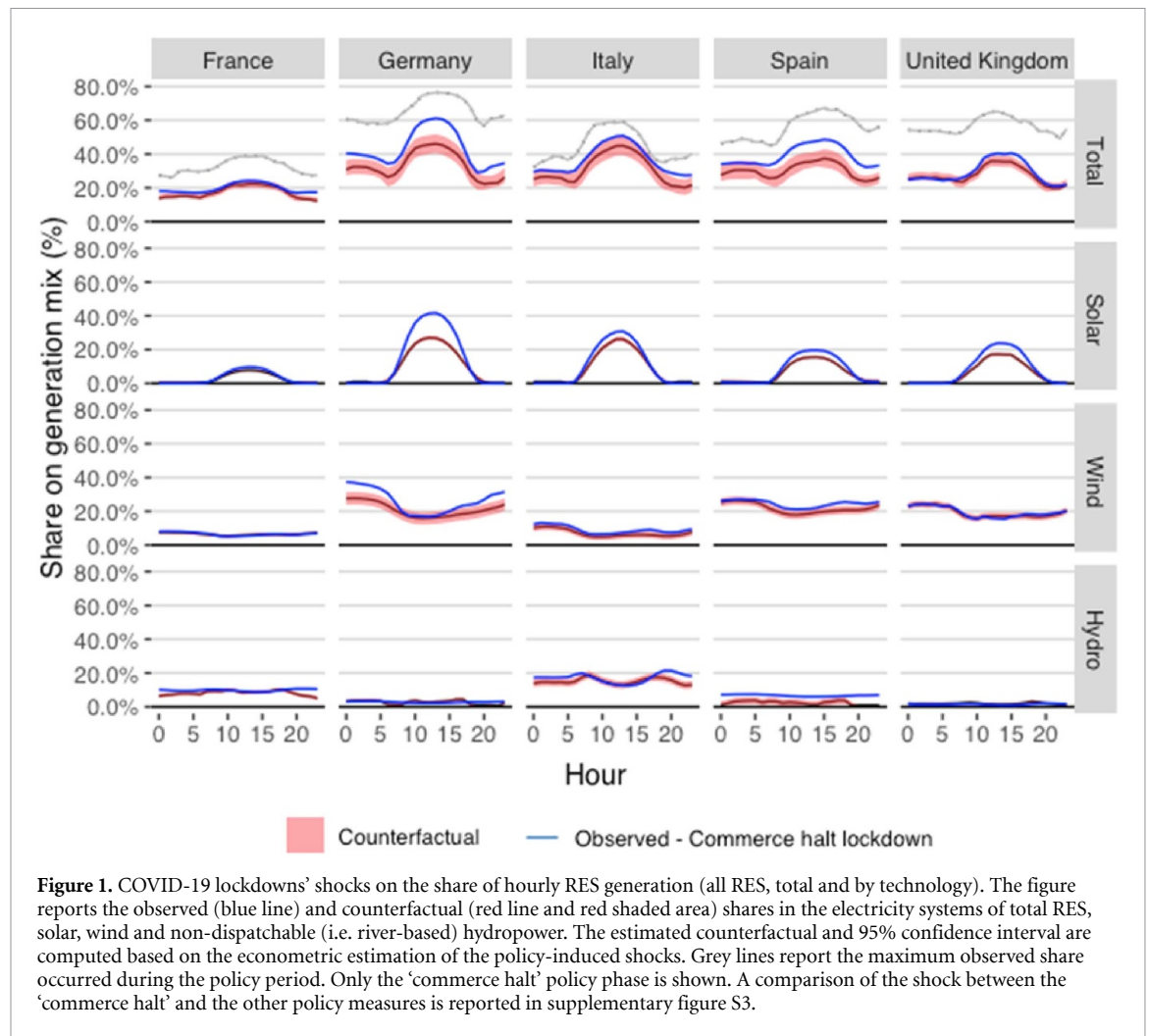


Figure 1. COVID-19 lockdowns' shocks on the share of hourly RES generation (all RES, total and by technology). The figure reports the observed (blue line) and counterfactual (red line and red shaded area) shares in the electricity systems of total RES, solar, wind and non-dispatchable (i.e. river-based) hydropower. The estimated counterfactual and 95% confidence interval are computed based on the econometric estimation of the policy-induced shocks. Grey lines report the maximum observed share occurred during the policy period. Only the 'commerce halt' policy phase is shown. A comparison of the shock between the 'commerce halt' and the other policy measures is reported in supplementary figure S3.

Among the power plants activated through the day, four alternative effects associated to the COVID-19 measures can be identified: (a) temporary phase-out; (b) partial market exit; (c) increase in flexibility requirements; (d) unaffected by market competition.

(a) Temporary phase-out: if the observed capacity factor has reached values around zero with respect to the counterfactual curvy shape, the technology has been cut out from the market. In this case the technology was likely to operate mostly as a marginal technology during demand peaks in the counterfactual and was hence sharply affected by the fall in demand induced by COVID-19 measures. Coal's capacity factor observed during the lockdown was much lower compared to the counterfactual scenario, meaning that the entire coal fleet in Germany, United Kingdom, France and Spain stood idle during the observed period instead of otherwise being activated at capacity factor ranging between 10% and 40%, depending on the hour of the day. As a result, the observed share of coal on the dispatchable generation mix fell to around 1%–2% in Spain, 5%–7% in Germany, as opposed to counterfactual shares ranging between 15% and 20% (supplementary figure S5).

(b) Partial market exit: if the observed capacity factor is both above zero and lower with respect to the counterfactual's shape, the technology has been only partially displaced from the market. Our estimates suggest that there has been both a fall and a flattening throughout the day of the capacity factor of the gas fleet in Spain and of the coal fleet in Italy, possibly indicating that only a part of the fleet has been pushed out of the market altogether, while the more efficient plants remained in the market to actively contribute to baseload but not flexibility. In Italy a small share of the coal fleet remained active during the COVID-19 induced net-load shock with roughly 20% of available capacity actively contributing to the power system compared to up to 50% of the capacity in the counterfactual scenario. On the other hand, the fall in the capacity margin coupled with a preservation of the ramp-up/ramp-down profile of the lignite fleet in Germany and gas fleet in the UK suggests that part of these fleets continued to provide both baseload and peak-time power¹⁴.

¹⁴ The lack of flexibility from high shutdown and restart costs is typically larger for lignite-fired plants than for coal-fired plants (Gonzalez-Salazar et al 2018). This effect is confirmed by the fact

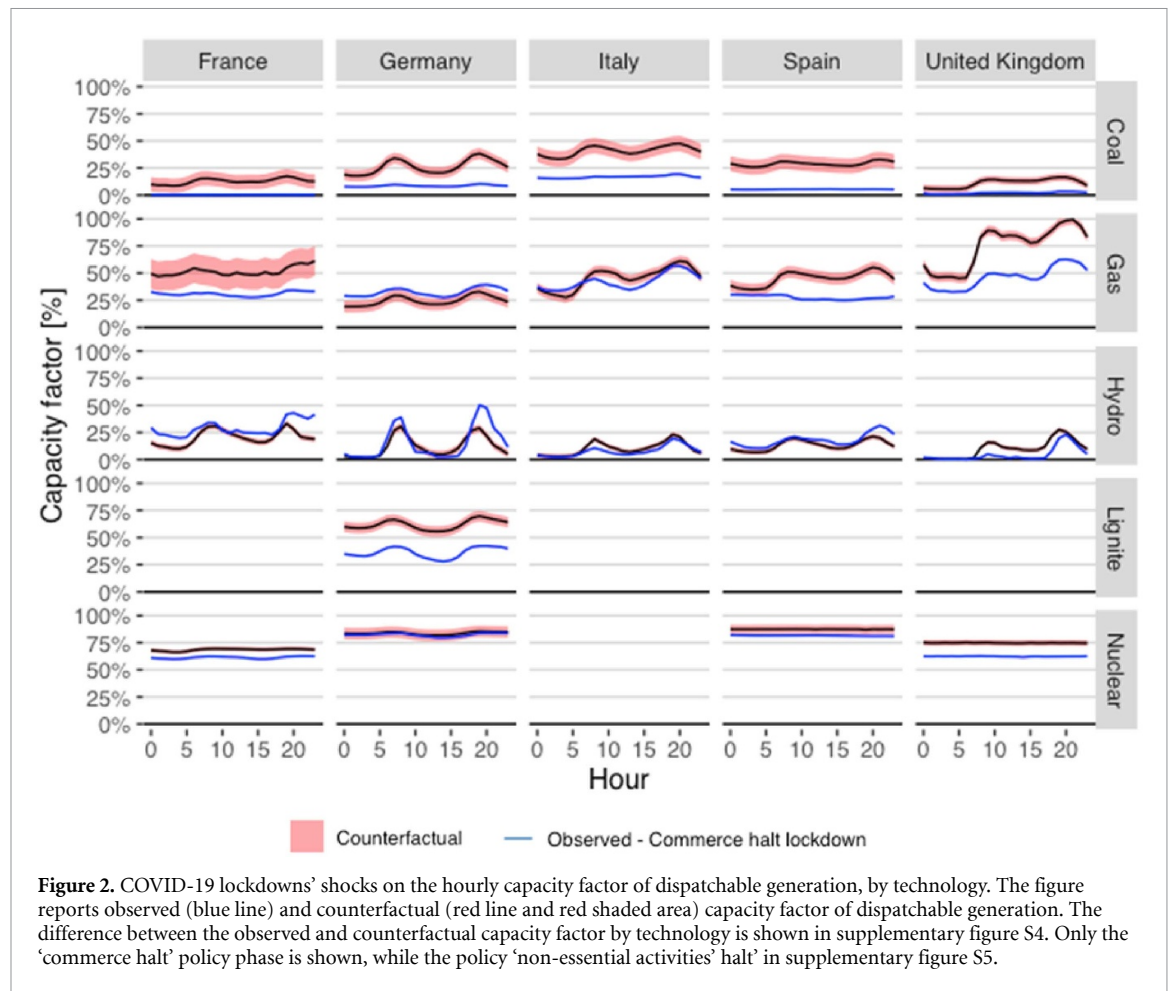


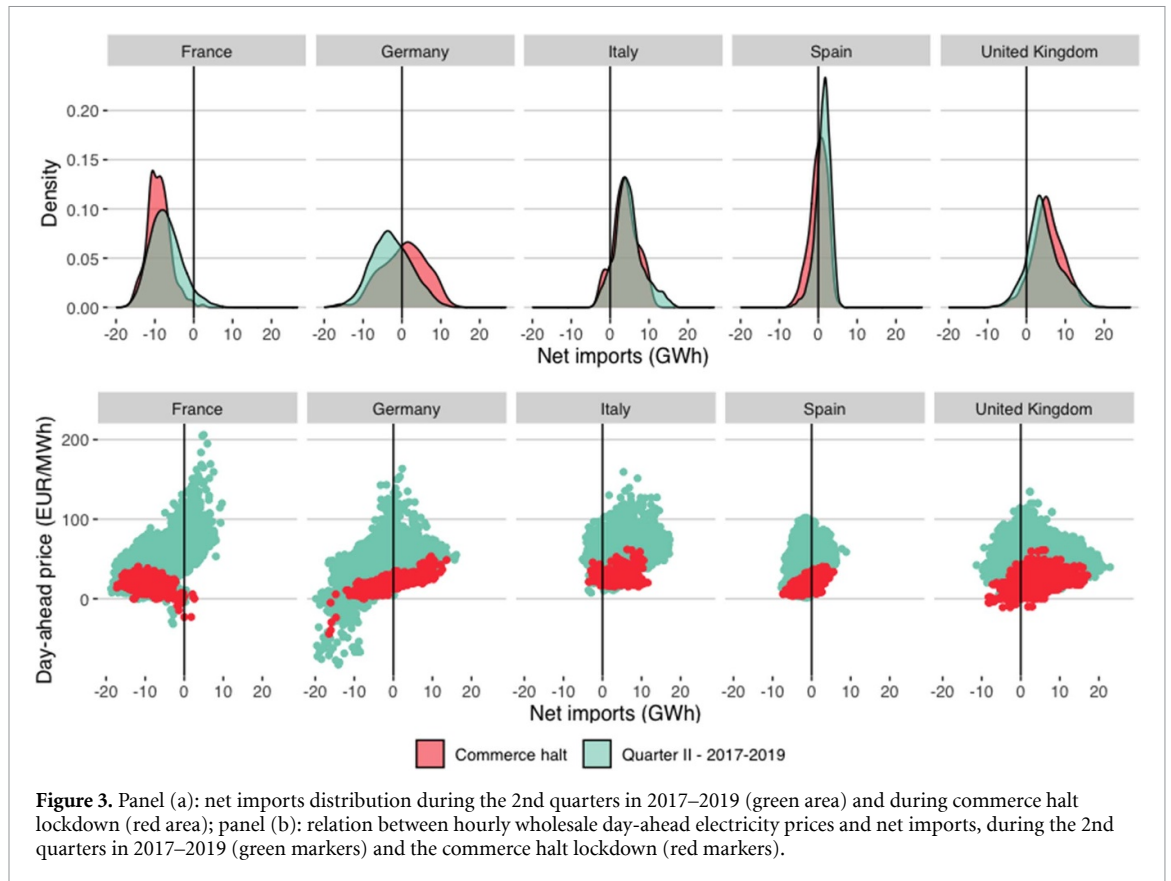
Figure 2. COVID-19 lockdowns' shocks on the hourly capacity factor of dispatchable generation, by technology. The figure reports observed (blue line) and counterfactual (red line and red shaded area) capacity factor of dispatchable generation. The difference between the observed and counterfactual capacity factor by technology is shown in supplementary figure S4. Only the 'commerce halt' policy phase is shown, while the policy 'non-essential activities' halt' in supplementary figure S5.

(c) Increase in flexibility requirements: more flexible technologies could fulfill market requirements without being cut out from the market, as opposed to cases (a) and (b), due to their lower marginal costs: this is the case of gas-fired generation in Germany (capacity factor increasing uniformly throughout the day by an additional 10% points) and in Italy (capacity factor mostly stable during peak hours and decreasing by 5% points during off-peak hours). Hydropower's flexibility has been considerably exploited due to the net-load shock in Germany, France and Spain, while it has remained stable in Italy. The technology has been used relatively less due to the net-load shock in the United Kingdom, where nonetheless it contributes only to a marginal (<3%) fraction of the dispatchable mix.

that in Germany the difference between the minimum and maximum counterfactual capacity margin during off-peak/peak times is larger for coal than for lignite (figure 2). This difference can be a factor explaining why more flexible coal power plants found more profitable to turn down production during lockdowns, as opposed to less flexible lignite power plants. During the lockdowns part of the lignite-fired fleet continued to operate with different capacity margins throughout the day. For each technology, a capacity margin varying throughout the day can derive from the operations of few flexible plants, while the rest of the fleet may be less flexible (i.e. characterized by higher ramp up/down costs).

(d) Unaffected by market competition: if the observed capacity factor is equal or slightly lower than the counterfactual and with the same overall shape, the technology has likely not been affected by the reduction in power demand leading to higher competition from renewables. A lower than usual capacity factor in this case might be the result of operational and maintenance complexities caused by the lockdowns' disruptions on workers' rather than by competition with other forms of generation (Farrar *et al* 2020). This is the case of nuclear power, as the technology's observed capacity factor is slightly lower than the counterfactual one in the UK, France and Spain, while it remained stable in Germany. Overall, the decreases in nuclear generation have been less marked than the overall reduction in total dispatchable generation, resulting in an increase in the share of nuclear on the mix.

The import/export balance is a key aspect affecting our assessment of power systems' response to COVID-19. The different responses of gas and coal generation across the countries which are typically reliant on these technologies can be associated to the countries' variation in the import/export balance. The countries which experienced a temporary shutdown of large amounts of coal power capacity (Spain and Germany) or gas (United Kingdom) relied more



often on imports to fulfill market flexibility requirements (as underscored by the difference in the distribution of day-ahead imports between the lockdowns and the 2nd quarters of 2017–2019 displayed in the figure 3). Germany typically exports 10 GW–20 GW of power each hour when low or negative wholesale prices occur. This condition has happened often both during the lockdown and in the 2nd quarters of 2017–2019. However, during the lockdown there were also times where similarly low price conditions went hand in hand with imports (figure 3). This may suggest that due to the fall in coal generation, the country relied not only on gas but also on imports for flexibility purposes. France is typically a net exporter. While a number of hours of net importing positions have been registered in the past when day-ahead prices were at least 50–70 € MWh⁻¹, during the lockdowns France has experienced almost no case of positive net imports as prices have been stably below that price range. Italian net imports on the other hand have been strongly reduced during the COVID-19 lockdowns with respect to previous years. Although the country remained a net importer during the lockdowns, volumes dropped and only a few hours registered hourly net imports above 10 GW (half of the maximum hourly net importing position registered during the 2nd quarters of 2017–2019). In Spain and the United Kingdom, net importing positions have not changed drastically, although the distribution points to an

increase in exports in Spain and of imports in the UK (figure 3).

Policy-induced net-load shocks have resulted in a fall in the utilization of fossil fuels, ranking higher in the merit-order curve compared to hydro and nuclear. Accordingly, carbon intensity of the dispatchable generation mix has fallen sharply during the lockdowns, resulting in a large reduction of emissions (see supplementary methods). We compute the COVID-19 induced marginal reduction in the dispatching of each conventional technology and apply country-specific coefficients of the emissions related to their operations (based on Tranberg *et al* 2019): we find that the net-load shocks have contributed to reduce emissions not only by the average emission factor per kilowatt-hour, but by a higher amount because generation from the more carbon-intensive technologies has been cut compared to counterfactual conditions. Across the five countries, total power emissions decreased by about 26 MtCO_{2eq} (see supplementary table S10). Emission savings have originated both from energy demand reductions (17 MtCO_{2eq}), and fuel switching (9 MtCO_{2eq}).

3.3. Drivers of the shock in wholesale day-ahead prices

The identification of a statistically significant effect of the operative costs (OC_d^n , OC_d^{gas} , OC_d^{gas} and OC_d^{coal} , OC_d^{gas} , OC_d^{coal} see supplementary methods and supplementary table S2) allows us to construct two coun-

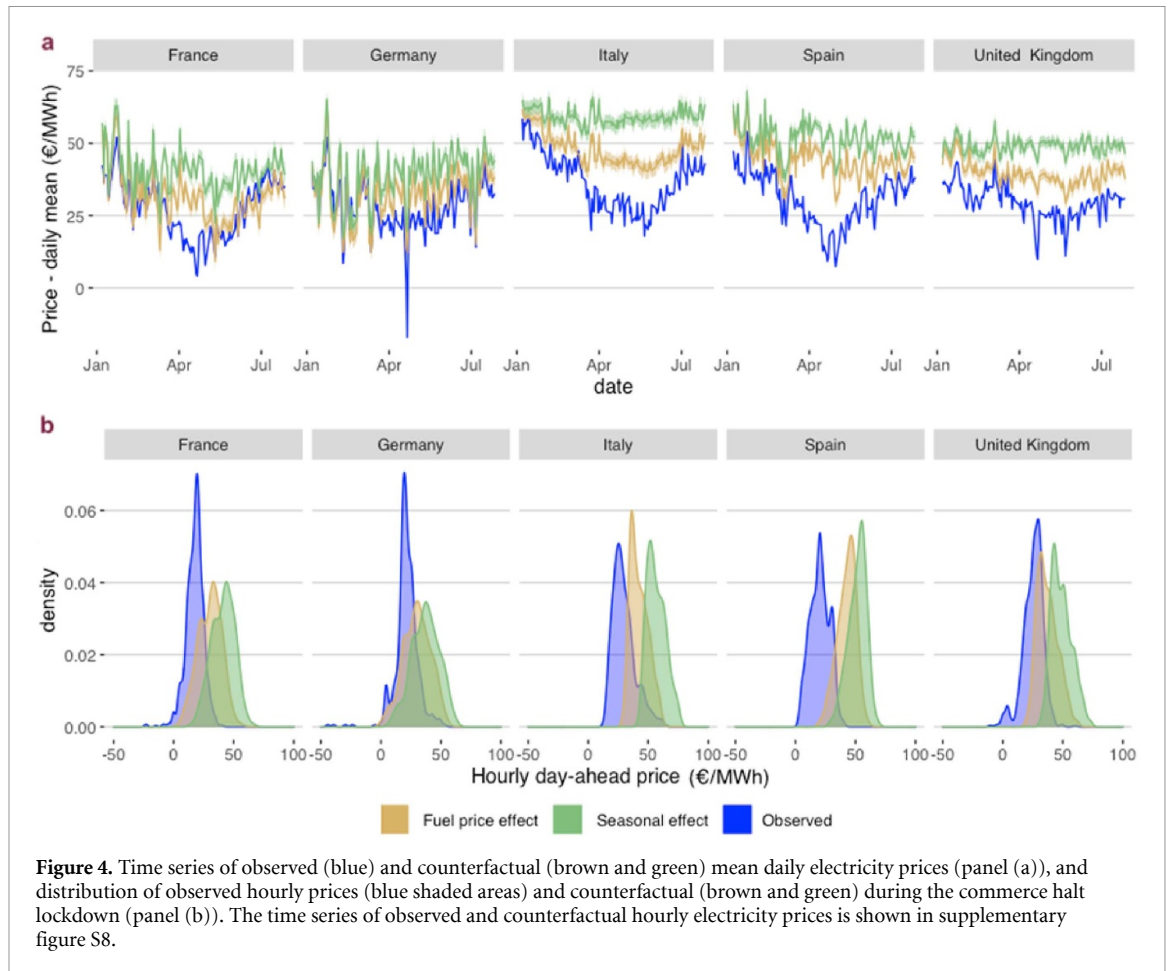


Figure 4. Time series of observed (blue) and counterfactual (brown and green) mean daily electricity prices (panel (a)), and distribution of observed hourly prices (blue shaded areas) and counterfactual (brown and green) during the commerce halt lockdown (panel (b)). The time series of observed and counterfactual hourly electricity prices is shown in supplementary figure S8.

terfactual scenarios of day-ahead wholesale electricity prices: (a) **seasonal scenario**, in which we simulate the evolution of day-ahead wholesale electricity prices based on the observed variation in renewable energy generation, the observed daily maximum temperature and the calendar effects, holding the value of the operative costs (OC_a^n) fixed to the mean level in 2019 (green line in figure 3); (b) **fuel price scenario**, in which we replace the 2019 mean of operative costs (OC_a^n) with the daily observed operative costs during the lockdowns.

The difference between the **seasonal** and the **fuel price** counterfactual scenarios quantifies the impact of the COVID-19 induced shock on fossil fuels' and ETS costs (henceforth 'fuel price effect') on the wholesale day-ahead prices. The difference between the **fuel price scenario** and the observed day-ahead prices (blue line in figure 4) quantifies the impact of the demand shock on the wholesale day-ahead prices (henceforth 'demand effect').

The wholesale electricity prices fell on average between 16 and 32 € MWh⁻¹ across countries, corresponding to a percentage fall ranging between 43% and 61%, due to the overall effect of the 'commerce halt' lockdown (see table 1). Our estimated total impact for Italy (47%) is in line with the aggregated shock obtained by Graf *et al* (2020). The decomposition suggests that both the demand effect

and the fuel price effect have caused a significant reduction of day-ahead wholesale prices compared to the day-ahead prices in the counterfactual scenario. We estimate the fuel price shock to cause a reduction in the wholesale electricity prices ranging between 7 € MWh⁻¹ and 14 € MWh⁻¹, while the demand shock reduced wholesale electricity prices by 9 € MWh⁻¹–23 € MWh⁻¹. While the fuel price and demand shock contributions to the total price reduction are roughly equal in most countries, the demand effect is relatively strong in Spain and accounts for 72% of the total fall in prices. The relatively uniform impact of the fossil fuel effect across power systems with heterogeneous dispatchable generation mixes suggests that to provide peak load most countries use relatively expensive gas plants. On the other hand, the relatively small role of the fossil fuel price shock in the Spanish system may be related to the role played by hydropower in the country, which reached a share of up to 35% of the dispatchable generation mix during peak hours during the lockdown (as opposed to 5%–15% in the other countries).

The distribution of the observed hourly day-ahead prices and of the counterfactual hourly day-ahead prices in the counterfactual scenarios provides an indication on the tails of the distribution (panel (b)). Two groups of countries can be distinguished based on the variation in the density functions. In

Table 1. Counterfactual and observed average electricity prices during the commerce halt lockdown.

	Observed day-ahead price (€ MWh ⁻¹)	Average price reduction (€ MWh ⁻¹)	Average percentage reduction (%)	Fuel price effect (€ MWh ⁻¹ -%)	Demand effect (€ MWh ⁻¹ -%)
France	18	23	57%	11 (48%)	12 (52%)
Germany	21	16	43%	7 (44%)	9 (56%)
Italy	30	27	47%	14 (52%)	13 (48%)
Spain	20	32	61%	9 (28%)	23 (72%)
UK	25	24	48%	12 (50%)	12 (50%)

Spain, Italy and the United Kingdom the observed density functions are characterized by a leftward shift in the mean, while the overall shape of the distribution does not change considerably. The shift is stronger in Spain and Italy compared to the UK: in the former two countries the mean price observed during the lockdown (blue) falls outside the left tail of the two counterfactual prices' distributions (95th percentile of green and red distributions).

In Italy, the fall in the costs of peak-load power plants, combined with the demand shock, was sufficiently large to displace the typical import/export balance. As the gap between the (higher) day-ahead prices in the home market with respect to the (lower) day-ahead price of net exporters such as France shrunk due to COVID-19, volumes of imported power have drastically fallen with respect to the 2nd quarters of 2017–2019.

In France and Germany, the mean of the observed distribution does not shift considerably with respect to the counterfactual distributions, while the kurtosis increases considerably. The probability to observe a price of 20 € MWh⁻¹, which is the mean price during the lockdown (blue distribution), is roughly four times higher than the probability associated with the same price in the 'fuel price' counterfactual. Therefore, the demand shock has induced most of the variation in the price distribution of these countries. The similarity in the distribution of observed prices the reduction in price volatility around the mean day-ahead price in Germany and France may derive from greater market integration than the rest of the countries, as the two systems take part to the same regional wholesale market, the Central Western Europe (including France, Belgium, Luxemburg, the Netherlands, Austria and Germany), which is connected through a flow-based market coupling (Felten *et al* 2019). While across Europe the day-ahead market coupling takes place *ex ante* the market clearing, in Central Western European a more flexible method has been in place since 2015 that operates simultaneously with the market clearing (Van den Bergh *et al* 2016)¹⁵.

¹⁵ In the available transfer capacity (ATC) method, TSOs calculate the available capacity for the market based on assumptions of the eventual market outcome and concomitant physical flows, and capacity allocation takes place *ex ante* the market clearing.

Despite that the occurrence of high negative prices in Germany has been associated with peaks in net exports, overall the country has experienced more frequent net importing positions than during the 2nd quarters of 2017–2019 (see figure 3). The shift towards more imports may be associated with the reduction in dispatchable power flexibility following the temporary phase out of coal generators (as underscored in section 3.2). Similarly, the UK experienced a shift in the distribution of the hourly net import position towards larger import volumes compared to past years' 2nd quarters (see figure 3). This shift should be evaluated in combination with the marked reduction in gas-fired generation during the lockdown, signaling that relatively cheap power from France has been preferred for flexibility purposes to the country's gas-fired fleet.

3.4. Balancing

The fall in net-load demand and the resulting change in the generation structure not only resulted in lower wholesale prices, but also affected the task of balancing the electricity system, possibly resulting in an increase in the costs incurred for grid operations. The stress on the system during COVID-19 lockdowns, characterized by the almost unprecedented condition of very low demand coupled with abundant renewable energy, results from the interaction of forecast errors for RES generation and demand (see supplementary results).

Upward and downward flexibility requirements during the lockdowns may also have been influenced by complementary market conditions. Under typical market conditions, the lack of downward system flexibility, also referred to as 'incompressibility', is exacerbated when baseload units are online due to stringent operational constraints or because they are contracted to provide reserve capacity (Brijs *et al* 2015). The decrease in baseload technologies' capacity factor

ATC market coupling is currently used in European electricity markets, except for the day-ahead market in Central Western Europe. The capacity allocation in FBMC happens partly *ex ante* the market clearing, and partly simultaneously with the market clearing. Unlike the ATC method, the allowable commercial export/import between two market zones is dependent of the allowable commercial export/import between other market zones (Van den Bergh *et al* 2016).

during the lockdowns has likely influenced this constraint (see section 3.2). Furthermore, low wholesale prices have reduced the incentives of power generators to offer their electricity in the electricity markets (see section 3.3).

It is important to remark that in our counterfactual out-of-sample predictions we include key variables such as the actual volume of imbalances, the day-ahead prices and the capacity factor observed during the lockdowns. These variables have been remarkably influenced by the COVID-19 induced shocks, as shown in the previous sections. In doing so, we test how well a model based on market conditions calibrated to the pre-COVID-19 period can describe the balancing markets conditions experienced by the power systems during the lockdowns. The comparison between the observed balancing costs and the model-based projections provides contrasting evidence across the four countries analyzed: projected balancing costs during the lockdown are close to the observed balancing costs in France and the UK, while our model systematically underestimates the price spikes that characterized the German and Italian systems (figure 5).

The inspection of the time series of the balancing costs per unit of demand underscores that Germany experienced very high balancing costs spikes, while Italy experienced an overall increase in the level of ancillary services' costs, which, in both cases, are not captured by the model-based projections. Germany in particular experienced two episodes when daily balancing prices were around 8 € MWh⁻¹ (blue markers in figure 5), a level which is roughly double the maximum registered in the past 3 years (equal to 4.5 € MWh⁻¹). France's balancing market has been characterized by a slight reduction in balancing costs, both as for surplus and for deficit conditions, which resulted in a slight overestimation of balancing costs by the model based on market fundamentals. The UK experienced an increase in balancing costs during the lockdowns compared to previous months, which are well described by our forecasting model based on market fundamentals.

The large abundance of gas capacity in the UK (as shown in section 2) might have played a role in keeping balancing costs much more under control compared to Italy and Germany, where gas-fired capacity was either unaffected (Italy) or even decreased (Germany) due to the day-ahead power market's equilibrium shocks induced by the lockdowns.

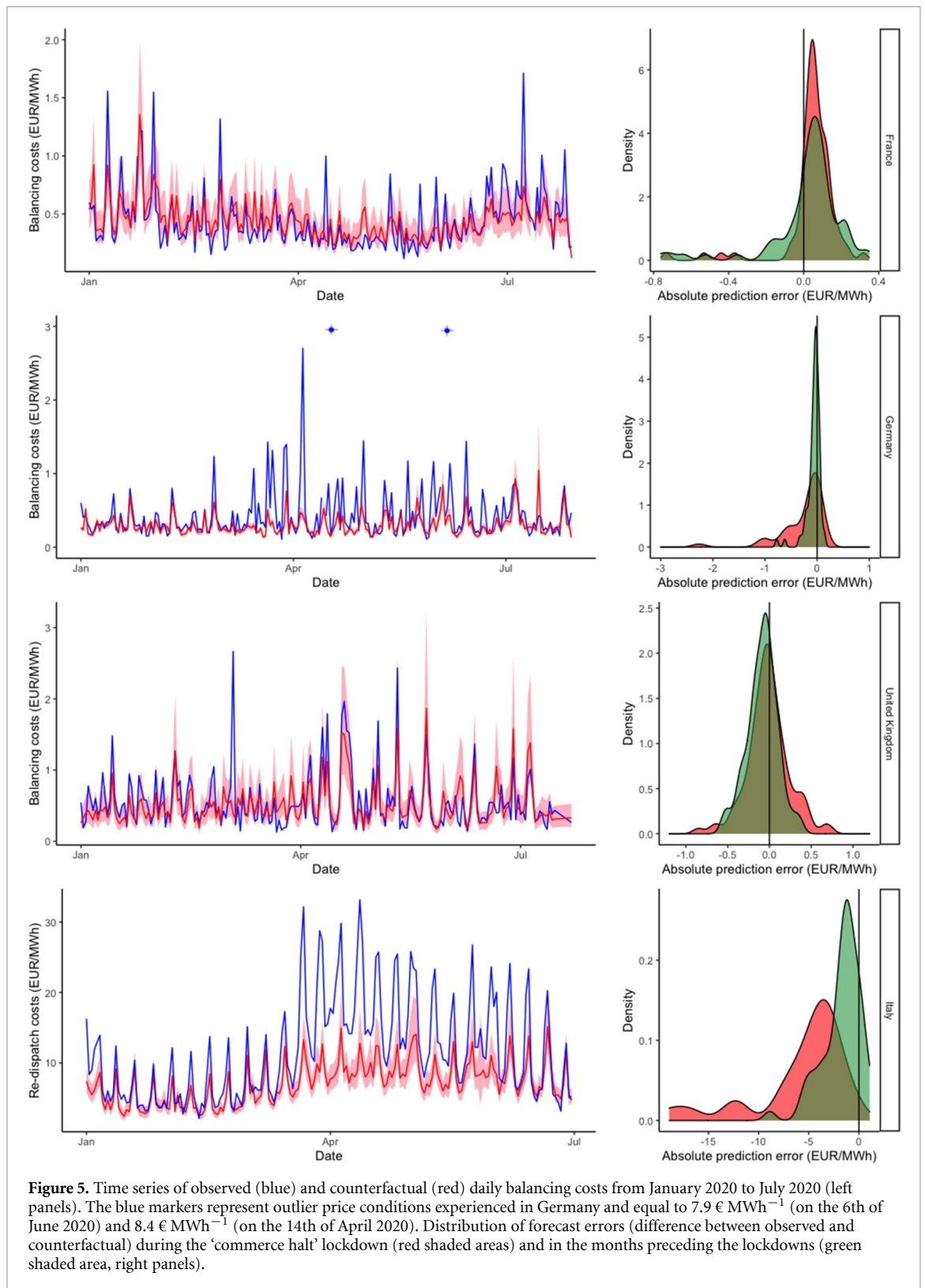
The inspection of the type of balancing requirements (surplus vs deficit) which characterized the four countries' markets before and during the lockdowns allows for the identification of a possible driver of the heterogeneity in the model's performance (supplementary figure S10). In France and the UK, the relative importance of downward imbalances (deriving from a generation surplus) and upward imbalances (deriving from a generation deficit) has

not changed drastically in the lockdown with respect to the first months of 2020. On the other hand, in Italy and Germany lockdowns were characterized by an unusual increase of downward flexibility costs: in Italy the distribution of balancing costs due to surpluses changed considerably in the 'commerce halt' lockdown and even more sharply in the 'non-essentials activity halt' lockdown, reaching values comparable to day-ahead wholesale prices (higher than 20 € MWh⁻¹). Costs associated with deficits were generally lower than the ones associated with surpluses. The German balancing market experienced an increase of both surplus and deficit costs during the lockdowns, but most of the cost increases derived from the former. The two spikes in balancing costs registered in the German balancing market were associated with a surge in both surplus and deficit prices, resulting from the bids of balancing market participants accepted by the German TSOs: the average price for each unit of activated power reached around -189 € MWh⁻¹ for the surpluses, while the price of the activated balancing power reached as high as 550 € MWh⁻¹ for the deficits (in both cases the prices represent the maximum value registered in 2020, as opposed to an average price of -38 € MWh⁻¹ for surpluses and 74 € MWh⁻¹ for deficits during the 'commerce halt' lockdown and of -12 € MWh⁻¹ for surpluses and 60 € MWh⁻¹ for deficits in the month preceding the lockdowns).

The estimated total balancing costs during the 'commerce halt' lockdown is 60% lower than the observed total costs in Germany (a difference of 23 million €), while it is 13% higher in France (a difference of 3.5 million €) and 4% higher in the United Kingdom (a difference of 2.5 million €)¹⁶. As for ancillary services' costs in Italy, the estimated total is 39% lower than the observed costs during the 'commerce halt' (a difference of 80 million €) and 48% lower during the 'non-essential activities halt' (a difference of 195 million €).

By evaluating the difference between our out-of-sample predictions and the observed balancing costs, we shed light on the possible occurrence of new market mechanisms affecting balancing markets. The aspects which could result in a deviation of our estimates from the observed balancing costs include: (a) new offer strategies employed to exercise market power by the participants in the balancing market (for instance, the reduction in the profits of power generators resulting from low day-ahead electricity prices may have triggered an increase in the value of the bids

¹⁶ Total estimated costs during the commerce halt phase are as follows: 29.53 million € in France, 62.52 million € in the United Kingdom, 135.12 million € in Italy and 14 million € in Germany. Total observed costs during the commerce halt phase are as follows: 26.00 million € in France, 60.00 million € in the United Kingdom, 209.94 million € in Italy and 37.45 million € in Germany.



placed by such parties in the ancillary services market); (b) a variation in the operating constraints (such as voltage regulation, reserve requirements or nodal network constraints), which can increase the requirements for re-dispatch actions (Graf *et al* 2020). Overall, we find evidence for the existence of a combination of such factors from the behavior of balancing

markets’ costs in Germany and of ancillary services’ costs in Italy.

4. Discussion

While the COVID-19 pandemic has coincided with a temporary change in the power system’s dynamics,

prospects for a consolidated structural change are the greatest at the time of societal transformations. This natural experiment has provided a unique opportunity to study power systems that have coped with high RES under a situation where demand is low and there is significant overcapacity. The quantification of the impacts that this atypical shock has had on the hourly operations of power generators, on day-ahead power prices and on balancing costs can provide valuable insights. It is important to underscore that the extent by which the effects we have measured can be informative of the long-run development of power systems will depend on how the underlying mechanisms will hold up in a situation with high RES and normal (or higher) demand, and relatively little dispatchable supply. The econometric models developed, capturing supply-demand effects based on current market conditions, should therefore be considered as a valuable empirical assessment shedding light on the current market dynamics, paving the way for new empirical analysis based on longer time series of data collected during the post-pandemic world, as well as for new model-based assessments and on political economy analysis of decarbonization.

When RES shares approached 80% in Germany, 70% in the UK and Spain, 60% in Italy and 40% in France, the power plants providing dispatchable generation responded very differently, depending on their marginal costs and capability to accommodate ramping requirements. The hourly profile of coal's capacity factor has been remarkably flattened due to the net-load shock. In Spain and Germany, both highly reliant on coal (i.e. with counterfactual shares in the dispatchable mix ranging between 15% and 20%), the observed share fell around 1% to 2% and 5%–7%, respectively ('temporary phase-out' category). In other cases, the net-load shock has forced only part of the fossil-based power plants to be cut out from the market, while part of it continued to operate, likely becoming the new marginal technology during peaks ('partial market exit' category). The need for flexible power generation was met through different sources across the power sectors analyzed ('increase in flexibility requirements' category): through an increase in the activation of hydropower, where available (Spain, Italy, Germany), or through flexible gas-fired plants (Italy, Germany and the UK). Finally, although partially hit by operational constraints, low-cost generation from nuclear sources fulfilled most of the remaining baseload requirements ('unaffected by market competition' category).

The sudden demand shock and the subsequent high RES penetration rate have reduced day-ahead prices by an extent ranging from 20% to 50% of counterfactual prices, once the effect of low fossil fuel prices is filtered out. The occurrence of negative prices in the day-ahead market in Germany and to a smaller extent in France and the United Kingdom, and of very high price spikes in the German

balancing market, underscores the need for more flexibility in the European power system. Although rising in the UK and Germany, costs of balancing markets remained a small component of overall power system costs (generally below 2 € MWh⁻¹ in France, the UK and Germany). On the other hand, the Italian costs of re-dispatch services, which include the costs incurred to adjust the schedules of RES to ensure that they are compatible with a secure operation of the grid, have increased substantially and reached values comparable or even higher than the daily wholesale prices. RES generation's impact on wholesale electricity prices was exacerbated by low net-demand, a condition that will likely be increasingly relevant in the coming years if power systems decarbonization is not coupled supply and demand flexibility evolving at a similar pace. While the conditions analyzed in this study arise from an unexpected, sudden shock, it still holds that these dynamics can be expected during times in which net demand and dispatchable supply do not match due to inflexibility. These conditions will be more likely to arise in the future as we shift from a fully dispatchable system where supply follows demand to one where an increasingly small share of supply is dispatchable and demand will (have to) become more flexible.

International power markets will likely play an increasingly important role, as we find considerable shifts in the distribution of hourly net imports compared to the 2nd quarters in 2017–2019. In Italy, for instance, a sharp reduction in power imports from abroad during the lockdowns was coupled by a milder shock to fossil fuel generation in the same weeks, compared to countries with a similar power mix (the United Kingdom and Spain). On the other hand, the French nuclear-based system was characterized by a shift towards increased exports. Our results suggest that as the EU power markets become more integrated (ENTSO-E 2021), high RES penetration rates will lead to a situation in which the least efficient plants are not only dependent on national net-load but also interconnected net-load, as efficient dispatchable plants will be freed up to compete internationally (under the limits posed by interconnection capacity constraints). Nuclear, due to its inflexible nature, will likely play an increasingly large role in exports when RES is pushing net-load down in countries which have abundant capacity.

Whether power systems will phase-out or, on the contrary, fall in a lock-in of coal power plants may not only depend on the profitability of wholesale markets, on cross-country markets' integration and on technical factors such as the degree of flexibility from high shutdown and restart costs, but also on market rules such as the presence of long-term contracts and capacity reserve mechanisms (Rentier *et al* 2019). A stronger EU-ETS scheme (e.g. following a reduction in emissions allowances) may put further pressures on the viability of coal-fired power plants and the least

efficient gas generators across Europe, tying power plants' marginal costs increasingly to their carbon intensity.

Our analysis underscores the need of powering up the grid infrastructure and ensuring additional flexibility from ancillary services. New real-time trading platforms for balancing resources among EU Member States, currently under development (ENTSO-E 2021), would further lessen the stress on grid management operations and mitigate the frequency of very high bids for surplus and deficit imbalances. Our results call for new research into the effect of the low net demand experienced during COVID-19 lockdowns on ancillary services' costs, including curtailment of renewables, as we suggest that the lockdown periods can act as a good natural experiment. Aggregate monthly statistics display that during COVID-19 lockdowns ancillary services' costs increased not only in Italy, but also in other countries such as the UK (National Grid 2021). Furthermore, due to the lack of available data¹⁷, we were unable to investigate the role of storage in response to the shocks induced by the pandemic. Including such aspects may provide further insight into power system characteristics that can enhance or limit the efficiency with which systems can deal with a fossil fuel price and demand shock in terms of financial, security and environmental performance.

Data availability statement

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The data that support the findings of this study are openly available at the following URL/DOI: hourly power sector from www.entsoe.eu/data/power-tats/ and <https://transparency.entsoe.eu/>; daily weather data from 'CPC global daily temperature', <https://psl.noaa.gov/data/gridded/data.cpc.globaltemp.html> (NOAA, 2020a) and 'NCEP/NCAR surface flux data', https://psl.noaa.gov/data/gridded/data.ncep_reanalysis.surfaceflux.html (NOAA, 2020b). The output data generated during our analyses and supporting the findings of this paper are available from the corresponding author upon reasonable request.

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Code availability

The code that supports the findings of this study are available from the corresponding author upon reasonable request

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¹⁷ To the best of our knowledge high frequency data is currently unavailable in the public repositories of TSOs and ENTSO-e.

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