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Greener, more integrated, and less volatile? A quantile regression analysis of Italian wholesale electricity prices

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ABSTRACT

This paper provides estimates of quantile regression models of the relationship between Italian day-ahead electricity prices, the supply of renewables and the inception of a new cable (SAPEI, linking Sardinia with the Italian peninsula), in the 2006–2015 time window. The results confirm the merit order effects detected in the existing literature, both for photovoltaics and wind power, more strongly in market conditions characterised by moderately low price levels and with some implied increase in volatility. The new cable has apparently challenged the ability of power generating companies to extract value through price spikes, has mitigated volatility, and its effects have been complementary with those of renewables. Effects from photovoltaics are more sensitive to robustness checks. Differences across zonal markets are nonetheless detected.

1. Introduction

This paper aims to assess the effects of two potentially pro-competitive changes in the Italian wholesale electricity market: the increasing penetration of renewables and a new transmission cable, called SAPEI, linking Sardinia with the Italian peninsula. Quantile regression models, augmented with exogenous variables, are estimated on daily data about the zonal electricity prices in the 2006–2015 time window.

There are a number of motivations for this research, of both policy and methodological nature. From a policy-making viewpoint, both market integration and the diffusion of green energy technologies can be seen as solutions to market power exploitation, which has long been a reason of concern in liberalised electricity markets, due to inelastic demand, vertical integration, and the influence of former monopolists. Such concern is magnified in relatively isolated regions, such as Sicily and Sardinia, that are often congested out of the grid, adding to their intrinsic vulnerability (Erdinc et al., 2015).

Clearly, market power mitigation is not the first and foremost goal of green energy policies, yet competition from green power producers could challenge the position of incumbents running conventional plants Ciarreta et al. (2017) have shown that bidding strategies by companies running combined cycle units in Spain have become more competitive after the policy-induced surge in renewables. The merit order effect of renewables would justify an alternative to building new lines, but possibly with a trade-off in terms of higher volatility due to intermittency. Distributed generation facilities, fuelled by renewable energy, may be localised appropriately, in a way that minimizes volatility and congestion probabilities, given the existing network configuration,[1] avoiding mismatches such as those detected by (Kunz, 2013) in regards to the German grid. Indeed, renewables can act as substitutes for electricity imports as empirically shown by Sapio (2015) and Brancucci Martinez-Anido and Hodge (2014). The transmission cost is a relevant component in the overall cost of running renewable energy units, especially for sources that are located far away from load centres. Market integration concurs to alleviate such costs, motivating the European Council to approve in October 2014 the 2030 Climate-Energy Package, where the issue of energy islands appeared prominently.

By means of quantile regression, one can test whether renewables and new transmission lines are as effective in mitigating the occurrence of very high prices. Comparing quantile regression coefficients across quantiles allows to identify what are the market conditions in which a certain policy action (supporting renewables; building new lines) is more impactful.

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[1] Personal communication by Silvano Cincotti on his unpublished research is acknowledged for this insight.

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Methodologically speaking, quantile regressions allow to study how given electricity fundamentals affect the market price at all points of its conditional probability distribution. One can disentangle the contribution of each electricity price driver not only at the median of the conditional price distribution, but also at quantiles that are more relevant vis-à-vis policy goals and risk measurement. In fact, the full profile of quantile regression coefficients is highly informative on how the variance of the outcome variable responds to marginal changes in the explanatory variables. Capasso et al. (2013) proved that if the variance of the error term is decreasing with respect to a given regressor, the quantile regression coefficients associated to that regressor are decreasing across quantiles. Applications of quantile regression to electricity prices include Westgaard et al. (2016), Hagfors et al. (2016), Paraschiv et al. (2016), who found stronger autocorrelation and stronger effects of reserve margins in the right tail, presumably due to market power, with however some exceptions in night-time auctions. The effect of renewables across price quantiles was not emerging clearly. However, those works were mainly interested in price forecasting.

Besides the few previous works that applied quantile regressions to electricity prices, cited above, further key references for this paper include the literature on merit order effects, that by now includes countless econometric articles, most of which are reviewed in Ballester and Furio (2015) (see also Section 3.2 in the present paper).[2] Theoretical analysis has been performed by Milstein and Tishler (2011) by means of a two-stage game involving strategic decisions on capacity building and power supply, and by Acemoglu et al. (2017) who proposed a Cournot oligopoly model accounting for spatial correlation in renewable sources.

This work also builds upon papers that explore the nexus between renewables penetration and market integration. de Menezes and Houllier (2015) placed a significant emphasis on the role of wind power penetration in triggering volatility transmission effects from Germany toward its neighbours before and after the nuclear phase-out. Figueiredo et al. (2015) showed, using Spanish data, that a larger availability of low marginal cost sources, such as wind power, implies an increase of market splitting probability. Results in Gianfreda et al. (2016) indicate that increasing renewables penetration has affected the electricity-fuel prices nexus and the speed of market integration in Europe. Ardian et al. (2018), in their analysis on Italian data, highlight that renewables in exporting regions drive congestion, but the correlation is negative if renewables are produced in importing regions. The impact of new inter-connectors on electricity price volatility has been assessed among others by (Ciarreta and Zarraga, 2012; Ciarreta and Zarraga, 2015) using multivariate GARCH on data from, respectively, Iberian markets and a larger set of European markets (MIBEL and EPEX); and by Worthington et al. (2005) and Higgs (2009) through a multivariate GARCH on the Australian National Electricity Market (NEM).

Concerning specifically the Italian electricity industry, contagion dynamics was studied on Italian electricity price samples by Gianfreda and Grossi (2012), Sapio (2015), Bigerna et al. (2015), Bigerna and Bollino (2016), Sapio and Spagnolo (2016), using various econometric methods.

The layout of the paper is the following. Section 2 describes the Italian electricity markets, the data, and summary statistics. The econometric model and expected results are described in Section 3. The main findings are summarized and discussed in Section 4, before the concluding remarks offered in Section 5.

[2] Simulative methods reaching similar results have been applied by Sensfuss et al. (2008), Veit et al. (2009), Banal-Estañol and Ruperez Micola (2011), and Guerci and Sapio (2012).

2. Context and data

2.1. The Italian power market

Day-ahead wholesale trading of electricity takes place in the Italian Power Exchange (IPEx), managed by a State-owned company, Gestore dei Mercati Energetici (GME). The IPEx day-ahead market is a closed, non-discriminatory, uniform-price double auction. Each day, market participants can submit bids and offers valid for each hour of the next day, used by GME to clear the market using a merit order rule. Wholesale demand for electricity can be considered as price-inelastic.[3]

If transmission constraints are not binding, all day-ahead supply offers are remunerated by the same price, the System Marginal Price, except for holders of long-term contracts, who receive the contract price, and subsidised plants, receiving the regulated tariffs. The optimal dispatch solution involves the calculation of zonal prices when lines are congested, in which case the Italian grid is segmented into up to 6 market zones (*Nord*, *Centro-Nord*, *Centro-Sud*, *Sud*, *Sicilia*, and *Sardegna*) and 5 limited production poles.[4]

Until 2009, Sardinia was only connected to the Italian peninsula through the Sardinia-Corse-Italy (SACOI) cable, with a transmission capacity of 300 MW. The Sardinian wholesale price was often above the average national price, signalling a chronic supply shortage in a region characterised by scarcity of hydropower sources. The Sardinian electricity system was fully integrated with the Italian grid on March 17, 2011, through a new HVDC interconnection, called SAPEI (SArdegna PEnisola Italiana), linking Sardinia with the Center-South market zone, covering 420 km under the sea and 15 km on land, with a total capacity of 1000 MW at 500 kV of voltage.

While the gap between Sardinian and peninsular prices has been bridged on average, no such convergence has occurred in terms of volatility: as highlighted by the annual reports of the Italian Power Exchange, the volatility in Sardinia and in the newly linked southern zones have diverged from the northern part of the Italian electricity system (GME, 2005-2015). This may be partly due to the burgeoning growth in renewables both on the island and elsewhere in Italy. Intermittent renewables (including wind and solar power) in Sardinia have reached a 24% penetration rate in 2014, more than twice than in 2011 (source: GME). As implied by the data reported in GSE Annual Reports (GSE, 2008-2013), wind and solar power together allowed to meet only 6.38% of electricity purchases in the Center-North zone in 2014, against 22.3% in Sardinia and 27.7% in Center-South. The penetration rates in 2008 were, respectively, 0.08%, 5.06%, and 3.99%. Hydropower in the North and Center-North allows for smoother price dynamics, while the same cannot be expected of Sardinia and southern regions.

Fig. 1 depicts the zonal markets in Italy, along with the transmission lines that are most relevant in this paper: SAPEI, SACOI, and the link between Center-North and Center-South.[5] Based on GME Annual Reports from 2005 to 2015 (GME, 2005-2015), one can identify trade flows across zones. Sardinia, and Sicily are characterised, on average, as net importers; North is a net exporter to Center-North; Center-North is a net importer from both North and Center-South; Center-South is a net importer from South and a net exporter to Center-North; South exports to both Sicily and Center-South (see also (Ardian et al., 2018)). Fig. 1

[3] End users who have not switched to competitive retailers consume electricity purchased by the publicly-owned company Acquirente Unico (single acquirer). The available evidence cast doubts on the efficacy of existing demand responsiveness programs, despite the relatively good diffusion of meters in Italy (Lo Schiavo et al., 2013).

[4] A zone is a subset of the transmission network that groups local unconstrained connections. Zones are defined and updated by the transmission system operator, or TSO (Terna in Italy) based on the structure of the transmission power-flow constraints.

[5] See all tables and figures.

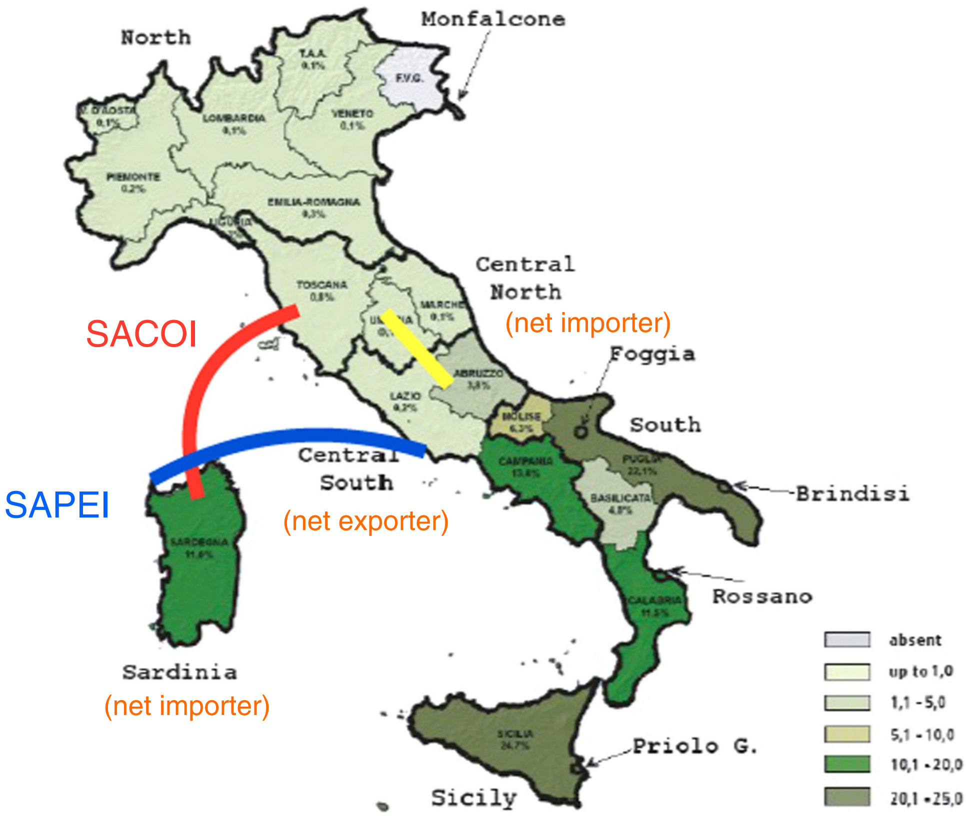


Fig. 1. Map of Italy showing the zonal markets (*Nord, Centro-Nord, CentroSud, Sud, Sicilia, Sardegna*) along with the physical links of interest for the paper (SACOI, SAPEI, and the link between *Centro-Sud* and *Centro-Nord*) and the percentages of installed wind capacity in each region, out of the national installed capacity of 5814 MW (in varying degrees of green) as of 2010 (sources: GSE 2010; (Guerci and Sapio, 2012)).

also shows the inter-zonal differences in the diffusion of the most volatile renewable power source, wind power. As it can be noticed, the southern regions and islands are the most vulnerable to wind power intermittency, unlike the northern ones. Fig. 2 shows the time series of average daily day-ahead electricity prices in the Italian market zones. Notice how Sardinia and Sicily displayed markedly higher average prices for most of the sample duration, except for the Sardinian convergence approximately from 2013. Notably, the inception of SAPEI was not immediately followed by lower and more stable prices: one can observe frequent spikes for about 1 year after the SAPEI inauguration. Price convergence failed to happen at first because Sardinia, historically a net electricity importer, in 2011 still had to satisfy a high load while still lacking a strong local availability of renewables.[6] The fall in electricity demand on the island, along with the boom in renewables, apparently has allowed the SAPEI interconnection to work while keeping congestion frequency relatively low.[7] Overall, prices have been declining due to the surge in intermittent renewables and the effects of the macroeconomic crisis (see GME Annual Reports from 2009 on).[8]

2.2. Data and variables

Data on the wholesale day-ahead zonal electricity prices (in Eur/MWh) have been collected from the IPEx website (www.mercatoelettrico.org) for the period Sep 13, 2006-Jul 31, 2015. The econometric analysis is performed on daily average prices.[9] The electricity market zones (North, Center-North, Center-South, South, Sicily, and Sardinia) are analyzed separately.[10] The sample does not include more recent years, such as 2016 and 2017, due to a structural break that occurred after the precautionary shut down of 18 nuclear plants in France in 2016, upsetting the usual import-export patterns and leading Italian prices to soar in early 2017.

Another reason is that due to the occurrence of very high prices, price setting in Sicily has been strictly regulated by means of compulsory supply of thermal plants with capacity above 50 MW located in Sicily, and remunerated at an administered tariff.

The set of regressors includes the main variables of interest for our analysis: the daily supply from intermittent renewables (wind and photovoltaics, separately considered) and a dummy for the inception of a new cable linking Sardinia with the Italian mainland. Supply from renewables is computed from individual bids published by GME. The SAPEI cable is taken into account by means of a dummy taking unit value from March 17, 2011 onwards. The sign and significance of the coefficients associated to these variables, quantile by quantile, will be the main focus towards understanding the merit order effect and the effects of the new cable, conditional upon the configuration of the Italian grid. Notice that because the paper deals with day-ahead market

[6] As reported in the 2012 GME Annual Report, during the summer of 2012 the transport capacity of SAPEI was reduced due to some maintenance work, thereby causing spikes.

[7] For structural details on the demand for electricity in Sardinia, please refer to Statzu and Strazzera (2008).

[8] The 2009 GME Annual Report noted that between 2008 and 2009 on the Italian day-ahead market "The worst contraction of consumption in the past 60 years (-6.7%) brought demand back to nearly 7 years ago" (p. 36; see also Table 4.2 in the Report).

[9] Simple averages have been computed, without assigning different weights to different hours. Taking the median daily prices would entail a problem: the "median hour" would change every day, questioning the comparability of successive price observations in the daily frequency sample.

[10] Calabria was a separate zone until 2009, when it was merged with the South zone. In order to keep a constant number of zones over the whole time span, here supply data from South and Calabria before 2009 are summed up, and the South price before then is a weighted average of Calabria and South prices, using zonal demands as weights.

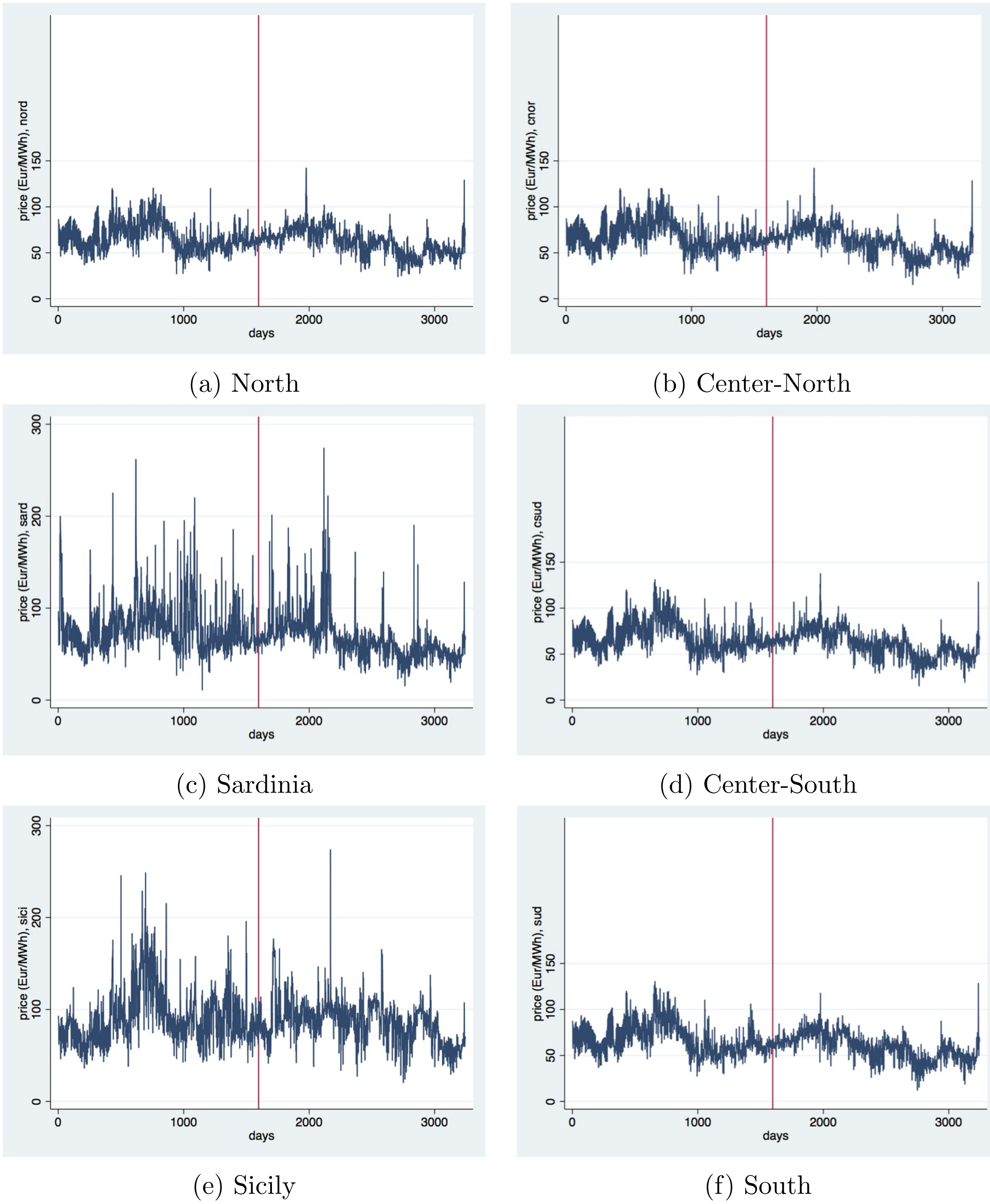


Fig. 2. Time series plots of the daily mean electricity prices in North, Center-North, Center-South, South, Sicily, and Sardinia between September 13, 2006 and Jul 31, 2015. Source: author's elaborations on GME data. The vertical line marks the inauguration of the SAPEI cable (17 March 2011).

data, the cable coefficient can only provide information on the effects of transmission patterns based on day-ahead bids and offers, but not on the actual flows that materialise in the real time operation of the grid.

As control variables, we include daily demand on the day-ahead market (source: GME); cost fundamentals proxied by daily gas prices (PSV), sourced from Eikon Thomson-Reuters, and daily coal prices (API2 quoted on the International Coal Exchange converted in Eur/MWh from US Dollars per metric tonne, downloaded from Datastream); European Emission Allowance prices, in Eur/tCO2 (source: EEX); and the daily average of the Residual Supply Index (RSI) published by GME,

Table 1
Descriptive statistics for zonal electricity prices in North, Center-North, Center-South, South, Sicily, and Sardinia. The sample size covers the period 13/09/2006–31/07/2015, for a total of 3864 observations. The new SAPEI cable started operating on 17/03/2011.

Descriptive statistics, zonal prices.							
Variable	Mean	Median	Std. dev.	Skewness	Kurtosis	Min	Max
Daily mean, whole sample, 3244 obs.							
North	65.646	64.274	14.742.	0.528	3.819	24.096	142.047
CNorth	66.465	64.847	15.604	0.419	3.554	15.485	142.047
CSouth	66.376	64.451	16.315	0.502	3.555	15.485	137.507
South	64.685	62.920	16.562	0.477	3.457	12.277	130.406
Sicily	89.577	87.301	26.181	1.152	6.246	20.608	273.637
Sardinia	73.602	67.917	25.936	1.863	9.227	11.151	273.854
Daily mean, pre cable, 1647 obs.							
North	68.650	66.045	15.055	0.564	3.200	27.231	120.273
CNorth	70.618	67.525	15.632	0.451	2.913	27.231	120.152
CSouth	71.299	67.948	16.500	0.560	3.098	27.606	130.904
South	69.818	66.005	17.233	0.550	2.911	27.606	130.406
Sicily	92.686	86.438	28.548	1.316	5.491	36.308	248.484
Sardinia	80.452	76.314	26.316	1.789	8.465	11.151	261.625
Daily mean, post cable, 1598 obs.							
North	62.550	62.795	13.742	0.425	4.574	24.096	142.047
CNorth	62.183	62.633	14.369	0.330	4.376	15.485	142.047
CSouth	61.299	61.616	14.463	0.294	3.827	15.485	137.507
South	59.391	60.275	13.991	− 0.034	3.118	12.277	128.233
Sicily	86.353	87.848	23.070	0.630	6.452	20.608	273.637
Sardinia	66.534	62.519	23.535	2.264	12.509	15.485	273.854

to account for market power. Monthly, weekend, and holiday dummies are included as well.[11]

In the regressions, an issue of timing needs to be tackled. Power generating companies place price bids under uncertainty on market demand and on supply from renewables. It is then more correct to regress electricity prices on the values that generating companies expect from purchasers and competitors, than on the actual ones. Such expected values can be proxied by forecasts based on past values.

Terna, the Italian transmission system operator, publishes the predicted values of aggregate output from intermittent renewables, but only since January 2012, hence an alternative approach is needed: namely, computing ex-novo forecasts on demand and renewables and including them as explanatory variables. This is done in this work by means of simple autoregressive processes.[12] For similar reasons, lagged values of all other explanatory variables are included in the model. In fact, offers submitted to the market by companies running solar and wind power plants are anyway based on their own predictions about the power to be generated at delivery time; but the issue being tackled here concerns the lack of information, by each generating company, about the bids and offers being simultaneously submitted by their competitors.

3244 data points are available at a daily frequency for each variable. The descriptive statistics are presented in Table 1 for the full sample, as well as before and after the cable.

Unit root tests (Augmented Dickey-Fuller, Phillips-Perron) performed on the time series of zonal electricity prices reject the null of non-stationary mean (Tables 2, 3). The same table shows that the null of stationarity tested through the KPSS is also rejected. We can thus estimate time series model specifications in log-levels.[13]

3. Modelling

3.1. A quantile regression model

Let $Q_p(y|X)$ denote the p-th quantile of y conditional on the matrix of explanatory variables X, with $p \in (0,1)$. A quantile regression model for electricity log-price y_t at time t (omitting zonal subscripts) reads

$$Q_p(y_t|X) = \beta_0^p + \beta_q^p \hat{q}_t + \mathrm{f}_{t-1}\beta_f^p + \beta_{rsi}^p rsi_{t-1} + \beta_s^p \hat{s}_t + \beta_w^p \hat{w}_t + \beta_c^p c_t + \mathrm{d}_t \beta_d^p \quad (1)$$

where $\hat{q}_t$ is the log-demand forecasted for day t, using information up to day $t-1$; $\mathbf{f}_{t-1}$ is a vector including fuel prices (gas, coal) and the CO_2 price on day $t-1$, in logs; rsi_{t-1} is the logarithm of the residual supply index, $\hat{s}_t$ stands for the forecasted log-supply of photovoltaic energy, $\hat{w}_t$ is forecasted wind power in-feed (in logs), and c_t is the SAPEI cable dummy. Matrix $\mathbf{d}_t$ collects all monthly, weekend, and holiday dummies. The previous-day RSI index is considered, instead of its simultaneous value, because it is computed by GME only after market clearing. Coefficients are denoted by a subscript, indicating the variable they are associated with. The p superscripts indicate that the model coefficients are allowed to vary across quantiles of the conditional log-price

[11] Markets for fuels and emission allowances are closed during weekends and holidays, unlike electricity markets. The associated missing data have been filled by considering the latest available price observation, e.g. the Friday price has been used also for the Saturday and the Sunday, as it represents the latest price in the information set used by power market participants. Natural gas is the most frequent marginal technology on the IPEX (GME Annual Reports 2006–2015). To exemplify, GME data indicate that coal and oil covered about 12% and 8% of the national electricity demand in Italy in 2013, versus 50% due to gas. It is also worth noting that the international coal and gas markets are considered integrated, as they are close substitutes in the electricity supply stack and involved in fuel switching decisions by power generating companies (see (Knittel et al., 2015)). Including the prices of both fuels in a regression model is therefore common practice, as in Chen and Bunn (2014) or Gianfreda and Bunn (2018).

[12] Anonymous referees are acknowledged for suggesting to use forecasted values instead of the actual ones published by GME. More sophisticated forecasting tools exist, of course (see (Weron, 2007)), yet a thorough investigation of alternative methods is beyond the scope of the paper. Specifically, an AR(1) has been used for log-wind and log-solar supply, and an AR(7) for log-demand. One-step ahead forecasts have been produced. Autoregressive lag orders have been selected by means of likelihood information criteria (Akaike, Bayesian). Root mean squared errors (RMSE) for power demand forecasts range between 0.1061 and 0.1945 depending on the market zone; for wind power, between 0.3689 and 0.8077; and for solar power between 0.1944 and 0.4453. More information is available upon request.

[13] The KPSS test results would motivate estimating fractionally-cointegrated models, an approach that we leave to future research.

Table 2
Unit root tests performed on zonal electricity log-prices in North, CenterNorth, and Center-South. ADF stands for Augmented Dickey-Fuller; PP for Phillips-Perron; KPSS for Kwiatowski, Phillips, Schmidt and Shin.

Test	Specification	Daily avg. Statistic	*p*-value	Outcome
ADF	7 lags	− 5.410	0.000	Reject I(1)
Sample: North	7 lags, trend	− 6.019	0.000	Reject I(1)
	7 lags, drift	− 5.410	0.000	Reject I(1)
	7 lags	− 20.301	0.000	Reject I(1)
PP	7 lags, trend	− 23.101	0.000	Reject I(1)
	7 lags	9.60	0.000	Reject I(0)
KPSS (at lag 7)	7 lags, trend	1.63	0.000	Reject I(0)
Sample: Center-North	7 lags	− 5.224	0.000	Reject I(1)
	7 lags, trend	− 6.157	0.000	Reject I(1)
	7 lags, drift	− 5.224	0.000	Reject I(1)
PP	7 lags	− 19.896	0.000	Reject I(1)
	7 lags, trend	− 24.013	0.000	Reject I(1)
KPSS (at lag 7)	7 lags	12.70	0.000	Reject I(0)
	7 lags, trend	1.60	0.000	Reject I(0)
Sample: Center-South	7 lags	− 5.117	0.000	Reject I(1)
	7 lags, trend	− 6.196	0.000	Reject I(1)
	7 lags, drift	− 5.117	0.000	Reject I(1)
PP	7 lags	− 20.119	0.000	Reject I(1)
	7 lags, trend	− 25.011	0.000	Reject I(1)
KPSS (at lag 7)	7 lags	14.30	0.000	Reject I(0)
	7 lags, trend	1.56	0.000	Reject I(0)

distribution. Each coefficient is interpreted as the marginal change in log-price due to a marginal change in the given regressor. If we wish to understand how explanatory variables affect price spikes we have to look at the coefficients associated to the highest quantiles (say, $p > 0.9$).[14]

Our main focus is on coefficients β_s^p and β_w^p, measuring merit order effects, and on β_c^p taking up the effect of market integration.

The model is estimated, for each electricity market zone, at percentiles separated by 5% intervals. Confidence intervals (at the 95% level) are obtained via bootstrapping. Patterns of coefficients across quantiles (rising or declining) are considered as suggestive of effects on volatility.

3.2. Expected results

As long as the variance of the electricity log-price depends on the explanatory variables, we should expect quantile regression coefficients to vary across quantiles (Capasso et al., 2013). From such patterns one can infer the economic mechanisms that may have been driving the electricity market.[15]

One common result in the literature is that *renewables crowd out fossil fuelled units, at least partly, thereby exercising a downward pressure on the electricity market-clearing price (merit order effect).* A perhaps non exhaustive list of papers corroborating this evidence features Clò et al. (2015), Sapio (2015) on Italy; Saenz de Miera et al. (2008), Gelabert et al. (2011), Azofra et al. (2014), and Ciarreta et al. (2014) on Spain; Prata et al., 2018 on the integrated Spain-Portugal market; Cludius et al. (2014), Ketterer (2014), Paraschiv et al. (2014), Veraart, (2016) on Germany, O'Mahoney and Denny (2011) on Ireland, Brancucci Martinez-Anido et al. (2016) on New England, Woo et al., 2011 on Texas among the many. In some cases it is shown that the electricity price savings achieved through higher renewable penetration exceed the volume of the net subsidy payments, or partly reduce the burden of feed-in tariffs (McConnell et al., 2013 on Australia, Tveten et al., 2013 on Germany), although Ciarreta et al., 2014 argue that, at least for Spain since the macroeconomic crisis, wholesale price savings due to renewables are no longer able to "repay" themselves. Finding a negative coefficient associated to renewables at the median of the conditional log-price distribution would add evidence to the merit order effect.

The merit order effect may even be reverted, because when the installed capacity of renewables is larger, conventional generators will ask for higher price spikes in order to profit from sudden disruptions in renewable energy, unless there is a price cap constraining this strategy. Evidence on this effect has been collected by Milstein and Tishler (2011) studying a sample from the Israeli electricity market, with a focus on photovoltaics.

The availability of non-storable, intermittent renewable resources depends on meteorological conditions that may change unexpectedly and display a rather high variability. Conversely, traditional energy sources, such as hydropower and fossil fuels, can be stored and controlled at any time. For these reasons, it may occur that *renewables increase volatility*: a higher share of renewables in the supply stack is supposed to bring about a more volatile matching between demand and supply (see results in Ketterer, 2014 and Rintamäki et al., 2017 on Germany, Brancucci Martinez-Anido et al., 2016 on New England, Woo et al., 2011 on Texas, Mauritzen, 2010 on Denmark) and possibly an impact on skewness (Veraart, 2016), due to increased spike frequencies. This is seemingly due to the fact that with higher renewables penetration, conventional units face higher ramping costs (Brancucci Martinez-Anido and Hodge, 2014). Also, a positive correlation among outputs from wind plants drives the electricity price volatility upwards (Morales et al., 2011). Such a volatility effect is challenged, on daily frequency data, when the renewable energy resource is evenly available across the day and when interconnection capacity allows imports of "smoothing" sources such as hydropower, as in the Danish sample analyzed by Rintamäki et al. (2017).

As a final take on the effects of renewables, it can be argued that *renewables mitigate market power by limiting markups on marginal units in peak-load periods* (see e.g. Milstein and Tishler, 2015). This may work through the higher risk of crowding out faced by companies that run peaking plants when renewables increase their penetration in the market. This effect would be testified by negative coefficients of renewables at the highest quantiles, whereas no statistically significant coefficients would be found at the other quantiles: when demand is low, market power exercise is anyway limited. The strength of this effect depends on whether the companies running the units exposed to the risk of crowding out respond by e.g. withholding infra-marginal capacity, as theoretically shown by Acemoglu et al. (2017), or by causing congestion (Guerci and Sapio, 2012), in a sort of negative externality (Hitaj, 2013), as empirically found in Sapio (2015). Coordination failures on low-price equilibria by generators running conventional energy units can be another explanation, proposed by Banal-Estañol and Ruperez Micola (2011). Ballester and Furiò (2017) instead find that conventional generators, the most affected by the merit order effect, charge a "wind risk premium" on their bids.

Concerning the effects of a new cable, it is expected that *market integration exercises a downward pressure on electricity prices.* In economic theory, market integration through a new interconnection cable is expected to bring local prices closer to marginal costs, improve security of supply, and reduce reserve requirements (see Neuhoff and Newbery, 2005, Newbery et al., 2016, Boffa and Sapio, 2015). Boffa et al. (2010), among others, have estimated the savings for end-users on energy bills,

[14] In an alternative specification we have included, along with the log of power demand, also 1st and 7th order lags of the log-prices. Indeed, a positive autocorrelation of log-prices is sometimes argued to suggest learning by power generating companies. Only the results about the specification in Eq. 1 are displayed, though, because by construction, lagged demand and lagged prices are collinear. Nonetheless, results from such alternative specification, available upon request, are not very far from the ones described in Section 4.1.

[15] In what follows, when mentioning renewables one refers to intermittent renewables, such as solar or wind.

Table 3
Unit root tests performed on zonal electricity log-prices in South, Sicily, and Sardinia. ADF stands for Augmented Dickey-Fuller; PP for Phillips-Perron; KPSS for Kwiatowski, Phillips, Schmidt and Shin.

	Daily avg.		
Test	**Specification**	**Statistic**	***p*-value**
Outcome			
ADF	7 lags	− 5.061	0.000
Reject I(1)	Sample: South	7 lags, trend	− 6.133
0.000	Reject I(1)		
	7 lags, drift	− 5.061	0.000
Reject I(1)		7 lags	− 19.300
0.000	Reject I(1)		
PP	7 lags, trend	− 24.334	0.000
Reject I(1)		7 lags	14.40
0.000	Reject I(0)		
KPSS (at lag 7)	7 lags, trend	1.40	0.000
Reject I(0)			
Sample: Sicily	7 lags	− 8.122	0.000
Reject I(1)		7 lags, trend	− 8.396
0.000	Reject I(1)		
	7 lags, drift	− 8.122	0.000
Reject I(1)	PP	7 lags	− 22.427
0.000	Reject I(1)		
	7 lags, trend	− 23.074	0.000
Reject I(1)	KPSS (at lag 7)	7 lags	3.73
0.000	Reject I(0)		
	7 lags, trend	1.61	0.000
Reject I(0)			
Sample: Sardinia	7 lags	− 7.804	0.000
Reject I(1)		7 lags, trend	− 9.342
0.000	Reject I(1)		
	7 lags, drift	− 7.804	0.000
Reject I(1)	PP	7 lags	− 22.787
0.000	Reject I(1)		
	7 lags, trend	− 26.715	0.000
Reject I(1)	KPSS (at lag 7)	7 lags	13.30
0.000	Reject I(0)		
	7 lags, trend	1.75	0.000
Reject I(0)			

arising from improved network capacity. The related welfare improvements mostly accrue to the region starting off with higher prices (Creti et al., 2010) since local market power is stronger in small and isolated electricity systems (see Viljainen et al., 2012, Ries et al., 2016). In fact, according to the GME annual reports the gap between Sardinian and peninsular prices has been bridged on average since the inauguration of SAPEI. If so, the coefficients associated to the cable should assume negative values around the median of the log-price distribution, at least in the smaller zone among those being connected (in our case, Sardinia). Such an effect may spread to other zones, even though more weakly so if they are farther.

Whether this prediction fails to be verified, it may depend on a number of reasons. One is that market integration may yield valuation anomalies, in which power flows against the efficient direction (Bunn and Martoccia, 2010; McInerney and Bunn, 2013; Bunn et al., 2015). Market power export effects have also been detected (see Neuhoff et al., 2008), (de Villemeur and Pineau, 2012)), e.g. when excess capacity in one zone can be deployed in other zones after market integration (Boffa and Scarpa, 2009) or when integration allows a low-cost dominant generator to access a more competitive zone (Bunn and Zachmann, 2010). These effects depend on the pricing mechanism at work and on the size of the link (Moselle et al., 2006).

Further, market integration may allow a flow of renewables in export from zones where those sources are excessively concentrated. Such an outflow dilutes the effect of renewables on volatility or, in other words, *market integration improves the allocation of resources, thereby mitigating volatility at both sides of the transmission line.* This inference would result from finding a decreasing pattern across quantiles of the coefficients associated to the new cable dummy (i.e. negative impact on top quantiles, together with a positive or mildly negative impact on lower quantiles). Failing to verify this result would add to the evidence reported in de Menezes and Houllier (2015), who highlight that physical interconnection among European electricity markets implies a trade off between lower average prices and the export of volatility from larger markets that are, at the same time, endowed with higher shares of intermittent renewable sources.

A final theoretical insight about market integration suggests that *market integration challenges the exercise of market power in the previously isolated zone, implying a lower frequency of price spikes.* By exposing the local market zones to more competition, companies attempting to exercise market power face a higher risk of undercutting by competitors from other zones. Clearly, no effect should be detected when demand

Table 4
Expected results about the effects of renewables and market integration.

Effects of renewables	
Merit order effect	$\beta_s^{0.5} < 0$, $\beta_w^{0.5} < 0$
Increasing volatility	β_s^p or β_w^p increasing across quantiles
Peak shaving	$\beta_s^p < 0$ or $\beta_w^p < 0$ for p large
Effects of market integration	
Price convergence	$\beta_c^{0.5} < 0$ in smaller zones being connected
Volatility mitigation	β_c^p decreasing across quantiles
Peak shaving	$\beta_c^p < 0$ for p large

(and prices alike) is already low, since there is no scarcity for the electricity commodity in that case. One therefore expects that only the higher quantiles of the conditional log-price distribution will change after the inauguration of a new cable.

Table 4 summarizes the expected results just described.

4. Results

4.1. Description of baseline results

Estimation results are displayed by means of 6 subplots, one for each electricity market zone, for the main variables of interest (Fig. 3)

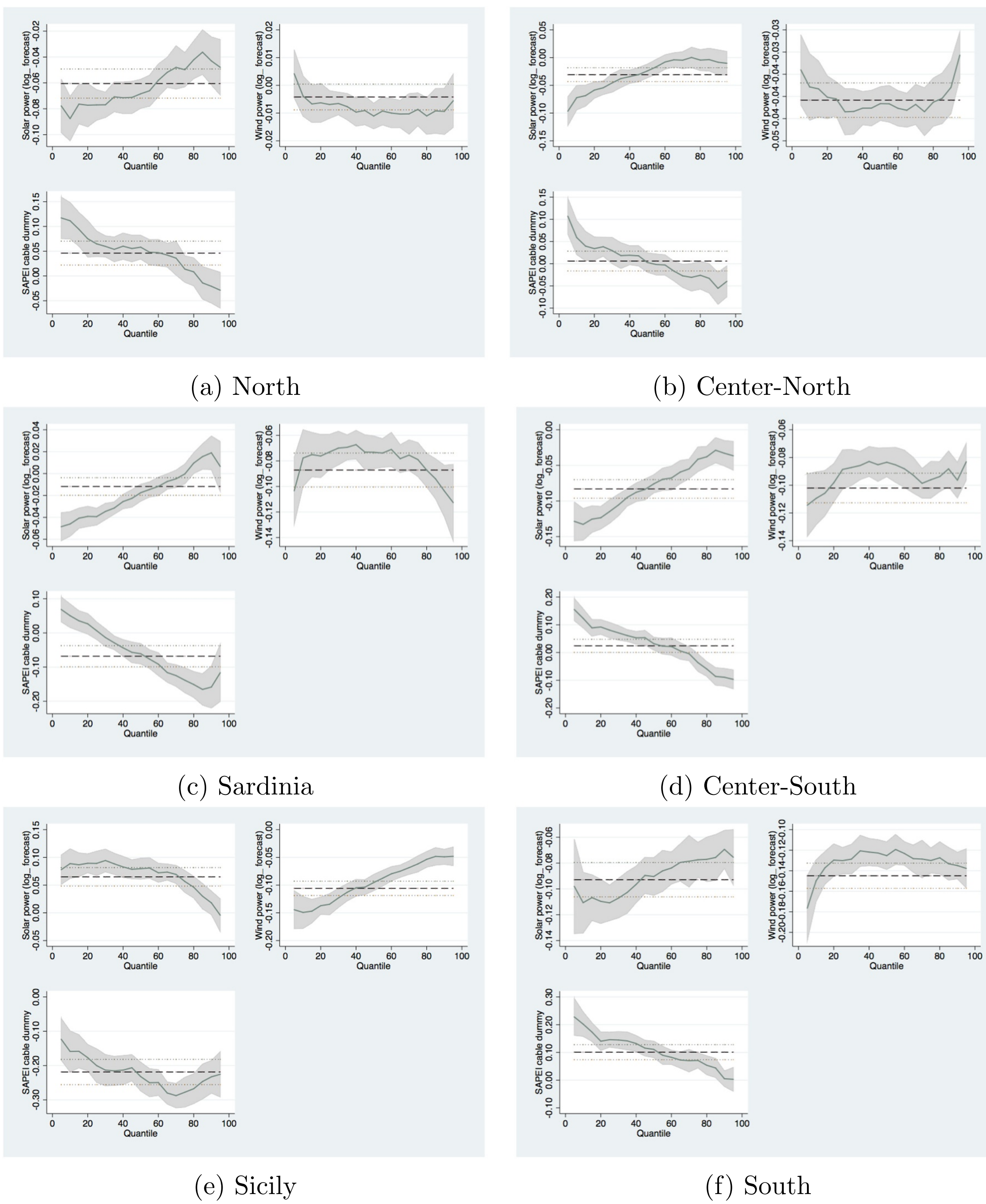
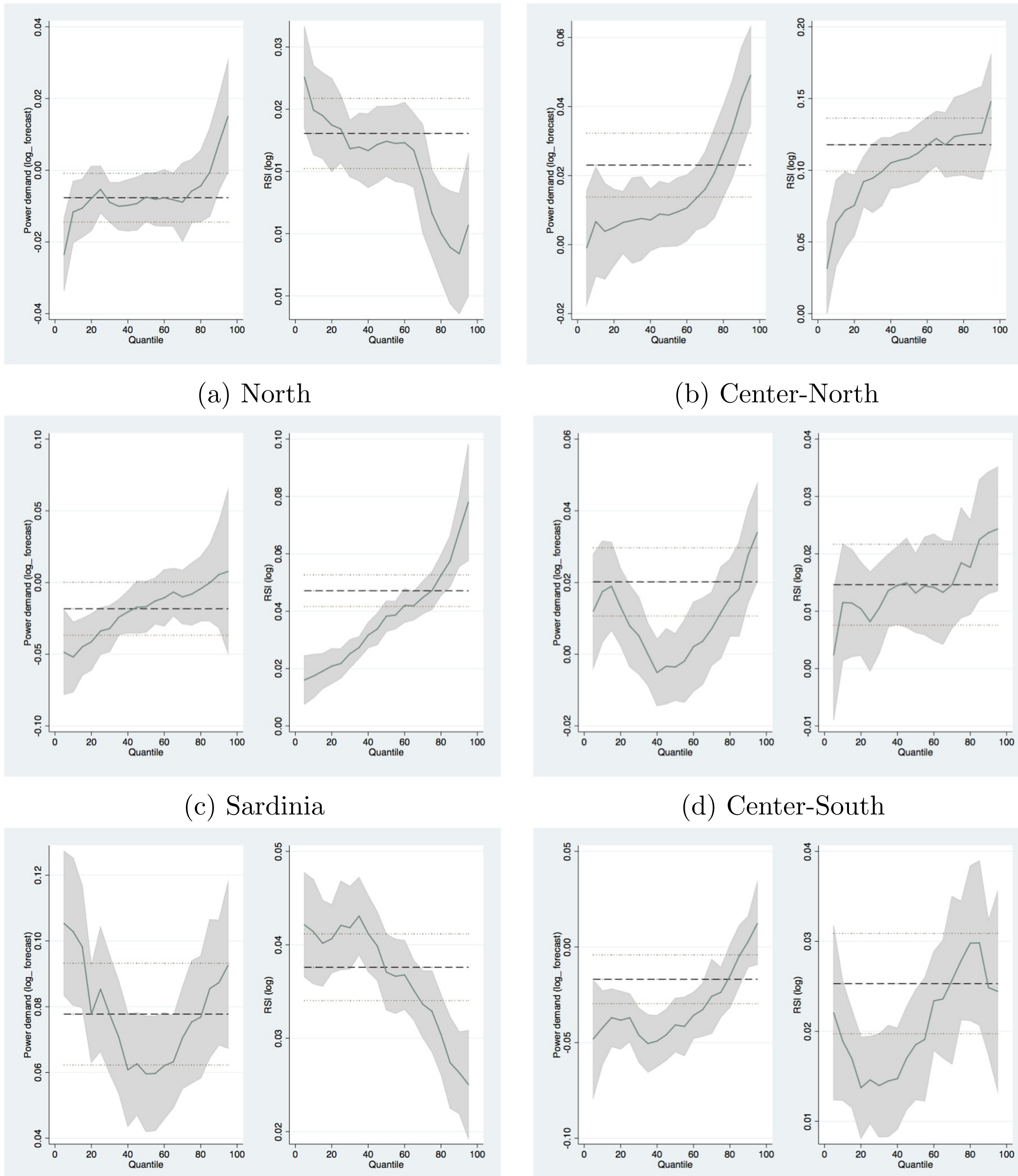


Fig. 3. Quantile regression baseline estimates. Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: log-solar power supply, log-wind power supply, SAPEI cable dummy.



(a) North (b) Center-North

(c) Sardinia (d) Center-South

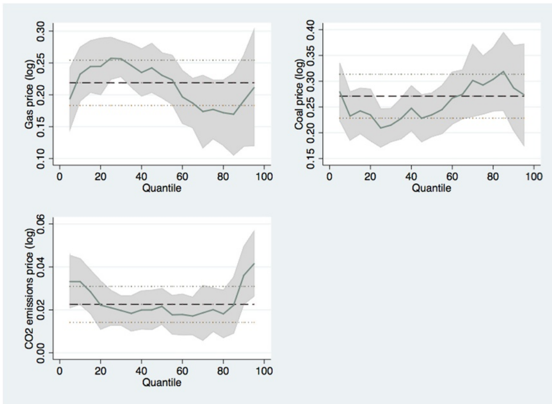
(e) Sicily (f) South

Fig. 4. Quantile regression baseline estimates. Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: forecasted log-demand, log-residual supply index.

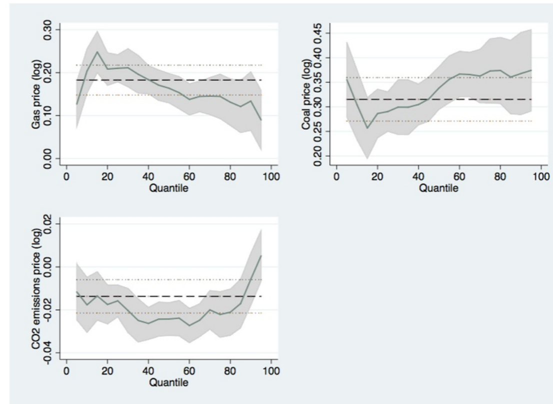
and for controls (Figs. 4 and 5).[16] In Fig. 3 each subplot includes the quantile regression profile for a set of 3 coefficients: photovoltaics ($\beta_s{}^p$), wind ($\beta_w{}^p$), and the cable ($\beta_c{}^p$). OLS point estimates and the associated 95% bootstrapped confidence intervals are superimposed for comparison. The focus is on the sign of the estimated coefficients as well as on the shape of the coefficient profile across quantiles. A rising pattern of coefficients across quantiles suggests a positive effect of the regressors on the variance of the dependent variable (Capasso et al., 2013). Demand coefficients and those associated to the residual supply index are in Fig. 4; those associated to costs (gas prices, coal prices, CO_2 prices) are reported in Fig. 5, whereas monthly, weekend, and holiday dummies coefficients are not reported for the sake of brevity.

Let us start from the two zones that are immediately affected by the new cable. Concerning the Center-South (mid-right panel of Fig. 3), interesting results are found for renewables. Forecasted photovoltaic supply affects electricity prices negatively. The increasing profile of coefficients across quantiles indicates that the spread of the electricity price distribution increases with solar power outputs. Wind power forecasted supply exercises a downward pressure on prices, following an irregular pattern mostly above the OLS estimate. Concerning the new cable, apparently it has allowed for lower prices, as testified by negative coefficients but only from the 85% quantile onwards and there

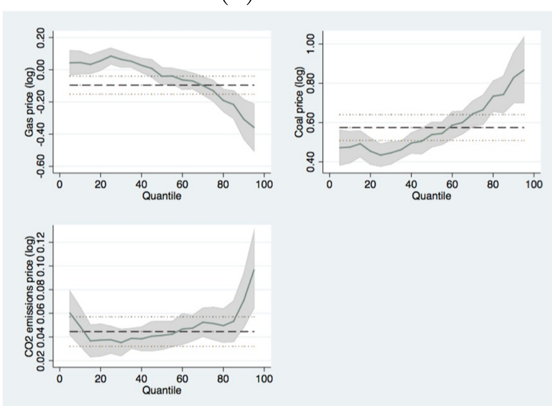
[16] Full results are available upon request.



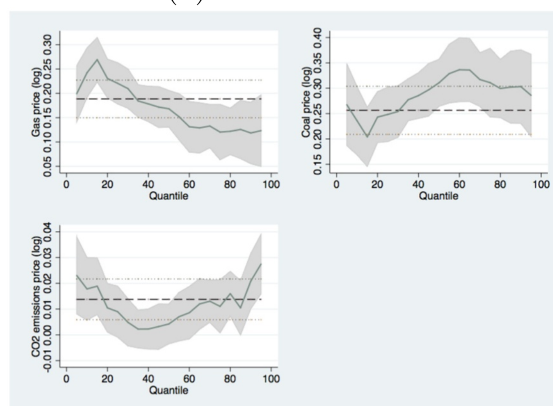
(a) North



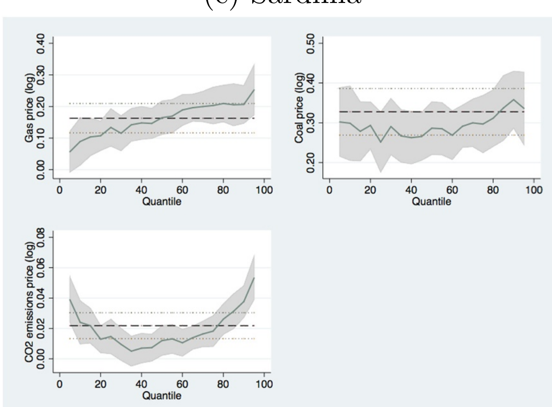
(b) Center-North



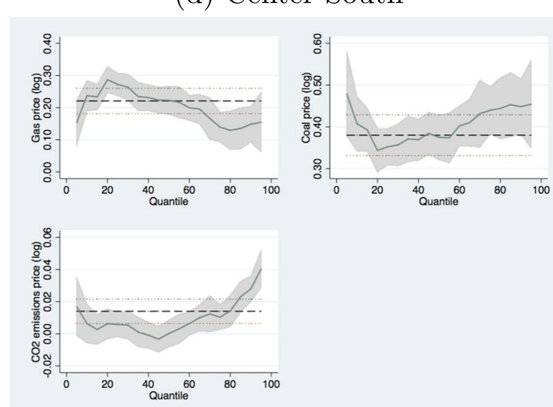
(c) Sardinia



(d) Center-South



(e) Sicily



(f) South

Fig. 5. Quantile regression baseline estimates. Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: log-gas prices, log-coal prices, log-CO_2 emission prices.

is no significant impact around the median. There are some positive coefficients at the lower tail. In other words, the new cable has shaved the price peaks while pushing the lowest prices up, implying volatility mitigation overall.

The mid-left panel of Fig. 3 is dedicated to Sardinia. One spots negative solar power coefficients, following an increasing profile, while losing significance at the 95% quantile, hinting that there is no peak-shaving. Wind power coefficients are negative at all quantiles, including the extreme ones, hence increasing wind outputs appear to have challenged price spikes in Sardinia. Cable coefficients are negative as expected, and decreasing across quantiles except in the upper tail.

Another zone that could have been influenced by the new cable is the Center-North, where SAPEI is now in competition with the old SACOI. Photovoltaic supply exhibits a negative impact, with coefficients of lower magnitudes as one moves towards the upper tail, and lacking significance from the 6th decile onwards.

Wind output coefficients are negative and more so in the body of the distribution. The SAPEI cable results mirror those about the Center-South zone, albeit with a narrower range of values.

The top-left panel displays evidence about the North zone. The results are similar to the previous ones about Center-North and Center-South, regarding the effects of photovoltaics (negative and milder in the upper tail, but statistically significant) and the new cable, whose coefficients switch from positive to negative.

Wind power coefficients are negative, but lack significance in the tails. Concerning the South (bottom-right panel), again one finds negative effects from solar power; negative impacts of wind power, and a surprisingly positive impact of the new cable, more so at the lower quantiles. The plots on Sicily (bottom-left) present some specificities: coefficients associated with photovoltaics are positive in the lowest part of the distribution, and lack significance at the top quantiles; wind power exercises a merit order effect that is milder in the right tail; as in Sardinia, the cable coefficients are negative and increasingly so in the top quantiles.

Some comments are due also on control variables (Figs. 4 and 5). Expectedly, forecasted demand coefficients are positive and increasing - i.e. demand exercises a stronger impact when prices are highest. RSI coefficients behave similarly, except in Sicily, South, and North, where they are positive, but declining across quantiles. In those zones, then, market power strategies prevent prices from dropping too much. Coefficients associated to cost variables (gas, coal, CO_2 prices) are positive with different patterns across zones.

The general picture is that in days when prices are peaking (upper quantiles), it is demand and the RSI that exercise stronger impacts, whereas in days when prices are lower (lower quantiles), the most impactful price determinants are cost components. Such a picture fits very well with standard theoretical insights on how an oligopolistic market works.

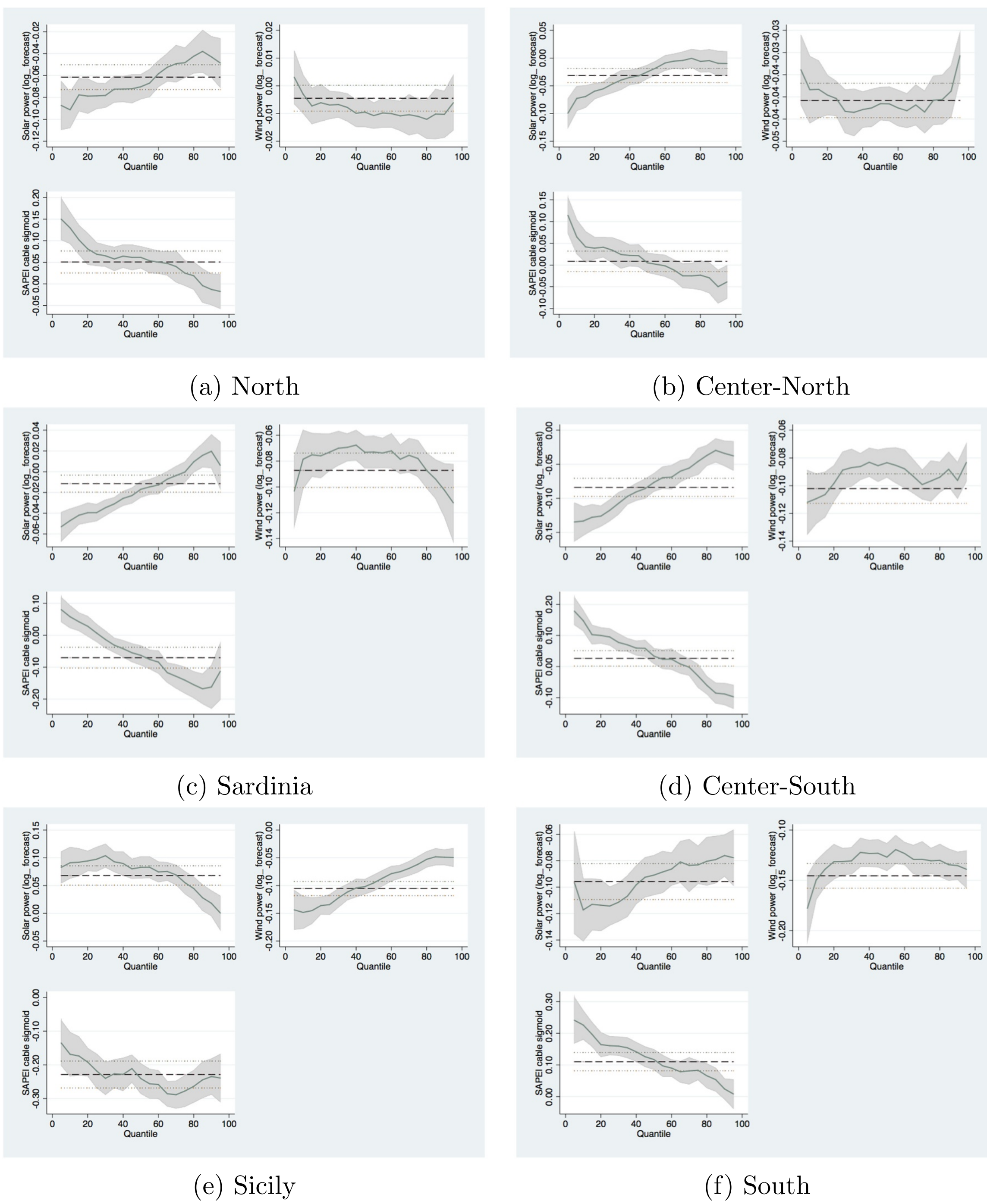


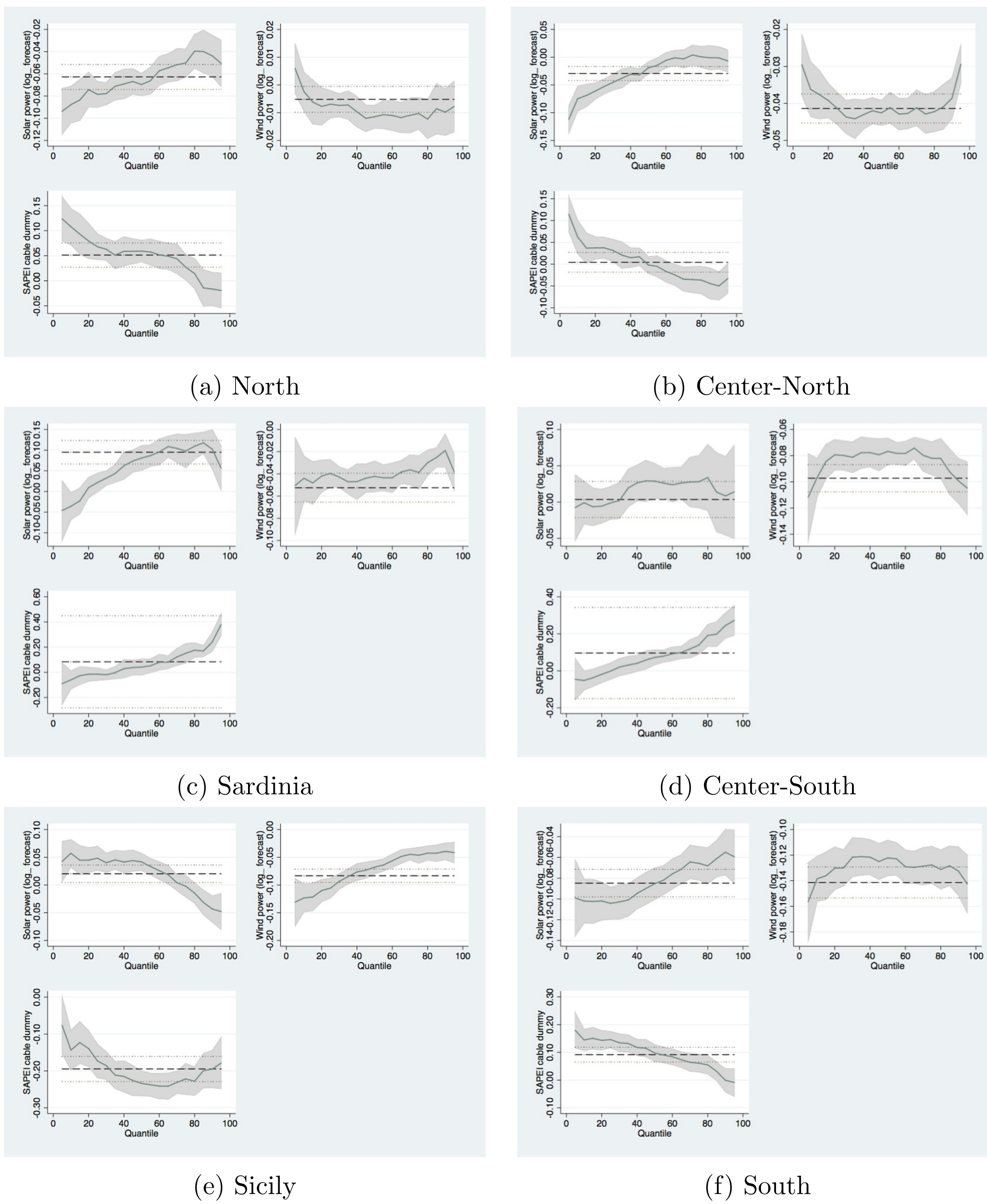
Fig. 6. Quantile regression estimates, robustness I (learning). Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: log-solar power supply, log-wind power supply, SAPEI cable "learning" variable.

4.2. Robustness

Robustness checks are hereby performed, in order to verify to what extent the results hold when removing some of the implicit assumptions behind the estimated model specification. The new results are displayed in Figs. 6–10.

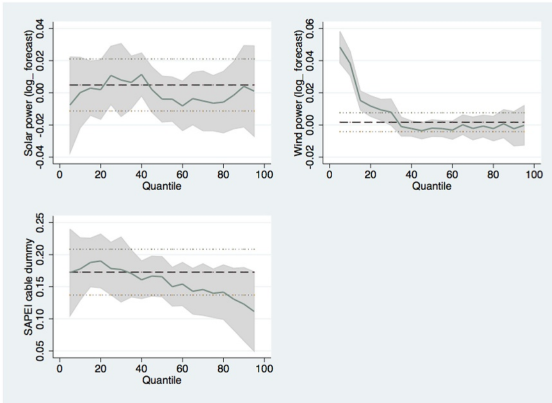
First, using the cable dummy provides a before-after assessment of the impact of the cable, but some learning might be needed before the cable delivers its full effects. Indeed, transport capacity was hampered by maintenance activities (see also footnote 6 in Section 2). For this reason, the cable dummy is replaced by a smooth time-varying variable that is equal to zero before 17 March 2011 and slowly converges to 1 afterwards. This has been chosen after experimenting with different specifications of a logistic function of the type $\frac{\rho t}{1+\rho t}$ for $t \geq 17$ March 2011, and 0 before, by letting ρ vary between 0.1 and 0.9. Next, these new variables have been included alternatively in quantile regressions. Only the results for the case ρ = 0.2 are hereby reported, which means that the variable reaches the value 1 approximately one year after the inauguration of the cable. The new estimates on the effects of renewables and the cable (Fig. 6) confirm the baseline ones with very minor differences.

In a second check, the equation for a given zone includes the share

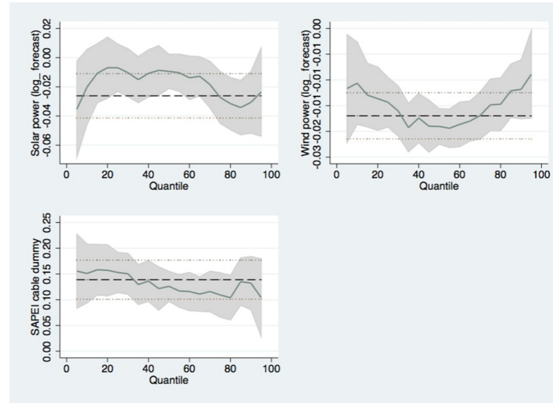


(a) North (b) Center-North (c) Sardinia (d) Center-South (e) Sicily (f) South

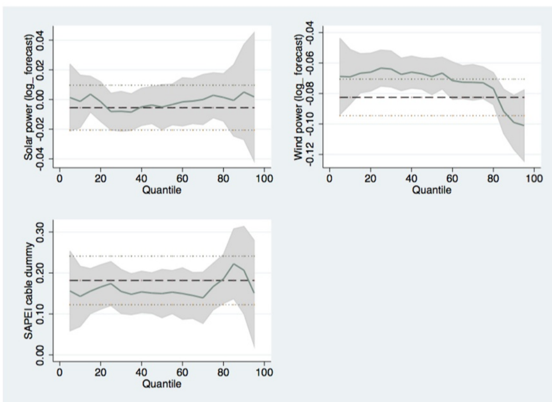
Fig. 7. Quantile regression estimates, robustness II (congestion). Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: log-solar power supply, log-wind power supply, SAPEI cable dummy.



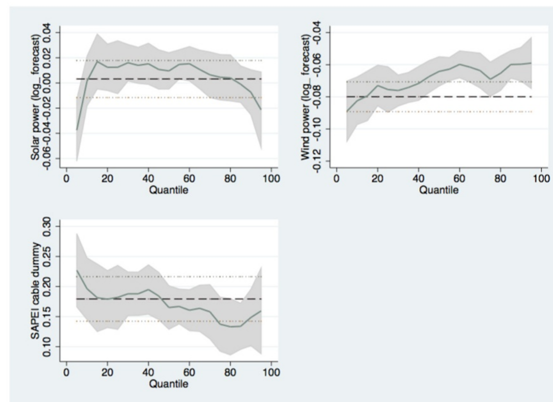
(a) North



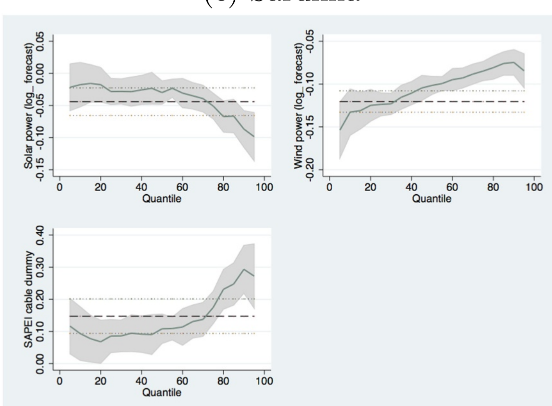
(b) Center-North



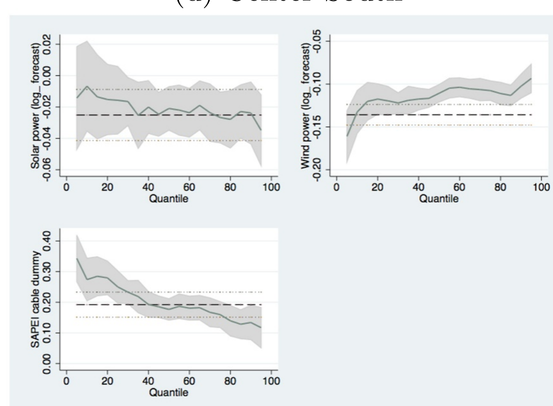
(c) Sardinia



(d) Center-South



(e) Sicily



(f) South

Fig. 8. Quantile regression estimates, robustness III (annual dummies). Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: log-solar power supply, log-wind power supply, SAPEI cable dummy.

of congested hours on the lines linking it with the other zones with which it is connected.[17] In the baseline specification, we had not considered that the price in a zone can be influenced by congestion in the lines connecting it with the other market zones. Indeed, the inability of renewables in some zones to challenge price peaks might hide the influence of congestion. Typically, when there is congestion in import the price goes up, while conversely the price decreases with congestion in export. Results on the impact of renewables do not change much (Fig. 7): the effect of solar power is confirmed negative with an implied volatility increase, except in Center-South (not significant), Sardinia (positive and increasing coefficients), and Sicily (decreasing coefficients, from positive to negative). The merit order effect from wind is confirmed, with some slight change in parameter estimates, but a volatility-increasing effect is detected only in Sicily. More remarkably, though, positive and increasing coefficients for the SAPEI cable appear in Center-South and in Sardinia. The congestion coefficients for the Center-South zone, not reported here for the sake of space, have the expected signs for CS-South (positive) and CS-CN (negative), but are negative also for the CS-Sardinia linkage. The congestion coefficients in Sardinia are positive (Sardinia-CS) and negative (Sardinia-CN).

Third, it is useful to relax the assumption that a stable model

[17] The share of congested hours on the Sardinia - Center-South line is set equal to 1 before the inception of the SAPEI cable.

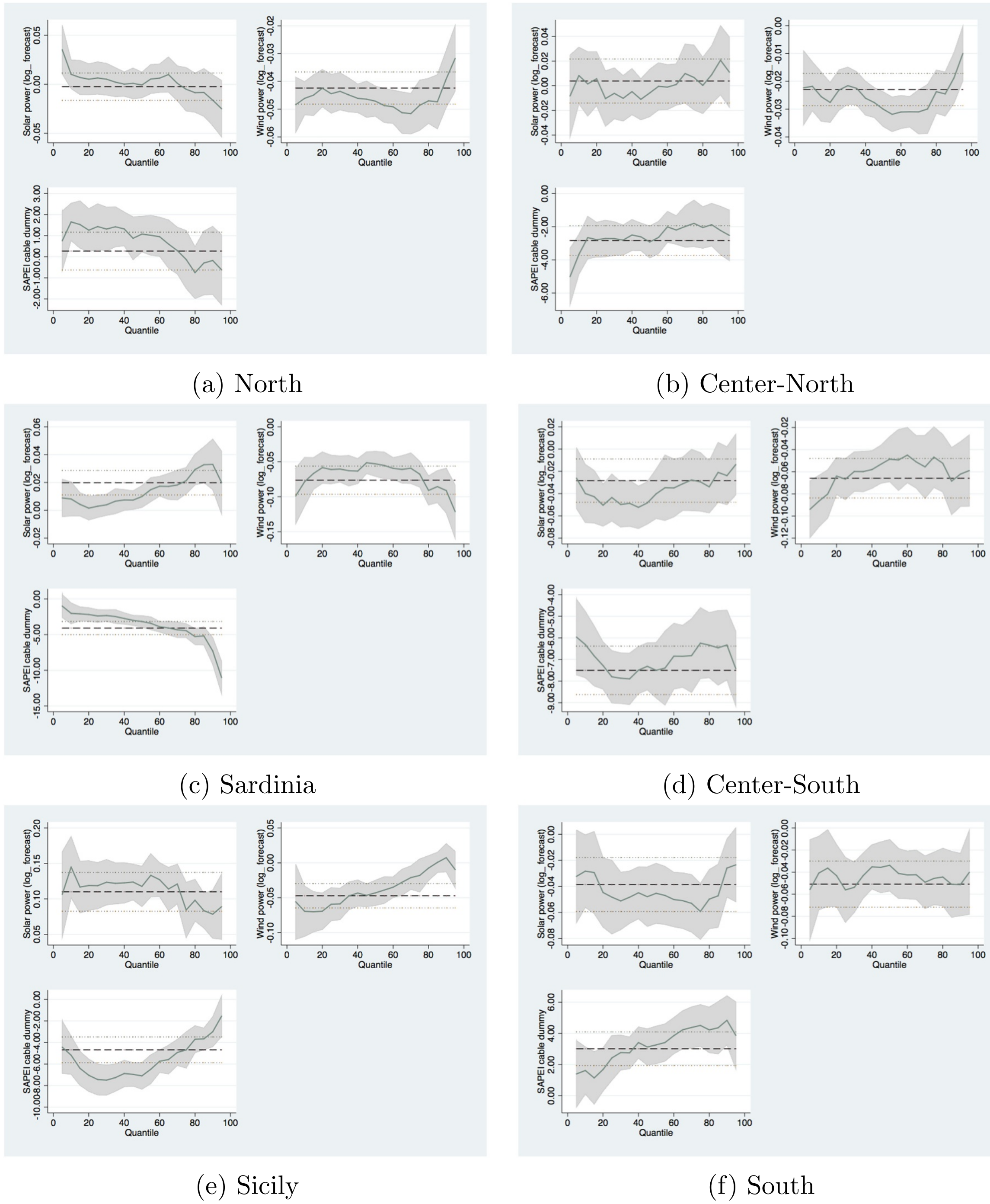


Fig. 9. Quantile regression estimates, robustness IV (complementarity). Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: log-solar power supply, log-wind power supply, SAPEI cable dummy.

intercept exists over nearly 10 years of data. Annual dummies are thus inserted among the explanatory variables (Fig. 8).[18]

Whereas merit order effects from wind power are confirmed, the inclusion of annual dummies implies that solar power coefficients lack significance in most zones, except South and Sicily. This is casting doubts on the robustness of solar power effects on prices. As implied by estimates, wind power pushes up volatility in Center-South, South, and Sicily. Interestingly, cable coefficients turn positive. A possible interpretation of such estimates concerning the SAPEI cable is that, in the period after the cable inauguration, other drivers affected electricity prices more strongly than the cable itself. Such a story is suggested by the negative annual dummy coefficients for Sardinia from 2013 onwards, even though positive shifts in the recent years are detected for the other zones.

A final test deals with whether renewables and interconnection are complementary in their effects on prices, by interacting the cable dummy with renewables and all other regressors. This is consistent with Veit et al. (2009) who found, through simulations of an agent-based model of the German electricity market, that the merit order effect of

[18] The default year is 2006. Another empirical strategy to tackle this issue could rely on time varying effects, as done by e.g. Ketterer (2014) or Sapio (2015). However, this would greatly increase the already high numerical burden involved in estimating quantile regressions.

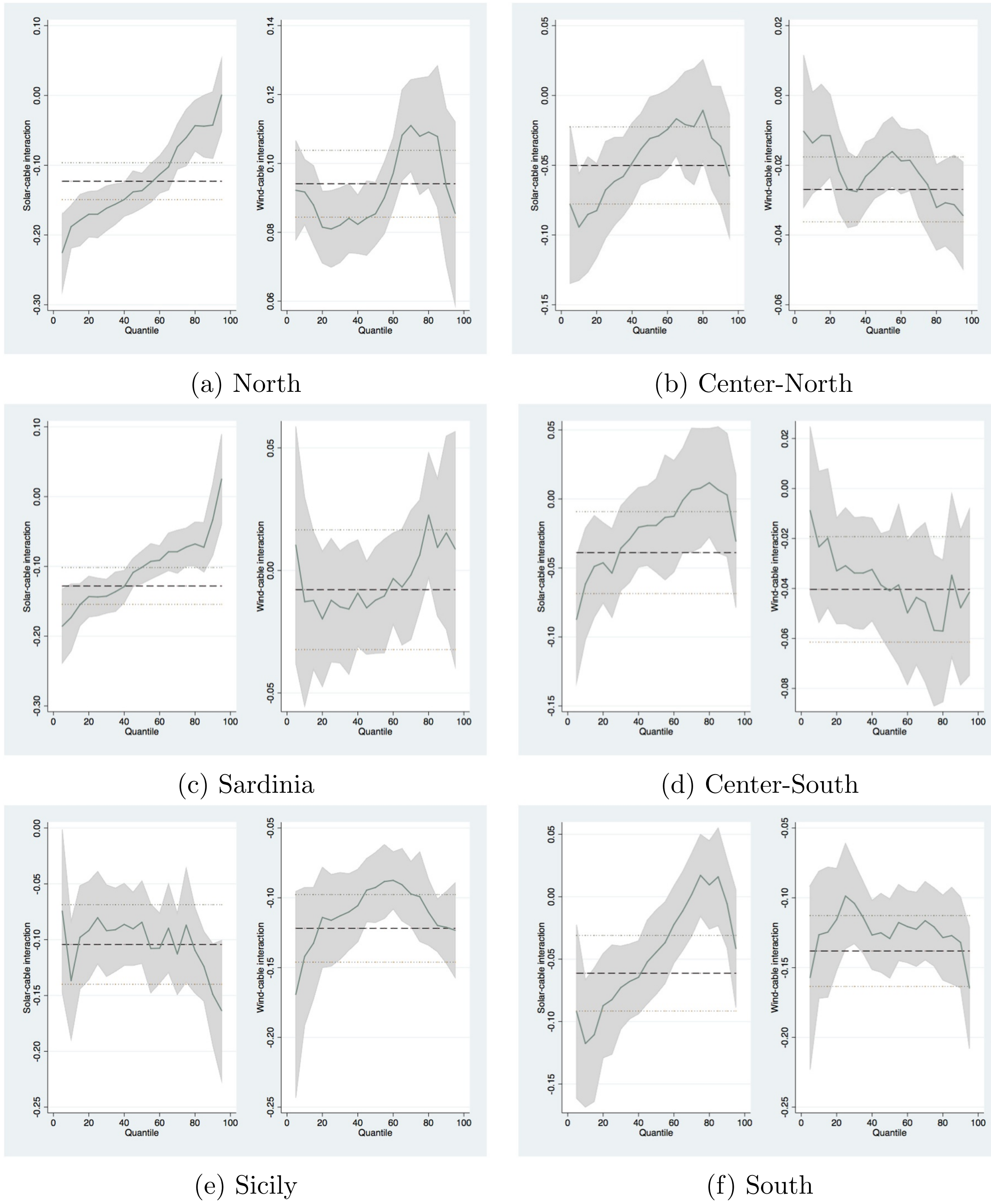


Fig. 10. Quantile regression estimates, robustness IV (complementarity). Sample: Italian day-ahead electricity prices (daily averages), 13 Sep 2006–31 Jul 2015, 6 market zones. Variables: interaction terms (cable*solar, cable*wind).

renewables was stronger when there were no transmission constraints. Annual dummies are not included in this specification.

Results in Fig. 10 show that the coefficients associated with the interaction terms cable*solar are significantly negative; those involving the cable*wind interaction are significantly negative as well, but in the North (positive) and Sardinia (not significant). Hence, in the post-cable period the merit order effects are strengthened. In Fig. 9, the (non-interacted) solar output coefficient is variable across zones (negative in South and Center-South, lacking significance in North and Center-North, positive in the islands). Concerning non-interacted wind, its coefficients remain negative, meaning that a merit order effect from wind was there before 2011, when the new cable was not yet operational. There is however some loss in statistical significance in Sicily and South. The SAPEI cable coefficients in these new estimates are not everywhere negative as expected (e.g. positive in North and South), suggesting that in some zones the cable delivered its price reduction effects mostly in conjunction with renewables.

4.3. Summary and discussion of results

The estimates described above allow to grasp the relationship between renewables penetration, market integration, and the statistical distribution of electricity prices, quite consistently with the expected results outlined in Table 4, albeit with some exceptions.

The merit order effect is confirmed, both for solar and wind power production, but the conditional electricity price distribution reacts differently to the two sources, and there is some zonal heterogeneity. Solar power has exercised a greater impact on the lower quantiles, namely in days when electricity prices are low, than on the upper ones, when in fact the merit order effect would be most needed. Though, this pattern is not observed in Sicily and South, where solar power delivered a stronger peak-shaving effect, and lacks statistical significance when annual dummies are included. The record for wind power is mixed, as it has everywhere exercised a downward pressure on prices at all quantiles, but with some relatively stronger peak-shaving effect only in Sardinia and Center-South. Consistently, solar power is found to magnify volatility, as testified by the increasing profile of coefficient across quantiles, whereas the volatility effect of wind power is less clear.

Further, the SAPEI cable has brought prices down, a sign of price convergence across zones, except in the South, whereas the volatility mitigation effect is confirmed everywhere (as shown by declining coefficients across quantiles). In particular, coefficients at higher quantiles in Sardinia are significantly negative and larger in magnitude than at lower quantiles, indicating a noticeable peak-shaving effect. The effect estimated at the median is only a fraction of the effect detected at the upper quantiles, suggesting that estimators focusing on the average of the log-price distribution may have underestimated the full effects of market integration.

Overall, these results on renewables suggest that increasing the penetration of green energy has worked as a pro-competition tool, but peak-shaving effects differ across sources: solar power may have been unable to deliver its downward pressure on price when it was most needed - i.e. in days of higher prices. This is consistent with the theoretical prediction by Acemoglu et al. (2017) that power generating companies strategically use capacity in order to offset the merit order effect, such as when renewable generating facilities are owned in portfolios including conventional units as well.

Another interesting result is obtained upon controlling for complementarity between renewables: the merit order effect of solar power is switched off in North and Center-North in the period after the new cable, when also the merit order effect of wind power in Sicily and South becomes weaker. However, this does not mean that prices have not been affected by renewables: negative and significant coefficients of the solar*cable and wind*cable interactions reveal that greening and market integration have worked jointly towards cheaper electricity. Such a complementarity is however less pronounced and less clearly estimated in the zones that have been connected by the SAPEI cable. However, the beneficial peak shaving effects of wind and of the cable in Sardinia and Center-South are robust to controlling for complementarity.

5. Conclusion

This paper has assessed how the probability distribution of wholesale electricity prices in Italy changed in response to potentially pro-competitive transformations of the industry, such as an increasing penetration of renewables and a new transmission cable. The assessment has been performed through quantile regressions on a sample covering the period from September 13 2006 to 31 July 2015.

The results confirm the merit order effects detected in the existing literature (Ballester and Furió, 2015), according to which renewables crowd out more expensive units and therefore put a downward pressure on market-clearing prices (Jensen and Skytte, 2002). In the sample, this is true for both photovoltaics and wind power, and with an implied increase in volatility mainly from photovoltaics, even though not in all zones. The merit order effect of solar power is detected mostly in the body of the electricity price distribution and in the lower quantiles, namely in market conditions when prices were already moderately low, and may be confounded with long-term drivers as captured by annual dummies. The new cable has apparently challenged the ability of power generating companies to extract value through price spikes and has mitigated volatility. Some differences across zonal markets are nonetheless detected. Robustness checks suggest that renewables and the cable mostly delivered their price reduction effects jointly or, in other words, the merit order and peak-shaving effects of renewables have been comparatively stronger in the post-SAPEI period.

From a policy-making viewpoint, it is worth noting that the increase in volatility from renewables, detected through quantile regressions, is not simply due to their intrinsic intermittency, but it is more specifically related to a larger spread between the baseline prices (those in the mid-to-low quantiles) and the peaking prices (i.e. the upper quantiles). The few existing attempts at theoretical modelling of the merit order effect, such as the analysis in Acemoglu et al. (2017), suggested that when both renewables and conventional sources belong to the same portfolio of a power generating company, the merit order effect can be neutralised by appropriately tuning the supply of electricity from storable resources (fossil fuels, water). The present results on the top quantiles, where coefficients associated to solar power are negative but smaller in magnitude, are consistent with this story, as well as with theoretical results in Milstein and Tishler (2011) and simulations in Guerci and Sapio (2012), according to which renewable penetration did not manage to deplete the markups on costs. Recent evidence in this direction has been reported by Ballester and Furiò (2017). The existence of a merit order effect at lower quantiles, instead, may suggest an extension of the models by Acemoglu et al. (2017) and Milstein and Tishler (2011), that would better allow to identify market conditions under which market power exercise offsets the potentially pro-competitive role of clean energy.

All in all, finding that the merit order effect is not always stronger when it is more needed sounds like a pessimistic assessment of policies supporting renewables, as far as their monetary effects are concerned - while not doubting their contributions in the fight against disruptive climate change (Atalla et al., 2018). It can be argued that a pro-competitive turn in the electricity industry could be reached by appropriately localising green energy generating facilities across regions without bearing the significant costs of building new transmission lines. The present results imply that such a solution is insufficient or, alternatively, that the spatial distribution of renewables observed in the period at hand is sub-optimal with respect to achieving the competitive benchmark. One conjecture, indeed, is that southern regions and islands have not invested enough in renewables, despite climatic conditions and geography that are more favorable to wind and solar power generation (see e.g. the data on renewable energy potentials in Guerci and Sapio (2012) and compare them with data from the most recent GME Annual Reports), but perhaps tighter financial constraints. More research would be needed to clarify this issue.

A richer picture will be attained through further steps in this research programme, which involve accounting for endogenous market power and congestion patterns, regime switches, or performing estimates on different hourly auctions, with a view to overcoming the present limitations of the analysis. Including more recent data would also be essential, although the joint occurrence of regulated price setting in Sicily and the temporary closure of nuclear plants in France would make the interpretation of results rather challenging. The effects of those events have not yet been studied in the literature, with one partial and noteworthy exception represented by a working paper by Rinne (2018), who is studying the effects of the French nuclear shock on the German electricity market.

Another route for future research acknowledges that collusive practices are harder to enforce in pay-as-bid auctions (Fabra, 2003). Regulatory discussions almost led to replacing the day-ahead uniform price auction in the Italian Power Exchange in 2009 under pressure from industrial consumers, before the project was halted by the new government. The pro-competitive properties of pay-as-bid auctions make one conjecture that in pay-as-bid markets the effect of renewables on the upper quantiles would be more sizeable. The regulatory debate may be re-opened should new empirical results confirm this conjecture.

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