

Fractional integration models for Italian electricity zonal prices

Angelica Gianfreda and Luigi Grossi

Abstract In the last few years we have observed an increasing interest in deregulated electricity markets. Only few papers, to the authors' knowledge, have considered the Italian Electricity Spot market since it has been deregulated recently. This contribution is an investigation with emphasis on price dynamics accounting for technologies, market concentration and congestions as well as extreme spiky behavior. We aim to understand how technologies, concentration and congestions affect the zonal prices since these ones combine to bring about the single national price (*prezzo unico d'acquisto*, PUN). Implementing Reg-ARFIMA-GARCH models, we draw policy indications based on the empirical evidence that technologies, concentration and congestions do affect Italian electricity prices.

Key words: Congestions, Electricity Prices, Long Memory, Market power, Statistical analysis of financial data

1 Introduction and literature review

Electricity prices display interesting features at daily level: mean-reversion, seasonality, time varying and clustered volatility, inverse leverage effect and extreme values called spikes or jumps, see for instance [9] and [5] among others.

Earlier contributions proposed several specifications for the electricity price process, taking into account traded volume, price volatility, demand and margin as in [8] and again power consumption and water supply as in [9]. Hence we have found precedents, but none of these has been employed in the first empirical investigations on the Italian market, see [2]. Following [7], we propose to consider possible congestions among zones, where a *congestion* is identified every time we observed different zonal prices. The technical factors underlying transmission network con-

University of Verona, Department of Economics, Via dell'artigliere, 19, 37129 Verona
e-mail: angelica.gianfreda@univr.it and luigi.grossi@univr.it

gestions may have a crucial influence over the behaviour of generators resulting in the allocation of production and this may affect the final prices paid for electricity. Hence generation, congestions and market power are strongly interdependent factors as stated in [4].

A generator has market power if it is able to raise the electricity price above marginal cost without experiencing a significant decline in demand. Previous studies focussed on this topic in the electricity generation sector relying on oligopoly theory, implementing simulation techniques to model the electricity generators' behavior. For a survey on models to detect market power see [3]. Traditionally, analysts and anti-trust regulators investigate market power issues using various measures of market concentration such as the popular *Hirschmann-Herfindahl* index (HHI), the *residual supply index* (RSI) and the *Lerner* index. Since there is not a consensus on which measure is the best indicator of market power for the electricity markets, because there is a number of factors to account for (transmission constraints are an example), we have decided to consider two structural indexes (the HHI and the RSI) provided by the Italian system operator (*Gestore del Mercato Elettrico*, GME).

Extreme values or spikes are results of abnormally large variations in price caused by weather conditions, outages or transmission failures ([11]). The influence of extreme observations is not generally considered in studying the generating processes of electricity time series, but the bias induced by outliers on model estimates is a very well-known problem, see [1] and cited references. We propose to treat daily spikes with median daily prices and consider network congestions as proposed by [7] recalling that the Italian market is segmented showing characteristics as those of Nord Pool because the most congested links identify aggregations of zones.

Summarizing our contribution, we propose a price dynamic modeling which takes into account simultaneously long memory, production technologies, concentration and congestions. We also provide evidence that the special zonal structure of this market must be considered when modeling these prices since all series have weighted influence in determining the single national price.

2 The Zonal Market Structure, Technologies, Concentration and Congestions

The Italian wholesale electricity market started its operations in April 2004 but became an Exchange only in 2005 registering an increasing in traded volumes from 73 TWh in 2004 to 232 TWh in 2008. It is important to emphasize that, since this market is comparatively young, there are continuous structural changes as for instance the abolition of the Calabria zone and its inclusion in the Southern zone starting from the beginning of 2009. Furthermore, the market has come to a steady phase only in the last years. Hence, our investigations refer only to a time period going from January 2007 to the end of 2008.

Italian electricity is produced by the following plants: thermal power plants only with coal, or with fuel oil or with natural gas; multifuel thermal power plants with oil and coal or with oil and natural gas; combined cycle gas turbines (CCGT); hydro power plants with pumped storage, with run of the river (fluent) or with reservoirs (modulation); gas turbine plants (GT); wind power plants and finally other generation plants not included in the previous ones. These technologies, used in ([6]) to detect influences of generation sources on price and volatility dynamics, have been clustered into the following six types of the marginal technology index (MTI) distinguishing between oil, gas and coal producing plants: *Coal* (all multifuel and thermal power plants with coal), *Thermal* (plants without coal), *Hydro*, *Wind* (renewables), *CC* represents combined cycles (CCGT and GT) and finally *Other* is meant for plants not included in the previous ones. In this work we compute for every group of technology the number of hours (frequency) in which it has fixed the price over the corresponding zone and we built a set of 6 dummies, one for each group, and we attributed one to the group with the maximum frequency over the day and zero to the others. Formally, let f_{rjt} the number of hour for the r -th technology group used in zone j on day t . The dummy variable for the r -th group in zone j is then defined as $d_{rjt} = 1$ if $f_{rjt} = \max_r(f_{rjt})$ and $d_{rjt} = 0$ otherwise. Relying on a preliminary analysis, it is possible to exclude two technologies, *Wind* and *Other* in all zones, since they have a low influence compared to the other sources.

Beside technologies, we want to analyze the effect of market power on wholesale prices. Hence we have considered the *Hirschmann–Herfindahl* index (HHI) and the *Residual Supply* index (RSI), whereas the *Lerner* index could be constructed on zonal basis once marginal costs of technologies will be available.

The HHI measures the degree of concentration and dispersion of volumes sold (and/or offered) by market participants for each hour and each zone. It is the sum of the shares of volumes sold in the market by market participants. The range values of this index are 0 when there is *perfect competition* and 10,000 points when there is *monopoly*. From a preliminary analysis of the Italian zonal HHI provided by GME (figures are not reported for lack of space), it is possible to state that in all Italian zones (apart from North) there is a poor competition on the generation side producing expectations on a direct relation between price and HHI, since when the latter increases then the price should increase as an effect of market concentration (or market power).

The RSI index measures the presence of residual market participants necessary to cover the total demand, thus the index measures the ex-post residuality. The hourly zonal RSI published by GME has the following formulation

$$RSI_i(j, h) = \sum_{l=1, l \neq i}^N S_l(j, h) - V_i(j, h) \quad (1)$$

where $l, i = 1, \dots, N$ are market participants, j represents the individual zones, h is the considered hour and finally V_i are volumes sold by the i -th participant. This difference between the total supply and the sum of i th sellers' supply (or in other words the quantity offered by other market participants) represents the *non-contestable*

volumes. Hence dividing this quantity by the total quantities sold in one zone at one particular hour, we determined the hourly and daily aggregated RSI_i . If the index is less than 1, then the i th firm is necessary to cover the demand and so it is a *pivotal* supplier in the market; if the index is greater or equal to 1, then the i th firm is not necessary and the market can be considered competitive.

The last issue we considered in this work is the influence of grid congestions on prices. In this paper we only consider five physical national zones which are (until 2008): North, Central North (CNorth), Central South (CSouth), South and Calabria (Calb). The two isles (Sardinia and Sicily) have not been considered because these are highly concentrated due to the limited connection to the peninsula. Electricity flows in both directions, and so a congestion occurs every time the transmission capacity is exceeded. We identify and define daily time series of frequencies of congestions every time we observe different zonal prices among contiguous zonal couples which are North–CNorth, CNorth–CSouth, CSouth–South and South–Calb.

3 Model Specifications and Empirical Results

A preliminary empirical analysis of the Italian zonal market carried out using daily medians of prices has provided evidence of the presence of seasonality at daily level and a long memory autocorrelation structure.

Figure 1 represents correlograms (AutoCorrelation Function, ACF, and Partial AutoCorrelation Function, PACF) for seasonally adjusted prices collected in the Northern zone. Seasonal adjustment has been carried out by using a linear model with dummy regressors for days of the week and calendar effects (*CalEf*). The pattern of ACF is typical of a long memory process, while the first few lags of the PACF are outside the probability bands. This means that the seasonal adjustment did not capture all the weekly seasonal dependence of the series. For this reason we decided to use the original series as dependent variable and explicitly model the seasonal pattern of the series. Long memory is usually captured by fractionally integrated processes. Taking into account the autocorrelation structure we could estimate ARFIMA models with seven Autoregressive terms, that is a ARFIMA(7,0) or seven Moving Average terms, that is a ARFIMA (0,7). Another stylized fact that should not be neglected is the mean reversion of electricity prices which is usually estimated by a one-lag autoregressive term. For this reason we added one AR term also in the case of the ARFIMA model with seven Moving Average terms. Finally the two estimated ARFIMA models are: ARFIMA(7,0) and ARFIMA(1,7). Residual diagnostics (tables are not reported for lack of space) from these models show that ACF and PACF functions are inside the confidence regions, but the null hypothesis of homoscedasticity according to the Engle LM test cannot be accepted. For this reason we estimated ARFIMA-GARCH models. Now all residuals diagnostics lead to the acceptance of the model (see Table 3 for the ARFIMA(1,7)–GARCH(1,1) model). Comparing the information criteria (AIC and BIC), the best model seems to be the ARFIMA(1,7)–GARCH(1,1), which is the model we used as a basic one

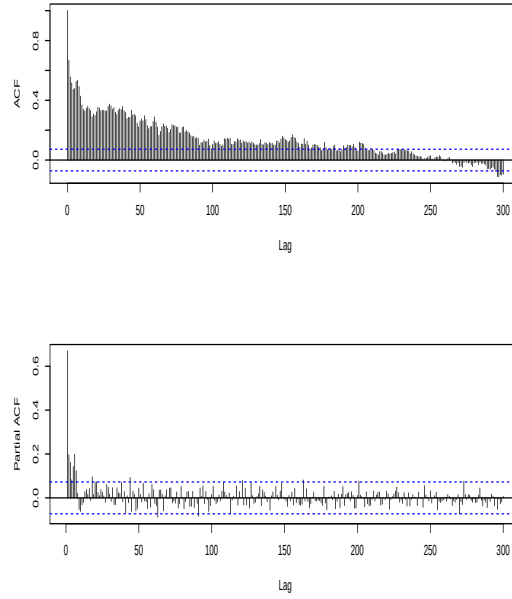


Fig. 1 Autocorrelation functions of seasonally adjusted prices for North

for testing the influence of exogenous explanatory variables on wholesale prices. To take into account the presence of many extreme values and consequent fat tails of the distribution of electricity prices, we estimated the models under the assumption of different distributions for residuals. The best performance has been obtained using a Student- t distribution.

Hence, the effect of exogenous factors on wholesale prices has been measured implementing Reg-ARFIMA-GARCH models [9] with dummies for group of technologies, frequencies of congestions and the market concentration index.

The proposed models can be formalized as follows:

$$(1 - L)^d(y_t - \mu_t) = \varepsilon_t + \theta_1 \varepsilon_{t-1} + \dots + \theta_q \varepsilon_{t-q} \quad \varepsilon_t | I_{t-1} \sim NID(0, \sigma_t^2) \quad (2)$$

where

$$\sigma_t^2 = \omega + \alpha \varepsilon_{t-1} + \beta \sigma_{t-1}^2 \quad (3)$$

for $t = 1, \dots, T$, y_t is the zonal median electricity price at time t , L is the lag operator defined by $Ly_t = y_{t-1}$ and $\mu_t = E(y_t | I_{t-1})$ is the mean equation conditioned to the set of information available at time $t - 1$. The $\theta_j \varepsilon_{t-j}$ terms represent the moving average component of the price dynamics with coefficients θ_j for $j = 1, \dots, q$. The following specification has been considered for the conditional mean function:

	NORTH	CNORTH	CSOUTH	SOUTH	CALB
Q-Statistics on Standardized Residuals					
Q(15)	0.302	0.406	0.340	0.369	0.251
Q(20)	0.234	0.560	0.656	0.724	0.454
Q(30)	0.112	0.373	0.242	0.394	0.165
Q-Statistics on Squared Standardized Residuals					
Q(15)	0.581	0.915	0.704	0.627	0.749
Q(20)	0.640	0.972	0.718	0.609	0.775
Q(30)	0.635	0.552	0.042	0.715	0.929
Diagnostic test based on the news impact curve (EGARCH vs. GARCH)					
Sign Bias Test	0.542	0.594	0.459	0.274	0.535
Negative Size Bias Test	0.851	0.620	0.820	0.674	0.835
Positive Size Bias Test	0.712	0.780	0.719	0.682	0.512
Joint Test	0.749	0.891	0.720	0.479	0.618
LM Engle test					
ARCH 1-2 test	0.742	0.984	0.851	0.750	0.744
ARCH 1-5 test	0.390	0.990	0.362	0.294	0.342
ARCH 1-10 test	0.575	0.835	0.475	0.385	0.511

Table 1 P-values of residuals diagnostic tests for ARFIMA(1,7)–GARCH(1,1) models estimated in five zones

$$\mu_t = \phi_1 y_{t-1} + \lambda_1 Tech_t + \lambda_2 MarPow_t + \lambda_3 Cong_t \quad (4)$$

where the $\phi_1 y_{t-1}$ term represents the autoregressive component of the price dynamics for $t = p + 1, \dots, T$. *Tech*, *MarPow* and *Cong* are respectively the dummy variables indicating the *technology group* determining the price, the index of *market power* and finally *Cong* are dummies for daily *congestion* events, λ s are regression coefficients.

Table 2 shows the maximum likelihood estimates of Reg–ARFIMA–GARCH parameters applied to time series of daily median prices. Looking at estimates, we can draw the following conclusions:

1. *Calendar effects, seasonality, fractional integration* as well as *volatility clustering* are important and salient features to take into account since the estimates of *CalEf*, days of the week, d , α and β are always significant. Moreover d is less than 0.5 for all zones, as found previously in [6], hence confirming that these price processes have long memory.
2. The *autoregressive structure*, that is the ϕ_1 term, is found to be important to capture the stylized fact of mean–reversion of electricity prices. Whereas the inclusion of moving average terms has been used to obtain white noise residuals.
3. The employed *groups of technologies* determining the zonal prices are generally significant across zones. In details looking at Table 2, *Combined Cycles* (CC) always reduce electricity zonal prices, whereas *Thermal power* (TNC) generally increases them.

4. *Concentration* (or market power) has been analyzed considering two indexes. Since we have found that the HHI has a controversial impact¹, only results with the RSI has been reported. The RSI indicates competitive markets when it approaches one, hence it should reduce the zonal prices but instead we always observe a positive sign.
5. *Congestions* are important only in North and CNorth. In the first case, it can be argued that when congestions affect the Northern zone, demand could be satisfied by imports. On the other hand, when congestions occur in CNorth electricity prices raise because of an excess of demand. Interestingly and not surprisingly, prices in CSouth, South and Calabria are not influenced by congestions².

	NORTH	CNORTH	CSOUTH	SOUTH	CALB
Const (mean)	54.09 (***)	50.64 (***)	54.35 (***)	51.89 (***)	36.30 (***)
RSI	0.77 (***)	0.11 (**)	0.04	0.17 (**)	0.18
Cong	-2.89 (***)	1.18 (**)	2.15	0.80	1.96
CC	-1.37 (**)	-0.68	-1.44 (**)	-1.55 (**)	-1.69 (***)
TNC	1.30	1.38 (*)	1.84 (***)	1.74 (**)	2.16 (***)
CalEf	-12.55 (***)	-21.83 (***)	-22.32 (***)	-22.89 (***)	-21.81 (***)
Mon	8.22 (***)	20.14 (***)	20.17 (***)	19.80 (***)	18.99 (***)
Tue	11.11 (***)	21.27 (***)	21.14 (***)	20.89 (***)	20.41 (***)
Wed	10.84 (***)	21.07 (***)	21.17 (***)	20.96 (***)	20.58 (***)
Thu	10.11 (***)	20.51 (***)	20.41 (***)	20.18 (***)	19.89 (***)
Fri	8.76 (***)	19.86 (***)	19.29 (***)	18.89 (***)	18.86 (***)
Sat	2.16 (**)	5.59 (***)	5.90 (***)	6.44 (***)	6.09 (***)
d-Arfima	0.50 (***)	0.49 (***)	0.48 (***)	0.47 (***)	0.49 (***)
ϕ_1	0.19 (**)	0.22 (*)	0.19 (***)	0.13 (**)	0.18 (**)
θ_1	-0.26 (**)	-0.23 (**)	-0.16	-0.14	-0.16
θ_2	0.00	-0.10 (**)	-0.14 (***)	-0.14 (***)	-0.12 (***)
θ_3	-0.02	-0.03	-0.05	-0.07	-0.08 (*)
θ_4	-0.01	0.00	0.00 (***)	0.01	0.02
θ_5	-0.03	-0.01	0.01	-0.01	-0.01
θ_6	0.04	0.07 (*)	0.03	0.03	0.02
θ_7	0.22 (***)	0.22 (***)	0.24 (***)	0.24 (***)	0.22 (***)
ω	1.08	2.39 (*)	1.74 (*)	2.24 (*)	2.03
ARCH Alpha	0.06 (***)	0.12 (***)	0.10 (***)	0.12 (***)	0.10 (***)
GARCH Beta	0.92 (***)	0.86 (***)	0.89 (***)	0.86 (***)	0.88 (***)
Student(DF)	6.37 (***)	4.42 (***)	4.85 (***)	5.21 (***)	5.10 (***)

Table 2 Reg-ARFIMA estimates (with p-values in brackets) for Italian Electricity Zonal Prices

¹ It is significant (with a negative sign) in some zones but it turns to be insignificant in some others, whereas it should always have a positive sign: when the HHI increases then the price increases as result of exercise of market power. These results are available on request.

² This could be due to the presence of limited production poles which only inject electricity into the system then providing the necessary supply: Brindisi in the Southern zone and Rossano in Calabria.

4 Conclusions

This paper is an analysis of effects of technologies, concentration and congestions on Italian Electricity zonal prices. According to the most recent contributions in the time series analysis applied to electricity prices for instance [7], we took into account the long memory feature of the generating stochastic process estimating a parameter of fractional integration, which turned out to lie very close to 0.5. A causal analysis in the framework of Reg-ARFIMA-GARCH models confirmed the significant impact of production technologies, market concentration and congestions on these price dynamics. These results can be converted in tentative suggestions for policy indications to be followed when programming the medium-long term energy policy in Italy.

Concluding, we have provided firstly insights on relationships between zonal electricity spot prices, technologies, concentration and congestions and finding significant and coherent parameters, specially for market power and production technologies. In addition, we would like to emphasize that special attention should be spent on the construction of new transmission lines given that generators can serve only if there exists adequate transmission capacity, since the installation of new generating capacity is expected to produce even more and sudden bottleneck problems.

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