Electricity Demand Responsiveness under Time-Of-Use Pricing: An Application to Italian Industrial Customers

Graziano ABRATE

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Fondazione Collegio Carlo Alberto
Via Real Collegio, 30
10024 - Moncalieri (TO)
Tel: 011 670 5250
Fax: 011 6705089
info@hermesricerche.it
http://www.hermesricerche.it

ELECTRICITY DEMAND RESPONSIVENESS UNDER TIME-OF-USE PRICING: AN APPLICATION TO ITALIAN INDUSTRIAL CUSTOMERS[♠]

Graziano Abrate

(University of Pavia, Ceris-CNR, HERMES)

HERMES Research Centre
c/o Fondazione Carlo Alberto
via Real Collegio 30
10023 Moncalieri (TO)
tel 011 670 5250
fax 011 670 5089
email: g.abrate@ceris.cnr.it

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Abstract

In the liberalised market, the wholesale hourly price of electricity will be defined in real time, giving a signal of the effective available resources in each moment of the year. Though most customers will not see this hourly variability on their bill, wholesale prices are likely to act as a benchmark and to influence the structure of retail agreements and retail tariffs. Moreover, the efficiency of the wholesale market will also depend on the aggregate demand elasticity, which is affected by retail pricing policies and by the effective willingness to shift consumption over time by the end user. This paper focuses on the measurement of final customer demand responsiveness, analysing monthly data on medium size Italian industrial consumers facing TOU pricing between 2000 and 2003. The econometric model employs a nested Constant Elasticity of Substitution (CES) input demand function, which allows estimating substitutability of electricity usage across different hourly intervals within a month and across different months. The results show that monthly substitutability is easier than hourly substitutability, and highlight a wide heterogeneity in customer response, suggesting that different pricing policies may be pursued across different industrial sectors.

Keywords: Electricity markets, Time of Use pricing, input demand, elasticity of substitution.

JEL Code: C23, L52, L94

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1. Introduction

The liberalisation process and the introduction of real time pricing in many wholesale electricity markets has increased the attention over the promotion of an active role of the demand side. Several authors have argued that an improvement of the demand elasticity in the wholesale market is desirable to reduce potential for market power by generators (among the others Borenstein and Bushnell, 1999; Day et al., 2002; Ilic et al., 2001). Moreover, the theoretical foundations for the existence of a spot market, which derive from the peak-load theory and its evolutions (e.g. Steiner, 1957; Bohn et al., 1984), can be applied to a deregulated market only if *all* customers are on real time pricing, but that situation is unlikely to represent any electricity system (Borenstein and Holland, 2004). A survey on theoretical issues concerning the role of time differentiated prices in electricity markets can be found in Abrate (2004).

A demand side participation programs can be defined as any possible method used to make the economic incentives of customers more accurately reflect the time-varying wholesale cost of electricity. Time-varying retail pricing schemes may enhance the efficiency of the market reducing the pressure on the capacity during peak hours. However, it is clear that the success of such policies depend crucially on the demand elasticity measured at the final customer level; in particular, it depends on the willingness to shift part of the consumption across time. Given the recent introduction (2004) of the Electricity Power eXchange (EPX), the Italian market has not yet experience with real time rates, but a long history of Time-of-Use pricing accompanies the industrial sector. For this reason, price responsive behaviour is measured on a sample of medium sized industrial consumers facing TOU schemes between 2000 and 2003. The analysis may shed some light on the opportunity of adopting more complex dynamic pricing schemes to this class of consumers.

The interest in energy demand elasticity is early dated in economics, such that a first review of empirical works can be found in Taylor (1975). More recent studies have focused on the measurement of electricity substitutability over time, under TOU pricing (among the others, Aigner, 1984; Aigner et al., 1994; Parks and Weitzel, 1984) or under dynamic prices (Herriges et al., 1993; Patrick and Wolak, 2001; King and Shatrawka, 1994; Schwarz et al, 2002). Many results on demand elasticity are summarised in Lafferty et al. (2002).

Though the international literature has provided many studies on the econometric measurement of electricity demand elasticity under TOU pricing, there is not yet any contribution based on Italian data. Furthermore, most available works has been made on experimental "ad hoc" tariff designs. This work instead uses data concerning the dynamic of the TOU tariff in Italy between 2000 and 2003, exploiting also the variability of the pricing schemes across different typologies of users. The econometric analysis uses monthly data on firm consumption, disaggregated according to the different pricing period. The model involves the estimation of a nested Constant Elasticity of Substitution (CES) input demand function, which allows estimating substitutability of electricity usage across different hourly intervals within a month and across different months. These values should be key variables when designing time-varying pricing policies, since they can be used to predict their impact on the load profile.

The structure of the paper is the following. After providing a brief overview of the tariff regulation in Italy (Section 2), I move more specifically to the description of time-dependent mechanisms which are applied to non residential customers. In Section 4, I describe the database; then Section 5 presents the econometric model and Section 6 concludes giving some policy indications.

2. An overview of tariff regulation

In Italy the role of defining the electricity tariff system is attributed to the Regulatory Authority for Electricity and Gas, an independent body which was established by the Law 481/1995 and is fully operating since April 1997.[1] The task of the Authority, as defined by the Law, is "to guarantee the promotion of competition and efficiency while ensuring adequate service quality standards". The main instrument is a "transparent and reliable tariff system, based on pre-defined criteria, which is required to reconcile the economic and financial goals of operators with general social goals, with environmental protection and the efficient use of resources".

The role of the Authority must be understood in the context of a progressively liberalised market. When, in March 1999, the Italian Parliament published Legislative

Decree 79/1999 (the Bersani Decree), following the outlines given by the European Directive 92/1996, it was clear the aim of unbundling the productive structure, to allow for competition in the phases of generation and retailing. In the meantime, the demand side was divided in two distinct markets, creating a transition between the previous monopolistic structure and the liberalised market. Therefore, only a part of the demand (*eligible customers*), corresponding to the largest non-residential consumers, was given the option to choose its own supplier, stipulating with them bilateral contracts (or, since January 2005, directly buying from the Power Exchange).[2] The other customers still remained *constrained* to their local distributor as in the past. The criteria for being "eligible" has progressively evolved: the minimum annual consumption required (1,000,000 kWh in 2000) was reduced to 100,000 kWh in May 2003; nowadays, all non-residential customers are eligible (since July 2004), while residential customers are still constrained until July 2007. According to the annual report of the Authority (2004), 40 per cent of the electricity was sold in the liberalised market in 2003, revealing an increase of 13 percentage points with respect to 2001.

Given this dynamic context, the functions of the Authority can be roughly summarised as follows:

a) favouring the development of a competitive market in the liberalised activities (generation, retailing);

b) setting the tariff components (i.e. the maximum price allowed) for the services which are not liberalised: in particular, the phase of transmission, reserved to the State and assigned to GRTN (Manager of the National Transmission Network), and the phase of distribution, assigned to local monopolists;

c) setting the tariff components with reference to the liberalised activities for the electricity sold in the constrained market. In this way, from one hand, the Authority gives protection to that part of demand which still cannot choose the supplier; from the other hand, she creates a benchmark for eligible customers, who may eventually decide to stick to the constrained market.

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[1] Formerly, the tariff was defined by the Interdepartmental Committee on Prices (CIP).

[2] Actually, the Power Exchange is operating since April 2004, but in a first period the demand side was not allowed to actively participate.

The current tariff system has been defined by the Authority with the Integrated Text for the period 2004-2007 (Attachment A to Decision 5/04, 30th January 2004). Tariffs are differentiated among categories of consumers: the main classification is between residential and non-residential customers, but further differentiation is defined according to the level of consumption, to the installed power, to the voltage. The tariff is vertically structured in the sense that its components are defined to cover the costs of each segment of the productive chain. Table 1 summarises the various components and their regulation; clearly, the customers buying electricity from the liberalised market are not subject to regulation concerning generation and retailing services, since they directly contract their price with distributors, or in the Power Exchange. There are three ways a payment can be specified:

a) fixed payments, which are not correlated to the level of consumption; they are used to cover general system costs, retailing and sometimes distribution service;

b) payments correlated to the power used (per kW); even if this does not depend on the level of consumption, it depends on the amount of "capacity" installed/used (roughly speaking, on the maximum hourly consumption). This type of payment is usually part of the remuneration to the local distributors for the distribution service;

c) payments depending on the actual electricity consumption (per kWh), applied to generation and transmission services, and partially to distribution and general system cost.

The amount to be paid for the distribution service is proposed by the local monopolist under the control of the Authority, which defines the maximum revenues allowed per customer category (first constraint, so called "V1"), and the maximum price to be allowed for each customer (second constraint, so called "V2"). The distributor can offer further tariff options, not subject to "V2".

As to the other components, they are all defined by the Authority. The payment for generation is revised every three months according to the budget needs of the Single Buyer, whose function, defined by the Ministerial Decree 19/12/2003, is to supply the energy relative to the constrained market to the local distributors.[3] Since the Single Buyer purchases a substantial part of electricity in the Power Exchange (56.3 per cent), the periodical revision of the tariff will be affected by the wholesale price variations. In other words, the price paid by constrained customers partially depends on the price paid in the liberalised market. The tariff for generation (as well as for transmission and distribution) can also be differentiated by time of consumption, for customers equipped with time-of-use metering. Other general system components are set up to cover a certain budget decided by the Government (A components) or other costs defined by the Authority (UC components).

Table 1. Structure of the tariff

Service	Who set the price?	Revision	Time-dependent?	Measure	Who pay?
Generation	Authority (depending on Single Buyer needs)	Every three month	Yes	-cents/kWh	Constrained market
Transmission	Authority	Annual	Yes	-cents/kWh	All customers
Distribution	Local monopolists under constraints defined by the Authority	Annual (generally)	Yes / No	-fixed -cents/kW -cents/kWh	All customers
Retailing	Authority	Annual	No	-fixed	Constrained market
General system costs (A-UC components)	Authority (depending on Government needs)	Every three month	No	-fixed -cents/kWh	All customers

3. Time-dependent pricing

The time of consumption can be relevant for the determination of the price paid by the customers. Real time pricing is the most extreme example, but various alternatives to flat rates have been proposed and implemented in practice. In particular, in Italy, two types of incentives to shift consumption across time can be found in tariff mechanisms: time-of-use (TOU) and demand charges.

TOU tariffs exist in Italy since 1980, when they were firstly applied to high-voltage (HV) industrial customers (more then 50 kV), before being extended to medium-voltage (MV) customers in 1982. Thus, the 8760 hours of the year were assigned to 5

[3] Formerly, local distributors were served by ENEL. The institution of an independent body such as the Single Buyer has the function to guarantee the customers of the constrained market, in a way that the price paid for generation services should reflect its effective cost.

time-periods (let us define them F = 1 to 5) corresponding to a different price level (decreasing from F1 to F5).[4] Since 2004, TOU (in this case with 2 time-periods) has been extended to residential consumers. Generally speaking, a TOU structure must be defined according to historical and provisional data on demand. This process can be described in two sequential and interrelated steps:

a) the choice of the distribution of the hours across the various pricing periods. This must be based on information over the systemic load profile, whose knowledge allows separating higher and lower demand states. The system load may be typically higher during certain hours within a day, during working days, or during certain seasons; a TOU structure must firstly define the desired direction for incentives to hourly, weekly or seasonal consumption shifts. This is not trivial, especially because the system load profile evolves over time. In Italy, in 1980 the objective was to induce a shift from winter to summer consumption; now, the demand has evolved and peak-load periods happen more frequently during the summer. Only in the new Integrated Text (2004) the Authority has recognised this trend, revising the time-frame definition of TOU tariffs. For example, while until 2003 the critical peak-hours assigned to period "F1" (maximum price) corresponded only to winter months (October to March), at present they are concentrated in summer months and in December (see Table 2 for a more detailed description of the evolution in the definition of the TOU pricing periods).

b) The second step is to define the degree of price-differentiation across periods. For example, according to Barteselli (1992), the average price per kWh paid by TOU customers in 1989 during peak-hours ("F1") was about 5 times the average price paid in "F5".[5] On the one hand, the choice of price levels requires information on the cost structure, giving a signal of the time varying cost of producing electricity. However, another key parameter is the demand price elasticity, whose knowledge would allow predicting the modifications on the load distribution across time induced by different tariff structures. If for example the price elasticity was 0, the introduction of a TOU cost-reflective tariff would be completely ineffective as a demand policy, since it would not produce any modification on the system load

[4] The number of time-periods was reduced when the time-frame structure was revised by the Interdepartmental Committee on Prices on 19th December 1990 (Decision n. 45).
[5] The average price is comprehensive of fixed, power and electricity charges.

profile. Several international studies have estimated demand responsiveness to time varying price signals (for a survey, see Abrate, 2004). As to the Italian market, Barteselli (1992) gave some insights on the effects of the introduction of TOU. In his analysis, he compared the total load of TOU customers before (1979) and after (1987) the introduction of TOU tariffs, finding that in high demand states (F1 and F2) consumption decreased by 6,88 percent, while low demand states registered an increase of 10,38 percent.[6] The estimation of price elasticity with reference to a sample of Italian non-residential consumers will be the focus of next Sections.

Table 2. Time-of-use in Italy: definition of the pricing periods

	1980-1990		**1990-2003**		**From 2004**	
	Period	**N°hours**	**Period**	**N°hours**	**Period**	**N°hours**
F1	Winter peak-hours	600	Winter peak-hours	520	Peak hours (december, hot days in summer)	410
F2	Winter high-load	1,800	- Winter shoulder - Summer peak-hours	1,812	High-load	1,240
F3	Summer high-load	1,760	Summer shoulder	1,238	Shoulder	1,650
F4	Winter off-peak	2,688	-Winter off-peak -Summer off-peak	5,190	Off-peak (night and weekends)	5,460
F5	Summer off-peak	1,912	_	_	_	_

An additional incentive to shift consumption is represented by the demand charges, i.e. payments that are based on the consumer peak consumption. In the Italian practice, distributors to TOU consumers sometimes apply these mechanisms, and the amount due can be calculated on different bases:

a) The maximum annual (or monthly) power utilisation in each pricing period (i.e. the consumer peak hour consumption in each time-period); in this case the charge per kW can be differentiated among periods. This mechanism was applied by ENEL to TOU consumers in 2001.

[6] More in detail, for high-voltage consumers, he found the following consumption variation (between 1987 and 1979): F1 –8,73%; F2 – 6,13%; F3 +2,99%; F4 + 6,59%; F5 +14,75%. Very similar values were registered by medium-voltage consumers.

b) The maximum annual (or monthly) power utilisation, regardless to the pricing period when it happens. In this case the charge is unique and therefore cannot be time-differentiated; however, there is an incentive for the consumer to flatten his load profile. This mechanism was applied by ENEL to TOU consumers in 2002 and 2003.

Demand charges can impact substantially on the marginal price of consuming in a certain hour; it is worthwhile to recall that this charge depends on the consumer peak and may not be correlated with the system peak hour (especially in case (b)).

Table 3. Sample by Activity Classification

Industry classification	**Number of Customers**	**Number of HV customers**
Agriculture	1	0
Mining and quarrying	3	0
Manufacturing	72	3
Food and beverages	11	0
Tobacco	1	0
Textiles	3	0
Paper, paper products, publishing and printing	7	0
Chemicals and chemical products	11	2
Plastics	8	0
Other non-metallic mineral products	6	0
Basic metals and metal products (except machinery)	8	1
Machinery and equipment	6	0
Office, accounting and computing machinery	9	0
Motor vehicles	1	0
Other manufacturing	1	0
Water supply	22	3
Transport, storage and communications	11	5
Financial intermediation	1	0
Computer and related activities	1	0
Public administration	4	0
Public education	1	0
Public health	14	0
Other community, social and personal service activities	8	0
Extraterritorial organisations and bodies	5	1
TOTAL	**143**	**12**

4. Data

Data were provided by ENEL and cover a sample of 143 industrial customers buying electricity from the constrained market according to TOU tariffs, in the period between 2000 and 2003. For each customer, the consumption is divided among 4 different pricing periods (F1, F2, F3, F4); additional information affecting the billing computation are provided, in particular the maximum power utilisation in each time-period. Monthly data are available from January 2001 to December 2003 (for the 2000 there are only the aggregate information).

Table 3 displays the number of customers associated with each industry classification represented in the sample, specifying the number of HV customers among each industry.[7] The sample includes a majority of medium-voltage MV customers; it is important to note that data refers to the period after the Bersani Decree and HV customers are more likely to be eligible and to move out from the constrained market.[8] Generally speaking, our sample is represented by medium size non-residential consumers, with an average monthly electricity expenditure of about 50,000 Euro and an average hourly consumption of about 1,000 kWh.

Table 4a and 4b describe more in detail the average characteristics of the sample and their evolution from 2000 to 2003 in terms of load and expenditure distribution across the time intervals. In particular, apart from the increase in the average price paid registered from 2001, the most evident trend seems to be a redistribution of the total expenditure among the different time intervals of the year. On the one hand, one can see that the cost share attributed to off-peak has substantially increased over the time, both in winter and in summer; the opposite trend is shown by the share attributed to peak hours (F1 in winter and F2 in summer). On the other hand, the monthly expenditure has increased relatively more in August and other summer months with respect to winter months. This can be explained by the dynamic of prices, whose increase has concerned in particular the cheapest pricing periods. During 2000, the marginal price in period F1 was 5 times the F4 marginal price; moreover, a further great time-differentiation came from the power pricing component, whose amount in

[7] Groups are based on the ISTAT classification (ATECO 2002).
[8] The original data set included 153 firms; 10 firms were excluded from the analysis because of missing data in the time series. Few of them had consumption only in F4, the cheapest time interval, suggesting that they may have a lot of own generation capacity to be used when electricity price is high.

F1 was at least 20 times the amount in F4.[9] Then, the incentive to shift consumption across periods has progressively became less strong (in 2003, F1 price was more or less 3 times the F4 price).[10] In addition, since 2001, power charge has been computed as a demand charge (as described in the previous Section), and its weight on the total expenditure has dramatically decreased from almost 50 percent to less than 10 percent.

Table 4a. Summary statistics (standard deviation in brackets)

Year – Season	**Average Price (€/kWh)**	**Monthly Expenditure (€)**	**Expenditure Share**			
			F1	**F2**	**F3**	**F4**
2000	*0.058 (0.010)*	*31,152 (17,795)*	*0.35 (0..06)*	*0.35 (0.02)*	*0.14 (0.02)*	*0.16 (0.06)*
2001	*0.094 (0.083)*	*53,144 (33,637)*	*0.15 (0.16)*	*0.28 (0.14)*	*0.17 (0.21)*	*0.40 (0.21)*
Winter	0.110 (0.107)	57,438 (39,450)	0.31 (0.08)	0.40 (0.06)	–	0.29 (0.10)
Summer (- August)	0,081 (0.046)	45,358 (30,429)	–	0.20 (0.05)	0.42 (0.06)	0.38 (0.10)
August	0.059 (0.005)	31,702 (29,110)	–	–	–	1
2002	*0.085 (0.021)*	*53,620 (34,783)*	*0.12 (0.15)*	*0.28 (0.17)*	*0.17 (0.21)*	*0.43 (0.21)*
Winter	0.095 (0.025)	49,901 (34,408)	0.26 (0.05)	0.41 (0.06)	–	0.33 (0.10)
Summer (- August)	0.079 (0.012)	43,424 (30,103)	–	0.18 (0.04)	0.43 (0.07)	0.39 (0.10)
August	0.070 (0.011)	33,038 (27.600)	–	–	–	1
2003	*0.087 (0.014)*	*58,497 (34,338)*	*0.12 (0.13)*	*0.28 (0.15)*	*0.18 (0.21)*	*0.42 (0.20)*
Winter	0.096 (0.013)	61,551 (44.334)	0.25 (0.05)	0.41 (0.05)	–	0.34 (0.09)
Summer (- August)	0.072 (0.006)	58,338 (42,182)	–	0.17 (0.04)	0.43 (0.06)	0.40 (0.09)
August	0.069 (0.009)	45,080 (42.983)	–	–	–	1

[9] The payment depended on the potential installed power, while since 2001 the payment depends on the *maximum* power usage. The price in F1 was further differentiated depending on the amount of installed power; in particular it was decreasing.

[10] Probably also the understanding that the time-frame definition of the tariff was no more corresponding to the actual load curve has produced this trend.

Table 4b. Summary statistics (standard errors in brackets)

Year – Season	Average hourly consumption (kWh)				Marginal price (€/kWh)			
	F1	F2	F3	F4	F1	F2	F3	F4
2000	*1,030 (620)*	*1,057 (595)*	*1,134 (594)*	*844 (547)*	*0.057 (0.010)*	*0.040 (0.010)*	*0.023 (0.004)*	*0.012 (0.001)*
2001	*1,052 (772)*	*1,084 (747)*	*1,082 (703)*	*842 (650)*	*0.193 (0.030)*	*0.106 (0.008)*	*0.083 (0.008)*	*0.059 (0.003)*
Winter	1,052 (772)	1,048 (748)	–	824 (665)	0.197 (0.025)	0.107 (0.007)	–	0.059 (0.003)
Summer (-A)		1,128 (745)	1,082 (703)	858 (618)	–	0.106 (0.007)	0.084 (0.003)	0.059 (0.003)
August	–	–	–	882 (722)	–	–	–	0.058 (0.003)
2002	*1,043 (728)*	*1,082 (750)*	*1,101 (749)*	*838 (633)*	*0.159 (0.008)*	*0.103 (0.008)*	*0.081 (0.004)*	*0.059 (0.004)*
Winter	1,043 (727)	1,033 (701)	–	807 (598)	0.162 (0.010)	0.102 (0.005)	–	0.059 (0.003)
Summer (-A)	–	1,141 (803)	1,101 (749)	867 (644)	–	0.104 (0.012)	0.083 (0.047)	0.059 (0.003)
August	–	–	–	874 (761)	–	–	–	0.062 (0.003)
2003	*1,088 (764)*	*1,155 (805)*	*1,205 (826)*	*891 (706)*	*0.171 (0.008)*	*0.106 (0.008)*	*0.088 (0.004)*	*0.060 (0.004)*
Winter	1,088 (764)	1,092 (738)	–	843 (640)	0.169 (0.011)	0.104 (0.005)	–	0.058 (0.004)
Summer (-A)	–	1,230 (873)	1,205 (826)	932 (717)	–	0.109 (0.011)	0.087 (0.004)	0.061 (0.003)
August	–	–	–	976 (965)	–	–	–	0.061 (0.002)

In Table 4b, the marginal price in 2000 does not include the power charge, thus underestimating the time-differentiation of the tariff (it was more properly considered as a fixed charge, even if time-differentiated). Instead, the marginal price does take into account of the demand charge from 2001, since in this case the payment is related to the actual peak of the consumer. In fact, the price of an additional kWh of consumption in a certain hour should also include the demand charge (D) times the probability that the hour will be the peak consumption over the relevant period (Patrick and Wolak, 2001). In our case, we can assume that the probability of being a peak is 1 over the total number of hours of a certain pricing period (H_F):

$$MP_F(per\ kWh) = \frac{D_F(per\ kW)}{H_F} \qquad [1]$$

While this is straightforward until the demand charge is computed on the maximum annual (or monthly) power utilisation in each pricing period, it can raise some issues when it applies to the maximum annual (or monthly) power utilisation, regardless to the pricing period when it happens. In this case, to capture the incentive to flatten the consumer load profile, a positive probability was assumed only for the hours belonging to the pricing period that actually registered the maximum power utilisation.

Table 4b also displays the average hourly consumption in the sample by time intervals and by seasons, showing a natural tendency to increase over the years, especially in summer months. A relation with the dynamic of marginal prices is certainly not intuitive from Table 4b; the econometric analysis on monthly data will provide more information.

5. The econometric model

A wide literature has grown over the estimation of electricity demand (recent surveys can be found in Lafferty et al., 2002 and in Abrate, 2003). Most TOU empirical applications rely on data from an experimental setting, where prices are set ad-hoc to study the customer responsiveness, and a control group still faces the flat tariff. As we have seen in previous Section, our sample includes industrial customers, which faced the standard TOU tariffs in Italy between 2000 and 2003, and were already under TOU in previous years. From one hand, a disadvantage with respect to an experimental setting may be the limited price variability across observations. However, variability still comes from different tariff options across customers, from revision of tariff components by the Authority (every 2 months) and from annual revision of the charge for the distribution service by ENEL. Therefore, it is possible to study the customer behaviour with respect to the dynamic of the tariff.

The basic model employs a procedure set out by Herriges et al. (1993), and extended by King and Shatrawka (1994), Schwarz et al. (2002). The model follows the standard hypothesis of cost minimisation, and electricity is assumed to be a weakly separable input in the production process. This means that the cost function can be written as follows:

$$C = C(Y, q, g(p)) \quad [2]$$

where Y is the output, *g(p)* is the aggregate price index of electricity and q is a vector of other input prices. Moreover, a nested CES functional form is specified, assuming that consumption within months is weakly separable from consumption across months. Thus:

$$g(p) = \left(\sum_{M=1}^{12} \beta_M \left(\sum_{F=1}^{3} \alpha_F (p_{MF})^{\lambda} \right)^{\frac{\gamma}{\lambda}} \right)^{\frac{1}{\gamma}} = \left(\sum_{M=1}^{12} \beta_M (M_M)^{\gamma} \right)^{\frac{1}{\gamma}} \quad [3]$$

The firm chooses the optimal time-allocation of electricity consumption, and the demand equations for electricity in each time interval (F) are derived by applying the Shepard's Lemma:

$$E_{MF} = \frac{\partial C}{\partial g(p)} \cdot \frac{\partial g(p)}{\partial p_{MF}} \quad [4]$$

where E_{MF} is the monthly demand for electricity in a certain time interval F and p_{MF} is the relative price.

This functional form allows for flexibility in electricity use among different hourly intervals within a certain month, through the elasticity parameter $\sigma_F = 1 - \lambda$, and between months in response to a monthly price index (M_M), through the elasticity parameter $\sigma_M = 1 - \gamma$. To better understand the meanings of these two parameters in our context, we must think to the structure of TOU tariffs (2000 to 2003). Within a certain month, the price is differentiated among three time intervals: peak, shoulder and off-peak. The associated elasticity parameter reflects the ability of firms to shift consumption among close time intervals, such as different hourly intervals within a certain day or different days of the week.[11] Moreover, the TOU structure may induce seasonal consumption shifts, since the price associated to peak, shoulder and off-peak is different across different months (in particular between summer and winter; in addition, all hours in August are considered as off-peak). The monthly price index may be further affected by tariff components revisions decided by the Authority.

[11] Hourly and daily substitution cannot be separated because off-peak periods include night hours for all days and all the hours of the weekend. For example, in a winter month, peak hours are defined from Monday to Friday between 9 to 11 a.m. and between 5 to 7 p.m.; shoulders from Monday to Friday between 6.30 a.m. to 9 a.m., between 11 a.m. to 5 p.m. and between 7 p.m. to 9 p.m.; off-peak all the remaining hours in the week (including all non-working days). During summer months the structure is similar but peak hours are defined from Monday to Friday between 8.30 to 12 a.m.

Following Schwarz et al. (2002), it is possible to write the equation for electricity demand in the following way:

$$\ln \frac{E_{MF}}{\overline{E}_{YF}} = A_Y - \sigma_F \ln \frac{p_{MF}}{\overline{p}_{YF}} - (\sigma_M - \sigma_F) \ln \frac{M_M}{\overline{M}} \qquad [5]$$

where:

- E_{MF} is the hourly electricity usage in the time interval F on month M;
- p_{MF} is the electricity price during the time interval F on month M;
- $\ln(E_{YF})$ is the log of geometric mean of consumption during the time interval F over the 12 months of a year:

$$\ln \overline{E}_{YF} = \frac{1}{12} \sum_{M=1}^{12} \ln(E_{MF}) \qquad [6]$$

- $\ln(p_{YF})$ is the log of geometric mean of price during the time interval F over the 12 months of a year:

$$\ln \overline{p}_{YF} = \frac{1}{12} \sum_{M=1}^{12} \ln(p_{MF}) \qquad [7]$$

- $\ln \frac{M_M}{\overline{M}}$ is a monthly price index formed using a Tornqvist price index:

$$\ln \frac{M_M}{\overline{M}} = \frac{1}{2} \sum_{F=1}^{3} (w_{MF} + \overline{w}_{YF}) \ln \frac{p_{MF}}{\overline{p}_{YF}} \qquad [8]$$

- w_{MF} and w_{YF} are weights defined respectively by the monthly and annual share of electricity expenditure during the time interval F:

$$w_{MF} = \frac{p_{MF} E_{MF}}{\sum_{F=1}^{3} E_{MF}} \qquad [9]$$

$$\overline{w}_{YF} = \frac{1}{12} \sum_{M=1}^{12} w_{MF} \qquad [10]$$

- A_Y is constant during a certain year, i.e. it is a vector of binary variables used to control for observation in different years of the time series. A further dummy variable is used to distinguish the month of August from the others. In fact, August is peculiar because all hours are off-peak, since there is a unique price and the time-frame distribution of the load is not known. For these reasons, we want August observations not to influence substitution among time intervals, while still affecting electricity substitutability among different months. Thus, three equal observations (related to each time interval) were generated for August, with [6] and [7] computed averaging also across time intervals.

Given the following definitions:

$$E \equiv \ln \frac{E_{MF}}{\overline{E}_{YF}} \qquad P \equiv \ln \frac{p_{MF}}{\overline{p}_{YF}} \qquad M \equiv \frac{M_M}{\overline{M}} \qquad [11]$$

it is possible to rewrite the estimating equation:

$$E = A_Y + \sigma_F (M - P) - \sigma_M (M) + \varepsilon \qquad [12]$$

where ε is the error term, which embodies the model in a stochastic framework.

Equation [12] provides the basic model that can be estimated for aggregated data or alternatively for each firm. In both cases, each estimation will use 108 observations, corresponding to 3 hourly intervals (F) times 36 months (M). Since the residuals may be serially correlated among each others, the structure of the error term needs to be carefully studied. Herriges et al. (1993) and Schwarz et al. (2002), assumed a first order auto-regressive process (AR(1)). While this assumption is reasonable for their application using hourly data, it is certainly problematic in our context, where the observations are not regularly spaced. For example, suppose to sort observations such that: 1) F=1; M=1. 2) F=2; M=1. 3) F=3; M=1. 4) F=1; M=2. 5) F=2; M=2… and so on. Observation 2 may be correlated with 1, and observation 3 with 2; however, there is no reason to have correlation between observation 4 and observation 3. The same reasoning applies if we sort data in the alternative way: in that case, it does not make sense imposing any correlation between F=1; M=36 and F=2; M=1.

In the rest of the paragraph, I will follow this approach. First, I will estimate the model by using aggregate data, testing the structure of the error term to find a suitable estimator. In a second step, I will apply this estimator also at firm level data, to investigate the individual customer elasticities. Finally, I will discuss how to estimate the whole panel in order to obtain an evaluation of the determinants of heterogeneity in individual customer response.

5.1. Aggregate elasticity

Data may be treated as a panel (3 F x 36 M), where three different types of deviation from the classical OLS assumptions on the error term ($\varepsilon \overset{\text{iid}}{\sim} N(0,\sigma^2)$) are likely to arise:

a) Serial correlation among monthly observation referred to a certain time intervals, i.e. $Cov(\varepsilon_{F,Mi}\varepsilon_{F,Mj} \mid X) \neq 0$. This hypothesis was confirmed by the Lagrange Multiplier test for first order serial correlation (Baltagi-Li, 1995).[12]

b) Heteroskedasticity among time intervals, i.e. $Var(\varepsilon_{Fi} \mid X) = \sigma_{Fi}^{\;2}$, confirmed by the Wald test for groupwise heteroskedasticity.[13]

c) Correlation across time intervals for a given month, i.e. $Cov(\varepsilon_{Fi,M}\varepsilon_{Fj,M} \mid X) \neq 0$, confirmed via The Breusch-Pagan Lagrange Multiplier test for independence.[14]

Specifying the covariance structure as above and estimating model [12] by Feasible Generalised Least Square (FGLS) yields the results shown in Table 5. Serial correlation coefficients were estimated separately for each time interval, i.e. the correlation between the residuals of observation (panel specific correlation). The estimates for the elasticity of substitution are both significant and have the expected sign; the results indicate that substitutability between different months (0.20) is higher than substitutability between different time intervals within a certain month (0.11).[15]

These values tell us the percentage change in relative consumption due to a variation in relative prices. To give a better idea of the magnitude of these estimates, suppose to apply them to the aggregate average hourly load in our sample. Take for example the summer load in 2003, i.e. F1 = 1230; F2 = 1205; F3 = 930; suppose that we want to

[12] The value of the chi-square statistic was 10.37, the p-value 0.001.
[13] The chi-square statistics was equal to 65.73, the p-value 0.000.
[14] The correlation matrix was the following:

	Eq. F1	Eq. F2	Eq. F3
Eq. F1	1		
Eq. F2	0.93	1	
Eq. F3	0.62	0.67	1

which resulted in a chi-square statistics equal to 61.27 (p-value 0.000).
[15] Note that the coefficient associated to P yields directly the elasticity of substitution among hourly intervals, while the coefficient associated to M yields the *negative* of the elasticity of substitution across months. Therefore both elasticities have the expected *positive* signs.

revise the TOU tariff in order to flatten the load over the three time intervals. With an elasticity of 0.11, and considering that the "old" tariff was PF1 =0.109; PF2 = 0.087; PF3 = 0.061, then we would need to set the new tariff such as the relative price PF1/PF2 = 1.5 and the relative price PF1/PF3 = 7. For example the new tariff could be set as follows: PF1 = 0.14; PF2 = 0.093; PF3 = 0.002. The same kind of exercise can be done using monthly average load and monthly elasticity of substitution.

Table 5. FGLS on aggregate data (equation [12])[16]

Cross-sectional time-series FGLS regression

Coefficients: generalized least squares
Panels: heteroskedastic with cross-sectional correlation
Correlation: panel-specific AR(1)

Estimated covariances	= 6	Number of obs	= 108
Estimated autocorrelations	= 3	Number of groups	= 3
Estimated coefficients	= 4	Time periods	= 36
		Wald chi2(3)	= 277.50
Log likelihood	= 257.2133	Prob > chi2	= 0.0000

E	Coef.	Std. Err.	z	P>|z|	[95% Conf.	Interval]
P	.1143397	.008647	13.22	0.000	.0973919	.1312876
M	-.199231	.0377613	-5.28	0.000	-.2732418	-.1252201
dummyM8	-.2061691	.0191355	-10.77	0.000	-.2436741	-.1686642
_cons	.0229249	.0082273	2.79	0.005	.0067997	.0390502

5.2. Individual elasticity

Equation [12] was then estimated for each firm; this may be problematic because the parameters can be greatly affected by unobserved shocks at the firm level, which instead may be assumed to average among the sample. In fact, the estimated coefficients were often not significant, and sometimes with the opposite sign. In any case, the results may spread some light on the heterogeneity of customer responsiveness to price variations. We can observe the characteristics of the consumers who showed the greatest price responsiveness (e.g. the activity sector, the voltage, the level of consumption and expenditure). Table 6 briefly summarises the

[16] Yearly dummies were dropped because the associated estimates were not significant.

results obtained from firm by firm estimation. Only in 27 cases (over 143) both estimates on the elasticities of substitution were statistically significant at the 5 percent level (and with the expected sign); however, almost 60 percent of the regressions yielded at least one significant parameter. Some interesting evidence emerges from this analysis:

a) the range of values assumed by σ_F was in line with the aggregate (average) coefficient; about 70 percent of these values were lower than 0.30, equally distributed between the class [0;0.10] and the class [0.10;0.30];

b) the range of values assumed by σ_M was instead higher than the aggregate estimate; 50 percent of the significant coefficients registered a value higher than 0.50;

c) the activity sector has great impact on the degree of electricity substitutability and also on the type of substitutability (i.e. hourly/daily or monthly). In particular, almost all Public Health firms (13 out of 14) showed significant coefficients, and their price responsiveness appeared to be quite homogeneous (σ_F between 0.10 and 0.30; σ_M higher than 0.50). Few "Food & Beverage" firms highlighted the highest price responsiveness among the sample. Other sector, such as Transport, Water and Paper industry, showed high coefficients especially in monthly substitutability. Finally, others sectors are not represented at all in Table 6 (i.e. Plastics), indicating that in these industries time-frame substitution of electricity is hardly a possibility.

In general, individual elasticity analysis highlighted a wide heterogeneity in price responsiveness, which can be partially explained by sector activity. This can be interesting in terms of policy indications. TOU tariffs generally have the goal to induce more efficient use of electricity, but this can be achieved only given that customers respond to price signals. For inelastic consumers, TOU is not effective and other types of demand policies should be applied; flat rate pricing accompanied with some form of rationing for system peak load may be a fairly better solution.

Table 6. Elasticity of substitution firm by firm

	Both σ_F and σ_M	Only σ_F	Only σ_M
Statistically significant (0.005)	27 9 Public Health 4 Food & Beverages 3 Transport 3 Chemicals 2 Mining and Quarrying 2 Public Administration 4 Others	25 4 Extraterritorial bodies 3 Office & Accounting 3 Non-metallic products 2 Metals 2 Public Health 2 Water 2 Chemicals 2 Social services 5 Others	29 5 Paper & printing 4 Water 2 Public Health 2 Textiles 2 Food & Beverages 2 Machinery & Equipment 2 Transport 2 Non-metallic products 2 Office & Accounting 6 Others

Values	**<0.10**	**[0.10,0.30]**	**[0.30,0.50]**	**>0.50**
σ_F	17 4 Office /Accounting 4 Chemicals 3 Public Health	21 7 Public Health 2 Extraterr. bodies 2 Transport 2 Non-metals	8 2 Water 2 Transport	6 2 Food & Beverages
σ_M	3 2 Chemicals	13 3 Public Health 3 Food & Beverages 2 Machinery / Eq. 2 Metals	12 2 Office / Accounting 2 Paper & printing 2 Public Health	28 6 Public Health 4 Transport 3 Paper & printing 3 Water 3 Food & Beverages

5.3. Joint estimation

By far we did not consider the joint estimation of the whole data set, exploiting the firm's dimension in our panel. Data includes 143 firms x 3 time intervals x 36 months, for a total of 15.444 observations. The specification of the panel raises methodological issues on how to treat the time intervals dimension. If we consider them in the time series dimension, the same problems highlighted in Section 5.1 would arise, since we would force the auto-correlation process over a heterogeneous time order. On the other hand, we can continue to treat the time intervals as a cross-sectional dimension. However, in this case, it would be clearly impossible to estimate the whole cross-sectional correlation structure (453 cross-sectional units!), because the number of parameters to be estimated will exceed the number of observations.

The solution could be to run the Least Square Dummy Variable estimator (fixed effects), allowing for an auto-correlation process across monthly observations. The hypothesis of fixed effect was however rejected with a Hausman specification test, which showed that estimating [12] with a random effect model, with the addition of 2 time interval dummies, was not significantly different with respect to the fixed effect model. Thus, it appeared more appropriate not to waste degree of freedom on firm specific dummies, and instead to specify the covariance matrix structure allowing for groupwise heteroskedasticity and panel specific auto-correlation (AR(1)). The model was estimated by means of FGLS.

The estimation on the whole panel allows to infer on time invariant variables that can affect the degree of elasticity. For example, we have seen in the previous Section that individual firm response varies greatly according to the activity sector. For this reason, the basic model was enriched by assuming the elasticities to have the following form:

$$\sigma_j = \delta_j + \sum_i Z_{ij}\delta_{ij} \qquad j = F, M \qquad [13]$$

where Z_i are firm-specific variables which are supposed to influence the elasticity of substitution. I estimated 4 models, whose results are summarised in Table 7. The first one is the basic model [12], with the inclusion of two time intervals dummy variables. The estimates for elasticity of substitution are a little lower than the values obtained using the information on aggregate data.

The second model estimates jointly [12] and [13], including the dummies for the activity sector in equation [13].[17] This is equivalent to estimate different elasticities of substitution for each activity sector. To avoid collinearity, the constant term in [13] was dropped, so that the parameter associated to each dummy variable yields directly the sector specific elasticity of substitution. Here we can see with more precision the sector specific price responsiveness. The most responsive sector appears to be the Transport industry, followed by Public Health, Extraterritorial bodies and Water industry; conversely all the Manufactory industries (with the exception of Paper industry) were proven to have a very rigid technology, and electricity in different time-of-use appear as complements[18].

[17] Sector specific dummies were initially introduced also in equation [12], then they were dropped because statistically not significant.

[18] In many cases the estimates for the elasticities of substitution resulted negative. This represents a problem of the estimation since they are not consistent with the economic theory, and it may be due to the fact that in the joint estimation we were not able to account for the correlation among time intervals.

Table 7. FGLS estimation on the whole panel

Cross-sectional time-series FGLS regression
Coefficients: generalized least squares
Panels: heteroskedastic
Correlation: panel-specific AR(1)

Estimated covariances =	429	Number of obs =	15444
Estimated autocorrelations =	429	Number of groups =	429
		Time periods =	36

E	Model 1	Model 2	Model 3	Model 4
_Cons	.0009062 (0.793)	.0033161 (0.318)	.0028888 (0.387)	.0027473 (0.409)
DummyM8	-.1682387 (0.000)	-.19389 (0.000)	-.1936195 (0.000)	-.1934899 (0.000)
DummyF1	.0244756 (0.000)	.0250701 (0.000)	.0254733 (0.000)	.0256532 (0.000)
DummyF2	.0201157 (0.000)	.0212528 (0.000)	.0218455 (0.000)	.021773 (0.000)
P	.0826515 (0.000)	-	-	-
M	-.1406195 (0.000)	-	-	-
P_Chemicals	-	-.0027071 (0.960)	-.0012305 (0.982)	-.0137593 (0.796)
P_Extrater	-	.2585566 (0.034)	.269964 (0.027)	.2833163 (0.022)
P_Food	-	.0509751 (0.397)	.0512493 (0.395)	.0403229 (0.507)
P_Office	-	-.132627 (0.072)	-.1325424 (0.072)	-.136018 (0.066)
P_OthMan	-	-.143424 (0.000)	-.1385988 (0.000)	-.1453731 (0.000)
P_Others	-	.1460756 (0.000)	.146232 (0.000)	.1384362 (0.000)
P_PHealth	-	.1866621 (0.000)	.186773 (0.000)	.1887232 (0.000)
P_Paper	-	-.0483338 (0.443)	-.0481846 (0.000)	-.0568347 (0.360)
P_Plastics	-	-.2903042 (0.004)	-.2900064 (0.004)	-.3048872 (0.003)
P_Transport	-	.5278805 (0.000)	.5269494 (0.000)	.4551028 (0.000)
P_Water	-	.10851 (0.000)	.1217862 (0.000)	.1031372 (0.000)
M_Chemicals	-	.0297825 (0.352)	0.045969 (0.173)	.0549414 (0.086)
M_Extrater	-	-.4176402 (0.000)	-.4219306 (0.000)	-.3605642 (0.000)
M_Food	-	-.0647283 (0.060)	-.0645468 (0.061)	-.0868531 (0.012)
M_Office	-	.2037334 (0.000)	.2039733 (0.000)	.1772603 (0.000)
M_OthMan	-	.4035219 (0.000)	.3986429 (0.000)	.3905031 (0.000)
M_Others	-	-.2728003 (0.000)	-.2725303 (0.000)	-.282921 (0.000)
M_PHealth	-	-.5384593 (0.000)	-.5382043 (0.000)	-.5666366 (0.000)
M_Paper	-	-.2019498 (0.000)	-.2017849 (0.000)	-.2019797 (0.000)
M_Plastics	-	.4821339 (0.000)	.4822347 (0.000)	.4575913 (0.000)
M_Transport	-	-.680706 (0.000)	-.6506112 (0.000)	-.7079699 (0.000)
M_Water	-	-.2529445 (0.000)	-.2618217 (0.000)	-.2609185 (0.000)
P_HV	-	-	-.0516416 (0.420)	-
M_HV	-	-	-.0177682 (0.627)	-
P_Dim	-	-		-.0662236 (0.097)
M_Dim	-	-		-.1384673 (0.000)
Log likelihood	-1,210.254	-754.7205	-756.4128	-741.5038
Wald chi2	738.22	2368.94	2360.01	2391.19
Prob > chi2	0.000	0.0000	0.0000	0.0000

In the third model I controlled for any difference in elasticity of substitution between HV and MV consumers was added, however both the dummies added to [13] were not statistically significant. Finally, last model attempts to investigate on the relation between the degree of elasticity and the firm dimension. This is problematic since, given the available data, the only way to approximate it is by using the total amount of consumption, which is endogenous in the model. To avoid this problem (at least partially if not totally), we used as a proxy of the firm dimension the average hourly consumption registered during the year 2000.[19] The results showed that within the dimension of our sample the total amount of electricity consumed has some positive influence on the monthly elasticity of substitution, while the effect on hourly/daily substitution was not significant at the 5 percent confidence interval level.

6. Conclusions

In the restructured electricity market, the Power Exchange will determine the wholesale hourly real time pricing of electricity, giving a signal of the effective available resources in each moment of the year. Though most customers will not see this hourly variability on their bill, the Power Exchange is likely to act as a benchmark and to influence the structure of retail agreements and retail tariffs. Looking at the experience of the other countries where energy market has been liberalised, many distributors offer real time rates to large industrial customers, and TOU is widely applied. As to Italy, the tariffs set up by the Authority already take into account (for a certain part of the generation components) of the monthly average price variations in the Power Exchange quotations. Another proof could be the fact that since 2004 TOU has been proposed in Italy for the first time also to residential customers.

Given this picture, this Paper aims at evaluating the extent of the possible customer response to time-varying prices, analysing how much electricity usages in different time of the day can really thought as they were substitutes. In other words, the aim is to analyse if customers care only about the average price paid or if they are likely to modify their load profile according to the time-differentiated price signals. In particular, the study is concerned with a sample of medium-sized industrial customers facing TOU tariffs in Italy in the period between 2000 and 2003. The results highlight a certain degree of substitutability among the different pricing periods; in particular

[19] Clearly we need to assume that firm dimension did not change over the years; since the observations in year 2000 (for which monthly data are not available) are not used in the estimation, they can provide a useful exogenous (at least partially) information to approximate firm dimension.

substitutability across months seems to be easier than substitutability across different hourly intervals within a month. However, the customer response was proved to be widely heterogeneous in the sample, and in particular among different activity sectors.

The estimated degree of elasticity of substitution should be a key variable to take into account when designing a TOU tariff. In particular, it permits to predict the effects on load variations induced by prices. Thus, TOU should not be merely cost-based, but one should attempt to analyse the desired modifications on the load profile. Given a desired modification on the load profile, the elasticity of substitution will permit to compute the change in the relative price that would be needed to achieve the goal.

Moreover, the heterogeneity in the customer response suggests that different tariff policies should be pursued. For elastic consumers, TOU effectively induces to a more efficient use of electricity. Those of them who highlighted a relatively high substitutability across hourly intervals may be probably interested in switching from TOU to real time rates. Instead, for activity sectors whose productive process hardly permits time substitutability, TOU would be completely ineffective. For them, flat rates accompanied with some form of rationing during the system peak loads seem to be a fairly better solution. From another point of view, in a fully liberalised electricity market, such heterogeneity in customer demand responsiveness may allow for price discrimination strategies in a non perfect retail competitive market.

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