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THE EFFECT OF OUTPUT SPECIFICATION ON THE OPTIMAL POLICY DESIGN FOR ELECTRIC UTILITIES

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Abstract

We show that the maner in which the production process is seen when analyzing data on electricity production has an impact on the policy conclusions. In particular, we show that the different specifications of output found in the literature can generate quite diverse views regarding regulation and optimal industry structure, even when using the same data to estimate a cost function. To illustrate this we use information gathered from the Spanish Electric Industry and analyse electricity activities following three approaches: the traditional aggregate activity view, the multistage model and the multioutput-multistage approach. We estimate the degree of economies of scale S and derive marginal costs for all models, plus economies of vertical integration (EVI) for the last two ones. Then we compare these results and verify that the aggregate analysis can mislead policymaking.

***Keywords**: electric utilities, scale economies, scope economies, economies of vertical integration, multistage-multiproduct cost functions.*

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1. INTRODUCTION

Electrical systems encompass a whole set of differentiated activities, all of which are necessary to provide the final service. These activities are: generation, transmission, distribution and supply (marketing) of electricity services to the end-users[1]. There are two views regarding the industrial organization of the industry. The traditional model states that there are both scale economies and major economies of vertical integration (EVI) between the different stages of supply, giving the operation as a whole the characteristics of a natural monopoly. This has been the justification for a single company operating all the stages of supply and, therefore, for its economic regulation through a pricing policy (see Joskow and Schmalensee, 1983).

On the other hand, in line with Landon (1983) and Joskow (1996) and against the traditional view presented above, there is the model that advocates competition, which is based upon a different view concerning the technology and the underlying cost structure in the different stages of the electricity supply and how it works as a whole. Firstly, the authors that supports this view argue that scale economies (S) would be exhausted at the generation stage related to market size, making competition among generators possible. Secondly, they see no major EVI between stages, such that integration would induce insignificant cost savings that would be off-set by improvements in efficiency arising from market competition.

We believe that the discussion regarding regulation or competition is more complex than the two extreme visions presented here, namely that there are either increasing returns to scale and EVI or constant returns and negligible EVI. For example, if there

[1] Transmission encompasses the management of the high tension transport network and also the coordination and management of generating capacity, or energy dispatch. Although traditionally considered as part of distribution, activities related with direct contact with clients like charging and billing can be considered as an independent activity.

were constant returns and EVI, the cost analysis would suggest that the optimal industry structure could well be many firms each one vertically integrated. As evident, in this debate knowing the industry cost function is fundamental for evaluating and discussing the two propositions described above or to find alternative outcomes. It should be noted immediately, though, that to investigate this issue the process should be modeled as a joint production activity, where firms can potentially operate at all stages. This is particularly relevant in this study as our main objective is to show that the maner in which the production process is seen when analyzing data has an impact on the policy conclusions. Even more, we show that the specification of a cost function using the same data could yield different conclusions regarding the optimal industry structure and the regulatory framework.

To show the effect on policy conclusions of the way in which data is used, we use information gathered from the Spanish Electric Industry and analyse electricity activities following three approaches: the traditional aggregate activity view, the multistage model and the multistage-multioutput approach. Then we estimate the degree of economies of scale *S* and derive marginal costs for all models, plus economies of vertical integration (EVI) for the last two ones. Then we compare these results and verify if this analysis can mislead policymaking. The paper is structured as follows. In section two, we describe the different model specifications to obtain *S*, marginal costs and EVI for vertical integrated electric utilities. In section three, we describe the data, the variables and the models that will be estimated. Section four contains the results and comparison between the single output, the multistage and the complete multioutput cost functions. Section five closes with the main conclusions.

2. DIFFERENT SPECIFICATIONS TO TEST FOR EVIs

In this section, we will present the different specifications that can be used to estimate the cost characteristics and to test the presence of scale economies and EVI for the vertical integrated utilities, noting that here we concentrate on those studies that only consider vertical integrated utilities. For a complete survey of the main articles that estimate cost functions in the differents stages of the electricity industry, see Ramos-Real (2005)[2]. When estimating a cost function for electric utilities, the literature shows three alternative methodologies depending on the treatment (definition) of the output. The first one is the aggregate model (AG) that uses the electricity delivered as a measure of output. The second model takes into account the multistage characteristic of electricity activity (MS), mainly distinguing between generation and distribution. And lastly, the third one treats the activity as multistage and multioutput (MSMO) because more than one product may be produced within each stage of electicity supply; under this view economies of joint production can be analysed not only between stages (i.e. economies of vertical integration) but also at a given stage (e.g. economies of using a generation mix).

2.1. The AG model: final delivery of KWh and supply cost function separability

Studies that follow this approach focus on costs per Kwh of electricity distributed, whereas the expenses to be explained are the global costs of supply. The samples used usually consider only companies that are vertically integrated in all the different stages, because in these studies generation and the purchased power are factors of production of the supply production function, along with capital and labour. These papers use samples where some homogeneity in the activity structure and in the technology of generation is

[2] The biases caused by an inadequate treatment of output have been examined in other fields. For instance, port cargo handling was analyzed by Jara-Diaz et al (2008) where the most appropriate (multioutput) specification revealed constant returns for big companies while the aggregate view showed increasing returns everywhere.

needed.[3] These two last aspects are essential for a correct estimation under this approach, as if firms produced with different technologies the cost of supply would not measure the same thing. On the other hand, if a relevant share of the energy generated is sold to the grid, energy delivered would not measure the activity of the company correctly. In this case, the energy supplied to the network should be regarded as another output. Another way to solve this problem is to take into account only those companies that hardly deliver electricity to the network; evidently, those firms whose ratio G/D is greater than one should be excluded.[4]

Within this framework, authors as Hayashi et al. (1998) or Nelson and Primeaux (1988) use a single output approach, but others as Roberts (1986) and Thompson (1997) differentiate deliveries between low-voltage and high-voltage customers. The results suggest that there are product-specific economies of density, i.e. for a given network size and a fixed number of clients, average costs fall when the quantity of power supplied increases.[5] But, as Joskow and Schmalensee (1983) pointed out, firms eventually get to the point where a proportional increase in product, in the service area and in consumers no longer leads to a reduction in average costs.[6]

Some papers that use the AG approach actually study the existence of EVI through the analysis of separability of the cost function between phases. In this specification, separability is tested by including stage-specific factor prices and then examine the significance of the cross terms among these and the products. Rejecting separability implies the beneficial use of common inputs and that there are economies of joint

[3] For example, in Naughton (1986), all utilities with less than 85% of steam generation are excluded. Hayashi et al. (1985) only considers conventional fossil fuels generation and firms that do not purchase and/or sell power.

[4] Using Spanish data Arcos et al. (2008) also included firms that nearly solely distribute but do not generate (surprisingly, they do not include input prices in the estimation either).

[5] Thompson's results indicate a 0.3% fall in average cost for every 1% increase in supply.

[6] Thompson observed that for large firms (above 26000 GWh) an increase in the service area does not generate any significant decrease in average cost.

production between stages, which is interpreted as a sign of the existence of EVI [Hayashi et al. (1998), Roberts (1986), Thompson (1997) and Nemoto and Goto (2004)]. As evident, the advantages or disadvantages of vertical and/or horizontal integration can not be properly quantified from this approach.

2.2. The MS and MSMO approaches: EVI and multiproduct theory

It is possible to detect and quantify the EVI using the different concepts provided by the multiproduct theory. As known, measuring economies of scope requires an orthogonal partition of the product vector, which means that some components should be valued at zero for each of the firms in the partition[7]. If the product vector includes outputs at different stages - as electrical systems do - the existence of economies of scope between stage-associated subsets implies the presence of EVI, provided double counting of products (costs) at the previous stage is avoided. In Kaserman and Mayo (1991), Gilsdorf (1994), Kwoka (2002), Fraquelli et al. (2005) and Jara-Díaz et al (2004), where the generation and distribution stages are considered, the cost of purchased power is not included to avoid double counting generation costs. In fact, the whole idea is to examine whether generation and distribution could be better produced separately. This requires a multistage formulation (MS). As more than one product may be produced in each stage, the most complete way to treat the activity is to characterise it as multistage and multioutput (MSMO), as in Jara-Díaz et al. (2004), which also allows to test for the possible existence of economies of horizontal integration (EHI).

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[7] The main concepts of the theory of multioutput that we will use are defined in Baumol, Panzar and Willig (1982). The condition of natural monopoly requires subadditivity of the cost function within the required range of products, which means that the division of total production in more than one firm is more expensive than concentration in a single one. Economies of scope are necessary but not sufficient for subadditivity. Stronger conditions are required, involving scale properties as well. Nevertheless, economies of scope play an important role in the study of optimal industry structure in general and of vertical and horizontal integration in particular; if there are economies of scope at a given product vector for a specific partition, it is better to produce that vector jointly with one firm than with more firms each producing a subset defined by that partition.

As Ramos-Real (2005) points out, there is no unanimous opinion on whether or not there is subadditivity in the cost function. But studies that analyse EVI between stages are inclined to believe that in general there is. Most authors have used the translogarithmic flexible functional form because it meets the flexibility and tractability criteria; however, economies of scope between stages can not be calculated properly because such form can not be evaluated at zero for outputs. The articles by Gilsdorf (1994, 1995) face this problem by studying cost complementarity in the former case, and by using Evans and Heckman's (1984) subadditivity test, in the latter.[8] Fraquelli et al. (2005) use a composite cost function to overcome this problem.

The quadratic flexible functional form, that enables authors to quantify economies of scope, has been used by Kaserman and Mayo (1991), Kwoka (2002) and Jara-Díaz et al. (2004). The quadratic functional form is particularly appropriate as it is flexible[9] and - most important - it can be evaluated at zero for one or more outputs, which permits the calculation of economies of scope. On the other hand, the quadratic has the limitation that certain theoretical properties can not be imposed *a priori* (as linear homogeneity and input price concavity); however, such property can be verified *a posteriory* as done by Jara-Díaz et al. (2004).[10]

It is worth recalling the results obtain in these studies, taking into account differences in the regulatory context and in the samples used. Kaserman and Mayo (1991) and Kwoka (2002) obtained values for EVI in the U.S.A. above 20% (22.5% and 26% respectively), larger than the 6.5% obtained by Jara-Díaz et al. (2004) measured at comparable points

[8] Röller (1990) argues that the translog cost estimates degenerate to either zero or infinite and advocates limiting the cost structure test to a local region and ensuring that the cost function is proper. The Evans and Heckman (1984) test is a specific procedure to do it.

[9] Meaning that no *a priori* signs are assigned to either first or second derivatives, which imply that marginal costs, cost complementarity between products and price elasticities of factor demands flow freely from the data.

[10] For a discussion of the merits of such specification see Pulley and Braunstein (1992), and Piacenza and Vannoni (2004).

for Spain (8.2 thousand GWh generation and 11.35 thousand GWh distribution). In Italy, Fraquelli et al. (2005) estimated that the rate of EVI is around 3% but for very small firms which generate 300 GWh and distribute 600 GWh. Jara-Díaz et al. (2004) do not consider the transmission stage and its costs because in the Spanish case an independent operator manages this phase, absorbing the coordination costs; the difference with the other studies should be interpreted as savings that correspond to transaction and coordination costs that are accounted for exogenously to the firms.[11]

But these differences could be due not only to the structure and regulatory context but also to the different specifications of the models. Unlike previous studies that use a pure MS approach, in Jara-Díaz et al. (2004), many products are considered in the generation stage. These different specifications may lead to different results regarding some of the relevant costs concepts. Therefore, using the database of Jara-Díaz et al. (2004), in the following section we will show the results from the three specifications described above in order to analyze the possible bias in the results.

3. COST MODEL, DATA AND VARIABLES

We will use data from the Spanish electricity sector between 1985 and 1996. In this period, the Spanish electric sector was organised around the existence of an independent operator (Red Eléctrica de España, REE) in charge of the management of both the energy transmission and the existing generation capacity (dispatching); the typical Spanish firm generated and distributed electricity only. For this reason, we do not consider the transmission stage and its costs. Generation was used either to feed the own market or to sell to other electric firms through the network managed by REE. Although some studies identify the size of the geographical area served as a variable that might influence distribution costs, this effect can not be detected if production and

[11] In this case, the advantages of vertical integration only can be measured between G and D. Arocena (2008) using DEA and spanish data for similar firm sizes also found weak EVI (in the range of 1,1% and

the number of customers vary proportionally (Roberts, 1986; Thompson, 1997). In our case, there is a 0.93 correlation between these two variables, which made us discard the inclusion of the area served in the model. Following a common practice in the literature, marketing costs are included in the distribution stage.

It is worth noting that we have used this database earlier in order to analyze economies of scale and scope and productivity evolution (Martínez-Budría et al., 2003; Jara-Díaz et al. 2004; Ramos-Real and Martínez-Budría; 2004). We have concluded, in line with most of the studies cited earlier, that data reflects long run behaviour. In our case this is due to the length of the period and the wide cross section of firms observed.

We will estimate different models where the dependent variable is the long-run economic cost of production and the explanatory variables are essentially production and factor prices. We assume cost minimizing behavior and exogenous outpus levels and inputs prices, as commonly done in the empirical literature in this industry. All expenditure variables are expressed in constant pesetas (1996).

3.1. Functional form

We use the quadratic functional form due to the direct interpretation of results and the properties mentioned in section 2.2. We specify and estimate the complete quadratic cost function proposed by Lau (1974) together with the input expenditure equations that result from Shephard's lemma. In addition to outputs and prices, we have included a time trend that interacts with all other variables, a firm specific dummy and a variable representing generation capacity utilisation (CU) that also interacts with other variables.

The time trend captures potential changes over time of the cost function, from which technical change can be controlled. This variable has been crossed with both factor

4,9%).

prices and products, such that non-neutral technical change and the contribution by product and phase can be dealt with. The CU variable represents the effect of the rate of use of the installed generation capacity on production costs. It enters the specification in three forms: linear, squared and crossed with generation products and the prices of capital and fuel. This makes marginal costs of generation and the derived demands for capital and fuel (potentially) dependent on CU. The firm specific effects D_i are designed to capture the differences among firms that are not explained by the rest of the variables, like potential geographical factors, among others. Although the model assumes that all firms have access to the same technology, they operate with different cost levels. In other words, ω_i permits a correction at the origin. This means that the error term can be looked at as

$$U_{it} = \omega_i + \varepsilon_{it}$$

where U_{it} is the sum of a firm specific term ω_i that captures non-observed heterogeneity at a firm level including individual inefficiency, and a purely random term ε_{it}.

To facilitate analysis at the mean of the observations, all variables were deviated with respect to the sample mean. The resulting model is:

$$\begin{aligned} C = {} & \alpha_0 + \sum_i^m \alpha_i (Q_i - \bar{Q}_i) + \sum_i^n \beta_i (W_i - \bar{W}_i) + \varphi_T (T - \bar{T}) + \varphi_{CU} (CU - \bar{CU}) + \\ & \frac{1}{2}\sum_i^m \sum_j^m \delta_{ij} (Q_i - \bar{Q}_i)(Q_j - \bar{Q}_j) + \frac{1}{2}\sum_i^n \sum_j^n \gamma_{ij} (W_i - \bar{W}_i)(W_j - \bar{W}_j) + \sum_i^m \sum_j^n \rho_{ij} (Q_i - \bar{Q}_i)(W_j - \bar{W}_j) + \\ & \sum_i^m \lambda_{iT} (Q_i - \bar{Q}_i)(T - \bar{T}) + \sum_i^m \lambda_{iCU} (Q_i - \bar{Q}_i)(CU - \bar{CU}) + \sum_i^n \mu_{iT} (W_i - \bar{W}_i)(T - \bar{T}) + \\ & \sum_i^n \mu_{iCU} (W_i - \bar{W}_i)(CU - \bar{CU}) + \pi_{TT} (T - \bar{T})(T - \bar{T}) + \pi_{TCU} (CU - \bar{CU})(CU - \bar{CU}) + \sum_i^{N-1} \omega_i D_i \end{aligned} \qquad \textbf{(1)}$$

where the bar represents sample mean, m is the number of products, n is the number of factors, W_i is a factor price, Q_i is a product quantity, T is trend (time), CU is capacity utilisation, D_i is the firm specific dummy variable and N is the number of firms.

Applying Shephard's lemma to equation 1 and multiplying times the factor prices, we obtain the factor expenditure equations given by

$$G_i = W_i \times \left[\beta_i + \gamma_{ii}(W_i - \bar{W}_i) + \mu_{iT}(T - \bar{T}) + \mu_{iCU}(CU - \bar{CU}) + \sum_{j \neq i}^{m} \gamma_{ij}(W_j - \bar{W}_j) + \sum_{j \neq i}^{n} \rho_{ij}(Q_j - \bar{Q}_j) \right] \quad \textbf{(2)}$$

where i stands for factor type and X_i are the factor derived demands.

For the three models we have estimated the complete quadratic cost function (1) together with the input expenditure equations (2) using Zellner's (1962) iterative procedure. Joint estimation of equations 1 and 2 increases the efficiency of parameters.

3.2. Output specification and the production process.

For the purpose of this paper, both the specification of products and the way in which the production process is looked at are key points. As stated earlier, the AG formulation considers energy delivered/distributed as the only output (di),[12] and the production process is seen as in Figure 1, where the purchased power (PP) is an input of the supply production function, along with capital, labour, fuel and the intermediate inputs. The energy delivered come from own generation and the purchased power.

Figure 1. Aggregate view of the production process.

For the MS (aggregated multistage) specification a single product was considered at each stage: generation (G) and distribution (di). Within the period analysed empirically in this paper the typical Spanish firm uses production factors that are common to generation and distribution: labour, capital and intermediate inputs. Fuel is a factor that is used for generation only, which has an impact on the properties and specification of

[12] Regarding distribution, although two outputs were identified according to final delivery voltage (high and low voltage), they were highly correlated in our sample and a single distribution output (di) was finally included. Note that correlation means that outputs "move together"; therefore this will not affect the estimate of either scale or EVI, but product-specific marginal costs cannot be estimated.

the corresponding factor expenditure equation and the cost function from which it is derived, particularly the absence of some interaction terms. Generation is used either to feed the own market or to sell to other electric firms through the network managed by the REE; purchased power is a factor that is specific to the distribution phase when self-produced generation is not enough. In Figure 2, we can see this second specification.

Figure 2. Multistage view of the production process.

Finally, in figure 3 the MSMO view is shown, where four types of generation products were included: coal (gc), oil-gas (gf), hydroelectric (gh), and nuclear (gn). Production was measured in million kWh units. Thus, the product vector for the AG specification is Q= (di); for the MS is Q= (G,di) and for the MSMO specification is Q=(gc, gf, gh, gn, di). Note that the observation made in the MS model regarding fuel as a factor that is used for generation only, here applies specifically for fossil-fueled generation (gc and gf); as fully explained in Jara-Diaz et al (2004) this makes interaction terms with other generation forms disappear.

Figure 3. Multistage-multioutput view of the production process.

3.3. Input prices

For all models, we use as factors capital, labour, fuel and intermediate input. Regarding purchased power, which is an input only in the AG model, it is included together with fuel in an input denominated supply cost; its price is obtained as the ratio between costs (fuel and purchased power) and energy units (Ton of oil equivalents) (see Tables A.3 and A.4 of Appendix). For multioutputs models, following Gilsdorf

(1994, 1995) and Kwoka (2002), purchased power was not included as an input[13]; accordingly, its price was not included in the cost function and these expenses were not included in *C*. This procedure avoids double counting of generation costs when calculating EVI from the definition of economies of scope.

As input markets were regulated during the period considered, firms are assumed to be price takers. Unlike other countries, in Spain there are neither regional nor national input price indices for specific industries. As production factors are aggregates, we constructed a capital price index (explained below) in the line of Hayashi et al (1985) and Naughton (1986). For labour, fuel and intermediate input we constructed price indices using the corresponding expenditures and a proxy measure for each factor, a procedure used by Kaserman and Mayo (1991) and Gilsdorf (1994, 1995), among others.

Thus, the calculation of a single labour price (pl) index is straightforward and units are million annual pesetas per worker. We use a fuel price (pc) variable obtained from the cost of an equivalent ton of oil that represents the cost of fossils fuels[14], obtaining pts/ kwh (only gc and gf). An index for capital price each firm was obtained as $p_{kt} = \frac{A_t + r_t * FP_t}{IMNE_t}$, where p_{kt} is the price of capital in year t, A_t is the amortisation in year t, r_t is the average rate of return in the electric sector in year t, FP_t is stockholders'equity in year t and $IMNE_t$ are the net tangible fixed assets used during year t[15]. Expenditures in intermediate inputs are related with operating expenses,

[13] Thus, marginal cost of distribution only takes into account operation and manteinance costs that are independent of the origin of power.

[14] We do not consider the fuel factor in the case of nuclear energy. The annual consumption of uranium is included as depreciation for the same year (i.e. part of the cost of capital).

[15] The price of capital thus defined is a relative rate that takes into account the depreciation charges of each year and the return on own funds as a proxy of capital expenditures. We use as (r_t) the average financial of the firms which are members of UNESA. Note that "back end" costs are not considered in firm data, which might increase nuclear marginal cost.

excluding labour costs and procurements (purchased power and fuel). To obtain a price index (pi), the corresponding expenses were divided into net revenues, subtracting those from purchased power. After the price indices were built, we verified that there was no correlation with expenditures.

3.4. Data

Data includes production, expenses and input prices for the most important twelve firms that generate and distribute electricity in Spain, from 1985 to 1996. The information was obtained directly from the annual reports released by the firms, adding up to 106 observations only because information was not available for some firms during some years. All firms are members of the electric entrepeneurial confederation UNESA (Unidad Eléctrica Española). ENDESA-Generación, self-generators, local distributors and systems that operate beyond mainland Spain are excluded.[16]

The firms finally considered are: Unión Eléctrica Fenosa (FENOSA), Compañía Sevillana de Electricidad (SEVILLANA), Fuerzas Eléctricas de Cataluña (FECSA), Empresa Nacional Hidroeléctrica del Ribagorzana (ENHER), Hidroeléctrica del Cantábrico (HC), Electra de Viesgo (VIESGO), Hidroeléctrica de Cataluña (HEC), Hidroléctrica Española (HE), Iberduero, Eléctricas Reunidas de Zaragoza (ERZ) and Empresa Nacional de Córdoba (ENECO). During the period, Hidroeléctrica Española and Iberduero merged, giving birth to Iberdrola, which was regarded as yet another firm from 1992 on. By 1996 the firms listed above represented 81% of the net consumption of electric energy in Spain, and approximately 50% of the gross production of electricity. Tables 1 and 2 in Appendix 1 contain the mean values of the

[16] The expenditure data of ENDESA-Generación was discarded because it included mining activities. By 1992 it represented 25% of total (national) generation, and it was not directly involved in distribution, which was done through firms that were part of the ENDESA group (ENHER, VIESGO, HEC and ERZ).

variables included in the estimation, as well as other variables and ratios that are of interest.

Following what we explained in section 2.1, for the estimation of the AG model we had to exclude (by definition) those firms that only generate and those whose ratio G/D is larger than 1. Finally, we included only those where at least the 50% of their own generation is termic (fossil fuel or nuclear). For these three reasons ERZ, HC, ENHER and ENECO were excluded. Note that the AG model is the only one estimated with a reduced data base. As discussed later, this will have to be taken into account only when comparing scale economies. Moreover, the most relevant comparison will be between the MS and MSMO models because they are both multistage, which allows for the analysis of vertical integration. This type of analysis is actually improved by the presence of observations (firms of periods) that include zeroes for some of the outputs; this would contribute to increase variance and to improve the reliability of the analysis of scope. On the other hand, to estimate an AG model it is necessary (by definition) to use vertically integrated firms that produce in all phases. As a consequence, the nature of the data to estimate the AG model is necessarily different from what is appropriate for the estimation of either MS or MSMO models. In addition, the large number of parameters for estimation in the MSMO model prevents the use of the (reduced) AG database. What is important, though, are the policy conclusions obtained in each case.

4. - RESULTS

In this section we present the main results of the estimation of the three cost function specifications mentioned in previous sections: aggregated (AG), multistage (MS) and multistage-multioutput (MSMO). We will focus on the differences on marginal costs, the degree of scale economies, *S*, and EVI.

Table 1 shows all the first-order parameters that are relevant for our interpretation and comparison of results, where the MSMO model replicates Jara-Díaz et al (2004). All the results are evaluated at the corresponding sample mean. All first-order parameters have the expected signs and are statistically significant at 99% with the exception of the CU coefficient for the MS model. Both the AG and MS models show a positive CU parameter, which would indicate that better utilisation of generation capacity would increase total costs; the richer MSMO model in fact corrects this counterintuitive result. The linear time related parameter is negative and significant which indicates that *ceteris paribus* cost diminishes with time at a constant rate. [17]

TABLE 1. FIRST ORDER COEFFICIENTS OF THE THREE MODELS

Before comparing the results it is necessary to point out that, as explained earlier, some observations had to be omitted in the AG model. As this is imposed by the conditions that the firms have to fulfil under the view of the production process behind that model, each of the columns in Table 1 is indeed the best that an analyst can obtain with the data for each case.

Marginal costs are part of the significant first order parameters in Table 1, one for the AG model, two for the MS model and five for the MSMO model. These marginal costs, however, are not directly comparable with the exception of distribution in MS and MSMO models as explained below. The marginal cost at the mean for the only product in the AG model, KWh delivered, is 13.35 pts. One should keep in mind that, because of the specification itself, delivery cost considers the complete cost of supply (including generation or purchased power). Therefore, it can not be compared directly with marginal cost of distribution in either the MS or MSMO models because

[17] The dummy variables are mostly significant; although each one is relatively small, we deem them necessary in the model as they capture the effect on costs of elements that have not been considered explicitly. The Haussman test confirmed the existence of fixed affects. Moreover, the importance of them as a whole was verified using a Wald test.

distribution cost only considers operating costs (excluding purchasing cost of kWh to avoid double counting).[18] For the MS model marginal costs estimated at the mean are 7.98 pts/kWh for generation, larger than the 3.21 pts/kWh for distribution. The results shown in the last column - when the complete output vector Q=(gc, gf, gh, gn, di) is used - confirm that marginal costs do vary across generation products and exhibit the expected ranking. The highest value corresponds to oil generation (17.02 pts/kWh), followed by coal (9.52 pts/kWh) and nuclear and hydro generation with similar magnitude (7.94 and 7.15 pts/kWh respectively).[19] All four values are larger than the marginal distribution cost of 2.95 pts/kWh. Recall that these values correspond to long run marginal costs (otherwise nuclear and hydro would be close to zero; see Ramos-Real and Martínez-Budría, 2004).

Table 2 shows the values of the product elasticities of cost plus the global degree of economies of scale *S* (the inverse of the cost-product elasticities summation) evaluated at the mean of the AG sub-sample for comparative purposes (with product some 31% larger than in the complete sample; see Table A.2 of Appendix 1). For the AG, MS and MSMO models the degree of economies of scale is 1.092,[20] 1.068 and 1.043, all measured at the same point. All of them happen to be significantly different from one, indicating slightly increasing returns to scale.

TABLE 2. PRODUCT ELASTICITIES AND ECONOMIES OF SCALE AT THE AG DATA SAMPLE MEAN

[18] Note that one could associate generation costs with a lower bound of purchased power. This suggests that the sum of the marginal costs for generation and distribution in the MS model (11.19 pts/kWh) should be somewhat less than the final delivery marginal cost in the AG model (13.35 pts/kWh) as is indeed the case.

[19] The weighted sum (by relative production) of the long run marginal costs of generation is 8.47 PTAs/kWh

[20] The value of *S* for the AG model at the (smaller) mean product of the complete sample is 1.113, indicating an L shaped cost curve as obtained in most aggregate studies in this industry. Measured at the same point, the estimates of *S* for the MS and MSMO models are 1.114 and 1.07 respectively, also larger than the estimates reported in Table 2.

Let us move now to the integration analysis, summarized in Table 3. In the MS model, EVI can be examined by comparing the cost of generating and distributing with a single firm, C(G, di), against the sum of the cost of one generation firm, C(G,0) and those of a distribution firm, C(0,di). This is, of course, the degree of economies of scope for such a partition using the estimated cost function. This yields a value of 0.094 evaluated at the mean (see table 3), which indicates the existence of economies of vertical integration or, analogously, that there is a 9.4% savings due to joint production. With the MSMO specification many types of economies of scope can be calculated at the generation level; in Table 3 all the values involving one specialised firm are shown to be significantly positive, which implies that – if all generation sources can be used – it would be better not to specialize. The analysis of EVI should be done by comparing the cost of generating and distributing with a single firm, C(gc,gf,gh,gn,di), against the sum of the cost of one generation firm, C(gc,gf,gh,gn,0) and those of a distribution firm, C(0,0,0,0,di). This yields a value of 0.065, significantly larger than zero, which indicates the existence of slight economies of vertical integration or, equivalent to a non-negligible 6.5% savings due to joint production.

TABLE 3. ECONOMIES OF SCOPE FOR VERTICAL AND HORIZONTAL INTEGRATION ANALYSIS

The comparison of results permits further insights along various dimensions. The long run marginal costs of the different types of generation obtained with the MSMO specification reveals that the marginal cost in the MS model (7.98 pts/kWh) indeed hides generation specific marginal costs that differ greatly, specially for oil generation (17.02 pts/kWh). Knowing these generation-specific marginal costs could be fundamental to determine the optimal pricing policy in a regulated electric system, or to test the exercise of market power in a liberalised one. Note that the marginal costs of distribution in both models are quite close (the 3.21 in the MS model enters the 95% confidence interval of the 2.95 in the MSMO one, and viceversa).

Regarding scale economies, comparison of *S* across the three specifications – calculated at the same production level of 14.4 thousand GWh in generation and 16.5 thousand GWh in distribution - suggests that the there are very slight increasing returns to scale. If one takes the MSMO value as the best possible estimate, the AG model overestimates its value by some 5% although they are not statistically different. However, when it comes to the analysis of the EVI, the differences in specification seem to matter. The MSMO model yields 44% lower savings than the purely MS model if generation and distribution are jointly produced; if this percentage difference was applied to MS models like those by Kaserman and Mayo (1991) and Kwoka (2002) - for other regulatory contexts – their reported savings of 22.5% and 26.4% respectively would turn into 13% and 15%. As these figures are much closer to the 6.5% of Jara-Díaz et al. (2004), it is likely that a substantial proportion of the large difference comes from their aggregated treatment rather than from the regulatory context.

Finally, we lose very important information when the economies of horizontal integration are lost in the MS model. In fact, cost savings through joint production seems to be more important horizontally than vertically.

5. SUMMARY AND CONCLUDING REMARKS

The proposals for deregulating the electric utility industry make a series of assumptions concerning the technology and the underlying cost structure in the different stages of this activity. Knowing the industry cost function is fundamental for evaluating and discussing the pros and cons of these proposed reforms. The objective of this study is to show that the maner in which the production process is seen when analyzing data has an impact on the policy conclusions. To show the effect on policy conclusions of the way in which data is used, we use information gathered from the Spanish Electric Industry for the period 1983-1996 following three approaches: the traditional aggregate activity view (AG), the multistage model (MS) and the multioutput-multistage approach (MSMO). We estimate the degree of economies of scale *S* and derive marginal costs for all models, plus economies of vertical integration (EVI) for the last two ones. From our comparative analysis we can conclude that:

1. Generation-specific marginal costs obtained with the MSMO model are lost in the MS model, hiding differences of up to 113%. This is quite an important loss of information for the optimal pricing and regulation analysis.

2. Calculated at the same point, the estimated degree of economies of scale *S* decreases slightly with the degree of detail that production is described. *S* gets very close to one in the MSMO model.

3. Estimated economies of vertical integration calculated from the MSMO model are 44% smaller than what is obtained using the MS specification, where the multioutput nature of generation is ignored.

4. Economies of scope at the generation stage – that can be calculated only with the MSMO model - are larger than the economies of vertical integration.

On qualitative grounds, the most important conclusion is that the right treatment of output in the analysis of costs in electric utilities plays an important role when moving into the regulatory arena. The traditional aggregate approach (AG) not only prevents the analysis of EVI, but also yields slightly larger estimates of scale economies, suggesting that the traditional view of a natural monopoly might be adequate. When moving to a multistage (MS) treatment of data, returns to scale become closer to constant and EVI are found. Finally, the cost function estimated using the detailed description of output (MSMO) reveals practically constant returns to scale and smaller EVI than those obtained with the MS approach, nevertheless non-negligible (6.5% savings). So the most complete specification of product would provide support to competitive but integrated view of electric utilities. Although this coincides with the qualitative conclusion using the MS approach, it could be argued that the smaller degree of EVI found with the MSMO model provides a case for non-integrated competition. However, horizontal economies of scope at the generation level provide additional information regarding the convenience of multioutput generation firms.

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TABLE 1. FIRST ORDER COEFFICIENTS OF THE THREE MODELS
(t-stats)

PARAMETER	AG model	MS model	MSMO model
Total cost at the mean	171708 (47.69)	111996 (52.90)	111874 (71.22)
Deliv marg.cost (pts/kwh)	13.35 (47.18)	--	--
Gen. marg cost (pts/kwh)	--	7.98 (11.21)	--
Coal marg.costs (pts/kwh)	--	--	9.52 (16.17)
Oil marg.costs (pts/kwh)	--	--	17.02 (4.09)
Hidr.marg.costs (pts/kwh)	--	--	7.15 (10.05)
Nuc.marg.costs (pts/kwh)	--	--	7.94 (16.13)
Dist.marg.costs (pts/kwh)	--	3.21 (5.69)	2.95 (15.62)
Capacity Utilization	179466 (3.21)	19115* (1.30)	-36390 (-4.61)
Demand for supply input	10903 (27.04)	--	--
Demand for fuel	--	2151 (12.26)	2089 (51.83)
Demand for labour	3459 (46.96)	3285 (66.61)	3278 (67.45)
Demand for input int.	125786 (46.96)	124596 (78.09)	124761 (106.21)
Demand for capital	462063 (18.66)	445420 (39.53)	435818 (43.40)
Trend	-5753 (-5.05)	-3684 (-6.37)	-2997.54 (-6.86)

All parameters are significant at 99% except *

TABLE 2. PRODUCT ELASTICITIES AND ECONOMIES OF SCALE AT THE AG DATA SAMPLE MEAN (t-stat)

Model	**Value**
Aggregate	
Scale Economies	1.09 (28.8)
Multistage	
$\varepsilon_{C,\,q}$ Generation	0.58 (17.2)
$\varepsilon_{C,\,q}$ Distribution	0.32 (8.3)
Scale Economies	1.07 (51.5)
Multistage-multioutput	
$\varepsilon_{C,\,q}$ Coal	0.23 (13.2)
$\varepsilon_{C,\,q}$ Oil	0.03 (3.2)
$\varepsilon_{C,\,q}$ Hydraulic	0.14 (6.4)
$\varepsilon_{C,\,q}$ Nuclear	0.23 (9.3)
$\varepsilon_{C,\,q}$ Distribution	0.30 (9.9)
Scale Economies	1.04 (82.5)

*All parameters are significant at 99%.

TABLE 3. ECONOMIES OF SCOPE FOR VERTICAL AND HORIZONTAL INTEGRATION ANALYSIS (t-stat)

Production involved	**Costs savings Millions pts 1996**	**Scope econ.**
MULTISTAGE		
Distribution – Generation	10739	0.094 (4.6)
MULTISTAGE-MULTIOUTPUT		
Distribution – Generation	7263	0.065 (3.4)
Coal – Oil, Hyd, Nuclear	7112	0.092 (3.7)
Oil – Coal, Hyd, Nuclear	7109	0.091 (3.7)
Hyd – Coal, Oil, Nuclear	7115	0.092 (3.7)
Nuclear – Coal, Oil, Hyd	7733	0.100 (4.2)
Four specialized firms	21521	0.281 (3.8)

*All parameters are significant at 99%.

Appendix. Description of firms

Table A1. MEAN FIRM PRODUCTION IN THE PERIOD 1985-1996 (million kwh).

	Gc	Gf	Gh	Gn	Total Gener.	Di	G+D	G/D	CU
Average	**2706**	**197**	**2176**	**3160**	**8239**	**11350**	**19589**	**0.72**	**0.32**
ENECO	2042	0	0	0	2042	0	2042	---	0.59
ENHER	0	0	2296	0	2296	8572	10868	0.27	0.21
ERZ	0	0	503	0	503	3745	4248	0.13	0.25
FECSA	710	328	1033	6633	8704	11630	20334	0.75	0.27
FENOSA	9178	273	3540	4621	17613	18867	36480	0.93	0.38
H.C.	5188	0	641	529	6358	5481	11839	1.16	0.46
H.E.	0	585	4111	13439	18135	21887	40022	0.83	0.27
H.E.C.	0	0	535	702	1237	3548	4785	0.35	0.25
IBERDUERO	2625	133	9636	4264	16658	22607	39264	0.74	0.28
IBERDROLA	5483	1163	11035	22813	40494	53753	94248	0.75	0.28
SEVILLANA	4777	865	429	4876	10948	18472	29419	0.59	0.30
VIESGO	957	0	624	0	1581	3109	4690	0.51	0.21

Source: firm released data.

Table A2. MEAN FIRM PRODUCTION IN THE PERIOD 1985-1996 FOR THE AGGREGATE SAMPLE (million kwh).

	Gc	Gf	Gh	Gn	Total Gener.	Di	G+D	G/D	CU
Average	**2966**	**418**	**3868**	**7168**	**14421**	**16493**	**30914**	**0.87**	**0.28**
FECSA	710	328	1033	6633	8704	11630	20334	0.75	0.27
FENOSA	9178	273	3540	4621	17613	18867	36480	0.93	0.38
H.E.	0	585	4111	13439	18135	21887	40022	0.83	0.27
H.E.C.	0	0	535	702	1237	3548	4785	0.35	0.25
IBERDUERO	2625	133	9636	4264	16658	22607	39264	0.74	0.28
IBERDROLA	5483	1163	11035	22813	40494	53753	94248	0.75	0.28
SEVILLANA	4777	865	429	4876	10948	18472	29419	0.59	0.30
VIESGO	957	0	624	0	1581	3109	4690	0.51	0.21

Source: firm released data.

Table A3. COSTS AND MEAN EXPENDITURE BY FIRM IN THE PERIOD 1985-1996.

	Total Cost A*	Labour expend.	Fuel expend.	Int.Inp expend.	K expend.	Cost supply Expend*	Total Cost B**
	Million pesetas 1996						
Average	107717	24963	17099	18588	47067	103428	240730
ENECO	19625	1469	11988	1200	4967	--	--
ENHER	52097	16005	0	12930	23162	--	--
ERZ	19863	7050	0	4905	7908	--	--
FECSA	117829	27779	7219	18947	63883	88800	199410
FENOSA	213259	43689	57790	29970	81810	135196	290665
H.C.	66199	8393	30569	7943	19294	--	--
H.E.	229728	51072	5871	43975	128810	106584	330441
H.E.C	27299	8479	0	4619	14202	32211	59510
IBERD	209836	56958	18983	38318	95577	120357	311210
IBERDROLA	501024	119234	37369	103601	240820	240443	662561
SEVILLANA	151195	37176	27204	23976	62839	127856	251846
VIESGO	27102	6683	5722	4281	10417	27907	49288

*Total cost A: Economic cost **Total cost B: total cost A + cost of supply

Source: firm released data.

Table A4. INPUT PRICES BY FIRM IN THE PERIOD 1985-1996.

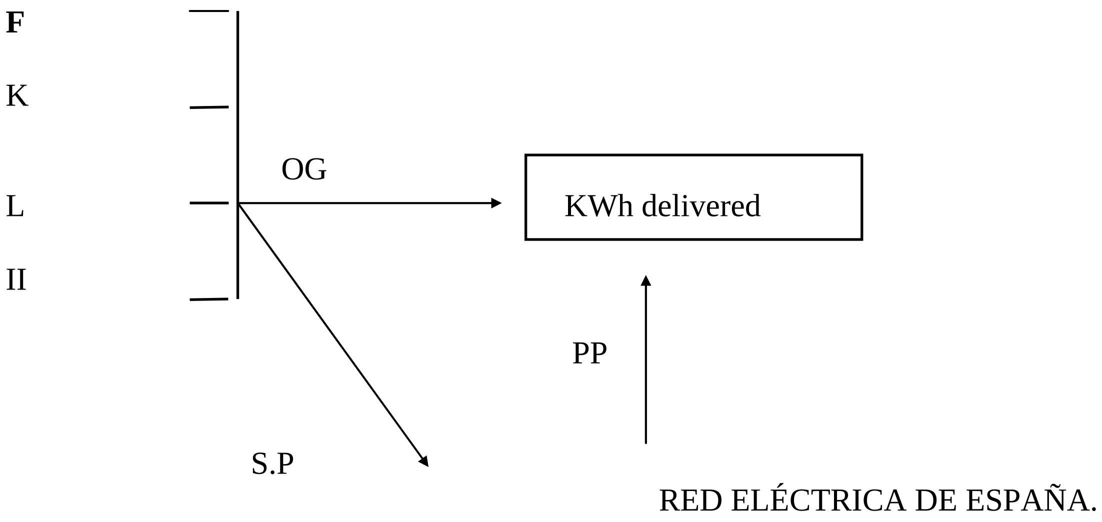
	Pl	Pk	Pc	PI	P.c.sp
	Million pt/ worker		10^3 pts/ eot		10^3 pts/ eot
Average	7.28	0.12	8.28	0.148	7.277
ENECO	6.46	0.254	8.06	0.054	--
ENHER	7.68	0.107	---	0.193	--
ERZ	6.70	0.11	---	0.201	--
FECSA	7.61	0.093	8.10	0.141	8.571
FENOSA	7.68	0.087	8.57	0.134	7.284
H.C.	7.57	0.092	8.57	0.159	--
H.E.	7.70	0.101	7.79	0.146	9.090
H.E.C	7.79	0.101	---	0.139	7.716
IBERD	7.95	0.094	9.15	0.146	5.647
IBERDROLA	7.94	0.119	7.94	0.155	5.999
SEVILLANA	6.25	0.146	7.97	0.125	7.247
VIESGO	6.51	0.113	7.97	0.167	6.815

eot: equivalent oil ton.

Source: firm released data.

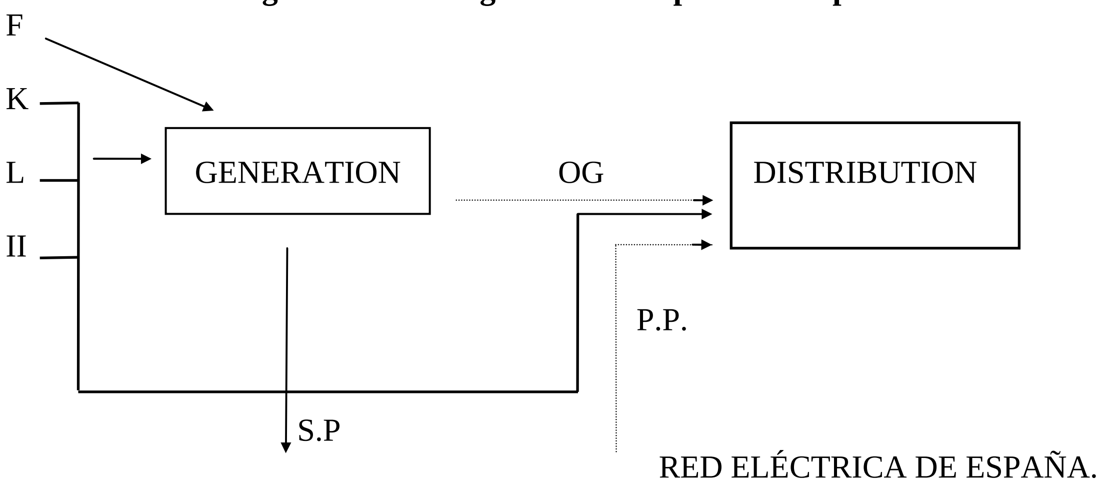
FIGURES

Figure 1. Aggregate view of the production process.



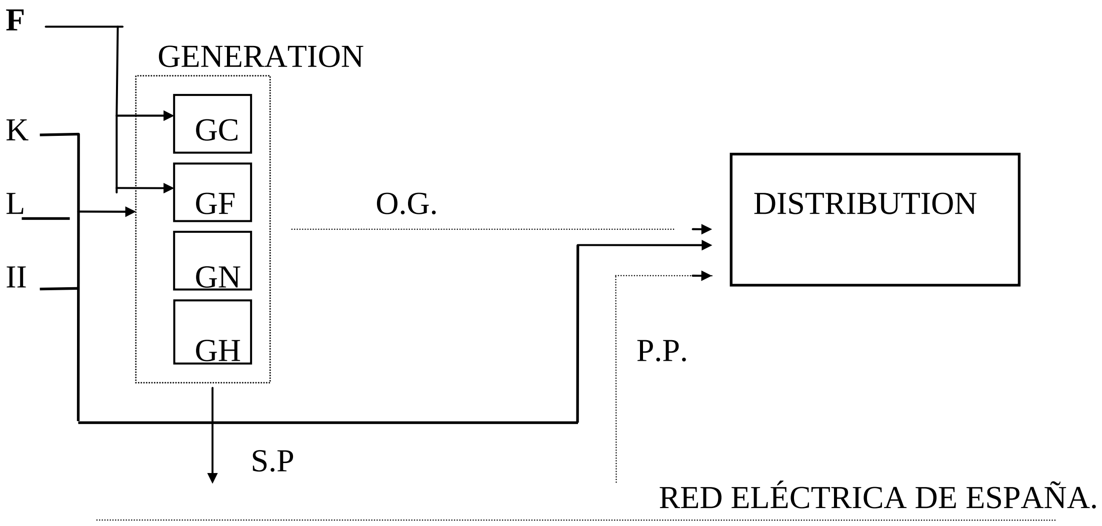
F: fuel; K: capital; L: labor; II: intermediate input; PP: purchased power; SP: sold power; OG: own generation;

Figure 2. Multistage view of the production process.



F: fuel; K: capital; L: labor; II: intermediate input; PP: purchased power; SP: sold power; OG: own generation;

Figure 3. Multistage-multioutput view of the production process.



F: fuel; K: capital; L: labor; II: intermediate input; PP: purchased power; SP: sold power; OG: own generation; CG: coal generation; GF: fuel-oil generation; GN: nuclear generation; GH: hydroelectric generation; Di: Distribution.