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## **Regional Differences in Electricity Distribution Costs and their Consequences for Yardstick Regulation of Access Prices\***

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### **Abstract**

In this paper we estimate an average-cost function for a panel of 59 Swiss local and regional electricity distribution utilities as a basis for yardstick regulation of the distribution-network access prices. Shleifer (1985) proposed yardstick competition in terms of price to regulate local monopolies producing a homogeneous good. The regulated price for the individual firms depends on the average costs of identical firms. The yardstick competition concept can also be applied to firms that are producing heterogeneous goods if these goods differ only in observable characteristics. To correct the yardstick for heterogeneity the regulator can use a multivariate estimation of an average cost function. In the case of electricity distribution the heterogeneity of output consists mainly of different characteristics of the distribution service areas.

In this paper we follow Shleifer's suggestion to estimate a multivariate average cost function that can be employed by the regulatory commission to benchmark network access prices at the distribution level. Several exogenous variables measuring the heterogeneity of the service areas were included in the cost model specification. We find that the regional differences of the service areas - e.g. area shares of forests, agricultural areas or unproductive land and population density - significantly influence electricity distribution costs.

*Keywords: electricity distribution, regional heterogeneity, yardstick competition, average cost function*

*JEL: L94, R32, L43*

### **1. Introduction**

The privatization and the deregulation of the electric power sector have been introduced in many countries, including England, Norway, Chile and New Zealand. In Switzerland, as in other European countries, several proposals exist to institute changes in the electricity market and therefore move to competition. All these proposals contain as a central element of the reform the introduction of third party access (TPA). With the introduction of TPA, the electricity distribution

utilities are obliged to allow nondiscriminatory access to companies that wish to transmit electricity over the utility's transmission and distribution lines for sale at the final consumer level.

As a result, the distribution utilities at the local level, which are the object of our study, must separate their different functions: the delivery of electricity (distribution) and the retail sale of electricity (supply). Because the electricity distribution utilities will still have a monopoly franchise to deliver electricity within their service territories, a rate regulation by the regulatory commission is necessary. Otherwise, the distribution utilities could raise the rates above what they would be in a competitive market. This raises the problem of determining proper rates for the delivery of electricity at the local level. On the one hand, prices should be high enough to guarantee the viability of regulated firm, on the other hand, prices that are set too high cause welfare losses. Because of asymmetric information, the regulator does not know the firm's true costs. High costs may be due to the firm's particular production situation or just because of its inefficiency.

Traditional regulation does not take into account the problem of inefficiency of regulated firms. Rate-of-return or cost-of-service regulation typically allows firms to set prices that cover all of costs, but no incentives for efficient production are given. In recent years, price-cap regulation, which gives firms better incentives for efficient production, is used to regulate natural monopolies (see Laffont and Tirole, 1993). The regulator sets a price cap (or price path) that will not be changed for a regulatory period (usually several years). However, due to the imperfect information available to the regulator there are problems with price-cap regulation, too. First, if price caps are set too high there is the possibility of a typical situation of deadweight loss. Second, the regulating authority might have a credibility or commitment problem if regulated firms are not viable due to price-caps that are set very low. Third, under price-cap regulation the regulator has only limited possibilities to react to general shocks that influence costs of all regulated firms in the same way.

Shleifer (1985) proposed yardstick competition in terms of price to regulate local monopolies producing a homogeneous good. The regulated price for the individual firms depends on the average costs of identical firms. Shleifer shows that under ideal circumstances it is the dominant strategy for each firm to choose the socially efficient level of cost reduction. Yardstick competition can also be used to set the informational basis for a more effective price-cap regulation because it reduces the informational asymmetries between firms and regulator regarding costs. It has the additional advantage of taking into account general shocks that might cause problems in a pure price-cap regulation.

The yardstick competition concept can also be applied to firms that are producing heterogeneous outputs if these outputs only differ in observable characteristics. To correct the yardstick for the heterogeneity the regulator can use a multivariate estimation of an average cost function.<sup>1</sup> The observable characteristics are included as explanatory variables and will in that way correct for cost differences

that are only due to the heterogeneity of output. Only exogenous heterogeneity factors that cannot be altered by the distribution utilities must therefore be incorporated in the yardstick regulation. The regulator sets, then, corrected yardstick prices for the individual firms that incorporate their heterogeneity.

The purpose of this paper is to make a contribution to the debate on access pricing of the distribution network. We suggest that yardstick regulation should be used to regulate prices for TPA to the distribution network. Because of the heterogeneity of electricity distribution we follow Shleifer's suggestion to estimate a multivariate average cost function that could be employed by the regulatory commission to benchmark network access prices at the distribution level. Therefore, in the empirical part we specify for a sample of Swiss distribution utilities an average cost function, which incorporates as explanatory variables some service area characteristics such as land use (share of land dedicated to farming, to forests and unproductive areas), the customer density, and the average demand of different customer groups.

The article is organized as follows. In the next section an average cost function for electricity distribution that takes into account the heterogeneity of the output is suggested. After that the database for the estimation of the average cost function is presented. The estimation results follow in section 4 and are complemented by the analysis of returns to density and scale. Section 5 shows how the results could be used to regulate the electricity distribution by yardstick competition. Section 6 reports the conclusions.

## **2. Specification of an Average Cost Function**

The estimation of cost functions in the electricity distribution industry are well documented in empirical research cf. Neuberger (1977) and Pollitt (1995) for the estimation of average cost functions and Nelson and Primeaux (1988), Salvanes and Tjøtta (1994), Burns and Weyman-Jones (1996), Filippini (1996), Hayashi, Goo, and Chamberlain (1997) and Filippini (1998) for the estimation of total cost functions. All of these studies estimated cost functions, which also include the expenditure for purchasing electricity in the total costs. As a result, these studies do not separate the electricity purchasing function of a utility from the network operation function and, therefore, are not ideal for benchmarking network access prices.

To overcome this problem we suggest in this study a very simple unbundling of costs between the network activities and the purchasing activities: only the costs of electricity purchasing belong to the supply, all the other costs belong to the network. This seems a reasonable approach because the supply activities in comparison to the network operation need only a limited amount of resources in terms of labor and capital. In addition, this simple unbundling mechanism considers the fact that the regulator is subject to asymmetric information and normally can not observe subcosts.

The costs of operating a distribution system are the costs of building and maintaining the system of service lines, mains and transformers, and of measuring and billing electricity. Burns and Weyman-Jones (1996) draw up a comprehensive list of the factors these costs may depend upon:

- (a) the maximum demand on the system;
- (b) the total number of customers served;
- (c) the type of consumer;
- (d) the dispersion of the consumers;
- (e) the size of the distribution area;
- (f) the total kWh sold;
- (g) system security;
- (h) the length of distribution line and
- (i) the transformer capacity.

However, the last two factors, the length of the distribution line and the transformer capacity, are inputs rather than output characteristics and therefore should not be included in the model. Moreover, Shleifer emphasized that only “observable characteristics that cannot be altered by the firm” should be used to model the heterogeneity of output. To overcome serious multicollinearity problems,<sup>2</sup> we are incorporating the different effects suggested by Burns and Weyman-Jones mostly in terms of relative rather than absolute variables.

In our model we distinguish three different network levels (high, medium, and low voltage). The main output is kWh transported on the medium-voltage grid. Additional variables for the high- and low-voltage grid are included. Maximum demand is embodied in form of the load factor (LF), which is the relation between average and maximum demand. To account for the heterogeneity of consumers we differentiate between two customer groups (medium- and low-voltage customers) with their respective average consumption levels. The dispersion of consumers and the structure of the service area are modeled by the incorporation of a customer-density variable and variables indicating the area shares of different ground categories. System security should also be used as an output indicator. Unfortunately, we are not able to include system security variables in our specification because no data are available.

The inputs to the operation of the distribution system consist primarily of labor and capital. Assuming that output and input prices are exogenous, and that (for a given technology) firms adjust input levels so as to minimize costs of distribution, the firm's total average cost of operating the electricity distribution system can be represented by the average cost function

$$AC = C / Y = AC ( Y, PL, PC, HGRID, LVSH, AVGM, AVGL, LF, CD, AGSH, FOSH, UPSH, OTSH, T ), \quad (1)$$

where C represents total cost, AC represents average cost per kWh and Y is the output represented by the total number of kWh transported on the medium-voltage

grid. PL and PC are the prices of labor and capital, respectively. HGRID is a dummy variable to separate distribution utilities that are also operating a high-voltage grid.<sup>3</sup> LVSH represents the share of electricity that is delivered on the low-voltage network. This variable considers the differences among the utilities in terms of customer structure. AVGL is the average consumption per low voltage customer. LF is the load factor and CD is the customer density measured in customers per hectare of settlement land. AGSH represents the share of agricultural land, FOSH represents the share of forest land and UPSH indicates the share of unproductive land with respect to the total size of the service area, respectively.<sup>4</sup> OTSH is a variable used to control for outputs other than the distribution of electricity that are included in the accounting data of electric utilities.<sup>5</sup> We use the share of “other revenues” on total revenues as output indicator for these activities. T is a time variable which captures the shift in technology representing change in technical efficiency.

Using a linear function, equation (1) can be approximated by the following average cost function:

$$\begin{aligned}
 AC = & \beta_0 + \beta_Y Y + \beta_{YY} Y^2 + \beta_{PL} PL + \beta_{PC} PC + \beta_{HG} HGRID + \beta_{LS} LVSH \\
 & + \beta_{AL} AVGL + \beta_{LF} LF + \beta_{CD} CD + \beta_{CDCD} CD^2 \\
 & + \beta_{AG} AGSH + \beta_{FO} FOSH + \beta_{UP} UPSH + \beta_{OT} OTSH + \beta_T T + \varepsilon_{it}
 \end{aligned} \tag{2}$$

The output  $Y$  and the customer density  $CD$  are included in linear and quadratic form to allow nonlinear variations of the average-cost function.

### 3. The Data

This study is based on a combined time series and cross-sectional data set for Swiss electricity distribution utilities over the period 1988-1996.<sup>7</sup> The primary sources were the Swiss Federal Office of Energy's “Finanzstatistik”; additional data were collected using a mail questionnaire sent to the utilities. Part of the companies listed in this sample, however, are not appropriate for the purpose of our analysis because the amount of self-generated electricity is high. Since the aim of this study is to analyze the cost structure of distribution companies, companies which had an amount of self-generated electricity higher than 20% of the total sales were excluded.<sup>6</sup> The restrictions on data described above and the completed questionnaires result in an unbalanced panel of 59 electricity distribution utilities (380 observations) for which appropriate data are available. All input prices, total cost and variable cost were deflated to 1996 constant Swiss francs using the Swiss Consumer Price Index.

For simplicity, total distribution cost is equated to total expenditure as reported by the companies excluding the expenditure for purchased electricity. Average yearly wage rates are estimated as the labor expenditure divided by the number of employees. Following Friedlaender and Wang Chang (1983) and Filippini and

Maggi (1993), the capital price is calculated from the residual capital costs divided by the capital stock. Residual capital cost is total distribution cost minus labor cost. According to Callan (1992), the capital stock is approximated by the total installed transformer capacity, measured in kVA.<sup>8</sup> Descriptive statistics of the variables are presented in Table 1.

Variable	Description	Dimension	1. Quartile	Median	3. Quartile
AC	Average cost	Swiss cents / kWh	5.86	7.95	10.03
Y	Output	GWh	67.6	104.6	198.7
PL	Price labor	1000 CHF / employee	82.6	97.0	113.5
PK	Price capital	CHF / kVA	62.6	88.1	123.5
HGRID	High voltage grid	Dummy	0	0	1
LVSH	Low voltage sales	Share	0.59	0.74	0.90
LF	Load factor		0.52	0.56	0.59
AVGL	Avg. consumption low voltage	kWh / customer	5'995	6'689	7'424
CD	Customer density	Customer / ha	14.92	19.51	22.92
AGSH	Agricultural land	Share	0.22	0.34	0.42
FOSH	Forest land	Share	0.22	0.30	0.40
UPSH	Unproductive land	Share	0.01	0.02	0.06
OTSH	Other activities	Share	0.03	0.07	0.13

*Table 1 - Descriptive statistics*

#### 4. Estimation Results

With regard to choice of econometric technique, it should be noted that in the econometric literature we can find various types of models focusing on cross-sectional variation, i.e., heterogeneity across units. The three most widely used approaches are: the OLS model, the least squares dummy variable (LSDV) model, and the error components model (EC). The fact that the average cost function (1) includes explanatory variables that remain constant over time excludes the possibility to estimate equation (2) by LSDV. Therefore, equation (2) has been estimated using the OLS and the EC models.

In Table 2 the OLS and the EC estimates of the average cost function (2) are presented. The estimated functions are well behaved. Most of the parameter estimates are statistically significant and carry the expected sign. Moreover, the coefficients of both models are similar.

To test whether individual effects are present we ran a Lagrange Multiplier test for the random effects model. The result of this test favors the random effects model over the OLS model. However, the estimated coefficients do not vary much between the two specifications.

	OLS		RE (GLS)	
	Coefficient	t-ratio	Coefficient	t-ratio
Constant	9.2284***	7.73	9.8260***	4.88
Y	-0.0063***	-8.59	-0.0050**	-3.28
Y <sup>2</sup>	0.000003***	7.57	0.000002**	2.85
PL	0.0080***	3.45	0.0057	1.70
PC	0.0409***	18.14	0.0294***	15.48
HGRID	1.5910***	7.46	1.6594**	3.14
LVSH	4.4542***	7.67	6.4288***	6.22
AVGN	-0.0005***	-7.35	-0.0007***	-8.43
LF	-11.2375***	-9.65	-7.8393***	-7.88
AGSH	5.0627***	6.45	5.6378**	2.82
FOSH	7.4453***	10.03	6.3170***	3.17
UPSH	2.0518*	2.51	1.7258	0.87
CD	-0.3782***	-7.43	-0.4109***	-3.91
CD <sup>2</sup>	0.0076***	8.04	0.0075***	3.62
OTSH	9.7348***	8.96	13.5576***	13.03
T	0.0115	0.37	0.0195	1.09
Adj. R2	0.817		0.784	

\*\*\*, \*\*, \*: significantly different from zero at the 99.9%, 99%, 95% confidence level.

*Table 2 - Average-cost parameter estimates*

As expected, an increase in the load factor – i.e. smaller fluctuations of electricity demand over time – will decrease average costs. This result indicates that to improve the load factor, the Swiss electric utilities could more strongly differentiate the time-of-use rates. Filippini (1997) shows a general responsiveness of electricity consumption in the Swiss residential sector to changes in peak and off-peak prices.

According to Roberts (1986), the inclusion of the number of customers and the size of the service territory in the cost function of network industries allows for the distinction of returns to output density, returns to customer density and returns to scale. Returns to scale (RS) measure the reaction of costs to an equal proportional increase in output, number of customers and size of the service area. In terms of our model specification this is equal to an expansion of output, holding output density and customer density constant. It can be shown that returns to scale – the effect of an expansion of  $Y$ , holding  $AVGL$ ,  $AVGM$  and  $CD$  constant on total costs - can be derived from the average cost elasticity with respect to  $Y$ , as follows

$$RS = \frac{1}{1 + \frac{\partial AC}{\partial Y} \frac{Y}{AC}} \quad (3)$$

Returns to customer density (RCD) measure the reaction of costs to an equal proportional increase of output and the number of customers, holding the size of the service area fixed. In terms of our model specification, this corresponds to an equal proportional expansion of output and customer density, holding output density constant. Returns to customer density can be derived from the average cost elasticity with respect to  $Y$  and  $CD$ , as follows:

$$RCD = \frac{1}{1 + \frac{\partial AC}{\partial Y} \frac{Y}{AC} + \frac{\partial AC}{\partial CD} \frac{CD}{AC}} \quad (4)$$

Finally, returns to output density (ROD) measure the reaction of costs to an increase in output holding the size of the service area and the number of customers fixed. In terms of our model specification, this corresponds to a proportional expansion of output and average consumption per customer, holding customer density constant. Returns to output density can be derived from the average cost elasticity with respect to  $Y$  and  $AVGL$ , as follows

$$ROD = \frac{1}{1 + \frac{\partial AC}{\partial Y} \frac{Y}{AC} + \frac{\partial AC}{\partial AVGL} \frac{AVGL}{AC}} \quad (5)$$

Returns to scale or density are said to be increasing, constant or decreasing, when RS, RCD or ROD are greater than unity, equal to unity, or less than unity, respectively. Although these definitions are based on the average cost specification, they correspond to – and can be compared with – those suggested by Roberts (1986) for the total cost function. The resulting returns to scale and density at the mean of the sample are summarized in Table 3.

	OLS (t-ratio)	RE (GLS) (t-ratio)
Returns to scale (RS)	1.181 *** (8.82)	1.140 *** (3.38)
Returns to customer density (RCD)	1.451 *** (7.35)	1.602 *** (4.49)
Returns to output density (ROD)	2.209 *** (9.73)	4.567 *** (10.26)

*Table 3 – Returns to scale and density at the mean of the sample*

We find increasing returns to scale for the electricity distribution utilities in our sample. In Figure 1 the scale expansion paths of the average costs are shown. Most of the utilities in our sample therefore are too small and do not reach the minimum efficient scale (the median utility delivers 110 GWh).

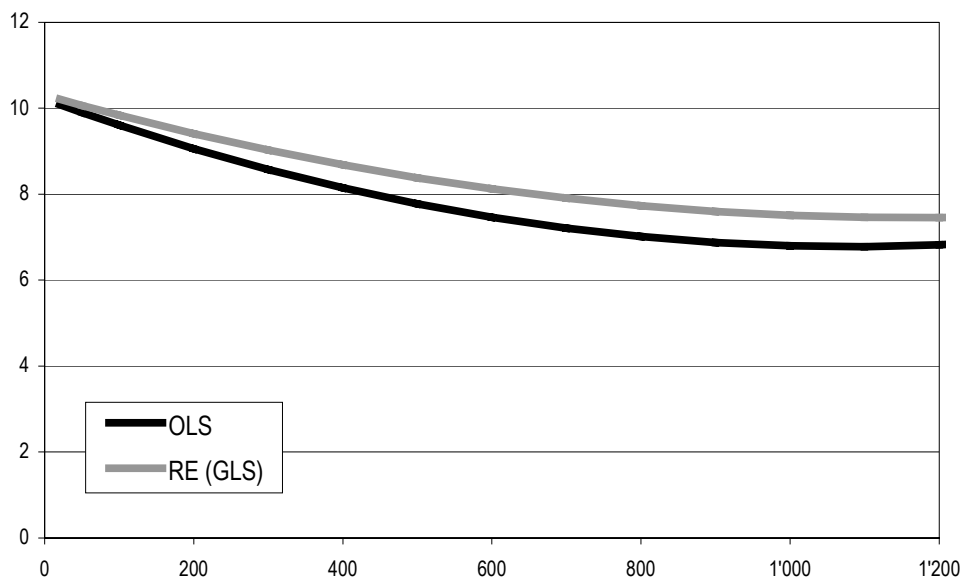


Figure 1 - Scale expansion paths of the average costs for all three voltage levels

In addition, there are significant economies of customer density and economies of output density. Average distribution costs fall the more densely populated a service area is, and the higher the average consumption per customer (i.e. the output density) is.

### 5. Using the Results for Yardstick Regulation

The estimation results can be used to predict the cost of the different voltage levels of the distribution network. The costs for the high-, medium- and low-voltage grids at the mean values of the sample are shown in Table 4.

	OLS	RE (GLS)
high-voltage grid (between 40 kV and 220 kV)	1.6	1.7
medium-voltage grid (between 1 kV and 40 kV)	2.6	1.0
low-voltage grid (up to 1 kV)	4.5	6.4
Total distribution costs (all three voltage levels)	8.7	9.1

Table 4 – Estimated average costs per voltage level (in Swiss cents per kWh)

The regulator might use these costs as price-caps for the regulation of electricity transport prices on the different distribution levels. However, these costs do not incorporate the heterogeneity of electricity distribution utilities. The estimation results in Table 2 suggest that the heterogeneity of output – customer density, the average output per customer, the shares of different area categories and the load

factor – significantly influence average costs. Table 5 shows the estimated average-cost elasticities of the heterogeneity variables in our model.

Heterogeneity factor		OLS	RE (GLS)
Customer density	CD	-0.16	-0.25
Average consumption per customer	AVGN	-0.39	-0.66
Agricultural land share	AGSH	0.20	0.23
Forest land share	FOSH	0.28	0.24
Unproductive land share	UPSH	0.02	0.02
Load factor	LF	-0.75	-0.52

*Table 5 – Estimated average-cost elasticities of service area characteristics*

The regulator to calculate individual price-caps for the different utilities might use these estimates. The individual price-caps reflect the heterogeneity of their service area, customers and demand characteristics. However, the size of the utilities – the output  $Y$  – must not be included in the yardstick price calculation because it is not a characteristic of the service area that cannot be altered by the firms. The exclusion of  $Y$  gives the small utilities incentives to merge, because they can decrease their costs due to increasing returns to scale.

Following the same argument, the load factor should be excluded from the calculation of individual price-caps, to give the network owners an incentive to undertake load management. As presented in Table 5, the load factor influences cost; therefore, the utilities could lower their cost by introducing time-of-use rates as suggested by Filippini (1997).

The yardstick regulation of firms with heterogeneous outputs is only appropriate if the observed characteristics allow the regulator to record most of the heterogeneity. The adjusted determination coefficients of our estimations are rather high, 0.836 and 0.85, suggesting that our model explains about 85% of the variation of average distribution costs.

## 6. Conclusions

In this paper we have estimated an average-cost function for a panel of 59 Swiss electricity distribution utilities as a basis for yardstick competition as suggested by Shleifer for the regulation of network access prices. Unlike the existing literature, we separated the sale function of a utility from the delivery function, and we did not include variables that can be influenced by the firms. Moreover, several variables measuring the heterogeneity of output were included in the model specification.

The estimation results indicate the existence of economies of output and customer density and economies of scale. A majority of the distribution utilities is not producing at an efficient scale. Moreover, we were able to identify different heterogeneity factors that affect average cost: These are the customer density, the average consumption per customer, area shares of different land categories and the load factor.

In Switzerland, there is currently a debate on the deregulation of the electricity market. In the Swiss Federal Office of Energy's (1998) proposal for a new electricity market bill ("Elektrizitätsmarktgesetz"). Distribution network owners have to give access to their network only if there is excess capacity (Art. 4, par. 2). The pricing of TPA to the distribution network follows the traditional cost-of-service regulation (Art. 5, par. 1). According to the proposal, therefore, each distribution utility is allowed to set the delivery rate at the level of its individual average cost. This proposal suffers from three main problems: First, if the network owners pretend that there is no capacity available, it will be difficult for potential network users to get access at all. Second, the cost-of-service regulation gives no incentives to the network owners to increase their efficiency. Third, the regulator does not use the fact that there are approximately 900 similar electricity distribution utilities in Switzerland to reduce the asymmetric information concerning the costs. We believe that the regulator could use the average cost function estimated in this paper for yardstick regulation of the network access prices and thus solving problems two and three.

### Endnotes

- \* The authors would like to thank Prof. Peter Zweifel (Socioeconomic Institute, University of Zurich), the Swiss Federal Office of Energy – namely Alfred Löhner – and all the distribution utilities that responded to the questionnaire for their cooperation.
- 1 Kittelsen (1995) and Weyman-Jones (1995) apply data envelopment analysis (DEA) for the yardstick regulation of electricity distribution.
- 2 In our sample, the correlation coefficient between maximum demand and total kWh sold is 0.99583; between the number of customers and total kWh sold it is 0.97745; and between maximum demand and the number of customers it is 0.97984.
- 3 Some utilities only operate medium- and low-voltage grids and are connected to a high-voltage grid that is operated by a different firm. The costs of this high-voltage grid are, then, implicitly part of their electricity purchasing costs and therefore not included in the network costs.
- 4 The remaining share of settlement land is excluded from the equation to avoid perfect collinearity between the area category shares and the constant.
- 5 Unfortunately, it is not possible to separate the costs of other activities from the network operation costs due to insufficient accounting data.

- 6 The Swiss electric power industry is composed of about 1200 firms, public and private, that are engaged in the generation, transmission and/or distribution of electric power. There is a great divergence both in terms of size and activities of these companies. In particular, approximately 900 utilities, or 74% of the total, are merely distributors of electric power. The municipalities and the regional electric utilities purchase most of their power from 10 utilities which form the backbone of the industry.
- 7 Due to insufficient accounting data we do not have the possibility to separate production and distribution cost.
- 8 Unfortunately, no data are available which would allow the calculation of the capital stock using the perpetual inventory method.

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