Electric Utilities: Scale Economies and Diseconomies*

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I. Introduction

For many decades, the electric power industry has been regarded as one of the more efficient sectors of American industry. Many observers have cited improvements in the productivity of all inputs as evidence of the industry's rate of technological progress and ability to exploit economies of scale. Economic studies of both plant and firm level economies have concentrated almost solely on the generating sector of the industry but have generally reached similar conclusions although there have been important disagreements as to the source of the efficiencies (i.e., economies of scale, technological change or utilization of capacity) and the ranking of productivity improvements among the inputs. None of these studies, however, has ever identified any diseconomies of scale or ever challenged the natural monopoly concept as applied to the electric power industry.[1]

The conclusions reached in this study are important for several reasons: they highlight shortcomings existing in previous studies of the electric power industry;[2] they extend to the firm level recent conclusions regarding scale

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1. A listing of these previous studies and a review of their assumptions and conclusions has been published elsewhere in [14] and [16], hence the details have been omitted here.

2. The most important shortcomings of previous economic studies of the electric power industry include: scale biases in the treatment of capital costs due to the assumption of equal economic lives for all plants; violation of the principle of cost minimization; and smaples concentrating exclusively on plant sizes below 400 megawatts. For further details, see [14] and [16].

diseconomies at the plant level; and, by questioning the natural monopoly concept as applied to this industry, they suggest that the range of public policy options vis-a-vis the electric utility industry should be broadened to include deregulation of some functions. While recent price and cost increases in the electric power industry have led some observers to speculate that scale economies may be nearing exhaustion, these speculations have not been documented in any systematic way nor based on current or past studies. In fact, past studies [1; 5; 6; 12; 17; 18; 19; 22; 23; 24; 26 and 27] have consistently reported the existence of scale economies throughout the range of observations.

The first studies documenting scale exhaustion at the plant level, [14] and [16], appeared in 1973 and 1975 respectively. The first published study indicating scale exhaustion at the firm level [4] appeared in 1976. Authored by Christensen and Greene (hereafter C and G), this study concluded that there were constant returns to scale in generation for firm sizes as low as 19.8 billion KWH (about 3,800 Megawatts). This study has somewhat limited public policy implications, however, for several reasons.

First, it concentrated solely on costs directly allocable to generating and therefore did not address scale issues in other cost categories comprising 50 percent of total costs. Second, while its use of a translog cost function does not restrict the form of the production function and hence the elasticities of substitution of the inputs, it does restrict the consideration of other important differences among firms in the sample and could introduce specification errors. These important differences include variations or differences among companies: in the degree of capacity utilization; in the types of fuels used; in their reliance on nuclear, hydro or gas turbine capacity and purchased power; and in regional differences in demand patterns, peak demand, and in construction types and costs. In addition, their procedure of summing the individual firms of a holding company and treating them as one entity assumes that the degree of integration is both high and constant across holding companies.[3] This procedure should shift the true scale curve to the right and flatten it out. Finally, C and G's use of accounting data on depreciation to measure capital (following Nerlove [26]) should introduce a scale opposed bias as has been noted in [16].

In a real sense, a researcher studying scale issues is frequently forced to choose which type of specification error he prefers. For example, if one chooses a translog cost function as did C and G, then restrictions on the production function and elasticities of substitution among inputs are minimized but at the cost of not controlling for important differences among firms

3. The degree of integration of holding companies varies considerably. For example, the A.E.P. System is highly integrated, the Southern System is loosely integrated, and the Central and Southwest System operates with minimum integration of its four operating companies.

that could well effect the scale conclusions. If, on the other hand, the researcher chooses a more pedestrian cost function that allows him to use dummy variables and otherwise control for important differences among firms, he will reduce this type of specification error but increase errors associated with restrictions on the elasticity of substitution among inputs.

C and G have elected to take the former approach while, in this study, we have elected to take the latter and also to treat holding companies differently. In addition, we have elected to examine scale relationships in generation, transmission, distribution, administration, customer accounts and sales. Finally, we have used an entirely different concept of a cost function than is usually used in economics. This approach is necessary to capture the cost implications of meeting peaked electricity loads yet deserves some justification since it is a marked departure from traditional economic theory and previous studies of the electric power industry. Section II of this study will justify the use of this non-traditional cost concept.

Turning next to another issue, it is worth noting that relationships observed at the plant level, particularly economies of scale, are often modified by interrelationships at higher levels of decision making, such as the firm and system level. The system level is perhaps the most natural level of analysis for this study but at least two factors indicate that statistical work cannot be confined to systems. First, existing electric power systems take many forms varying from loose to tightly knit.[4] Second, there is little relevant data on systems. For these reasons, the empirical analysis of this study will be based exclusively on the firm level. Firm level relationships, however, can be predicted by taking the plant level relationships, observed in [14] and [16] and combining them with system level relationships described in the engineering literature [7]. This analysis[5] (details omitted) provides some scale predictions or benchmarks against which the regression results of Section III can be compared and indicates that the long run average cost curves for generating should be U shaped, and that operating and fixed costs in generation should be a minimum for firm sizes of 2,000 MW and 3,000 MW respectively.[6]

Section III of this study will utilize multivariate regression analysis to assess firm level economies of scale in generation, transmission, distribution and administration. Existing econometric studies cannot form the basis for this analysis because, as noted above, they have had several important shortcomings, have concentrated primarily on generation and excluded transmission and distribution, and have, with two exceptions, been based on data existing prior to 1959. The fourth and concluding section will summarize and evaluate the results.

4. For a discussion of the myriad forms of interconnection, see [25]. Also see [15].
5. Details of this analysis have been omitted but can be obtained from the authors.
6. Note that the abbreviation MW stands for megawatts (i.e., 1,000 kilowatts).

Two points should be noted before turning to the next section. The first is that 1971 data will be used in this study to rule out most effects of pollution control equipment on scale relationships. Very few of the plants operating in 1971 employed pollution control equipment but since that date many plants have been retrofitted with pollution control equipment or forced to burn fuels for which they were not designed.

The second point to note is that Averch-Johnson or A-J effects will be ignored throughout this study. This position is justified for several reasons noted in [2], and by others, including: the capital constraints on the electric power industry; the existence or lack of existence of an A-J effect depending on the model assumed;and the small or non-existent A-J effects reported in empirical studies.

II. Cost Functions for Public Utilities

Traditional economic theory produces cost functions that have input prices, $P_1, \ldots, P_n$ and the quantity of output, Q, as arguments and a functional form determined by the production function as in Equation 1:

$$C = f(Q;P_1,\ldots,P_n) \tag{1}$$

These traditional functions are useful for characterizing operations where peak demands do not have to be met (i.e., order backlogs) or operations where output can be stored and peak demands met by sales from inventory. Under these conditions, production costs are not heavily influenced by demand peaks or the annual pattern of demand hence one can assume that production takes place at an even rate or that output is an appropriate measure of the scale of production as in Equation 1.

Public utilities (and some private sector activities as well) generally provide services such as electricity, communications, or transportation that cannot be stored. In addition, public utilities are generally required to meet demands for their services at all times of the day or year hence they must build capacity capable of producing the quantity demanded at peak periods. Meeting a peaked load is clearly more expensive than meeting an even load even if the total quantity produced is the same. In addition, the quantity of output loses its meaning as an accurate index of scale particularly in capital intensive industries such as public utilities where input relationships are determined by the level of planned activity—peak capacity requirements.

The above arguments suggest that costs and scale relationships in public utilities could be better measured if costs were expressed as a function of peak capacity, K, the rate of utilization of peak capacity, U, and input prices as in Equation 2.

$$C = g(K,U,P_1,\ldots,P_n) \tag{2}$$

Of course $Q = KU$ but does not appear in Equation 2 since peak capacity and the pattern of annual demand relative to peak capacity are the factors determining scale and costs.

We do not pretend to know what type of a production function would produce the cost relationship in Equation 2 but can make some observations on the duality relationship that is presumed to exist. The fact that public utilities with the same production function and level of output can have widely different costs due to differences in demand patterns suggests that a unique duality relationship can only be preserved under certain conditions. If costs for a given level of output, production function, and input prices are minimized subject to the constraint that demand follow a given pattern, then it would appear to follow that a unique duality relationship could be preserved. Of course the relationship would probably be different for each different demand pattern since peak capacity requirements and the rate of utilization of capacity would undoubtedly be changed.

An additional issue not generally addressed in either cost or production function studies concerns the durability of capital. Public utilities are generally capital intensive and the physical or economic life of capacity is an important consideration generally ignored by economic theory. Indeed, it is difficult to see how one could incorporate it into traditional production function analysis although a start has at least been made from the cost side [16]. Again, we do not pretend to have the answer to this question but we do explicitly recognize that we have skirted this issue whereas the study by Christensen and Greene does not.

Our method of skirting this issue is to simply separate operating and fixed costs and express fixed costs in terms of $/kilowatt of capacity instead of dollars per unit of output (i.e., kilowatt-hours). This procedure allows us to examine scale effects on fixed costs without making assumptions about economic life vs. plant size and about the particular depreciation method to be used. For a more complete discussion of these issues see [16].

This study is concerned with a particular type of public utility—electric utilities. Because of this, we have elected to use the non-traditional cost concept described in Equation 2. We realize that this may give our cost function an *"ad hoc"* flavor to which some may object, but it should be remembered that our approach does allow testing of certain firm characteristics not otherwise examined and therefore minimizes some types of specification errors at the cost of increasing others.

III. Economies of Scale For Electric Utilities

This section will present an empirical analysis of firm level economies in generation, transmission, distribution, sales, customer accounts and administration. This study will not attempt to disentangle cost advantages or disadvantages at the firm level from those arising at other levels of decision making, but will merely seek to test the degree to whicb large firms are associated with lower unit costs.[7] As noted earlier, the transmission and distribution functions have not been subjected to empirically-based economic studies but all of the engineering-based studies such as [9], [10], and [11] have reported substantial economies of scale in both fixed costs and operating costs. Of the four firm level economic studies reviewed in [14] and [16], three reported substantial economies of scale in generation and the single study of administration costs concluded that there were constant returns to scale. In addition, all four were based on pre-1955 data.[8] Clearly, our understanding of firm level economies is fragmented, out of date, and based mainly on engineering relationships or economic studies concentrating on the generating function alone.

The regression analysis that follows was based on 1971 data taken from the FPC [8]. The sample was limited to the 74 electric utilities who: sold to residential, commercial and industrial customers; had fossil steam capacity comprising at least 80 percent of their total generating capacity; and generated at least 80 percent of their own power. Single equation models will be developed for each of the major cost categories comprising total operating expenses except for depreciation charges which have been excluded from the analysis. The use of single equation models is defended on the grounds that the data to develop a demand model for each utility are currently unavailable.[9] It should also be recalled that 1971 data will be used in this section to rule out most effects of pollution control equipment on scale relationships.

The major cost categories to be examined in this section include, for operating cost: production; transmission; distribution; administrative and general; customer accounts; and sales expense. Long run average variable cost curves will be estimated for each of these expense categories. In addition,

7. Since most firms are integrated to some degree in pools or systems, the unit costs observed at the firm level may be lower than those that would be observed if no integration were present. This factor could alter the shape of the LRAC curve particularly for smaller firms but it cannot explain the diseconomies of large firms described later in this section.

8. Of the five empirically based generating plant studies reviewed in [14] and [16], only two were based on post-1955 data, the most recent including some generating plants constructed in 1965.

9. We are currently collecting data on demand and demographic factors by utility service area.

scale relationships for adjusted, undepreciated fixed investment per KW of capacity will be estimated for production.[10]

Two basic measures of firm size will be employed in the regressions that follow—company generating capacity in megawatts (MW) and total annual company sales in megawatt-hours (MWH). Generating capacity will be used as the firm size measure for production, transmission and distribution expenses since these are most closely related to the physical size of the company's stock of equipment. Total annual company output or sales in MWH will be used for the remaining cost categories since they are more closely related to annual sales, particularly for companies that purchase a significant portion of their power.

The square of the firm size variable will be included in each regression to test for U shaped long run average cost curves. An additional test of the scale effect will also be made by performing separate regressions on firms having generating capacity under 2,000 MW and those over 2,000 MW. Based on the literature reviewed in Section I, one would expect to find long run average variable cost curves declining throughout the entire range of observation. The system level of analysis referred to in Section I, however, questioned this view and suggested that L shaped or U shaped cost curves are more likely to occur.

Utilization of generating capacity and its square will also be included in the production, transmission and distribution cost regressions to test for a U shaped short run average cost curve. Additional variables to be included in these regressions are input prices, regional dummy variables (costs are expected to be lowest in the South and highest in the Northeast), and holding company dummy variables (costs are generally expected to be lower for companies belonging to holding companies). Other variable specific to each cost category will also be included in each regression.[11]

Production Costs

Tables I and II present the regression results for fossil steam production expense per KWH and total production expense per KWH respectively. In both tables the coefficients of the capacity variables are significant and of the

10. Details of this adjustment will be provided in a later section but the adjustment consists of the use of an age-weighted Handy-Whitman construction cost index constructed by the authors.

11. Two characteristics that could not be included were the number of generating plants and the average plant capacity. Both are highly ($r > 0.8$) correlated with firm generating capacity and hence were excluded from the analysis. Note that two holding companies, American Electric Power and the Southern Company were explicitly included in the analysis due to their reputations as efficient producers.

Table I. Regression Analysis of 1971 Fossil Steam Production Expense Per KWH of Steam Generation in Mills/KWH*

	Variable	Expected Sign	Regression 1		Regression 2	
			Coefficient	t-ratio	Coefficient	t-ratio
	Constant		19.44	5.53[a]	19.75	5.56[a]
1.	Natural Log of Steam Capacity	-	-4.57	-5.83[a]	-4.54	-5.74[a]
2.	(Natural Log of Steam Capacity)^2	+	0.31	5.46[a]	0.30	5.35[a]
3.	Utilization of Steam Capacity	-	-4.48	-0.47	-5.05	-0.53
4.	(Utilization of Steam Capacity)^2	+	2.81	0.35	3.11	0.38
5.	Northeast Dummy	+	0.54	1.54[c]	0.58	1.65[c]
6.	North Central Dummy	+	0.32	1.20	0.31	1.21
7.	West Dummy	+	0.06	0.21	0.03	0.10
8.	Company Fuel Cost (¢/MBTU)	+	0.06	4.95[a]	0.06	4.84[a]
9.	Company Wage Cost ($/hour)	+	0.05	1.24	0.05	1.08
10.	Coal BTUs as a Percentage of Total	+	0.70	2.12[b]	0.61	1.80[b]
11.	Oil BTUs as a Percentage of Total	+	1.86	3.50[a]	1.80	3.24[a]
12.	Percent Nuclear Capacity	+	11.43	1.43[c]	11.82	1.47[c]
13.	Percent Hydro Capacity	+	1.66	0.63	2.17	0.82
14.	Percent Gas Turbine Capacity	+	1.23	0.56	1.61	0.73
15.	A.E.P. Holding Company Dummy	-	-0.81	-1.36[c]		
16.	Southern Holding Company Dummy	-	0.17	0.20		
17.	Any Holding Company Dummy	-			-0.09	-0.35
	Sample Size, N		74		74	
	Coefficient of Determination, R^2		0.8095		0.8037	
	Standard Error of the Estimate, σ_y		0.7601		0.7651	

*Note that the three regional dummy variables 5, 6 and 7 indicate cost difference relative to the South region of the United States. Based on a one-tailed test, significance at the 99% level is denoted by a, at the 95% level by b, at the 90% level by c. Data are taken from the Federal Power Commission's Statistics of Privately Owned Electric Utilities in the U.S., 1971. This sample includes all electric utilities who (1) sold to residential, commercial and industrial customers, (2) had fossil steam capacity comprising at least 80% of their total generating capacity and (3) generated at least 80% of their own power.

Table II. Regression Analysis of 1971 Total Production Expense Per KWH Generated and Received in Mills/KWH*

	Variable	Expected Sign	Regression 1 Coefficient	Regression 1 t-ratio	Regression 2 Coefficient	Regression 2 t-ratio
	Constant		22.96	5.28[a]	23.38	5.03[a]
1.	Natural Log of Total Capacity	-	-5.96	-6.37[a]	-6.01	-5.99[a]
2.	(Natural Log of Total Capacity)^2	+	0.41	6.07[a]	0.40	5.62[a]
3.	Utilization of Total Capacity	-	1.61	0.13	3.32	0.24
4.	(Utilization of Total Capacity)^2	+	-2.64	-0.23	-5.03	-0.41
5.	Northeast Dummy	+	0.96	2.17[b]	1.07	2.27[b]
6.	North Central Dummy	+	0.42	1.27	0.44	1.27
7.	West Dummy	+	-0.05	-0.13	-0.08	-0.21
8.	Company Fuel Cost (¢/MBTU)	+	0.06	3.85[a]	0.06	3.48[a]
9.	Company Wage Cost ($/hour)	+	0.04	0.74	0.02	0.32
10.	Coal BTUs as a Percentage of Total	+	0.57	1.37[c]	0.37	0.83
11.	Oil BTUs as a Percentage of Total	+	1.73	2.66[a]	1.68	2.32[b]
12.	Percent Nuclear Capacity	+	2.16	0.22	3.72	0.35
13.	Percent Hydro Capacity	-	0.89	0.28	2.46	0.71
14.	Percent Gas Turbine Capacity	+	3.42	1.22	4.32	1.48[c]
15.	A.E.P. Holding Company Dummy	-	-2.28	-3.07[a]		
16.	Southern Holding Company Dummy	-	0.14	0.14		
17.	Any Holding Company Dummy	-			-0.08	-0.23
	Sample Size, N		74		74	
	Coefficient of Determination, R^2		0.778		0.7389	
	Standard Error of the Estimate, σ_y		0.9388		1.0042	

*Note that capacity has been measured in megawatts (MW) of generating capacity; utilization of capacity has been expressed as a percent (i.e., a number between zero and 1.0); dummy variables have been expressed as 1.0 if true and zero otherwise; and variables 10 through 14 have been expressed as a number between zero and 1.0. Confidence intervals for the regression may be obtained by using the $\pm 2\sigma_y$ rule.

appropriate signs indicating a U shaped long run average production cost curve when all firm sizes are considered. The minimum point of the U shaped long run average production cost curve occurs at a firm size of 1,600 MW, well within the range of observation and close to the 2,000 MW prediction of Section I.[12] The estimated unit production cost for 1,600 MW firm is about 2.4 mill/KWH lower than that of a 100 MW firm and 1.0 mill/KWH lower than that of a 9,000MW firm. When the sample was split in separate regressions for utilities above and below 2,000 MW, the results (not shown) again indicated a U shaped cost curve.

The coefficients of the utilization of capacity variables in Tables I and II were not significant and were of the appropriate signs for a U shaped short run average production cost curve only in Table I. Closer examination revealed that, within the range of observed rates of utilization, costs declined continuously hence the short run average production cost curves are downward sloping in both Tables I and II. Minimum costs occurred at a utilization of 83 percent and were approximately 0.2 mills/KWH lower than costs at a utilization rate of 30 percent.[13]

The regional dummy variables indicate the cost differential between the Northeast, North Central and West relative to the South. These dummy variables were expected to have positive coefficients because wage rates and the general price level are generally higher in regions outside of the South. The coefficients for these regional variables were positive in ten of twelve cases but insignificant except for the Northeast.

The coefficients of the company's average fuel cost and wage cost variables were positive, as expected, but significant only for fuel costs. Fuel costs are a major component of production costs and, on the average, each one cent per million BTU increase in a company's fuel cost resulted in a 0.6 mill/KWH increase in production costs.

Variables 10 and 11, the percentage of total BTUs obtained from coal and oil respectively, were included to detect production cost differences associated with fuel type. These variables, in effect, measure fuel cost differences relative to natural gas since the firm would be 100 percent gas-fired if both the coal and oil BTU percentages are zero. Because of this, these variables were expected to have positive signs but the coefficient of Variable 11 was expected to be the larger of the two since oil is more expensive and less efficient than coal on a BTU basis. These expectations were met in all of the four regressions

12. The range of firm size in the sample varied from 100 MW to slightly over 9,000 MW. Note that in Table II, total production expense includes the cost of purchased power and for this reason the expenses for this table were computed per KWH "generated and received."

13. Utilization of capacity ranged from 0.3–0.83 for the 74 firms. Note that in [14] utilization of plant capacity was not a significant explanatory variable for plant fuel cost per KWH hence it is not surprising to find a similar result at the firm level.

in Tables I and II with the coefficients being statistically significant in every case except one.

Variables 12, 13, and 14 indicate the percentage of capacity by type of energy source. Nuclear, hydro and gas turbine capacity were all expected to increase unit costs (hence have positive signs) in Table I but only nuclear and gas turbine capacity were expected to increase costs in Table II.[14] These expectations were fulfilled in all cases except for hydro capacity in Table II (the coefficient of this variable was not significant, however). The size and significance of the nuclear capacity variables in Table I reflects the more specialized use of fossil capacity for cycling and peaking as nuclear capacity increases. Similarly, the significance of the gas turbine variable in Table I reflects the higher fuel costs and conversion inefficiencies of this type of capacity.

Variables 15, 16, and 17 indicate the effect of holding company affiliation on production expenses. The coefficients of these variables were expected to be negative due to potential efficiencies when a number of separate firms are controlled by a single holding company. The coefficients of these variables were of the appropriate sign in eight of twelve cases but not statistically significant except for the American Electric Power hereafter (A.E.P.) variable. The lower significance and smaller coefficient of the A.E.P. variable in Table I (fossil steam production expense) suggest that A.E.P.'s lower total production costs in Table II are due to non-fossil fuel generation. Yet 99 percent of A.E.P.'s capacity in 1971 was coal-fired, therefore, the only non-fossil steam possibility was purchased power. The proximity of much of A.E.P.'s service area to other large power producers suggests that low cost purchased power, and not holding company efficiency, explains the results of Table II. The results of Table I are, therefore a better indicator of A.E.P.'s efficiency and offer only modest support for superior production efficiency.

Transmission Costs

The regression results for transmission expense per/KWH are displayed in Table III.[15] The coefficients of the capacity variables are insignificant and their signs indicate a long run average variable transmission cost curve shaped like an inverted U, with the maximum point of this curve occurring at a capacity

14. Increased nuclear and hydro capacity were expected to increase fossil steam production expenses in Table I because of the increased use of fossil plants for cycling and peaking. Increased reliance on hydro capacity was expected to reduce total production costs in Table II, however, due to the known low costs of hydro power. The high fuel costs and low conversion efficiencies of gas turbines were expected to lead to increased costs in both Tables I and II (and, therefore, a positive sign for the coefficient of this variable).

15. Note that correlation matrices have been omitted throughout this paper since examination of them suggested that first order multicollinearity was not a problem. Similarly, details of tests of the regression residuals have also been omitted although these tests did confirm that the residuals were random, homoskedastic and normally distributed.

Table III. Regression Analysis of 1971 Transmission Expense Per KWH Generated and Received in Mills/KWH*

	Variable	Expected Sign	Regression 1 Coefficient	Regression 1 t-ratio	Regression 2 Coefficient	Regression 2 t-ratio
	Constant		-0.033	-0.06	-0.130	-0.22
1.	Natural Log of Total Capacity	-	0.017	0.15	0.021	0.19
2.	(Natural Log of Total Capacity)^2	+	0.0001	0.01	-0.0003	-0.04
3.	Utilization of Total Capacity	-	0.925	0.57	1.166	0.72
4.	(Utilization of Total Capacity)^2	+	-0.412	-0.28	-0.633	-0.44
5.	Northeast Dummy	+	0.153	3.02[a]	0.148	3.02[a]
6.	North Central Dummy	+	0.021	0.63	0.006	0.17
7.	West Dummy	+	0.084	1.92[b]	0.075	1.74[b]
8.	Company Wage Cost ($/hour)	+	0.007	1.16	0.008	1.33[c]
9.	Underground Circuit Miles/1000 Customers	+	0.503	0.88	0.595	1.06
10.	Structure Miles/1000 Customers	+	6.746	3.19[a]	7.538	3.52[a]
11.	Commercial KWH (% of Total)	-	-0.782	-2.39[b]	-0.759	-2.38[b]
12.	Industrial KWH (% of Total)	-	-0.418	-2.05[b]	-0.370	-1.85[b]
13.	Utility--Muni KWH (% of Total)	-	-0.150	-1.58[c]	-0.115	-1.21
14.	A.E.P. Holding Company Dummy	-	-0.024	-0.26		
15.	Southern Holding Company Dummy	-	-0.021	-0.18		
16.	Any Holding Company Dummy	-			-0.051	-1.34[c]
	Sample Size, N		74		74	
	Coefficient of Determination, R^2		0.4185		0.4347	
	Standard Error of the Estimate, σ_y		0.1126		0.1101	

*Variables 11, 12 and 13 are expressed as a number between zero and 1.0. See Tables I and II for an explanation of the other variables, notation, the data source and a definition of utilities included in the sample.

of 4,000 trillion MW. Within the range of observation, however, unit costs increased steadily with increased firm size, but the estimated magnitude of the increase was only 0.1 mill/KWH as firm size increased from 100 MW to 9,000 MW.

The coefficients of the utilization variables were also not significant and their signs indicate a short run average variable transmission cost curve shaped like an inverted U with the maximum point of this curve occurring at a utilization of 94 percent—above the upper end of the range of observations. Within the range of observations, the short run average variable transmission costs rose steadily as utilization increased with the overall size of the utilization effect being 0.2 mills/KWH.

The regional variables in Table III were positive in all three cases as expected and significant for the Northeast and the West. The coefficient of the average company wage cost variable was positive as epxected but statistically insignificant and of little importance in terms of magnitude of effect. Underground circuit miles increased transmission costs, as expected, but the coefficient was not significant. Most transmission lines are overhead and the coefficient of this variable was positive and significant.

Also in Table III, the percentages of large customers (Variables 11, 12 and 13) had negative coefficients, as expected. The coefficients were significant, and of roughly the same magnitude, indicating that unit variable transmission expense per KWH is lower for firms oriented toward non-residential loads.

Holding company status, Variables 14, 15 and 16, were of the correct sign but had no highly significant effect on transmission operating costs. Although the A.E.P. holding companies are highly integrated, its transmission costs were not significantly lower than those of independent companies (nor were those of the Southern Company).

Distribution Costs

The regression results for distribution expense/KWH are displayed in Table IV. The coefficients of the capacity variables are significant and of the appropriate sign for a U shaped LRAVC curve with the minimum point occurring at a firm size of 2,600MW. This U shaped curve is somewhat L shaped over the range of observed firm sizes, however, since the long run average variable distribution cost curve declines by 0.9 mill/KWH between firm sizes of 100MW and 2,600MW and then increases by only 0.1 mill/KWH as firm size increases to 9,000 MW. Splitting the sample at 2,000 MW (details omitted) confirms the result that the LRAVC distribution cost curve is U shaped.

The coefficients of the utilization variables in Table IV are significant in two cases and their signs indicate a short run average distribution cost curve shaped like an inverted U and having a maximum occurring at a utilization of 54 percent. The SRAV distribution cost curve rises at first over the range of

Table IV. Regression Analysis of 1971 Distribution Expense Per KWH Generated and Received in Mills/KWH*

Variable	Expected Sign	Regression 1 Coefficient	Regression 1 t-ratio	Regression 2 Coefficient	Regression 2 t-ratio
Constant		4.478	3.20[a]	4.217	2.99[a]
1. Natural Log of Total Capacity	-	-1.325	-4.64[a]	-1.295	-4.56[a]
2. (Natural Log of Total Capacity)^2	+	0.084	4.12[a]	0.082	4.02[a]
3. Utilization of Total Capacity	-	7.997	1.88[b]	8.797	2.07[b]
4. (Utilization of Total Capacity)^2	+	-7.398	-1.92[b]	-8.221	-2.15[b]
5. Northeast Dummy	+	0.013	0.08	0.015	0.09
6. North Central Dummy	+	0.003	0.03	-0.025	-0.26
7. West Dummy	+	-0.200	-1.80[b]	-0.204	-1.85[b]
8. Company Wage Cost ($/hour)	+	0.038	2.42[a]	0.037	2.46[a]
9. No. of Line Transformers/Customer	+	-1.183	-2.20[b]	-1.063	-1.98[b]
10. MWH/Residential Customer	-	-0.058	-2.52[a]	-0.060	-2.64[a]
11. MWH/Commercial Customer	-	0.0004	0.18	0.001	0.51
12. MWH/Industrial Customer	-	-0.003	-0.42	-0.006	-0.86
13. A.E.P. Holding Company Dummy	-	-0.302	-1.28		
14. Southern Holding Company Dummy	-	-0.261	-0.82		
15. Any Holding Company Dummy	-			-0.145	-1.50[c]
Sample Size, N		74		74	
Coefficient of Determination, R^2		0.6045		0.6038	
Standard Error of the Estimate, σ_y		0.2992		0.2970	

*See Tables I and II for an explanation of the variables, notation, the data source, and a definition of utilities included in the sample.

observed values and then declines to a minimum at 83 percent utilization.

The regional variables were of the correct sign but insignificant for both the Northeast and North Central regions. Distribution costs were significantly lower in the West, however. Average company wage cost was positive, as expected, and significant but in terms of magnitude of effect was only of minor importance.

The number of line transformers per customer is a measure of the density of the distribution network—the higher the value of this variable the lower the density. It was expected that unit costs would decline as density increased due to the opportunity to use larger scale transformers and other equipment,[16] but the significant and negative coefficients for this variable indicate that higher density service areas are associated with higher unit costs of power distribution. Clearly, the higher costs and congestion associated with metropolitan areas may more than offset the positive effects of density on distribution costs.

Variables 10 through 15 were expected to have negative coefficients. This expectation was realized in all cases and the significance of the coefficient for Variable 10 indicates that distribution costs decline as the average intensity of residential customer use increases (offering modest support for a declining block rate structure). Holding company status was associated with lower distribution costs in each case but attained a low level of significance only for holding companies in general.

Fixed Investment

Tables I to IV above have concentrated on unit variable costs excluding depreciation charges. Table V presents the regression results for firm level fixed cost per KW of steam capacity. Firm level fixed costs were obtained by taking gross, undeflated, undepreciated investment in plant and adjusting by an age-weighted Handy-Whitman index of steam generating plant construction costs. This age-weighted Handy-Whitman index was constructed by the authors using the Handy-Whitman index [29] and noting that most electric utilities have grown at constant compound growth rates between 1941 and 1971.[17] Once a firm's growth rate is known, the age distribution of its generating capacity can be computed in percentage terms and applied to the standard Handy-Whitman index. The resulting age-weighted Handy-Whitman

16. The cost per unit of capacity for distribution equipment, such as transformers, control equipment, busses, and so on, decrease with the capacity of the equipment. Since fixed costs are 85 percent of total distribution costs, there are potential economies of scale in distribution but these economies are heavily dependent on the load density and other characteristics of the area served. For a more complete discussion see [9].

17. Thirty years is the generally accepted life of a generating plant used for depreciation purposes hence a firm's generating capacity in place in 1971 should be composed almost entirely of generating plants built between 1941 and 1971.

Table V. Regression Analysis of Adjusted Steam Production Plant Per KW of Steam Capacity in $/KW (1971)*

	Variable	Expected Sign	Regression 1		Regression 2	
			Coefficient	t-ratio	Coefficient	t-ratio
	Constant		681.51	6.21[a]	678.43	6.23[a]
1.	Natural Log of Steam Capacity	-	-146.87	-4.61[a]	-143.95	-4.53[a]
2.	(Natural Log of Steam Capacity)^2	+	9.06	3.89[a]	8.95	3.86[a]
3.	Northeast Dummy	+	77.95	5.70[a]	78.46	5.84[a]
4.	North Central Dummy	+	38.08	4.06[a]	36.45	3.84[a]
5.	West Dummy	+	10.40	0.76	8.65	0.63
6.	Company Fuel Cost (¢/MBTU)	+	1.47	3.44[a]	1.24	2.68[a]
7.	Coal-fired Capacity (%)	+	27.41	1.83[b]	18.43	1.26
8.	Oil-fired Capacity (%)	+	- 1.66	-0.12	- 0.52	-0.04
9.	A.E.P. Holding Company Dummy	-	16.21	0.65		
10.	Southern Holding Company Dummy	-	- 32.74	-0.89		
11.	Any Holding Company Dummy	-			- 13.32	-1.18
	Sample Size, N		74		74	
	Coefficient of Determination, R^2		0.6779		0.6787	
	Standard Error of the Estimate, σ_y		34.2779		33.9672	

*Adjusted by use of an age-weighted Handy-Whitman Index developed by the authors.

index can then be used to inflate that company's gross investment to a value in terms of 1971 dollars.

An age-weighted index of this type was constructed for each of the 74 companies in our sample based on each company's average growth rate over the years 1941–1971. Gross, undepreciated investment in steam generating plant for each company was then inflated to 1971 dollars by use of the age-weighted construction cost index calculated for each company. The regression analysis of Table V uses the \$/KW for each company adjusted by the above process.

In Table V, the coefficients of the capacity variables are signfiicant and of the appropriate signs indicating a U shaped relationship with the minimum of the fixed cost per unit of capacity curve occurring at a firm size of 3,100 MW —a result very similar to that hypothesized earlier in Section I. The estimated equation indicates that the fixed investment of a 3,100 MW firm in generation is \$13/KW less than that of a 1,000 MW firm[18] and \$8/KW less than that of a 9,000 MW firm.

The regional variables were all expected to have positive coefficients due to the higher construction wages for regions outside of the South. All of the regional coefficients were positive, as expected, and significant except for the West. The coefficient of the company fuel cost variable was positive and highly significant indicating that fixed cost per KW was increased where fuel costs were high in order to obtain lower fuel consumption.

Variables 7 and 8 are the percent of coal and oil fired capacity. In effect, these variables measure \$/KW costs relative to gas fired capacity since the firm would be 100 percent gas fired if both the coal and oil percents took the value of zero (there were few nuclear plants operating in 1971). Both variables were expected to have positive signs with the coefficient of the coal fired variable being the larger of two due to the higher \$/KW costs of coal capacity. These expectations were fulfilled for coal but not for oil where the coefficients were negative and statistically insignificant.

The coefficients of the holding company variables were all expected to be negative due to the ability of holding companies to obtain discounts from equipment manufacturers or to efficiencies in designing and managing construction projects. At present we do not have sufficient information to further

18. Note that splitting the sample at 2,000 MW confirmed all of the results presented in Tables I through X hence the details of these tests have been omitted throughout this paper. Note also that A.E.P. and some other large utilities have frequently used supercritical, cross compound, double reheat generating units. As shown in [14], these generating units cost more per KW to construct but unfortunately have not lowered operating costs as expected. Therefore, the types of generating units selected by large utilities as well as diseconomies of scale may account for the reuslts of Table V.

isolate the cause of this possible holding company advantage.[19] As for results, the coefficient was positive for the A.E.P. variable and negative for the Southern Company variable but neither was significant. The negative coefficient for Variable 11 indicates lower construction costs for the steam plant capacity of holding companies in general but the lack of significance for this variable indicates inconsistency in this result and the need for further testing. In general, the results do not support the hypothesis that holding companies have superior efficiencies in the area of plant design and construction costs.

Other Cost Categories

The above scale results are incomplete in that they do not reflect all of the operating costs of the utilities surveyed. Additional operating costs include Administrative and General Expenses, Customer Accounts Expenses, and Sales Expenses. Tables VI, VII and VIII present the scale results for these additional expense categories for 176 Class A and B electric utility companies. We elected to use the larger sample here (as opposed to the 74 company sample used for the production cost estimates) since these cost categories should be much less sensitive to the technology used in electricity production.

In Table VI we examine the scale effects in Administrative and General Expenses. Again we find evidence of a U shaped cost curve; the natural log of MWH (in thousands) generated and received is negative and significant, and this term squared is positive and significant. The minimum of the long run average administrative and general expense curve occurs at a firm size of 2,500 MW, but over the range of observation, the curve is somewhat L shaped since the unit costs of a 9,000 MW firm are only 0.06 mill/KWH more than that of a 2,500 MW firm.[20]

Variables 3, 4 and 5 in Table VI were all expected to be associated with higher administrative costs. These expectations were fulfilled with the coefficients being statistically significant in each case. Average company wage cost was positively associated with higher administrative costs but the coefficient was again insignificant and small in magnitude. The coefficients of the regional variables were all positive and significant as expected. The A.E.P. variable was significantly related to lower administrative costs but the South-

19. Tests in [14] indicated that quantity discounts were not a significant factor in plant level construction costs. Holding company status was not a variable in that analysis, however, so the possibility of holding companies obtaining quantity discounts from equipment manufacturers cannot be ruled out.

20. Firm size measured in 1,000's of MWH sales has been converted to a capacity measure (MW) by assuming a 60 percent rate of utilization of capacity—the national average—and using the following relationship:

$$\text{Firm capacity (MW)} = \text{Firm Output (MWH)}/0.60 \times 8{,}760$$

This conversion has been used in the discussion of the regression results of Tables VI, VII, VIII and X. Note that there are 8,760 hours in a year.

Table VI. Regression Analysis of 1971 Administrative and General Expenses in Mills/KWH Generated and Received*

	Variable	Expected Sign	Regression 1		Regression 2	
			Coefficient	t-ratio	Coefficient	t-ratio
	Constant		3.376	4.31[a]	3.276	4.16[a]
1.	Natural Log of MWH Gen. & Rec.	-	-0.828	-4.68[a]	-0.831	-4.61[a]
2.	(Natural Log of MWH Gen. & Rec.)^2	+	0.044	3.94[a]	0.044	3.89[a]
3.	Own Generation (%)	+	0.336	4.28[a]	0.345	4.29[a]
4.	Sales to Ultimate Customers (%)	+	0.493	2.06[b]	0.491	1.99[b]
5.	Residential KWH as Percentage of Sales	+	1.352	4.75[a]	1.441	4.98[a]
6.	Company Wage Cost ($/hour)	+	0.017	0.97	0.022	1.28
7.	Northeast Dummy	+	0.442	6.18[a]	0.461	6.47[a]
8.	North Central Dummy	+	0.192	2.99[a]	0.198	2.97[a]
9.	West Dummy	+	0.200	2.63[a]	0.228	2.91[a]
10.	A.E.P. Holding Company Dummy	-	-0.330	-2.51[a]		
11.	Southern Holding Company Dummy	-	0.096	0.48		
12.	Any Holding Company Dummy	-			0.013	0.20
	Sample Size, N		176		176	
	Coefficient of Determination, R^2		0.5259		0.5065	
	Standard Error of Estimate, σ_y		0.3297		0.3354	

*See Tables I and II for an explanation of the variables, data sources and notations. Megawatt hours generated and received is in 1000 MWH.

Table VII. Regression Analysis of 1971 Customer Accounts Expense in Mills/KWH of Sales to Ultimate Customers*

	Variable	Expected Sign	Regression 1		Regression 2	
			Coefficient	t-ratio	Coefficient	t-ratio
	Constant		2.416	6.41[a]	2.356	6.30[a]
1.	Natural Log of Sales to Ultimate Customers	-	-0.375	-4.16[a]	-0.359	-3.98[a]
2.	(Natural Log of Sales to Ultimate Customers)^2	+	0.021	3.54[a]	0.019	3.36[a]
3.	Residential KWH (% of Total)	+	-0.029	-0.12	-0.042	-0.18
4.	Industrial KWH (% of Total)	-	-0.752	-5.11[a]	-0.777	-5.32[a]
5.	Company Wage Cost ($/hour)	+	-0.003	-0.37	-0.002	-0.18
6.	Northeast Dummy	+	0.188	5.09[a]	0.198	5.44[a]
7.	North Central Dummy	+	0.046	1.33[c]	0.049	1.38[c]
8.	West Dummy	+	0.002	0.04	0.006	0.15
9.	Structure Miles/1000 Customers	+	7.183	3.87[a]	7.142	3.88[a]
10.	A.E.P. Holding Company Dummy	-	-0.074	-1.07		
11.	Southern Holding Company Dummy	-	-0.106	-1.01		
12.	Any Holding Company Dummy	-			-0.018	-0.55
	Sample Size, N		176		176	
	Coefficient of Determination, R^2		0.5425		0.5377	
	Standard Error of Estimate, σ_y		0.1711		0.1715	

*See Tables I and II for an explanation of the variables, data source and notations. Sales to ultimate customers are measured in 1000 MWH.

ern Company variable and any holding company variable were both positive and insignificant.

The results for Customer Accounts Expense in Table VII indicate that the long run average variable cost curve is U shaped with the minimum occurring at a firm size of 1,700 MW (both capacity variables were of the correct sign and highly significant). This curve is somewhat L shaped, however, since the unit costs of a 1,000 MW and 9,000 MW firm were only 0.01 and 0.05 mills/KWH higher than those of a 1,700 MW firm.

As for the remaining variables in Table VII, the percent of sales to residential users was not of the appropriate sign nor significant but an increase in the percent of industrial sales was significantly related to lower costs. The average company wage rate was not positively related to higher costs but the coefficient of this variable was not significant nor large in magnitude either. The coefficients of the regional variables were of the appropriate sign and significant for the Northeast and North Central regions. Structure miles per 1,000 customers is an inverse measure of density and its coefficient was positive and significant, as expected, indicating that customer accounts expenses were lower for utilities with higher density service areas. Holding company status had no significant effect on costs but the coefficients were negative as expected.

The results for Sales Expense in Table VIII indicate that the long run average variable cost curve is L shaped but the coefficients of the capacity variables were not statistically significant. Although costs declined with firm size, a 9,000 MW firm had a unit cost advantage of only 0.1 mills/KWH over a 100 MW firm.

The overall regression results for Table VIII were markedly poorer than for Tables I through VII as judged by number of significant coefficients and R^2. The coefficients were generally of the correct signs, however, except for holding company status where the coefficients were all positive and, in the case of holding companies in general, statistically significant.

IV. Summary and Conclusions

Economies of Scale

Table IX presents a summary of the scale results of Tables I through VIII. For five of the six operating cost categories and for the sum of all six categories (total operating expenses) there are diseconomies of scale beyond moderate firm sizes. Only sales expense, a minor component of total operating costs, exhibited scale economies across the entire range of observed firm sizes. Unit costs for fixed investment are available only for production plant but again the results indicate that there are diseconomies of scale beyond moderate firm sizes. The results in Table IX indicate that the long run average variable cost

Table VIII. Regression Analysis of 1971 Sales Expense in Mills/KWH of Sales to Ultimate Customers*

	Variable	Expected Sign	Regression 1		Regression 2	
			Coefficient	t-ratio	Coefficient	t-ratio
	Constant		0.066	0.20	0.110	0.36
1.	Natural Log of Sales to Ultimate Customers	-	0.040	0.52	0.006	0.08
2.	(Natural Log of Sales to Ultimate Customers)^2	+	-0.004	-0.71	-0.001	-0.28
3.	Residential KWH (% of Total)	+	0.399	1.99[b]	0.477	2.47[a]
4.	Industrial KWH (% of Total)	-	-0.053	-0.42	-0.028	-0.24
5.	Company Wage Cost ($/hour)	+	0.001	0.11	0.003	0.36
6.	Northeast Dummy	+	0.014	0.44	0.004	0.14
7.	North Central Dummy	+	-0.006	-0.21	0.018	0.62
8.	West Dummy	+	0.006	0.16	0.035	1.01
9.	Structure Miles/1000 Customers	+	3.128	1.97[b]	2.739	1.82[b]
10.	A.E.P. Holding Company Dummy	-	0.043	0.73		
11.	Southern Holding Company Dummy	-	0.031	0.34		
12.	Any Holding Company Dummy	-			0.099	3.66[a]
	Sample Size, N		176		176	
	Coefficient of Determination, R^2		0.1489		0.2098	
	Standard Error of Estimate, σ_y		0.1459		0.1402	

*See Tables I and II for an explanation of the variables, data source and notation. Sales to ultimate customers are measured in 1000 MWH.

Table IX. Summary of Scale Results of Tables I through VIII,* Long Run Average Variable Cost Curves

Category	Capacity Variables Statistically Significant	Shape of LRAVC Curve	Cost Differential in Mills/KWH by Firm Size				Maximum Size of Scale Effect
			100/MW	1000MW	1600MW	9000MW	
Production	Yes	U-shaped	+2.4	+0.1	Minimum	+1.0	2.4
			100MW	1000MW		9000MW	
Transmission	No	Upward sloping	Min.	+0.05		+0.1	0.1
			100MW	1000MW	2600MW	9000MW	
Distribution	Yes	U-shaped	+0.9	+0.1	Min.	+0.1	0.9
			100MW	1000MW	2500MW	9000MW	
Administrative and General	Yes	U-shaped	+0.5	+0.4	Min.	+0.06	0.5
			100MW	1000MW	1700MW	9000MW	
Customer Accounts Expense	Yes	U-shaped	+0.2	+0.01	Min.	+0.05	0.2
			100MW	1000MW		9000MW	
Sales Expense	No	L-shaped	+0.1	+0.05		Min.	0.1
			100MW	1000MW	1600MW	9000MW	
Estimated Total Operating Expense	--	U-shaped	+3.9	+0.2	Min.	+1.1	3.9

Table IX, continued

Category	Adjusted Fixed Investment per Unit of Capacity			
	Capacity Variables Statistically Significant	Shape of Fixed Investment Per Unit of Capacity Curve	Cost Differential Per Unit of Capacity By Firm Size	Maximum Size of Scale Effect
Production	Yes	U-shaped	100MW 1000MW 3100MW 9000MW $111/KW $13/KW MIN. $8/KW	$111/KW
Transmission	--	--	--	--
Distribution	--	--	--	--

*The results summarized are those occurring within the range of observation. Note also that for Tables VI, VII and VIII firm size measured in KWH has been converted to MW as per footnote 20.

curve for total operating costs is U shaped as is the fixed investment curve with costs minimized for firm sizes of 1,600 MW and 3,100 MW respectively. These results are in close agreement with the respective 2,000 MW and 3,000 MW firm size predictions of Section I.

It should be noted that scale effects are generally regarded as an important source of cost reductions in transmission. One explanation for the failure to confirm this expectation is that utilities can reduce generating costs by increasing transmission costs.[21] As long as generating costs fall more than transmission costs increase, this tradeoff is desirable.[22] One would expect, however, that the effects of this tradeoff would appear in the SRAC curve but not in the LRAVC curve. Another explanation for the upward sloping LRAVC curve in transmission is that generating capacity is a poor measure of transmission capacity. While this may be true in general, the limitations placed on the sample in this study should have mitigated this problem.

Clearly, the above findings question the natural monopoly status of this industry and raise serious issues as to the appropriateness of current public policies towards it and the generating sector in particular. In addition, one author [13] has suggested that a scale bias exists in utility and government R & D funding and new innovation preferences . From a long run point of view, it is imperative that the structure of this industry encourage the maximum responsiveness to changes in scale, technology, plant siting needs, fuel availability, and pollution requirements. At the very least, the findings of this study suggest that there may be a far wider range of choices regarding industry structure and public policy options than regulation of all phases of this industry.

We have suggested elsewhere the divorcement of electricity distribution from its production with distribution companies buying power on long term contracts from unregulated private producers.[23] The present results indicate that such a policy option may be more viable than many have suspected. Certainly there is little support for those advocating the merging of electric utilities into 30 or 40 massive companies.[24]

Also, it should be noted that the scale results of this study are likely to be applicable in the future even when the costs of pollution control equipment become clarified and available for quantitative analysis. This statement is based on the fact that pollution control costs, even with today's primitive

21. Note that such tradeoffs do not exist between distribution costs and transmission or generation costs.

22. Transmission costs are frequently ignored in discussions of merit loading of generating plants hence it is possible that generating costs are minimized and transmission costs simply allowed to fall where they will. In addition, since transmission costs are generally much lower than generating costs, any merit loading practice that minimized their sum would probably result in increased transmission costs and reduced generating costs being optimal.

23. For details of this proposal, see [21]. Also, see [28].

24. For example, see [3].

technologies, do not exceed twenty percent of total unit costs for large, new generating plants. Unless the scale economies of pollution control facilities are markedly different from those of the rest of the plant, it is unlikely that the shape of the long run average cost curve will be radically altered.

Finally, it will be useful to compare the results of our study with those of Christensen and Greene (C and G) in the one area in which they overlap—generation. Controlling for differences among firms, we found that generating costs were minimized for firm sizes between 1,600 MW and 3,100 MW depending on the mix of fixed and variable costs. While C and G did not allow for many differences among firms, they did not restrict elasticities and concluded that costs were minimized for firm sizes as low as 3,800 MW. These results are consistent with our expectations, stated in the introduction, that C and G's treatment of holding companies should shift the scale curves to the right (and flatten it out).[25] Despite differences in approach, the results of both studies are in remarkably close agreement suggesting that the scale conclusions reached are valid despite potential specification errors contained in each.

Holding Company Results

Table X summarizes the regression results for the holding company variables. The holding company variables were of the correct sign in 16 of 24 cases but were negative and significant in only five of 24 cases. In one of these five cases (A.E.P's total production costs) the negative sign could reasonably be attributed to factors other than holding company efficiencies. Furthermore, in three of these five cases, the holding company coefficients attained significance barely exceeding the 90 percent level. In general, there does not appear to be any strong, consistent evidence that holding company affiliation is associated with substantial cost savings.

In the absence of any strong showing of benefit resulting from holding company affiliation, the economies of scale at the firm level would seem to be controlling in terms of the optimal structure of the industry. Furthermore, there is little evidence to support the treatment of holding companies used by Christensen and Greene and others. Our results indicate that, in general, electric utilities owned by holding companies should not be summed and treated as one entity for analysis of scale economies.

Non-Traditional Cost Functions and Their Uses

Section II of this paper presented several theoretical justifications for our use of a non-traditional cost function for electric utilities. These justifications

25. Differences in treatment of holding companies are particularly important since we found that the costs of firms owned by holding companies were not significantly different from those of non-holding company firms.

Table X. Summary of Regression Results for Utilization and Holding Company Variables,* Short Run Average Variable Cost Curves

	Utilization Variables Statistically Significant	Shape of SRAVC Curve	Cost Differential in Mills/KWH by Degree of Utilization	Maximum Size of Utilization Effect
Production	No	Downward sloping	30%: +0.2; 83%: Min.	0.2
Transmission	No	Upward sloping	30%: Min.; 83%: +0.2	0.2
Distribution	Yes	∩-shaped	30%: +0.2; 54%: +0.7; 83%: Min.	0.7

Holding Company Variables

Expense Category	Any Holding Co. Coef.	Any Holding Co. Signif.	AEP Coef.	AEP Signif.	Southern Co. Coef.	Southern Co. Signif.
Fossil Steam Production	-0.09	No	-0.81	Yes[c]	+0.17	No
Total Production	-0.08	No	-2.28	Yes[a]	+0.14	No
Transmission	-0.05	Yes[c]	-0.02	No	-0.02	No
Distribution	-0.14	Yes[c]	-0.30	No	-0.26	No
Administrative & General	+0.01	No	-0.33	Yes[a]	+0.09	No
Customer Accounts	-0.02	No	-0.07	No	-0.10	No
Sales	+0.09	Yes[a]	+0.04	No	+0.03	No
Fixed Investment/unit of Production Cap.	-13.32	No	+16.21	No	-32.74	No

*Summarized from Tables I to Table VIII. Note that a, b, and c indicate significance levels as defined in Table I.

included: the inappropriateness of quantity of output as a measure of scale; the peaked nature of demand; the need to treat durability of capital explicitly; and the need to include specific firm characteristics in the analysis. An additional, pragmatic reason for interest in non-traditional cost functions is their potential usefulness in measuring utility performance and the growing interest of several regulatory commissions[26] in this possibility.

From an overall point of view, the regression analysis of Tables I through VIII were highly successful if one uses percentage of regression coefficients with the sign predicted by economic theory, percentage of regression coefficients that are statistically significant, and R^2 as the basis for judging the single equation models developed.[27] The capacity variables were statistically significant in six of eight regressions and indicated U shaped long run average cost curves in all but two regressions.

The regression results for the utilization variables are summarized in Table X. Utilization of capacity was a significant variable only in the distribution cost regressions and the short run average cost curves were, over the range of observation, downward sloping for production costs, upward sloping for transmission costs, and shaped like an inverse U for distribution costs. The magnitude of the utilization effect over the range of observation (0.30 to 0.83) is smaller than that of the scale effects in Table IX. This result is in agreement with results reported for plant level analysis in [14]. The shape of the SRAC curve in distribution is the only one we cannot explain based on economic theory. The results do suggest that demand patterns may be too complex and varied to be measured by utilization alone.

As acknowledged in Section II, our approach did not explicitly deal with durability of capital but at least it avoided most implicit assumptions.

As for specific firm characteristics, the regression results support the view that they can be incorporated into the analysis and are important both in terms of statistical significance and magnitude of effect. This should be of interest to those advocating increased use of econometric techniques to measure the performance of utility managements. Yet other results suggest that further problems lie ahead.

For example, one can pretend that the objective of our analysis was to evaluate the management performance of the A.E.P. and the Southern Company. Based on the statistical results summarized in Table X, one might conclude that the Southern Company management performance was average since the hypothesis that they were average could not be rejected and even the signs of the coefficients of the Southern Company variable were mixed.

26. The Michigan, New York, and Wisconsin regulator commissions are all investigating various methods of measuring or comparing performance by utility management.

27. More than 70 percent of the regression coefficients were of the expected sign in seven of the eight regressions; more than 47 percent of the regression coefficients were statistically significant in six of the eight regressions, and R^2 exceeded 50 percent in six of the eight regressions.

Yet the magnitude of the effect of the −32.74 coefficient in the Fixed Investment regression is not easily ignored. This effect is sizeable given the capital intensity of this industry yet the coefficient is not statistically significant. How should the regulators proceed in this case?

Turning next to the A.E.P. variable, the coefficients indicate lower costs in six of eight cases and in three border on or exceed statistical significance. Can one conclude that A.E.P. management performance tends, in some cases, to be above average (allowing, of course, for the importance of each cost category in total costs)? Again, how does one allow for the +16.21 coefficient for fixed investment even though it is not statistically significant?

The A.E.P. and Southern Company are reputed to be well managed yet our regressions have some difficulty confirming this.[28] Perhaps their reputations are not based on fact. Indeed, it might be useful to select some utilities with poor reputations to see if that judgment can be confirmed.

Several basic problems with statistical evaluations of management performance are apparent, however. First, some aspects of performance (i.e., personnel policy, financial results) may not be easily measured or entirely under management control. Secondly, if high levels of significance are used, one knows that few firms will appear in the tails of the distribution leaving most firms to be defined as average. Use of lower levels of statistical significance would reduce the number of "average" firms but would increase the number of type II errors. Evaluation of performance is always difficult and management performance reviews by regulatory commissions may be more difficult than expected.

28. Our regressions have two potential shortcomings, however, for evaluating management performance. The first is that additional utility characteristics, particularly demographic characteristics, should be considered. This shortcoming will be addressed in future regressions when a demand equation is estimated. A second factor to be considered in future work is the utility's participation in power pooling. Since larger utilities have easier access to power pools, the regressions in this study may be slightly biased in favor of larger utilities, i.e., the higher costs observed for small utilities may be due to smaller scale as well as inability to join a power pool.

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