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ECONOMIES OF SCALE AND VERTICAL INTEGRATION IN THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

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EXECUTIVE SUMMARY

This report analyzes the nature of costs in a vertically-integrated electric utility. The major findings of this study provide new insights into the operations of the vertically-integrated electric utility and support a number of results and trends reported in earlier research on economies of scale and density. The results also provide insights for policy makers dealing with electric industry restructuring issues such as competitive structure and mergers.

Overall, the results indicate that for a majority of firms in the industry, average costs would not be reduced through the expansion of generation, numbers of customers, or the delivery system. Evidently, the combination of the benefits from large-scale technologies, managerial experience, coordination, or load diversity have been exhausted by the larger firms in the industry. However, the evidence strongly supports the notion that many firms would benefit from reducing their generation-to-sales ratio and by increasing sales to their existing customer base.

To conduct the analysis, three separate models were estimated to provide a comprehensive cost analysis. Economies of scale were estimated for the power generation and the power procurement and delivery functions of the vertically-integrated utility, using the separate cost models. A restricted profit model (where the firm can choose some of its output levels but not all) was determined to be the most representative of the combined functions of a vertically-integrated electric utility. Results provide an estimate of the optimal generation to sales ratio and, therefore, the optimal degree of vertical integration. This model explores the market responsiveness of the firm's power generation and sales functions. Estimates are also provided for technical change, optimal capacity, and changes in scale economies and minimum efficient scale over time.

Major Findings of this Study

1. The typical electric utility, when analyzed as a profit-maximizing, vertically-integrated power supply and delivery firm, would choose to generate less power and reduce its sales volume relative to current industry averages. The degree of vertical integration would remain roughly the same. These results also show that utilities would change the quantity of power generated in direct response to changes in the market price for power.
2. There is evidence that most utilities do not benefit from economies of scale when expanding their generation operations. In fact, approximately 75 percent of industry output is produced in a range of constant or increasing long-run average costs. These findings support the trends identified by previous research on economies of scale in generation.
3. When examining the power delivery functions of the electric utility, the evidence indicates that significant reductions in average costs can result from the expansion of power sales to a given number of customers in a service territory of a given size.
4. Average costs are only slightly reduced when the sales volume and the number of customers are expanded proportionately in a service territory of fixed size. There is no evidence that economies of scale in the delivery network of the typical vertically-integrated electric utility offset the rising costs of power procurement.
5. There is no evidence of reduced average cost when utilities expand output, number of customers, and the size of their service territory proportionately. The evidence does not support the existence of economies of scale or "synergies" resulting from utility expansion by any method.

6. The results of one measure of productivity in the electric utility industry show slightly negative growth in technological change during the time period of the analysis.

Data and Case Studies

The analysis of this report uses a panel of investor-owned electric utility actual data, consisting of four cross-sections taken at five-year intervals for the period 1977 through 1992. The sample consists of all major investor-owned utilities (IOU's) that provided electric supply (generation and purchased power) and delivery (transmission and distribution) services during this period. The primary source of data is the annual Federal Energy Regulatory Commission (FERC) Form 1.

Case studies are used to illustrate the results of the cost models as they apply to two utility firms: American Electric Power (AEP) and the Entergy Corporation. These utilities were selected based on having diverse customer loads, geographical characteristics, and production technologies. The authors compared utility-specific results with the model estimates applied to sample mean values (the typical firm), and drew conclusions with respect to variations in sales performance, capacity growth or other forms of expansion.

Applying the model estimates to the case studies of AEP and Entergy indicates that both firms have a higher than optimal generation-to-sales ratio, slight diseconomies of scale in generation, and significant economies of density in power delivery, indicating that they would benefit from increased sales volumes to existing customers. Results for AEP show that the firm may also benefit from expanding the overall size of its service territory.

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PREFACE

This report is intended to serve as a technical foundation analysis to aid the current policy debate on electric industry restructuring. It is hoped that the empirical analysis of this report and the summaries of others' work in this area will provide technical guidance when state and federal authorities consider restructuring of the electric utility industry. The main issues discussed here, economies of scale and density and vertical integration, should provide insights into how to proceed on such questions as mergers, regulatory changes, and how the industry should be restructured. The main body and appendices of this report are intended for economists and other technical readers, while the Executive Summary and concluding chapter (Chapter 7) are intended for all interested readers.

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CHAPTER 1

INTRODUCTION

In the latter half of the 1990's and beyond, significant changes will be occurring in the structure of the electric utility industry in the United States and abroad. These changes are motivated by dissatisfaction with the existing regulatory structure, new generation and transmission technologies, significant differences in average costs across firms, and the desire for increased consumer choice. However, little empirical analysis has been done on the relationship between the functions of vertically-integrated electric utilities (generation, transmission, distribution), which supply and deliver over 85 percent of the power in the U.S. Such studies are necessary first steps in determining the potential results of proposals for restructuring.

From the 1950's to the early 1970's few questioned the structure of an industry that was meeting rising demand with lower costs and prices. In recent decades, however, increasing attention has been focused on the operations of electric utilities as costs increased markedly. Additional doubts about the existing structure have been raised by studies finding economies of scale in power generation exhausted for many firms and preliminary estimates of significant benefits from a more competitive power market.

Rigorous econometric techniques applied to available data can produce important insights into the efficient structure of the electric utility industry. The efficiency consequences of firm size and vertical integration can both be addressed. These findings may aid public policy analysts who are asked to consider the options available for industry restructuring.

Research Methodology

The purpose of this study is to explore the nature of vertical integration and specifically to determine economies of scale and related measures for the electric utility industry during the turbulent years of 1977-1992. This study produces important results focusing on these issues and in doing so, provides information about the behavior of participants in a competitive power market, as well as identifying candidates for continued regulation.

To provide a comprehensive analysis, three separate economic models are estimated. A restricted profit model is determined to be the most representative of the combined functions of the vertically-integrated electric utility. This model treats the power supply decisions of the firm as the result of a cost minimization process. It provides insight into the optimal balance of generation and sales within the firm, while making no explicit assumptions regarding the ability to analyze these functions separately. Results of the model provide an estimate of the optimal generation to sales ratio and, therefore, the optimal degree of vertical integration. By using this model, it is also possible to explore the consequences of firms having the choice of pursuing the optimal level of sales.

Economies of scale and related measures for power generation and the power merchant and delivery functions of utilities are analyzed next, using separate cost models. Economies of density measure the impact on average cost from changes in sales volume to a fixed number of customers (output density) or within a fixed service territory (customer density). Estimates are also provided for technical change and changes in scale economies and minimum efficient scale over time.

A number of researchers are of the opinion that the accounting data used in these economic profit and cost studies are problematic.[1] These views fall into two

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[1] See, for example, P.L. Joskow and R. Schmalensee, *Markets for Power: An Analysis of Electricity Utility Deregulation* (Cambridge, MA: The MIT Press, 1983) and the discussion in Chapter 2.

categories. First, the output measures used in most cost studies lack the dimensions necessary to distinguish optimal scale. The absence of peak demand data that are consistent with reported energy measures is an example. Second, as a result of the physical complementarity between the generation and delivery of power, the technical substitution taking place between them makes it difficult to measure the optimal scale of the separate functions.

Other researchers have presented evidence suggesting the existence of cost complementarities.[2] According to these studies, an integrated electric utility could be economically efficient with declining average cost, regardless of whether scale economies in generation exist or are exhausted. In this context, an important question in the restructuring debate in this context is whether the efficiency gains from increased competition in the supply markets are sufficient to offset the potential efficiency losses from lost cost complementarities.

Various specifications of the models used in this study were employed and tested. Efforts were made in both the data preparation and model specification to overcome the difficulties from using accounting data and to correct for previously misspecified models, regulatory biases, and other problems encountered in research on these issues.

Outline of the Study

Chapter 2 contains a detailed discussion of the nature of vertical integration and economies of scale for electric utilities and the results of several recent studies

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[2] See J. Steven Henderson, "Cost Estimation for Vertically Integrated Forms: The Case of Electricity," in *Analyzing the Impact of Regulatory Change in Public Utilities*, ed., Michael A. Crew (Lexington, MA: Lexington Book, 1985) for a discussion of the issues. M.J. Roberts, "Economies of Density and Size in the Production and Delivery of Electric Power," *Land Economics* Vol. 62, 4 (1986): 234-48, tests the hypothesis of separability of integrated utility functions. Kaserman and Mayo, "The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Industry," *Journal of Industrial Economics* Vol. 38, 5 (1991): 483-502, provide specific measures of "economies of vertical integration."

on these subjects. Chapter 3 discusses the theoretical models used in the analysis. Chapter 4 describes the sample period, variable construction, and data used in the analysis. Chapter 5 presents the empirical results. Chapter 6 analyses the results as they apply to case studies of two electric utilities; American Electric Power and the Entergy Corporation. Chapter 7 provides a summary and some concluding remarks. Appendix A describes the method used to calculate capital costs. Appendix B contains a table of the means of the variables used to estimate the models in this study.

CHAPTER 2

THE INTEGRATED ELECTRIC UTILITY

Economies of Scale and Economies of Vertical Integration

The justification for the single monopoly provider of utility service, and the regulation thereof, is based largely on the assumed cost characteristics of such service. Specifically, where the output or service is produced centrally and distributed to end-users over a physically connected network, the firm providing increasing service may experience declining average cost. Scale economies are the measure of how costs change as the firm expands all of its productive resources proportionately to provide increased service. Economies of scale occur when average cost (cost per unit of service) fall over the relevant service volume. Should this be the case, the firm is said to be a natural monopoly. The smallest level of firm output that just exhausts economies of scale is referred to as the minimum efficient scale (MES).

Providing service to the electricity customer, however, involves the multi-stage activities of generating electricity, transmitting the electricity over high voltage lines, and distributing electric power at low voltage. Certain aspects of these activities, such as power procurement and merchant services, may also be considered as separate functions. A vertically-integrated electric utility performs all of these functions. The issue then arises as to whether efficient scale should refer to function-specific or utility-wide activities.

Economies of vertical integration occur when the sum of the costs (or value added) of separately owned stages of production exceed the costs of a single firm performing the same stages of production at relevant levels of output. A firm with economies of vertical integration could be considered a natural monopoly even if scale economies are not present for specific functions. These cost savings can be analyzed as either the technical relationships between the various stages of production or as the market transactions costs saved as a result of the single ownership of the production stages.

The Vertically-Integrated Production Function

Vertical integration is a special form of joint production in which the output of the upstream production stage (an intermediate product) is transferred without cost to a downstream production stage for additional processing or sale. The reasons why a single firm incorporating upstream and downstream activities could be more efficient than separate firms engaging in market transactions are complex. Economies of scope, for example, are believed to stem from the employment of public inputs (once purchased for a specific stage are then available free to another stage of production), or from quasi-public or "shareable" resources. The cost of providing a high degree of coordination where stability and reliability are important characteristics of the service may be significant. The importance of these conditions in the production and distribution of electricity has not been adequately measured.

The degree of vertical integration varies significantly across firms in the current industry structure. Many firms, such as municipals and many rural cooperatives, only procure and distribute power. Other firms, such as independent power producers (IPPs), cogenerators, some coops, and wholesale generating companies (investor-owned generating utilities) only generate power and own little or no transmission or distribution assets.[3] There are also generation and transmission (G&T) cooperatives that do not own distribution networks. Among

[3] Nonexempt wholesale generator companies are usually wholly owned subsidiaries of centrally planned holding companies, and would not have the kinds of transactions costs that would exist between different owners. Exempt wholesale generating companies, allowed under the Energy Policy Act of 1992, permit utilities to construct and operate generators outside their jurisdictions.

vertically-integrated IOUs, some firms purchase as much as 50 percent of their power sales, while others generate virtually all of their power needs.[4]

Although the majority of electricity in the U.S. is currently generated and sold by the same integrated utility, nonutility generators (NUGs) account for 23 percent of the power produced in 1992. This percentage will undoubtedly increase as nearly one-half of the projected capacity additions are expected to be made by NUGs. Evidence clearly exists that nonintegrated electric utility operations are already a significant part of the power market.

23%
nb of
x sales
ΔI =
50% more of new generation NUGs

Several issues that constitute the focal point of the ongoing restructuring debate in this context have been addressed in earlier research but have not been adequately resolved. These issues are summarized in the following questions.

1) To what extent is utility-owned generation a natural monopoly?
2) What are the cost savings associated with joint production economies?
3) What are the cost savings associated with the coordination function residing within a single firm?
4) Will the efficiency gains from increased competition in the power generation market be sufficient to offset the losses associated with declines in joint production and coordination economies?
5) To what extent are economies of scale present in the nongeneration functions of electric utilities?

This research addresses several of these important questions.

Empirical Research: Electric Generation

The early research on the cost structure of electric utilities focussed on scale economies in power generation. Nerlove estimated a relatively simple cost function

[4] A number of the generation- or distribution-only companies filing FERC Form 1 are subsidiaries of registered holding companies. For this study, however, the operations of these subsidiaries are considered as supply and delivery functions of a single company.

using accounting data for 145 firms from 1955.[5] Nerlove found evidence of economies of scale in electric utility generation in the 1950's. However, Nerlove also found that economies of scale for the larger firms in the sample were exhausted. Since then, it has become apparent that engineering predictions of unlimited economies of scale in generation were unfounded.

Beginning with the influential study of the economies of scale of generation by Christensen and Greene,[6] a number of researchers have verified the trend they revealed. They found that although economies of scale in generation are significant and some firms can yet benefit from exploiting them, an increasing number of firms, along with a rising portion of industry output, have reached or exceeded their MES.

Greene studied economies of scale and other measures of efficiency using five, five-year cross-sections of electric IOU data from 1955-1975.[7] Greene found that scale economies decreased in the industry over the period. As firms expanded production, an increasing proportion of industry output fell beyond MES. Greene also found that technical change made a significant contribution to decreasing average costs over this time period. Kamerschen and Thompson,[8] and Thompson and Wolf[9] found a continuation in the trend of declining industry output produced under economies of scale, using 1985 data.

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[5] M. Nerlove, "Returns to Scale in Electricity Supply," in *Measurements in Economics*, ed., C. Christ (Palo Alto, CA: Stanford University Press, 1963), 167-98.

[6] L.R. Christensen and W.H. Greene, "Economies of Scale in U.S. Electric Power Generation," *Journal of Political Economy* 84, 4 (1976): 655-76.

[7] W. H. Greene, "Simultaneous Estimation of Factor Substitution, Economies of Scale, Productivity, and Non-Neutral Technical Change," in *Econometric Analysis of Productivity*, ed., A. Dogramaci (Boston: Kluwer-Nijoff, 1985).

[8] D.R. Kamerschen and H.G. Thompson, Jr., "Nuclear and Fossil Fuel Steam Generation of Electricity: Differences and Similarities," *Southern Economic Journal* Vol. 60, 1 (1993): 14-27.

[9] H.G. Thompson, Jr. and L.L. Wolf, "Regional Differences in Nuclear and Fossil Fuel Generation of Electricity," *Land Economics* Vol. 69, 3 (1993): 234-48.

The 1955-1975 study period used in Greene's analysis, except for the last years, can be characterized as one in which thermal efficiencies were being exhausted, but had rising demand for electricity, declining power prices, and stable input prices. In contrast, the decades that followed were extremely turbulent ones for the electric utility industry. Rapidly rising fuel prices preceded a period of high inflation, rising capital prices, and a sharp decline in the demand for electricity. These circumstances resulted in an electric utility industry completing expensive capital projects, which were begun in the previous expansion period, and then facing growing surplus capacity. The combination of expensive surplus capacity and the impact of high energy prices on consumer demand created a financial crisis for many utilities. The late 1980s and early 1990s showed an improvement in the industries' financial condition as result of lower fuel prices and a cautious approach to new investments.

The prevailing explanation for the decline in power generation scale economies is that thermal efficiencies at the plant level were exhausted by the mid-1970s. Other industry analysts believe that the combination of declining thermal efficiencies in conjunction with a sluggish demand for electricity, little outside competition, and regulation-induced inefficiencies may be responsible.

Evidence of the MES for electric utility functions other than generation is less consistent. Most researchers agree that economies of scale in power delivery are likely to be significant. However, they disagree as to how these economies can be measured given their dependency on system-specific load and geographical characteristics.

Appears to ignore new technolo[gy] e.g. combined cycle gas turbine

Empirical Research: Vertical Integration and Coordination

Joskow and Schmalensee[10] as well as others, argue that a high degree of coordination during the production and delivery of electricity results in significant scope economies for the integrated firm. The coordination function consists of maintaining system integrity and minimizing power supply costs in addition to balancing resource planning and load forecasts. The current variety of structures suggests, however, that coordination activities do not require electric supply and delivery functions to be under common ownership to be economic. These coordination activities are seen as separate regulated activities in a popular view of the evolving industry structure referred to as regional power exchanges or poolcos. The ability of a poolco to perform the coordination function at a cost and degree of reliability comparable to that of a similar-sized integrated utility is an empirical question yet to be answered.[11]

Regional Power Exch ≡ poolco

The findings of several recent studies indicate that accurate analysis of the generally accepted stages or functions of the vertically-integrated electric utility is often difficult using the available data. This conclusion is based on empirical evidence that economies of vertical integration exist and are a result of joint production economies and the internalization of significant externalities. Where true, the allocation of the considerable common costs to specific utility functions becomes, to some degree, arbitrary. The studies, however, also suffer from the same difficulties, particularly when defining the stages of production and measuring output at each stage.

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[10] Joskow and Schmalensee, *Markets for Power.*

[11] The best-known example of a Poolco is in England. Norway and Argentina employ a similar arrangement. Proposals for arrangements similar to England's have occurred in New Zealand, Australia, Canada, and the U.S.

Henderson[12] estimates several cost functions using 1970 data. Henderson finds stage-specific economies of scale and economies of vertical integration. Although Henderson tests for and rejects the separability of generation and distribution functions, his model is deficient in the specification of the generation and transmission functions of the utility. Roberts[13] uses a cost function for procurement and delivery services of integrated utilities that is similar to Henderson's. Roberts reports finding economies of output and customer density. Roberts' model includes the price of transmission capital and tests for and rejects the hypothesis that transmission and distribution are separate utility functions. However, he does not explicitly model the generation and purchased power activities of the firm.

Kaserman and Mayo[14] find vertical integration economies in electric utilities using a cost function specification different from that of Henderson and Roberts. First, their model contains both integrated utilities and specialized generation and distribution utilities, using 1981 data. Second, their model contains both generation output and sales volume as exogenous variables, along with input prices for all utility-owned inputs and purchased power. This specification makes an explicit assumption that generated output is exogenous whereas the quantity of purchased power is endogenous.

Gilsdorf[15] uses a cost model similar to Kaserman and Mayo but without purchased power costs. Gilsdorf finds, however, no strong evidence that the vertically-integrated electric utility experiences subadditivity (declining average cost

[12] Henderson, "Cost Estimation for Vertically Integrated Firms."

[13] Roberts, "Economies of Density and Size in the Production and Delivery of Electric Power."

[14] Kaserman and Mayo, "The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Industry."

[15] K. Gilsdorf,"Testing for Subadditivity of Vertically Integrated Electric Utilities," *Southern Economic Journal* Vol. 62, 1 (1995): 126-38.

over all conceivable ranges of output). Gilsdorf's evidence, therefore, does not directly address the issue of whether the vertically-integrated electric utility is a natural monopoly.

Empirical Analysis in This Study

The discussion above suggests that it is difficult to accurately measure economies of scale for the various functions of an integrated electric utility. An analysis of a number of specialized power companies, such as IPPs and other gencos or rural distribution companies, would be the best way to measure scale economies. However, data sources are limited, particularly for generation companies. Limited experience, proprietary data, and nonstandard accounting methods all argue against its use at this time. The authors believe that using the correct treatment of accounting data, in conjunction with properly specified econometric models, can produce estimates of economies of scale and other insights into the operations of the integrated firm that are useful for policy analysis.

CHAPTER 3

ECONOMETRIC MODELS

Overview

This report analyzes three separate models of electric utility operations: a restricted profit model, a power generation cost model, and a power procurement and delivery cost model. The models are discussed in this chapter. Data sources are discussed in Chapter 4. The estimation results of these models are reported in Chapter 5.

The restricted profit model measures profit as generation supply revenue net of the cost of electric utility operation. This limited definition of profit represents the net value of the input and output options selected by the firm among those available, given the firm's operating environment. Restricted profit is regressed against operating environment characteristics including the sales volume, supply and input prices, and quantities of fixed inputs. The purpose of analyzing this model is to provide insights into the relationship between the functions of the vertically-integrated electric utility.

Generation cost is analyzed using a partial equilibrium, variable cost specification. Variable power generation cost is regressed against variable input prices, the volume of generation output, and a measure of generation capital stock, which is assumed to be quasi-fixed. The purpose of analyzing this model is to estimate economies of scale and technological change in utility power generation, using the most recent data available.

Finally, the procurement and delivery cost model analyzes the total cost of electric utility service with an emphasis on customer and service territory characteristics. The costs of electricity supply and delivery are regressed against a power supply price, transmission and distribution input prices, multiple-output sales volumes, and variables representing delivery service characteristics. The purpose of analyzing this model is to estimate the economies associated with the multiple dimensions, or different definitions of firm size, of power delivery service. Hypotheses regarding the ability to analyze separately the power supply, transmission, and distribution functions of the utility can be tested with this specification.

The Restricted Profit Model

This model makes specific assumptions about the structure of the vertically-integrated electric utility. Unlike the specification employed in previous analyses of the firm, this specification treats generation output as an endogenous variable. An exogenously-determined final sales volume is assumed to be a characteristic of firms in most utility industries and is related to the nature of the utility's obligation to serve where the utility is required to meet its demand. However, the level of generation output relative to the level of purchased power is seen as a choice exercised by management to minimize cost.

In this view of the vertically-integrated electric firm's behavior, revenue is derived from power generation and delivery services. The utility operates to maximize profits by choosing the optimal level of generation relative to purchased power, and by minimizing the costs of generation and delivery inputs. The profit maximizing revenue is equal to the product of the wholesale market price of generated power and power volume generated, plus the net revenue derived from the final sales of output.

The distinction between ordinary profit and restricted profit can be made clearer by examining the revenue relationship. The general form for the gross revenue function is

$$R = p_G \cdot Y_G + (p_S - p_G) \cdot Y_S$$

where p_G is the wholesale market price for generated power, and p_S is the final sales price. The value of $(p_S - p_G)$ can be viewed as the value-added price for delivery services. Y_G and Y_S are the volumes of generated power and final sales volumes, respectively. Alternatively, the firm's revenue can be viewed as the full value of delivery services less the cost of purchased power or $p_S \cdot Y_S - p_G \cdot (Y_S - Y_G)$. The inputs used for generation and delivery services are labor, capital, and fuel, but not purchased power.

In models where generation output or sales volume is considered as exogenous, a cost function is used to estimate the model. However, when generated supply is a choice variable, a restricted profit function should be estimated. Restricted profit, $\prod^R$, is a function of generation supply and exogenous variable input prices, final sales volume, and fixed inputs, or

$$\Pi^R(p_G\,,\ w_v;\ Y_S,\ X_G),$$

where w_V is a vector of variable input prices and X_G is the fixed input quantity vector. With the application of Hotelling's lemma, the generation supply and input demand equations are

$$\frac{\partial\ \Pi^R}{\partial\ p_G} = Y_G\ (p_G,\ w_v;\ Y_S,\ X_G), \quad and$$

$$\frac{\partial\ \Pi^R}{\partial\ w_v} = -X\ (p_G,\ w_v;\ Y_S,\ X_G) \quad for\ all\ v,$$

respectively. The model can also be augmented to include service area characteristics, such as the number of customers and square miles of service territory, and a linear time trend.

This model may be estimated using a variety of functional forms. The translog model allows for the direct estimation of elasticities. These can then be used to derive the supply and input demand functions, or to solve for the optimal levels of fixed of fixed output. The translog specification for a restricted profit model is

$$\begin{aligned}\ln \Pi^R &= \alpha_o + \sum_h \alpha_h \ln Z_h + \sum_i \alpha_i \ln p_i + \sum_l \alpha_l \ln w_l + \alpha_t t \\ &+ \frac{1}{2} [\sum_h \sum_k \gamma_{hk} \ln Z_h \ln Z_k + \sum_i \sum_j \gamma_{ij} \ln p_i \ln p_j + \sum_l \sum_m \gamma_{ln} \ln w_l \ln w_m + \gamma_{tt} t^2] \\ &+ \sum_h \sum_i \gamma_{hi} \ln Z_h \ln p_i + \sum_h \sum_l \gamma_{hl} \ln Z_h \ln w_l + \sum_i \sum_l \gamma_{il} \ln p_i \ln w_l \\ &+ \sum_h \gamma_{ht} \ln Z_h t + \sum_i \gamma_{it} \ln p_i t + \sum_l \gamma_{lt} \ln w_l t .\end{aligned}$$

Here, p_i consists of the supply price for generated power (p_G), and w_l represents input prices. The Z_k's represent the exogenous determinants of the model including the final sales volume (Y_S), the quantity of quasi-fixed generation capital (X_G), the number of customers (N), and the square miles of service territory (A).

Referring to Hotelling's lemma for the restricted profit function in log form, the supply function is given as

$$\frac{\partial \ln \Pi^R}{\partial \ln p_G} = \frac{p_G \cdot Y_G}{\Pi^R} = \alpha_G + \gamma_{GG} \ln p_G + \sum_h \gamma_{Gh} \ln Z_h + \sum_l \gamma_{Gl} \ln w_l + \gamma_{Gt} t.$$

With this equation, the level of Y_G can then be evaluated by using the estimated parameter values of the restricted profit function and sample values. The factor demand equations for the inputs are derived in a similar fashion.

A measure of the optimal, unrestricted sales volume, Y_S^*, can be determined from the envelope condition:

$$\frac{\partial \Pi^R}{\partial Y_S^*} = - P_S .$$

Setting

$$\frac{\partial \ln \hat{\Pi}^R}{\partial \ln Y_S^*} = \frac{P_S \cdot Y_S^*}{\hat{\Pi}^R} = \alpha_{Y_S} + \gamma_{SS} \ln Y_S + \sum_h \gamma_{Sh} \ln Z_h + \sum_i \gamma_{Si} \ln p_i + \sum_l \gamma_{Sl} \ln w_l + \gamma_{St}\, t \,,$$

and solving for Y_S^* gives one measure of the optimal (profit-maximizing) final sales volume.

Power Generation Cost Model

A short-run variable cost model is used to estimate scale economies in the generation function of integrated IOUs. This specification is desirable for several reasons. First, a primary function of regulation is to establish a regulated cost of capital, whereas other input prices can reasonably be assumed to be market determined. By removing generation capital as a choice variable, a potential source of regulation-induced bias in the model is removed. Second, it can be argued that generation capital is quasi-fixed and, therefore, not responsive to market prices in the short-run.

In addition, the short-run model provides insights into equilibrium conditions in the industry using the following envelope condition

$$\frac{\partial VC}{\partial K^*} = -P_K \,,$$

where K^* represents the optimal level of the capital stock. A graphical representation of this condition is the well-known tangency between the long-run average cost curve and the short-run average cost curve. When this condition is not met (the tangency does not occur), either a surplus or shortage of capital exists.

The authors estimate the partial equilibrium, variable cost generation model as a function of generation output, variable input prices, and a measure of the generation capital stock. More formally,

$$VC_G(w_{LG}, w_F, Y_G, K_G, t) ,$$

where VC_G, the variable cost of generation, is the sum of fuel and labor generation costs. The price of labor used in generation is w_{LG}, w_F is the price of fuel, Y_G is generation output in kilowatthours (kWh), K_G is the stock of generation capital, and t is a linear time trend.

A translog specification for the variable cost model suggested above is

$$\begin{aligned} \ln VC_G = \alpha_o &+ \alpha_Y \ln Y + \sum_i \alpha_i \ln w_i + \alpha_K \ln K + \alpha_t t \\ &+ \frac{1}{2} [\gamma_{YY} (\ln Y)^2 + \sum_i \sum_j \gamma_{ij} \ln w_i \ln w_j + \gamma_{KK} (\ln K)^2 + \gamma_{tt} t^2] \\ &+ \sum_i \gamma_{Yi} \ln Y \ln w_i + \sum_i \gamma_{iK} \ln w_i \ln K + \sum_i \gamma_{it} \ln w_i t \\ &+ \gamma_{KY} \ln K \ln Y + \gamma_{Kt} \ln K t + \gamma_{Yt} \ln Y t \quad . \end{aligned}$$

The variable cost equation is estimated in conjunction with the input cost share equations. The usual duality restrictions of homogeneity of degree one in input prices and symmetry of input price cross-products are imposed prior to estimating the model.

This model provides all of the necessary information to estimate returns to scale and related measures. Recognizing that measuring returns to scale requires all inputs to be changed, from the translog variable cost function we have

$$RTS_{VC} = (1 - \frac{\partial \ln VC}{\partial \ln K}) / (\frac{\partial \ln VC}{\partial \ln Y}) .$$

Caves, Christensen, and Swanson[16] developed relationships between the derivatives of the variable cost function to estimate two measures of technological change; *PGX*, the rate at which cost is decreased over time, assuming outputs are held fixed, and *PGY*, the rate at which output can be increased over time as costs are held fixed. Formally,

$$PGX = -\left(\frac{\partial \ln CV}{\partial t}\right) / \left(1 - \frac{\partial \ln CV}{\partial \ln K}\right)$$

and

$$PGY = -\left(\frac{\partial \ln CV}{\partial t}\right) / \left(\frac{\partial \ln CV}{\partial \ln Y}\right) \quad .$$

PGY and *PGX* are related by the degree of returns to scale; *PGY* is the produce of *PGX* and *RTS*.

Power Procurement and Delivery Cost Model

The next step in the analysis of the efficient size of utility operations involves estimating the economies of power delivery. The cost of delivering power to the customer is affected by a number of conditions, in addition to input prices and the total delivery volume. These conditions include load diversity, customer density, and geographical characteristics of the service territory. To estimate the importance of these conditions on system cost, we use an augmented procurement

[16] D.W. Caves, L.R. Christensen, and Joseph A. Swanson, "Productivity Growth, Scale Economies, and Capacity Utilization in U.S. Railroads 1955-74," *American Economic Review* Vol. 39, 5 (December 1981): 483-503.

and delivery cost model developed by Roberts.[17] This model treats the vertically-integrated electric utility as a firm that secures power for delivery from its own generation and outside sources at marginal costs. It includes output sold at different voltages and customer and service area variables, and the prices for delivery system inputs. A linear time trend is added to the model.

The general equation for the total cost form of this model is

$$TC_D\ (w_E,\ w_{LD},\ w_{KT},\ w_{KD},\ Y_H,\ Y_L,\ S,\ N,\ t)\ ,$$

where w_E represent the price of energy supplied, w_{LD} is the price of labor in the utility distribution function. w_{KT} and w_{KD} are the price of transmission and distribution capital, respectively. Y_H and Y_L are high voltage and low voltage output. S is the service territory of the utility in square miles, and N is the number of customers. The growth of the delivery system with regard to the number of customers and size of service territory, which are exogenous factors in this model, suggests the estimation of the long-run cost specification.

Hypotheses concerning the separability of the integrated electric utility into supply, transmission, and distribution functions can be tested using the delivery cost model. The assumption of separability implies an ability to analyze these functions on a stand-alone basis. If separability is assumed, one form of the cost function can be expressed as

$$TC_D\ (\ C_G(w_E),\ C_D(w_{LD},\ w_{KD},\ w_{KT},\ Y_L,\ S,\ N),\ Y_H,\ t).$$

[17] Roberts, "Economies of Density and Size in the Production and Delivery of Electric Power."

The translog form for the general delivery cost function is

$$\begin{aligned}\ln TC_D &= \alpha_o + \sum_h \alpha_h \ln Z_h + \sum_i \alpha_i \ln w_i + \alpha_t t \\ &\quad + \frac{1}{2}\Big[\sum_h \sum_k \gamma_{hk} \ln Z_h \ln Z_k + \sum_i \sum_j \gamma_{ij} \ln w_i \ln w_j + \gamma_{tt} t^2\Big] \\ &\quad + \sum_h \sum_i \gamma_{hi} \ln Z_h \ln w_i + \sum_h \gamma_{ht} \ln Z_h t + \sum_i \gamma_{it} \ln w_i t \ .\end{aligned}$$

The w^i's represent the prices of energy, labor, transmission, and distribution capital (w_E, w_{LD}, w_{KT}, and w_{KD}, respectively).[18] The Z_k's represent high and low voltage service, numbers of customers, and square miles of service territory (Y_H, Y_L, N, and S, respectively).

The efficient size of a power delivery system is multi-dimensional and, therefore, can not be reflected in a single measure. Using the delivery cost model discussed above, economies of output and customer density, and economies of size can now be derived. The elasticities of delivery cost with respect to low voltage and high voltage service are

$$E_L = \frac{\partial \ln TC_D}{\partial \ln Y_L} \quad \text{and} \quad E_H = \frac{\partial \ln TC_D}{\partial \ln Y_H} \ ,$$

respectively. Since each of these measures reflects the impact on total cost of the levels of output, holding other effects constant, then a measure of economies of output density may be defined as

[18] Given the reporting requirements of FERC Form 1 data, it is not possible to calculate the wage rates for the individual labor functions. Since only one utility-wide wage rate is determined, only one wage rate can be used in an estimation. The calculation of the wage rate is discussed in Chapter 4.

$$RYD = \frac{1}{E_L + E_H} .$$

Economies of output density (RYD) is the relevant concept to use when measuring the impact on average costs of an increase in sales output sold to a fixed number of customers in a fixed service territory area.

The relative change in delivery costs that arise when customer density increases, while holding the sales level fixed, is measured by

$$E_N = \frac{\partial \ln TC_D}{\partial \ln N} .$$

Cost changes can occur when both the number of customers and sales levels increase proportionately within a given service territory. This would be the case of a growing population in a given area, such as a city or other developing areas. Economies of customer density are measured as

$$RCD = \frac{1}{E_L + E_H + E_N} .$$

Finally, the relative cost changes that occur when holding sales levels and numbers of customers constant, while increasing the area of the service territory, is measured as

$$E_S = \frac{\partial \ln TC_D}{\partial \ln S} .$$

The relative cost of expanding the size of the service territory isolated from the effects of changing sales and customer numbers can be measured as

$$RTS_D = \frac{1}{E_L + E_H + E_N + E_S} \quad .$$

These measures provide meaningful insight to the debate on the benefits of mergers, divestitures, spinoffs, and other forms of customer or territorial changes. Also, the several measures of technical change (PGX and PGY), discussed with the generation costs, can be estimated for this model.

CHAPTER 4

SAMPLE SELECTION AND DATA REQUIREMENTS

Sample Selection

The sample consists of all major investor-owned electric utilities in the U.S. for the years 1977, 1982, 1987, and 1992.[19] Regional multi-state holding companies were aggregated into single companies, based on the authors' understanding of their integrated operation. This process allowed the inclusion of data for a number of wholesales generation and distribution utilities.[20] Other "specialists," such as a limited number of IPPs recently reported on FERC Form 1, were not included. Several small firms were excluded because of erroneous or incomplete data. This selection process resulted in a sample of eighty-three firms in 1977 and 1982, and eighty-five firms in 1987 and 1992. The panel data set therefore consists of 336 observations.

All observations were used in the estimation of all models with the exception of the restricted profit model. Several observations were found to have negative values of the dependant variable, and were excluded from the sample for that model because of the inability to use negative values in a model of the translog form. This resulted in six fewer observations in 1977 and one less in 1992.

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[19] The selection criteria used in determining the major IOU classification is detailed in *Financial Statistics of Major Investor-Owned Electric Utilities*, Energy Information Administration (various years).

[20] Several utilities in the northeastern U.S. (EUA, New England Electric System, Northeast Utilities) are examples where a number of separate regulated generation and distribution companies are members of the same holding company. A number of other holding companies have regulated wholesale generation companies as subsidiaries.

Data Used in the Models

Supply and Input Price, and Quantity Data

For the restricted profit model, the authors used a weighted average of bulk power transactions average revenue and average cost, and average generation cost as the measure of the generation supply price. It would be desirable to use the average revenue from sales for resale as the market price, but irregularities in the reporting of bulk power transactions on FERC Form 1 made this infeasible. This generation supply price was also used in the delivery cost model as the marginal cost of energy supply. These data are all from FERC Form 1 sources.

The price of fuel in all models consists of the delivered cost per million British thermal units (MBtu) for coal, oil, natural gas, and nuclear fuel. Nuclear fuel was, at first, to be considered capital and included with nuclear plant. However, since nuclear fuel is not included in FERC Form 1 plant accounts, the data are not available to construct a nuclear fuel cost and service price in a manner consistent with the authors' treatment of the cost and prices of other capital assets. Moreover, utility sources agree that reported nuclear fuel expenses are broadly consistent with the rate of decay of nuclear fuel and the heat rate of nuclear plants. Fossil fuel prices, quantities, and costs are from the Energy Information Administration's *Cost and Quality of Fuels*.[21] The nuclear fuel prices are from EEI's *Statistical Year Book*.[22]

Using FERC Form 1 data, a single price of labor for all utility service categories is calculated using the total labor cost-to-total numbers of employees (full time plus one-half part-time) ratio. This measure was developed in Christensen

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[21] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plant* (Washington, D.C.: GPO, various years).

[22] Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* (Washington, D.C.: EEI, various years).

and Greene.[23] Based on their method for allocating labor expenses to generation costs, labor costs were also allocated to the delivery functions of the utility. In addition, the costs of a number of activities not specifically assigned to a well-defined function, such as general and administrative expenses, were allocated to the generation and delivery functions. The allocator, which also served to allocate general plant and nonlabor operating and maintenance (O&M) expenses, was the ratio of the wage expenses of function-specific labor to the sum of all the supply, transmission, and distribution function wage expenses.

The price and quantity of capital are measured by multilateral Tornqvist indexes of the prices and quantities of capital services employed in various utility functions. In total, seven capital asset categories are included. These are steam generation plant, nuclear plant, hydroelectric plant, other generation plant, transmission plant, distribution plant, and general plant. All nonlabor, nonfuel O&M expenses are included in general plant. Capital service prices and costs are developed using the methods developed by Christensen and Jorgenson.[24] This method provides an economic measure of capital services that is consistent across jurisdictional boundaries. Details of this methodology are found in Appendix A.

Output Data

The generation power supply in the restricted profit model, and the output in the generation cost model is the net volume (in megawatthours [MWh]) of electricity generated from all sources. The measure of sales output is a multilateral Tornqvist index of the volumes of four kinds of sales services. These are residential sales, industrial sales, commercial and miscellaneous retail sales, and

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[23] Christensen and Greene, "Economies of Scale in U.S. Electric Power Generation."

[24] L.R. Christensen and D.W. Jorgenson, "The Measurement of U.S. Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, 4 (1969): 293-320.

sales for resale. The index is constructed using revenue weights, where revenue is the value-added revenue in the restricted profit model, and sales revenue in the delivery cost model. The delivery cost model uses two output quantity variables: low-voltage sales—equal to the sum of residential and commercial sales, and high-voltage sales—equal to the sum of industrial and wholesale sales. All of these data are from FERC Form 1 sources.

Other Variables

The number of customers is reported on FERC Form 1. The size of the service network, as used in the restricted profit and the delivery cost models, is measured in square miles. These data are found in *Moody's Public Utility Manual*.[25]

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[25] *Moody's Public Utility Manual* (New York: The Dun & Bradstreet Corporation, various years and volumes).

CHAPTER 5

EMPIRICAL ANALYSIS AND RESULTS

The Restricted Profit Function

Two circumstances prevented the authors from estimating the full range of specifications of the restricted profit model in all years. First, as alluded to in the discussion of the data, profit as measured in this model (supply revenue minus costs) was negative in about half the observations when the variable cost (short-run) specification was evaluated. Profit was negative for nearly all observations in the long-run model. Therefore, the authors estimated a "loss" function with the long-run specification. This specification requires a reversal of the signs of the supply and input demand functions normally used with the profit function. Second, the irregularities in the reporting of bulk power revenues and the costs prior to changes in FERC accounting regulations in 1991 created estimation difficulties. As a result, estimates are only provided for 1992.

The parameter estimates for the restricted profit (loss) function are reported in Table 5-1. It was difficult to hypothesize about the expected sign for some of the parameters of this new model. However, standard errors are consistently low and the results show a high degree of explanatory power for a restricted profit model of this specification. Monotonicity conditions were satisfied at every observation. Concavity conditions were not satisfied consistently. However, the second derivative values are close to zero implying a high probability of statistical insignificance.

Table 5-2 contains the estimated restricted and unrestricted price elasticities of the profit function with respect to the choice variables of the model and the sales volume for the typical firm. Unrestricted elasticities are estimated using the estimated profit-maximizing unrestricted sales volume, Y_S^*. The generation supply

TABLE 5-1

Restricted Profit Function Parameter Estimates: 1992
(asymptotic t ratios in parentheses)

α_O	0.111	(1.11)	γ_{FF}	0.423	(2.78)
α_Y	-0.376	(-1.26)	γ_{FK}	-0.929	(6.59)
α_N	1.349	(4.45)	γ_{FL}	-0.085	(2.12)
α_S	-0.064	(0.91)	γ_{KK}	-1.034	(4.69)
α_G	-2.074	(15.77)	γ_{KL}	-0.403	(5.45)
α_F	0.692	(10.02)	γ_{LL}	0.229	(4.10)
α_K	1.979	(23.06)	γ_{GY}	-2.178	(4.97)
α_L	0.403	(22.76)	γ_{GN}	2.132	(4.71)
γ_{YY}	-3.179	(2.27)	γ_{GS}	0.029	(0.38)
γ_{NY}	3.072	(2.15)	γ_{FY}	0.747	(3.19)
γ_{SY}	0.090	(0.63)	γ_{FN}	-0.796	(3.30)
γ_{NN}	-2.901	(2.02)	γ_{FS}	0.005	(0.13)
γ_{NS}	-0.083	(0.60)	γ_{KY}	1.302	(4.66)
γ_{SS}	-0.020	(0.44)	γ_{KN}	-2.204	(4.17)
γ_{GG}	-3.216	(8.48)	γ_{KS}	-0.034	(0.68)
γ_{GF}	0.592	(2.83)	γ_{LY}	0.129	(2.17)
γ^{GK}	2.365	(10.81)	γ_{LN}	-0.132	(2.14)
γ_{GL}	0.260	(4.72)	γ_{LS}	-0.001	(0.07)

Notes: R^2 for this system are: profit equation, 0.66; energy supply share equation, 0.23; fuel share equation, 0.21, capital share equation, 0.09. The t ratios are reported in absolute values.

TABLE 5-2

Restricted and Unrestricted Estimated Supply, Input, and Sales Elasticities: Restricted Profit Model
(t ratios in parentheses)

	Supply	Labor	Capital	Fuel	Sales
Restricted	-1.900 (18.16)	0.390 (22.66)	1.870 (21.06)	0.641 (11.57)	-0.2347 (0.99)
Unrestricted	-2.937	0.451	2.489	0.997	-1.748

Notes: These estimates are derived from the parameters of the profit model and sample mean values for input prices, sales volumes, and service area characteristics. The t ratios are reported in absolute values.

elasticity has the anticipated sign and magnitude. As the generation supply price increases, negative profits decrease, *ceterus paribus*. All input price elasticities are positive, and the elasticity of losses with respect to sales has the expected negative sign. The results indicate that changes in generation supply have the strongest effect on profits, followed closely by the changes in the capital input. Most of the estimated coefficients of elasticity are statistically significant, with the exception of sales.[26] Replacing actual sales with unrestricted sales produces a significant increase in the response of estimated losses, particularly for changes in supply price and sales.

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[26] The estimated coefficient for sales elasticity, and several other estimates to follow, are non-linear functions of the estimated parameters. As such, only the approximate t-ratios are reported.

Table 5-3 shows the cross-price elasticity of substitution and own-price elasticity estimates for the supply and input variables. These estimates have the expected sign for a "loss" function given that substitution, as opposed to complementarity between inputs, is what generally occurs.[27] The strongest responses occur with interactions involving the capital input. The results indicate that the loss-minimizing (profit-maximizing) firm makes significant changes in its input and output mix in response to changes in capital's price. Changes in the price of fuel are the next most important factor, followed by labor's price.

The generation supply shows the strongest response to changes in its own price. Own-price elasticity estimates for capital reveal its strong impact on profits. Fuel, followed by labor, have a significantly weaker response. These estimates, along with the estimates of cost elasticities discussed above, are all consistent with the generally understood circumstances surrounding electric utilities in 1992.

Determining the amount of energy supplied by the profit maximizing firm involves solving the energy elasticity function for the unknown supply quantity, using sample means for energy prices and other values. Table 5-4 reports the amount of estimated generation supplied, given the mean restricted and unrestricted sales volumes. The typical profit maximizing firm would produce about 83 percent of the current sample mean generation supply level, while selling about 85 percent of sample average sales volume. This would leave the sample mean firm with about the same generation supply-to-sales volume ratio (one measure of the degree of vertical integration) as actually existed in the 1992 sample period. In other words, the optimal firm would generate about the same fraction of its final sales (77 percent) as the average 1992 firm (79 percent), but roughly at a 15 percent smaller scale of operation.

[27] Recall that when estimating the "loss" function, the signs on the supply and input demand functions were reversed. With this in mind, the signs of these derivatives should be evaluated relative to the sign opposite to the one theory would predict for a profit function.

TABLE 5-3

Estimated Cross-Price and Own-Price Elasticities: Restricted Profit Function

Cross-Price Elasticities

Supply-Fuel	Supply-Capital	Supply-Labor	Fuel-Capital	Fuel-Labor	Labor-Capital
0.971	2.495	0.643	2.290	0.646	2.706

Own-Price Elasticities:

Supply	Fuel	Capital	Labor
-3.1092	0.941	2.187	0.366

Note: These estimates are derived from the parameters of the profit model and sample mean values for input prices, sales volumes, and service area characteristics.

TABLE 5-4

Optimal Generation Supply and Sales Volume Ratios

	Optimal-to-Actual Sales	Optimal-to-Actual Generation Supply	Actual Generation Supply-to-Sales	Optimal Generation Supply-to-Sales	Optimal Generation Supply-to-Sales [1]
Ratio	85%	83%	79%	56%	77%

[1] Generation supply function is estimated using optimal sales volume.

Note: Estimated values are evaluated at sample mean values for prices, volumes, and service are characteristics.

By allowing the market price for generated energy in the energy elasticity function to vary over the sample values, an explicit demonstration of the supply function of the utility is possible. Table 5-5 and Figure 5-1 clearly show that the typical firm has an elastic response to rising prices in a moderate price range but diminishing elasticity at higher prices. The typical firm would not offer generation at prices below about 2.3 cents per kWh, but would choose to purchase all its power needs instead.

TABLE 5-5

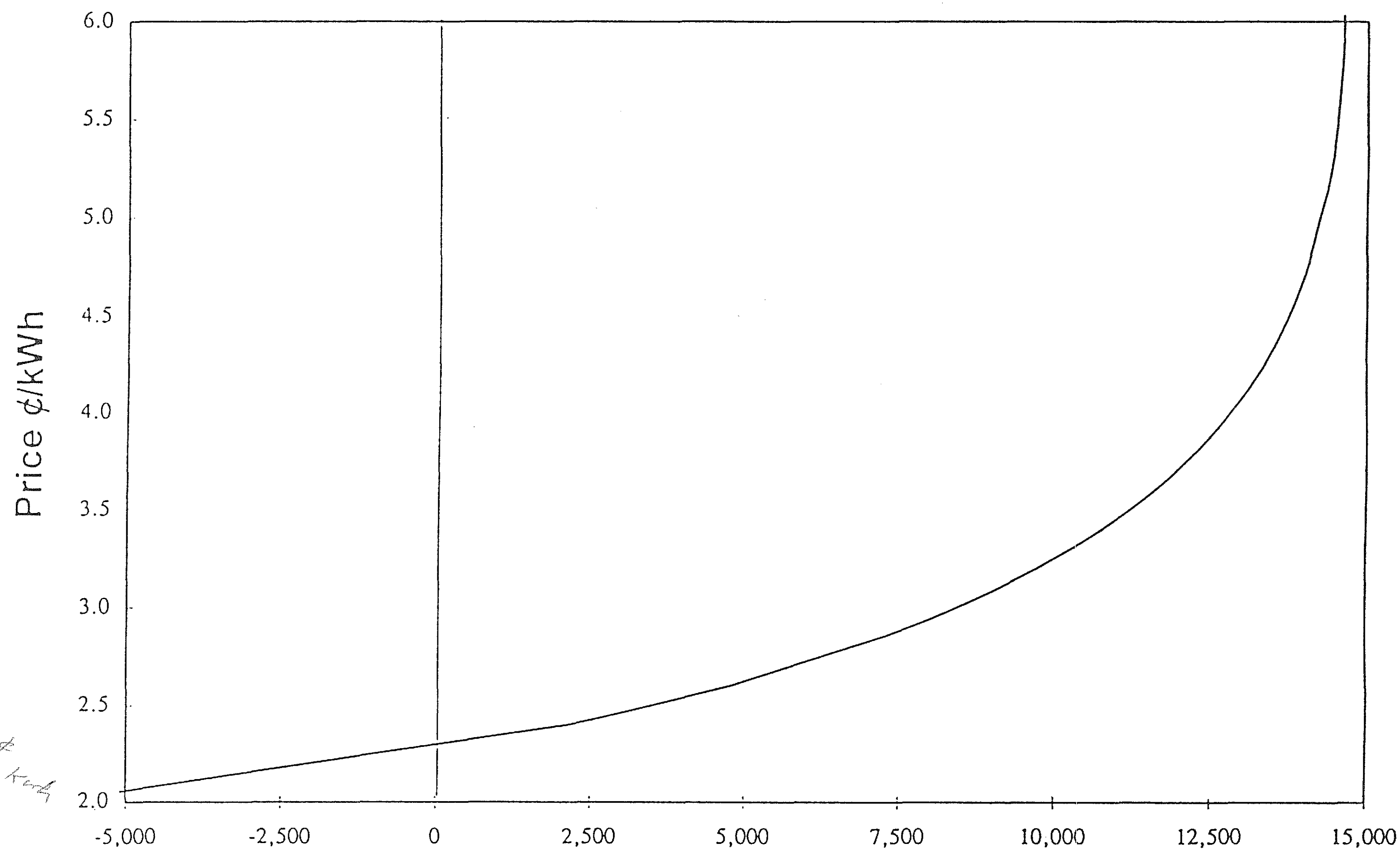
Supply Function: Optimal Supply Volumes and Market Prices for Generation (volumes are in thousands of MWh)

Price (¢/kWh)	2.0	3.0	4.0	5.0	6.0	7.0	8.0
Supply Volume	-7,715	8,615	12,800	14,250	14,600	14,600	14,000

Note: Estimates of the supply function are made with mean sample values for input prices, sales volumes, and service area characteristics.

Figure 5-1

1992 Electric Utility Generation Supply Function



What about supply conditions at 2¢ kwh or below? Reliability?

Source: Authors' construct.

1000 MWhs

Power Generation Cost Model

The panel data parameter estimates for the short-run variable cost model are found in Table 5-6. It can be seen that most of the parameters are statistically significant. The second-order generation output parameter, α_{YY}, is insignificant. This would indicate an absence of curvature in the cost function, this implies that either economies or diseconomies of scale may exist over much of the sample. The measure of quasi-fixed capital stock has the expected sign but is insignificant. The first-order linear time trend parameter has a positive sign but is also insignificant.

TABLE 5-6

Variable Cost Function Parameter Estimates: Generation Cost Model (asymptotic t ratios in parentheses)

α_O	-0.023	(0.07)	γ_{FF}	0.115	11.38
α_Y	1.091	(12.52)	γ_{KK}	-0.451	(1.66)
α_{YY}	-0.367	(1.65)	γ_{TT}	-0.490	(0.59)
α_L	0.193	(24.35)	γ_{LY}	-0.160	(8.79)
α_F	0.808	(102.12)	γ_{FY}	0.160	(8.79)
α_K	-0.099	(1.05)	γ_{KY}	0.412	(1.70)
γ_T	0.048	(0.43)	γ_{TY}	-0.016	(0.23)
γ_{LF}	-0.115	(11.38)	γ_{LT}	-0.014	(1.60)
γ_{FK}	-0.146	(7.50)	γ_{FT}	-0.014	(1.60)
γ_{LK}	0.146	(7.50)	γ_{KT}	0.048	(0.63)
γ_{LL}	0.115	(11.38)			

Notes: R^2 for the cost equation is 0.86, and 0.30 for the fuel share equation. The t ratios are reported in absolute values.

Monotonicity conditions are satisfied at every observation. Concavity conditions are satisfied at about 90 percent of the observations.[28] The elasticity of the capital stock with respect to variable costs is negative at every observation. However, the test of the envelope condition indicates that the capital stock is in excess of the long-run cost minimizing level in all years.

Estimates of economies of scale in generation based on the sample mean firm are found in Table 5-7. Results indicate significant diseconomies of scale for the average or typical firm (upward slope in the average cost curve) in 1982 with a gradual return to constant returns to scale (flattening of the average cost curve) by 1992. There is little doubt that utilities of virtually every size were significantly affected by the rapid increases in energy and capital costs, and the decline in sales as a result of higher energy prices and slower economic growth over the period between 1977 and 1987.

Table 5-8 demonstrates more clearly how large and small firms were impacted by these events. This table arrays the output of the firms in this sample from the smallest to the largest in each of the four years. The array is then divided into quartiles and estimates of scale economies are provided for each quartile. The years 1977 and 1992 may be characterized by a flat average cost curve or constant returns to scale for the utility generation industry. The years 1982 and 1987 are more characteristic of upward-sloping average cost curves where firms of all sizes, particularly small firms, exhibit diseconomies of scale. More importantly, over time as the output of the industry and the size of the firms grew, economies of scale first dropped sharply, and then nearly returned to their 1977 levels.

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[28] The incomplete satisfaction of the concavity restrictions, as well as several forms of regulatory bias, do not affect the estimation of scale economies or other relationships between output levels and cost.

TABLE 5-7

Estimates of Economies of Scale (RTS) for the Typical Firm: Generation Cost Model (t ratios in parentheses)

1977	1.0050	(25.97)
1982	0.9067	(9.60)
1987	0.9353	(22.11)
1992	0.9683	(25.09)
Pooled	0.9915	(40.73)

Note: These estimates are derived from the parameters of the variable cost model and sample mean values for input prices, output, and capital stocks.

TABLE 5-8

Estimated Scale Economies (SCE) by Quartiles of Output: Generation Cost Model

	Output (thousands of MWh)			
	25%	**50%**	**75%**	**Sample Mean**
1977-Output	4,366	9,453	18,124	16,786
SCE	1.032	1.008	1.008	1.008
1982-Output	4,826	10,767	18,979	17,313
SCE	0.903	0.915	1.003	0.989
1987-Output	5,358	12,181	23,283	20,270
SCE	0.926	0.936	0.977	0.967
1992-Output	5,463	12,525	24,466	21,241
SCE	0.987	0.993	0.988	1.003

Setting the equation for estimating returns to scale equal to one and solving for the output level produced the MES results reported on Table 5-9. These results demonstrate that about three-fourths of the industry's generated output was produced at constant or decreasing returns to scale. Based on these results, and given similar conditions, such as costs, weather, and load profiles, it is reasonable to conclude that in 1992 firms larger than 20,000 gigawatthours (GWh) (or about 4,000 megawatts [MW] of capacity) could generate additional power as efficiently as smaller firms. Results for individual firms facing the variety of actual conditions, however, vary widely.

TABLE 5-9

Minimum Efficient Scale of Generation: Generation Cost Model (in thousands of MWh)

	Lower Bound Region with no Economies of Scale	Proportion of Firms Above Lower Bound	Proportion of Output Above Lower Bound
1977	3,801	80%	97%
1982	15,365	37%	76%
1987	20,225	37%	74%
1992	13,855	73%	84%

Table 5-10 provides an indication of the adjustments utilities have made to the economic conditions they faced during this time frame. With the short-run model, however, only fuel and labor are considered variable. The partial elasticity of substitution between labor and fuel indicates moderate substitution with the weakest response in 1987, where own-price elasticities were also the lowest. Estimated cost shares, equal to the estimated cost elasticity of the inputs, reflect the impact of input prices. The fuel-to-labor-cost share ratio reached a maximum in 1982 and declined steadily thereafter. Fuel's response to changes in its own market price, generally very low in most empirical studies, shows a marked increase in 1992. This could indicate a change in generation technology over time, allowing a more flexible response to changing fuel prices.

Differentiating the RTS equation and the equation for determining the minimum efficiently sized firm, both with respect to the time trend variable, produces a measure of the changes occurring in these values over time. For example, the derivative of RTS with respect to time results in an estimate of the change in the shape of the average cost curve. When evaluated at the sample mean, a negative value of this derivative would indicate a movement toward constant returns to scale, since the mean firm experienced diseconomies of scale. The estimates of these derivatives and the time-related measures of productivity are reported in Table 5-11. The RTS derivative agrees with that indicated by the trend illustrated in Table 5-7. The results show that the productivity of IOU power generation declined during this period with a -0.1 percent average annual growth rate. The minimum efficient size of the generation firm also declined as indicated above.

* 1977-92 Δ cap was high cost cap,

nuclear costs?,

What about combined cycle plants?,

TABLE 5-10

Estimated Partial Elasticities of Substitution, Factor Shares, and Own-Price Elasticities: Generation Cost Function

Elasticity of Substitution:	**1977**	**1982**	**1987**	**1992**
Labor-Fuel	0.3440	0.3567	0.1154	0.4095
Factor Shares:				
Fuel	0.8278	0.8317	0.7705	0.7225
Labor	0.1722	0.1683	0.2295	0.2775
Own-Price Elasticities:				
Labor	-0.2848	-0.2966	-0.0889	-0.2959
Fuel	-0.0593	-0.0600	-0.0265	-0.1136

Note: Estimates are made at mean sample values.

TABLE 5-11

Changes in Measures of Firm Efficiency Over Time: Generation Cost Model (t ratios in parentheses)

	Estimated Value	Average Annual Change
Technical Change (PGX)	-0.0058 (0.065)	-0.13%
Economies of Scale (RTS)	-0.0262 (8.733)	-0.52%
Technical Change (PGY)	-0.0056 (0.066)	-0.12%
Minimum Efficient Scale	-0.7068 (0.724)	-14.14%

Notes: Estimates are made at mean sample values. The t ratios are reported in absolute values. The t ratios are reported in absolute values.

Power Procurement and Delivery Cost Model

The parameter estimates for the delivery cost model are reported in Table 5-12. Most of the parameters are highly significant with the exception of some of the time trend variables. Monotonicity conditions are met at every observation. Concavity conditions are met at over 97 percent of the observations.

The elasticity of the cost function with respect to the volumes of low- and high-voltage service, customer numbers, and size of the service territory for the typical firm, is reported in Table 5-13. The results are similar to the ones reported

TABLE 5-12

Total Cost Function Parameter Estimates: Delivery Cost Model (asymptotic t ratios in parentheses)

α_O	0.030	(2.79)	γ_{EPT}	-0.032	(11.83)
α_{YL}	0.247	(8.48)	γ_{LL}	0.024	(11.91)
α_{YH}	0.373	(26.36)	γ_{LPD}	0.001	(0.06)
α_N	0.326	(10.26)	γ_{LPT}	-0.009	(4.31)
α_S	0.035	(4.59)	γ_{PDPD}	0.034	(3.38)
α_T	0.039	(1.27)	γ_{PDPT}	0.024	(3.78)
α_E	0.738	(242.92)	γ_{PTPTL}	0.017	(3.86)
α_L	0.033	(34.57)	γ_{EYL}	0.007	(0.82)
α_{PD}	0.156	(74.39)	γ_{LYL}	-0.003	(1.28)
α_{PT}	0.074	(49.62)	γ_{PDYL}	0.006	(1.00)
γ_{YLYL}	-0.508	(5.15)	γ_{PTYL}	-0.009	(2.34)
γ_{YHYH}	0.285	(15.26)	γ_{EYH}	0.062	(15.33)
γ_{NN}	-0.114	(0.91)	γ_{LYH}	-0.006	(5.23)
γ_{SS}	0.029	(4.96)	γ_{PDYH}	-0.043	(15.81)
γ_{TT}	-0.031	(1.37)	γ_{PTYH}	-0.012	(6.49)
γ_{YLYH}	0.064	(1.71)	γ_{EN}	-0.062	(6.71)
γ_{YLS}	0.033	(1.91)	γ_{LN}	0.006	(2.34)
γ_{YHS}	-0.064	(8.16)	γ_{PDN}	0.039	(6.19)
γ_{YLN}	0.420	(3.98)	γ_{PTN}	0.017	(3.81)
γ_{YHN}	-0.326	(7.49)	γ_{ES}	-0.003	(1.66)
γ_{NS}	0.013	(0.72)	γ_{LS}	0.001	(1.82)
γ_{YLT}	0.041	(1.55)	γ_{PDS}	-0.002	(1.55)
γ_{YHT}	-0.014	(1.16)	γ_{PTS}	0.004	(4.53)
γ_{NT}	-0.016	(0.53)	γ_{ET}	-0.001	(0.02)
γ_{ST}	-0.004	(0.80)	γ_{LT}	-0.001	(0.90)
γ_{EE}	0.105	(19.69)	γ_{PDT}	-0.001	(0.12)
γ_{EL}	-0.015	(6.92)	γ_{PTT}	0.001	(0.78)
γ_{EPD}	-0.059	(14.07)			

Notes: R^2 for this system are: cost equation, 0.99; energy share equation, 0.68; labor share equation, 0.41, distribution capital share equation, 0.70. The t ratios are reported in absolute values.

TABLE 5-13

Estimates of the Elasticities of Cost with Respect to Low Voltage Sales (EL), High Voltage Sales (EH), Numbers of Customers (EN), and Size of Service Territory (ES) for the Typical Firm: Delivery Cost Model (t ratios in parentheses)

1977 -	EL	0.3157	(7.990)
	EH	0.4397	(22.661)
	EN	0.2972	(5.015)
	ES	0.0179	(2.323)
1982 -	EL	0.2467	(5.546)
	EH	0.4390	(20.825)
	EN	0.3292	(4.913)
	ES	-0.0030	(0.347)
1987 -	EL	0.2737	(5.439)
	EH	0.4000	(17.354)
	EN	0.3614	(4.428)
	ES	0.0101	(0.999)
1992 -	EL	0.2592	(5.360)
	EH	0.3609	(14.519)
	EN	0.4998	(6.097)
	ES	0.0200	(1.856)
Pooled -	EL	0.2768	(11.773)
	EH	0.4145	(36.303)
	EN	0.3630	(9.876)
	ES	0.0123	(2.521)

Notes: These estimates are derived from the parameters of the delivery cost model and sample mean values for input prices, sales volumes, and service area characteristics. The t ratios are reported in absolute values.

by Roberts.[29] However, the authors' results consistently show a smaller impact on costs of low-voltage sales and a larger impact of numbers of customers. Like Roberts, the authors found that the expansion of the size of the service territory, all else the same, does not significantly impact costs.

The estimated elasticity results shed light on the nature of power delivery costs. The low and slightly declining elasticity of low-voltage service indicates the significant economies that exist in a distribution end of the delivery network. On the other hand, the noticeable increasing trend in the contribution to costs of increasing the customer base is indicative of the rising costs of expanding the distribution system. Rising land and capital costs, increased taxes, increasing environmental concerns (including the increasing use of underground lines mentioned by Roberts), and increased peak demand, may all contribute to this trend. It would also appear that the benefits of increased load diversity are not an important factor.[30]

Table 5-14 reports the estimates of the economies of output and customer density, and the economies of size for the typical firm. The trends in these estimates illustrate the impact on costs of the changing dimensions of the delivery system. The economies of output density are substantial and rise considerably over the study period. On average, a 1 percent proportional increase in power sales to low- and high-voltage service customers, all else the same, increases total costs 0.70 percent. This results in ray average costs decreasing about 0.30 percent.

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[29] Roberts, "Economies of Density and Size in the Production and Delivery of Electric Power."

[30] P.L. Joskow and R. Schmalensee, *Markets for Power: An Analysis of Electricity Utility Deregulation* (Cambridge, MA: The MIT Press, 1983), argue that customer growth and customer diversity improve a utility's load factor and reduce costs. They conclude, however, that these benefits are quickly exhausted at a moderate number of customers. A number of utilities have used this argument to justify mergers or other forms of expansion.

TABLE 5-14

Estimates of Economies of Output Density (RYD), Customer Density (RCD), and Size (RTS) for the Typical Firm: Delivery Cost Model
(t ratios in parentheses)

1977 -	RYD	1.3239	(18.993)
	RCD	1.0250	(79.746)
	RTS	1.0065	(86.651)
1982 -	RYD	1.4583	(14.562)
	RCD	1.0107	(70.991)
	RTS	1.0140	(73.901)
1987 -	RYD	1.4844	(12.313)
	RCD	1.0042	(61.232)
	RTS	0.9942	(68.859)
1992 -	RYD	1.6126	(11.242)
	RCD	1.0189	(55.676)
	RTS	0.9985	(63.554)
Pooled -	RYD	1.4465	(27.414)
	RCD	1.0221	(128.312)
	RTS	1.0094	(139.317)

Notes: These estimates are derived from the parameters of the delivery cost model and sample mean values for input prices, sales volumes and service area characteristics. The t ratios are reported in absolute values.

The economies of customer density, measuring the impact on costs of a proportional increases in output and the number of customers, are small. For most years, a 1 percent proportional increase in output and the number of customers, all else the same, increases total costs by more than 0.98 percent, and reduce ray average costs by less than 0.02 percent. Increasing the firm's service territory in proportion to sales and customer numbers results in no decrease in average cost.

note

It would be misleading with the results of this model to speculate on the minimum efficient scale of a utility-owned electric transmission and distribution system. Given the multiple output characteristic of the model, attempts to hold some factors constant while solving for the efficient scale of other factors will produce unreliable results. However, it is reasonable to conclude, given the above elasticity estimates, that firms expanding output to a fixed number of customers in a given area will experience decreasing average costs well beyond the sample mean levels for low- and high-voltage output. On the other hand, firms that expand output, numbers of customers, and service territory proportionately will not experience decreasing average costs if the firm is beyond sample mean size.

Cannot est MES for transmission & distribution

note

Table 5-15 reports the time-related impacts on firm efficiency. As with generation, measures of technical change (PGX and PGY) in the provision of delivery service declined on average over the sample period. The same lack of technical progress accompanied by slow sales growth and rising costs contributed to these results. Changes in returns to output density reflect the steepening of the slope of the cost curve in the output space around the mean firm. Changes in the returns to customer density and to service area reflect the small effect on the cost curve of these measures.

Additional insight into the changes occurring in the cost of power delivery can be gained from examining the cost shares, elasticities of substitution, and own-price elasticities over the study period. Table 5-16 contains the actual and estimated shares of total cost of delivery system inputs. The results show modest

TABLE 5-15

Estimated Changes in Measures of Firm Efficiency over Time: Delivery Cost Model (t ratios in parentheses)

		Estimated Value	Average Annual Change
Technical Change (PGX)		-0.0260 (1.092)	-0.52%
Returns to:	- Output Density	0.1526 (1.944)	3.05%
	- Customer Density	0.0059 (9.833)	0.12%
	- Size	-0.0016 (16.000)	-0.03%
Technical Change (PGY)		-0.0057 (0.127)	-0.11%

Notes: Estimates are made at mean sample values. The t ratios are reported in absolute values.

TABLE 5-16

Estimated and Actual Input Cost Shares and Changes Over Time: Delivery Cost Model

	Energy	Dist. Capital	Trans. Capital	Labor
1977				
(estimated)	80.6%	10.4%	4.0%	5.0%
(actual)	80.2%	10.6%	4.1%	5.1%
1982				
(estimated)	72.6%	16.1%	8.3%	3.0%
(actual)	72.4%	16.2%	8.4%	3.0%
1987				
(estimated)	71.2%	17.5%	8.3%	3.1%
(actual)	70.9%	22.1%	7.7%	4.2%
1992				
(estimated)	74.0%	15.9%	6.7%	3.6%
(actual)	73.9%	15.9%	6.6%	3.6%
Average Annual Change:	-0.6%	2.8%	3.4%	-2.2%

Note: Estimates are made using mean sample values.

Table 5-17 contains estimated elasticities of substitution between inputs and own-price elasticities of demand. Results show an increasing amount of labor being substituted for energy and distribution capital (or vice versa) but a strong trend of complementarity between labor and transmission capital over time. Declining fuel prices relative to capital prices would produce mixed explanations for the declining cost share of labor.

The issue of separability of electric utility functions can be addressed using the results in Table 5-17. The elasticities of substitution between inputs in the supply, transmission, and distribution functions reveal the ease with which inputs in one function can replace those in another function. The elasticities of substitution between energy and distribution labor and distribution capital reveal a growing degree of substitutability over time. This result supports the finding of several recent studies, as well as the discussion of the issue in Joskow and Schmalensee.[31] They state that investments in the distribution network can reduce line loss and, therefore, reduce the need for some generation investment, for example. The weak results on the substitution between energy and transmission capital, however, argue against another contention of Joskow and Schmalensee—that transmission and generation are strong substitutes.

note

note

The evidence from this table on the ease of separation between the transmission and distribution networks is unclear. Distribution labor and transmission capital appear to be strong complements, whereas transmission and distribution capital appear to be substitutes, ignoring the anomalous results of 1987. In any case, since elasticities of substitution are highly nonlinear, no direct statistical significance can be assigned to these estimates. However, a cursory examination of the interaction parameter estimates in Table 5-12 indicate a significant production relationship exists between the inputs of the model.

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[31] Ibid.

TABLE 5-17

Estimated Elasticities of Substitution and Own-Price Elasticities: Generation Cost Function

Elasticities of Substitution:	**1977**	**1982**	**1987**	**1992**
Energy-Labor	0.1204	0.2674	0.5113	0.5008
Energy-Distribution	0.1684	0.3101	0.4552	0.5072
Energy-Transmission	-0.1413	0.1974	0.4905	-0.0348
Labor-Distribution	-0.6154	1.9116	2.5992	1.9995
Labor-Transmission	2.9311	-2.8474	-6.6264	-4.9855
Distribution-Transmission	0.4883	4.3561	-18.7091	3.1659
Own-Price Elasticities:	**1977**	**1982**	**1987**	**1992**
Energy	-0.0178	-0.0743	-0.1359	-0.0960
Labor	-0.1677	-0.3140	-0.3440	-0.4032
Distribution	-0.1325	-0.6550	1.1329	-0.6649
Transmission	-0.0828	-0.7587	3.1225	-0.2987

Note: These estimates are derived from the parameters of the delivery cost model and sample mean values for input prices, sales volumes and service area characteristics.

Earlier, a general function was developed that identified the inputs to the separate utility functions of power procurement, transmission, and distribution. A direct test of this hypothesis of separability was performed using a likelihood ratio test from the cost equation that used the value of the log likelihood function from the restricted and unrestricted second-order interaction parameters as discussed above. The results strongly reject the hypothesis of separability of the three major electric utility functions.

CHAPTER 6

CASE STUDIES

Introduction

In this chapter, the authors compare their findings in the previous chapter with profiles of two major investor-owned U.S. electric utilities—American Electric Power (AEP) and the Entergy Corporation (Entergy). AEP is a utility holding company with seven operating companies in the Midwest. It provides power supply and delivery service to a large residential population but serves relatively few large urban centers given its size. AEP relies almost exclusively on coal-fired generation capacity.

Entergy is also a utility holding company with five operating subsidiaries in the Midsouth. It serves an economically diverse population, concentrated in several large cities or thinly scattered in rural locations. Industrial load is high relative to population density. Entergy has a diverse generation mix including significant nuclear, as well as gas and coal-fuel, generation capacity. It has also undergone a large merger, adding significantly to its generating capacity and customer base.

Profile of American Electric Power

Overview

AEP is a holding company for seven electric power operating companies spanning 45,500 square miles from southwest Michigan to Virginia and Tennessee in the southeast (a statistical overview of AEP is found in Table 6-1). In all, it serves parts of seven contiguous states. AEP subsidiaries are coordinated through

TABLE 6-1

American Electric Power Company

Statistical Overview

	1977	1982	1987	1992	Average Growth Rate
Square Mileage [1]	39,501	45,710	45,550	45,550	0.95%
Generating Capacity (megawatts)	17,261	21,505	22,566	24,084	2.22%
Total Possible Generating Capacity (mil kWh)	151,206	188,384	197,678	210,976	2.22%
Contracted Power (megawatts)	609	882	364	118	-10.94%
Total Capability (mil kWh)	156,541	196,110	200,867	212,010	2.02%
Net Generation (millions of kWh)	97,014	98,237	101,915	114,606	1.11%
Net Purchased and Interchange	549	6,618	4,133	3,467	12.29%
Total System Load	97,563	104,855	106,048	118,073	1.27%
Net Purchase Power (%)	0.56%	6.31%	3.90%	2.94%	11.01%
Capacity Factor	64.16%	52.15%	51.56%	54.32%	
Customer Numbers					
Residential	1,724,500	2,237,239	2,343,018	2,471,470	2.40%
Commercial	201,524	252,195	274,671	303,073	2.72%
Industrial	11,811	18,247	21,427	22,404	4.27%
Miscellaneous	8,468	10,406	11,005	10,694	1.56%
Total [2]	1,946,303	2,518,087	2,650,121	2,807,641	2.44%
Customer Distribution					
Residential	88.60%	88.85%	88.41%	88.03%	-0.04%
Commercial	10.35%	10.02%	10.36%	10.79%	0.28%
Industrial	0.61%	0.72%	0.81%	0.80%	1.83%
Miscellaneous	0.44%	0.41%	0.42%	0.38%	-0.89%
Total	100.00%	100.00%	100.00%	100.00%	

TABLE 6-1 — *Continued*

	1977	1982	1987	1992	Average Growth Rate
Sales (millions of kWh)					
Residential	20,693	22,090	24,494	26,998	1.77%
Commercial	12,273	14,078	16,846	19,661	3.14%
Industrial	35,851	29,532	36,668	41,327	0.95%
Miscellaneous	1,162	1,238	1,360	1,269	0.59%
Wholesale	20,719	31,027	19,500	21,596	0.28%
Total	90,698	97,965	98,868	110,851	1.34%
Sales Distribution					
Residential	22.82%	22.55%	24.77%	24.36%	0.44%
Commercial	13.53%	14.37%	17.04%	17.74%	1.80%
Industrial	39.53%	30.15%	37.09%	37.28%	-0.39%
Miscellaneous	1.28%	1.26%	1.38%	1.14%	-0.75%
Wholesale	22.84%	31.67%	19.72%	19.48%	-1.06%
Total	100.00%	100.00%	100.00%	100.00%	

[1] The 1992 Annual Report statistic was taken as a basis for all years. Two adjustments were made:

First, the 1980 merger with Columbus Southern was backed out of the 1980 statistic. Second, changes noted in the *Financial & Statistical Review, 1983 - 1993,* were incorporated.

[2] Resales not included.

NOTE: Data for this table was taken from several sources. The primary sources were the company's *Annual Report* and the *Financial and Statistical Review* for the relevant years. *Moody's Public Utility Manual* was also used.

an interconnected transmission network to create a single integrated electric system. In 1993, the number of customers served was nearly three million (2,840,217). In 1993, AEP's largest operating subsidiary, Ohio Power had electric sales of 44,938 million kWh. Appalachian Power was second with 34,872 million kWh. It had the largest number of customers at 837,645 in the AEP system. AEP's total net generating capacity was 25,179 MW as of January 1, 1994.

Significant Mergers and Sales

In May of 1980, AEP acquired Columbus and Southern Ohio Electric Company. The utility's name was changed to Columbus Southern Power Company in 1987. This sizeable merger added 6,209 square service miles, over one million customers, and generating capacity of 2,625 MW. At the end of February 1992, Michigan Power merged with the Indiana Michigan Power subsidiary. No subsidiaries were sold during the study period.

Service Territory

Of the seven states served by AEP, over 95 percent of the territory falls within Indiana, Ohio, Kentucky, Virginia, and West Virginia, with a small portion of southwest Michigan and Northeast Tennessee accounting for the remainder. The two subsidiaries with the largest service territories are Appalachian Power, serving Virginia and West Virginia, and Ohio Power, serving Ohio. Columbus Southern Power is noteworthy for serving Columbus, Ohio, the largest city in AEP's service area with a core population of 688,000. There are only three other cities that exceed 100,000 in population: Fort Wayne, Indiana with a population of approximately 160,000; South Bend, Indiana with a population of approximately 113,000; and Roanoke, Virginia with a population of approximately 100,000. Few of the remaining cities exceed 50,000 in population. AEP's 1992 customer density is sixty-two customers per square mile. In several cases, AEP territory occupies a rural niche between metropolitan areas that are served by other utility companies. In Ohio, for example, Cincinnati, Cleveland, Dayton, Toledo, and Youngstown are all served by other utilities.

Generating Output and System Capability

AEP's generating capacity increased from 17,870 MW in 1977, to 24,202 MW in 1992. This represents an average annual growth rate of 2.02 percent over the study period. Actual generated power increased from 97,563 million kWh in 1977, to 118,073 million kWh, in 1992, a 1.27 percent average annual growth rate. Since the growth rate of capacity (2.02 percent) was substantially higher than that of generation (1.27 percent), the load factor decreased during the sample period from 64.52 percent to 55.97 percent. Coal-fired plants were responsible for over 80 percent of the system-wide capability for all years and over 90 percent of the actual energy supplied for 1992.

Customer Characteristics

Sales volumes for all AEP customers increased over the study period. The commercial sector grew the fastest, with an average annual growth rate of 3.14 percent. This was significantly higher than the residential class, which had an annual rate of 1.77 percent. The industrial sector grew at an annual rate of 0.95 percent. The wholesale sector had the lowest growth rate at 0.28 percent, while the corresponding rate over all sectors was 1.34 percent for the sixteen-year study period. The sales volume figures associated with this modest growth rate are 90,698 million kWh in 1977 versus 110,851 million kWh in 1992. The industrial sector had the largest portion of the sales load, which was consistently between 30 percent and 40 percent of total sales. AEP's industrial sales for 1992 were

41,327 million kWh or 37 percent of the 1992 total sales volume. The residential and wholesale sectors each represented an average of 23 percent of the sales distribution over the 1977 to 1992 period. Commercial sales were consistently less than one-fifth of the overall sales distribution.

Throughout the study period, the number of residential customers was over 88 percent of the total, while a majority of the remainder was comprised of commercial customers (10 percent). Industrial and miscellaneous classes made up less than 1 percent each. The overall total number of customers increased over the study period by an average annual growth rate of 2.44 percent. All customer classes experienced growth, but the industrial class had the highest customer growth rate (4.27 percent).

Profile of the Entergy Corporation

Overview

Entergy was created as Middle South Utilities in 1949, and changed to its current name in August 1989. A statistical overview of Entergy is found in Table 6-2. During the first several decades of its existence, Entergy developed into a holding company of both gas and electric operating companies including Arkansas, Louisiana and Mississippi Power and Light Companies, and New Orleans Public Service. Their combined service territories cover much of the south-central U.S. In 1992, Entergy had a generating capacity of 14,517 MW. The total system load for their 1.7 million customers was 75,920 million kWh. Louisiana Power and Light was the largest of the subsidiaries with a net capability of 5,262 MW, sales of 28,006 million kWh, and 595,000 customers.

TABLE 6-2

Entergy

Statistical Overview

	1977	1982	1987	1992	Average Growth Rate	Selected 1993 GSU Statistics
Square Mileage	92,000	92,000	91,000	91,000	-0.07%	28,000
Generating Capacity (megawatts)	11,014	12,895	15,019	14,517	1.84%	6,825
Total Possible Generating Capacity (mil	96,483	112,960	131,566	127,169	1.84%	59,787
Net Non-Firm Purchases (megawatts)	355	446	481	(370)	N/A	N/A
Total Capability (mil kWh)	99,592	116,867	135,780	123,928	1.46%	N/A
Net Generation (millions of kWh)	46,845	38,180	53,366	52,849	0.80%	N/A
Net Purchased and Interchange	4,937	9,851	3,949	9,143	4.11%	N/A
Total System Load (millions of kWh)	51,782	38,180	53,366	52,849	0.14%	N/A
Net Purchase Power (%)	9.5%	25.8%	7.4%	17.3%	3.97%	N/A
Capacity Factor	48.6%	33.8%	40.6%	41.6%	-1.04%	N/A
Customer Numbers						N/A
Residential	1252236	1387389	1462917	1500808	1.21%	518,346
Commercial	148943	165460	178504	185576	1.47%	65,292
Industrial	23636	24390	27379	29440	1.46%	4,490
Miscellaneous	8315	9635	9484	9188	0.67%	5,847
Total [1]	1433130	1586874	1678284	1725012	1.24%	593,975
Customer Distribution						
Residential	87.38%	87.43%	87.17%	87.00%	-0.03%	87.27%
Commercial	10.39%	10.43%	10.64%	10.76%	0.23%	10.99%
Industrial	1.65%	1.54%	1.63%	1.71%	0.23%	0.76%
Miscellaneous	0.58%	0.61%	0.57%	0.53%	-0.57%	0.98%
Total	100.00%	100.00%	100.00%	100.00%		100.00%
Sales (millions of kWh)						
Residential	13,852	15,596	17,053	17,549	1.58%	7,192
Commercial	7,972	9,620	11,693	12,928	3.22%	5,711
Industrial	18,712	22,092	20,615	23,610	1.55%	14,275
Miscellaneous	1,651	2,045	2,050	1,839	0.72%	1,912
Wholesale	6,289	2,103	6,220	7,979	1.59%	666
Total	48,477	51,456	57,631	63,905	1.84%	29,756
Sales Distribution						
Residential	28.58%	30.31%	29.59%	27.46%	-0.27%	24.17%
Commercial	16.45%	18.70%	20.29%	20.23%	1.38%	19.19%
Industrial	38.60%	42.93%	35.77%	36.95%	-0.29%	47.97%
Miscellaneous	3.41%	3.97%	3.56%	2.88%	-1.12%	6.43%
Wholesale	12.97%	4.09%	10.79%	12.49%	-0.26%	2.24%
Total	100.00%	100.00%	100.00%	100.00%		100.00%

[1] Resales not included.

NOTE: Data Sources were the *Annual Report* and the *Supplement to the Annual Report* for the relevant years. Moody's *Public Utility Manual* was also used.

Significant Mergers and Sales

There have been a few mergers and one notable sale from 1977 to present. In January of 1978, a distribution company, Citizen's Power & Light, was purchased by Arkansas Power & Light (AP&L). In January of 1981, AP&L also acquired Arkansas-Missouri Power, another Middle South subsidiary, in an internal restructuring. Starting in 1992, Entergy began selling its Missouri-based operations. Entergy's sales volume dropped from 64,208 million kWh in 1991, to 63,905 million kWh in 1992, and the service territory decreased by approximately 7,000 square miles.

The most dramatic restructuring of Entergy took place after the 1977-1992 study period. Entergy's base of operations and service territory recently expanded from a 1993 merger with Gulf States Utilities (GSU). This significant merger increased Entergy's service territory westward along the Gulf Coast, starting with the metro area of Baton Rouge and extending to southeast Texas, adding 28,000 square miles. The merger enlarged the system capacity by 6,825 MW, a 45 percent increase. The number of electric customers increased by 585,000, a 35 percent increase. The combined service territories now have a customer base of 2.3 million in 1993, serving a population of approximately six million. Figures for GSU are not incorporated into the Statistical Overview (Table 6-2) since the final merger date is beyond the end date of the study period. Nonetheless, the size of the merger points to potential impacts in the company's future performance. For this reason, 1993 GSU statistics are listed in the table. With the addition of GSU, Entergy's 1992 customer numbers and generating capacity are 82 percent and 89 percent of those of AEP's, respectively.

Service Territory

Before the 1992 sale of Entergy's retail operations in Missouri, the territory included the southeast corner of the state starting at the point where the Ohio River merges from the east (the northern border of Kentucky). Now the most northern point of the current service territory is the northern border of Arkansas. With the addition of GSU, the service territory of Entergy covers parts of four states (Arkansas, Mississippi, Louisiana and Texas). Entergy serves more than 80 percent of Arkansas including the entire eastern border running along the Mississippi. Approximately one-half of the state of Mississippi bordering the Mississippi River is served. Including GSU, Entergy covers the majority of both Louisiana and the lower Mississippi River frontage.

Although many rural areas are served, the territory includes the metropolitan areas of New Orleans and Baton Rouge in Louisiana, Jackson, Mississippi and Little Rock, Arkansas. These are all moderately-sized metropolitan areas with a core population ranging from 175,795 in Little Rock, to 536,370 in New Orleans. Entergy has substantially more cities in this 200,000 population range than does AEP. However, the higher frequency of midsized metro areas in the Entergy service territory can be misleading. The AEP service territory contains more moderate-sized towns and a higher 1993 population relative to Entergy, and is smaller in size. Therefore, despite having more midsized metropolitan areas, Entergy's customer densities are substantially lower than AEP's. The average density figure for Entergy is twenty-one customers per square mile, compared to sixty-two customers per square mile for AEP.

Generating Output and System Capability

Entergy's generating capacity increased from 11,014 MW in 1977, to 14,517 MW in 1992, a 1.84 percent annual increase. This is somewhat less than

AEP's rate of 2.02 percent over the same period of time. Generated power increased approximately 1.95 percent annually, relative to AEP's rate of 1.27 percent. In 1992, 38.6 percent of generation was derived from nuclear power, 26.9 percent from gas, 16.4 percent from coal and 17.3 percent was purchased. The 38.6 percent 1992 energy share from nuclear power was up substantially from its 1977 share of 9.8 percent. The percentage of power that is coal generated also went up substantially, especially in relative terms, from 0 in 1977 to 16.4 percent in 1992. Gas generation declined from a 1977 share of 39.0 percent, to 26.9 percent in 1992, while oil generation dropped from a 41.4 percent to 0.6 percent.

Including the GSU merger, Entergy's total generating capacity in 1993 was 22,469 MW. Both the actual distribution of generation by fuel type and the capacity by fuel type are affected by this merger. The generating capacity mix is now heavily slanted toward gas and oil fired plants (70 percent), while nuclear and coal account for 20 percent and 10 percent of the mix, respectively. The figure of 10 percent for coal generation is in sharp contrast to AEP where 80 percent of the capacity is from coal fired plants. AEP's nuclear share of capacity was only 8.7 percent in 1992, while Entergy's nuclear capacity share was of 20 percent. Entergy's generating mix heavily relied upon oil and gas fired plants (70 percent), while AEP's oil and gas generated fuel was less than 5 percent.

New merger

Customer Characterization

Commercial sales grew at a rate of 3.22 percent over the study period, more than twice the rate of a sales increase of any other class. Residential, industrial and wholesale sales all had growth rates ranging from 1.55 percent to 1.59 percent. Miscellaneous sales grew at a more modest rate of 0.72 percent. The overall growth rate was 1.84 percent from 1977 to 1992. This is comparatively 37 percent higher than AEP's sales growth rate of 1.34 percent. During the study period, the percentage of sales attributed to the commercial class rose from 16.45

percent to 20.23 percent. Industrial sales were 36.95 percent, and residential sales were 27.46 percent of the total. Wholesale and miscellaneous sales comprised the last 15 percent of 1992 total sales.

During the study period, Entergy's number of customers grew modestly across all customer classes. The commercial class grew at 1.47 percent annually from 1977, while the miscellaneous class grew only 0.67 percent annually. However, little relative change in the number of customers took place during the study period.

The Relative Performance of AEP and Entergy: 1977–1992

Table 6-3 contains the results from the key estimates of the restricted profit, the generation cost, and the delivery cost models using the pooled sample data. Values are the estimates using the industry sample mean firm, AEP, and Entergy-specific data values (sample values are used instead of estimated values where appropriate).

One subject of comparison is the degree of self-generation that exists in the firm. The typical profit-maximizing firm, free to choose its own level of power generation and sales, would optimally generate 73 percent of its sales volume. Both AEP and Entergy generate more than an optimal proportion and somewhat more than the sample average of 79 percent. In addition, the results show that both firms experience more diseconomies of scale in generation than the typical firm in our sample. Thus, both companies may be able to reduce average costs by reducing self-generated output.

Entergy and AEP both show significant economies of output density. This means that average costs could be lowered by increasing sales to existing customers in their service territory, despite the fact that their sales are well above sample mean levels. Entergy shows a much greater response in this measure, relative to AEP. This could be a result of several circumstances. First, Entergy has

Explain hostility to Conservation

Table 6-3

Key Estimated Industry Efficiency Measures and the Values for American Electric Power and the Entergy Corporation: 1977-1992

	Industry Estimates	American Electric Power	Entergy Corporation
Generation-to-sales Ratio	73%	89%	85%
Price-Energy Supply (1992)	2,165@ \$.024/kWh 8,220@ \$.030/kWh	110,096 @ \$0.24/kWh	28,062 @ \$0.30/kWh
Economies of Scale-Generation	0.9915	0.9724	0.9666
Minimum Efficient Scale-Generation	12,163	99,145	28,360
Economies of Output Density	1.4465	1.8636	2.8223
Economies of Customer Density	1.0221	1.0972	1.0801
Economies of Territory Size	1.0094	1.0726	1.0140
Productivity: Generation	-0.12%	-4.97%	-0.38%
Productivity: Delivery	-0.49%	-3.59%	-3.41%

Note: Volumes are in thousands of MWh. Volumes, customer numbers, and service areas for AEP and Entergy are sample values.

high customer density → fuller use of transm + distrib. network

a large but relatively underexploited transmission and distribution network, evidenced by its relatively low customer density. Also, Entergy has significant surplus generation capacity and much of this is nuclear. Increasing sales without the need for new investments, as in the case of Entergy, would reduce average costs significantly.

Customer growth, in conjunction with increased sales (economies of customer density), would also reduce costs further for AEP and Entergy, and by more than for the typical firm. This fact again demonstrates the benefits firms derive from expanding sales in the presence of surplus capacity. Both of these firms suffered sales losses or slow load growth during the early years of the study period and a slower recovery at the end of the period, relative to firms in the northeast or middle Atlantic region. Continued economic recovery will benefit these firms more noticeably than other firms with less surplus capacity.

AEP would benefit by expanding the size of its service territory in proportion to its sales and customer base nearly as much as with customers alone, based on its estimated returns to size coefficient. Entergy would not benefit as much from such an expansion based on these results. In fact, the 1992 estimated values for this elasticity for Entergy (not reported on this table) reveal diseconomies of firm size. This is important because Entergy's 1992 merger with GSU added more than one-third of the premerger sales volume, number of customers, and service area to its operations.

Finally, the productivity growth of AEP and Entergy, relative to the typical firm in the industry, was disappointing throughout the sample period. These differences are likely to be found for any utility company that experienced above average capital additions or other forms of expansion, while at the same time experiencing below average sales performance. Utilities that have recession-sensitive customer profiles will have particularly poor productivity performance in an economic downturn.

CHAPTER 7

SUMMARY AND CONCLUDING COMMENTS

Summary of the Results

The estimates of the restricted profit model produce important insights into the nature of the integrated electric utility. They indicate that if there is a required sales obligation, as in the case of a regulated utility firm, the optimal (profit-maximizing) firm would choose to generate less power than the average firm in the sample. If sales are unrestricted such that a firm could choose its profit maximizing level of sales, the optimal firm would choose to generate less power than the restricted average firm, and to reduce the sales volume. The overall smaller scale for the optimal-sized firm is strongly supported by the other results of this study.

assumes cost minimization = profit max.

The optimal firm's generation of electricity is shown to respond predictably to the market price of power. The firm would supply more power as the market price increased through the midrange of prices. At very low prices, the firm would not generate but only purchase power. At the high end of prices, the supply function becomes unresponsive to price increases.

The generation cost function results illustrate the impact of the chaotic years of the late 1970s to the mid-1980s. In 1977, the smallest 25 percent of firms experienced economies of scale while larger firms produced power in the constant returns to scale range. In 1982 and 1987, however, firms of all sizes exhibited some degree of diseconomies of scale (*i.e.* rising average costs) for all ranges of output. This is probably the result of inflated fuel costs and capacity additions made during this era. By 1992, firms returned to a constant returns-to-scale status for most ranges of output. It would appear that regardless of input cost or electricity demand conditions, the expansion of utility generation for most firms will not reduce their average cost.

generation

The delivery cost model produces estimates for economies in the provision of power delivery services. In all of the study years, expanding sales to a given number of customers in a fixed service area resulted in significant reductions in average cost. Average costs were also reduced when the number of customers served increased in a fixed service area. Increasing the size of the service territory alone produced no measurable cost benefits. Estimates of the efficiently sized firm delivering power are not reliable for this model because of the multiple output specification. However, results indicate that expanding output to a fixed customer base and service area will result in reduced average costs for firms significantly larger than the mean-sized firm. The proportional expansion of output, customers, and service territory beyond the mean-sized firm will not produce cost savings.

The estimates of these measures for the case study utilities, when compared to the typical firm, produce the expected results for large firms with surplus capacity during the turbulent study period. AEP and Entergy both had a higher than optimal generation-to-sales ratio and diseconomies of scale in generation for most years. Both firms had significantly higher economies of density than the typical firm. AEP also demonstrated that average costs could improve by expanding firm size. Neither these utilities, nor the typical firm in the industry, showed positive productivity growth during this time period.

Concluding Comments

Several important conclusions of a general nature can be drawn from the results of this study. They concern the current interpretation and near-future implications of these findings and implications for future research on the subject of economies of scale in the electric utility industry.

First, the evidence contained in this report and in the majority of such studies made in the last two decades, is fairly unanimous in concluding that economies of scale of generation at the firm-level are exhausted at moderate to small scales.

NUG costs are high
NUG ↑ ⇏ Eff. ↑ (BRAE)

These findings, however, do not, by themselves, warrant the conclusion that adding nonutility generation (NUG) capacity to the utility's input mix will result in reducing the long-run average cost. Casual evidence from some regions of the U.S. argues that the opposite might be true. NUG costs are high in many areas as a result of mandated pricing; however, it is unclear what the cost impacts of increased financial risk, nondispatchability, and fuel mix rigidities will be in the near future. Determining the economies of scale for NUGs requires a plant-level study where, particularly in the case of cogeneration, the necessary data are difficult to obtain. Again, casual evidence suggests that the minimum efficient scale for nonutility generators has been falling steadily in response to increasing competition.

NUG need a plant-level study

?

Second, the empirical estimation of economies of scale and similar measures are based on the input cost and output data (or similar information) in the sample. When these estimates are made during a period of rapidly changing prices and demand, the results can be misleading if they are applied too generally. For example, it is unreasonable to assume that the diseconomies of scale in generation found for the majority of firms in the 1982 cross-section is an accurate description of the U.S. electric utility industry today. On the other hand, analysis of the industry over the last twenty years indicates that constant returns to scale is the dominant situation for firms producing more than 60 percent of the industry's output.

Although the results do not indicate that expansion of a utility's delivery system beyond that of the average-sized firm in this sample (about 800,000 customers and 20,000 square miles of service territory) is justified on an efficiency basis, many firms could reduce average costs significantly through increased sales within their service area. Some of the questions policy makers might ask regarding these results are:

- How much can average costs be reduced through growth in sales volumes (movements along an existing average cost curve) compared to the cost

converse is also true

Av. cost ↑ → sales vol ↓

reductions that are possible through competition and new technology (downward shift in the average cost curve)?

- How rapidly are these movements likely to occur?
- For which utilities is this comparison most relevant?

Emerging power markets will find efficient answers to these questions. However, market solutions do not guarantee an equitable distribution of the costs involved. It is clear that a number of utilities currently have such high average costs that no amount of sales growth will hold off competition or the inevitable revaluation of their assets. Indeed, many utilities may experience significant declines in sales as a result of competition.

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APPENDIX A

CONSTRUCTION OF CAPITAL STOCKS AND SERVICE PRICES

Capital cost is the cost of generation, transmission, and distribution plant, or combinations of plant used in the empirical studies presented above. Capital cost contains a portion of general plant calculated by using the common cost share factor. These function-specific aggregations are performed by using Tornqvist multilateral indexes. The data are for steam plant, nuclear plant, hydroelectric plant, other generation plant, transmission plant, distribution plant, and general plant.

The capital cost of each plant class, *i*, in each year, *t*, is computed using the following formulas used by Christensen and Jorgenson:[32]

$$CK_t^i = WK_{t-1}^i \cdot XK_t^i \, .$$

This formula implies that the annual cost of the services provided by capital is equal to the product of the implicit rental price of a unit of capital stock and the number units of capital stock available for service. This method implicitly assumes that service quantity is proportional to the capital stock. The first part of this expression contains the sources of imputed cost to the owner of a unit of capital stock or

$$WK_t^i = \left[\frac{1 - U_t \cdot Z_t^i - K + Y_t \cdot K_t \cdot U_t \cdot Z_t^i}{1 - U_t}\right] \cdot \left[WKA_{t-1}^i \cdot r_t^i + WKA_t^{i,\ expected} \cdot d^{\,i} - (WKA_t^{i,\ expected} - WKA_{t-1}^i) \right] + WKA_t^{i,\ expected} \cdot T_t .$$

[32] See L. R. Christensen and D. W. Jorgenson, "The Measurement of U.S. Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, 4 (December 1969), 293-320.

Here WK_t^i is the rental service price of capital, and XK_t^i is the capital quantity index for the i^{th} capital asset. U_t is the rate of corporate income taxation. Z_t^i is the present value of tax deductible depreciation. K_t is the rate of investment tax credit. Y_t is a binary variable that indicates the years when tax credits are excluded from the depreciation base. WKA_t^i is an index of electric utility asset prices. $WKA_t^{i,expected}$ is the expected value of same in the previous year. The parameter, r_t^i, is the nominal interest rate, while d^i is the rate of replacement. T_t is the rate of indirect taxation.

Federal tax rates, investment tax credits, tax lives, and the rate of depreciation for tax purposes were found in the Research Institute of America's *Federal Tax Handbook*.[33] Indirect tax rates were determined for FERC Form 1 data. The nominal interest rate was obtained from yields on public utility bonds as published in *Moody's Bond Record*.[34]

The electric utility asset price index was constructed from data in the *Handy Whitman Index of Public Utility Construction Costs*.[35] These indexes were then modified to correct for the regional differences that exist in the prices. The Handy Whitman indexes require adjustment since they start with the same reference value in the same year. Regional differences in asset prices were constructed by using the 1965 differentials developed in the study by Christensen, Gollop, and Stevenson.[36]

The rate of replacement in the capital stock was chosen using the declining balance method. Here $d^i = 1.5/L^i$ where L^i is the estimated average service life of

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[33] *Federal Tax Handbook* (New York: Research Institute of America, Inc., 1993).

[34] *Moody's Bond Record, Volume 1* (New York: The Dun & Bradstreet Corporation, 1993).

[35] *Handy-Whitman Index of Public Utility Construction Costs* (Baltimore: Whitman, Requardt and Associates, 1993).

[36] L.R. Christensen, F.M. Gollop, and R.E. Stevenson, *Estimates of Capital Stocks and Capital Service Flows for Privately-Owned Electric Utilities in the U.S.: 1950-1975*, unpublished manuscript.

the particular electric utility plant. The estimated service life for each plant type was determined from Bureau of Economic Analysis (BEA) sources and FERC accounting guidelines. The service lives of fifty kinds of nonresidential capital assets were provided by the BEA. These include furniture as fixtures, engines and turbines, electrical equipment, instruments, commercial buildings, and other buildings. In addition, the BEA provided a mapping of these classifications to electric utility-specific capital assets. The FERC accounting guidelines aided in further refining these classifications and in determining the relative weights to be assigned to each category.

The value of the capital quantity index for each plant type in the benchmark year is the ratio of the net book value of the electric utility plant as reported in FERC Form 1 to a triangularized weighted average of pre-1965 Handy Whitman index numbers. The values of XK^i for subsequent years are constructed using a perpetual inventory equation that features geometric decay. The equation is *

$$XK_t^i = XK_{t-1}^i \cdot (1-d^i) + XK_t^{i,\ additions}.$$

Here $XK_t^{i,\ additions}$ is the value of plant additions divided by the contemporaneous asset price index. The sensitivity of XK^i to the benchmark year calculation recedes with time. If the perpetual inventory equation is valid, it is then desirable to begin total factor productivity (TFP) indexing some years after the benchmark year. The authors use 1965 data for the benchmark year.

APPENDIX B

MEAN SAMPLE VALUES FOR THE VARIABLES USED IN THE STUDY

MEAN SAMPLE VALUES FOR THE VARIABLES USED IN THE STUDY

Variable	1977	1982	1987	1992
Price of Labor	$14,350	$22,510	$31,548	$40,275
Price of Fuel ($/MMBtu)	$128.46	$225.92	$161.64	$143.73
Price of Capital-Steam Plant ($/kW)	$170	$697	$937	$858
Price of Capital-Nuclear Plant ($/kW)	$264	$857	$1,210	$1,119
Price of Capital-Hydro Plant ($/kW)	$338	$1,770	$1,602	$1,526
Price of Capital-Other Generation Plant ($/kW)	$145	$495	$596	$565
Price of Capital-Transmission Plant ($/1,000 circuit miles)	$10,072	$56,863	$71,903	$60,548
Price of Capital-Distribution Plant ($/1,000 customer hookups)	$235	$991	$1,320	$1,126
Price of Capital-General Plant ($/square foot)	$0.27	$0.76	$0.83	$0.85
Generation Supply Price ($/MWh)	$18.40	$41.60	$43.66	$43.15
Total Sales (1000 MWh)	19,565	21,263	24,682	26,990
Low-Voltage Sales (1000 MWh)	10,251	11,235	13,534	15,714
High-Voltage Sales (1000 MWh)	9,313	10,028	11,149	11,276
Generation Output (1000 MWh)	16,786	17,312	20,270	21,241
Square Miles of Service Territory	21,261	19,434	21,061	20,974
Number of Customers	675,542	762,716	838,770	891,752
Variable Cost ($1000)	$209,352	$407,149	$387,690	$350,773
Total Delivery Cost ($1000)	$414,811	$1,147,550	$1,456,760	$1,133,120
Restricted Profit ($1000)	$68,111	$328,566	$440,730	$308,224

NOTE: Prices for capital items are rental service prices which are adjusted for federal taxes, expected appreciation, depreciation, property taxes, and other factors as discussed in Appendix A.

APPENDIX C

SUMMARY OF OTHER STUDIES ON SCALE ECONOMIES, SCOPE ECONOMIES AND ECONOMIES OF DENSITY IN THE ELECTRIC POWER INDUSTRY

Summarized Articles

L.R. Christensen and William Greene, "Economies of Scale in U.S. Electric Power Generation," *Journal of Political Economy*, No. 84 (1976): 655-676.

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TABLE C-1

METHODOLOGIES AND MAJOR FINDINGS OF STUDIES SUMMARIZED

Study	Christensen & Green (1976)
Functional Form	Translog cost function to estimate economies of scale
Economic Rationale	Homotheticity and homogeneity conditions are imposed. Scale economies can be realized through the average cost function for a range of outputs holding the factor prices fixed at the sample means.
Data Used	Two sets of cross-sectional data: one for the year 1955 and the other for the year 1970.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	Homogeneous model presents inaccurate scenarios that there exists economies of scale for any size of firm whereas the non-homogeneous model indicates that scale economies are exhausted. The imposition of homotheticity changes the shape of the cost curve substantially. The technical change unrelated to increase in scale deserves the primary attribution for declines in the cost function.
Policy Conclusions	Technical change unrelated to increase in scale deserves the primary attribution for declines in the cost function.

TABLE C-1 — *Continued*

Study	Atkinson & Halvorsen (1984)
Functional Form	Generalized cost function and duality theory
Economic Rationale	At constant output, total shadow cost increases proportionately when all shadow prices increase proportionately. The production function is restricted to homotheticity if the shadow cost function can be written as a separate function in prices and output. The production function is further restricted to be homogeneous if cost with respect to output is constant.
Data Used	Almost the same data set used by Christensen and Green (1976). The sample consists of 1970 data for 123 privately owned electric utilities.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	The homotheticity restriction is tested and rejected at the 0.001 level. The estimate of scale economies with respect to actual cost at the means is 5.6 percent. 12 out of 123 firms in the sample have negative scale economies with respect to actual cost. The estimates of scale economies with respect to total shadow cost are larger than estimates of scale economies with actual cost. Only 2 of 123 firms have negative scale economies with respect to shadow cost.
Policy Conclusions	Firms operating in the upward sloping portion of their long-run average cost curves are largely eliminated when scale economies are measured with respect to shadow cost rather than actual cost.

TABLE C-1 — *Continued*

Study	Mayo (1984)
Functional Form	Multiproduct quadratic cost function is derived using a transformation function (Flexible Functional Cost Quadratic) for gas and electricity.
Economic Rationale	The multiproduct quadratic cost function is the stringent specification of fixed costs, as compared to a single but constant parameter. However, fixed costs may vary depending on which subset of the total product set is being produced. Product specific fixed costs are captured by a dummy variable whose value is unity whenever positive amounts of product 1 are produced and zero otherwise.
Data Used	Firm level costs and outputs for 1979 are chosen for 200 public utilities. Of the 200 firms, 131 are solely electric firms, 20 are exclusively natural gas, and 49 are engaged in both electricity and gas.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	The presence of fixed costs generates a regions of ray economies of scale. For gas, the estimation indicates that the cost function is concave and thereby generates ray economies that give way to diseconomies. For FFCQ model, incremental costs are estimated to be $108 million and $20.2 million for electricity and gas respectively. Ray cost output elasticities for the quadratic cost function shows that at lower levels of output the firm enjoys ray economies ($K<1$) while at large output levels ray diseconomies appear. The decline in K reflects the influence on firm costs of the presence of economies in natural gas. In the case of quadratic model estimation, costs of a joint electricity-natural gas firm that produces 1250 million kWh and distributes 50 million Mcf of natural gas are 0.77 percent lower than having the same output produced by two speciality firms. For both quadratic and FFCQ models, the estimates product specific economies appear to be in closer accord with the ray economies of scale estimates for larger rather than smaller firms.
Policy Conclusions	Estimates of the degree of economies and diseconomies of scope provide a useful input in the construction of an appropriate public policy towards multiproduct firms. The estimations indicate that natural gas firms are characterized by product-specific economies of scale throughout the relevant output region. However, as multiproduct output grows, the absence of competitive pressure leads to cost inefficiencies and eventually diseconomies of scope.

TABLE C-1 — *Continued*

Study	Henderson (1985)
Functional Form	Firms are assumed to have two components: generation and distribution of electricity. A generation cost function is designed for vertically-integrated firms. It is assumed that electricity is delivered to final customers in four ways: purchases from neighboring utilities, or generated power with a primary technology of hydroelectricity, non-nuclear steam, and nuclear steam. A shadow cost function with duality properties is then defined.
Economic Rationale	Economies of scale of each of two production stages such as the generation phase and the distribution stage are defined in terms of ultimate output Y. Distribution economies cannot be estimated as those associated with a shadow cost function. If the shadow cost function can be written as a separable cost function, generation is separable from labor and capital of the distribution phase. The translog cost function used for the distributional phase provides a suitable way of testing the underlying hypothesis.
Data Used	The data for this study was a 1970 cross-section of 160 class A and B investor-owned electric companies. These were mostly integrated utilities, although a few firms that mostly provide distribution services were also included.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	Scale economies have been exhausted for generating plants. Empirical measures of distribution economies can differ dramatically depending on the input factors included within the distribution sector. The average scale economies for the distribution and transmission parts of the firm were 17.7 percent. This has been computed as the average of the measure for each firm, using the factor prices prevailing for each. So the average cost of transporting electricity is about 17.7 percent higher than the long-run marginal cost. This is larger than the scale effects found for steam or hydrogeneration.
Policy Conclusions	The statistical findings confirmed that the distribution network has substantial economies of scale, which suggests that the firm is a natural monopoly. Since distribution and generation are not separable, the price of obtaining input electrical energy does matter in the optimal design of the distribution networks. Vertically-integrated firms help reduce the transaction cost.

TABLE C-1 — ***Continued***

Study	Chappell & Wilder (1986)
Functional Form	Multiproduct cost function using the same model as Mayo (quadratic functional form).
Economic Rationale	Accurate information about the presence or absence of economies of scale and scope are of particular interests for regulators of the "supposed" natural monopolies. Multiproduct costs include the degree of economies of scale, the degrees of economies of scope, and degree of product-specific economies of scale.
Data Used	Cost and output data for 88 electric utilities, 51 combination electric-gas utilities and 18 natural gas distributors in 1981.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	The degree of economies of scope measures relative cost savings from joint rather than separate production. Both the multiproduct and restricted multiproduct cost function specifications indicate multiproduct economies of scale for the relevant range of outputs. Product-specific economies of scale for the relevant range of outputs exist. Economies of scope also prevail over most of the range of outputs. Therefore, the cost function is subadditive over that range. Subadditivity implies that a single firm could most efficiently produce the range of outputs.
Policy Conclusions	Because subadditivity exits, natural monopoly prevails for most electricity-gas utilities. The authors conclude that Mayo's estimated diseconomies of scale and scope primarily reflect the higher ex post cost of nuclear technology.

TABLE C-1 — *Continued*

Study	Roberts (1986)
Functional Form	Production and delivery cost function. The cost function is a translog approximation. The complete estimating model consists of the cost equation and four share equations.
Economic Rationale	Estimated elasticities are a function of input prices, output, and service area characteristics. The hypothesis that the distribution system can be studied independently of the generation and transmission systems can be tested by requiring that distribution inputs be separable from generation and transmission inputs.
Data Used	The data set for estimating the cost function is of privately owned vertically-integrated electric utilities in 1978. The important data includes the prices and quantities of kWh input, transmission and distribution capital and labor, as well as quantity of output delivered to both customer groups, number of customers, and square miles of service area for each utility.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	Dividing the firm into separate production stages is an inaccurate starting point for the estimation of the production structure. This is implied from the results that separability of the distribution function is rejected with a X^2 test statistic of 169 which exceeds the critical value. Estimated mean values of ϵ_H and ϵ_L indicate a one percent increase in output to residential and industrial customers, holding the number of customers and service areas fixed, raises cost by 0.434 percent and 0.391 percent, respectively. On average, a one percent expansion in output raises total cost by .825 percent and reduces ray average cost 0.175 percent. The mean value of R_{QD} equals 1.212, which reveals fairly substantial economies of output density. The hypothesis that there are no economies of output density is tested by restricting the sum of ϵ_H and ϵ_L to equal to one for all firms. The hypothesis is rejected at the .01 significance level with a X^2-test statistics of 40.11. R_{QD} captures a movement along the ray average cost curve as output rises, and the shift in the ray average cost curve as output rises, and the shift in the ray average cost curve as the number of customers rises. On average ϵ_A equals -.005 with a sample range -.021 to .013. Overall, the size of the service area has no significant effect on the cost of delivering electricity. There is no strong evidence that larger service areas result in any economies in power delivery.
Policy Conclusions	Natural monopoly arguments are insufficient to justify expansion of an existing firm into newly developing communities. Rather, the possibility of competitive bidding for the right to provide service to newly developing or expanding areas does not appear to be ruled out by the nature of the technology.

TABLE C-1 — *Continued*

Study	Sing (1987)
Function Form	Multiproduct hybrid translog cost function.
Economic Rationale	Economies of scope are present if the multiproduct cost function exhibits orthogonal subadditivity. Cost complementarities at all output levels up to a given level are a sufficient condition for subadditivity.
Data Used	Cross-sectional data set from 1981. 108 different firms either single electric and gas or combination of the two.
Findings on scale eocnomies, scope economies, and economies of density in the electric power industry and their consequences	The degree of product-specific economies of scope is observed at the mean output vector which indicates that cost for the average combination utility mean output vector could be decreased by 7.2 percent if electricity and gas are supplied separately. That no economies of scope are observed may be due to combination utilities providing higher quality services. At the mean combination of utility output vector product-specific economies of scale are present for electricity (S_e = 1.66) but not for gas (S_g=0.80)
Policy Conclusions	Benefits from competition between two regulated energy utilities are substantially greater than the cost of corporate reorganization.

TABLE C-1 — *Continued*

Study	Krautmann & Solow (1988)
Functional Form	A restricted cost function assuming that plants are in static equilibrium with respect to inputs that can be varied in the short run.
Economic Rationale	Modified Christensen and Green model for nuclear power generation
Data Used	Capital inputs are not variable in the short-run and are minimized with respect to inputs conditional on capital and expected output, there exists a restricted or variable cost function duel to the stochastic variable.
Findings on scale economies, scope eocnomies, and economies of density in the electric power industry and their consequences	The single reactor plants will have a lower average cost at small output level while producing those outputs with two reactors would require either smaller than optimal reactors or low capacity utilization if the reactors are the efficient size. Conversely, at large outputs, dual reactor plants will have lower average costs, since producing those outputs with a single reactor would require a unit well above the optimal size. The long-run average cost curve for single-reactor plants exhibit decreasing returns to scale throughout the range of outputs. In contrast, the long-run average cost-curve for dual-reactor plants exhibits increasing returns to scale throughout the range of outputs.
Policy Conclusions	The results suggest that reductions in the cost of nuclear power are not likely to come from increased reactor size. For large output levels, multiunit plants are more efficient than single unit plants.

TABLE C-1 — *Continued*

Study	Kaserman & Mayo (1991)
Functional Form	Multistage cost function modified for the case of vertically-integrated production. Cost estimation for four alternative specifications are used.
Economic Rationale	Dependent variable is total utility operating expenses. Output at the generation stage. Data on four primary inputs — fuel, capital, and purchased power.
Data Used	Data are drawn from the set of class A and B firms in the 1981 Statistics of Privately Owned Electric Utilities.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	For the output of each separate stage of multistage economies, economies of scale are exhausted well within the range of representative outputs. The presence of cost complementarities across vertical stages, however, extends the region of multistage economies beyond the point at which stage-specific economies are exhausted. The concept of vertical economies is weaker than a natural monopoly (subadditivity) condition, but is useful for describing the cost savings associated with vertical integration. With the exception of some very small output levels, results indicate that vertical economies prevail throughout the relevant range of outputs.
Policy Conclusions	Multiproduct cost concepts can be extended to provide a general measure of vertical economies. The introduction of an explicit measure of vertical economies should provide a useful vehicle for evaluation of proposals involving vertical divesture in other industries. No sweeping policy recommendations concerning optimal regulatory designs can be made, however, the evidence presented does place a heavy burden on proponents of deregulation schemes that are premised upon forced vertical divestiture in the industry.

TABLE C-1 — *Continued*

Study	Gilsdorf (1995)
Functional Form	Multistage cost function developed by Evans and Heckman (1984).
Economic Rationale	The subadditivity question is examined within the framework of a multiproduct cost function and a multiproduct firm producing an output from each production stage. While most studies look into economies of scale, this model looks into the effect of vertical integration on cost structure. It is estimated using a multistage cost function because it provides information about conditions necessary for a multistage natural monopoly.
Data Used	The study sample consists of 72 privately-owned electric utilities (defined on a holding company basis where applicable). These utilities accounted for over 72 percent of investor-owned conventional steam generation in 1985.
Findings on scale economies, scope economies, and economies of density in the electric power industry and their consequences	This study did not consider economies of scale but rather considered a subadditivity test that provides estimates for each utility that satisfied positive marginal cost, monotonicity, and input price concavity conditions of the cost function used. The results do not support the hypothesis that integrated electric utilities are multistage natural monopolies. Results of subadditivity measures at the sample mean indicate that all but three combinations present small, but statistically insignificant, degrees of subadditivity. Failure to reject the additivity hypothesis does not necessarily imply a lack of vertical integration economies. Economies of scope between stages is a necessary but not a sufficient condition for subadditivity. It does imply that integration economies do not make the multistage cost function subadditive. The results also indicate that regulatory policies designed to increase utilization rates will reduce electric costs for various utilities. The evidence provides some support for the hypothesis that scope economies exist between sales for resale and ultimate sales, implying that complete divestiture of wholesale activities from retail sales would entail a certain loss of efficiency.
Policy Conclusions	The study's findings provide no evidence of subadditivity for vertically-integrated electric utilities over the admissible region, implying that integrated utilities are not multistage natural monopolies. Although this result is consistent with pro-competition policies, it does not necessarily support complete industry divesture since economies of scope between stages may exist in the absence of subadditivity. The cost-reducing effect of higher load factor rates represents another potential benefit of expanded wholesale markets arising from deregulatory policies.

DETAILED SUMMARY OF STUDIES

I. Christensen, L.R., and William Greene, "Economies of Scale in U.S. Electric Power Generation," *Journal of Political Economy*, No. 84 (1976): 655-676.

This paper focuses on scale economies and used a translog cost function to estimate economies of scale. The model imposes neither homotheticity nor unitary elasticities of substitution. In estimation, it is important to distinguish scale economies from decrease in cost as result of technical change. They used two sets of cross-section data, one for the year 1955 (as used by Nerlove) and the second for 1970.

Translog Cost Function

The translog cost function is written as:

$$\ln C = \alpha_0 + \alpha_Y \ln Y + \tfrac{1}{2}\gamma_{YY}(in Y)^2 + \sum \alpha_i \ln P_i + \tfrac{1}{2}\sum\sum \gamma_{ij}\ln P_i ln P_j + \sum \gamma_{Yi} ln Y ln P_i \qquad (1)$$

where $\gamma_{ij} = \gamma_{ji}$, C is total cost function, Y is output, and the Pi's are the prices the factor inputs. A duel of a well-behaved production function is a cost function which is homogeneous of degree one in prices; that is for a fixed level of output, total cost must increase proportionally when all prices increase proportionally. This implies that the following relationships among parameters must hold:

$\Sigma\, \alpha_i = 1,$
$\Sigma\, \gamma_{Yi} = 0,$
$\Sigma\, \gamma_{ij} = \Sigma\gamma_{ji} = \Sigma\Sigma\gamma_{ij} = 0.$

Using Shephard's lemma, a share equation is computed as follows:

$$S_i = \frac{\partial lnC}{\partial lnP_i} = \frac{P_i X_i}{C_i} \qquad (2)$$

$$S_i = \alpha_i + \gamma_{Yi} \ln Y + \sum \gamma_{ij} lnP_j \qquad (3)$$

The scale economies (SCE) is usually defined in terms of the relative increase in output resulting from a proportional increase in all inputs. A natural way to express the extent of scale economies is as the proportional increase in cost as a result of small proportional increase in the level of output, or the elasticity of total cost with respect to output. Therefore, scale economies (SCE) is defined as unity minus the elasticity of cost with respect to output:

$$SCE = 1 - \frac{\partial \ln C}{\partial ln Y} \tag{4}$$

This result is in positive numbers for positive scale economies and negative numbers for scale diseconomies.

There are altogether six models:
Model A corresponds to Translog cost function.
Model B imposes homotheticity. A cost function corresponds to a homothetic production structure if and only if the cost function (here translog cost) can be written as a separable function in output and factor prices.
Model C imposes homogeneity. A homothetic production structure is further restricted to homogenous function if and only if the elasticity of cost function with respect to output is constant.

For translog cost function, homotheticity and homogeneity restrictions are, respectively:

$$\gamma_{Yi} = 0;$$

and

$$\gamma_{Yi} = 0 \ , \ \gamma_{YY} = 0$$

Model D, Model E and Model F correspond to Model A, Model B and Model C respectively with unitary elasticity of substitutions.

SCE for different model

$$SCE(A) = 1 - (\alpha_Y + \gamma_{YY} \ln Y + \Sigma \gamma_{Yt} ln P_t)$$

$$SCE(B) = 1 - (\alpha_Y + \gamma_{YY} \ln Y)$$

$$SCE(F) = 1 - \alpha_Y$$

$$SCE(D) = 1 - (\alpha_Y + \gamma_{YY} \ln Y + \Sigma \gamma_{Yt} ln P_t)$$

$$SCE(C) = 1 - \alpha_Y$$

Inputs used: Capital (K), Labor (L) and Fuel (F)

Results and Discussion

<u>Economies of Scale</u>

First, the authors used 1955's data set as used by Nerlove. 1955 I estimates of scale economies for the firm with the median output in each group.

Table 1: Estimated Scale Economies Under Various Specifications of Technology
(t- ratios in Parenthesis)

	Size Group 1	2	3	4	5
Output (mill kWh)	43	338	1,109	2,226	5,819
1955 I					
Model: Homogeneous					
F	.203 (13.61)	.203 (13.61)	.203 (13.61)	.203 (13.61)	.203 (13.11)
C	.190 (13.11)	.190 (13.11)	.190 (13.11)	.190 (13.11)	.190 (13.11)
Homothetic					
E	.388 (17.00)	.216 (16.90)	.117 (6.28)	.059 (2.43)	-.020 (-0.62)
B	.359 (16.62)	.208 (16.66)	.113 (6.20)	.059 (2.44)	-.017 (-0.53)
Nonhomothetic					
D	.418 (18.00)	.258 (18.53)	.153 (7.94)	.096 (3.83)	.026 (0.77)
A	.408 (17.88)	.258 (18.44)	.157 (8.25)	.104 (4.16)	.040 (1.20)
1955 II					
Model A	.351 (13.66)	.243 (15.67)	.167 (8.68)	.27 (5.15)	.076 (2.26)

- The estimates of scale economies for homogeneous models C and F are constant at all levels of the output.
- Other four models allow economies of scale to vary with respect to level of output. This also indicates that scale economies decrease with an increase in firm size.
- Although imposition of unitary elasticity of substitution leads to a statistically loss of goodness of fit, the impact of scale economies is not large.
- The estimates of the model D, E, F are roughly same as those for A, B, and C, respectively.
- The effects of homotheticity constraint are much more rigorous.
- The estimates of scale economies for Model B and E, the homothetic models, are considerably less than those for Model A and D.
- The homogeneous models C and F give inaccurate impression that there are significant economies of scale for firms of any size. The nonhomogeneous models indicate that scale economies are exhausted well within the sample output range. The median firm in group 5, which had output less than one third that of the largest firm, shows no significant scale economies.
- A convenient way to summarize scale economies is to present the average cost function for a range of outputs while holding the factor prices fixed at the sample means. This can be seen through graphical representation. The cost curve be derived by evaluating the average cost function for a range of outputs while holding the factor prices fixed at the sample means.

The imposition of unitary elasticities of substitution has some effects on the shape of a curve, and imposition of homotheticity changes the shape of the cost curve substantially.

- The authors concluded that technical change unrelated to increase in scale deserves the primary attribution for declines in the cost function.

II. Atkinson, Scott E., and Robert Halvorsen, "Parametric Efficiency Tests, Economies of Scale, and Input Demand in U.S. Electric Power Generation," *International Economic Review* 25, No.3 (1984): 647-662.

This paper uses duality theory to study the structure of production which is appropriate only if the corresponding maintained hypothesis concerning economic behavior (e.g, cost minimization or profit maximization) exits. This paper deals with a generalized cost function that retains the principal advantage of the neoclassical cost function. Firms are assumed to base their production decisions on unobservable shadow prices which reflect the effects of regulation on the effective prices of inputs. Parametric test for cost minimization are obtained by expressing shadow prices as functions of market prices.

Shadow and Actual Cost Functions

The firm's dual total shadow cost function is defined as:

$$C^s = C^s(k_P, Q)$$

where k_P is vector of firm and input-specific shadow prices.

The firms's total cost function is defined as:

$$C^A = \Sigma P_i X_i + \Sigma P_i \, \partial C^s / \partial k_i \, P_i \qquad i=1...n \tag{1}$$

By specifying an appropriate functional form for the shadow cost function, we can derive a parametric expression for the firm's total actual costs.

The shadow cost share of input i is

$$M_i^s = (k_i P_i X_i)/C^s$$

$$X_i = M_i^s C^s (k_i, P_i)^{-1}$$

Substituting X_i into (1) total cost function is

$$C^A = C^s \Sigma k_i^{-1} M_i^s \tag{2}$$

Taking logarithms

$$\ln C^A = \ln C^s + \ln \Sigma k_i^{-1} M_i^s \quad i=1,2,3....n \tag{3}$$

The translog functional form provides a convenient second-order approximation to an arbitrary continuously twice-differentiable shadow cost function:

$$\ln C^{s}=\alpha_{o}+\alpha_{Q}lnQ+\tfrac{1}{2}\gamma_{QQ}(lnQ)^{2}+\Sigma\gamma_{iQ}lnQln(k_{i}P_{i})$$

$$+\Sigma\alpha_{i}\ln(k_{i}P_{i})+\tfrac{1}{2}\Sigma\Sigma\gamma_{ij}\ln(K_{i}P_{i})\ln(K_{j}P_{j}) \qquad i,j=1.....n \tag{4}$$

where $\gamma_{ij} = \gamma_{ji}$

Holding output constant, total shadow cost should increase proportionately when all shadow prices increase proportionally. Linear homogeneous of the total shadow cost function in shadow prices implies the following relationships among the parameters.

$$\Sigma\gamma_{ij}=\Sigma\gamma_{ij}=\Sigma\Sigma\gamma_{ij}=0 \qquad i,j=1,2,......n \tag{5}$$

$$\Sigma\alpha_{i}=1; \quad \Sigma\gamma iQ=0,$$

Logarithmetic differentiation of equation (4) yields parametric expression for shadow cost shares mentioned above.

$$=M_{i}^{s}=\alpha_{i}+\Sigma\gamma_{ij}\ln(k_{iP_{j}})+\gamma_{iQ}lnQ \qquad i,j=1,.........,n. \tag{6}$$

$$\frac{\partial lnC^{s}}{\partial\ln(k_{i}P_{i})}=\frac{k_{i}P_{i}}{C^{s}}\frac{\partial C^{s}}{\partial k_{i}P_{i}}=\frac{k_{i}P_{i}X_{i}}{C^{s}}$$

Substituting in equation (3) for in C^s from equation (5) and for M^s from equation (6) yields the total actual cost.

$$\ln C^{A}=\alpha_{o}+\alpha_{Q}lnQ+\tfrac{1}{2}\gamma_{QQ}(lnQ)^{2}+\sum_{i=1}^{n}\gamma_{iQ}\,lnQ\,\ln(k_{i}P_{i}) \tag{7}$$

$$+\Sigma\alpha_{i}\ln(k_{i}P_{i})+\tfrac{1}{2}\Sigma\Sigma\gamma_{ij}\ln(k_{i}P_{i})\ln(k_{j}P_{j})$$

$$+\ln[\Sigma K_{i}^{-1}(\alpha_{i}+\Sigma\gamma_{ij}\ln(k_{j}P_{j})+\gamma_{iQ}lnQ)]$$

Note that if $K_i = K_j$ for all i,j, the firm's total actual cost function (5) reduces to its shadow cost function, which in turn is equivalent under these conditions to the neoclassical cost function.

Economies of Scale

Returns to scale are most appropriately measured by the relationship between total cost and output along the expansion path. In present situation, two concepts of return to scale are involved and found relevant. The relationship between total actual cost and output corresponds to the usual definition of returns to scale and is relevant for evaluating the optimum scale of firms from a public policy point of view. Because it is total shadow cost rather than total actual cost that firms are assumed to minimize.

Scale economies (SE) are defined as unity minus the elasticity of total cost with respect to output:

$$SE^A = 1 - \frac{\partial \ln C^A}{\partial \ln Q}, \quad SE^s = 1 - \frac{\partial in C^s}{\partial ln Q} \tag{8}$$

Multiplication by 100 yields estimates of scale economies as expressed as percents.

Scale economies are independent of factor prices if and only if the production function is homothetic. The production function is restricted to be homothetic if and only if the shadow cost function can be written as a separate function in prices and output. The homotheticity restrictions are

$$\gamma_{iQ} = 0, \; i = 1, \ldots.. n \tag{9}$$

The production function is further restricted to be homogeneous if and only if the elasticity of cost with respect to output is constant. The homogeneity restrictions are

$$\gamma_{iQ} = 0, \; i = 1, \ldots.. n \quad \text{and} \quad \gamma_{QQ} = 0.$$

Results and Discussion

A large but almost the same data set used by Critensen and Greene (1976) is also used for this study. The sample consists of 1970 data for 123 privately-owned electric utilities.

Economies of Scale

Homotheticity of production function was tested using restrictions in (9) and rejected at the 0.001 level. The estimate of scale economies with respect to actual cost, SE^A at the means of data (output of 8,778 million kilowatthours [kWh]) is 5.6 percent. The estimates of SE^A for some individual firms, including the largest and smallest in the sample, are shown in the third column of table 1 presented below.

Table 1: Estimates of Scale Economies for Selected Firms

Firms	1970 Output (million kWh)	Estimates of Scale Economies		
		Relative Price Efficiency Not Imposed		Relative Price Efficiency Imposed
		SE^A	SE^S	SE^A
Central Ver. Public Service	4	47.8%	54.0%	45.2%
Newport Electric	50	34.7	40.8	33.2
Community Public Service	183	26.1	30.8	25.1
United Gas Improvement	487	22.5	28.0	21.9
Montana Power	869	19.5	25.1	19.2
Upper Peninsula Power	1,412	15.4	20.2	14.8
Tucson Gas & Electric	2,632	12.6	17.4	12.7
Public Service Co. of New Hampshire	3,965	10.1	14.8	10.5
Columbus & Southern Ohio Electric	5,292	9.2	14.1	9.8
Central Power and Light	7,896	6.8	11.7	9.0
Northern States Power	11,837	4.1	8.6	5.1
Carolina Power and Light	16,311	1.2	5.2	2.5
Houston Lighting and Power	27,708	-0.5	4.0	1.1
Southern California Edison	38,343	-2.4	1.9	-0.9
Commonwealth Edison	46,870	-3.5	0.8	-1.9
Southern	53,918	-5.5	-1.5	-3.3
American Electric Power	72,247	-6.0	-1.7	-4.1

Results and Discussion:

• The estimate for firm with the median output (5,292 million kWh) is 9.2 percent and the range of estimated scale economies is 47.8 percent (output of 4 million kWh) to -6.0 percent (output of 72,247 million kWh).
• Twelve of the 123 firms in the sample have negative scale economies with respect to actual cost, implying that they are operating in the upward sloping portion of their long-run average cost functions.
• The findings that 12 largest firms are operating in the upward sloping portion of their actual cost functions do not necessarily imply that they are behaving nonoptimality from their own point of view. Because firms are assumed to minimize total shadow cost rather than the total actual cost. The estimates of scale economies with respect to total shadow cost, SE^s are shown in the fourth column of the table 3. The estimates of SE^s are larger than the estimates of SE^A for all firms. The estimate of SE^s at the mean level of output and input prices is 10.2 percent and the range of estimated scale economies with respect to shadow cost is 54.0 percent to -1.7 percent.
• Only 2 out of 123 firms have negative scale economies with respect to shadow cost. The smallest firm with negative estimated scale economies with respect to shadow costs has an output of 53,918 kWh.

Thus the apparently incongruous findings of firms operating in the upward sloping portions of their long-run average cost curves are largely eliminated when scale economies are measured with respect to shadow cost rather than actual cost.

III. Mayo, John W., "The Multiproduct Monopoly, Regulation, and Firm Costs," *Southern Economic Journal*, No. 51 (1984): 208-218.

Recent theoretical advances regarding mutiproduct cost concepts have spawned renewed interest in the estimation of cost functions, particularly for multiproduct firms. In this paper, the author analyzed mutiproduct cost functions for gas-electric utilities. The author of this paper examines whether cost efficiencies that are regarded to characterize multiproduct public utilities are offset by increased cost permitted by a lack of inter-energy competition.

Theoretical Structure and Estimating Model

Using a transformation function, the production technology of the multiproduct firm can be represented as t(x,y) where x is a vector of inputs and y is a vector of outputs. If input prices are constant, under unrestrictive condition a cost function C(y) is constructed. Unlike a single cost product firm, analysis of the multiproduct firm costs require several concepts to be taken care of.

Ray average costs are given by C(hy)/h where h >0 and y is given output vector which is arbitrarily set to unity. Thus, ray average costs describe the behavior of the cost function as output is expanded proportionately along a ray coming from the origin. However, for the multiproduct firms output is not always expanded proportionally. In this situation, one can consider an incremental cost.

Incremental cost of a multiproduct firm is defined as:

IC(yi) = $C(y_N) - C(Y_{N-1})$ where $C(y_{N-1})$ is the cost of producing all N of the multiproduct firm outputs except product i.

The average incremental cost is defined as:

$$AIC(y_i) = [C(y_N) - C(y_N - 1)]/y_i = Ic(y_i) / y_i \qquad (1)$$

The specification of average incremental cost allows the identification of returns to scale that are specific to a particular output. These product-specific returns to scale for product i are given by:

$$S_i(y) = AIC(y_i) / (\partial C/\partial y_i) \qquad (2)$$

Mayo argued that efficient industry structure is dogged by the behavior of costs as the scope of the firm is altered. The cost savings or dissavings that result from multiproduct versus specified firm operations are given by the notion of economies and diseconomies of scope. For the two product case, weak economies (diseconomies) of scope are given by :

$$C(y_1,y_2) \leq(\geq) \{C(y_1,0) + C(0,y_2)\} \qquad (3)$$

The degree of economies of scope is given by :

$$[C(y_1,0)+C(0,y_2) \ - \ C(y_1,y_2)] \ / \ C(y_1,y_2) \tag{4}$$

Mayo has argued that efficient allocation of societal resources needs that mutiproduct operations be characterized by at least weak economies of scope.

This study has employed a multiproduct quadratic cost function (developed by Lau, 1974). The quadratic cost function is:

$$C(y) \ = \alpha_0 + \sum_{i=1} \alpha_{iy_i} + (1/2) \ \sum_i \sum_j \alpha_{ij} y_i y_j \tag{5}$$

For the case of two product case, the quadratic cost function can be written as:

$$C(y_1,y_2)=\alpha_0+\alpha_1 y_1+\alpha_2 y_2+(1/2)\alpha_3 y_1^2+(1/2)\alpha_4 y_2^2+(1/2)\alpha_4 y_1 y_2 \tag{6}$$

For the cost function the ray cost output elasticity, k is given by :

$$k=[(\alpha_1+\alpha_2 v)+(\alpha_3+\alpha_4 v^2+\alpha_5 v)y_1]/ \tag{7}$$

$$[(\alpha_0/y_1)+\alpha_1+\alpha_2 v+(1/2)(\alpha_3^2+\alpha_4 v+\alpha_5 v)y_1]$$

where v $=y_1/y_2$

The degree of product specific returns to scale S_i is given by

$$S_i=(\alpha_1 y_1+(1/2)\alpha_{ii} y_i^2+(1/2)\sum_{j\neq 1} y_i y_j)+\alpha_{ii} y_i^2+(1/2)\sum_{j\neq 1}\alpha_{ij} y_i y_j) \quad i=1.2 \tag{8}$$

The degree of economies of scope, S_c is

$$S_c=(\alpha_0-(1/2)\alpha_5 y_1 y_2)/(\alpha_0+\alpha_1 y_1+\alpha_2 y_2+(1/2)\alpha_3 y_1^2+(1/2)\alpha_4 y_2^2+ \tag{9}$$

$$(1/2)\alpha_4 y_2^2+(1/2)\alpha_5 y_1 y_2)$$

One disadvantage of the multiproduct quadratic cost function is the stringent specification of fixed cost as being compared in the single, constant parameter α_0. In real world situations, fixed cost may vary depending upon the situation that the subset of the total product set is being produced. However, in particular product specific fixed costs are captured by a dummy variable F_i, whose value is unity whenever positive amounts of product i are produced and zero otherwise. This leads to the following flexible functional form:

$$C=\alpha_0+\sum_i \alpha_i F_i+\sum_i \alpha_i y_i+(1/2)\sum_i\sum_j \alpha_{ij} y_i y_j \qquad (10)$$

The expressions for cost output elasticity; product-specific economies of scale and the degree of economies of scope are similar to those for the quadratic model, and are derived straightforward from those definitions.

Data:

Firm level costs and outputs for 1979 are chosen for 200 public utilities. Of the 200 firms, 131 are solely electrical and outputs for 1979 are solely electric firms, 20 are exclusively natural gas distribution and 49 are engaged in both electricity and natural gas. The data are taken from Statistics of Privately owned Electric Utilities in the U.S. and from Brown's Directory to the North American Natural Gas Companies.

Results and Discussion

The multiproduct cost functions described above are estimated using ordinary least square and results are reported in the following table:

Table 1: Cost-Output Structure of Electricity-Natural Gas Public Utilities *

	Quadratic	FFCG
Intercept	3.77×10^6 (.191)	-1.07×10^8 (-1.08)
F_E	--	1.08×10^8 (1.09)
F_G	--	2.02×10^7 (.602)
Electricity	0.0206 (9.34)	0.02564 (9.04)
Gas	3.15798 (12.13)	3.47271 (7.19)
Electricity^2	1.65×10^{-8} (1.457)	1.84×10^{-8} (1.60)
Gas^2	-.00012 (-2.20)	-.00017 (-2.02)
Interaction	7.26×10^{-6} (2.24)	4.54×10^{-6} (1.15)
F	327.4	233.6
R^2	.894	.895

* t-statistics are in parenthesis.

The results indicate that both models have high explanatory power with coefficients of determination approximately 0.90. Moreover, the output variable coefficients are credible and are mostly significant. The presence of a positive estimate for the quadratic electricity term indicates that for electricity speciality firms, the cost function exhibits convexity.

- The presence of fixed costs generates a region of ray economies of scale. However as output expands, ray economies give way to diseconomies.
- For the gas specialist, the estimations indicate that the cost function is concave, and thereby generates ray economies. Also, the output variable coefficients appear relatively stable with respect to model specification.
- For FFCQ model, incremental fixed costs are estimated to $108 million and $20.2 million for electricity and gas respectively. An F-test on the coefficients of the additional dummy variables in the FFCQ model fails to indicate their statistical significance. Moreover, a test for statistically significant presence of fixed cost economies is rejected in the FFCQ model. Therefore, results based on the quadratic model seem to be very important.

Table 2: Ray Cost Elasticity — Quadratic Cost Function, v *

	0	.005	0.01	0.02	0.03
electricity output (million kWh)					
2,500	.95316	.97987	.99092	.99897	1.0041
5,000	.98754	1.01123	1.01942	1.02234	1.01897
8,800	1.01109	1.03970	1.04818	1.04805	1.03994
10,000	1.01661	1.04732	1.05616	1.05540	1.04600
12,500	1.02685	1.06218	1.07191	1.07005	1.05815
17,600	1.04495	1.08985	1.10157	1.09797	1.08155

v* = ratio of natural gas output (million mcf) to electricity sales (million kWh).

- In table 2, ray cost output elasticities for the quadratic cost function are depicted for output levels and mixes most representative of firms in the sample. The ray cost output elasticities show that at lower levels of output, firms enjoy ray economies $k < 1$, while at large output levels ray diseconomies appear.
- Holding electricity output constant, as the output proportions move from electricity specialization to more gas production, k rises then falls. The decline in k reflects the influence on firm costs of the presence of economies in natural gas operations. These estimates of ray economies can be compared with traditional estimates of economies of scale for the electricity firm.
- Up to this point the possibility of differential factor prices has not been explicitly incorporated into either the quadratic or FCQ models. This type of omission in a statistical cost estimation may be justified on the assumption that factor prices do no vary across cross-sectional data.
- However, price of two primary inputs, labor and fuel, are explicitly included in the cost function estimation. Both P_l and p_f are considered as weighted prices for labor and fuel.

Table 3: Product Specific Economies of Scale

Company	Product Specific Economies of Scale 1979a 1979b
St. Joseph Light & Power	1.004 .216
Iowa Southern	1.005 .292
Missouri Public Service	1.008 .390
Rochester Gas & Electricity	1.021 .657
Iowa Electric L &P	1.013 .524
Wisconsin Public Service	1.022 .650
Atlantic City Electric	1.018 .599
Central Illinois Public Service	1.028 .727
Kansas Gas & Electric	1.025 .680
Northern Indiana PS	1.034 .848
Indianapolis P&L	1.029 .722
Oklahoma G&E	1.063 .904
Niagra Mohawk Power	1.090 1.005
Virginia Electric Power	1.112 1.033
Consolidated Edison	1.086 .991
Detroit Edison	1.112 1.028
Duke Power	1.148 1.092
Commonwealth Edison	1.177 1.138

- The degree of product specific economies of scale for electricity is presented in the above table (table 3). The product specific returns the economies or diseconomies uniquely associated with the product of a single product, given that the firm may produce positive amounts of other products. For both, the quadratic and FFCQ models, the estimates of product specific economies appear to be in closer accord with ray economies of scale estimates for larger rather smaller firms.
- The presence or absence of economies of scope will critically depend upon the signs of parameters on the interaction variable and the constant terms. Estimates of degree of economies and diseconomies of scope provide a useful input in the construction of an appropriate public policy towards multiproduct firms.

Table 4: The Degree of Economies of Scope

Natural Gas Output (million mcf)	Electricity Output					
	1,250	2,500	5,000	8,800	10,000	12,500
50	.0077	-.0033	-.0716	- .0296	-.0322	-.0363
150	-.0060	- .0181	-.0376	-.0591	-.0644	-.0734
300	-.0104	-.0237	-.0468	-.0750	-.0825	-.0965
450	-.0123	-.0263	-.0514	-.0833	-.0920	-.1087
600	-.0135	-.0282	-.0547	-.0892	-.0984	-.1172

From table 4, it is observed that the estimation of the quadratic model indicates that the costs of a joint electricity-natural gas firm that produces 1250 million kWh and distributes 50 million Mcf of natural gas are 0.77 percent lower than having the same output produced by two speciality firms. Similarly, firm costs are 11.7 percent lower for speciality firms producing 12.5 billion kWh and 600 million mcf for a multiproduct firm producing the same output.

The two functions are estimated including labor and fuel prices. The first model (A) allows input prices to enter the model linearly. The second model is estimated with strict input-output separability restrictions and homogeneity in input price conditions. The first two model are presented as

Table 5: The Role of Input Prices in Cost-Output Relationships *

	Model A	Model B **
Intercept	-3.37×10^{8} (-3.3)	-39391 (-.13)
Electricity	0.3601 (23.4)	0.03416 (1.69)
Gas	3.25673 (3.6)	3.14723 (1.57)
Electricity ^{2}	-1.41×10^{8} (-10.7)	-1.185×10^{-8} (1.69)
Gas^2	-.00173 (-4.2)	-.00118 (-1.63)
Interaction	1.76×10^{-5} (3.9)	1.03×10^{-5} (1.65)
P_1	.09210 (1.4)	.3886 (6.13)
P_f	1017.57 (4.2)	.6114 (9.65)
R^2	.874	.966

Notes: t-statistics are in parentheses
* Constraints on input price data availability limited the number of observations in these models to 151 of the original sample firms.
** In order to facilitate comparison with the other model's results, the parameter estimates reported here are for mean values of labor and fuel costs \$14,369 and \$1,646/Btu, respectively.

Here is another form of cost function described as:

$$C=\alpha_0+\sum_i \alpha_i y_i+(1/2)\sum_i \sum_j \alpha_{ij} y_i y_j+\sum_k \beta_k w_k$$

This form sacrifices a desirable property of theoretical and empirical cost functions; namely, linear homogeneity of the cost function with respect to factor prices. However, the model will correct this shortcoming of the model A by imposing strict input-output separability and linear homogeneity in input prices. This is done by retaining the basic quadratic model in outputs.

The general form of the estimated model becomes:

$$C=(\alpha_0+\sum_i\sum_j \alpha_i y_i+(1/2)\sum_i\sum_j \alpha_{ij} y_i y_j).\prod_k \beta_k w_k$$

In table 5, it is observed that the essence of the cost-output estimation is left unaffected by the inclusion of input prices. This finding strengthens the conclusion that cost-output differences between single and multiproduct utilities is due to differences in the competitive environment.

Conclusion

Two cost functions that are capable of identifying the multiproduct nature of firms were estimated. The estimates of ray economies of scale and economies of scope are higher for FFCQ model than for the quadratic model. This is not surprising because the FFCQ model explicitly allows for savings in fixed costs through multiproduct organization. The estimations indicate that natural gas firms are characterized by product-specific economies of scale throughout the relevant output region. Finally, the estimates indicate that there appear to be economies of scope for small firms and those that produce near the output level. However, as multiproduct output grows, the absence of competitive pressure leads to cost-inefficiencies and eventually diseconomies of scope.

IV. Henderson, J. Stephen, " Cost Estimation for Vertically-Integrated Firms: The Case Of Electricity," in *Analyzing the Impact of Regulatory Change in Public Utilities*, edited by Michael A. Crew (Lexington: Lexington Books, 1985), 75-94.

This study examines the cost structure of the electricity industry which generates, transmits and distributes electricity and therefore acts as a vertically-integrated electricity industry. The cost estimates of a vertically-integrated electricity industry and their implications on the market has not been estimated by any statistical procedure. The cost function adopted in this study is suitable for testing the hypothesis that generation is separable from the rest of the electricity delivery system.

Therefore, policy implication of separability in the electricity industry are also discussed. In this paper the author not only examines the scale economies of a vertically-integrated industry but also the separability of the industry cost function.

The cost specification for vertically-integrated firm

An individual firm may obtain the electricity to be delivered to final customers in four ways such as purchase from neighboring utilities and generate power with any of these primary technologies such as hydroelectricity, non-nuclear steam combining all generation technologies together. The generation cost function can be written as:

$$C^{G}(E,P_L,P_K,P_F)=P_L^{G}+P_{KL}^{G}+P_F F^{G} \tag{1}$$

where G denotes generation activity, E is the electrical energy generated, and P_i is the price of a factor of production including labor (L), capital (K), and fuel (F). Therefore, in the first phase of the work, utilities combine labor, capital and fuel to create electricity which is ultimately delivered to customers over the distribution system. In the distribution phase-distinction between the electrical energy injected and electrical energy finally delivered are carried out. However, three production factors such as labor, capital and electrical energy for the generalized distribution phase are distinguished. The distribution cost function is defined as:

$$C^{D}(Y,P_L,P_K,P_E)=P_L^{D}+P_K L^{D} \tag{2}$$

where Y is the delivered electricity output, D denotes distribution activity.

Therefore, the total cost of vertically-integrated firm is:

$$C(Y,P_l,P_K,P_F)=C^{G}(E,P_L,P_K,P_F)+C^{D}(Y,P_L,P_K,P_E) \tag{3}$$

which includes labor, capital, and fuel expenses of generation and labor and capital expenses of distribution.

Two important properties of the cost function, scale economies and separability, are discussed.

Economies of Scale

The utility's overall scale economies can be defined as the percentage difference between average cost (AC) and marginal cost (MC).

$$U=\frac{AC-MC}{AC}=1-\frac{\partial C}{\partial Y}.\frac{y}{c}$$

where U denotes scale economies.

The overall scale economies measure is

$$U=1-M_E^G\eta EY\frac{C^G}{C}-M_Y^D\frac{C^D}{C} \tag{4}$$

The scale economies of each of the two production stages can be defined in terms of ultimate output Y. For the generation phase, scale economies are:

$$U^G=\frac{AC^G-MC^G}{AC^G}=1-M_E^G\eta EY \tag{5}$$

For the distribution stage, scale economies are:

$$U^D=\frac{AC^D-MC^D}{AC^D}=1-M_Y^D \tag{6}$$

Combining (4), (6) yields the following expression for overall scale economies:

$$U=\frac{C^G}{C}U^G+\frac{C^D}{c}U^D \tag{7}$$

This implies that the measure of overall scale economies is the weighted average of the similar measures for generation and distribution separately. This adding up property is the direct result of the distribution cost function and distribution separately.
A shadow cost function with duality properties is defined as:

$$C^1(Y,P_L,P_K,P_E)=P_LL^D+P_KK^D+P_EE \tag{8}$$

where P_E is a shadow price of input electrical energy defined as the marginal cost of generation, $\partial C^G / \partial E$. Note that, it is not the total cost of electricity production unless marginal generation cost happens to equal average generation cost. However, when generation exhibits scale economies, marginal cost is less than average cost, and the shadow cost function is less than total cost.

The utility's overall scale economies is written as:

$$U = 1 - \frac{\partial C^1}{\partial Y}\frac{Y}{C^1}\frac{C^1}{C} = 1 - M_x^1 \frac{C^1}{C} \tag{9}$$

Likewise, the economies associated with the distribution phase are:

$$U^D = 1 - \frac{\partial C^D}{\partial Y}\frac{Y}{C^D} = 1 - \frac{\partial C^1}{\partial Y} - P_E \frac{\partial E}{\partial Y}\frac{Y}{C^D} = 1 - M_Y^1 \frac{C^1}{C^D} + \frac{P_E E}{C^D} \eta EY \tag{10}$$

Equation (10) depicts that distribution economies cannot be estimated simply as those associated with shadow cost function. However, using Shephard's Lemma one can have simpler expression for equation (10) such as:

$$\frac{\partial C^1}{\partial P_E} = E$$

and consequently,

$$\eta EY + \frac{\partial E}{\partial Y}\frac{y}{E} = C_{Ey}^1 \frac{y}{E} = \frac{M_{YE}^1 + M_E^1 M_Y^1}{M_E^1} \tag{11}$$

where the last step involves the customary relationship between second partial derivatives of cost functions and second partial logarithmic derivatives of such cost function. Substituting (11) into (10) we have:

$$U^{D}=1-M_{Y}^{1}+M_{YE}^{1}\frac{C^{1}}{C^{D}} \tag{12}$$

Therefore, distribution economies are not equal to those of the shadow cost function alone. The first term in equation (12) corrects the shadow cost scale measure (l-M ' y) for purchased electricity expenditures which appear as part of shadow costs but not as part of distribution costs. If M^1_{YE} is positive, then utilities that must pay more for input electricity have costs that exhibit greater sensitivity to output. Hence, the shadow cost function has the advantage that it is a complete cost function with all three factors of production including the raw material, energy. If the shadow cost function can be written as a separable cost function, then generation is separable from the labor and capital of the distribution phase. So the shadow cost function can be written as:

$$C^{1}(Y,P_{L},P_{K},P_{E})=C^{1}[(y,P_{L},P_{K}),P_{E}] \tag{13}$$

which shows that generation is separable from the labor and capital in the distribution phase. The translog cost function used later provides a suitable way of testing the underlying hypothesis.

Cost Estimation

Any flexible functional form can be used to estimate the cost of electricity. In general, a translog cost function can be written as:

$$\begin{aligned} lnC&=g_{0}+g_{y}lnY+1/2g_{yy}(\ln=y)^{2}+\sum g_{yi}\ln YlnP_{i}+\sum_{i} g_{i}lnP_{i}+ \\ &1/2\sum_{i}\sum_{j} g_{ij}lnP_{i}lnP_{j}+gzlnz+1/2g_{zz}(lnZ)^{2}+g_{yz}\ln y.lnz \end{aligned} \tag{14}$$

where i and j are equal to L, K and either F or E, $g_{ij}=g_{ji}$, C is cost, Y is output, P is the price of factor i and Z is an exogenous determinant. The cost function must be homogeneous of degree one in prices so that cost increases proportionately to an increase in all factor prices. The following restrictions are applied:

$$\sum g_{i}=1,\quad \sum G_{yi},\quad \sum_{i} g_{ij}=0 \quad \textit{for all } j$$

Using Shephard Lemma, the cost share equation is obtained from the cost function is:

$$S_{i}=\frac{\partial lnC}{\partial P_{i}}=g_{i}+g_{yi}lny+\sum_{j} g_{ij}lnP_{j} \tag{15}$$

Allen partial elasticities of substitution are expressed as:

$$\delta_{ii}=(g_{ii}+S_i^2-S_i)/S_i \qquad for \quad all \quad i$$

The scale economy measure is

$$\delta_{ij}=(g_{ij}+S_{iS_j})/S_iS_j \qquad for \quad all \quad i=j$$

$$U = 1 - M$$

$$=1-(g_y+G_{yy}lny+\sum_i g_{yi}p_i+g_{yz}\ln Z)$$

For the shadow cost function, the separability conditions can be written as:

$$S_LgKE=S_KgLE; \qquad S_LgYE=S_ygYL; \qquad S_KgYE=S_ygYK$$

When a linear restriction is applied (as pointed out by Berdt and Wood (1975), the above separability condition can be written as:

$$gKE = gLE = gYE = 0 \tag{16}$$

The intuition of presenting this condition is that if equation (16) is satisfied, the price of purchased electricity does not interact with any other factor price or output. Consequently, it is independent of them, and optimal production decisions regarding labor and capital can be segmented from those involving purchased electricity. The estimation of actual cost function is done in two ways. First, the long-run marginal cost of purchased electricity was estimated. The electrical output of the first production phase, which is the quantity of input energy for the subsequent distribution phase, was assumed to come from three sources: non-nuclear steam generation, hydrogeneration, and power purchased from neighboring utilities. A translog cost function and share equation system was estimated for steam generation with three factors of production such as: capital, labor, and fuel. A separate, two-factor (labor and capital) translog system was estimated for hydrogeneration. The marginal cost of non-nuclear steam and hydrogeneration was then estimated as the derivative of the respective, estimated cost function. The estimated marginal cost of generation was the imputed transfer price used to value the input energy of the distribution phase. This shadow cost function, having three factors — labor, capital, and energy — and its associated factor share equations are estimated as a translog system.

Data

The data for this study was a 1970 cross-section of 160 class A and class B investor-owned electric companies.

These were mostly-integrated utilities, although a few firms that mostly provide distribution services were also included if a good estimate of the imputed shadow price could be obtained. Different subsets were used in the steam and hydrogenerated cost estimation. The entire sample was included in the shadow cost function.

Results and Discussion

It is observed that scale economies have been exhausted for generating plants. Empirical measures of distribution economies can differ dramatically depending on the input factors included within the distribution sector. The average scale economies for the distribution and transmission parts of the firm were 17.7 percent. This has been computed as the average of the measure for each firm, using the factor prices prevailing for each. Thus, the average cost of transporting electricity is about 17.7 percent higher than the long-run marginal cost. This is substantially larger than the scale effects found for steam or hydrogeneration.

Conclusion

The statistical findings confirmed that the distribution network has substantial economies of scale. This suggests that distribution strongly displays the characteristics of a natural monopoly. The results also reject strongly the hypothesis that distribution and generation are functionally separable. Consequently, the price of obtaining input electrical energy does matter in the optimal design of the distribution networks. Both of these findings bear the question of how best the electric industry can be organized. The existence of a functional dependency between production stages tends to favor a vertically-integrated firm to the extent that it reduces the transactions costs of dealing with the uncertainty about the transfer price.

V. Chappell, Jr., Henry W., and Ronald P. Wilder, " Multiproduct Monopoly, Regulated, and Firms Costs: Comments," *Southern Economic Journal*, No, 52 (1986): 1168-1174.

The authors have used the model developed by Mayo with different data sets with some modification of the model. They pointed out that accurate information about the presence or absence of economies of scale and scope would be of particular interest for regulators of the "supposed" natural monopolies. They argue that given such information, regulators could in principle prescribe the set products to be produced by a regulated firm, as well as the scale of its operations, in order to enhance productive efficiency.

Modifying Mayo's Model:

For the estimation of long run cost functions, one should use observations over which a common technology is in use. Therefore, for electric utilities it is potentially important to distinguish those firms using fossil fuel versus nuclear technologies in generation. Mayo's results suggest that there exits diseconomies of scale and scope which might be the result of X-inefficiency by larger firms. However, this study concludes that given the prevalence of nuclear generation for larger firms, it would seem likely that this result could simply be an artifact of higher ex post costs of nuclear versus non-nuclear generation.

The data set for this study consists of cost and output data for 88 electric utilities, 51 combination electric-gas utilities, and 18 natural gas distributors for 1981.

Mutiproduct Cost Functions

This study follows Mayo's quadratic specification of total cost function. The study assumes constant input prices for all firms in the sample, only two outputs will appear on the right-hand side:

$$C = \beta_0 + \beta_1 y_1 + \beta_2 y_2 + \beta_{12} y_1 y_2.$$

The authors are interested in computing values for important multiproduct cost concepts, including the degree of overall (multiproduct) economies of scale, the degree of economies of scope, and degree of product-specific economies of scale.

For a two output model, the degree of overall economies of scale can be interpreted as the reciprocal of the elasticity of total cost with respect to a proportionate increase in all outputs and is computed as:

$$S_N = C(y_1, y_2)/(C_1 y_1 + C_2 y_2)$$

where C_i represents the marginal cost of product i. Values of S_N greater than one indicate economies of scale, while values less than one indicate diseconomies of scale.

The degree of economies of scope measures relative cost savings from joint rather than separate production. The degree of economies of scope for a two output cost function is given by:

$$S_c = [C(y_1,0) + C(0,y_2) - C(y)]/C(y_1,y_2)$$

Positive values of S_c indicate economies of scope, negative values indicate diseconomies.
To find product-specific economies of scale may then be defined as:

$$S_i = AIC_i/Ci$$

Product-specific economies or diseconomies of scale exist when S_i is respectively greater or less than one.

The authors use cross-sectional data and interpret the estimated relationships as long run cost functions.

Table 1: Cost Functions for Electric-Gas Utilities
(Dependent Variable: Total Cost)

Variable	Complete Sample *	Fossil Fuel Sub-sample
INTERCEPTS	81.5202 (3.0604)	50.0893 (1.5842)
YGAS	3.5389 (5.8416)	3.8037 (4.3893)
YEL	0.5182 (14.0060)	0.5944 (12.2209)
YGAS*YGAS	-4.3677×10^{-3} (-1.3719)	-2.5234×10^{-3} (-.5922)
YEL*YEL	1.4873×10^{-3} (1.8367)	-9.6014×10^{-6} (.8258)
YGAS*YEL	1.1171×10^{-3} (4.8658)	1.6026×10^{-4} (.2828)
R^2	0.9538	0.8975

* t-statistics are in parenthesis

Table 2: Multiproduct Cost Measures (Complete Sample)

Electricity Output	Gas Output				
	37.5	75	150	300	600
	Degree of Multiproduct of Economies of Scale				
375	1.19940	1.15195	1.17444	1.47819	-3.37148
750	1.08133	1.04668	1.04617	1.18157	3.93515
1500	0.99208	0.95956	0.93754	0.97104	1.33543
3000	0.92167	0.89017	0.85555	0.83824	0.89824
6000	0.85445	0.82746	0.79142	0.75563	0.74084
	Degree of Economies of Scope				
375	0.15661	0.09106	0.02416	-0.04118	-0.15721
750	0.07871	0.02388	-0.04259	-0.12144	-0.27488
1500	0.01727	-0.03507	-0.10774	-0.20410	-0.37730
3000	-0.02183	-0.07507	-0.15569	-0.26825	-0.44537
6000	-0.04138	-0.09423	-0.17890	-0.30118	-0.47477
	Degree of Product-Specific Economies of Scale- Gas				
375	1.04512	1.09918	1.24746	1.97992	-1.04183
750	1.04045	1.09902	1.21366	1.74616	-2.03119
1500	1.03351	1.07185	1.16781	1.50515	-97.04195
3000	1.02496	1.05254	1.11741	1.30690	2.58930
6000	1.01651	1.03417	1.07335	1.17194	1.52410
	Degree of Product-Specific Economies of Scale- Electricity				
375	0.99023	0.99090	0.99200	0.99355	0.99535
750	0.98085	0.98213	0.98425	0.98726	0.99079
1500	0.96311	0.96550	0.96946	0.97516	0.98191
3000	0.93129	0.93545	0.94243	0.95266	0.96508
6000	0.87918	0.89566	0.89675	0.91352	0.93472

Table 3: Multiproduct Cost Measures (Fossil Fuel Generating Subsample)

	Gas Output				
Electricity output	37.5	75	150	300	600
375	1.14638	1.12575	1.14269	1.27622	2.21923
750	1.09409	1.08546	1.10154	1.20648	1.85371
1500	1.06610	1.05945	1.06709	1.13497	1.52170
3000	1.06848	1.05911	1.05478	1.08484	1.28517
6000	1.11783	1.10311	1.08515	1.08079	1.16181
	Degree of Economies of Scope				
375	0.11583	0.08330	0.05170	0.02664	0.00834
750	0.07189	0.05330	0.03136	0.00974	-0.01138
1500	0.03845	0.02651	-0.00944	-0.03356	-0.06992
3000	0.01684	0.00683	-0.00944	-0.03356	-0.06992
6000	0.00407	-0.00609	-0.02396	-0.05329	-0.10090
	Degree of Product-Specific Economies of Scale- Gas				
375	1.02575	1.05430	1.12183	1.32217	2.81162
750	1.02534	1.05338	1.11952	1.31413	2.69009
1500	1.02455	1.05163	1.11515	1.29921	2.49016
3000	1.02311	1.04845	1.10730	1.27325	2.20504
6000	1.02068	1.04314	1.09443	1.23283	1.87154
	Degree of Product-Specific Economies of Scale - Electricity				
375	1.00607	1.00601	1.00589	1.00566	1.00527
750	1.01229	1.01216	1.01192	1.01146	1.01065
1500	1.02520	1.02493	1.02443	1.02347	1.02176
3000	1.05307	1.05249	1.05136	1.04925	1.04551
6000	1.11874	1.11728	1.11448	1.01926	1.10013

The estimated marginal cost for gas are found to be extremely small or negative for some output combinations. From table 2, some of these results presented are peculiar estimates for product-specific economies of scale for gas (at high gas outputs).

A restriction is imposed by not using nuclear power as a major means of generating electricity. Some companies produce more than 10 percent of their generated electricity by nonfossil-fuel technologies. Regression results are reported in the second column of table 1 and multiproduct cost measures are presented in Table 3.

Some important differences are observed from results reported earlier. First, both specifications indicate that multiproduct economies of scale persist almost throughout the relative range of outputs. Second, there are product-specific economies of scale for the relevant range of outputs. Finally, economies of scope prevail over most of the range of outputs. Because results indicate that both economies of scope and product-specific economies of scale (for all outputs) prevail over the relevant range of outputs, the cost function is subadditive over that range. However, subadditivity implies that a single firm could most efficiently produce for that range of outputs. That means natural monopoly prevails for most electric-gas utilities.

Conclusion:

The results indicate that electric-gas utilities could be natural monopolies. The authors conclude that Mayo's estimated diseconomies of scale and scope primarily reflect the higher ex post costs of nuclear technology.

VI. Roberts, Mark J., "Economies of Density and Size in the Production and Delivery of Electric Power" *Land Economics* Vol. 62, No. 4 (November 1986): 379-387.

Economies of density and size in the electricity industry production process are specified and documented in this paper. The possible existence of scale economies in the transmission and distribution of electricity are assumed, as a result, many economists argue that all or some of the components of the delivery system need to be regulated regardless of any regulatory changes at the generation stage. However, the problem with analyzing scale effects in transmission and distribution was ignored. This study has analyzed scale effects in industries that deliver a product to a spatially dispersed group of consumers and where output expansion is likely to take place.

This paper develops three measures of economies of density and size which help to analyze the cost structure of electricity firms. The firms are considered to serve their output to geographically dispersed customers. The measures are used to analyze differences in the average cost of supplying electric power among firms. The density and size in the production are estimated using translog flexible functional form.

Cost Function for the Production and Delivery of Electric Power

The cost function used for this study identifies that the number of customers and the size of the firm's service area influence the firm's choice of inputs and thus the cost of supplying electricity. The cost function developed here has taken this into consideration for the measurement of scale economies. The empirical model aims to explain the firm's cost of supplying power to final customers. The firm's transformation function for electricity production and delivery is represented by:

$$T(K_G,F_G,M_G,E_P,K_T,K_D,M_D,Q_L,Q_H)=0 \tag{1}$$

where K_G, F_G, and M_G are the quantities of capital services, fuel, and labor used in generation. E_p is the quantity of electricity purchased from other utilities. K_T and K_D are quantities of capital services used in transmission and distribution networks. MD is labor input in the distribution system and Q_L and Q_H are quantities of low-voltage and high voltage kWh delivered to final consumers. The above transformation function can be considered as a separable cost function which can be written as:

$$T(E_1,(K_G,F_G,M_G,E_P),K_T,K_D,M_D,Q_L,Q_H)=0 \tag{2}$$

where the E_1, subfunction represents the firm's accumulation of the kWhs it will deliver.
With the above production-separable transformation function (2), the firm is able to make input decision in two stages. In the first stage, the quantities of K_G, F_G, M_G and E_P are chosen to minimize the cost of producing the kWh. In the second stage, the firm chooses E, K_T, K_D, and M_D to minimize the cost of producing, low-voltage and high-voltage deliveries Q_L and Q_H. The first stage gives rise to a cost function as:

$$C^1(P_{KG},P_{FG},P_{MG},P_{EP},E_P)$$

where P_{KG}, P_{FG}, P_{MG}, and P_{EP} are the prices of generation, capital, fuel, labor, and purchased power, respectively.

The firm's total cost of supplying electricity can be denoted by a mutiproduct cost function which is given by:

$$C(P_1,P_T,P_D,P_M,Q_L,Q_H,A,N) \tag{3}$$

where P_1, P_T, P_D, and P_M are prices of the kWh input, transmissions and distribution capital, and labor, respectively.

A is the square miles of service area and N is the total number of customers. This cost function has several uncommon characteristics which are described in the following fashion. First, electric utilities are vertically-integrated firms with generation, transmission and distribution components. This helps the cost function recognizes that substitution can occur among all three stages of production. Second, because a firm's demand can vary depending on the service area characteristics, the cost model is able to distinguish between transmission and distribution capital. Third, low and high voltage deliveries of power are considered as separate products. Utilities with a large proportion of low voltage deliveries will tend to serve residential and commercial customers and have larger demands for capital. On the other hand, the high-voltage deliveries tend to be sales to industrial customers and other utilities and increase the firm's demand for transmission capital. However, input demands and cost are sensitive to the firm's mix of outputs. This study tries to test if the distribution function is separate from generation and transmission. The cost function is written as a separable function as:

$$C(P_1,P_T,Q_H,C_D(P_D,P_M,Q_L,A,N)$$

where C_D is the distribution cost function.

If the hypothesis is rejected, it is not possible to study the distribution system independent of the transmission and generation system because of changes in the price of generated power or transmission capital effects.

<u>Economies of Density and Size</u>

The measures of economies of density and size examine cost impacts of modifying output holding both the number of customers and size of the service area fixed. The elasticities of total cost with respect to low-voltage and high-voltage output are defined respectively as:

$$\epsilon_L = \frac{\partial lnC}{\partial lnQ_L}; \qquad \epsilon_H = \frac{\partial lnC}{\partial lnQ_H}$$

A measure of economies of output density is defined,

$$R_{CD} = \frac{1}{\epsilon_L + \epsilon_H}$$

as measures of the cost effect of an equal proportional increase in both low and high voltage outputs.

The term output density identifies the level of output per customer which is allowed to change. R_{QD} is the relevant measure of economies which arise when there is an increased demand for power from a fixed number of customers in a fixed service area.

Holding total output fixed, the effect of changing customer density on cost is measured by the elasticity:

$$\epsilon_N = \frac{lnC}{\partial lnN}$$

If both the numbers of customers and quantities of output increase, economies of customer density increase while output per customer are held constant. This is measured by:

$$R_{CD} = \frac{1}{\epsilon_L + \epsilon_H + \epsilon_N}$$

where R_{CD} is both the fixed size of the service area and output per customer. It is the appropriate measure for examining the cost of producing and delivering more power to a fixed service area as it becomes more densely populated. The change in cost as a result of increasing the size of the firm's service area, holding the level of output and number of customers fixed, is measured by the elasticity

$$\epsilon_A = \frac{lnC}{\partial lnA}$$

Holding the customer density and output per customer fixed and by allowing the service area to increase, a useful measure of economies of size can be defined as:

$$R_{CD}=\frac{1}{\epsilon_L+\epsilon_H+\epsilon_N+\epsilon_A}$$

The Empirical Model And Data

Because estimates of economies of size and density are estimated using the estimates of cost elasticities, a parametric version of the production and delivery cost function is developed for this study. The cost function is a translog approximation represented by:

$$lnC+\beta_o+\sum_i\beta_i lnP_i+1/2\sum_i\sum_j lnP_i lnP_j+$$

$$1/2\sum_i\sum_j\gamma_{ik}lnP_i lnZ_k\sum_i\beta lnZ_i+1/2\sum_h\sum_k\gamma_{hk}\ln Z_h lnZ_k \tag{4}$$

where i,j = I,T,D,M; h,k = L,H,A,N; Z_K = QL,QH,A,N

The cost share equation is estimated from the translog cost function using Shephard Lemma. The complete estimating model consists of the cost equation and four share equations. Since the authors are interested in elasticities, four cost elasticities are estimated as:

$$\epsilon_A=\beta_A+\sum_i\gamma_{iA}lnP_i+\gamma_{LA}lnQ_L+\gamma_{HA}lnQ_H+\gamma_{AA}lnA+\gamma_{AN}\ln N$$

$$\epsilon_H=\beta_H+\sum_i\gamma_{iH}lnP_i+\gamma_{LH}lnQ_L+\gamma_{HH}lnQ_H+\gamma_{HA}lnA+\gamma_{HN}\ln N$$

$$\epsilon_L=\beta_L+\sum_i\gamma_{iL}lnP_i+\gamma_{LL}lnQ_L+\gamma_{LH}lnQ_H+\gamma_{LA}lnA+\gamma_{LN}\ln N$$

$$\epsilon_N=\beta_H+\sum_i\gamma_{\epsilon}lnP_i+\gamma_{LN}lnQ_L+\gamma_{HN}lnQ_H+\gamma_{AN}lnA+\gamma_{NN}\ln N$$

where i = I, T, D, M

Each estimated elasticity is a function of input prices, inputs, and service area characteristics. Each data series is scaled by its sample mean and the parameters β_L, β_H, β_N, β_A represent the elasticities of a hypothetical firm which faces the average input prices, outputs, and service area characteristics for the sample.

The data set used for estimating the cost function is of privately owned vertically-integrated electric utilities in 1978. The important data include the prices and quantities of kWh input, transmission and distribution capital and labor, as well as the quantity of output delivered to both customer groups, number of customers, and square miles of service area for each utility. The average cost of privately own-generated power is constructed by calculating the firm's expenditures on generation capital, labor, and fuel and dividing the sum by kWh's of net generation. The price of kWh input is a weighted average of the average cost of the two types of kWh where the weights are quantity shares. Firm output includes all deliveries of power to other utilities as to final consumers. Total number of customers is constructed as the sum of the number of residential, commercial, and industrial customers reported in the statistics.

Results and Discussion

• The hypothesis that the distribution system can be studied independently of the generation and transmission systems can be tested by requiring that distribution inputs be separated from generation and transmission inputs. Separability of the distribution function is rejected with a 2 percent-test statistic of 169.0, which exceeds the critical value at the 0.01 significance level. This implies that dividing the firm into separate production stages is an inaccurate starting point for the estimation of the production structure.

• Here we only discuss the results pertaining to economies of density and size. These are reported in the following table:

Estimated Cost Elasticities, Economies of Density, and Economies of Size

	Mean	Sample Range
Economies of Output Density		
ϵ_L	0.434 (0.038)*	0.047 to 0.781
ϵ_H	0.391 (0.015)	0.080 to 0.764
Economies of Customer Density		
ϵ_N	1.212 (0.58)	1.089 to 1.501
R_{CD}	1.014 (.009)	0.957 to 1.113
Economies of Size		
ϵ_A	-.005 (.007)	-.021 to .013
R_s	1.019 (0.010)	.968 - 1.122

* Standard errors are reported in the parenthesis.

- **Economies of Output Density**

Estimated mean values of ϵ_H and ϵ_L indicate that a one percent increase in output to residential and industrial customers, holding the number of customers and service area fixed, raises cost by .434 percent and 0.391 percent, respectively. On average, a one percent expansion in output raises total cost by 0.825 percent and reduces ray average cost by 0.175 percent.

The mean value of R_{QD} equals 1.212 which reveals that there are fairly substantial economies of output density. In addition, every sample firm has a value of R_{QD} which exceeds one. The hypothesis that there are no economies of output density is tested by restricting the sum of ϵ_L and ϵ_H to equal one for all firms. The hypothesis is rejected at the .01 significance level with a X^2-test statistics of 40.11.

- **Economies of Customer Density**

The results presented in the table indicate that the elasticity of cost with respect to the number of customers served ϵ_N equals 0.161 when evaluated at the sample means of the data. The hypothesis that ϵ_N equals zero for all firms is rejected with a test statistic of 40.45. The fact that ϵ_N is positive but less than one for all sample firms implies that distributing a fixed amount of output over a larger number of customers lowers the average cost per customer but raises the average cost per unit of output.

The average estimate of economies of customer density R_{CD} equals 1.014, which indicates only a very slight reduction in ray average cost resulting from increases in output used to serve an increased number of customers. Within the sample R_{CD} varies from 0.957 to 1.113 with 80 percent of firms between 0.98 and 1.05.

To test the hypothesis that there are no economies of customer density, the sum of ϵ_L, ϵ_H, and ϵ_N is restricted to equal one at every observation. The test statistic equals 23.28, which exceeds the 0.01 critical value of 20.09. While the hypothesis and economies of customer density is rejected, the estimated values indicate that increased customer density would not result in substantial reductions in ray average cost for most sample firms.

R_{CD} captures a movement along the ray average cost curve as output rises, a shift in the ray average cost curve as output rises, and a shift in the ray average cost curve as the number of customers rises. A one percent increase in both outputs reduces ray average cost by 0.175 percent. A corresponding one percent increase in the number of customers shifts the average cost curve up by 0.161 percent. On average the net effect of the two is close to zero indicating roughly constant ray average cost.

- **Economies of Size**:

Economies of size R_S are reported in the above table. On average ϵ_A equals -.005 with a sample range -021 to .013. The hypothesis that ϵ_A equals zero for a firm cannot be rejected at the usual significance level. Overall, the size of the service area has no significant effect on the cost of delivering electricity.

The test statistic of 17.59 leads to a rejection of the hypothesis at the .05 significance level but not at the .01 percent level. There is no strong evidence that larger service areas result in any economies in power delivery.

Conclusion

The findings discussed in the paper indicate that there would be efficiency losses if individual customers were served by more than one utility. However, natural monopoly arguments are insufficient to justify expansion of an existing firm into newly developing communities. Rather, the possibility of competitive bidding for the right to provide service to newly developing or expanding areas does not appear to be ruled by the nature of the technology. In addition, territorial assignments which prevent competition among companies at the borders of their service areas would not appear to result in efficiency gains. The methodology applied in this paper can be applied in the study of distribution activities of other utilities company.

VII. Sing, Merrile, "Are Combination Gas and Electric Utilities Multiproduct Natural Monopolies?" ***Review of Economics and Statistics*** **(1987): 392-398**

This paper examines scope and scale economies in gas and electric utility industries to determine whether these services are more efficiently supplied combination gas and electric utilities or by separate utilities. A model of firm behavior is developed from multiproduct cost theory, and cost functions are estimated with price and cost variables.

Gas and electric utilities are uniquely suitable for multiproduct empirical analysis. Output are homogeneous across firms. Single product suppliers are present for all products in the output vector of the multiproduct firm.

A multiproduct cost function for a cross section of 108 combination and separate gas and electric utilities using 1981 data is estimated.

The Model

The cost structure of electric and gas utilities is described as:

$$C = f(Y,P,D) \tag{1}$$

where

C = total costs
Y = output vector
P = input price vector
D = distribution cost ratio (customers per square of service area)

Two assumptions about firm behavior are incorporated in this cost function:
(i) firms face exogenous output bundles and input prices, and are subject to a given technology. This is consistent with energy utility operations.
(ii) firms employ input levels that minimize production costs.
— This states that there is no Averch-Johnson effect.

A necessary and sufficient condition for a natural monopoly is a subadditive cost function. A multiproduct cost function $C(Y_1,Y_2)$ is subadditive if:

$$\Sigma\, C(a_iY_1,\, b_jY_2) > C(Y_1,Y_2) \qquad i,j = 1,\ldots.n \tag{2}$$

$$\Sigma a_i = 1 \;\; \Sigma b_j = 1$$

for at least two a_i or b_j not equal to zero.

Economies of scope are necessary condition for subadditivity. Economies of scope are present when the cost of producing the two products jointly is less than the cost of producing them separately. Economies of scope are present if the multiproduct cost function $C(Y_1,Y_2)$ exhibits orthogonal subadditivity:

$$C(Y_1,Y_2) < C(Y_1,0) + C(0,Y_2) \tag{3}$$

Overall economies of scope are present if

$$C(Y_1,Y_2) < C_1(Y_1) + C_2(Y_2) \tag{4}$$

where $C_1(Y_1)$ and $C_2(Y_2)$ are single-product cost functions.

- Cost complementarities or the presence of both economies of scope and product-specific economies of scale for each product at all output levels up to a given level are sufficient conditions for subadditivity.
- Cost complementarities present are sufficient conditions for subadditivity. Cost complementarities are present when the marginal cost of producing one product decreases when the quantity of other product is increased.
- Product-specific economies of scale indicate that the behavior of costs as on output level is changed while the output levels of the other products are held constant. For the two product case the product-specific economies of scale for product one, S_1, is:

$$S_i = \frac{C(Y_1,Y_2) - C(0,Y_2)}{Y_1(\partial C/\partial Y_1)} \tag{5}$$

and similarly for product two. S_1 is the ratio of average to marginal cost at Y_1. When $S_1 > 1$ i.e, when average incremental costs are greater(less than marginal costs, there are increasing (decreasing) returns to scale with respect to product one.

- If economies of scope are found in conjunction with product-specific economies of scale, then joint supply is a natural monopoly.
- If economies of scope are not present, then joint supply of electricity and gas is not a natural monopoly.
- If economies of scope are present, but product-specific economies of scale are not, nothing can be concluded about subadditivity.

Scope and Scale Economies

Economies of scope, a necessary condition for subadditivity, are examined by comparing fitted costs of joints suppliers to separate suppliers with the estimated multiproduct hybrid translog function coefficients.

Table 1: Fitted Multiproduct Cost Minus Fitted Single Product Costs

Output of Electricity	Output of Gas			
	0	300	429	600
0		122 125	174 178	243 244
7000	403 398		49 50	
9344	527 551	-54 -81	5 -23	58 33
11242	626 675	-105 -157		25 -25
13000	717 788			
15000	820 913		-134 -231	
25000	1325 1494			
59073	2991 2979			

Output of Electricity	Output of Gas			
	788	900	5000	8125
0	320 316	365 357	2075 1568	3417 2294
7000	116 125			
9344			-260 223	
11242	74 29		-175 283	
13000		73 10		
15000	9 -80			
25000	-221 -386			
59073				-12 1123

* Negative values indicate scope economies.

The degree of product-specific economies of scope, SC_i measures the proportional increase or decrease in cost from independent supply of electricity and gas:

$$SC_i = \frac{C(Y_1,0) + C(0,Y_2) - (y_1,Y_2)}{C(Y_1,Y_2)} \tag{6}$$

• In the above table, both scope economies and scope diseconomies are noted. At the mean output vector for combination utilities, $(Y_e,Y_g) =$ (11242.1, 787.759) economies of scope are not present. Thus, mean combination of gas and electric utility is not a natural monopoly. The authors also tested for cost complementarities, a sufficient condition for subadditivity.
• The degree of product-specific economies of scope (SC_j), measures the proportional increase or decrease in cost from independent supply of electricity and gas. SC_j is -0.072 at the combination utility mean output vector, suggesting that costs for the average combination utility mean output vector could be decreased by 7.2 percent if electricity and gas are supplied separately.
One possible explanation for the absence of economies of scope despite the presence of shared inputs and shared intangible assets is that combination utilities provide higher quality services.
• At the mean combination of utility output vector product-specific economies of scale are present for electricity ($S_e =$ 1.66) but not for gas ($S_g = 0.80$)

It is concluded that benefits from competition between two regulated energy utilities are substantially greater than the costs of corporate reorganization.

VIII. Krautmann, A.C., and John L. Solow, "Economies of Scale in Nuclear Generation," *Southern Economic Journal*, No. 55 (July 1988): 70-85.

This paper focuses on the scale economies in nuclear power generation as economies of scale are crucial consideration in addressing nuclear power costs. The authors argue that the straightforward application of Christensen and Greene's techniques to nuclear power creates problem. The reasons are:

(i) Cristensen and Greene model deals with a long-run cost function which takes as its arguments prices of capital services, labor and fuel but there is little scope for adjusting capital stock to changing relative prices. Therefore, the assumptions that underlie the long-run analysis does not seem valid in the case of nuclear power generation. They argue that it seems more reasonable to assume that plants are in static equilibrium with respect to those inputs that can be varied in the short-run, conditional on the value of capital stock. The authors thus estimate a restricted cost function. The properties of the long run cost function can be recovered from the restricted production function.

(ii) The process of generating electricity from nuclear power is stochastic. Output that will be produced from a given set of inputs is uncertain ex ante. The regulatory environment for plants is also uncertain.

Model Specification

A general production function of electric output(Y) is described as

$$Y = f(K,L,F,\theta) \tag{1}$$

where K is capital services, L is labor and F is fuel and θ captures the whole range of technological, regulatory and other uncertainties regarding the production function.
A dual to the stochastic cost function is given as

$$TC = g(P_K, P_L, P_F, \hat{Y}) \tag{2}$$

where P_i dentes the price of input i and Y denotes the expected output (i=K,L,F).

If capital inputs are not variable in the short run and costs are minimized with respect to inputs conditional on capital and expected output, then there exists a variable or restricted cost function duel to the stochastic variable.

$$VC = h(P_L, P_F, \hat{Y}) \tag{3}$$

where VC is variable costs.

The model is specified along the translog cost function with an addition of error term ϵ_c

$$\begin{aligned}\ln VC = {} & \alpha_0 + \alpha_Y \ln\hat{Y} + \tfrac{1}{2}\beta_{YY}(\ln\hat{Y})^2 + \sum_{i=L,F} \alpha_i \ln p_i \\ & + \tfrac{1}{2}\sum_{i=L,K}\sum_{j=L,K} \beta_{ij} lnP_i lnP_j + \alpha_k \ln K \\ & + \tfrac{1}{2}\beta_{kk}(lnK)^2 + \sum_{i=L,F} \gamma_{Y_i}\ln\hat{Y} lnP_i + \sum_{i=L,F} \gamma_{ki} lnK lnP_i \\ & + \gamma_{YK}\ln\hat{Y} lnK + \eta_V V + \epsilon_C\end{aligned} \tag{4}$$

where independent variable V, vintage of the plant is included to allow embodied technical change. Using Shepard's lemma, the shares of the inputs used in variable cost function are derived as:

$$S_L = \alpha_L + \sum_{i=L,F} \beta_{Li}\ln P_i + \gamma_{YL}\ln\hat{Y} + \gamma_{KL}\ln K + \varepsilon_L \tag{5}$$

$$S_F = \alpha_F + \sum_{i=L,F} \beta_{Fi}\ln P_i + \gamma_{YF}\ln\hat{Y} + \gamma_{KF} lnK + \varepsilon_F \tag{6}$$

where S_i denotes the cost shares of input i in variable costs. Equations (4), (5) and (6) are used to estimate the parameters of the variable cost function, from which the long run cost function will be derived.

Scale Economies

A measure of scale economies, defined as the proportional increase in output resulting from a proportional increase in all inputs (variable and fixed) is given by (1);

$$SCE = \frac{(1 - \partial lnVC/\partial lnK)}{(\partial lnVC/\partial \ln\hat{Y})} \tag{7}$$

To measure economies of scale along the long-run expansion path, the derivatives in equation (5) must be evaluated at the long-run equilibrium for given input prices and expected output, which help to get the optimal capital stock (K*) implied prices and output. K* is given by

$$K^* = \arg\min TC \tag{8}$$

where TC denotes total cost curve and

$$TC = VC(P_L, P_F, K, \hat{Y}) + P_K K \tag{9}$$

Numerical methods can be used to find the optimal K for any set of prices and expected output, which can then be used to evaluate long-run scale economies.

The envelop of the short-run average cost functions gives the long-run average cost curve. Short-run average total cost can be calculated from equation (9). This requires a measure of the price of capital services.

Economies of Scale along the long-run cost function can be measured using equation (5), which for the translog specification evaluated at mean prices and vintage, is:

$$SCE=\frac{(1-\alpha_k-\beta_{KK}lnK^*-\gamma_{YK}lnY)}{(\alpha_Y+\beta_{YY}lnY+\gamma_{YK}lnK^*)} \tag{10}$$

To evaluate (10) at some output, optimal capital stock should be calculated. Optimal capital stock is a function of output and all input prices. This is done by numerically calculating the value of K that minimizes total costs as given by (7) and (8).

Economies of scale along the long-run cost function can be measured using the equation (9), which, for the translog specification evaluated at mean prices and vintage, implies:

$$SCE=(1-\alpha_K-\beta_{KK}lnK^*-\gamma_{YK}LnY)/(\alpha_K+\beta_{YY}lnK^*+\gamma_{YK}InK^*) \tag{11}$$

Results

Estimates of SCE for several outputs are presented in the following table:

Table 1: Estimated Scale Economies (SCE)

Expected output (GWh)	Model I (all plants)	Model II Single	Model II Dual
3,000	0.458 (0.440)[1]	0.553 (0.518)	-
4,500	-	0.608 (0.291)	-
6,000	0.951 (0.182)	0.652 (0.329)	1.723 (2.148)
9,000	-	-	1.828 (0.716)
12,000	3.598 (3.860)	-	1.836 (1.558)

[1] standard errors are in parentheses

- The output covers the range of data and 6,000 GWh is approximately the mean output. Recall that SCE greater (less) than 1 implies increasing (decreasing) returns to scale. The result implies that decreasing returns to scale are at smaller output, with increasing return to scale prevailing at larger outputs, or in other words, the cost curve is a long-run average total cost curve.
- The unusual behavior of the average cost curve can be explained by the presence of both single and dual-reactor plants in the sample. It is observed that single reactor plants will have lower average cost at small output levels. Production of outputs with a single reactor would require a unit well above the optimal size. The long-run average total cost curve for the technology at the plant level is the lower envelope of these curves, which is W-shaped in this range.
- The long-run average total cost curve for single-reactor plants exhibit decreasing returns to scale throughout the range of outputs. In contrast, the long-run average total cost curve for dual-reactor plants exhibits increasing returns to scale throughout the range of outputs. The estimates of SCE for single and dual-reactor plants given in the table 4 under columns of Model II, provide a measure of these scale economies.
- The confidence interval of the estimates of SCE for single and dual-reactor plants are considered so that there remains a fair degree of uncertainty about the magnitude of scale economies. It is showed that one can reject the hypothesis of constant return to scale (i.e., SCE = 1) for either of these technologies in these range of outputs. At the same time one can neither reject hypothesis of stronger scale effects. Anyone with a strong a priori belief regarding economies of scale in nuclear power is unlikely to be swayed by this evidence.

Conclusion:

The results suggests that reduction in the cost of nuclear power are not likely to come from increased reactor size. The large single-reactor plants are operating in the decreasing returns range of the long-run cost function. The result also indicates that multiunit plants are more efficient than single unit plants. This is implied by increasing costs for large single-reactor plants alone, there may be additional cost savings from multinational siting per se. Decreasing returns for single reactor only implies that it is more efficient to build two reactors to produce a large output.

IX. **Kaserman, David L., and John W. Mayo, "The Measurement of Vertical Economies and the Efficient Structure of Electric Utility Industry,"** ***The Journal of Industrial Economics*** **Vol. 39, No. 5 (1991): 483-502.**

This paper presents a unique analysis on the concepts of multiproduct cost economies modified to the case of production at vertically-related stages to derive explicit and general measures of economies of vertical integration. The authors pointed out that economies of scale at both the generation and distribution stages are thought to retain over a sufficiently wide range of output to dictate the existence of only one firm in each relevant geographic market.

Economies of scale is expected to be at the distributional stage of the industry and as a result proposals for deregulation of the generation stage are generally premised upon a vertical restructuring of the industry that would separate the two stages of production. It is argued that those firms that are currently involved in both generation and distribution would be forced to vertically divest. This paper modifies the concept of multiproduct cost economies to the case of production at vertically-related stages to devise an explicit and general measures of economies of vertical integration. They use a multistage cost function for electric utilities and calculate the degree of vertical economies that exist between the generation and distribution stages.

Vertical economies may arise from two sources: (I) if the upstream stages exercise monopoly power in pricing the intermediate product and downstream stage uses this product in variable proportions with its other inputs, then costs at the downstream stage will be inflated by an inefficient combination of inputs; (ii) depending upon various characteristics of the intermediate product market, transaction costs associated with the use of the market mechanism may be large.

Model of the Measurement and Estimation of Vertical Economies

For the vertically-integrated firm producing at multiple stages of production, the most general specification of the production relationships is given by the transformation function t(x,y), where x is a vector for m inputs and y is a vector of n outputs at the various stages of production. With certain conditions to be satisfied, a cost function C(y,w,Z) duel to a transformation function exists where w is a vector of input prices and Z is a vector of other hedonic variables that shift cost. For this cost function, there exist $y_j>0$, for every i.

Under these conditions, the multistage cost function is applicable with some modification. The multistage measure of economies of scale is given by:

$$Sn=C(y)/y\bullet\nabla C(Y)=C(y)/\sum_{i=1}^{n} YiC(Y) \qquad (1)$$

where $C_i(y) = \partial C(y)/\partial yj$.

Similarly, stage-specific returns to scale at the ith level are given by:

$$S_i = (\,IC_i(y)/y_i)\ /C_i(y) \qquad (2)$$

where $IC_j\ (y)\ = C(y_n)$- $C(Y_{n-l})$ and Y_{n-l} is the n vector of outputs with a zero component at the ith stage of production.

The extent of vertical economies is critical for the determination of the optimal degree of vertical integration. There should be some modification required for the case of vertical economies. Account is made, therefore, for sales of the intermediate product between successive stages when production occurs on a stand-alone (or disintegrated) basis. Thus, weak economies of vertical integration between two successive stages of production, i and j are said to exist if

$$C(y_i y_j) \le C(y_i,0) + C(0,y_j,P_i) - (P_i y_i(y_j,\bar{P}) \qquad (3)$$

where y_i is output at the upstream stage, y_j is output at the downstream stage, p_i is the market price of the intermediate product y_i (y_j, p) is derived demand for this product, and p is a vector of all input prices at the downstream stages (including Pi). The LHS of (3) represents the costs of vertically-integrated production across stages i and j. The first term on the RHS is the cost of stand-alone production at the upstream stage i. The second term is the cost of stand-alone production at the ~ stages, j. Finally, the third term on the RHS nets out the downstream firms; expenditures on the intermediate product produced by the stand-alone upstream firm to avoid double-counting of the (disintegrated) costs of producing this product, since these costs have already been accounted for in C (Y_i,O).

The equation (3) will only consider the real cost savings attributable to vertical integration and will discard pure transfers that result from pricing the intermediate product above marginal costs. Both C(Y_i,) and $C(O,y_j,p_i)$ will reflect any production inefficiencies caused by suboptimal input combinations. Equation (3) also indicates that weak economies of vertical integration occur whenever the cost of vertically-integrated production is less than or equal to the costs of producing each output in the vertical chain independently. The degree of vertical economies between stages i and j is then given by:

$$S_{ij}(y) = [C(y_i),0) + C(0,y_j,P_i) - P_{iy_i}(y_j,\bar{P}) - c(y_i y_j)]/C(y_i,y_j) \qquad (4)$$

If the inequality in equation (3) is satisfied (i.e., if weak economies of vertical integration exist) S_j $(y) \ge 0$.

In the electric industry, there are two basic vertical stages of production which we may characterize as the input and output stages. These stages determine the firm's costs and revenues respectively. At the input stage, the utility may choose to either generate its own power or not may purchase from other firms. Its choice determines the degree to which the firm is vertically integrated. Two characteristics of the electric utility industry facilitate application if the multistage cost function described in the paper. First, substitution facilities between generated or purchased power and capital at the downstream stage of production (i.e., in the distribution of power to final consumers). The ratio of outputs at the generation and distributional stages are not fixed from one to another.

Second, the firms in this industry exhibit substantial variation in the degree of which they are vertically integrated. While most electric utilities are vertically integrated across these stages, considerable variation in the ratio of generation to distribution among these firms are observed. This variation in the output intensities across vertical stages, combined with the ability to operate at a single stage on a stand-alone basis, provides the foundation for multistage approach to the measurement of vertical economies. In order to operationalize the concept of vertical economies, the authors use a multistage quadratic cost function (MQCF) as a base case estimating model. The MQCF function is described in the following equation. For fixed input prices, the MQCF is generally written as:

$$C(y)=\alpha_0+\sum_i\alpha_i y_i+\tfrac{1}{2}\sum_i\sum_j\alpha_{ij}y_i y_j \tag{5}$$

This suggests that the multistage economies of scales are given by

$$S_n=(\alpha_0+\sum\alpha_i y_i+1/2\sum_i\sum_j\alpha_{ij}y_i y_j)/(\sum_i\alpha_i y_i+\sum_i\sum_j Y_i y_j) \tag{6}$$

Then $S_n \begin{smallmatrix}<\\-\\>\end{smallmatrix} 1$ as

$$\alpha_0 \begin{smallmatrix}<\\-\\>\end{smallmatrix} 1/2 \sum_i \sum_j \alpha_{ij}y_i y_j$$

The degree of stage-specific returns to scale at stage i is given by

$$S_i=(\alpha_i y_i+1/2\alpha_{ii}y_i^2+1/2\sum_{j\neq i}\alpha_{ij}y_i yj)/(\alpha_i y_i+\alpha_{ii}y_i^2+1/2\sum_{j\neq i}\alpha_{ij}y_i y_j) \tag{7}$$

Finally, the degree of vertical economics or diseconomies is given by

$$S_{ij}=(\alpha_0-P_i y_i(y,\overline{P})-1/2\sum_{i\neq j}\alpha_i y_i+\alpha_{ij}y_i y_j)/C(y) \tag{8}$$

There is a potential problem with the specification of fixed cost being captured in a single constant parameter α_0. To allow the cost function to capture these potential differences in fixed costs, a generalization of the specification of fixed cost F will be generalized, this can be written as $F=\alpha_0+\beta_i$ where α_0 remains a constant parameter and F_i is a dummy variable whose value is unity whenever the firm operates in vertical segment i and zero otherwise. Thus, β_is represent stage-specific costs, which is called the Flexible Fixed Costs Quadratic (FFCQ) cost function and is given as:

$$C(y)=\alpha_0+\sum_i\beta_i F_i+\sum_i\alpha_i y_i+1/2\sum_i\sum_j y_i y_j \tag{9}$$

The above expression for overall firm economies, stage-specific economies and vertical economies are similar to those for the MQCF and are derived exactly the same as in the other cases. Although additional flexibility of specification of fixed costs is afforded through use of the FFCQ, it is quite demanding in its requirement of information about the cost function near the axis of output space. The authors include the percent of generation capacity that is nuclear, hydro, and gas; the percent of sales to residential and industrial customers; the percent of transmission capacity that is underground; and a series of regional dummies in the model.

Data:

The data are drawn from the set of class A and B firms in the 1981 Statistics of Privately Owned Electric Utilities. The dependent variable is total utility operating expenses. Output at the generation stage is defined as net MWh generation from the firms' power plants. Data on four primary inputs--fuel, labor, capital, and purchased power- are included.

Empirical Results

The results of the cost estimations for the four alternative specifications are reported in table 1.

Table 1: Vertical Cost Structure Of the Electric Utility Industry

	MFCQ	FFCQ	MFCQ with hedonic variables	FFCQ with hedonic Characteristics	MFCQ with hedonic characteristics & input prices	FFCQ with hedonic characteristics & input prices
Intercept	1.95x 10^7	3.11X10^5	4.76X10^7	2.40X10^7	-3.5X10^8	-4.68X10^8
	(0.757)	(0.005)	(0.76)	(0.307)	(-2.14)	(-2.14)
F_g	-	-1.2 x10^7	-	1.26 x 10^7	-	-8.88 x10^7
		(-.235)		(0.205)		
F_d	-	3.28 x 10^7	-	6.48 x 10^7	-	(-1.27)
		(.539)		(0.205)		1.35 x 10^8
GEN	21.71	24.44	27.7	26.6	25.21	(1.47)
	(3.95)	(3.06)	(3.16)	(2.73)	(2.65)	25.33
DIST	28.00	24.81	26.7	25.83	28.00	(2.61)
	(4.04)	(2.82)	(2.87)	(2.70)	(2.90)	30.23
GEN^2	1.13 x10^{-6}	1.14 x10^{-6}	8.11 x 10^7	8.64 x 10^{-7}	9.64 x 10^{-7}	(3.08)
	(2.50)	(2.52)	(2.87)	(1.69)	(1.93)	8.61 x 10^{-7}
$DIST^2$	3.74 x 10^{-6}	3.89 x 10^{-6}	3.29 x 10^{-6}	3.38 x 10^{-6}	3.45 x 10^{-6}	(1.71)
	(4.81)	(2.52)	(3.78)	(3.79)	(3.71)	3.29 x 10^{-6}
Gen * Dist	-4,70 x 10^{-6}	-4.84 x 10^{-6}	-4.01 x 10^{-6}	-4.11 x 10^{-6}	-4.30 x 10^{-6}	(3.58)
	(-4.11)	(-4.08)	(-3.14)	(-3.15)	(-3.24)	4.07 x 10^{-6}
PLABOR	-	-	-	-	9889.5	(-3.08)
					(1.33)	16213
PFUEL	-	-	-	-	1.69x 10^6	(2.03)
					(1.56)	2.81 x 10^6
PCAPITAL	-	-	-	-	9.57 x 10^6	(2.24)
					(1.44)	8.84 x 10^4
Ppower	-	-	-	-	4.93 x 10^3	(1.35)
					(1.19)	3.69 x 10^5
PERIND	-	-	-2.00 x 10^8	-2.5 x 10^8	-2.44 x 10^8	(0.891)
			(1.51)	(-1.65)	(-1.70)	-3.21x 10^8
PERRES	-	-	1.53 x 10^8	9.66 x 10^7	3.01 x 10^8	(-2.09)
			(1.20)	(0.617)	(2.09)	1.88 x 10^8
PERNUC	-	-	-7.93 x 10^7	- 6.09 x 10^7	-1.10 x 10^8	(1.21)
			(-0.927)	(-.670)	(-1.18)	-7.99 x 10^7
PERGAS	-	-	3.33 x 10^7 (1.74)	3.16 x 10^8 (1.54)	-1.02 x 10^8	(-0.852)
					(-.478)	1.04 x 10^6
PERHYD			5.24 x 10^7	9.69 x 10^7	-2.46 x 10^7	(.489)
			(.381)	(.062)	(-.180)	-7.27 x 10^7
Uground			7.40 x 10^7	2.89 x 10^7	-6.44 x 10^7	(.486)
			(.634)	(.132)	(-.277)	-3.05 x 10^7
Holding Co.			2.62 x 10^7	1.91 x 10^7	2.74 x 10^7	(-1.17)
			(.634)	(0.444)	(.644)	2.19 x 10^7
			-----------------	---------------	-------------	(.512)
Regional[1]			45.82	40.50	40.69	---------------
						39.04
F	163.99	114.36	.926	.924	.93	
R^2	0.919	0.917				.932

Notes: t-statistics are in parenthesis. To conserve space the coefficients and t-statistics of the regional variables are not reported here.

The results in table 1 of all four models have high explanatory power with adjusted R^2's over 0.91. All the parameter estimates are of the expected signs. All four models indicate highly significant parameters on the linear and quadratic output terms. This gives rise to U-shaped average costs along each output axis, which is a constant with classical theory. The interaction term between generation and distribution is negative and statistically significant at the 0.01 level in every model. This indicates that cost complementarities exist between the vertical stages in the electric utility industry. The robustness of this finding across alternative model specifications offers additional confidence in the basic estimation results. Neither the flexible fixed cost specification nor the model which included input prices and hedonic cost characteristics alter the basic MQCF results. While the output variables remain significant, both the t-statistics on the individual fixed cost terms and F-tests on the set of fixed cost terms in the FFCQ model generally fail to be statistically significant.

The estimations reported in table 1 indicate that the cost structure of the electric utility industry is consistent with the presence of stage-specific economies, stage-specific diseconomies and vertical cost complementarities.

Vertical Economies in the Electrical Utility Industry Generation

In table 2 the multistage economies of scale implied by the MQCF model are calculated for output levels for sample firms.

Table 2: Multistage Economies (Sn) in the Electric Industry Generation

Distribution	(Millions MWh)									
(million MWh)	0	2	4	6	8	10	12	14	16	18
0		1.89	1.33	1.13	1.02	0.95	0.90	0.86	0.82	0.80
2	1.59	1.55	1.44	1.32	1.21	1.13	1.06	1.00	0.95	0.91
4	1.05	1.19	1.29	1.33	1.32	1.28	1.23	1.17	1.11	1.06
6	0.87	0.98	1.10	1.21	1.29	1.33	1.34	1.32	1.28	1.23
8	0.78	0.86	0.96	1.07	1.17	1.27	1.34	1.39	1.41	1.40
10	0.72	0.79	0.86	0.95	1.05	1.15	1.26	1.36	1.44	1.49
12	0.68	0.73	0.79	0.86	0.94	1.04	1.15	1.26	1.38	1.49
14	0.66	0.70	0.74	0.80	0.86	0.94	1.03	1.14	1.26	1.40
16	0.64	0.67	0.71	0.75	0.80	0.87	0.94	1.03	1.14	1.27
18	0.62	0.65	0.68	0.71	0.76	0.81	0.87	0.94	1.03	1.14

For the output of each separate stage, it is observed that economies of scale are exhausted well within the range of representative outputs. The presence of cost complementarities across vertical stages, however, extends the region of multistage economies beyond the point at which stage-specific economies are exhausted. The concept of vertical economies is found to be weaker as compared to natural monopoly (subadditivity) condition. So it is useful for describing the cost savings associated with vertical integration. In table 3 the degree of vertical economies is shown for various levels of generation and distribution of electricity.

Table 3: Estimated Degree of Vertical Economies in the Electric Utility Industry Generation

Distribution (million MWh)	(Million MWh) 2	4	6	8	10	12	14	16	18
2	-0.32	-0.12	0.02	0.07	0.11	0.14	0.15	0.16	0.17
4	-0.08	-0.26	-0.05	0.05	0.16	0.24	0.29	0.32	0.34
6	0.01	-0.04	-0.13	0.04	0.19	0.32	0.41	0.48	0.53
8	0.05	0.05	0.07	0.03	0.20	0.36	0.50	0.62	0.70
10	0.07	0.10	0.15	0.19	0.19	0.38	0.55	0.71	0.84
12	0.07	0.13	0.20	0.27	0.34	0.37	0.56	0.75	0.92
14	0.08	0.14	0.22	0.30	0.39	0.49	0.54	0.75	0.95
16	0.07	0.14	0.22	0.32	0.42	0.53	0.64	0.72	0.94
18	0.07	0.14	0.22	0.32	0.42	0.54	0.66	0.80	0.89

With the exception of some small output levels, table 3 indicates that vertical economies prevail throughout the relevant range of outputs. For a vertically-integrated firm producing sample mean generation and distribution levels, the estimations suggest that costs of vertically-disintegrated production are 11.96 percent higher than for vertically-integrated production. The presence of vertical economies shown in table 3 reveal that the cost of providing the total industry output vector would rise if the industry were vertically divested.

Conclusion:

In the paper the authors have extended multiproduct cost concepts to provide a general measure of vertical economies. They have demonstrated the use of this measure by estimating a multistage cost function for the electric utility industry. The authors concluded that the introduction of an explicit measure of vertical economies should provide a useful vehicle for evaluation of proposals involving vertical divesture in other industries. They also conclude that results with regard to the electric utility industry do not justify any sweeping policy recommendations concerning optimal regulatory designs.

X. Gilsdorf, Keith, "Testing for Subadditivity of Vertically-Integrated Electric Utilities," ***Southern Economic Journal*** **Vol. 18, No. 12 (1995): 126-138.**

The policy debate on electric utility deregulation has a long history. Much research has been conducted focused on estimating the degree of scale economies in generation. But the effect of vertical integration on cost structure is rarely studied in the case of electric utilities even though most electric utilities possess the characteristics of vertical integration on cost structure and most researchers consider the transmission and distribution stages to be natural monopolies. However, several important questions arise whether integration economies make the cost function subadditive. But subadditivity implies that electric firms are multistage natural monopoly and as a result, deregulated generation markets would not display effective competition.

This paper examines thoroughly the issue of subadditivity using a multiproduct cost function framework of a multiproduct firm producing an output from each production stage. Because a multistage cost function provides information about conditions necessary for multistage natural monopoly, a multistage cost function is estimated to capture the effects of vertical integration on cost structure. Two other important questions on cost structure are also considered for analysis; these questions are related to: (i) impact of capacity utilization on production cost and (ii) the effect of the utility's sale-output mix on production costs.

Methodology

To examine the cost effects of vertical integration, the study considered a multiproduct function and administered test for subadditivity using a procedure developed by Evans and Heckman. They considered that a utility produces two outputs: generation (G) and transmission-distribution services (T). The utility's cost function is globally subadditive at output vector $u_{o.} = (G_0, T_0)$ if

$$C(u_o) < C(u^*) + C(u_o - u^*) \qquad (1)$$

for all $u^* \le u_o$. A cost function is additive at u_o if $c(u_o) = c(u^*) + c(u_o - u^*)$ and super-additive if ">" is inserted into the equation. Superadditivity indicates some degree of cost diseconomies exists between outputs and entail lower production costs with further divestiture. The subadditivity test is based on the procedure adopted by E & H, which can avoid extrapolating costs beyond the observed industry data. (Note: a cost function is globally subadditive if and only if, it is subadditive over the observed input levels. If costs are not subadditive over the relevant range, global subadditivity can be rejected.) Following E & H, the admissible region is defined but two constraints are imposed. The first is that the smallest output level per hypothetical firm for generation (G) and transmission/ distribution (T) must be at least as large as the minimum observed output level for each stage, respectively (G_m, T_m). Second, constraint requires output ratios for the hypothetical firms to be within observed output ratios in the sample.

E & H's measure of subadditivity (sub) is calculated as follows:

$$\text{Sub}(\phi, \omega) = (C(u_o) - C(u^A) - C(u^B))/C(u_0) \qquad (2)$$

Equation (2) reveals that the subadditivity measure depends on the (ϕ, ω) combination specified. Sub (ϕ, ω) is estimated over a grid where ϕ and ω vary by intervals. If sub (ϕ, ω) < 0, the cost function is subadditive at u_o at the particular ϕ and ω combination. If the highest value of Sub (ϕ, ω) (Max Sub) ≠ 0 and statistically significant, the hypothesis that the cost function is additive over the admissible range can be rejected. If the Sub (ϕ , ω) = 0, the cost function is additive at the ϕ and ω combination. Findings of Sub (ϕ , ω) ≥ 0 leads to the rejection of the subadditivity hypothesis.

Variables

The utility's multistage cost function contains two outputs, three input prices, and three hedonic variables. The utility provides two outputs: generation and transmission-distribution service measured by MWh produced by fossil-fuel steam plants and total MWh sales (which sales for resale plus ultimate sales), respectively. The analysis concentrates on fossil fuel steam plants because other production technologies (nuclear, hydroelectric) differ substantially. The input prices are wages, fuel, and capital services. The implicit rental price is a Divisia price index derived from capital service prices for generation, transmission, distribution, and general plant. To derive the weighted average cost of capital, a discounted cash flow model is used to estimate the cost of equity while yields based on published ratings measure the cost of debt and preferred stock.

The hedonic variables are customer density (DN), capacity utilization (CU), and the percentage of total sales to ultimate consumers (PULT). Customer density refers to the number of ultimate consumers per square mile of service territory. Capacity utilization is defined as the ratio of total sales to annualized system capacity. Total cost includes operation and maintenance expenses plus imputed capital expenditures minus purchased power cost.

The study sample includes seventy-two privately owned electric utilities, defined on a holding-company basis where applicable, with at least 65 percent of their total steam generation produced from non-nuclear steam processes.

Cost Function

The translog multiproduct cost function (TMCF) which has several desirable properties such as flexibility, tractability, and other properties is adopted to estimate the parameters. This cost function is specified with two outputs (Y_i), three input prices (P_j) and three hedonic variables (Z_i).

TMCF is defined as:

$$InC = \beta_0 + \sum_{i=1}^{m} \beta_i lnY_i + \sum_{j=1}^{n} \gamma_j lnP_j + \sum_{i=1}^{t} \alpha_i \ln Z_i +$$

$$1/2 \sum_{i=1}^{m} \sum_{j=1}^{m} \beta_{ij} \ln Y_i \ln Y_j + 1/2 \sum_{i=1}^{n} \sum_{j=1}^{n} \gamma_{ij} \ln P_i \ln P_j$$

$$+ 1/2 \sum_{i=1}^{t} \sum_{j=1}^{t} \alpha_{ij} \ln Z_i lnZ_j + \sum_{i=1}^{m} \sum_{j=1}^{n} \delta_{ij} \ln Y_i lnP_j +$$

$$\sum_{i=1}^{t} \sum_{j=1}^{n} \sigma_{ij} \ln Z_i lnP_j + \sum_{i=1}^{m} \sum_{j=1}^{t} \lambda_{ij} \ln Y_i lnZ_j$$

where m = generation, transmission-distribution;
n = labor, fuel, capital services;
t = customer density, capacity utilization, and ratio of ultimate sales to total sales.

To ensure linear homogeneity with respect to input prices, the following restrictions are imposed:

$$\sum_{j=1}^{n}\gamma_{ij}=1;\quad \sum_{j=1}^{n}\gamma_{ij}=0;\quad \sum_{j=1}^{n}\delta_{ij}=0;\quad \sum_{j=1}^{n}\sigma_{ij}=0; \tag{3}$$

The cost share equation is derived using Shephard's Lemma and is written as

$$\partial lnC/\partial lnP_j=\gamma_{ij}+\sum_{i=1}^{m}\delta_{ij}lnY_i+\sum_{i=1}^{n}\gamma_{ij}lnP_i+\sum_{i=1}^{r}\sigma_{ij}lnZ_i \tag{4}$$

Results and Discussion

The estimates of Max Sub for each utility that satisfied the positive marginal cost, monotonicity, and input price concavity conditions of a proper cost function are depicted in table 1. The results indicate that sixteen companies exhibit negative estimates for Max Sub while thirty-seven estimates are positive but none of them are statistically significant. The results do not support the hypothesis that integrated electric utilities are multistage natural monopoly.

Subadditivity measures at the sample mean along with their associated standard errors are depicted in table 2. It reveals that all but three combinations show small, but statistically not significant, degrees of subadditivity. The failure to reject the additivity hypothesis does not necessarily imply a lack of vertical integration economies. Economies of scope between stages is a necessary but not sufficient condition for subadditivity.

Table 3 presents firm-specific estimates of capacity utilization and sales mix on cost structure along with their standard errors. In all but sixteen cases, increased utilization reduces production costs. The findings suggest that regulatory policies designed to increase utilization rates will reduce electric costs for various utilities.

The production cost may fall with increased but not complete specialization in retail sales. The evidence provides some support for the hypothesis that some economies exist between sales for resale and ultimate sales, implying that complete divesture of wholesale activities from retail sales would entail a certain loss of efficiency.

Table 1: Max Sub Estimates for Observations Meeting Requirements of a Well-Behaved Cost Function

Company Name	Max Sub	(φ, ώ)	Standard Error
Mean	-0.0143	.1, .5	0.1684798
American Electric Power	0.01754	.1, .5	0.5041628
Allegheny Power System	0.0329	.1, .4	0.3449835
Arizona Public Service	-0.0033	0,.2	0.201541
Carolina Power & Light	-0.0089	0,0	0.0660756
Central Hudson G&L	-0.0031	0,.6	0.4552253
Central Illinois Public service	-0.0305	0,0	0.2729533
Central Louisiana Electric	-0.0293	0,.3	0.5546074
Commonwealth Energy System	0.00564884	.1,.4	0.443636
Central Illinois Corp	-0.0438	0,.2	0.579397
Cincinnati Gas & Electric	-0.0182	0,.2	0.1684798
Cleveland Electric Illuminating	-0089	0,.1	0.1478072
Consolidated Edison	-0.0182	0,0	0.1183828
Central & Southwest Corp.	-0.0048	.1,.3	0.1549385
Delmarva Power & Light	-.0145	0,.3	0.3396517
Detroit Edison	-0.001	0,0	0.0602203
Dayton Power & Light	-.0167	0,.2	0.2742058
Duquesne Light Co.	-0.0127	0,.2	0.2272017
Eastern Utilities Associates	-0.0134	0,.7	0.6445545
El Paso Electric	-0.0096	0,.1	0.7467374
Florida Progress Corp	-0.0129	.2,.6	0.1474494
Gulf States Utilities	0.00794	0,0	0.0953107
Houston Industries Inc.	-0.0064	0,.1	0.0380859
Illinois Power Co.	-0.0127	0,.4	0.1717078
Interstate Power Co.	-0.035	0,.3	0.6607064
Iowa Southern Utilities	-0.0778	0,0	1.0418521
IPALCO Enterprises	-0.0304	0,.2	0.2632314
Kansas Power & Light	-0.0214	0,0	0.309627
Louisville Gas & Electric	-0.0396	0,.1	0.3438256
Middle South Utilities	-0.0039	0,0	0.0540628
Midwest Energy Co.	-0.0777	.1,.4	0.8427565
New England Electric System	-0.0114	.1,.4	0.1873368
New York State E & G	0.00912	0,0	0.1649581

Table 1: Max Sub Estimates for Observations Meeting Requirements of a Well-Behaved Cost Function — *Continued*

Company Name	Max Sub	(φ, ώ)	Standard Error
Northern Indiana Public Service	-0.0224	0,0	0.2430784
Orange & Rockland	-0.027	0,.7	07102835
Ohio Edison	0.0904	.1,.4	0.1510671
Oklahoma Gas & Electric	-0.0117	0,.1	01438191
Pacific Gas & Electric	-0.0054	0,0	0.040894
Pennsylvania Power & Light	-0.0091	0,.1	0.080752
Potomac Electric Power	-0.0176	0,0	0.1348051
PSI Holdings Inc.	-0.0175	0,0	0.1214782
Public Service Co. of New Mexico	-0.0692	.5,.5	0.4690542
Savannah Electric & Power	-0.0695	0,.7	0.9978636
SCANA Corp	-0.0237	0,0	0.214679
Southern Companies	0.03988	.2,.6	0.6584236
Southern Indiana Gas & Electric	-0.0305	0,.3	0.530199
TECO Energy Inc.	0.00287	0,.2	0.1492719
Texas Utilities	-0.0038	0,0	0.0190
Toledo Edison	-0.0209	0,.4	0.4734008
United Illuminating	-0.0402	0,.2	0.5307189
Utah Power & Light	0.02526	.1, .4	0.1761229
Wisconsin Public Services	-0.0019	0,.5	0.4379415
Wisconsin Power & Light	0.00445	0,.4	0.3328225

Table 2: Subadditivity Measure (Sub) for Selected (φ, ώ) Combinations At the Point Of Approximation

	φ										
v	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1
0	-.02 (.13)*										
.1	-.01 (.16)	-.03 (.15)									
.2		-.03 (.15)	-.03 (.14)	-.04 (.14)							
.3		-.02 (.16)	-.03 (.14)	-.04 (.14)	-.04 (.13)	-.04 (.13)					
.4		-.01 (.17)	-.03 (.14)	-.04 (.14)	-.04 (.12)	-.04 (.12)	-.04 (.12)	-.03 (.13)			
.5			-.03 (.14)	-.04 (.13)	-.04 (.12)	-.04 (.12)	-.04 (.12)	-.04 (.12)	-.03 (.14)	-.01 (.17)	
.6				-.03 (.13)	-.04 (.12)	-.04 (.12)	-.04 (.12)	-.04 (.13)	-.03 (.14)	-.02 (.16)	
.7						-.04 (.13)	-.04 (.13)	-.04 (.13)	-.03 (.14)	-.02 (.16)	
.8								-.04 (.14)	-.03 (.14)	-.03 (.15)	-.01 (.16)
.9										-.03 (.15)	-.02 (.13)
1											

* Standard errors are given in parentheses.

Table 3: Capacity Utilization and Sales Mix Impact Estimates

Company Name	Utilization Effect	Sales Mix Effect	Standard Error Utilization	Standard Error Sales Mix
Mean	-.2862*	-0.3865**	0.12372	0.20507
Allegheny Power System	-0.5504	0.06364	0.69355	0.48045
American Electric Power	-0.2861*	-0.3162	0.25308	0.35167
Arizona Public Service	-0.1316	0.40751	0.17436	0.59302
Carolina Power & Light	-0.4605*	-0.3541	0.19356	0.31154
Central & Southern Corp.	-0.0292	-0.022	0.21323	0.29377
Central Hudson G&L	-0.5416**	-0.1811	0.29466	0.25669
Central Illinois Corp.	-0.0386	-0.0381	0.17543	0.34905
Central Illinois P.S	-0.3806	-0.7523*	0.43055	0.3817
Central Louisiana Electric	-0.0021	0.2092	0.15943	0.3655
Cincinnati Gas & Electric	0.01465	-0.2623	0.16363	0.3346
Cleveland Electric Illuminating	0.10846	0.2952	0.37068	0.50404
Commonwealth Energy	-0.7818	-0.2126	0.79421	0.5484
Consolidated Edison	-0.6299	-1.4953*	0.55371	0.58211
Dayton Power & Light	0.00542	0.02691	0.12077	0.32562
Delmarva Power & Light	-0.3463	-0.3948**	0.11738	0.20189
Detroit Edison	-0.0291	-0.393	0.19198	0.29941
Duquesne Light Co.	-0.3719	-0.4152	0.24666	0.25726
Eastern Utilities Associates	-0.7204	-0.4288	0.38537	0.3848
El Paso Electric	-0.5764	0.40189	0.29026	0.37877
Florida Progress Corp	-0.2634	-0.4107**	0.24589	0.21416
Gulf States Utilities	-0.0512	0.42611	0.17209	0.36189
Houston Industries Inc.	0.00861	-0.3119	0.41484	0.34369
Illinois Power Co.	0.10028	0.20477	0.13456	0.37133
Interstate Power Co.	-0.1243	0.3716	0.149	0.36033
Iowa Southern Utilities	-0.2501	-0.1597	0.35428	0.33752
IPALCO Enterprises	-0.0641	-0.3338	0.1755	0.37058
Kansas Power & Light	-0.5597*	-0.5767	0.23558	0.60876
Louisville Gas & Electric	-0.149	-0.503	0.26195	0.32741
Middle South Utilities	-0.1828	-0.0094	0.25382	0.33445
Midwest Energy Co.	-0.308	-0.5835	0.66913	0.35927
New England Electric	-0.2043	-0.1603	0.12962	0.26103
New York State E&G	-0.52	-0.0964	0.42084	0.35086
Northern Indiana Public Service	-0.1525	0.01386	0.22682	0.31269

Table 3: Capacity Utilization and Sales Mix Impact Estimates — *Continued*

Company Name	Utilization Effect	Sales Mix Effect	Standard Error Utilization	Standard Error Sales Mix
Ohio Edison	-0.4363	-0.26	0.35019	0.31471
Oklahoma G & E	-0.1061	-0.257	0.24458	0.23156
Orange & Rockland	-0.6801*	-0.5939**	0.16083	0.3393
Pacific G& E	-0.1252	-0.1008	0.33485	0.41565
Pennsylvania P& L	-0.2712	-0.6577*	0.2057	0.27636
Savannah E & P	-0.2082	-0.5945	0.229	0.5257
PSI Holdings Inc	-0.1726	-0.625**	0.39548	0.3216
PUCO New Mexico	-0.4649*	-0.8516*	0.21112	0.40539
Savannah E&Power	-0.205	-0.1092	0.27038	0.35238
SCANA Corp	-0.2425	-0.2077	0.28899	0.2479
Southern Companies	-0.4468	-0.0935	0.35294	0.42725
Southern Indiana	-0.3697	-0.107	0.24471	0.25421
TECO Energy INC	-0.1597	-0.0078	0.4101	0.26746
Texas Utilities	0.13563	-0.0089	0.21679	0.36768
Toledo Edision	-0.1944	0.1123	0.15501	0.31699
United Illuminating	-0.0656	-0.4457	0.19958	0.38571
Utah Power & Light	-0.1607	0.98079*	0.7523	0.41945
Wisconsin P & L	-0.725*	-0.1855	0.24311	0.41229
Wisconsin Public Service	-0.4413	0.12266	0.49306	0.21029

* Significant at 0.05 level of significance
** Significant at 0.10 level of significance

Conclusions

The results of the study provide no evidence of subadditivity for vertically-integrated electric utilities over the admissible region, implying that integrated utilities are not multistage natural monopolies. Even though the result is consistent with procompetition policies, it does not necesarily support complete industry divestiture since economies of scope between stages may exist in the absence of subadditivity. The analysis indicates support for regulatory policies which encourage higher annual utlization rates, including ensuring nondiscriminatory access to transmission service. The cost-saving effect of higher load-factor rates indicate another potential benefit of expanded wholesale markets arising from deregulatory policies.