Go to Table of Contents

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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.

TABLE OF CONTENTS

TABLE OF CONTENTS—*Continued*

LIST OF TABLE

TABLE | PAGE

LIST OF TABLES—*Continued*

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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Go to Table of Contents

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 on these subjects. Chapter 3 discusses the theoretical models used in the analysis.

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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."

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

[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.

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.

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.

The 1955-1975 study period used in Greene's analysis, except for the last years,

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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.

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.

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]

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 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.

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[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.

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

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

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

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

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

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

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 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

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[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.

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

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

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

The translog form for the general delivery cost function is

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

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

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

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

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

[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.

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

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

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.

Go to Chapters 4-7

Go to Table of Contents

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.[1] 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.[2] 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.

[1] 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).

[2] 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*.[3] The nuclear fuel prices are from EEI's *Statistical Year Book*.[4]

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 and Greene.[5]

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

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

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

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.[6] 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 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

[6] 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.

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*.[7]

[7] *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.[8] Replacing actual sales with unrestricted sales produces a significant increase in the response of estimated losses, particularly for changes in supply price and sales.

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

[8] 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.

expected sign for a "loss" function given that substitution, as opposed to complementarity between inputs, is what generally occurs.[9] 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.

[9] 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

Source: Authors' construct.

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.[10] 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.

[10] 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.

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.

<u>Power Procurement and Delivery Cost Model</u>

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.[11] 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.[12]

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

[12] 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.

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.

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.

declines in the cost shares of energy and labor and modest increases in the cost share for transmission and distribution capital. The declining energy share is attributed to declining fossil fuel prices. The declining share of labor is possibly a result of capital for labor substitution.

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.[13] 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.

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

[13] 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.

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.

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

American Electric Power Company

Statistical Overview

	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 kwh)	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.

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

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.

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.

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.

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. 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.

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 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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Go to Table of Contents

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:[1]

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

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

$$WK_t^i = \left[\frac{1 - U_t{\cdot}Z_t^i - K + Y_t{\cdot}K_t{\cdot}U_t{\cdot}Z_t^i}{1 - U_t}\right] \cdot \left[\, WKA_{t-1}^i \cdot r_t^i \; + \right.$$

$$\left. WKA_t^{i,\,expected} \cdot d^{\,i} - (WKA_t^{i,\,expected} - WKA_{t-1}^i)\,\right] + WKA_t^{i,\,expected} \cdot T_t.$$

[1] 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*.[2] 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*.[3]

The electric utility asset price index was constructed from data in the *Handy Whitman Index of Public Utility Construction Costs*.[4] 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.[5]

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 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

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

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

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

[5] 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.

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.