ECONOMICS

# IMPACT OF DEREGULATION ON COST EFFICIENCY, FINANCIAL PERFORMANCE AND SHAREHOLDER WEALTH OF ELECTRIC UTILITIES IN THE UNITED STATES

ASTER RUTIBABALIRA ADAMS

Dissertation under the direction of Professor Kathryn H. Anderson

In this dissertation, we evaluate the efficiency of electric utilities in the United States since 1997, and determine whether investor owned electric utilities (IOUs) and cooperatives (COOPs) achieve higher cost, technical and allocative efficiency and greater financial performance than publicly owned peer utilities (POUs). Our analysis includes the estimation of stochastic frontier production functions, Data Envelopment Analysis (DEA), the Juhn-Murphy-Pierce (JMP) cost decomposition and a modified three-factor French-Fama capital asset pricing model (CAPM), which includes technological and total factor productivity (TFP) change to measure firm efficiency. We find that electric utilities in states with electricity deregulation are characterized by greater increases in average costs than their peers in regulated states. Deregulation improved the TFP and the efficiency of IOUs and COOPs compared to their regulated peers and to POUs; stochastic frontier analysis corroborates this finding only for power generation in combination with increased market power in generation. The JMP cost decomposition shows that changes in observable prices and unobservable quantities and prices account for most of the changes in the differences in average costs at all levels of costs. Technological and TFP changes were not important determinants of stock performance for deregulated IOUs.

Approved_________________________________ Date __________________

# IMPACT OF DEREGULATION ON COST EFFICIENCY, FINANCIAL PERFORMANCE AND SHAREHOLDER WEALTH OF ELECTRIC UTILITIES IN THE UNITED STATES

By

Aster Rutibabalira Adams

Dissertation

Submitted to the Faculty of the

Graduate School of Vanderbilt University

in partial fulfillment of the requirements

for the degree of

DOCTOR OF PHILOSOPHY

in

Economics

December, 2008

Nashville, Tennessee

Approved:

Professor Kathryn H. Anderson

Professor Malcolm Getz

Professor Yanqin Fan

Professor John J. Siegfried

Professor Christopher C. Klein

To my mother Mary Salome Mukabaziga, my brother Sylvère Bugilimfura;

Without you I would be nothing. Thank you.

To my beloved wife Tatiana, for your invaluable support

To my beloved children for all you mean to me.

To all my family and Tatiana’s family, thank you

To John and Kay Eaves, for your amazing love

To Mouzon Siddiqi and Kathleen Finn, God bless you.

ACKNOWLEDGEMENTS

This work would not have been possible without the financial support of the Africa-America Institute, the Graduate School at Vanderbilt University, and my friend Todd Middlebrook. I am especially indebted to Dr. Russell G. Hamilton, Jr., former Dean of the Graduate School, and to Professor Kathryn H. Anderson, who have been supportive of my career goals even under the most difficult life circumstances during my stay at Vanderbilt University.

I am grateful to all of those in Nashville, Tennessee, especially at Vanderbilt University and Belmont United Methodist Church and at St Andrew's Episcopal Church in Maryville, Tennessee, who supported me and my family. I am thankful to Dr. Win Hurlburt and Pastor Richard Kabazzi for engineering the road to safety for my family. Each member of my Dissertation Committee has gone beyond what is professionally required to encourage me to complete this project and provided me with extensive guidance. Again, I would especially like to thank Professor Kathryn H. Anderson, for accepting to chair my committee. As my teacher, mentor, friend of my family, you have taught me more than I could possibly give you credit for here.

In the pursuit of this project, nobody has been more important to me than the members of my family. I would especially like to thank my mother and my brother Sylvère, whose support, love and guidance will be with me for the rest of my life. Most importantly, I wish to thank my loving and supportive wife, Tatiana, and my wonderful children Liliane, Gilbert, Nelson and Marie-Paule who provide me unending inspiration.

TABLE OF CONTENTS

LIST OF TABLES

Table Page

LIST OF FIGURES

Figure Page

# CHAPTER I

# INTRODUCTION

## 1.1. Motivation

The electricity supply industry is one of the largest and most dominant industries in a modern industrial economy. However, this industry is going through major structural changes. Instead of the traditional reliance on state and federal regulation, market forces have acquired greater weight than ever before.

Traditionally, economists argued that electric utilities were natural monopolies, and monopoly electric utilities provided consumers a package of services at regulated rates. These services may include power generation (the production of power), transmission (the movement of power from generation facilities over high voltage lines), distribution (reducing voltage and delivering power to individual customers), and customer service (communication with customers including metering, meter reading, ancillary, and billing and collection). Efficiency and fairness required that these natural monopolies be either owned and operated by state or federal government or regulated by them. The industry included private investor-owned utilities (IOUs); federal and state utilities (publicly-owned utilities, POUs), local government entities (municipally-owned utilities, MUNIs); and consumer-owned cooperatives (COOPs).

The electric industry has been regulated in the United States since 1907. This corresponds to the period from the passage of the Public Utility Holding Company Act (PUHCA) of 1935 to the passage of the Energy Policy Act (EPACT) of 1992, EPACT 2005 and the more recent industry restructuring/deregulation bills in federal and state legislation. The passage of PUHCA allowed electric utilities to be involved in all phases of power generation and sale. With the passage of the Public Utility Regulatory Act (PURPA) of 1978, new generating firms entered the market selling their output not to customers but to utilities. PURPA opened the stage for limited competition in the generation sector.

Beginning in 1992, electric restructuring laws were enacted in many states, and power supply and retail services were opened to competition. EPACT 1992 created a new category of corporations, exempt wholesale generators (EWGs), which were allowed to own generators and sell electricity at wholesale anywhere in the world or at retail outside the United States (Hempling, 1995). EPACT 1992 opened the stage for a nationwide competition in the generation sector.

Restructuring unbundled the services in a way that allowed many energy service providers to compete in the supply of electricity with the incumbent utility. These providers included independent power producers, power marketers, and energy service providers. As of December 2002, the United States General Accounting Office ("GAO") reported that "24 states and the District of Columbia have enacted legislation and/or issued regulatory orders to restructure their retail electricity markets. Of these, 17 states and the District of Columbia continue to be active in implementing retail access, thereby allowing customers to choose their own electricity supplier." Electricity restructuring or deregulation in these states deregulated the wholesale market by lifting nearly all restrictions to how wholesale prices are set by generators while keeping the wires function (transmission and distribution) fully regulated and provided by regulated monopolies.[1]

This industry has remained one of the most tightly regulated industries in the United States (White, 1996); social concerns about service reliability, affordability, and environmental issues drove regulatory agendas (Stevenson and Penn 1995). Most economists agree that a

---

[1] While we use interchangeably the words restructuring and deregulation, these terms are not always the same. Restructuring refers to attempts to reorganize the roles of the market players but not necessarily deregulate the market. Full deregulation means that the deregulated industry functions without a regulator. The case of the U.S. electricity deregulation is different because deregulated electricity markets still use a regulator or a market monitor. Sioshansi (2006, p.71)

natural monopoly leads to deadweight social loss when a profit maximizing monopolist charges prices above the marginal costs. The expectation from states that opened their electric market to competition is that lower power supply prices will follow electric restructuring and benefit all consumers; new, low-cost generation companies will enter the market, and existing generators will cut costs due to the increased efficiency in production brought about by competition. In general, it is believed that a competitive electric market will provide residential, commercial, and industrial consumers benefits greater than those offered by the current regulated regime. The primary goal of electric restructuring is to enable market forces, not regulators, to influence utilities' decisions related to cost, pricing, and power supply. However, electric restructuring has other effects including revenue, tax, profit and earning effects, and there are concerns that restructuring primarily benefits consumers in high-cost states at the expense of those in low-cost states. Although deregulation is expected to lead to competition with the right price signals to consumers and better consumer choice, at market prices and higher quality of service, it is built on the promise of higher cost efficiencies (lower marginal and average costs) and lower retail prices. Lower prices in turn result in lower utility revenues, lower state and local government taxes and potentially lower utility profits if proper cost adjustments are not undertaken or if new entrants operate at lower cost or can sell only to the most profitable customers.

Most states developed rules that dictated a slow transition to competition, and only in a handful of states have customers switched to competing electric providers. Brown (2000, p.28) reports that in Massachusetts, only 15.8 percent of customers switched to a different provider. The number is 19.6 percent in California, 60 percent of industrial customers in Pennsylvania's PECO Energy service territory and 455 large customers (about 17 percent of the kilowatt-hours sold to that class of industrial customers) in Maine.

However, there are signs that restructuring/ deregulation may produce unintended results for the industry. First, in 1999, electric utility share prices declined sharply. The Dow-Jones

Utility Average index tracking 15 stocks declined in the last six months of 1999 by 14.7%. According to the Dow Theory Forecasts (May 4, 2000) "[T]he [electric utility] sector ranks among the worst for 12-month performance, and few utility stocks have escaped the carnage. For the 77 electric-utility stocks rated on the electric-utilities table, the average 12-month total return is negative 13.5%. Excluding takeover beneficiaries, only two of the 77 stocks have gained at least 9%. Ten of the stocks have lost at least 30%, and 36 have lost at least 20%." This online report claimed that three factors explain this decline in the value of electric utility stocks: (1) interest rates moved sharply higher after October 1998 and utility stock prices are strongly correlated with bond prices; (2) uncertainty vis-à-vis deregulation and mergers of electric utilities; and (3) the flow of money out of utilities into technology industries.

Second, for the period 1992 through 1998, the number of IOUs decreased by 8 percent (261 in 1992 to. 239 in 1998) while the number of nonutilities generating electricity increased by 9 percent (1,792 in 1992 to. 1,954 in 1998) (EIA, 2000) . In addition, utilities added less capacity compared to nonutilities, a trend that is observed with deregulation. Third, the unexpected rise in natural gas prices during the years 2000-01 caused increases in wholesale rates while many of the states where deregulation occurred froze retail electricity rates, resulting in retail prices set artificially below equilibrium rates. Many state utility commissions allowed the utilities to book the difference between allowed revenues and those increased costs as deferred costs which ultimately were charged to consumers with carrying costs often calculated based on the utility allowed average weighted cost of capital or the long-term debt rate. Fourth, the failure of the California electricity market[2] convinced proponents of electric deregulation to question the timing and the efficacy of competition in electric power generation and distribution. This created price disparities causing state officials and the Federal Energy Regulatory Commission (FERC) to

[2] California's energy crisis was characterized by very high wholesale prices, escalating financial problems for utility providers and electricity consumers, as well as unprecedented rolling blackouts over an extended period of time.

intervene and fix the power market in California. As a result, many states, including Oklahoma and Arkansas, decided to delay the implementation of their restructuring plans. Tables 1 and 2 provide a comparison of retail prices in states which enacted a deregulation legislation and Appendix 1 through 4 provide a comparison of retail prices in regulated and deregulated states.

### 1.2. Why Study Electric Utilities in the United States

Electricity plays a critical role in our modern society. Electricity is an integral part of life, indispensable to factories, commercial establishments, homes, and other facilities including sport and recreational facilities in most developed countries. Lack of electricity can cause irreparable damage and economic loss from reduced industrial production, and also it inconveniences many homeowners. Indeed, electricity is a vital input in the production of nearly all other goods and services, and it is also a final good consumed by almost all households.

The regulatory environment of the electricity supply industry changed over the past two decades. During the last five years there have been major outages[3] and dramatic increases in electricity prices in the west and Midwest as a result of extremely hot summers. The energy crisis in California became so alarming that it attracted national attention.

However, in order to understand recent regulatory changes in the industry, it is important to understand the functional decomposition of the electricity supply industry into generation, transmission, and distribution. Generation is the production of electricity using different energy

[3] On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between \$4 billion and \$10 billion (US dollars). In Canada, gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down \$2.3 billion (Canadian dollars). See UNITED STATES-Canada Power System Outage Task Force. "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004

sources and different technologies. The main energy sources are fossil fuels (coal, petroleum, natural gas, and other gases), hydroelectric power, nuclear power, and renewable fuels (geothermal, wind turbines, solar, waste, and other sources). Transmission involves “high-voltage” transport of electricity. Distribution involves “low-voltage” electricity to end-users. Another function of the electricity industry often confused with the distribution function is the supply of electricity or the sale of electricity to end-users. The supply of electricity includes metering, billing, and marketing, both at retail and wholesale levels. This function is also being opened to competition.

Competition in electricity markets is a recent but rapidly growing phenomenon in the United States. It began as an unexpected movement when utilities were required to buy power from qualifying facilities (QFs) at avoided costs[4] and expanded with the requirement by EPACT 1992 that the utilities buy power from exempt wholesale generators.

In all states, deregulation took the form of functional separation (or unbundling) of generation, and transmission and distribution (T&D), and supply of electricity. Competition was introduced in the generation and supply of electricity. Some states introduced wholesale and retail consumer choice of supplier, some phased-in consumer choice of supplier, and others introduced full consumer choice at the onset of deregulation. However, transmission and distribution networks were nearly always viewed as natural monopolies (White, 1996). T&D are regulated through a “rate-of-return” regulation or cost-based pricing of T&D services. Hence, since 1978, with the introduction of the Public Utilities Regulatory Policy Act (PURPA) of 1978, the electric generation sector is no longer a natural monopoly, and some evidence indicates that this sector better serves consumers than the existing regulated monopoly system. Transmission and distribution services on the other hand continue to be regulated services.

[4] Avoided costs are the incremental savings associated with **not** having to produce additional units of electricity while meeting demand requirements.

Electric restructuring is happening in almost all states. Electric competition no longer means generators competing to sell power to transmission companies. It means allowing wholesale or retail customers to buy their power from several competing suppliers. This implies that not only electric utilities need to make major changes in their organization, but also to change their business plan and consider many issues like the recovery of stranded costs[5] that monopoly electric utilities had not considered to date. Stranded costs are above-market costs or assets with book values that exceeds their estimated market value. Nunez (2007, pp. 196-197) defines three major categories of stranded costs: regulatory assets, i.e., expenses deferred by a state regulatory commission in order to stabilize electricity rates; generating plants, i.e., investment in generating plants such as nuclear plants depreciable over long time horizon and not recoverable in its entirety at the time competition is introduced in the industry; and long-term contracts to purchase and sell electricity from utility and nonutility generators based on energy prices that were in effect prior to deregulation of the wholesale market.

A vast literature has examined the effects of competition on market structure. However, most empirical studies considered the electric utility industry as a whole and ignored region, state, and time effects. Not all states have moved to electric restructuring, and those which did experienced different levels of restructuring and competition. On the other side, because of data availability, most studies compared IOUs and POUs or
MUNIs and ignored rural electric cooperatives (COOPs) and other small electric utilities. Even though they are privately owned, COOPs have not received much attention in the existing related studies.

A few empirical studies compared the relative efficiencies of investor-owned electric utilities (IOUs) and government-owned electric utilities. For example Hausman and Neufeld

---

[5] Stranded costs are defined as prudent costs incurred by a regulated utility which may not be recoverable under market-based retail competition. Examples are undepreciated generating facilities, deferred costs, and long-term contract costs. See http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html#st

(1991) found that that MUNIs significantly lower costs compared to IOUs and that scale inefficiency accounted for most of the technical inefficiency observed in IOUs. Others like Hollas and Stansell (1988) compared the efficiencies of IOUs and rural electric cooperatives (COOPs) and found that MUNIs were the least efficient, followed by COOPs and the IOUs. Berry (1994) also found that COOPs were less efficient than IOUs.

White (1996) provided state-by-state evidence on the distribution of potential gains to consumers (and losses to utilities) from deregulatory reforms. He affirmed that new power production facilities can be developed by entrants at average costs well below those of many incumbent utilities.

Stigler (1971) noted that the incentive of large firms within the industry may differ substantially from their smaller counterparts. Thus, conclusions from studies of large IOUs and POUs cannot be applied to small cooperatives and municipal utilities.

The diversity of the United States electric power industry provides an opportunity for research into the efficiency and the performance of the industry under different and changing regimes in order to further anticipate the impact of future changes in the industry. By limiting the analysis to a single industry but studying multiple facets of the industry, our research explores the process by which the introduction of deregulation and/or competition in a network industry like the United States electric power industry impacts the efficiency and the profitability of the firms in the industry. These firms have different ownership and size, and may or may not be open to competition. As noted by Kwoka (1996), the diversity of restructuring approaches employed or under consideration makes it difficult to predict the final structure of the transformed industry. This diversity of factors makes our research even more interesting.

In April 1994, the California Public Utilities Commission released a plan to deregulate the power generation business in the state. White (1996) reported that with deregulatory reform proposals in California, the market value of the three investor-owned electric utilities plummeted more than $12 billion over the ensuing six months of formal electric industry restructuring proceedings. More than ten years have passed since the first States passed their deregulation legislation; yet, studies continue to analyze different aspects of the electricity industry without conclusive evidence that deregulation produced significant reductions in cost and gains in productive efficiency and the financial performance of electric utilities. Despite the extensive research many questions remain unanswered concerning the impact of deregulation on cost efficiency and shareholder wealth of electric utilities in the United States.

### 1.3. Contribution

The literature on utility deregulation leaves many unanswered questions. Are electric deregulation and competition occurring in states or regions where their benefits are most likely to outweigh the costs or inefficiencies from regulation? Is competition in the United States electricity supply industry warranted? Do deregulated electric utilities perform better than regulated electric utilities in the United States? How do major deregulation events affect shareholder wealth? Do deregulated electric utilities face higher market, systematic risk[6] than regulated utilities?

We try to answer some of these questions in the following chapters. Specifically, this dissertation addresses the following specific issues:

(1) We describe the landscape of the United States electric industry in terms of federal and state jurisdictions, state restructuring and deregulation patterns, industry structure, reforms in the electric utility industry and their implications for utility performance, ownership, size, consumer access, and the future of the industry.

---

6 Systematic risk, also called market risk is defined as Risk which is common to an entire class of assets or liabilities. The value of investments may decline over a given time period simply because of economic changes or other events that impact large portions of the market. Asset allocation and diversification can protect against systematic risk because different portions of the market tend to underperform at different times. See http://www.investorwords.com/4857/systematic_risk.html

(2) We investigate whether or not competition in the electric supply industry is needed and explain how industry structure affects restructuring choice.

(3) We determine whether the change from "rate-of-return" regulation to "managed competition" or "deregulation" in a more competitive market affects the efficiency, performance, and profitability of the industry.

(4) We determine whether deregulation affects the diffusion of new technologies in the electric supply industry.

(5) Finally, we discuss the performance implications of structure and governance differences among firms and examine how we can anticipate the consequences of further changes in the industry.

In our analysis, we compare investor-owned utilities, publicly-owned utilities, and cooperative utilities, and take into account differences in policy within the states in which they operate, firm size, and other characteristics of the industry. Because two groups of electric utilities are investigated –regulated and deregulated utilities- the structure of each group is described. It is important to note *a priori* that there is no consensus concerning the best restructuring pattern to adapt.

This dissertation is organized as follows. Chapter 2 presents a historical view of electric utilities in the United States, discusses the regulatory regimes that were imposed on the industry throughout the past, provides an overview of the cost and price differences across states which justify the introduction of deregulation, discusses the issue of ownership and the contribution of privately and publicly owned electric utilities to the industry and the issue of deregulation in network industries. Chapter 3 reviews the literature on economies of scale and vertical integration in the electric industry and on the effects of ownership and deregulation of electric utilities on efficiency and profitability in the United States and around the world. Chapter 4 examines the methodological approaches used to study the effects of deregulation on cost and production efficiencies, shareholder wealth and the profitability of United States electric utilities. Chapter 5 describes our data and the variables used in this study. Chapter 6 presents empirical results of my analyses. Chapter 7 presents our conclusions and policy implications for our analysis of the electric utility industry in the United States.

# CHAPTER II

## ELECTRIC UTILITIES IN THE UNITED STATES: A HISTORICAL PERSPECTIVE

### 2.1. Introduction

The United States electricity industry has evolved into firms that are vertically integrated into generation, transmission, distribution, and retailing. Those firms have exclusive rights to serve retail customers within a franchised geographic area. They were generally subject to "cost of service" or "rate of return" regulation by state public service commissions. A more detailed description of the structure of the industry, its regulation and deregulation can be found in Joskow and Schmalensee (1983), Joskow (1997), and Kwoka (1996).

The United States electricity supply industry has been regulated by state and federal governments for decades. Competition was introduced in the wholesale electricity market along with the introduction of the Public Utilities Regulatory Policy Act (PURPA) of 1978. PURPA was meant to promote energy conservation in the wake of the second energy crisis of the 1970s. Even though limited competition arose between generation utilities and non-utility generators such as the Qualifying Facilities (QFs) and other Independent Power Producers (IPPs), high electricity prices due to an excessive amount of investment in power generation, transmission, and distribution prevailed in most high-cost states. After the introduction of the Energy Policy Act (EPACT) of 1992 and Order 888 and 889 of the Federal Energy Regulatory Commission (FERC) in 1996, the power generation sector of the industry progressed toward a complete deregulation. While only 367 billion kilowatthours (kWh) or only 11 percent of the total net generation in the United States was produced by non-utility power producers in 1996, the figure rose to 787 billion kWh or 21 percent in 2000 and to 1,581 billion kWh in 2006.[7] Annual sales

[7] Energy Information Administration (EIA), 2006. Electric Power Annual 2006.

of electric power at retail were $213 billion in 1996, $233 billion in 2000, and $327 billion in 2006, and the electric power industry accounted for approximately 2.5 per cent share of the United States GDP during that period.

Although the US electric system is probably the most reliable system among developed countries, high electricity prices continue to prevail in many states due in part to excessive amounts of stranded investments which the stock market often values negatively (Nunez, 2007) combined with low productivity and to other factors that may be less obvious to outside observers. As can be seen in the following section, states that historically had higher than average electricity prices have been the first to open their retail electricity markets to competition.

### 2.2. Comparison of Electric Utilities' Costs, Prices, and Markets

Many factors may explain the move toward competition. First, competition is believed to improve efficiency. Critics argue that regulation lacks the proper incentives for effective cost control and efficiency (Averch and Johnson 1962; Sherman 1989).

The second factor driving deregulation is the difference between electricity rates across the United States. It is not surprising that most States in the forefront of electric restructuring are high-cost/high-price states (see Table 1). Only a few low-cost states began the process of restructuring their power industry. Baum et al. (1996, p. 3) maintain that the single largest factor driving the move to increase competition is the difference between today’s low marginal cost of electric power production and existing rates which are set to recover costs incurred in the past. While past costs include stranded costs put in place to address the rapid growth in energy demand in the 1970s, marginal costs are lower than average costs during the study period due also to decreasing cost of fossil fuel like natural gas, reduced capital cost and excess capacity.

Technological improvements in gas turbines and in renewable sources of electricity constitute the third factor. This and the previous factors are linked because new power generators have significantly lower marginal costs due to the lower cost of fossil fuel[8], reduced capital cost, and improved efficiency and reliability of gas-fired combustion turbine and combined cycle power plants. In addition, the deregulation of other network activities in the United States made it possible to think about the need for regulated electric utilities. Studies reported successful market deregulation in the airline, banking, natural gas, transportation, and long distance telephone industries.[9]

[8] This was especially true during most of the study period from 1997 to 2003. The cost of fuel has increased due to many factors such as hurricanes Katrina and Rita, global economic uncertainty, wars, federal and state environmental requirements and the recent increase in oil prices.

[9] Peltzman and Winston (2000) discuss deregulation of the Airline, Railroad, Telecommunications and Electricity Industries in the United States.

Table 1: Average Electricity Prices of States with Enacted Restructuring Legislation as of February 2001, 1999*(cents/kWh)*

| State | All Sectors | Residential | Commercial | Industrial |
|---|---|---|---|---|
| Oregon | 4.87 | 5.75 | 4.94 | 3.55 |
| Montana | 5.01 | 6.78 | 6.35 | 2.84 |
| West Virginia | 5.09 | 6.27 | 5.53 | 3.80 |
| Oklahoma | 5.37 | 6.60 | 5.58 | 3.60 |
| Arkansas | 5.68 | 7.43 | 5.82 | 4.12 |
| Virginia | 5.86 | 7.48 | 5.55 | 3.84 |
| Nevada | 5.93 | 7.13 | 6.66 | 4.77 |
| Texas | 6.04 | 7.55 | 6.52 | 3.97 |
| Ohio | 6.40 | 8.68 | 7.67 | 4.33 |
| New Mexico | 6.58 | 8.62 | 7.53 | 4.25 |
| **US Average** | **6.66** | **8.16** | **7.26** | **4.43** |
| Illinois | 6.98 | 8.83 | 7.39 | 5.02 |
| Maryland | 7.04 | 8.39 | 6.82 | 4.26 |
| Delaware | 7.12 | 9.17 | 7.39 | 4.73 |
| Michigan | 7.14 | 8.73 | 7.86 | 5.05 |
| Arizona | 7.23 | 8.53 | 7.51 | 5.04 |
| District of Columbia | 7.45 | 8.00 | 7.47 | 4.59 |
| Pennsylvania | 7.67 | 9.19 | 7.90 | 5.22 |
| Rhode Island | 9.02 | 10.13 | 8.49 | 7.39 |
| Massachusetts | 9.16 | 10.09 | 8.90 | 7.75 |
| California | 9.34 | 10.71 | 10.05 | 7.16 |
| Maine | 9.77 | 13.07 | 10.51 | 6.42 |
| Connecticut | 9.96 | 11.46 | 9.69 | 7.42 |
| New Jersey | 9.99 | 11.40 | 9.74 | 7.69 |
| New York | 10.40 | 13.32 | 11.19 | 4.77 |
| New Hampshire | 11.75 | 13.84 | 11.39 | 9.21 |

Source: Energy Information Administration, Electric Sales and Revenue 1999, 24-27. Data sorted by "All Sectors."

Almost all high-cost/high-price states have enacted electric restructuring legislation with the exception of Vermont, Alaska, and Hawaii which do not report any restructuring activity. A few low-cost states enacted restructuring legislation. Those states include Arkansas, Oklahoma, Montana, Nevada, Oregon, Virginia and West Virginia.[10] The following table shows the average retail rates as of December 2006 for the states which enacted restructuring legislation.

Table 2: Average Electricity Prices of States with Enacted Restructuring Legislation as of December 2006 *(cents/kWh)*

| State | All Sectors | Residential | Commercial | Industrial |
|---|---|---|---|---|
| West Virginia | 5.04 | 6.35 | 5.59 | 3.71 |
| Oregon | 6.53 | 7.48 | 6.77 | 4.85 |
| Virginia | 6.86 | 8.49 | 6.21 | 4.69 |
| Montana | 6.91 | 8.28 | 7.44 | 5.12 |
| Arkansas | 6.99 | 8.85 | 6.96 | 5.24 |
| Illinois | 7.07 | 8.42 | 7.95 | 4.69 |
| Oklahoma | 7.30 | 8.55 | 7.34 | 5.46 |
| New Mexico | 7.37 | 9.06 | 7.61 | 5.57 |
| Ohio | 7.71 | 9.34 | 8.44 | 5.61 |
| Michigan | 8.14 | 9.77 | 8.51 | 6.05 |
| Arizona | 8.24 | 9.40 | 8.02 | 5.69 |
| Pennsylvania | 8.68 | 10.35 | 8.94 | 6.63 |
| **US Average** | **8.90** | **10.40** | **9.46** | **6.16** |
| Nevada | 9.63 | 11.08 | 10.12 | 8.03 |
| Maryland | 9.95 | 9.71 | 10.56 | 8.14 |
| Delaware | 10.13 | 11.85 | 10.21 | 7.67 |
| Texas | 10.34 | 12.86 | 9.85 | 7.82 |
| District of Columbia | 11.08 | 9.88 | 11.17 | 17.43 |
| Maine | 11.80 | 13.80 | 12.42 | 8.83 |
| New Jersey | 11.88 | 12.84 | 11.62 | 10.42 |
| California | 12.82 | 14.33 | 12.90 | 10.09 |
| New Hampshire | 13.84 | 14.68 | 14.07 | 11.62 |
| Rhode Island | 13.98 | 15.12 | 13.51 | 12.51 |
| Connecticut | 14.83 | 16.86 | 14.03 | 11.71 |
| New York | 15.27 | 16.89 | 15.51 | 9.39 |
| Massachusetts | 15.45 | 16.60 | 15.54 | 13.04 |

Source: Energy Information Administration, Electric Sales and Revenue 2006. Available at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html
Data sorted by "All Sectors."

[10] Arkansas and Oklahoma have taken steps to delay the process.

Appendix 1, 2, 3 and 4 at the end of this study show that from 1996 to 2003, average residential electricity rates in deregulated states decreased by 2.3% while at the same time average residential electricity rates in regulated states increased by 9%. During the same period, commercial, industrial and average electricity rates increased in both deregulated and regulated states, but at a much slower pace in deregulated states. A t-test statistics shows that in 2003, residential prices, commercial prices and retail prices of all sectors combined were significantly higher in regulated states than in deregulated states respectively at the 1%, 10% and 1% levels. There was no significant difference in industrial prices between regulated and deregulated states in 2003, probably due to deliberate state policies to meet economic development goals such as employment by providing incentives to industrial customers. The same test statistic reveals no significant differences between prices in regulated and deregulated states. For example average retail rates for all sectors from 1996 to 2003 increased in deregulated states by only 1.9% while they increased by 10.6% in regulated states.

These results suggest that deregulation may have improved the cost efficiencies of electric utilities in deregulated states compared to regulated electric utilities. Because of changes in the industry that occurred post-2003, especially as a direct consequence of the Enron implosion and the California electricity market restructuring debacle, the changes in average prices in deregulated and regulated states converge to the average of the industry.

### 2.3. Ownership and State Regulation of Electric Utilities in the United States

A crucial question is why the electricity industry in the United States is heavily regulated by states. An even deeper question is why the US electricity industry switched from a system of municipal regulation to state regulation. Knittel (1999, p. 2 and 16) studied the origins of state electricity regulation and found that "it was corruptibleness of the municipal regulators that led some industry officials to favor state regulation… State regulation gave the industry relief from the corruptive nature of municipal regulation while keeping regulation decentralized enough to provide ample opportunity for the influencing of its decisions in the future." Our analysis of the effects of regulation of public utilities in a later section tries to provide answers to these questions.

In 1877 the United States Supreme Court issued a landmark decision in United States constitutional history. The case of Munn vs. Illinois, 94 US 113 (1877), instituted the rights of governments to regulate and set rates for companies that provide vital public services in a monopolistic business environment. Because the services provided were vital to the welfare of those being served, and the providers of such services operated without direct competition; the "public utility" status was attributed to these companies. In that case, the U.S. Supreme Court ruled that "when private property is devoted to a public use, it is subject to public regulation."[11]

As early as 1885, electricity regulation began with municipal authorities offering franchise licenses to control rates and right-of-way, which gave municipal utilities exclusive access to serve a territory to the practical exclusion of all others and to charge for the service without any price regulation. Municipal regulation promoted competition at the same time it promoted a loss of efficiency because of the possibilities of duplicate capacity as each franchise laid down its own power lines.

---

[11] Defendants charged with operating a public warehouse in Chicago in which they unlawfully transacted business without procuring a license under An Act to Regulate Public Warehouses and the Warehousing and Inspection of Grain, and to Give Effect to Ill. Const. art. XIII (Grain Act). The lower court held that defendants had complied except in two respects: first, they had not complied with licensing requirements; second, they had charged rates higher than those fixed by § 15 of the Grain Act. Defendants appealed, and the state supreme court affirmed. Defendants appealed to the United States Supreme Court, arguing that the Grain Act was unconstitutional. The Court held that the Illinois statute in question was not unconstitutional because defendants were engaged in a public business to such an extent that the state was permitted to regulate, and the statute did not impermissibly interfere with the Commerce Clause of Constitution because the state's regulation of commerce was within its own boundaries. The Court held that the statute was a legitimate regulation of business under state law as the state was free to regulate commerce within its own boundaries even if it might incidentally become connected with interstate commerce. The Court affirmed the lower court's ruling.

From 1877 to 1907, electric utilities were not subject to any price regulation. It was in 1907 that state regulation went into effect in Wisconsin and New York, and state regulatory bodies were expanded to include gas and electric companies. State regulators had the power to set rates and standards and control entry and exit. Federal regulation began later in 1920 with the creation of the Federal Power Commission.

EIA (2000) reports that as of December 1998, the electric industry was composed of 239 investor-owned, 2,009 publicly owned, 912 cooperative and 10 federal electric utilities, in addition to 1,934 non-utility power producers and approximately 400 power marketers.[12] In 2006, EEI reported that the industry was composed of 203 IOUs, 2,038 publicly-owned (MUNIs, state projects and public power districts), 870 cooperative and 9 federal electric utilities. There were a total of 1,688 non-utility generators and 143 energy service providers. Investor-Owned Utilities (IOUs) accounted for about 75 percent of all utility generation and capacity. IOUs are generally vertically integrated taxable corporations owned by shareholders who earn a return on their investment. The rates that investor-owned electric utilities charge for electric service are regulated on a cost-of-service basis by federal or state and local regulatory agencies. Traditionally, IOUs are granted service monopolies in specified geographic areas, and they have an obligation to provide reliable electric power at reasonable rates to customers in those areas.

Publicly Owned Utilities (POUs) are owned by state and local governments and include municipal utilities, public power districts, state authorities, and irrigation districts. They are non-profit agencies and serve at cost. Any excess funds are returned to consumers in the form of community contributions and reduced rates. Generally, POUs are not subject to federal, state and local taxes, though they may collect gross receipts taxes. Most POUs are in the distribution business exclusively, although a few produce and transmit electricity.

---

[12] http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/chapter3_2.html

Rural Electric Cooperatives (COOPs) are owned by member-customers (rural farmers and communities). There are over 900 rural electric cooperatives. Most COOPs do not own generation facilities. An elected board of directors and appointed manager manage rural electric cooperatives. COOPs are subject to state regulation in some jurisdictions. The Rural Utilities Service (formerly the Rural Electrification Administration) is under the United States Department of Agriculture. It was established under the Rural Electrification Act of 1936, which intended to extend credit at discounted interest rates to cooperatives to provide electric service to small rural communities and farms where it was expensive to provide the service. However, some cooperatives operate in urban areas. COOPs are usually exempt from federal and state income taxes, but do pay other types of state and local taxes.

Federally Owned Utilities (FOUs) produce not-for-profit power and give preference in wholesale supply to POUs, COOPs, and other nonprofit entities. Ten such FOUs operate in the United States and include the Tennessee Valley Authority (TVA), the Bonneville Power Administration and other Power Marketing Administrations (PMAs). TVA is the largest power producer in this group and markets at wholesale and retail levels. Most of the electricity produced by these entities is sold for resale. These utilities are generally exempt from federal, state and local taxes.

Non-utilities or independent power producers generate power for their own use and/or for sale in wholesale power markets. These are qualifying facilities under PURPA, exempt wholesale generators (EWG)[13] under EPACT, co-generators, non-QF co-generators, QF small power producers, and /or non-QF other. Power marketers are independent marketers who buy and sell electricity without owning or operating generation, transmission, or distribution facilities. Power marketers may or may not be affiliated with a utility (an example would be Enron).

---

[13] EWG are wholesale generators created under the 1992 Energy Policy Act that are exempt from certain financial and legal restrictions stipulated in the Public Utilities Holding Company Act of 1935.

Apparently, social concerns about service reliability, affordability, and environmental issues drove regulatory agendas (Stevenson and Penn, 1995). There are different types of regulation of natural monopolies (Laffont, 1994). The most common are the "cost of service regulation" and the "Ramsey-Boiteux regulation". Under the cost of service regulation, regulators wanted to make sure that the industry was earning a fair "rate-of-return", a rate of return necessary to attract capital to utilities while at the same time avoid excessive exercise of monopoly power. The main features of the cost of service regulation are: (a) a fair rate of return on investment above the market rate; (b) prices are determined to equal average costs with this imputed charge for capital; (c) prices remain fixed during the regulatory lag until some party, the regulatory commission, the firm, or the consumers, initiates a new regulatory review leading to new prices; (d) the regulatory review is a process of checks and balances in which the conflicts between the firm which wishes high prices and the consumers who wish low prices are arbitrated by the regulatory commission.

The Ramsey-Boiteux regulation is based on the principle that the regulator maximizes social welfare by choosing tariffs under a budget constraint. When fixed and joint costs are present (reflecting economies of scale and scope), efficiency pricing or marginal cost pricing results in losses to the suppliers because they will not be able to recover fixed costs. According to the "Ramsey-Boiteux" regulation also called the "Second Best" pricing, prices deviate from marginal costs so as to minimize deadweight loss and satisfy the budget constraint.

The main differences are that the cost of service regulation provides incentives for firms to inflate costs (resulting in excessive and inefficient consumer prices) and at the same time, it provides a strong incentive for over-investment (the "Averch-Johnson Effect"). The prices fixed through the Ramsey-Boiteux regulation depend on demand and cost attributes and generally do not lead to a uniform mark-up over marginal costs. According to Ross (1986), under the Ramsey pricing, Pareto-efficient prices result from the fact that prices are selected based on the inverse elasticity rule in order to maximize consumers' surplus subject to a profit constraint, with no regard for the distribution of surplus between the buyers since all consumers' surpluses enter the optimization problem with equal weight.

### 2.4. The Historical Role of Competition in Electric Network Industries

There is substantial empirical evidence showing that (perfect) competition is the most efficient market structure. Basic microeconomic theory suggests that competition reduces costs, improves quality of services, and increases efficiency of production in markets. Thus, competition ensures operational and allocative efficiency. However, network industries have some distinctive characteristics when compared to other industries, and these characteristics suggest that the traditional competitive model may not be appropriate for this industry or may affect the speed with which competition can be adopted. According to Bauer (1997), those characteristics are the following:

(1) They may exhibit significant and unique externalities where positive network externalities prevail if all subscribers to a network benefit from the addition of a new subscriber. According to Hogan (1992), in the case of electricity, externalities occur predominantly in the transmission segment of the industry as the addition or disconnection of load influences the transmission capacity throughout the integrated grid.

(2) They produce “composite” goods that consist of the more or less simultaneous combination of different inputs.

(3) Network industries markets are often vertically related and the degree of competition in the various market segments uneven.

(4) The vertical relation of markets may cause input bottlenecks with competing entities providing the same input (unless a “pure utility” approach is implemented with full divestiture between monopoly and competitive operations).

In the recent past, there has been a national trend toward competition in the network industries. This trend began with the financial services in the aftermath of the Great Depression. The next industry to move toward competition was the gas industry following the Natural Gas Policy Act of 1978 and FERC's orders unbundling the production and transportation of natural gas. The airline industry followed thereafter. This was made possible by the Airline Deregulation Act of 1978 which created competitive routes and pricing in the industry. The transportation industry followed in 1980 when the Congress enacted the Motor Carrier Act of 1980 aimed at the deregulation of the trucking industry. During the same year, the Staggers Rail Act deregulated the rail industry. Finally, in 1984, a court ordered the divestiture of AT&T, which led to the birth of the regional Bell Operating Companies (RBOCs). In 1996, the Congress enacted the federal Telecommunications Act allowed greater competition in the local and long-distance telephone services. The Act essentially removed the legal barriers to entry for competitors at the local level.

Bauer (1997) observes that one of the recurring experiences is the fact that competition is slower to take hold in network industries than was often expected at the time of liberalization.

However, because electric industries produce a composite service through a more or less simultaneous combination of different inputs (generation, transmission, transformation, and distribution), the traditional competition model may not be appropriate for this industry. Electricity generation, transmission, and distribution are tightly connected and require far greater cooperation and coordination than is necessary for other goods and services. In fact, transmission and distribution do not only exercise the “wires” function. The management of the grid has to maintain appropriate voltage and frequency in order to avoid a system breakdown. To achieve that goal, it is necessary to integrate electric generation with transmission and distribution, because decisions made by the many generators geographically dispersed in a grid will necessarily impact the success of the transmission and distribution. The coordination problem is exacerbated by the variability of demand by time of day, day of week and season as well as the interconnection of several thousands of independent distributed generators using different generation technologies.

In the pre-PURPA era, some form of competition existed in the electric supply industry. Kwoka (1996) reports that the most common forms of competition were franchise competition which is a periodic process in which one utility is chosen from a group of “bidders” for the right to supply a particular service territory; benchmark or “yardstick” competition which relies on the characteristics of other utilities as a benchmark against which to compare other utilities; competition for large industrial customers; and wholesale competition in the form of utilities purchasing power from each other in order to balance their loads. In the post-PURPA era, the most significant form of competition has been wholesale competition facilitated by non-utility generators or independent power producers. As of May 2001, electric utilities generated 71 percent of total generation and nonutility power producers generated 29 percent of total generation (DOE, Electric Power Monthly, August 2001).

It is important to understand the real meaning of competition as it is used here. In a fully competitive market, all resources compete to be added to an existing system to produce the next unit of output. Competition has only been introduced in the generation of power as wholesale competition. This is to be understood as purchasing electricity for resale. Wholesale sales of electricity are regulated by the federal government through the FERC. Retail competition is regulated by state utility commissions.

Because deregulation is intended to provide firms stronger incentives to control their costs and to innovate, state commissions hope that the costs saved will be passed on to customers. In addition, because state commissions took different restructuring paths, the results achieved may be totally different. However, it is expected that wholesale competition will offer three potential benefits: cost reduction; use of markets to balance reliability and cost; and a change in how risks are allocated between customers and electricity suppliers (Baum et al. 1996).

Many states have also allowed retail competition such that customers have the choice of a power supplier, and the traditional monopoly is no longer required to purchase power on behalf of all customers in the franchise territory. Customers can now contract directly with generators or indirectly with aggregators, power marketers or brokers. Because retail competition breaks the link between customers and the traditional regulated utility, the main benefits it offers are potentially lower rates and customer choice of suppliers. Customer choice of suppliers allow customers to control their electricity use, react more efficiently to price signals, and make decisions regarding energy efficiency and the source of electricity in a manner which can help ensure cleaner air, reduce carbon dioxide emissions or promote the use of renewable and other alternative sources of power.

### 2.5. The New Waves of Deregulation of the U.S. Electric Power Industry

In the past, power was supplied by regulated, vertically-integrated electric companies which were granted monopoly franchises over specific geographic areas. These natural monopolies enjoyed large economies of scale in production and delivery of electricity. In recent years, many countries have deregulated or restructured their electric industry. An extensive review of reforms in the US electric industry is provided in Joskow (1997). The British experience and other countries' experiences are discussed in Green (1998).

EPACT (1992) and FERC's Orders 888 (*Open Access Transmission)* and 889 required electric utilities to make transmission capacity available to all parties on equal terms and triggered competition in wholesale power markets in which producers exchange power among themselves and with independent power marketing firms. With the passage of PURPA in 1978, non-utility generators, particularly independent power producers, began to generate power and trade with electric utilities. Their contribution to the total power generated increases every year.

As seen in Appendix 5, California pioneered the electric restructuring movement in the United States. California was soon followed by Rhode Island, New Hampshire, Pennsylvania and New York. In all these states and in all the other states that implemented electricity restructuring, the move toward competition in the electricity supply industry was characterized by major variation across the states in the reform patterns. In all cases, state statutes allowed a functional separation between generation and T&D. The ultimate goal for all states that implemented electric restructuring was the introduction of consumer choice of supplier. Most states allowed open access for large customers while phasing-in retail choice of suppliers for other customers. Only California, Massachusetts, Maine, Delaware, New Jersey, Ohio, Michigan, and the District of Columbia introduced full consumer choice immediately upon implementation of electricity restructuring program.

# CHAPTER III

# LITERATURE REVIEW

## 3.1. Introduction

The structure and ownership of the electricity supply industry varies. Historically, all stages of the electricity production process were vertically integrated by private or public firms which had a monopoly of generating, transmitting, and distributing power for their franchise territory. In the previous chapter, we describe the different characteristics of major electric utilities in the United States including difference in production costs, sales and prices, and ownership of electric utilities in the United States, and we presented a summary of electric deregulation patterns prevailing in most states.[14] Costs, prices, and efficiencies of production were also described for electric utilities in states where deregulation occurred and in non-deregulated states. In this chapter, we review empirical studies that examine different aspects of electric utilities and utility deregulation. The main results from our review are summarized in section 3.8 below.

## 3.2. Studies of Economies of Scale and Vertical Integration in the Electric Industry

Scale economies exist when larger output quantities can be produced using less-than-proportionally greater input quantities. In this case, the producer is said to be more cost efficient than an industry comprised of more members but producing with more-than-proportionally greater input quantities for the same output. In general, we must distinguish economies of vertical integration from economies of horizontal integration. Economies of vertical integration occur when successive stages of production are performed together by a single more efficient

---

[14] See also the description of the data in Chapter 5.

producer rather than by many producers. In this case, a firm combines activities unlike those it currently performs but that are related to them in the sequence of marketing activities. Vertically integrated electric utilities are involved in electric power generation, transmission, and distribution activities. Horizontal integration occurs when firms gain control over other firms performing similar activities at the same level in the marketing sequence. Pollitt (1995) and Kwoka (1996) present summaries of studies of economies of scale and vertical integration in the US electric utility industry.

For generation plants, Joskow and Schmalensee (1993) and Cowing and Smith (1978) found evidence of significant scale economies for plants of 400 MW of capacity for conventional steam generation and 900 to 1100 MW for nuclear units. Kaserman and Mayo (1991) used a multiproduct cost function to find that, with the exception of smaller electric utilities, there are significant efficiencies of integration for most electric utilities, with cost savings of about 12 percent for an average size utility. Christensen and Greene (1976) used a translog cost function for steam generation of a sample of 114 electric utilities and concluded that by 1970, most firms were at or above minimum efficient firm scale of about 3800 MW. Neuberg (1977), Henderson (1985), Roberts (1986) found evidence of economies of scale in distribution.

Christensen and Greene (1976) first challenged the assumption of economies of scale in electric generation and concluded that the economies of scale present in 1955 were exhausted by 1970. Using firm-level data, they found a flatter U-shaped average cost function and a range of generation capacity with no significant economies or diseconomies of scale. Other empirical works (Huettner and Landon, 1974; Bopp and Costello, 1990; Kamerschen and Thompson, 1993; Atkinson and Halvorsen, 1986; Thompson and Wolf, 1993) have more or less corroborated these findings, concluding to the U shaped average cost function with ranges of scale economies.

Pollitt (1995) reported nine papers on the nature of scale economies in the United States electricity supply industry. The results suggest that MUNIs are significantly less scale efficient than IOUs (Wallace and Junk, 1970). Others found less evidence of the existence of increasing returns to scale (Nerlove, 1968; Christensen and Greene, 1976; Huettner and Landon, 1977). Roberts (1986) studied a sample of 65 vertically integrated US IOUs in 1978 and found that there are economies of output density but diseconomies in the number of consumers and that increasing consumer density has an insignificant effect on average cost. A New Zealand Ministry of Energy (1989) study found that cost savings are not significant beyond 500 mkWh[15] and that economies exist in sales per customer but not in number of customers. Stewart (1979) found that capacity utilization has a much greater effect on average cost than unit size, and he found a minimum efficient scale of 250MW for a high load factor plant, which was also confirmed by Seitz (1971). Kerkvliet (1991) and Kaserman and Mayo (1991) present strong empirical support for integrated electric utilities in the United States; they found that non-integrated plants had 28% and 11.96% higher unit costs than comparable integrated plants.

Yatchew (2000) analyzed scale economies in electricity distribution using a semi-parametric analysis. He found substantial evidence of increasing returns to scale with minimum efficient scale being achieved by firms with about 20,000 customers. He found also that larger firms exhibit constant or decreasing returns and utilities that deliver non-electric services have significantly lower costs, indicating the presence of economies of scope.

Abbott (2005) lists a number of studies that chronologically attempted to determine the levels of productivity and efficiency in the electricity industry. He concluded that studies from the 1970s raised doubt about the existence of significant economies of scale in generation at higher levels, paving the way to arguments in favor of competition in power generation. He also found that studies in the 1990s tended to analyze the issue of economies of scale in the distribution sector and there were economies of scale justifying the existence of monopolies in distribution. As for the difference in efficiencies between IOUs and publicly-owned electric

[15] One million kWh equals one thousand MWh.

utilities, Abbott (2005, p.68) found no conclusive evidence from previous studies; most studies found either no significant differences or the existence of differences in favor of IOUs or POUs. He concluded that "[g]iven that the main purpose of this restructuring has been to improve the productivity and efficiency performance of the industry it would be expected that it would have generated a considerable amount of research on whether this has been achieved. Although this has been partially true there still appears scope for a considerable amount of work to be undertaken in order to confirm or reject many of the claims about the efficiency benefits of restructuring."

In summary, studies of economies of scale and vertical integration in the electric industry found mixed evidence of significant economies of scale, concluding that economies of scale were exhausted by the 1970s and that MUNIs are less scale efficient than IOUs. Other studies concluded that there is doubt about the existence of significant economies of scale in generation, but found economies of scale in distribution, justifying the existence of monopoly in distribution. In general, these studies presented no conclusive evidence on economies of scale or differences in efficiencies by firm type. Our study builds on this research and tries to determine whether in the more recent period there are efficiencies due to economies of scale in vertically integrated electric utilities, by ownership and over time. We found that IOUs, the most vertically integrated electric utilities which have higher economies of scale enjoy higher technical, allocative and cost efficiencies than POUs.

### 3.3. Review of Empirical Research into the Effects of Regulation of Public Utilities

According to Pollitt (1995), the historical purpose of electric utility regulation in the United States was to prevent the exploitation of monopoly power and hence to reduce prices below the monopoly price. There are many competing theories to explain why regulation is necessary. The most popular reasons are explained through public interest theory, capture theory, and the literature on private and public monopolies.

The proponents of the public interest theory of state regulation argued that because electric firms enjoyed declining average cost over the relevant output range, efficiency gains were achieved when one firm supplied the market (Knittel, 1999). According to Knittel (1999, p. 4),

> There are two reasons justifying the regulation of a natural monopoly. First, given the declining average costs of firms, competition, which lowers per firm output, has the effect of pushing firms up their average cost curve leading to inefficiency. By reducing the number of firms serving the market, each firm travels further down its average cost curve. Regulation can therefore be used to eliminate competition and increase efficiency by allowing only one firm to serve the market. However, left alone, the monopolist would charge the profit- maximizing price, while the regulatory commission would like the firm to price at marginal cost. Therefore, the second justification to regulate natural monopolist is to assure price is set more socially efficiently.

Some empirical research to support the public interest theory is found in Emmons (1997). He found evidence in favor of the public interest theory but also in favor of competition. He found that regulation, public ownership, and competition reduced prices during the years of 1930 to 1942. He found that competition largely served to dissipate monopoly rents and may have led to lower prices primarily by spurring improvements in technical efficiency.

The proponents of capture theory claim that firms themselves sought to be regulated to ward off fierce competition, and that the government was subsequently “captured” by the industry (Stigler and Friedland, 1962; Stigler 1971; Noll 1971; Jarrell, 1978; Knittel 1999[16]). Capture theory maintains thus that state regulation was passed to limit competition and increase the profits of electricity firms.

The third theory is drawn from the literature on private and public monopolies. It suggests that private utilities are often regulated monopolies, and, as such, they may be

---

[16] Knittel noted that Stigler and Friedland (1962) and Jarrell (1978) based their conclusions on erroneous models because they did not correct for the endogeneity of the variable used to account for regulation. After correcting this problem, the results appear less robust or are insignificant.

more inefficient than public monopolies. Based on this theory, profit-maximizing private monopolies, when facing rate-of-return regulation, will employ more capital than is socially efficient (Averch and Johnson, 1962). The allocative inefficiency created by private monopolies may require government intervention either in the form of some type of regulation of the private firms or by some type of government ownership.

Regulation is a controversial research subject. Many believe that regulation imposes costs but does not yield benefits (Stigler, 1971 and Demsetz, 1968). Stigler supports the introduction of competition and the elimination of regulation.

There seems to be less clear-cut evidence in support of public interest and capture theories. Knittel (1999, p. 16) found weak evidence in favor of the public interest theory and concluded that the results cast doubt on the capture theory rather than overwhelmingly support the rival public interest theory. Studies which reviewed the empirical effects of regulation of electric utilities did not provide robust evidence that benefits of competition justify elimination of regulation. Our study attempts to determine whether or not deregulation of the electric industry yields significant benefits to justify the change from regulation to competition.

### 3.4. Review of Empirical Research into the Effects of Ownership

The theoretical literature on the effects of ownership on productive efficiency and financial performance has produced contradictory results. An extensive review of the theories of ownership and productive efficiency is offered by Pollitt (1995). The link between ownership and productive efficiency has at least three perspectives.

The leading view is the property rights literature. This view is rooted in the work of Pigou (1932) and Coase (1960) who were concerned that ad hoc allocation of rights based on established legal practice was not necessarily economically efficient (Pollitt, 1995). According to Alchian (1965) who identified the difference between municipally-owned and IOUs, the inability to transfer ownership rights under public ownership prevents the capitalization of gains in efficiency and hence reduces the incentives of the owners to seek such gains (Pollitt, 1995). In contrast to this theory, many studies show also that managers of large IOUs exhibit similar tendencies to deviate from cost-minimization, but regulation of government-granted monopolies allows regulators to ensure that some incentives to control costs remain.

The second view is the public choice theory. Following Niskanen (1971), this theory claims that bureaucrats and politicians maximize their own budgets and, as a consequence, do not strive to minimize production costs (Pollitt, 1995). In other words, bureaucrats and politicians maximize their own objectives to the detriment of cost-minimization and social welfare.

The last view, the private monopoly theory, stipulates that regulated private monopolies may be more inefficient than public monopolies. The leading defenders of this view are Averch and Johnson (1962).

In general, theory suggests that privately-owned utilities are more efficient than publicly-owned utilities. De Fraja (1991) suggests that the main arguments put forward in favor of privately owned companies as compared to publicly owned companies are that (1) the profit motive is a more effective way of reducing inefficiencies in production than any form of monitoring of public managers, and, other things equal, a private firm will be more efficient than a public one, and that (2) a more efficient firm improves the efficiency of the industry. Commonly used variables to study the effects of ownership on productive efficiency include the degree of competition, economies of scale and size of the firm, and the degree and type of regulation.

Although electric utilities were not included in both their studies of the largest 500 non-US manufacturing firms and of the 500 largest firms in Canada, Boardman and Vining (1989 and 1992) found that private firms were more efficient than public firms when they operate in competitive markets. Picot and Kaulman (1989), using data from 15 industries and 6 countries, found also that municipally-owned electric utilities have lower productivity, lower rates of return, and lower increases in profits for given increases in size (Pollitt, 1995).

Regulation also affects productive efficiency. Because different types of regulation have different effects on how firms strive to minimize costs, it is very important to differentiate the effects of ownership from the effects of regulation. Averch and Johnson (1962) analyzed the case of AT&T in the telecommunications industry in the 1950s and found that rate of return regulation created a serious incentive to set predatory prices in competitive markets, which in turn led to over-investment in competitive services to meet inflated demand. However, this finding was refuted by Crain and Zardkoohi (1980) in the water industry. Moore (1970) analyzed 62 IOUs and 7 MUNIs in 1963 and found that MUNIs were charging prices on average 10-22% below the profit maximizing price level, while IOUs were charging prices on average within 5% of the monopoly price. Stigler (1971) found that freight haulage rates were higher in states with regulation than without. Primeaux and Nelson (1980) analyzed 80 IOUs and found no evidence of politically motivated rate structures. They also found, as did Wenders (1986), evidence of higher unit costs than under marginal cost pricing.

Concerning other types of regulation, Fare et al. (1985b) studied a sample of electric plants in 1969 and in 1977 and found that environmental regulation had no significant negative effect on cost efficiency. Eckert (1973) found evidence that bureaus were significantly more often associated with monopolies than commissions,[17] which indicates that the reward structure is more complicated than the simple theory suggests (Pollitt, 1995).

Using data on US electric utilities, DeAlessi (1974a,b, 1977), Peltzman (1971), Junker (1975), Meyer (1975), Neuberg (1977), DiLorenzo and Robinson (1982), Pescatrice and Trapani (1980), Atkinson and Halvorsen (1986), Cote (1989), Fare et al. (1989), Hausman and Neufeld

[17] A bureau is run by civil servants with incentives to increase its size by regulating more firms and bringing in more bureaucratic procedures while a commission is run by commissioners on fixed salaries and with terms of office fixed by statute (Pollitt, 1995).

(1991) conducted analyses of IOUs and MUNIs and found little or no evidence of the general view (Alchian's view) that IOUs are more efficient than MUNIs. Many of the studies do indeed find that MUNIs are more efficient than IOUs, even though many of the studies were criticized for their statistical and economic shortcomings. DeAlessi (1974a) confirmed the Averch-Johnson theory and found that MUNIs in general have lower prices and higher operating costs than IOUs. This was also confirmed by his other study in 1997 which concluded that managers of MUNIs are failing to make decisions which would reduce costs and raise profitability. Peltzman (1971) also found that MUNIs had lower rates than IOUs. In contrast, Junker (1975) and Neuberg (1977) found that there is no evidence of relative cost inefficiency in publicly owned enterprises. Meyer (1975), Neuberg (1977), Pescatrice and Trapani (1980), Cote (1989), and Hausman and Neufeld (1991) found that MUNIs had significantly lower costs than IOUs. However, DiLorenzo and Robinson (1982) found that MUNIs had insignificantly lower costs than IOUs. Finally, Atkinson and Halvorsen (1986) studied 123 IOUs and 30 MUNIs and found them to be equally cost efficient given the internal factor prices that they faced.

In his other paper, DeAlessi (1974b) tried to link the length of managerial tenure with efficiency. He found that managers of MUNIs have longer tenure than managers of IOUs. However, the link between tenure and efficiency is not clear.

Pollitt (1995, p. 48) concluded that, based on past literature, ownership is not a major determinant of differences in productive efficiency. However, he observed that under the UK privatization of the electricity supply industry, production costs were falling and wondered whether costs would have fallen as much under more efficient public management.

Multiple econometric models have been used to analyze the differences in productive efficiency due to ownership. Following the review of Lovell and Schmidt (1988), Pollitt (1995) used four methodologies to test for the effects of ownership on efficiency using data from 14 countries. He used Data Envelopment Analysis (DEA), the Parametric Programming Approach

(PPA), the Deterministic Statistical Approach (DSA), and the Stochastic Frontier Method (SFM). In addition to comparing productive efficiency of power generation, Pollitt also analyzed the efficiency in electricity T&D using the DEA method.

Pollitt (1995) performed the following analyses to compare productive efficiencies of IOUs and MUNIs:

(1) Measured the effects of ownership on the productive efficiency of an international sample of electric utilities, using two different methodologies applied to a common sample;

(2) Measured the technical productive efficiency of an international sample of electric power plants using the four major methodologies for measuring productive efficiency as identified above;

(3) Measured overall and allocative productive efficiencies in base load electric power plants using both historic and current cost of capital measures; and

(4) Measured the productive efficiency in the electricity transmission and distribution system.

Pollitt found that: (1) given scale effects, there is no significant evidence for the superior performance of IOUs over MUNIs after appropriate allowance has been made for differences in technology; (2) publicly owned and privately owned electric power plants exhibit significant differences in technical efficiency; (3) privately-owned plants exhibit significantly higher overall and allocative efficiencies than publicly-owned plants (or IOUs exhibit lower unit costs than MUNIS); and finally (4) privately-owned and publicly-owned electricity transmission and distribution systems exhibit no significant difference in technical or cost efficiency.

In summary, Pollitt found evidence that in the long run, privately-owned generation firms have lower operating costs. There is no evidence that privately-owned electricity transmission and distribution systems have lower costs than publicly-owned electricity transmission and distribution systems.  His study, however, does not include cooperative and other publicly-owned electric utilities.  Our study compares all types of ownership.

Kwoka (1996) found that collectively these results suggest that public and private utilities have comparable advantages in *different facets* of the electric utility industry. Public ownership achieves lower costs in the end-user functions, and IOUs realize greater efficiency in power production and from vertical integration. The evidence shows that on balance IOUs gain more from integration into more local distribution than do public systems from integration into generation. These results contrast with previous analyses that tended to give overall superiority to one type of utility over the other.

Kwoka (1996) found also that, after subsidies are accounted for, the net effect of public ownership is to reduce a utility's costs (relative to IOUs) by 5.5 percent. This percentage advantage comes from a greater reduction in distribution costs (about an average of 11 percent), offset by increases of 4.4 percent in generation, 0.5 percent in vertical integration, and 0.6 percent in power purchases. After controlling for outputs, factor prices, and other variables, utility costs are significantly affected by vertical integration, by public ownership, and by competition[18]. Competition appears to increase fixed costs, but to lower variable costs by more; public ownership reduces the utility's total costs through efficient distribution; and vertical integration lowers the utility's costs as well but through efficient power generation. With competition, public ownership, more than private ownership, succeeds in lowering costs, and then after doing so, in lowering prices further. Finally, Kwoka (1996) also found that large integrated utilities appear to have similar cost structures regardless of their mode of ownership.

Kwoka (2005) analyzed the comparative advantage of public and private ownership in electric utilities in the United States. Unlike most studies cited above which used DEA, SFA, or estimated a translog cost function, this study models utility costs using a quadratic cost function; this functional form has a clear advantage because it handles zero values of variables better than

[18] Kwoka considers three types of "competitive" utilities: true duopoly, new hookup regimes, and competition at the boundary of service territories. (p.92)

does the translog. He found that while IOUs are more cost efficient in generation than POUs, the latter generally have an advantage in the end-user-oriented distribution function, which is consistent with his previous findings (Kwoka, 1996). Kwoka also found some evidence of a service quality differential in favor of small electric utilities and municipal electric utilities over large IOUs or POUs.

Even though these findings add important insight to the understanding of the effects of ownership, integration, and competition on utility costs, they leave many unanswered questions regarding the effect of competition which will be answered here. Using a larger sample of electric utilities over an eight-year period, this study will provide results to confirm or rebut past findings of the effects of ownership and competition on cost efficiency. Previous studies do not find conclusive evidence of superior efficiency of IOUs over POUs. Some studies found that IOUs were more efficient than POUs while others found the opposite. Most of these studies relied on small samples and analyzed short-term effects. Our study uses a large sample of electric utilities and focuses on cost efficiency differences due to deregulation. This study will provide further evidence of the effects of ownership and deregulation.

### 3.5. Review of Empirical Research into the Effects of Deregulation and Competition on Profitability, Productive and Cost Efficiencies

"Deregulation" of the United States electricity system is expected to bring large annual benefits due to expected operational improvements. However, deregulation will inevitably have other effects on capital formation and efficiency. The benefits of introducing competition in a regulated industry are diverse. Free entry, lower production costs, improvements in efficiency and productivity are expected to lead to a better electricity production. In addition, lower rates and customer choice are expected benefits from retail competition.

Research shows efficiency gains from deregulating a monopolistic market. Following McCormick, Shughart and Tollison (1984) who argued that the initial effort to establish regulation dissipates the monopoly profit, limiting the gain from deregulation to the efficiency cost of monopoly, Poitras and Sutter (1997) analyzed the efficiency gains from deregulating monopolies using an equilibrium rent seeking model. Their results support policies aimed at eliminating monopolies and other types of economic distortions.

The gains from deregulation should at first equal the cost of monopoly. The gains from deregulation should be calculated as the deadweight loss from the monopolist. Harberger (1954), Kamerschen (1966), Tullock (1967), Cowling and Mueller (1978), Jenny and Weber (1983) estimated the monopoly deadweight losses due to regulation. They found different sizes of the deadweight losses. Tullock included sunk costs in the monopoly costs.

Poitras and Sutter (P&S) find that the size of the gains from deregulation is a function of (1) whether the monopoly franchise is subject to subsequent competition from other rent seekers (contestable), and (2) whether the initial rent seekers anticipate the possibility of deregulation. The analysis found that the potential benefits of deregulation can exceed the costs, even if rent seeking expenditures are upfront and sunk. However, it is possible that the cost of deregulation exceeds its potential benefits. Reformers assume that deregulation will yield benefits higher than the costs of deregulation or the deadweight loss from a monopoly because, at the end, deregulation will correct existing economic distortions.

Using a two-period model, P&S assume that a government regulates an industry to create a constant cost monopoly in period 1 and deregulates in period 2. They also assume that the reformer (government) and the monopolist invest resources to achieve or resist deregulation. Thus, the probability of deregulation is endogenous and depends upon committed resources for deregulation or deregulation avoidance.

Posner (1975) suggests that monopolizing activities can be deterred at low social cost. Tollison and Wagner (1991) claim that the cost of achieving deregulation precludes any actual gains. P&S consider deregulation of a non-contestable franchise.[19] This case is very similar to the electricity industry since rent seeking expenditures are upfront and sunk.

Although the beneficiaries of deregulation may be numerous, P&S model the reformer as a single player. Following Tollison and Wagner (1991), they distinguish between a factional reformer who represents consumer interests and a utilitarian reformer who is only concerned with social welfare. A factional reformer values the deadweight loss (H) to consumers, but a utilitarian reformer does not value any part of the transfer. Denoting the benefit from deregulation to the reformer by X, and the monopolist profit by $\pi$, $X=\pi+H$ for the factional reformer, and X=H for the utilitarian reformer. The model is as follows. The reformer and the monopolist choose their expenditures to solve

$$\begin{aligned} &\underset{R}{Max}\, X \bullet \frac{R}{R+M_2} - R, \qquad \textit{and} \\ &\underset{M_2}{Max}\, \pi \bullet \frac{M_2}{R+M_2} - M_2 \end{aligned} \tag{1}$$

where $X \in [0, \pi + H]$, $M_i$, i=1,2, is the rent seeking expenditures for the period i, and R is the expenditures by the reformer. They assume that, for the non-contestable monopoly, $\beta$ -- the probability that rent seeking competition takes place in period 2, conditional on deregulation not occurring -- equals zero. P&S also assume that all rent seekers are risk neutral, and that all rent seeking expenditures are social costs.

Solving the above model for equilibrium expenditures and probability of deregulation:

[19] A monopoly is contestable if the franchise can be transferred to another rent seeker by the legislature in period 2. If the franchise once awarded cannot be transferred, the monopoly is non-contestable (Poitras and Sutter, 1997).

$$R = X^2 \bullet \frac{\pi}{(\pi + X)^2}$$

$$M_2 = \pi^2 \bullet \frac{X}{(\pi + X)^2} \qquad (2)$$

$$\theta = \frac{X}{\pi + X}$$

In this case, the total first period expenditure is a function of the monopolist profit less the present value of expenditure to resist deregulation in the second period.

$$M_1 = \pi \bullet [1 + \delta(1-\theta)] - \delta \bullet M_2$$

$$M_1 = \pi \left\{ \frac{1+\delta\pi^2}{(\pi + X)^2} \right\} \qquad (3)$$

where δ<1 is the discount factor. The total welfare gain from deregulation is

$$(1+\delta) \bullet (\pi + H) - M_1 - H - \delta[M_2 + R + (1-\theta) \bullet H]$$

$$or \qquad (4)$$

$$\delta \bullet X \bullet \left[ \frac{\pi^2 + \pi H + XH}{(\pi + X^2)} \right]$$

which is positive. They concluded from this equation that "actual welfare gains from deregulation occur with the ratio success function, notwithstanding upfront rent seeking and costly deregulation." The benefits of deregulation do not depend on the type of the reformer, although the gain is a function of the size of X. The derivative of (4) above with respect to X yields the following result:

$$\delta\pi \left[ \frac{\pi^2 + \pi H + XH - \pi X}{(\pi + X)^3} \right] \qquad (5)$$

Because $X \in [0, \pi + H]$, (5) is positive. Based on this finding, since the factional reformer has a greater value of X, he generates greater efficiency gains from deregulation, even though he does not seek to maximize social welfare.

Nwaeze (2000) studied the effects of deregulation of the electric power industry on earnings, risk, and returns. Using OLS, GLS, and a system of equations, he found positive shifts in earnings variability after the reforms. His results reveal that even though there are significant increases in systematic risk and abnormal declines in returns around the events associated with the reforms, larger utilities experienced the largest increase in risk and the most abnormal decline in returns. Further, small electric utilities had a more pronounced negative return effect. Although this study used a limited data set comprised using Compustat and data from the University of Chicago Center for Research in Security Prices (CRSP) data, it shows that further reforms may produce even more undesirable results. The study does not include publicly-owned and cooperative electric utilities.

Since such authors as Debreu (1951) and Koopmans (1951) introduced the analysis of efficiency in the economic literature, there has been a large collection of papers and articles devoted to the measurement of productive efficiency. Some of the most cited references are Farrell (1957), Charnes and Cooper (1962), Charnes, Cooper and Rhodes (CCR, 1978), and Banker, Charnes, and Cooper (BCC, 1984). CCR (1978) and BCC (1984) became the foundation of a non-parametric analysis called the Data Envelopment Analysis (DEA), which has been used in a wide-collection of analyses of efficiencies.

The DEA technique has been widely used to measure productivity and cost efficiency. Seiford (1996) gives a comprehensive survey of the evolution of the DEA technique from 1978 to 1995. In the first years, DEA was exclusively used to measure technical efficiency. Over the past two decades, the DEA technique flourished and was applied across all disciplines.

Studies using non-parametric analysis covered a wide range of areas from agriculture (Sueyoshi et al, 1998; Sueyoshi, 1999b); credit cooperatives (Fukuyama et al., 1999); banks (Taylor et al., 1997; Thompson et al., 1997; Chu and Lim, 1998)); telecommunications (Fuss, 1994; Staranczak et al., 1994; Sueyoshi, 1995, 1997; Lien and Peng, 2001); electricity (Schmidt and Lovell, 1979, 1980; Greene, 1990; Färe et al. ((1983, 1985(a), 1985(b), 1986, 1987, 1989); Thomas, 1985; Charnes et al., 1989; Hjalmarsson et al., (1992(a), 1992(b)); Miliotis, 1992; Olatubi and Dismukes, 2000; Pollitt, 1995; Goto and Tsutsui, 1998; Sueyoshi, 1999; Park and Lesourd, 2000; and Murillo-Zamorano et al., 2001; and many other sectors.

The studies that analyzed the electric supply industry assessed the links between deregulation and competition on one side, and wealth, share performance, profit efficiency, productive efficiency and cost efficiency on the other. While many earlier studies used regression analysis, the most recent studies used parametric frontier functions and non-parametric methods.

Non-parametric analysis does not require the specification of any particular functional form to describe the efficient frontier or envelopment surface. DEA, for instance, does not include a statistical noise variable in the estimation while a parametric frontier function requires a specific functional form. New research (Sengupta, 1999; Sueyoshi, 2000) extended the use of DEA to a dynamic framework by incorporating changes in productivity due to technological change and introduced a stochastic DEA approach.

Non-parametric techniques like DEA allow for several alternative formulations. The two versions most used in the literature make specific returns to scale assumptions.
Charnes, Cooper, and Rhodes (1978) used a single-constant-returns-to-scale model to measure technical efficiency. This model, now known as the CCR model, has been used in many research papers. The CCR model was joined later by the variable-returns-to-scale model of Banker, Charnes, and Cooper (BCC, 1984) for measuring scale efficiency, multiplicative models for piecewise log-linear frontiers (Charnes et al. 1982, 1983), and the nonoriented additive model (Charnes et al. 1985).

Some results of DEA analyses are presented here. Using DEA techniques, Goto and Tsutsui (1998) measured the overall cost efficiency and technical efficiency bilaterally between nine Japanese and 14 US electric utilities for the period from 1984 to 1993. Their main findings were that: (1) the overall cost efficiency of Japanese electric utilities was consistently higher than that of US electric utilities from 1984 to 1993; (2) Japanese utilities were more efficient than US utilities in terms of technical, allocative and scale efficiencies; (3) allocative inefficiency was a main source of overall cost inefficiency for the Japanese utilities; and (4) Japanese utilities overuse capital and underuse power purchase for cost-minimized production.

Using data from the 1996 *Steam Electric Generating Facility Database* of the Utility Data Institute (UDI) and from the US Energy Information Administration (IEA) report *Financial Statistics for Privately Owned US Electric Utilities*, Olatubi and Dismukes (2000) analyzed cost efficiency of coal-fired electric power generation. A sample of 313 IOUs is included in their study. First, a DEA approach generated efficiency scores; then, the authors estimated a Tobit model of the inefficiency scores using maximum likelihood techniques and assuming a logistic distribution for the errors. The results are as follows:

(1) Most coal-fired electric generation plants have almost exhausted their potential for technical efficiency. Given the current regulatory environment, future gains in a competitive environment should be expected on allocative capabilities of a plant's operations.

(2) Specific attention should be paid to the use of capital. Among the non-fuel inputs, capital is the most misused.

Olatubi and Dismukes (2000) concluded that there are potential opportunities for cost efficiency gains, and most of the inefficiencies arise from allocative efficiency (mean = 0.66) rather than in technical efficiency (mean=0.93).

Murillo-Zamorano and Vega-Cervera (2001) presented a comparative study of the use of parametric and non-parametric frontier methods to measure the productive efficiency of the US electric power industry. The study investigated a sample of 70 US (investor-owned) electric utility firms in 1990, evenly spread across the United States. Both the CCR and the BCC were used in this study. In addition, OLS techniques were used to analyze inefficiency scores. The results showed that there is no relationship between the size of firms and their inefficiencies. The authors found that the choice of parametric or non-parametric techniques, deterministic or stochastic approaches, or between different distribution assumptions within stochastic techniques is irrelevant if one is interested in ranking electric utilities according to their individual efficiency scores. The results show also that the parametric-deterministic approaches for the measurement of productive efficiency do not seem suitable for this kind of analysis. They concluded that DEA, because of its flexibility, can improve the accuracy of parametric techniques.

DEA models provide performance measures that can be communicated to managers, indicating by how much inputs have to be decreased (or outputs increased) in order to achieve cost (production) efficiency. DEA models also provide a set of efficient peer firms which serve as a benchmark for improvement and to which each inefficient decision making unit (DMU) should compare. For example, Barros (2008, p. 59) used DEA analysis on the hydroelectric generating plants of the Portugal Electricity Company (EDP) to recommend that management of EDP "should adopt an internal benchmark management procedure in order to evaluate the relative position of each hydroelectric generating plant and to adopt managerial strategies designed to catch up with the frontier of best practices."

Zhou et al. (2008) conducted a survey of 100 studies in energy and environmental studies which used DEA techniques. They found that 38% of the studies dealt with issues in the electricity industry, primarily electricity generation (for pre-1990 studies) and efficiency of electricity distribution utilities (post-1990). DEA techniques have also been used in modeling environmental performance, energy efficiency, and the productive efficiency of other energy sectors, such as district heating plants, gas industries, coal mines, and emissions permit allocations. Their other major findings are that most studies assumed that inputs and outputs are strongly disposable, that the return to scale property of the reference technology exhibits constant return to scale (CRS) even though the variable return to scale (VRS) technology might be a more appropriate assumption, and that input-oriented DEA models were more utilized than output-oriented models. They also found that the Malmquist Productivity Index (MPI)[20] was very popular during the period 1999-2006, most likely due to studies of productivity over time in deregulated electricity utilities.

Barros (2008) presented a number of efficiency analyses of electricity companies and found that the most recent papers used DEA and/or the Stochastic Frontier Analysis (SFA). Most of the studies reported by Barros (2008, 66-67) found that deregulating generation increases efficiency (Kleit and Terrell, 2001); alternative regulatory programs provide firms with incentive to increase efficiency (Knittel, 2002); public firms are more efficient under cost-of-service regulation, compared with price-cap regulation (Arocena and Waddams Price, 2002); and privately-owned plants exhibit higher average efficiency than publicly-owned plants (Pollitt, 1995).

Nakano and Managi (2008) used the TFP of DEA to analyze the impact of regulatory reforms on the Japanese electricity industry and found that regulatory reforms have a positive effect on productivity, mainly because of technological change.

Arocena (2008) used DEA to estimate the impact of alternative forms of unbundling on the cost and quality of supply and found evidence of cost and quality gains from vertical integration of power generation and distribution and from diversification of the sources of power generation. Further findings were that the design of the regulatory reform failed to create a market structure sufficiently competitive that would have allowed the maximization of the diversification and vertical integration because of the presence of market power.

[20] A DEA technique to measure Total Factor Productivity Index change from a defined distance function using CRS technology and decompose TFP into technical efficiency change and technical change.

Or and Sarica (2007) studied the efficiency of Turkish power plants using DEA and found that the private sector plants perform significantly better than the public sector plants, natural gas fired power plants have higher investment performance efficiency than coal-fired plants, and wind power plants have the highest efficiency values in operational and investment performance models.

Thakur et al. (2006) evaluated the efficiency of state owned electric utilities in India using DEA and found evidence of sub-optimal performances especially among the bigger utilities. Estache et al. (2008) studied the efficiency of African electricity companies that were members of the Southern Africa Power Pool. Using the MPI, they estimated the Malmquist Total Factor Productivity (TFP) index and found that the average efficiency level was higher when combined outputs were considered in comparison to each individual output separately.

Abbott (2006) used a DEA Malmquist approach to evaluate the productivity and efficiency of the Australian electricity supply industry and found that although technical progress occurred, there is still room for improvement since its growth rate was lower than the growth rate of the economy.

For the electric power industry in the United States, Vaninsky (2006) used a DEA analysis to study the efficiency of electric power generation He found a relative stability in efficiency from 1994 to 2000 at levels of 99 – 100% but concluded that the efficiency declined to 94 – 95% levels during the years after 2000.

Knittel (2002) evaluated alternative regulatory methods and firm efficiency of the US electricity industry using the SFA methodology. He analyzed the impact of alternative regulatory methods on the performance of coal electricity generation plants compared to gas-fired power plants. He found that coal plants that did not operate under alternative regulatory incentives experienced a mean level of inefficiency of 17.57% and that gas plants operating without any alternative regulation programs or incentives experienced a mean level of inefficiency of only

5.37%. Further findings show that the marginal impact of alternative regulatory programs was higher for coal plants than gas plants.

Markiewicz et al. (2004) used a translog regression model to study how transition to market-oriented environments affected electric generating plants in the United States. His results show that generation plants most affected by restructuring reduced labor and nonfuel expenses, holding output constant, by three to five percent relative to other investor-owned generation plants, and by six to twelve percent relative to generation plants owned by POUs and cooperative electric utilities that were not affected by restructuring incentives.

Goto and Tsutsui (2008) used a translog stochastic frontier analysis to study the impacts of deregulation on technical efficiency of generation, transmission/distribution, and general administration function and its change over time for large-scale electric power utilities in the United States during the period from 1992 through 2000. They found that firms located in states with advanced deregulation were less efficient in generation and general administration than firms in states without electric restructuring, and no effects of deregulation were observed in the transmission/distribution network function.

In summary, these studies generally used the data envelopment analysis (DEA) or the stochastic frontier analysis (SFA). Although most studies generally found evidence of efficiency gains in other countries, the evidence for the electric utilities in the United States is mixed. Olatubi and Dismukes (2000) found that most coal generation plants almost exhausted their potential for technical efficiency, and Goto and Tsutsui (2008) used a stochastic frontier analysis and found that firms located in advanced deregulation states were less efficient in generation but that the average degree of efficiency is higher for firms that are located in states with slower progress of deregulation. Our study will determine if IOUs, COOPs and POUs in deregulated states are more efficient in generation and overall operations than regulated firms in a more recent period of time.

### 3.6. Review of Recent Empirical Research into Electricity Deregulation in the United States

Kwoka (2006) reviewed twelve studies of the cost efficiencies and price benefits of deregulation of the electric power industry in the United States. He concentrated on the strengths and limitations of the methodologies used in those studies and on the confidence one might place in their conclusions and recommendations. Four studies compared prices before and after restructuring, or with and without restructuring; they represented pricing as a function of causal variables, estimated the relationship, and contrasted actual prices with predicted prices in the absence of restructuring. Those are studies by Cambridge Economic Research Associates (2005); Joskow (2006); Taber, Chapman, and Mount (2006); and Fagan (2006). Five studies simply compared prices (or costs) under restructuring relative to what they would have been in the absence of restructuring. Those were studies by Center for the Advancement of Energy Markets (2003); Apt (2005); Synapse (2004); Global Energy Decisions (2005); and Energy Security Analysis, Inc (2005). Finally, studies by Weaver (2004), the ISO/RTO Council (2005), and the N.Y. State Department of Public Service (2006) were more descriptive and evaluated the impact on single companies or institutions in restructured electricity markets.

Nine of the studies found that there were retail price benefits or cost efficiencies from electricity restructuring while the remaining three found no benefits or even found outright consumer costs from restructuring. However, Kwoka concluded that all twelve studies suffered from three major deficiencies:

(1) The lack of precision about the meaning and measurement of electricity restructuring;

(2) Overlooking the fact that the post-restructuring prices in many states were administratively set and not a reflection of the equilibrium market price; and

(3) Failure to control for many other factors besides electricity restructuring that may have affected post-restructuring prices.

Without properly reflecting these factors, the price effects of electricity restructuring may not necessarily be the result of restructuring itself.

In addition, Kwoka noticed three other factors that most studies failed to take into consideration, even though they should be included in any study of the impact of electricity restructuring:

(1) the existence of market power, market manipulation, and numerous mergers among utilities;

(2) the rising costs of regional transmission organizations (RTOs), inadequate RTO governance processes, and the failure of RTOs to deal with transmission congestion or to successfully encourage new investment in the grid; and

(3) the potentially adverse effects of restructuring on service quality and reliability effects.

Kwoka (2006, p. vii) concluded that "the methodologies used in these studies consistently fall short of the standards for good economic research. In addition, most of these studies fail to fully address the effects of restructuring. These deficiencies call into question the conclusions reached by existing studies of restructuring. In particular, despite much advocacy, there is no reliable and convincing evidence that consumers are better off as a result of restructuring of the US electric power industry."

Other studies not included in Kwoka's 2006 review concluded that more and better assessment of the effects of electricity restructuring needed to be performed in order to have better results. Blumsack et al. (2006) critiqued the studies by the Center for the Advancement of Energy Markets (2003), Cambridge Energy Research Associates (2005), and Joskow (2006) stating that, contrary to the findings in these studies, their research found no evidence that electricity restructuring produced any benefits. Spinner (2006) identified problems in the studies of the Cambridge Energy Research Associates (2005) and the Global Energy Decisions (2005) similar to the deficiencies found by Kwoka (2006).

In conclusion, these studies provide no evidence of gains in efficiency or benefits due to deregulation in the United States. Kwoka (2006), Blumsack et al. (2006) and Spinner (2006) discussed the methodological deficiencies, including the failure to correct for selection bias in their samples, in many recent studies which concluded that deregulation had benefited the public. They all concluded that there is need for more research into the benefits of electricity deregulation in the United States.

In our research, we use a cost decomposition technique first introduced by Juhn, Murphy and Pierce (JMP, 1993) to study the effects of deregulation on US electric utilities. This approach decomposes cost differences due to deregulation into changes in observable quantities, changes in observable prices, and changes in unobservable residuals. Using the JMP decomposition, our study decomposes the change over time in the difference in costs of regulated and deregulated electric utilities into changes in their characteristics over time, changes in prices over time, and changes in residuals (unexplained differences) over time. This approach goes beyond the analysis of mean cost and mean price differences between regulated and deregulated firms. It allows us to determine the cost, price and quantity differentials between the two groups at any point in their cost distribution. The JMP decomposition permits us to also analyze the effects of changes in the residual of cost differences between the groups of regulated and deregulated electric utilities. Finally, using this approach is the most accurate way to analyze the effects of possible changes in relative costs due to unobservable characteristics.

### 3.7. Review of Empirical Research into Shareholder Wealth

The profitability of the electricity supply industry is dependent upon state and federal regulation for many decades. Regulations assure that firms in the industry operate as natural monopolies and recover their costs plus receive a reasonable return on investment. With the introduction of competition in the industry, it is possible that shareholder wealth suffers due to stranded assets,[21] increased market and firm specific risk, and possible transfers of wealth from producers to consumers. Indeed, it is possible that a utility which loses its monopoly power due to deregulation will see the value to its owners decline by the present discounted value of expected future monopoly profits.

The change in shareholders wealth is measured by abnormal returns and the change in earnings per share due to competition and restructuring (deregulation). Financial performance is measured in terms of profitability or profit margin and return on assets in the year when deregulation and competition were introduced and in subsequent years relative to pre-competition and pre-deregulation years.

Much of the literature analyzing the impact of deregulation on shareholder wealth in the electricity supply industry used event study techniques. Event study methodology capitalizes on the Efficient Markets Hypothesis which predicts that new information is immediately reflected in security prices. Event history studies of regulatory change were conducted for many other industries including banking ( Aharony and Swary, 1981; Amoako-Adu and Smith, 1995; Cornett and Tehranian, 1990; Carow and Heron, 1998; Dann and James, 1982 ; Madura and Bartunek, 1995; Liang et al., 1996; Akhigbe and Whyte, 2001), airlines (Banker et al., 1997; Vetsuypens et al., 1988), tobacco (Jognson et al., 1991), and electricity (Besanko et al., 2001; Berry, 2000; ). It was also used to study the impact of product recall (Jarrell and Peltzman, 1985); merger regulations (Schipper and Thompson, 1983), and environmental regulation (Blacconiere and Patten, 1994).

All of these studies attempted to predict movements in stock returns in response to legislative and regulatory events. Empirical studies provided support for the hypothesis that stock movements are not idiosyncratic and can, in fact, be predicted (Ferson and Harvey, 1991). Before

---

21 The value of stranded assets would be lost if markets were to become competitive because lower cost producers could compete against higher cost producers and drive them out of the market.

using event studies, early attempts at predicting stock returns were based on the Capital Asset Pricing Model (CAPM). Other studies substituted the CAPM with the Arbitrage Pricing Theory (APT) because this theory was readily testable since it does not require the measurement of the market portfolio (Kumar et al., 2000). APT attempted to measure the various dimensions of market related risk in terms of several underlying economic factors which systematically affect the price of all shares (Kumar et al., 2000). However, APT is not useful if one is unable to identify additional risk factors that are relevant.

Nwaeze (2000) noted that, according to the theories of economic regulation, regulation reduces earnings variability and risk and enhances share value by buffering the regulated firms against the profit effects of cost and demand shocks and shifting the burden of inefficiencies to consumers. These views motivated an opposite argument that reductions in regulation would reverse the predicted effects of regulation. Testing whether recent reforms of the electric power industry reversed the predicted effects of regulation on profits, risk, and return for electric utilities, Nwaeze (2000) found that: (1) the buffering effect of regulation was reversed, (2) subsidies attributable to regulation existed, and (3) shareholder wealth was redistributed during the reforms.

Using multivariate analysis, Johnson et al. (1998) investigated the effects of regulatory changes in the electricity utility industry on shareholder wealth. They analyzed the effects of the 1992 Energy Policy Act and of the 1993 announcement by the FERC that forced competition in Florida and found that these regulatory changes and the opening of transmission lines to outsiders had negative and significant effects on stock values for the overall sample of firms examined. They found that greater competition dissipated economic rents associated with the previously held monopolistic situations.

They found that (1) firms with greater levels of nuclear assets and higher earnings per dollar of assets prior to the regulatory actions suffered greater negative abnormal returns than other firms in the sample; (2) firms in a more competitive environment prior to regulatory changes had less negative abnormal returns; (3) after deregulation, market risk increased by 48.88% while firm specific risk increased by 23.66%; and (4) firms which were previously the most protected by receiving greater revenue relative to capital investments faced greater risk of a change in revenue in a competitive environment .

Berry (2000) used event history methodology to investigate excess returns in electric utility mergers during the transition to competition. He focused on the day before the announcement and the day of the announcement and found small but statistically significant effects. He concluded that shareholders perceived few merger benefits in a highly competitive generation sector; that markets reacted more positively to the gas/electric mergers, indicating shareholder appreciation for opportunities for scope economies; and that acquirers in the United States suffered no significant wealth losses in mergers with British and Australian utilities.

Besanko et al. (2001) used event history methods to analyze electric utility stock price reactions to events preceding the passage of the Energy Policy Act of 1992. For the industry as a whole, the authors found that, at worst, investors had neutral reactions to events preceding wholesale deregulation. However, stock price reactions varied systematically with differences in incumbent utilities' marginal costs, though not with differences in fixed costs or purchased power costs. These results were consistent with the notion that new technologies substantially reduced barriers to entry into the electric power generation industry, rendering capital cost advantages of incumbent utilities vulnerable to new entrants. However, marginal cost advantages were more sustainable because they were likely driven by inimitable locational advantages.

The samples studied in previous research into the wealth effects varied. Johnson et al (1998) investigated a sample of 68 investor-owned electric utilities with daily stock returns published by the University of Chicago Center for Research in Security Prices (CRSP). Blacconiere et al. (2000) collected data on all investor-owned electric utilities --933 firm/year observations-- (Standard Industrial Classification codes 4910, 4911, and 4931) that were publicly traded four years before and four years after the passage of the 1992 EPAct and whose data were available from COMPUSTAT. Their analysis was also conducted for a non-electric utility sample of firms from many different industries which formed the control group.

In all the studies, firms were indistinctly combined in a sample even though many of the firms operated strictly in states where deregulation was not in place. It is important not to lose sight of the fact that not all states have reached the same degree of competitiveness and that many electric utilities operate in both regulated and deregulated states at the same time. In addition, many electric utilities are multiproduct firms. Some of the inputs used by the firm may be divided in the production of the many outputs. Failing to incorporate that aspect in an analysis biases the results.

Previous studies failed to distinguish between short-term and long-term wealth effects. Short-term effects were investigated using event history analysis for individual events while long-term effects were analyzed using a multivariate regression model for the combined effects of all events. Most studies limited the time period to the short time period.

Cornett and Tehranian (1990) noted that the use of a multivariate regression model incorporated heteroscedasticity across equations and contemporaneous dependence of the disturbances into the hypothesis tests. In addition, because the magnitude of the unsystematic risk differs across firms, the variance in abnormal returns varied across firms (Fama, 1976). Schwert (1981) stated that individual asset returns for firms in the same industry measured over a common time period were contemporaneously correlated because firms reacted similarly to any unanticipated event. Thus, contrary to the requirements of the standard event history methodology, residuals are not identically and independently distributed. Indeed, with common calendar day announcements for all stocks, the error term is not independent across equations which reduces the efficiency of the estimated coefficients and renders the t-statistics unreliable if each equation is estimated separately (Amoako-Adu and Smith, 1995).

Studies of wealth effects of electricity deregulation focused exclusively on the impact of different events on returns. Overall, these studies found that deregulation can potentially impact both shareholder wealth and risk. In addition, they suggested that the impact is likely to depend on factors such as size, degree of competition, and other market variables. Previous studies demonstrated that most deregulation events resulted in wealth effects for electric utility shareholders. However, not only are there only a few studies of wealth effects, but the results vary significantly across studies. Most past studies focused on general policies reforming the electricity industry in the United States rather than on state specific deregulation policies and their impact on the profitability of electric utilities. They also focused on short term effects of deregulation. We use a regression analysis of the effects of cost efficiency due to state deregulation policies across all the states and determine whether or not electricity deregulation resulted in long-term benefits for shareholders and in long-term profitability of the IOUs.

### 3.8. Summary of Main Findings and Issues Study

Past research left many unanswered questions about the effects of ownership and deregulation or competition on the efficiencies and profitability of electric utilities in the United States. This study addresses some of the gaps left by those studies. Studies of economies of scale and vertical integration left doubt about the existence of significant economies of scale. We make five major contributions to the literature on electricity deregulation in the United States.

First, our study attempts to determine whether or not there are efficiencies due to economies of scale in vertically integrated electric utilities by ownership. We also determine whether deregulation yields significant benefits to justify the elimination of regulation. The question of benefits and costs of regulation is ancient but unresolved to date. Past research into the effects of ownership produced mixed results with some studies showing that privately owned utilities have greater efficiencies than publicly owned utilities and others showing the opposite.

Second, we study a large sample of electric utilities over 8 years compared to most past studies which limited their analyses to smaller samples and shorter time periods. We focus on cost efficiency differences among electric utilities due to deregulation for each type of ownership and provide further evidence of the effects of ownership and deregulation.

Third, our study uses DEA and SFA techniques to determine if IOUs, COOPs and POUs in deregulated states are more efficient in generation and overall operations. Previous studies of the effects of deregulation on cost efficiency used DEA and SFA techniques to show evidence of efficiency gains in other countries which deregulated their electricity industry. The evidence for the US electricity industry is at best mixed with some studies concluding that deregulation generally increases efficiency, or that deregulation has produced less efficiency in generation, and others concluding that the costs of deregulation outweighed the actual gains from deregulation. Recent studies of the benefits of deregulation of the electric utilities in the United States confirmed the need for better methodological approaches in order to account for the total impact of deregulation on the industry.

Fourth, we use a cost decomposition analysis to study the effects of deregulation on electric utilities. This approach takes into consideration the fact that deregulation may not result in a random sample of all states but rather a select sample from states with high production costs and high electricity prices. This study decomposes the change over time in the difference in costs of regulated and deregulated electric utilities into changes in their characteristics over time, changes in prices over time, and changes in residuals (unexplained differences) over time.

Fifth, the final contribution of this research is an analysis of the effects of deregulation on the profitability of electric utilities. Although most past studies relied on event history methodology to investigate excess returns due to competition, this study measures the effects of cost efficiencies due to deregulation of IOUs on the stock returns of IOUs and on their profitability.

Overall, this provides the most recent evidence to date on the efficiency of the electricity industry in the United States and the impact of federal and state deregulation on production, generation, and transmission of electricity to consumers.

# CHAPTER IV

# MODEL DESCRIPTION

## 4.1. Introduction

This chapter describes the economic model that will form the basis for our study of efficiency among electric utilities in the United States. Efficiency estimates of deregulated electric utilities are compared with those of regulated electric utilities and other characteristics of firms are identified that are linked to observed efficiency.

Efficiency measurement began with Farrell (1957). He proposed that the efficiency of a firm consists of technical and allocative efficiency. Technical efficiency refers to the capacity to produce the maximum level of output for a given quantity of inputs under the given technology; allocative efficiency refers to the ability of a firm to use inputs optimally given their respective input prices and expenditure limitations. Figure 1 below illustrates technical efficiency while Figure 2 illustrates technical and allocative efficiencies of a firm.

Figure 1. Technical Efficiency

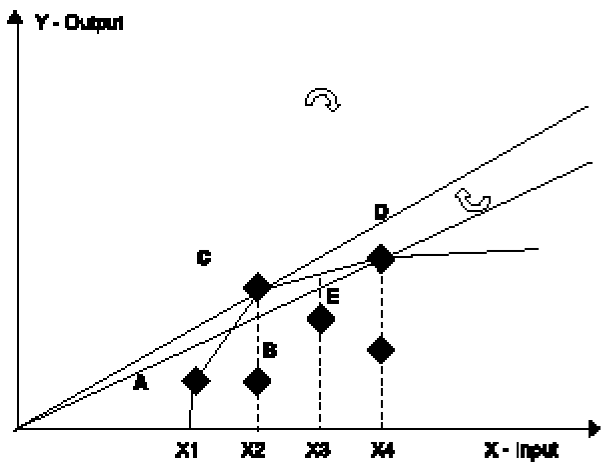



Figure 1. Technical Efficiency

Technical efficiency consists of pure technical efficiency, scale efficiency and capacity utilization. Figure 1 graphs six points A, B, C, D, and E. The curve ACD is the production possibility frontier. Firms lying on the frontier (i.e., A, C and D) gain 100% pure technical efficiency while firms which lie under the frontier (i.e., B and E) do not.

Firm C achieves optimal pure technical efficiency and faces constant-returns-to-scale; therefore, firm C is maximizing its technical efficiency. Firms A and D reach maximal pure technical efficiency but do not achieve optimal scale efficiency. Even though a firm at point B reaches the maximal scale efficiency, it is technically inefficient because it uses the same input, $x_2$, as firm C but achieves a lower level of output.

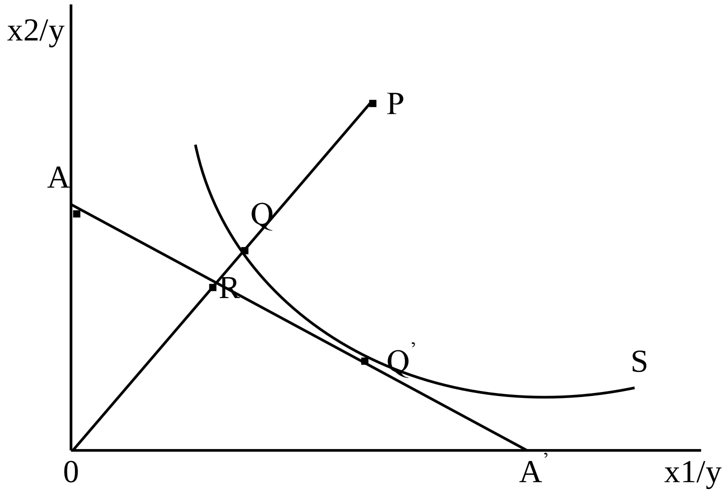


Figure 2: Technical and Allocative Efficiencies

Figure 2 above illustrates the concepts of technical and allocative efficiencies under the assumption of constant returns to scale and two inputs (x1 and x2) and one output (y), technology. An efficient firm produces along the efficient isoquant S. A firm which produces at P is inefficient because it could produce the same output at Q with fewer inputs. The distance QP is the amount by which all inputs could be proportionally reduced without a reduction in output. The technical efficiency of this firm is measured by the ratio: TE = OQ/OP = 1- QP/OP.

A value of one means that the firm is fully technically efficient. This firm is fully technically efficient at Q. If the budget constraint is known and represented by the line AA', then the allocative efficiency of this firm at P is measured by the ratio:

AE = OR/OQ.

At point R, the firm can reduce the production costs if production were to occur at the allocative (and technically) efficient point Q'. The total economic efficiency is then represented by the ratio: EE = OR/OP = TE x AE.

The distance RP represents the total cost reduction that can be achieved by a firm operating at the allocatively efficient point.[22]

In the sections below, methodological approaches to cost efficiency are presented. DEA and SFA methods are discussed with respect to the study of efficiency gains from electricity deregulation. These methods have the advantage over econometric analysis because of their ability to separate firm efficiencies in technical, allocative, economic efficiencies and total factor productivity analysis. We further decompose the efficiency gains due to electricity deregulation using the Juhn-Murphy-Pierce decomposition explained below. This methodology allows us to determine the sources of efficiency gains (or losses) in a manner not explored before.

## 4.2. Cost and Production Efficiencies

This study investigates the effects of deregulation and competition on the efficiency and performance of United States electric utilities. The review of the literature in Chapter 3 summarized the results from many empirical models that tested the hypothesis that deregulation improves cost efficiency –cost minimization and profit maximization-, productivity and profitability in privately-owned electric utilities and improves efficiency in cooperative and publicly-owned electric utilities. We focus on productivity and efficiency for two reasons. First, firm use of accumulated resources is a major consequence of gaining competitive advantage, and second, efficiency of resource allocation affects the ability of a firm to grow (Majumdar., 1998). In addition, better financial performance implies that a firm has reached a certain level of productive efficiency and, in the context of deregulation, a certain level of successful adaptation to the new market environment.

Earlier research efforts used linear programming methods to measure changes in productivity and efficiency due to increased competition. These methods are nonstochastic and

[22] The description of efficiency in this introduction was drawn from Coelli (96/08).

do not allow for random error. The most popular technique to date is the Data Envelopment Analysis (DEA). With linear programming, one can calculate the Malmquist index which decomposes productivity changes into changes in efficiency, shifts in the production function, and changes in the scale of operations. Other research estimated stochastic models of production on costs. The most common approach was to estimate a translog cost function and use parameter estimates to measure the changes in efficiency and productivity over time or across firms.

There is no way to determine whether electric utilities became more or less efficient or productive in an economic sense or responded more or less appropriately to deregulation and competition when one ignores the stochastic component of the introduction of deregulation or competition in the industry. However, techniques like DEA which ignore the stochastic term are useful because technically, productivity changes are based on quantities of outputs and inputs without regard to changes in prices.

We use both approaches in this study, and we compare the results. . The first method uses the optimization approach of DEA, and the second method decomposes average cost into quantity and price changes due to deregulation.

### 4.3. Decomposition of Cost changes due to Deregulation

Our first econometric cost analysis determines whether there are sufficient input cost and output price differences between deregulated and regulated electric utilities, which would justify an analysis of the potential selection bias in the sample of deregulated electric utilities. First, we estimate a cost function for electric utilities and use the model to determine whether firms in states with electric restructuring laws are more cost efficient than regulated utilities. We assume a quadratic cost function for both regulated and deregulated electric utilities. We choose a quadratic cost function because it handles zero values of variables such as some output values and fixed effects variables better than the translog cost function (Kwoka, 2005).

Second, we measure the extent of inefficiency between deregulated and regulated electric utilities. We decompose the regulated-deregulated cost differential into a predicted and a residual component, where the predicted component is divided into quantity and price components. From the decomposition, one can determine the source of cost inefficiency. While both quantity and price changes are important determinants of changes in costs, price changes provide the right signal to electric utilities to become more cost efficient.

Third, we measure the change in cost differentials over the sample period. The variable cost function is given in (1) below:

$$C_{it} = X_{it}\,\beta_t + e_{it} \qquad i = \text{deregulated, regulated, } t\text{=time period} \qquad (1)$$

where C is the average costs; X is a K by 1 vector of exogenous variables (input prices, variable output quantities, environmental variables, efficiency factors and other productivity related variables) that affect costs; β is a 1 by K vector of parameters representing the impact of these attributes on variable costs; and e is a random error assumed to have zero mean each period.

If group membership is not randomly selected; characteristics of firms, observed and unobserved, are systematically linked to whether firms are deregulated. In this case, the expected value of the error term in (1) with non-random selection does not equal zero. [23]

Following Juhn, Murphy, and Pierce (1993), we rewrite the residual in (1) for each regulated and deregulated firm in terms of a standardized residual in the average cost distribution

[23] Kwoka (2006) describes how econometric models encounter a methodological problem of causation because some states may have restructured as a consequence of pre-restructuring unusually high prices or because other relevant factors existed that pushed the states to restructure. Thus, the restructuring states may not be a random sample of all states, as single equation econometric modeling requires, and the results of the econometric models may be biased estimates of the price effect of restructuring since the estimates are derived from a non-random selected set of states. If one does not correct the selection bias, Kwoka (2006, p. 24) concludes that "[t]he estimate at best might measure the effect of restructuring for high-price states. At worst, it may be entirely suspect if some characteristic of those states' political, social, or economic make-up simultaneously causes both the high prices and its effort to restructure." The JMP decomposition accounts for the impact of differences in observable characteristics which explain some of the sample selection. However, we do not further decompose the residuals into a component that explains non-random selection. This should be a focus of future research.

($\theta_t$) with mean zero and variance one and the within-group standard deviation of the costs of regulated firms in year t ($\sigma_t$).

$$C_{dt} = X_{dt}\beta_{dt} + u_{dt} \quad (2)$$
$$C_{rt} = X_{rt}\beta_{rt} + u_{rt} \quad (3)$$

where $C_{dt}$ and $C_{rt}$ are the average costs of deregulated and regulated electric utilities in year t, $X_{dt}$ and $X_{rt}$ are vectors of individual characteristics, and $u_{dt}$ and $u_{rt}$ are the components of average costs accounted for by the unobservable characteristics of firms. As explained above, $u_t = \sigma_t\theta_t$ for each firm in the deregulated and regulated samples. The cost gap in year t can be written as

$$CD_t = \Delta X_t\, \beta_{rt} + \sigma_{rt}\Delta\theta_t \quad (4)$$

$\Delta\theta_t$ is the difference in the average standardized residual for deregulated and regulated firms ($\theta_{dt} - \theta_{rt}$). The actual change in the cost gap from year t to year t+k is shown in below:

$$D_{t+k} - D_t = (\Delta X_{t+k} - \Delta X_t)\, \beta_t + \Delta X_{t+k}\, (\beta_{t+k} - \beta_t) + [(\theta_{dt+k} - \theta_{rt+k}) - (\theta_{dt} - \theta_{rt})]\, \sigma_{rt} \quad (5)$$
$$+ (\theta_{dt+k} - \theta_{rt+k})\, (\sigma_{rt+k} - \sigma_{rt})$$

$$D_{t+k} - D_t = (\Delta X_{t+k} - \Delta X_t)\, \beta_t + \Delta X_{t+k}\, (\beta_{t+k} - \beta_t) + (\Delta\theta_{t+k} - \Delta\theta_t)\, \sigma_{rt} + \Delta\theta_{t+k}\, (\sigma_{rt+k} - \sigma_{rt}).$$

$(\Delta X_{t+k} - \Delta X_t)\, \beta_t$ is the change over time in the difference in the average costs of regulated and deregulated firms due to changes in their observable characteristics over time and evaluated at prices in period t; $\Delta X_{t+k}\, (\beta_{t+k} - \beta_t)$ is the change in the average cost difference due to changes in prices over time evaluated at the (t+k) difference in observed characteristics. The third term captures changes in the relative positions of deregulated and regulated firms in the residual distribution of regulated firms. If $\Delta\theta_j$.> 0, (j=t, t+k), then deregulated firms are less efficient than regulated firms in period t. If $(\Delta\theta_{t-k} - \Delta\theta_t)$ >0, then this disadvantage for deregulated firms increased over time. The fourth term captures the effect of the change in the residual cost distribution over time.

Our cost efficiency conclusions therefore depend on the relative values of $\theta_{dt+k}$,$\sigma_{rt+k}$, and $\sigma_{rt.}$ If, over the study period, the residual cost difference increases ($\sigma_{rt+k} < \sigma_{rt}$) for regulated firms, the efficiency gap in favor of deregulated electric utilities will increase as long as $\theta_{dt+k} < \theta_{rt+k.}$ This means that as long as the average deregulated electric utility is more cost efficient than the average regulated utility, the fourth term implies that a rise in inefficiency of regulated utilities as compared to deregulated utilities increases the cost differential. If deregulated electric utilities remain in the same position in the regulated utilities' distribution, a rise in residual inefficiency of regulated utilities will increase the cost gap between the two groups. Following Juhn, Murphy, and Pierce, we refer to the third and fourth terms as the Gap and the Unobserved Price terms.[24]

A profit decomposition can be done using the same procedures adopted for the cost minimization problem. However, because profit maximization is not the primary goal for many utilities (for example cooperatives), we only use the cost decomposition for the analysis of all utilities.

### 4.4. Competition, Production Efficiency and Non-Parametric Methods

Theory predicts that competition in the markets drives firms to search for better technologies to improve production efficiency and enhance profits. On the contrary, in order to improve profits, a monopolist simply raises the prices of its products. Since competition promotes production efficiency, competition yields superior outcomes compared to a monopoly market. In an industry where economies of scale are prevalent, the existence of a natural monopoly is more justified. For competition to be effective, it has to break the natural monopoly through entry of new players. For competition to prevail, it must bring about benefits greater than monopoly costs

---

[24] Vides Andrade used the same decomposition in her analysis of wage inequalities in El Salvador (see references).

to the society.  We investigate the relationships among competition, profitability, production efficiency, and scale economies using a combination of parametric and non-parametric methods.

Knight (1933), Debreu (1951), Koopmans (1951), and Farrell (1957) laid the foundation for current approaches to measuring production efficiency (or inefficiency) by developing a system of equations known as distance functions. Shephard's (1953) duality theorem established the link between production and costs while Farrell's work enabled theoretical estimation of productive efficiency scores.  Cost function approaches to the evaluation of firm performance are particularly relevant in a regulatory environment that constrains output or price.

Three methods of estimation have been developed: linear programming, deterministic frontiers, and stochastic frontiers.  First, there is the data envelopment analysis (DEA) method which stems, historically, from the Debreu-Farrell efficiency concept.  Charnes et al. (1978), Banker (1984), Banker et al. (1984), and Färe et al. (1985) were the first authors to develop DEA studies.  DEA evaluates global efficiencies of production systems, as revealed through micro-economic (generally cross-sectional) data.  Many other studies such as Barr et al. (1993) investigated the possibility of combining DEA approaches to parametric models, by introducing into such models DEA efficiencies as exogenous variables. Others such as Sueyoshi (1999b) investigated the possibility of combining DEA with stochastic approaches.

Only a few past studies of the electric industry investigated technical changes using parametric techniques.  Most cost analyses focused on scale economies.
The problem with previous studies that relied on a traditional econometric estimate of a production function is that the estimated function traced out the least cost locus for varying output, the 'average' output for varying input levels, or minimum cost given output levels. Hence, the average production function represents maximum output levels given fixed input

levels. Underlying this methodological approach is the assumption that all firms are operating efficiently.[25]

Another line of empirical work takes a slightly different route using stochastic cost or production frontiers. The model assumes that inefficiency of the firm is embedded in the error term of the traditional econometric regression (i.e. a composed error). The structure of the error term and the validity of the assumption about its distribution influence the measured efficiency of the firm.

A methodological alternative to the regression to the mean analysis of past utility cost analysis was presented by Charnes et al. (1978), who coined the term data envelopment analysis, and introduced a mathematical programming framework into Farrell (1957). DEA uses a linear programming method to search for the optimal combinations of outputs and inputs. In cost applications, DEA seeks the minimum cost associated with the highest level of outputs. The method optimizes on each individual observation with the objective of calculating a discrete piecewise frontier in contrast to the focus on averages and estimation of parameters with statistical approaches. DEA is similar to the parametric frontier analysis in the sense that it uses best practice observations to trace out a least-cost operating locus. Its main difference, however, is that as a deterministic method, it makes no adjustments for random noise, and can be sensitive to outlier observations.[26]

In DEA analysis, some attention must be given to assumptions regarding cost returns. Although Charnes et al. (1994) considered only constant returns to scale (CRS), other studies have included a variety of approaches such as variable returns to scale (VRS), and even non-increasing returns to scale (NIRS). Our analysis assumes variable returns to scale given the

[25] Under certain conditions a fitted (average) function can permit a ranking of observations by technical efficiency. Nevertheless, it cannot provide any quantitative information on technical inefficiency for any observation in the sample (Schmidt and Lovell, 1979).

increasingly competitive nature of the power industry and the host of prior studies that have undermined the natural monopoly assumption. From a practical perspective, the use of variable returns to scale permits the estimation of efficiency scores that are not confounded by scale effects.

In Figure 1, we illustrate the differences between the traditional parametric approach and the DEA in measuring efficiency.

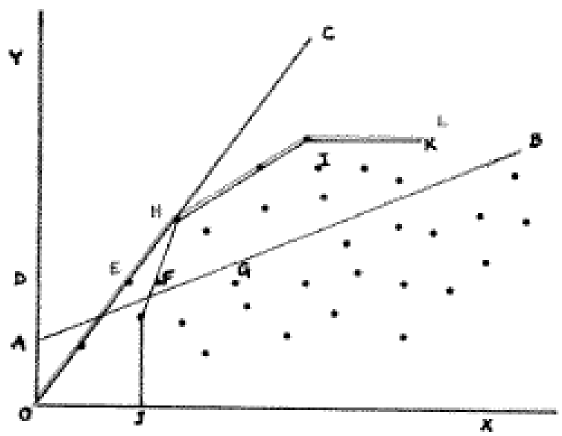



Figure 3: Comparison of average function and DEA frontiers.

While most parametric approaches using linear functions seek to optimize a single plane (AB) through the data, the DEA approach takes an alternative route by optimizing on the individual observation.[27] The goal of DEA is to estimate a discrete piecewise frontier (an envelope) as determined by the given data set of Pareto-efficient firms. We have presented an

---

[26] Since the true level of efficiency or inefficiency is not known, it is not possible to ascertain which of the assumptions underlying the stochastic frontier or the DEA dominates the other.

[27] Most empirical parametric approaches assumed linear functions. However, under non-linearity optimization is over multiple planes.

illustration of this frontier in Figure 3.  For our example, we assumed a one-input, one-output firm, although the analysis can be easily extended to multiple-output, multiple-input situations.

Depending on the particular assumption about returns to scale, a frontier that envelops the data may be given by the CRS projection (OC), the VRS projection (JK), or non- increasing returns (NIRS) projection (OL).[28]  Thus, in the parametric average function it is assumed that each individual firm takes on the score of the 'average'
performance unit or firm.  In contrast, the DEA focus is on each individual firm's score in relation to the best performer such that each firm lies on or below the extreme frontier. Each firm not on the relevant frontier (OC, JK, or OL) is scaled against a convex combination of the firm or unit of observation on the frontier closest to it.  All firms located below the relevant frontier are thus technically inefficient and hence, cannot be minimizing cost since they will be, by definition, using inputs excessively given the prices of those inputs.

There are two versions of DEA efficiency measures, the CCR measure and the BCC measure; see Charnes et al. (1978) and Banker et al. (1984).  The CCR measure is calculated with the constant returns to scale (CRS) assumption whereas the BCC method allows for variable returns to scale (VRS).  Both methods are applied to examine electricity supply industry performance.

Following Lien and Peng (2001), consider *n* decision making units (DMUs), $j=1,\ldots,n.$ The units are homogenous with the same types of inputs and outputs. Assume there are *m* inputs and *k* outputs. Let $x_j$ and $y_j$ denote, respectively, the input and output vectors for the j-th DMU. Thus, $x_j$ is a (mx1) column vector and $y_j$ is a (kx1) column vector. Moreover, $x = (x_1, x_2, \ldots, x_n)$ is the $m \: X \: n$ input matrix and $y = (y_1, y_2, \ldots, y_n)$ is the $k \: X \: n$ output matrix.

[28] This illustration combines three different frontiers and the traditional 'average' function (AB) into one graph so readers can easily grasp the differences. Each of the three frontiers, OC, JK, or OL is only relevant for the return-to-scale it represents, and hence, the data points they envelope.

The CCR model assigns weights to each input and output, and then assesses the efficiency of a given DMU by the ratio of the aggregate weighted output to the aggregate weighted input. The weights assigned must be nonnegative. Also, they must restrict each DMU from receiving a ratio (of the weighted output to the weighted input) that is greater than one. Mathematically, when evaluating the efficiency of the decision-making unit "o", we solve the following problem:

$$\underset{\{u,v\}}{Maximize}\; u^T y_o / v^T x_o \qquad (6)$$
$$Subject \quad to: u^T y_j / v^T x_j \quad \leq 1,\; j = 1, \ldots, n;\, u, v \geq 0.$$

where *u* is the *(*kX1) vector of output weights and *v* is the *(*mX1) vector of input weights. "T" denotes the matrix transpose operator. Thus, *u* and *v* are chosen to maximize the efficiency measure of the DMU "o" subject to the constraints that the efficiency levels of all units must be less than or equal to one.

The above problem has an infinite number of solutions. To generate a unique solution, the following constraint is imposed: $u^T y_o = 1$. The maximization problem then becomes:

$$\underset{\{u,v\}}{Minimize} \quad v^T x_o \qquad (7)$$
$$Subject\ to: u^T y_o = 1,\, u^T y_j - v^T x_j \leq 0,\; j = 1, \ldots, n;\, u, v \geq 0.$$

The duality problem to (16) can be written as follows:

$$\underset{\{u,v\}}{Maximize}\; \phi_o \qquad (8)$$
$$Subject\ to: \phi_o y_o \leq \lambda^T y,\, x_o \geq \lambda^T x,\, \lambda \geq 0.$$

where λ is a *(*nX1) column vector and $\phi_o$ is a scalar. In other words, we search for all linear combinations of input vectors in current practices that can be provided by the input vector of the "o" unit. We then compute the maximal proportional output vector that can be produced by these linear combinations. Let $\phi_o^*$ denote the solution to (8). Obviously $\phi_o^* \geq 1$. If $\phi_o^* = 1$ , then the decision-making unit "o" is (CCR) technically efficient. Otherwise, $\phi_o^* > 1$ and "o" is (CCR) inefficient. Later we also denote $\phi_o^*$ by $E_{ccr}$, the efficiency score measured by the CCR method.

Underlying the CCR method is the assumption of constant returns to scale. This assumption is not supportable in imperfectly competitive markets. The BCC model modifies the CCR method by allowing variable returns to scale (VRS). This is done by simply adding the convexity constraint $e^T\lambda=1$ into Equation (8), where $e$ is an $(nX1)$ column vector of ones. Let $\phi_o^{**}$ be the solution to the new problem, also denoted as $E_{bcc}$ . Clearly, $E_{bcc} \leq E_{ccr}$ . Note that the BCC method measures purely technical efficiency whereas the CCR method measures both technical efficiency and scale efficiency. We derive a measure for scale efficiency $E_{scale} = E_{ccr} / E_{bcc}$. In this study, all three of the above efficiency measures are compared across regulated and deregulated electric utilities, ownership, degree of competition, size, and region.

The DEA measure of technical inefficiency does not allow observation noise. However, analysts know that noise can come from many sources including measurement error and should be separated from the inefficiency scores. Many studies combined DEA and regression analysis to generate a stochastic frontier from which noise can be filtered. Rhodes and Southwick (1986) adopted a Tobit analysis by eliminating the inefficient units (based on the DEA measures) and estimating a frontier from efficient units only. Banker et al. (1992) applied the maximum likelihood estimation (MLE) method to the efficient units to determine the frontier. Cooper and Gallegos (1991) adjusted the input vectors for inefficient units based on the deterministic frontier calculated from the DEA method. They ran an ordinary least square (OLS) regression to estimate the parameters of the frontier. Sengupta (1989, 1991) developed a series of stochastic DEA frontiers allowing for various functional forms and distribution functions for the disturbances.

Instead of OLS, Charnes et al. (1991) adopted the robust Least Absolute Value (LAV) method to estimate the frontier. In fact, Ray (1992) pointed out that, when all the units are projected into the frontier and later used in an OLS procedure, the disturbance terms exhibit heteroscedasticity and are no longer independently and identically distributed. Both factors advise against the use of the OLS method.

Our study uses DEAP Version 2.1 developed by Tim Coelli to measure technical, allocative and cost efficiencies of US electricity firms. We also perform DEA-like linear programs and estimate a Malmquist Total Factor Productivity ("TFP") index to measure productivity change and productivity differences between deregulated and regulated US electricity firms.[29]

### 4.5. Shareholder Wealth, Firm Risk and Stock Returns

The CAPM is the most common asset pricing model to determine the expected return of a company's stock.[30] However, other approaches have been used to analyze the impact of regulatory changes or policy on shareholders' expected return. Other models include the APT, the Discounted Cash Flow (DCF) model and the Fama-French (FF) three-factor model. Unlike the DCF which does not incorporate risk as a determinant of the expected stock return, the CAPM, APT and FF models differ in how they define risk. While the CAPM defines a stock's risk as its sensitivity to the stock market, the FF model defines a stock's risk as its sensitivity to the stock market, a portfolio based on firm size, and a portfolio based on book-to-market ratios.

In its general formula, the CAPM can be expressed as follows:

[29] Hanoch and Rothschild (1972, page 273, footnote 15) noted that the use of some data in linear programming (such as the DEA) may be dangerous as serious and unexplainable violations of quasi-concavity and monotonicity abound.

$$E(R_s) = r_f + \beta [E(R_m) - r_f] \quad (9)$$

Where, $E(R_s)$ is the expected return for company s; $r_f$ is the expected return of the riskless asset; $\beta_s$ is the company s stock's sensitivity to the market; and, $R_m$ is the expected of the market.

The CAPM is used to calculate a stock return in excess of the risk-free asset rate plus an additional market-based return to compensate for the systematic risk of the stock. However, the CAPM does not fully account for the higher returns of small company stocks (Morningstar, 2007)[31] nor does it consider a firm's book-to-market ratio.

The FF three-factor model was introduced in Fama and French's 1992 paper and they concluded that their tests did not support the most basic prediction of the CAPM. They concluded that equity returns are inversely related to the size of a company and positively related to the book-to-market ratio.

Barber et al. (1997, p. 370) used all firms with available data on the monthly return files created by the CRSP[32] and analyzed statistical tests used in event studies to detect long-run abnormal stock returns and concluded that models using a reference portfolio such as a market index are misspecified. They found that "matching sample firms to control firms of similar size and book-to-market ratios yield well-specified test statistics in virtually all sampling situations" considered. Kumar et al. (2000) used a multistage model to explain the stock returns of a representative set of U.S. companies randomly drawn from 21 industries and found that stock returns are related to economic factors such as the cost and supply of money or the industry

---

[30] The CAPM is attributed to William Sharpe(1964) and Lintner (1965). Their work drew on Harry Markowitz's portfolio theory. Sharpe, Markowitz and Merton Miller received the 1990 Nobel Prize in Economics.

[31] This book is a continuation of an annual book previously published by Ibbotson.

[32] This is comprised of all firms listed on the New York Stock Exchange (NYSE), American Stock Exchange (AMEX) and the National Association of Securities Dealers Automated Quotation (NASDAQ).

membership not previously associated with the Arbitrage Pricing Theory (APT) or the Capital Asset Pricing Model (CAPM).

Jayaraman et al (2002, p. 1548) used a single-factor CAPM and the Fama and French (1992) three-factor model to evaluate the impact of mutual fund mergers on shareholder wealth and found evidence that shareholders of the target fund realize significant improvements in performance after the merger, but that shareholders of the acquiring fund experience significant deterioration in performance.

Chu and Lim (1998) used regression analysis to link stock performance and profit and cost efficiencies of banks in Singapore and found a significant relationship between profit efficiencies and bank share prices, but no such relationship with respect to cost efficiencies. More recently, Zhong et al. (2008) used event methodology and multivariate regression analysis and found that deregulation of the telecommunications industry in 1996 had significant positive effects on stock returns for broadcasting firms, with significant stock return gains for firms focusing on broadcasting business and small television groups.

Johnston (1984) used a seemingly unrelated regression (SUR) model to estimate the share price response of utility portfolios. He argued that in the presence of contemporaneous correlation the SUR methodology generates more efficient estimates. Following Johnston (1984), Akhigbe and Whyte (2001) used the model given in (19) below to analyze the impact of the Federal Deposit Insurance Corporation Improvement Act (FDICIA) of 1991 on bank stock returns and risk:

$$\begin{aligned} R_{1t} &= \alpha_1 + \beta_{m1} R_{mt} + \gamma_{i1} R_{it} + \sum_{k=1}^{n} \delta_{1k} D_{kt} + \varepsilon_{1t} \\ &\vdots \\ R_{pt} &= \alpha_p + \beta_{mp} R_{mt} + \gamma_{ip} R_{it} + \sum_{k=1}^{n} \delta_{pk} D_{kt} + \varepsilon_{pt} \end{aligned} \tag{10}$$

where $R_{pt}$ is the return on electric utility p's stock on day t, $\alpha_p$ is the intercept term,

$\beta_{mp}$ measures market/systematic risk for firm or group of firms p, $R_{mt}$ is the return on the CRSP equally-weighted market portfolio on day t, $\gamma_{ip}$ measures economy-wide risk for firm or group of firms p, $R_{it}$ is the daily change in the market interest rate, $\delta_{pk}$ measures the sensitivity of the firm's stocks to event k, $D_{kt}$ is a dummy variable equal to 1 for the $k_{th}$ event date and 0 otherwise, and $\varepsilon_{pt}$ is the disturbance term on the stock on day t. The regressions used in their SUR estimations were based on the CAPM in which the daily change in the market interest rate replaced the risk-free interest rate and an additional variable, a dummy, was introduced to represent the sensitivity of the company's stock to an event. They found that the FDICIA positively affected bank stock returns and resulted in a significant reduction in bank risk.

Studies on the stock markets, the CAPM and the APT suggest that stock prices incorporate all relevant publicly available and known information. Cost efficiency scores are obtained from accounting information on total cost and capital, labor and other input prices which are public information. In this chapter, we link the original CAPM of Sharpe (1964) and the modern theory of the three-factor model developed by Fama and French (1992) to the technical efficiencies of electric utilities. Specifically, we insert technical efficiencies and total factor productivity scores in the CAPM to investigate the impact of technical efficiencies and deregulation of the U.S. electricity industry on stock returns of electric utilities. By definition, the return from a stock is determined by the accrual of income from dividends and capital gains due to changes in its market price. During periods of economic growth, it is expected that higher incomes, lower interest rates, lower inflation rates, higher outputs, and other market indicators will cause the returns from a stock to be high. Each of these factors is a candidate in explaining expected returns. Theory suggests that there is a link between interest rates and stock returns. Indeed, stocks historically perform better under falling interest rates than under rising interest rates, suggesting that the link is between high and falling interest rates and stock returns.

Following Akhigbe and Whyte (2001), we use the yield on the long-term (20 years) U.S. Treasury bond as a proxy for the unanticipated changes in the interest rate index. Following Brown and Warner (1980, 1985), Hughes et al. (1986), Jarrell and Peltzman (1985), Binder and Summer (1985), Johnson et al. (1991, 1998), and Akhigbe and Whyte (2001), an equally-weighted market portfolio index is used as a proxy for the market rate of return in the estimated equation. Our model is estimated for all firms in the sample of IOUs for which stock return information is available for the period from 1997 to 2003. The firms are grouped into deregulated and regulated firms.

We expanded the capital market measures of risk obtained using the two-index model which has been utilized extensively in other areas of research (Flannery and James, 1984; Aharony et al., 1986, 1988; Barber et al., 1997; Akhigbe and Whyte, 2001) by including information on technical efficiency, deregulation, and firm size and book-to-market value:

$$R_{pt} - Rf_t = \alpha_p + \beta_{mp}(R_{mt} - Rf_t) + s_p SMB_t + h_p HML_t + \varepsilon_{pt} \qquad (11)$$

where $R_{pt}$ is the annual stock return on the common stock of utility p, $R_{ft}$ if the risk-free government backed 20-year bonds, $R_{mt}$ is the annual market return or the return on an equally-weighted index, SMB (Small Minus Big) is "the average return on three small portfolios minus the average return on three big portfolios, controlling for the same weighted average book-to-market equity in the two portfolios,

*SMB = 1/3 (Small Value + Small Neutral + Small Growth)*
*- 1/3 (Big Value + Big Neutral + Big Growth).*

and HML (High Minus Low) is the average return on two value portfolios minus the average return on two growth portfolios,

*HML = 1/2 (Small Value + Big Value)*
*- 1/2 (Small Growth + Big Growth)."*

The regression also included additional variables TECHCH (technological change) and TFPCH (total factor productivity change) obtained in the Malmquist TFP Index analysis. In this study, we tested whether shareholders benefit from electricity deregulation. We hypothesized that shareholders would not invest in a firm which does not take advantage of the new technological advances that are likely to increase profits and dividends. Thus, technological changes and total factor productivity are expected to be important factors in the determination of stock returns and profitability in utility companies.

The modified CAPM equation (11) above is used to investigate the existence of any statistical relationship between technical efficiency scores and stock returns and to determine if deregulated IOUs performed better in the marketplace than regulated IOUs. The following hypotheses were tested for the sample of investor-owned electric utilities included in this section:

H1: Firms in states with restructuring laws experienced stronger wealth effects than firms in states without restructuring laws;

H2: Firms in deregulated states experienced higher systematic risk than regulated firms in the post- major deregulation events.

A positive intercept in (11) indicates that the sample firms performed better than expected, controlling for market, firm size, book-to-market value, and technological change factors in returns. The coefficient on the market return variable is interpreted as the systematic risk faced by the utilities. A higher value of $\beta_m$ means that the sample utilities experienced greater market volatility of returns. A positive and significant coefficient on the size variable means that small size company are associated with higher stock return and a positive and significant coefficient on the book-to-market variable means that stock return is positively related to the ratio of a company's book value relative to its market value of equity. We test the two main hypotheses through a SUR estimation of our sample of IOUs, grouped between regulated and deregulated IOUs. A positive and statistically significant coefficient of the intercept means that the group of IOUs outperformed the market after controlling for the market, size, book-to-market, and technical and productivity changes (H1). Finally, a statistically significant beta ($\beta$) greater than one means that the group of IOUs is more risky than the market. We test H2 by comparing the beta coefficients of the groups of regulated and deregulated IOUs.

## CHAPTER V

## DATA DESCRIPTION

Most studies have analyzed the most dominant segment of the industry, namely the IOUs. Even though they account for only 7.6 percent of the electric utilities in the country, they account for more than 75 percent of all revenues from sales of electricity to all consumers. This study is interested not only in IOUS, but also in all other types of electric utilities.

The data are drawn from major databases maintained by the FERC and the Energy Administration Agency (EIA) of the United States Department of Energy. Data on IOUs and COOPs are obtained from FERC Form 1, “Annual Report of Major Electric Utilities, Licensees, and Others.” Data on POUs (municipal, state and federal electric utilities) are obtained from EIA forms (EIA-860, EIA-861 and EIA-412). FERC Form 1 is a comprehensive financial and operating report submitted for Electric Rate regulation and financial audits. FERC Form 1 compiles all utility data as reported in the annual report by any electric utility having (1) one million Megawatt hours or more; (2) 100 megawatt hours of annual sales for resale; (3) 500 megawatt hours of annual power exchange delivered; or (4) 500 megawatt hours of annual wheeling[33] for others (deliveries plus losses).[34]

Form EIA-861, “Annual Electric Power Industry Report,” is “an electric utility data file that includes such information as peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering

---

33 Wheeling service is defined as the use of the transmission facilities of one system to transmit power for another system. Wheeling can apply to either wholesale or retail service.

[34] See http://www.ferc.gov/docs-filing/eforms.asp#1

programs, and distributed generation capacity."[35] Form EIA-412 collects accounting, plant statistics, and transmission data from various electric industry entities in the United States. Each municipality, political subdivision, State, and Federal entity engaged in the generation, transmission, or distribution of electricity, which had at least 150,000 megawatthours of sales to ultimate consumers and/or at least 150,000 megawatthours of sales for resale for each of the 2 previous years has to fill out this form.[36] Form EIA-860 collects data on the status of existing electric generating plants and associated equipment in the United States, and those scheduled for initial commercial operation within 5 years of the filing of this report. Form EIA-860 is completed for all electric generating plants, which have or will have a nameplate rating of 1 megawatt (1000 kW) or more, and are operating or plan to be operating within 5 years of the year of this form.[37]

The US electric power industry is a $300-billion industry whose products are vital to the US economy. According to Edison Electric Institute ("EEI), "electricity is the lifeblood of the U.S. economy. It powers our homes, offices, and industries; provides communications, entertainment, and medical services; powers computers, technology, and the Internet; and runs various forms of transportation. Not only is electricity the cleanest, most flexible, and most controllable form of energy, its versatility

---

[35] See http://www.eia.doe.gov/cneaf/electricity/page/eia861.html

[36]The accounting data (Schedules 1 through 8) are completed by The plant statistics data (Schedule 9) are completed by each municipality, political subdivision, State, Federal, and unregulated entity owning plants with a nameplate of 10 megawatts or larger. The transmission data (Schedules 10 and 11) are completed by each municipality, political subdivision, State, Federal, and generation and transmission cooperative owning transmission lines having a nominal voltage of 132 kilovolts or greater. **Note: The EIA-412 Survey was suspended at the end of 2003 due to budget constraints.** Since then no data was collected, processed or summarized. The Financial Statistics of Major U.S. Publicly Owned Electric Utilities publication was discontinued in the year 2000; however, summary data are available in the *Electric Power Annual*.

[37] See http://www.eia.doe.gov/oss/forms.html#eia-860

is unparalleled."[38] As of 2006, the industry is comprised of 1,874 Government-owned municipal systems, 1,688 non-utility generators, 870 cooperatives, 203 investor-owned electric companies, 143 energy service providers, 133, public power systems, 31 state-owned projects, and 9 federal utilities.[39]

Our study evaluates the performance of all electric utilities in the United States for the period of 1996 to 2003. The sample includes the majority of privately held Investor-Owned utilities ("IOUs"), and the majority of publicly-owned electric utilities (federal electric utilities, cooperative electric utilities, municipal electric utilities, and state-owned electric utilities). Among the state-owned electric utilities were utilities owned by state political subdivisions. The final sample consisted of 433 POUs and 139 IOUs and COOPs. Because many utilities went through mergers, acquisitions and other reorganizations, and many others did not have data for most years, our study eliminated utilities with consistent missing data and for which data on total sales, net generation and total costs were incomplete. DEA methodology utilized in this study requires balanced data as all firms must be observed in all time periods.

The period of study coincides with the advent of electric deregulation or limited competition in the electric industry, which most often started with retail choice and gradually included competition in the power procurement of generation. California led the way with deregulation debate starting at the end of 1996, although it was the state that suffered the most negative economic and political backlashes from the introduction of competition in the electric industry. This led to a suspension of electric deregulation in California at the beginning of 2003. However, due to a strong development of the major independent transmission system operators ("ISOs") and regional transmission organizations ("RTOs"), other states continue to develop forms of electric competition.

---

38 Edison Electric Institute. 2006 Financial Review, May 2007 (EEI 2007)

[39] Id.

A sample of firms during the period beginning with January 1996 and ending with December 2003 was collected. One of the data forms from the EIA, Form EIA-412, was no longer published after the end of 2003, and it would be too difficult to collect the same information from other sources.

Besides the data collected from EIA forms EIA-412, EIA-861, EIA-860, and FERC-1, financial data on the market, industry and IOUs' returns were obtained from the Center for Research in Security Prices (CRSP).

Only those electric utilities for which complete primary data were compiled are included in this study. The following is a list of empirical variables included in our models.

Table 3: Identification of Variables and Source of Data

| Variable names | Identification of variables | Source of the variable |
|---|---|---|
| TOTCOST | Total cost is the sum of operation, maintenance, depreciation, and capital costs ($) | FERC-1, EIA-412 |
| CAPCOST | Net electric utility plant multiplied by the price of capital for electric utilities[40]($) | FERC-1, EIA-412 |
| DISTR | Total megawatt-hours sold by each utility to final customers and to the resale market (MWH) | EIA-861 |
| DISTRES | Distribution sales to residential customers (MWH) | EIA-861, FERC-1 |
| DISTCOM | Distribution sales to commercial customers (MWH) | |
| DISTIND | Distribution sales to industrial customers (MWH) | FERC-1, EIA-412, |
| DISTNONRES | DISTR minus DISTRES (MWH) | EIA-861 |
| GENER | Net generation output (MWH) | EIA-861 |
| PURCHUTI | Quantity of power purchased (MWH) | EIA-860, EIA-412 |
| TOTASSETS | Total electric utility assets ($) | FERC-1, EIA-412 |
| FUELCOST | Total generation fuel costs used ($) | |
| PCAPITAL | Weighted average price of capital (“WACC”) (%) | FERC-1, EIA-412 |
| PLABOR | Total salaries and wages divided by total disposition of electricity ($/MWH) | FERC-1, EIA-412 |
| PFUEL | Weighted average of steam, nuclear, and other fuel costs over total generation ($/MWH) | FERC-1, EIA- |
| CUSTOMERS | Total number of utility customers | 412,EIA-861 |
| STEAM | Percent of steam generation over total generation | FERC-1, EIA-412 |
| NUCLEAR | Percent of nuclear generation over total generation | FERC-1, EIA-412 |
| HYDRO | Percent of hydro generation over total generation | FERC-1, EIA-412 |
| SALESHARE | Utility proportion of state total sales | |
| SUPPLYSHARE | Utility proportion of state total power supply | |
| COMPETE | Deregulation/competition (0,1) | |
| FEGEN | If GENER>0, then FEGEN=1 | |

Daily and monthly stock returns were obtained from the CRSP (University of Chicago Center for Research in Security Prices) database for the study period. Total assets, operating income, operating expenses for electric utilities were compiled from FERC and EIA forms described above, and from the annual Compustat. Quarterly data for these variables were also available from the quarterly Compustat. For each utility, total costs are the sum of general operation and maintenance expenses (O&M), depreciation, and capital costs associated with the generation, transmission, and distribution of electric power and with the purchase of power that utilities need to offset the shortage of their output in order to meet the demand.

For input costs, electricity can be generated by steam power, nuclear power, hydraulic power, and other technology such as internal combustion or combined cycle using natural gas turbines and many others. Steam fuel cost per kwh generated by steam and nuclear fuel cost per kwh generated by nuclear power are obtained by dividing for each fuel total costs by the amount of power generated by that fuel.

For labor costs, actual payroll data are available from FERC Form 1, EIA-412, and DOE/EIA reports. Labor cost equals the total amount of labor cost divided by the number of employees.

The cost of capital is primarily the cost of long-term debt. Following Kwoka (1996), the cost of capital for IOUs is calculated as a weighted average cost of common stock, preferred stock, and long-term debt.

Ownership variables are included in the study as time invariant variables [state, federal, municipal, IOUs, cooperative]. In addition, the size of the firm, the degree of competition, the diversification of activities, taxes and other payments, the region, and other market characteristics are included in the study.

The following tables present the descriptive statistics for the sample of firms included in this study.

---

[40] http://pages.stern.nyu.edu/~adamodar/; Cost of Capital by Sector.

Table 4: Summary Statistics of the Sample of POUs

| Variable | Description | Mean | Std. Dev | Min | Max |
|---|---|---|---|---|---|
| Year | Year | 1999.5 | 2.29 | 1996 | 2003 |
| N | Number of yearly observations | 216.46 | 125.06 | 1 | 433 |
| T | Time periods | 4.50 | 2.29 | 1 | 8 |
| Federal | Federal electric utilities | 0.009 | 0.096 | 0 | 1 |
| Municipal | Municipal electric utilities | 0.88 | 0.324 | 0 | 1 |
| State | State owned electric utilities | 0.08 | 0.26 | 0 | 1 |
| Totdisp | Total disposition(/1,000,000) | 1.28 | 7.68 | 0 | 155.00 |
| Nuclear | Nuclear generation | 0.014 | 0.10 | 0 | 1 |
| Steam | Steam generation | 0.13 | 0.33 | 0 | 1 |
| Totcosts | Total utility costs(/1,000,000) | 97.83 | 399.45 | 4.13 | 7347.03 |
| Avgcost | Average cost | 73.39 | 794.99 | 7.48 | 46672.75 |
| Totsales | Total electricity sales(/1,000,000) | 1.66 | 7.58 | 0 | 151.03 |
| Netgener | Net generation(/1,000,000) | 1.29 | 9.16 | -0.01 | 155.48 |
| Purchuti | Purchased power(/1,000,000) | 0.80 | 1.74 | 0 | 26.16 |
| Totcons | Total number of customers(/1,000) | 33.66 | 95.06 | 0 | 1535.27 |
| Compete | Deregulated (=1, 0 otherwise) | 0.13 | 0.34 | 0 | 1 |
| Saleshare | Share of state electricity sales | 0.025 | 0.14 | 0 | 3.74 |
| Supplyshare | Share of state electricity supply | 0.018 | 0.13 | 0 | 2.27 |
| Fegen | Generation function (0 or 1) | 0.43 | 0.49 | 0 | 1 |

Table 5: Summary Statistics of the Sample of POUs in Deregulated States

| Variable | Description | Mean | Std. Dev | Min | Max |
|---|---|---|---|---|---|
| Year | Year | 2001.09 | 1.53 | 1998 | 2003 |
| N | Number of yearly observations | 235.63 | 128.15 | 2 | 429 |
| T | Time periods | 6.09 | 1.53 | 3 | 8 |
| Federal | Federal electric utilities | 0 | 0 | 0 | 0 |
| Municipal | Municipal electric utilities | 0.92 | 0.28 | 0 | 1 |
| State | State owned electric utilities | 0.075 | 0.26 | 0 | 1 |
| Totdisp | Total disposition(/1,000,000) | 0.84 | 4.12 | 0 | 48.80 |
| Nuclear | Nuclear generation | 0.024 | 0.13 | 0 | 1 |
| Steam | Steam generation | 0.071 | 0.24 | 0 | 1 |
| Totcosts | Total utility costs(/1,000,000) | 139.11 | 393.04 | 6.62 | 2971.34 |
| Avgcost | Average cost | 77.62 | 27.46 | 7.48 | 289.37 |
| Totsales | Total electricity sales(/1,000,000) | 1.67 | 4.84 | 0 | 48.47 |
| Netgener | Net generation(/1,000,000) | 1.04 | 4.14 | 0 | 35.51 |
| Purchuti | Purchased power(/1,000,000) | 1.12 | 2.87 | 0 | 26.16 |
| Totcons | Total number of customers(/1,000) | 55.92 | 176.25 | 0 | 1459.15 |
| Compete | Deregulated (=1, 0 otherwise) | 1 | 0 | 1 | 1 |
| Saleshare | Share of state electricity sales | 0.014 | 0.05 | 0 | 0.56 |
| Supplyshare | Share of state electricity supply | 0.007 | 0.033 | 0 | 0.28 |
| Fegen | Generation function (0 or 1) | 0.57 | 0.50 | 0 | 1 |

Table 6: Summary Statistics of the Sample of POUs in Regulated States

| Variable | Description | Mean | Std. Dev | Min | Max |
|---|---|---|---|---|---|
| Year | Year | 1999.26 | 2.29 | 1996 | 2003 |
| N | Number of yearly observations | 213.53 | 124.35 | 1 | 433 |
| T | Time periods | 4.26 | 2.29 | 1 | 8 |
| Federal | Federal electric utilities | 0.011 | 0.103 | 0 | 1 |
| Municipal | Municipal electric utilities | 0.88 | 0.33 | 0 | 1 |
| State | State owned electric utilities | 0.076 | 0.26 | 0 | 1 |
| Totdisp | Total disposition(/1,000,000) | 1.35 | 8.09 | 0 | 155.00 |
| Nuclear | Nuclear generation | 0.013 | 0.09 | 0 | 1 |
| Steam | Steam generation | 0.14 | 0.34 | 0 | 1 |
| Totcosts | Total utility costs(/1,000,000) | 91.52 | 400.11 | 4.13 | 7347.03 |
| Avgcost | Average cost | 72.74 | 853.52 | 7.56 | 46672.75 |
| Totsales | Total electricity sales(/1,000,000) | 1.65 | 7.91 | 0.034 | 151.03 |
| Netgener | Net generation(/1,000,000) | 1.33 | 9.70 | -0 | 155.48 |
| Purchuti | Purchased power(/1,000,000) | 0.75 | 1.49 | 0 | 18.35 |
| Totcons | Total number of customers(/1,000) | 30.26 | 74.78 | 0 | 1535.27 |
| Compete | Deregulated (=1, 0 otherwise) | 0 | 0 | 0 | 0 |
| Saleshare | Share of state electricity sales | 0.027 | 0.15 | 0 | 3.74 |
| Supplyshare | Share of state electricity supply | 0.018 | 0.14 | -0 | 2.27 |
| Fegen | Generation function (0 or 1) | 0.404 | 0.49 | 0 | 1 |

Table 7: Summary Statistics of the Sample of IOUs and COOPs

| Variable | Description | Mean | Std. Dev | Min | Max |
|---|---|---|---|---|---|
| Year | Year | 1999.5 | 2.29 | 1996 | 2003 |
| N | Number of yearly observations | 70 | 40.14 | 1 | 139 |
| T | Time periods | 4.5 | 2.29 | 1 | 8 |
| Totdisp | Total disposition(/1,000,000) | 21.08 | 77.52 | 0.01 | 184.70 |
| Nuclear | Nuclear generation | 0.13 | 0.24 | 0 | 1.00 |
| Steam | Steam generation | 0.54 | 0.41 | 0 | 1.01 |
| Totcosts | Total utility costs(/1,000,000) | 952.64 | 1322.23 | 0.97 | 12644.41 |
| Avgcost | Average cost | 52.91 | 25.73 | 0.06 | 169.70 |
| Totsales | Total electricity sales(/1,000,000) | 17.69 | 22.99 | 0 | 182.19 |
| Netgener | Net generation(/1,000,000) | 11.86 | 16.48 | 0 | 88.41 |
| Purchuti | Purchased power(/1,000,000) | 6.04 | 10.80 | 0 | 159.05 |
| Totcons | Total number of customers(/1,000) | 488.77 | 755.01 | 0 | 4889.12 |
| Compete | Deregulated (=1, 0 otherwise) | 0.25 | 0.43 | 0 | 1 |
| Saleshare | Share of state electricity sales | 0.25 | 0.30 | 0 | 2.17 |
| Supplyshare | Share of state electricity supply | 0.15 | 0.20 | 0 | 1.42 |
| Fegen | Generation function (0 or 1) | 0.87 | 0.33 | 0 | 1 |

Table 8: Summary Statistics of the Sample of IOUs and COOPs in Deregulated States

| Variable | Description | Mean | Std. Dev | Min | Max |
|---|---|---|---|---|---|
| Year | Year | 2001.16 | 1.50 | 1998 | 2003 |
| N | Number of yearly observations | 63.06 | 39.53 | 1 | 138 |
| T | Time periods | 6.16 | 1.50 | 3 | 8 |
| Totdisp | Total disposition(/1,000,000) | 15.86 | 21.29 | 0.12 | 165.61 |
| Nuclear | Nuclear generation | 0.18 | 0.31 | 0 | 1 |
| Steam | Steam generation | 0.38 | 0.42 | 0 | 1 |
| Totcosts | Total utility costs(/1,000,000) | 1061.64 | 1660.38 | 4.81 | 12644.41 |
| Avgcost | Average cost | 67.00 | 30.79 | 12.87 | 169.70 |
| Totsales | Total electricity sales(/1,000,000) | 16.90 | 24.97 | 0.12 | 179.08 |
| Netgener | Net generation(/1,000,000) | 7.68 | 12.15 | 0 | 53.10 |
| Purchuti | Purchased power(/1,000,000) | 8.23 | 13.27 | 0 | 119.10 |
| Totcons | Total number of customers(/1,000) | 555.30 | 935.58 | 0 | 4759.42 |
| Compete | Deregulated (=1, 0 otherwise) | 1 | 0 | 1 | 1 |
| Saleshare | Share of state electricity sales | 0.20 | 0.28 | 0 | 1.69 |
| Supplyshare | Share of state electricity supply | 0.07 | 0.10 | 0 | 0.47 |
| Fegen | Generation function (0 or 1) | 0.79 | 0.41 | 0 | 1 |

Table 9: Summary Statistics of the Sample of IOUs and COOPs in Regulated States

| Variable | Description | Mean | Std. Dev | Min | Max |
|---|---|---|---|---|---|
| Year | Year | 1998.96 | 2.25 | 1996 | 2003 |
| N | Number of yearly observations | 72.28 | 40.10 | 1 | 139 |
| T | Time periods | 3.95 | 2.25 | 1 | 8 |
| Totdisp | Total disposition(/1,000,000) | 22.79 | 88.47 | 0 | 1804.70 |
| Nuclear | Nuclear generation | 0.12 | 0.21 | 0 | 1 |
| Steam | Steam generation | 0.60 | 0.39 | 0 | 1.01 |
| Totcosts | Total utility costs(/1,000,000) | 916.82 | 1189.38 | 0.97 | 7468.03 |
| Avgcost | Average cost | 53.60 | 22.90 | 0.06 | 155.77 |
| Totsales | Total electricity sales(/1,000,000) | 17.95 | 22.31 | 0 | 182.19 |
| Netgener | Net generation(/1,000,000) | 13.23 | 17.47 | 0 | 88.41 |
| Purchuti | Purchased power(/1,000,000) | 5.32 | 9.76 | 0 | 159.05 |
| Totcons | Total number of customers(/1,000) | 466.92 | 684.64 | 0 | 4889.12 |
| Compete | Deregulated (=1, 0 otherwise) | 0 | 0 | 0 | 0 |
| Saleshare | Share of state electricity sales | 0.27 | 0.31 | 0 | 2.17 |
| Supplyshare | Share of state electricity supply | 0.17 | 0.22 | 0 | 1.42 |
| Fegen | Generation function (0 or 1) | 0.90 | 0.30 | 0 | 1 |

Privately-owned utilities averaged eleven (11) times more total electricity sales than POUs, averaged nine (9) times more net generation, and averaged fourteen (14) times more total number of consumers than POUs.   While twenty-five (25) percent of privately-owned utilities were in deregulated states, only thirteen (13) percent of POUs operated in deregulated states. Privately-owned utilities had substantially higher market shares in sales and generation (respectively 25% and 15% on average) more than POUs (respectively 2.5% and 1.8%).  Finally, more privately-owned utilities owned nuclear and steam power generation plants (respectively 13% and 54%) than POUs (1.4% and 13%).

Thus, the size difference among privately and publicly owned electric utilities is an important element to consider during the empirical analysis.  COOPs regulated by the Rural Utilities Service are not included in this sample.  We were not able to collect the needed data for most of the study period as such data was collected. Only seven (7) COOPs which meet the FERC requirements to file FERC Form 1 were included in the sample of privately owned utilities. The CRSP provides information on the history of companies traded on the NYSE/AMEX/NASDAQ stock exchanges.  Our data retained only the IOUs whose stock return could be linked to its name history and to its utility subsidiaries.  Companies whose stocks were delisted during the study period from the stock exchanges were also not included in our sample.

# CHAPTER VI

# EMPIRICAL RESULTS

## 6.1. Data envelopment analysis (DEA) of cost efficiency

### 6.1.a. DEA Model

In order to assess the differences in cost efficiencies that are explained by firm ownership, we perform an input-oriented DEA analysis of IOUs and publicly-owned electric utilities. We chose an input-oriented DEA analysis because the data include electricity generation which is highly dependent on management decisions over which inputs to use first in the power generation process. Electric utilities have different sources of competing resources (steam, hydroelectric, nuclear, and others) such that the fixed input constraint needed to maximize output is not an issue.

We apply the DEA input-oriented variable returns ("VRS") to scale model under the assumption that many electric utilities are still vertically integrated and most of them enjoy economies of scale in power generation and distribution. The model follows from Färe et al. (1985) and Coelli, Rao and Battese (1998).

The envelopment form of a cost efficiency-oriented VRS model is specified as:

Minimize $\theta,\lambda$ $\theta$, (12)

Subject to $y_{it} + Y\lambda \geq 0,$

$$\theta x_{it} - X\lambda \geq 0,$$

$$N1' \times \lambda = 1$$

$$\lambda \geq 0$$

where θ is the input technical efficiency measure with 0≤ θ≤1. A score of θ=1 means that the DMU is on the frontier.

The cost-minimizing vector of input quantities for the i-th time period is obtained from:

$$\begin{aligned}
&Min\ \lambda, x_{it}^{*} w_{it}^{'} x_{it}^{*},\\
&subject\ to - y_{it} + Y\lambda \geq 0,\\
&\qquad\qquad x_{it}^{*} - X\lambda \geq 0, \qquad\qquad (13)\\
&\qquad\qquad N1^{'}\lambda = 1,\\
&\qquad\qquad \lambda \geq 0,
\end{aligned}$$

where $w_{it}$ is a vector of input prices for firm i at time t, and $x_{it}$* is the cost-minimizing vector of input quantities given input prices $w_{it}$ and output levels $y_{it}$ for DMU i in period t. Given this cost minimization problem, the total cost efficiency (CE) or economic efficiency of DMU i is calculated as: CE = $w_{it}'x_{it}^{*}/ w_{it}'x_{it}$ .

The economic or cost efficiency (CE) is defined as the ratio of the minimum cost to observed cost. Allocative efficiency is calculated as the ratio of CE over technical efficiency (TE): AE = CE / TE where TE is the θ obtained from the solution of the envelopment problem above.

### 6.1.b. DEA Empirical Results

The estimates of technical, allocative and cost efficiencies are obtained using DEAP Version 2.1. developed by Tim Coelli (1996) and are given in Table 10 below. The cost efficiency DEA analysis uses total distribution sales and net power generation as the output variables and total assets, labor and the price of labor (wages) and capital as the inputs. Although fuel costs vary across the country, data were not available for all the years in the study following a modification in the reporting form EIA-412 starting in 2001.

Table 10: Summary of efficiency scores for private and publicly-owned electric utilities, 1996-2003.

| MEAN DEA COST EFFICIENCY RESULTS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Technical Efficiency (TE) | Allocative Efficiency (AE) | Cost Efficiency (CE) | Sample Size | N (%) Max TE | N (%) Max AE | N (%) Max CE | N above Mean (%) | | |
| | | | | | | | | TE | AE | CE |
| **PRIVATE DMUs** | | | | | | | | | | |
| Generation | 0.353 | 0.839 | 0.308 | 125 | 9 (7.2%) | 10(8.0%) | 7 (5.6%) | 40.0 | 53.6 | 34.4 |
| Electric Utility | 0.311 | 0.737 | 0.251 | 139 | 9 (6.5%) | 7 (5.0%) | 7 (5.0%) | 36.0 | 54.7 | 30.9 |
| **PUBLIC DMUs** | | | | | | | | | | |
| Generation | 0.331 | 0.483 | 0.150 | 193 | 8 (4.1%) | 5 (2.6%) | 4 (2.1%) | 39.9 | 40.9 | 28.0 |
| Electric Utility | 0.273 | 0.691 | 0.182 | 305 | 8 (2.6%) | 8 (2.6%) | 4 (1.3%) | 37.4 | 45.6 | 33.1 |

The Kruskal-Wallis Test for DEA efficiency scores
Ho: There is no difference in efficiency between private DMUs and public DMUs

| | |
|---|---|
| P Value | 0.5127 |
| Critical Value | 0.05- 0.10 |
| Decision | Accept |

The data used include total costs as a function of total utility assets, number of full-time and part-time employees, the price of capital and total wages paid by the electric utility. The mean values of TE, AE and CE for private utilities are respectively 0.353, 0.839 and 0.308 using the generation cost specification and 0.311, 0.737 and 0.251 using the distribution cost specification. These results suggest that the IOUs in the sample could increase efficiency levels by reducing the mean cost by 70 and 75 percent respectively.

The mean values of TE, AE and CE for public utilities are respectively 0.331, 0.483 and 0.15 using the generation cost specification and 0.273, 0.691 and 0.182 using distribution cost specification. These results suggest that the publicly-owned utilities in the sample could increase efficiency levels by reducing the mean cost by 85 and 82 percent respectively.

The results show that only a small number of firms are cost efficient due to the existence of technical and allocative inefficiencies. They also show that in general IOUs were more efficient than publicly owned electric utilities both in generation and as vertically integrated utilities.

The Kruskal-Wallis test was performed to test for significant differences between the IOUs and the publicly-owned utilities. The null hypothesis that the efficiency scores of the IOUs and publicly-owned utilities are not significantly different cannot be rejected at the 5 percent level of significance.

Table 11 below presents a similar analysis performed comparing the efficiency of privately and publicly owned DMUs under a deregulated regime and over fully regulated DMUs.

Table 11: Mean DEA Cost Efficiency Comparison

| MEAN DEA COST EFFICIENCY ANALYSIS: DEREGULATED vs. REGULATED DMUs | | | | |
|---|---|---|---|---|
| | Technical Efficiency | Allocative Efficiency | Cost Efficiency | Sample Size |
| **PRIVATE DMUs** | | | | |
| **Generation Only** | | | | |
| Deregulated | 0.328 | 0.851 | 0.289 | 61 |
| Regulated | 0.378 | 0.828 | 0.326 | 64 |
| **% Improved** | **-13.2%** | **2.8%** | **-11.3%** | |
| **Electric utility** | | | | |
| Deregulated | 0.322 | 0.758 | 0.265 | 67 |
| Regulated | 0.301 | 0.717 | 0.238 | 72 |
| **% Improved** | **7.0%** | **5.7%** | **11.3%** | |
| **PUBLIC DMUs** | | | | |
| **Generation Only** | | | | |
| Deregulated | 0.337 | 0.458 | 0.15 | 76 |
| Regulated | 0.327 | 0.5 | 0.151 | 117 |
| **% Improved** | **3.1%** | **-8.4%** | **-0.7%** | |
| **Electric Utility** | | | | |
| Deregulated | 0.232 | 0.678 | 0.148 | 100 |
| Regulated | 0.292 | 0.697 | 0.199 | 205 |
| **% Improved** | **-20.5%** | **-2.7%** | **-25.6%** | |

The Kruskal-Wallis Test for DEA efficiency scores: Ho: There is no difference in efficiency scores between privately and publicly owned generation plants.
P-Value = 0.8273
Decision: Accept Ho

Ho: There is no difference in efficiency scores between privately and publicly owned vertically integrated electric utilities.
P-Value = 0.2752
Decision: Accept Ho.

The results in Table 11 show that, in general, private and public generation plant efficiency was worse in deregulated states than in regulated states, but that privately owned deregulated power generation plants had higher allocative and cost efficiency scores than publicly owned power generation plants. Privately owned electric utilities (IOUs and COOPs) in deregulated states achieved greater technical, allocative and cost efficiencies than publicly owned electric utilities, improving respectively by 7%, 5.7% and 11.3% over the study period from 1998 to 2003. Publicly owned electric utilities operating in deregulated states achieved technical, allocative and cost efficiencies lower than similar utilities in regulated states, respectively by 20.5%, 2.7% and 25.6%[41].

A Kruskal-Wallis test statistic was performed to test for significant differences in efficiencies between the deregulated IOUs and deregulated POUs, for both generation and vertically integrated utilities. The test fails to give sufficient evidence against the null hypothesis for both generation and vertically integrated utilities; so we cannot conclude that there are differences in efficiency scores between privately owned generation plants and publicly owned generation plants and between vertically integrated IOUs and POUs.

#### 6.1. c. DEA Total Factor Productivity

Using DEAP 2.1, we calculated the Malmquist Total Factor Productivity ("TFP") index to measure total productivity change and to decompose this productivity change into technical change and technical efficiency change. This analysis was developed by Färe and Grosskopf (1994). Five indices were developed: technical efficiency change (relative to a CRS technology) (EFFCH); technological change (TECHCH); pure technical efficiency change (i.e., relative to a VRS technology) (PECH); scale efficiency change (SECH); and total factor productivity (TFPCH) change.

The decomposition of the Malmquist Index can be explained as follows. The overall efficiency is the product of technical efficiency and input allocative efficiency. Technical

---

[41] It is worth noting that many state public utilities commissions do not have regulatory oversight over publicly owned electric utilities, which are regulated by the municipal authority who answers directly to the ratepayers. However, an implicit assumption was made for this study that "unregulated electric utilities in regulated states tend to adjust their behavior to improve efficiency in order to keep their captive customers."

efficiency can also be decomposed into the product of scale efficiency and pure technical efficiency. Fukuyama et al. (1999) explains that scale inefficiency happens whenever a DMU is not operating at constant returns to scale, while pure technical inefficiency occurs from a lack of managerial oversight of the production process.

The Malmquist TFP decomposition separates pure technological change from pure technical change and pure scale change. The following equalities hold:

$$EFFCH = PECH * SECH$$
$$TFP = EFFCH * TECHCH = PECH * SECH * TECHCH$$

We performed an output-oriented Malmquist Index analysis; an index greater than one represents progress, and an index less than one represents regression. Output-oriented TFP measurements were more appropriate because we assumed that electric utilities operate in competitive markets (Barros, p. 68). The TFP analysis uses total distribution sales and net power generation as the output variables and total assets, total salaries and wages and purchased power as inputs. When the TFP is greater than unity, total factor productivity increased in the period for the utility.

Table 12: Malmquist Efficiency Measures using Total Utility Sales Data

| Malmquist Efficiency Measures Geometric Means (Total Sales) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Public Variable** | 1997 N=382 | 1998 N=382 | 1999 N=382 | 2000 N=382 | 2001 N=382 | 2002 N=382 | 2003 N=382 | Mean N=382 |
| **TFP** | 0.978 | 1.001 | 1.000 | 0.968 | 0.853 | 0.974 | 0.982 | 0.964 |
| **EFFCH** | 0.995 | 1.044 | 0.900 | 1.024 | 1.447 | 0.977 | 1.016 | 1.047 |
| **PECH** | 1.002 | 1.046 | 0.921 | 1.033 | 1.388 | 0.979 | 0.994 | 1.043 |
| **SECH** | 0.993 | 0.998 | 0.978 | 0.991 | 1.042 | 0.998 | 1.023 | 1.003 |
| **TECHCH** | 0.983 | 0.959 | 1.110 | 0.945 | 0.590 | 0.997 | 0.966 | 0.921 |
| **Private Variable** | 1997 N=143 | 1998 N=143 | 1999 N=143 | 2000 N=143 | 2001 N=143 | 2002 N=143 | 2003 N=143 | Mean N=143 |
| **TFP** | 1.024 | 0.998 | 1.050 | 0.999 | 1.026 | 0.964 | 0.964 | 1.003 |
| **EFFCH** | 1.029 | 1.292 | 0.817 | 1.029 | 1.215 | 0.943 | 0.759 | 0.996 |
| **PECH** | 0.990 | 0.939 | 1.106 | 0.982 | 0.869 | 0.811 | 0.779 | 0.995 |
| **SECH** | 1.039 | 1.376 | 0.736 | 1.048 | 1.398 | 1.162 | 0.975 | 0.919 |
| **TECHCH** | 0.995 | 0.772 | 1.286 | 0.971 | 0.845 | 1.022 | 1.269 | 1.083 |

T-Test for equality of mean TFP, equal variances: Pr. > |t| = 0.1180

Table 12 shows that the mean Malmquist score is 1.003 for IOUs and 0.964 for POUs; on average, the total productivity decreased by 2% for IOUs and decreased by 1.4% for POUs. A t-test statistic to test for equality of the means TFP of IOUs and POUs provides sufficient evidence against the null hypothesis, so we conclude that the mean TFP for IOUs is significantly different from the mean TFP for POUs. However, detailed data show that the total productivity of IOUs and of POUs regressed over the period from 1997 to 2003 even though in some years (such as 1998 and 1999 for the POUs and 1997, 1999 and 2001 for the IOUs) total factor productivity increased. During the same time period, POUs improved their EFFCH by 5.2% from 0.995 to 1.047 while IOUs lost 3.21 percent in EFFCH. The main factors in the opposing productivity changes seem to be that municipal, federal and state utilities gained ground in pure technical efficiency change (by 4.1%), and scale efficiency change remained flat over the period for POUs (only 1% improvement) but decreased by 8.0% for IOUs on average.  Table 13) below shows a similar analysis using power generation data.

Table 13: Malmquist Efficiency Measures using Generation Data

| **Malmquist Efficiency Measures Geometric Means (Generation)** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Public Variable** | 1997 N=191 | 1998 N=191 | 1999 N=191 | 2000 N=191 | 2001 N=191 | 2002 N=191 | 2003 N=191 | Mean N=191 |
| **TFP** | 0.932 | 1.120 | 1.034 | 0.946 | 0.825 | 0.949 | 0.931 | 0.959 |
| **EFFCH** | 0.913 | 1.286 | 1.436 | 1.260 | 0.956 | 0.915 | 0.525 | 1.008 |
| **PECH** | 1.045 | 1.236 | 1.265 | 1.297 | 0.900 | 0.956 | 0.525 | 0.994 |
| **SECH** | 0.950 | 1.040 | 1.135 | 0.972 | 1.063 | 0.957 | 0.997 | 1.015 |
| **TECHCH** | 0.939 | 0.871 | 0.720 | 0.751 | 0.863 | 1.037 | 1.773 | 0.951 |
| | | | | | | | | |
| **Private Variable** | 1997 N=106 | 1998 N=106 | 1999 N=106 | 2000 N=106 | 2001 N=106 | 2002 N=106 | 2003 N=106 | Mean N=106 |
| **TFP** | 1.022 | 1.008 | 0.999 | 0.950 | 0.937 | 0.968 | 0.957 | 0.977 |
| **EFFCH** | 1.038 | 1.340 | 0.764 | 0.989 | 1.120 | 0.914 | 1.090 | 1.023 |
| **PECH** | 1.025 | 0.995 | 1.034 | 1.008 | 0.959 | 0.907 | 1.000 | 0.989 |
| **SECH** | 1.013 | 1.346 | 0.739 | 0.981 | 1.168 | 1.008 | 1.090 | 1.035 |
| **TECHCH** | 0.985 | 0.752 | 1.307 | 0.960 | 0.836 | 1.059 | 0.878 | 0.955 |

T-Test for equality of mean TFP, unequal variances: Pr. > |t| = 0.6992

This analysis of the Malmquist Index using total net generation as the output variable shows that for the POUs, all indices are on average equal to unity; on average, POUs realized a 2.9% improvement in total factor productivity from 1997 to 2003.  Total factor productivity of IOUs decreased by 4.6% due to a combined reduction in technological change by 3.0% (from 0.985 to 0.955) and in pure technical efficiency change by 3.6% (from 1.025 to 0.989). A t-test statistic to test for equality of the means TFP of IOUs and POUs provides sufficient evidence against the null hypothesis, so we conclude that the mean TFP for generation plants owned by IOUs is significantly different from the mean TFP for generation plants owned by POUs. Thus, POUs achieved an improvement in TFP in generation statistically significant compared to IOUs whose TFP in generation regressed over the study period.

In summary, some of the results of the DEA Malmquist Index analysis indicate that publicly owned electric utilities outperformed IOUs, but others provide evidence that IOUs performed better than POUs.

The following graphs illustrate the fact that the large majority of electric utilities gravitated around a TFP of one, which means that during the period of study, most of the firms did not improve their total productivity in distribution and in generation.

The TFP index for privately and publicly owned electric utilities when comparing total sales showed no discernable differences except that IOUs and cooperatives exhibited increasing technological change starting in 2001.

Figure 4: Malmquist TFP Index of Integrated POUs

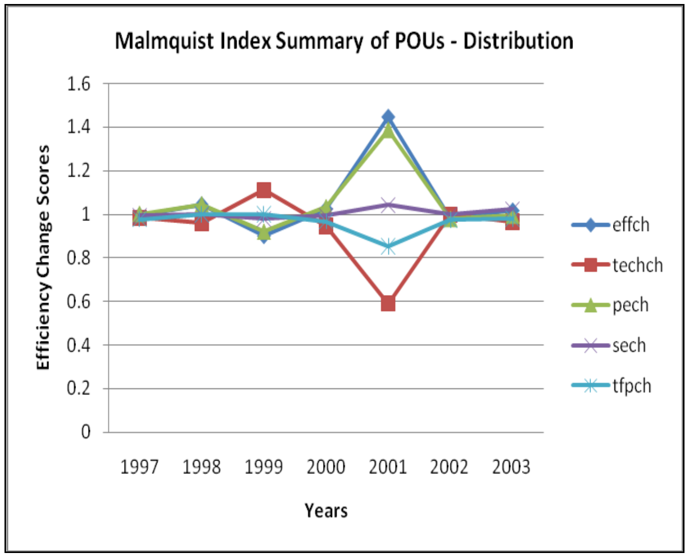
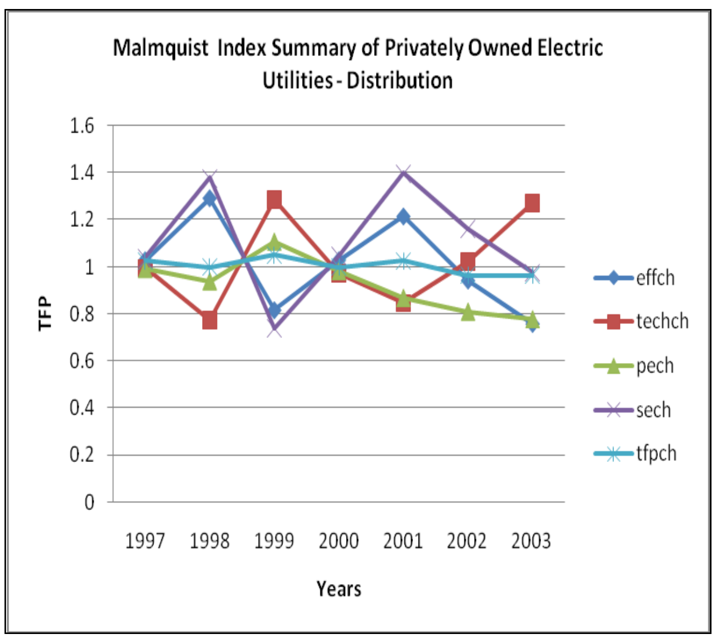



Figure 5: Malmquist TFP Index of Integrated IOUs/COOPs




For power generation plants, TFP did not improve in general, but most indices declined over time. The following figures show that the index of technological change increased substantially for publicly owned generation plants. The indices were constant for IOUs and COOPs during the same period.

Figure 6:Malmquist TFP Index of POUs – Generation Only

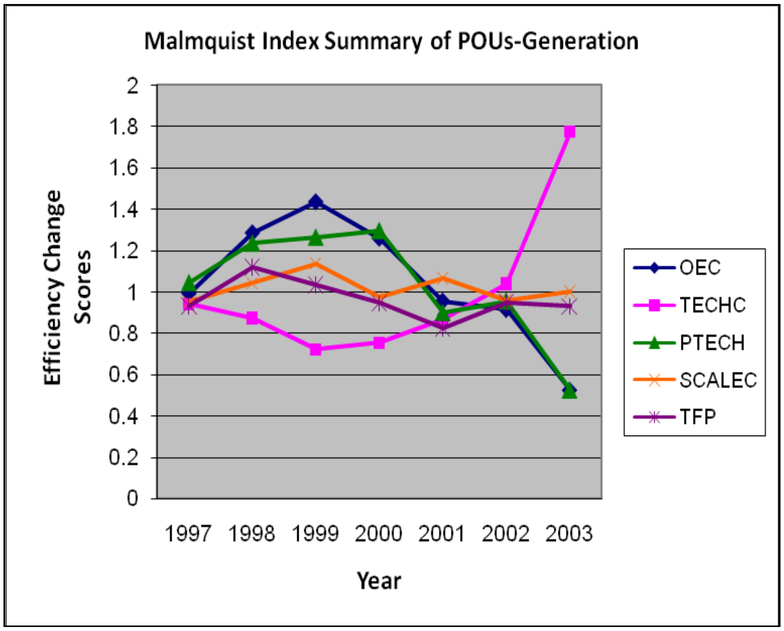
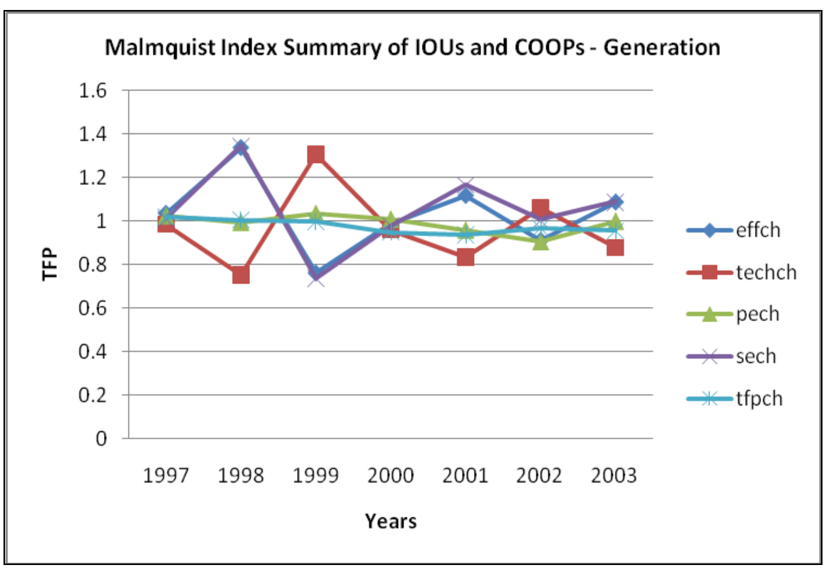



Figure 7: Malmquist TFP Index of IOUs and COOPs – Generation Only



It is worth noting the difference in productivity indices change between deregulated and regulated electric utilities. The following table indicates that TFP improved for deregulated privately owned electric utilities (3.0%) more than it did for publicly owned electric utilities (0.4%), but that generation TFP improved for municipal, state and federal electric utilities (1.3%) while it declined for IOUs and large cooperative electric utilities (-2.6%). Based on these results, we find slight evidence that deregulation improved TFP of privately owned electric utilities.

Table 14: Mean DEA TFP analysis

| MEAN DEA TFP ANALYSIS: DEREGULATED vs. REGULATED DMUs | | | | | | |
|---|---|---|---|---|---|---|
| | effch | techch | pech | Sech | tfpch | Sample |
| **PRIVATE DMUs** | | | | | | |
| **Generation** | | | | | | |
| Deregulated | 1.006 | 0.955 | 0.957 | 1.051 | 0.961 | 41 |
| Regulated | 1.034 | 0.954 | 1.01 | 1.024 | 0.987 | 65 |
| **% Improved** | **-2.7%** | **0.1%** | **-5.2%** | **2.6%** | **-2.6%** | |
| t-test | | | | | | |
| **Electric utility** | | | | | | |
| Deregulated | 1.01 | 1.009 | 0.92 | 1.098 | 1.019 | 68 |
| Regulated | 0.983 | 1.006 | 0.919 | 1.07 | 0.989 | 75 |
| **% Improved** | **2.7%** | **0.3%** | **0.1%** | **2.6%** | **3.0%** | |
| **PUBLIC DMUs** | | | | | | |
| **Generation** | | | | | | |
| Deregulated | 1.016 | 0.951 | 1.004 | 1.011 | 0.966 | 71 |
| Regulated | 1.004 | 0.951 | 0.987 | 1.017 | 0.954 | 120 |
| **% Improved** | **1.2%** | **0.0%** | **1.7%** | **-0.6%** | **1.3%** | |
| **Electric Utility** | | | | | | |
| Deregulated | 1.06 | 0.912 | 1.057 | 1.003 | 0.967 | 101 |
| Regulated | 1.042 | 0.924 | 1.039 | 1.003 | 0.963 | 281 |
| **% Improved** | **1.7%** | **-1.3%** | **1.7%** | **0.0%** | **0.4%** | |

A Kruskal-Wallis test statistic was performed to test for significant differences in Malmquist TFP index scores between the deregulated IOUs and deregulated POUs, for both generation and vertically integrated utilities.  The test fails to give sufficient evidence against the null hypothesis for both generation and vertically integrated utilities; so we cannot conclude that there are differences in efficiency changes between deregulated privately owned generation plants and deregulated publicly owned generation plants and between vertically integrated IOUs and POUs.

### 6.2. Stochastic frontier analysis

Coelli (1997, p.5) expressed his concerns that the two-stage estimation procedure used by other economists who estimated stochastic frontier functions and predicted firm-level efficiencies "is unlikely to provide estimates which are as efficient as those that could be obtained using a single-stage estimation procedure." Coelli proposed a stochastic frontier model in which the inefficiency effects ($U_i$) are an explicit function of a vector of firm-specific variables and a random error. This model was proposed in Battese and Coelli (1995).

The technical inefficiency effects are defined by: $U_{it} = z_{it}\delta + W_{it}$ where $z_{it}$ is a (1 x M) vector of explanatory variables associated with the technical inefficiency effects; $\delta$ is an (M x 1) vector of unknown parameters to be estimated; and $W_{it}$ are unobservable random variables, defined by the truncation of the normal distribution with zero mean and variance $\sigma^2$ such that the point of truncation is $- z_{it}\delta$, i.e., $W_{it} \geq - z_{it}\delta$. (See Battese and Coelli, 1995)

The electric industry is a complex system in which the functions of generation, transmission and distribution of power are entwined and are rarely distinctly separate. Historically, the majority of IOUs have been vertically integrated utilities generating their own power and transmitting and distributing their generation and purchased power to their ultimate final consumers. The introduction of competition or deregulation in the electric industry sought to break the links among the three functions such that an independent provider, often called a power marketer, interacts with generators and consumers of power.

In order to accurately model the production function of the electric industry, we start with a multiproduct cost function which embodies the complex relationships between ownership, efficiency and profitability of the firms in the sample. The cost function must reflect not only the differences in ownership, but also the differences in the products and the many inputs.

We use a quadratic cost function instead of a translog cost function because the quadratic function better handles the zero values of various variables included in the study.[42]

For each utility, total costs are the total of general operation and maintenance expenses (O&M), depreciation, and capital costs associated with the generation, transmission, distribution of electric power, and with the purchase of power that utilities need to offset the shortage of their output in order to meet the demand. An interaction variable (DIST.GENER) is added to capture possible economies of vertical integration, and SALESHARE and SUPPLYSHARE are added to explain the inefficiencies and capture market shares and the competitive advantages associated with large electric utilities compared to small cooperative, municipal or state-owned utilities. The standard quadratic cost function is as follows:

$$C(\text{GEN, TRANSM, DISTR}) = \alpha0 + \alpha11\ \text{DISTR} + \alpha12\ \text{DISTRSQ} + \alpha21\ \text{GENER} + \alpha22\ \text{GENERSQ} + \alpha3\ \text{DIST.GENER} + \alpha4\ \text{PURCHUTI} + \alpha5\ \text{NUCLEAR} + \alpha6\ \text{STEAM} + \alpha7\ \text{CUSTOMERS} + \varepsilon \qquad (14)$$

The dependent variable is an average utility cost estimated as the total costs as defined above divided by the total power disposition.[43] Estimated average cost is the appropriate variable because electric utilities are expected to be in long run competitive equilibrium which requires the equality of price, marginal and average cost of production in order to assure equilibrium for the individual firm and the industry.

---

[42] John E. Kwoka, Jr., "The comparative advantage of public ownership: evidence from United States electric utilities," *Canadian Journal of Economics,* May 2005 (627).

[43] Total disposition of power is the sum of sales to ultimate consumers, sales for resale, energy furnished without charge, energy used by the company, and total energy losses.

We include time-invariant variables to capture the impact of competition (COMPETE) and generation costs (FEGEN). Other cost variables include the interaction variables CAP.DIST, CAP.GEN and FUEL.GEN.

We expect both distribution and generation outputs to have positive signs, but the sign of the interaction DIST.GENER is ambiguous at best. Positive signs on the output variables and their square terms (DIST, GENER, DISTRSQ, and GENERSQ) reflect the convexity of the cost function with respect to each output.

If joint power production and distribution bring about economies of scale, that will translate into lower costs and a negative sign. We expect positive signs for the factor cost variables and the total number of customers. The variable NUCLEAR is expected to have a positive sign and the variable STEAM a negative sign to illustrate the least cost option of steam generation. As explained above, the inefficiency effects (Uit) are an explicit function of a vector of firm-specific variables which include the time-invariant variables COMPETE, SALESHARE, SUPPLYSHARE, FEGEN and a random error.

The model we use was developed by Battese and Coelli (1995) and designed for stochastic production frontier analysis. The production function was expressed as:

$$Y_{it} = x_{it}\beta + (V_{it} - U_{it}) \qquad \text{where i=1,..,N and t=1,,,,T} \qquad (15)$$

where $Y_{it}$, $X_{it}$ and β are respectively the production of firm i in period t, a kx1 vector of input quantities of firm i in period t, and a vector of unknown parameters; $V_{it}$ are random errors which are assumed to be iid $N(0,\sigma_v^2)$, and independent of the $U_{it}$. $U_{it}$ are non-negative random errors assumed to account for the cost inefficiency in production and iid $|N(0,\sigma_u^2)|$. $U_{it}$=($U_i$exp(-η(t-T))) where η is a parameter to be estimated.

Following Coelli (1997), the model is modified for the analysis of a cost of production function by altering the error term specification from (Vit – $U_{it}$) to (Vit + $U_{it}$). $U_{it}$ define how far a DMU operates above the cost frontier, and, given that the model imposes allocative efficiency,

$U_{it}$ is closely related to the cost of technical inefficiency. While in the estimation of a frontier production function the measures of technical efficiency take values between zero and one, they take a value between one and infinity in the case of a cost function. The results of the stochastic frontier analysis are given in Tables 15 and 16. Table 15 illustrates the results of a stochastic frontier analysis of the IOUs' average cost function, and Table 16 shows the results for the POUs. Both tables show the basic Model 1, Model 2 and Model 3 with the same output and input variables and the same explanatory variables of $U_{it}$.

Table 15: Maximum-likelihood estimates of the stochastic cost frontier with inefficiency effects (IOUs and COOPs)

| Independent variable | Model 1 | Model 2 | Model 3 |
|---|---|---|---|
| CONSTANT | 32.156 | 33.71 | 36.23 |
| | (24.54) | (16.87) | (18.50) |
| DISTR | 0.447 | 0.579 | 0.75 |
| | (3.72) | (3.47) | (4.52) |
| DISTRSQ | -0.004 | 0.001 | 0.002 |
| | (-3.92) | (0.67) | (1.79) |
| GENER | -0.643 | -1.018 | -1.64 |
| | (-3.55) | (-4.83) | (-7.15) |
| GENERSQ | -0.0024 | 0.001 | 0.006 |
| | (-0.59) | 0.27 | (1.49) |
| DISTR.GENER | 0.0096 | -0.001 | -0.007 |
| | (2.22) | (-0.12) | (-1.51) |
| PURCHUTI | | -0.90 | -0.92 |
| | | (-7.95) | (-8.50) |
| CONSUMERS | | 0.02 | 0.002 |
| | | (11.85) | (0.51) |
| NUCLEAR | | 11.49 | 8.20 |
| | | (4.50) | (3.26) |
| STEAM | | -1.51 | -1.89 |
| | | (-0.82) | (-0.99) |
| CAP.DISTR | | | 0.066 |
| | | | (3.56) |
| CAP.GENER | | | 0.024 |
| | | | (2.43) |
| FUEL.GENER | | | 0.019 |
| | | | (4.20) |
| **Constant** | **0.486** | **4.32** | **8.96** |
| | **(0.09)** | **(0.69)** | **(1.53)** |
| **Year** | **1.53** | **2.21** | **1.02** |
| | **(1.74)** | **(2.62)** | **(1.22)** |
| **COMPETE** | **19.04** | **7.01** | **6.63** |
| | **(3.97)** | **(1.78)** | **(1.63)** |
| **SALESHARE** | **46.42** | **40.99** | **45.23** |
| | **(4.96)** | **(12.06)** | **(6.98)** |
| **SUPPLYSHARE** | **-214.39** | **-189.19** | **-179.56** |
| | **(-7.57)** | **(-13.49)** | **(-6.64)** |
| **FEGEN** | **-11.56** | **-11.89** | **-17.09** |
| | **(-3.14)** | **(-2.95)** | **(-3.98)** |
| **Variance Parameters** | | | |
| $\boldsymbol{\sigma_s^2}$ | **1220.35** | **904.97** | **850.20** |
| | **(268.17)** | **(214.42)** | **(105.73)** |
| $\boldsymbol{\gamma}$ | **0.896** | **0.88** | **0.87** |
| | **(136.53)** | **(64.88)** | **(47.31)** |
| **Log Likelihood** | **-4969.35** | **-4859.08** | **-4851.23** |

Table 16: Maximum-likelihood estimates of the stochastic cost frontier with inefficiency effects (POUs)

| Independent variable | Model 1 | Model 2 | Model 3 |
|---|---|---|---|
| CONSTANT | -798.29 | -795.15 | 26.80 |
| | (-1236.66) | (-578.88) | (43.19) |
| DISTR | -1.051 | -1.88 | -6.41 |
| | (-1.83) | (-1.73) | (-9.37) |
| DISTRSQ | 0.29 | -0.021 | 0.060 |
| | (2.82) | (-0.033) | (3.18) |
| GENER | -0.60 | -0.194 | -3.56 |
| | (-0.67) | (-0.19) | (-9.91) |
| GENERSQ | 0.07 | 0.031 | 0.05 |
| | (3.78) | 0.28 | (10.14) |
| DISTR.GENER | -0.32 | 0.029 | -0.016 |
| | (-2.54) | (0.04) | (-0.77) |
| PURCHUTI | | -1.70 | -1.57 |
| | | (-1.58) | (-3.08) |
| CONSUMERS | | 0.603 | 0.201 |
| | | (2.23) | (4.99) |
| NUCLEAR | | 4.73 | 16.95 |
| | | (4.72) | (16.35) |
| STEAM | | -15.46 | -0.386 |
| | | (-15.24) | (-0.316) |
| CAP.DISTR | | | -0.025 |
| | | | (-0.123) |
| CAP.GENER | | | -0.324 |
| | | | (-9.92) |
| FUEL.GENER | | | 0.078 |
| | | | (5.23) |
| **Constant** | **-0.025** | **-0.06** | **-51.5** |
| | **(-0.025)** | **(-0.06)** | **(-42.66)** |
| **Year** | **-0.12** | **-0.28** | **-1209.81** |
| | **(-0.13)** | **(-0.20)** | **(-1617.79)** |
| **COMPETE** | **-0.003** | **-0.01** | **-4.40** |
| | **(-0.003)** | **(-0.01)** | **(-4.39)** |
| **SALESHARE** | **-0.002** | **-0.005** | **-2.42** |
| | **(-0.002)** | **(-0.005)** | **(-2.42)** |
| **SUPPLYSHARE** | **-0.002** | **-0.004** | **-1.83** |
| | **(-0.002)** | **(-0.004)** | **(-1.83)** |
| **FEGEN** | **-0.013** | **-0.036** | **-23.83** |
| | **(-0.013)** | **(-0.035)** | **(-23.04)** |
| **Variance Parameters** | | | |
| $\sigma_s^2$ | **1396164.6** | **1396069.1** | **1395952.7** |
| | **(1396164.6)** | **(1396069.0)** | **(1395952.4)** |
| $\gamma$ | **1.0** | **1.0** | **1.0** |
| | **(9788013.6)** | **(3393.1)** | **386012.59** |
| **Log Likelihood** | **-26825.48** | **-26792.27** | **-20815.16** |

For both the IOUs and POUs, Model 3 in Table 15 and Table 16 is the preferred model. The results for both IOUs and POUs indicate that more power generation (GENER) is associated with lower total costs, which is consistent with economies of scale in generation enjoyed by electric utilities. The coefficient for the square term GENSQ in both regressions is positive, but small and only significant for POUs. This means that the average cost function is convex with respect to generation, implying that the cost function exhibits product-specific diseconomies of scale for POUs. The coefficient for DISTRSQ in both regressions is also positive and significant, implying diseconomies of scale for IOUs, COOPs and POUs, with the POUs experiencing higher diseconomies of scale than privately owned electric utilities. Total sales variable (DISTR) is negative and significant for POUs, but positive and significant for IOUs, implying that POUs experience economies of size in total sales while privately owned electric utilities become less cost efficient with higher total sales. The results also indicate that NUCLEAR is associated with higher costs while STEAM generation is the least cost option for all electric utilities. Not surprisingly, purchased power (PURCHUTI) lowers total costs of electric utilities. The total number of consumers has mixed results; POUs reduce their total costs when they serve a larger customer base while IOUs and COOPs do not. The coefficient on DISTGEN is negative, but not significant in both regressions.

The explanatory variables of the inefficiency effects have the opposite signs for privately and publicly owned electric utilities, except for SUPPLYSHARE and FEGEN; generation and higher market share in generation are related to higher efficiency. Deregulation (COMPETE), higher market shares in distribution sales, and the time trend (year) are negatively related to the inefficiency effects for publicly owned electric firms. For POUs, a negative coefficient of the variable COMPETE supports the hypothesis that deregulation improves efficiency of POUs. Further, these results show that POUs are more efficient in distribution and generation, and that cost efficiency improves over time. For IOUs and COOPs, the results show that COMPETE, SALESHARE and YEAR are positively related to the costs of technical inefficiencies, implying that these firms became less cost efficient with deregulation and are less efficient in distribution and over time. IOUs and COOPs were found to be more cost efficient in power generation and with increased share in the generation relative to their state's electricity supply.

An analysis of the efficiency scores from the SFA shows that in general, the IOUs and COOPs are less cost efficient than POUs. The results also show that deregulated IOUs and COOPs are less cost efficient than their regulated peers. However, the SFA efficiency scores show that there are no efficiency gains or losses from deregulation for POUs. Detailed analysis of the SFA cost efficiencies are presented below.

Figure 8: Stochastic Frontier Cost Efficiencies of IOUs and COOPs:
1996 –2003

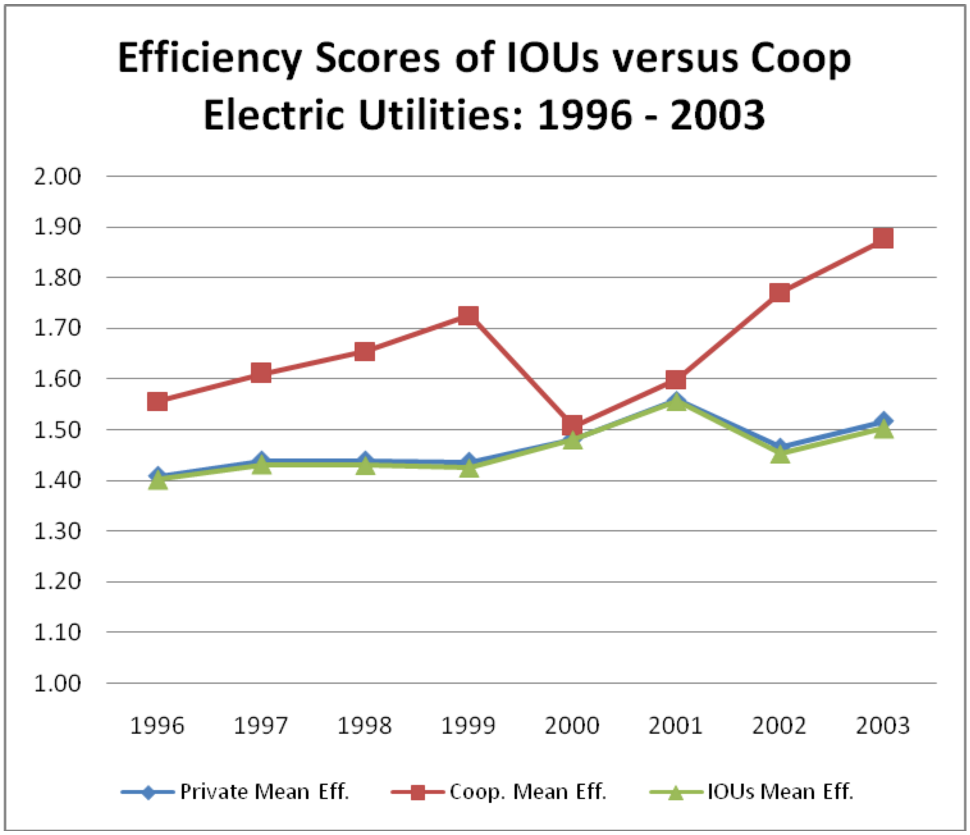



Figure 8 shows that COOPs were more cost efficient than IOUs and that their cost efficiency scores increased from 1996 to 1999 and from 2000 to 2003. At the same time, the cost efficiency scores of IOUs increased at a slower pace during the study period.

Figure 9:  Stochastic Frontier Cost Efficiencies of POUs: 1996 – 2003

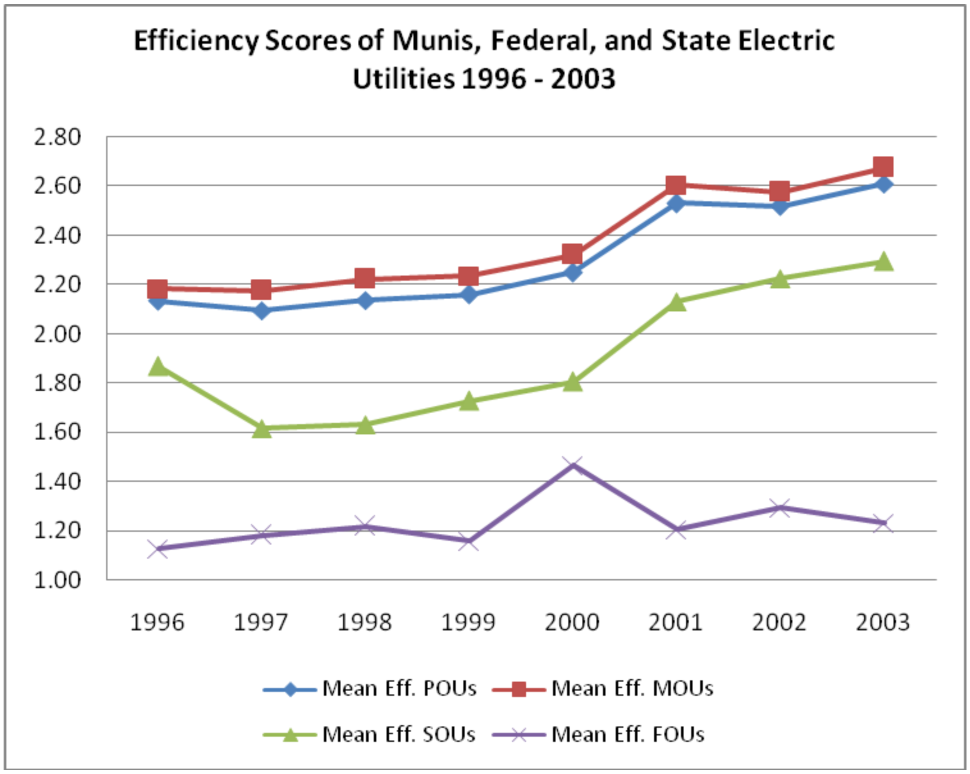
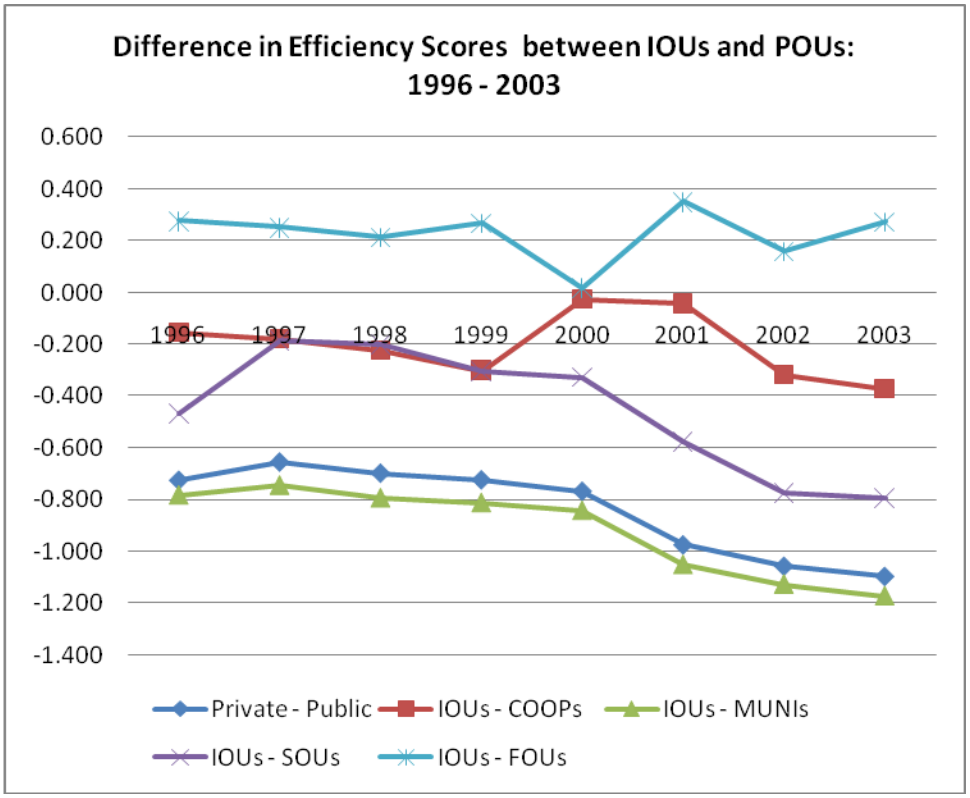



Figure 9 above shows that municipal utilities were more cost efficient than state owned electric utilities and that federally-owned electric utilities were the least cost efficient among POUs.  While the cost efficiency scores of the MUNIs and state or subdivision-owned electric utilities increased over the study period, the cost efficiency scores of federally-owned electric utilities remained almost constant.

Figure 10: Differences in Stochastic Frontier Cost Efficiencies Between IOUs/COOPs and POUs: 1996 - 2003.




## 6.3. Results of the Juhn-Murphy-Pierce Decomposition

### 6.3. a. Regression Analysis

The results of the estimated average cost functions of IOUs and POUs for 1998, 2003 and the period from 1998 to 2003 are presented in Tables 17, 18 and 19. The dependent variable is the utility's average cost. The signs on most coefficients are as expected; however, some of the coefficients have unexpected signs but are not statistically significant. In all regressions, the coefficients on power generation (GENER) are negative and significant, whether firms operate in deregulated or regulated states. Although not always significant, the coefficient on FEGEN is negative except for private and municipal regulated electric utilities as well as state and federal electric utilities. This means that owning a generation plant and more power generation are associated with lower average costs. Contrary to conventional wisdom, we found that, in general, large scale power generation plants are more cost efficient than large scale IOUs and state-owned or federally-owned electricity firms.

The results are mixed for purchased power to supplement power generation; the coefficient is negative and significant for IOUs and COOPs which means that purchasing supplemental power lowers average costs. The coefficient is positive and significant for POUs in 2003 and POUs in deregulated states from 1998 to 2003. This implies that POUs purchasing supplemental power are high cost utilities. The coefficient on number of consumers is generally positive and significant implying that average cost increases when the utilities add new consumers. The expectation that nuclear power generation is more expensive than steam power generation is supported in our data, except for IOUs in non-competitive states and some state and federally-owned power generation plants. The coefficient on steam power is positive and significant for deregulated IOUs and COOPs and all POUs (regulated or deregulated), which implies that these utilities do not consider steam power as a least cost option to nuclear power generation. With few exceptions, the coefficient on market share in distribution[44] is associated with increasing costs while the coefficient on market share in generation and power supply is associated with decreasing costs. As expected, the interaction between fuel costs and generation (FUEL.GENER) increase the average cost of electric utilities with generation power plants. The coefficients on the year variables are generally not significant. It is worth noting that the coefficient on year 2001 is generally positive and often significant, implying that electric utilities increased their costs during that year.[45]

[44] SALESHARE is a proxy for market power in distribution, and SUPPLYSHARE is a proxy for market power in generation and supply of power.

[45] The year 2001 is coincidentally the year during which terrorist attacks on the World Trade Center in New York and the Pentagon in Washington, DC occurred.

Table 17: Comparative Results of Regression Analysis: 1998 and 2003

| Independent variable | Private 1998 N = 139 | Private 2003 N = 139 | Public 1998 N = 430 | Public 2003 N=430 |
|---|---|---|---|---|
| CONSTANT | 62.97 | 76.20 | 56.54 | 68.09 |
| | (12.68) | (14.45) | (47.11) | (47.64) |
| **DISTR** | 0.48 | 2.45 | 1.84 | **-5.97** |
| | (0.47) | (1.87) | (0.44) | **(-2.40)** |
| **DISTRSQ** | 0.011 | **-0.011** | 0.10 | 0.04 |
| | (0.39) | **(-1.24)** | (0.71) | (0.34) |
| GENER | -2.83 | -4.03 | -5.48 | -2.76 |
| | (-2.51) | (-2.71) | (-1.21) | (-3.48) |
| **GENERSQ** | 0.018 | **-0.01** | **-0.24** | 0.03 |
| | (0.42) | **(-0.36)** | **(-1.47)** | (2.25) |
| DISTR.GENER | **-0.021** | 0.022 | 0.17 | **-0.09** |
| | **(-0.30)** | (0.85) | (0.59) | **(-0.95)** |
| **PURCHUTI** | -1.54 | -3.51 | -4.16 | **2.66** |
| | (-2.40) | (-2.90) | (-1.02) | **(2.60)** |
| CONSUMERS | 0.017 | **-0.02** | 0.08 | 0.07 |
| | (1.36) | **(-1.28)** | (1.50) | (1.08) |
| NUCLEAR | 22.03 | 7.47 | 23.78 | 25.43 |
| | (2.36) | (0.77) | (3.72) | (3.17) |
| STEAM | -7.82 | -7.79 | **4.08** | **6.49** |
| | (-1.33) | (-1.15) | **(1.57)** | **(2.01)** |
| SALESHARE | 23.57 | 19.42 | **-125.41** | 1.95 |
| | (1.92) | (1.58) | **(-2.34)** | (0.03) |
| SUPPLYSHARE | -14.18 | -6.66 | **164.76** | -12.64 |
| | (-0.67) | (-0.35) | **(2.35)** | (-0.73) |
| FEGEN | -3.47 | -10.65 | -2.77 | -1.41 |
| | (-0.54) | (-1.56) | (-1.36) | (-0.56) |
| CAP.DISTR | 0.03 | 0.26 | **-0.19** | 0.23 |
| | (0.51) | (3.12) | **(-0.70)** | (0.76) |
| **CAP.GENER** | 0.02 | **-0.03** | 0.04 | 0.02 |
| | (0.60) | **(-0.76)** | (0.59) | (0.21) |
| FUEL.GENER | 0.05 | 0.03 | 0.05 | 0.19 |
| | (1.84) | (2.55) | (0.74) | (3.13) |
| **R-squared** | **0.41** | **0.46** | **0.14** | **0.13** |
| **Adj R-squared** | **0.33** | **0.39** | **0.11** | **0.10** |

Table 18: Regression analysis of competitive electric utilities: 1998 to 2003

| Independent variable | Private N=275 | Public N=456 | Municipal N=418 | State & Federal N=38 |
|---|---|---|---|---|
| CONSTANT | 78.23 | 76.52 | 79.21 | 32.89 |
| | (13.98) | (16.23) | (15.90) | (2.22) |
| **DISTR** | **0.35** | **-5.10** | **-9.14** | **10.71** |
| | **(1.00)** | **(-2.76)** | **(-2.39)** | **(0.64)** |
| **DISTRSQ** | **0.0014** | **-0.075** | **0.41** | **-0.34** |
| | **(0.53)** | **(-0.89)** | **(2.08)** | **(-0.35)** |
| GENER | -5.05 | -3.93 | -0.17 | -4.80 |
| | (-6.06) | (-1.32) | (-0.02) | (-0.47) |
| **GENERSQ** | **0.036** | **-0.54** | **1.10** | **0.91** |
| | **(2.51)** | **(-0.32)** | **(3.50)** | **(1.39)** |
| DISTR.GENER | 0.0113 | 0.32 | **-1.80** | **-0.19** |
| | (0.96) | (1.86) | **(-3.34)** | **(-0.13)** |
| **PURCHUTI** | **-1.28** | **3.30** | **-3.85** | **0.06** |
| | **(-6.19)** | **(3.01)** | **(-1.57)** | **(0.01)** |
| CONSUMERS | 0.013 | 0.02 | 0.17 | **-0.19** |
| | (1.62) | (0.27) | (1.53) | **(-1.19)** |
| NUCLEAR | 26.69 | 23.06 | 17.01 | **-71.47** |
| | (5.33) | (3.22) | (2.37) | **(-0.10)** |
| STEAM | 8.23 | 13.05 | 13.01 | 3.55 |
| | (1.70) | (3.56) | (3.40) | (0.24) |
| SALESHARE | 11.78 | 174.48 | 4.54 | 1141.35 |
| | (1.56) | (1.19) | (0.03) | (1.15) |
| SUPPLYSHARE | -20.58 | -471.60 | -2660.81 | -3096.64 |
| | (-0.67) | (-1.39) | (-3.15) | (-1.17) |
| FEGEN | -16.65 | -4.85 | -3.43 | **4.21** |
| | (-4.15) | (-1.60) | (-1.12) | **(0.30)** |
| CAP.DISTR | 0.09 | 0.16 | 1.02 | 1.13 |
| | (2.48) | (0.54) | (2.39) | (0.96) |
| **CAP.GENER** | **-0.021** | **0.053** | **0.24** | **-0.29** |
| | **(-0.77)** | **(0.40)** | **(1.02)** | **(-0.27)** |
| FUEL.GENER | 0.11 | 0.12 | 0.12 | 0.22 |
| | (5.26) | (2.13) | (1.62) | (1.29) |
| **YEAR99** | -4.91 | -1.27 | -0.85 | **2.02** |
| | (-0.77) | (-0.22) | (-0.14) | **(0.16)** |
| **YEAR00** | -0.67 | -6.06 | -6.35 | **2.31** |
| | (-0.11) | (-0.16) | (-1.18) | **(0.18)** |
| **YEAR01** | 2.15 | 8.28 | 6.33 | **37.44** |
| | (0.37) | (1.61) | (1.20) | **(2.45)** |
| **YEAR02** | -4.22 | -0.80 | -2.81 | **17.44** |
| | (-0.74) | (-0.16) | (-0.56) | **(1.10)** |
| **YEAR03** | **-0.47** | **0.21** | **-1.88** | **19.88** |
| | **(-0.08)** | **(0.04)** | **(-0.36)** | **(1.19)** |
| **R-squared** | **0.59** | **0.17** | **0.22** | **0.80** |
| **Adj R-squared** | **0.56** | **0.13** | **0.18** | **0.57** |

Table 19: Regression analysis of non-competitive electric utilities: 1998 to 2003

| Independent variable | Private N=559 | Public N=2124 | Municipal N=1855 | State & Federal N=269 |
|---|---|---|---|---|
| CONSTANT | 53.64 | 52.53 | 53.06 | 44.08 |
| | (16.85) | (64.17) | (62.54) | (17.40) |
| **DISTR** | **0.72** | **-0.19** | **-4.63** | **0.60** |
| | **(2.22)** | **(-0.72)** | **(-2.98)** | **(1.80)** |
| **DISTRSQ** | **0.004** | **0.014** | **-0.11** | **0.02** |
| | **(2.35)** | **(1.12)** | **(-1.70)** | **(1.34)** |
| GENER | -2.23 | -1.24 | -17.25 | -1.24 |
| | (-4.96) | (-5.47) | (-10.44) | (-3.46) |
| **GENERSQ** | **0.01** | **0.013** | **-1.42** | **0.013** |
| | **(1.00)** | **(4.45)** | **(-6.56)** | **(3.45)** |
| DISTR.GENER | -0.011 | -0.015 | **1.26** | -0.025 |
| | (-1.28) | (-0.99) | **(5.54)** | (-1.50) |
| **PURCHUTI** | **-1.50** | **-0.82** | **0.04** | **0.024** |
| | **(-5.91)** | **(-2.20)** | **(0.03)** | **(0.03)** |
| CONSUMERS | 0.0013 | 0.06 | 0.28 | 0.045 |
| | (0.18) | (2.52) | (8.82) | (0.92) |
| **NUCLEAR** | **-16.24** | **15.02** | **8.43** | **14.13** |
| | **(-3.10)** | **(4.66)** | **(2.76)** | **(0.60)** |
| **STEAM** | **-21.80** | **2.52** | **-0.53** | **7.65** |
| | **(-7.09)** | **(2.16)** | **(-0.44)** | **(2.02)** |
| SALESHARE | 18.60 | 1.27 | **-193.91** | 1.71 |
| | (3.14) | (0.23) | **(-4.01)** | (0.29) |
| SUPPLYSHARE | -9.80 | -5.39 | **253.07** | **-6.91** |
| | (-1.25) | (-1.03) | **(3.29)** | **(-1.06)** |
| FEGEN | **15.44** | -1.05 | **1.30** | -9.99 |
| | **(4.40)** | (-1.16) | **(1.37)** | (-4.43) |
| CAP.DISTR | 0.09 | -0.04 | **0.08** | **-0.065** |
| | (2.31) | (-0.37) | **(0.68)** | **(-0.29)** |
| **CAP.GENER** | **0.05** | **-0.053** | **0.79** | **-0.03** |
| | **(2.82)** | **(-3.25)** | **(10.00)** | **(-1.67)** |
| FUEL.GENER | 0.03 | 0.03 | 0.32 | 0.03 |
| | (3.71) | (1.51) | (8.21) | (1.06) |
| YEAR99 | 1.45 | 0.63 | 0.69 | 0.25 |
| | (0.56) | (0.59) | (0.67) | (0.08) |
| YEAR00 | 2.80 | 1.70 | 1.37 | 1.78 |
| | (1.04) | (1.55) | (1.29) | (0.56) |
| **YEAR01** | **6.89** | **10.02** | **8.60** | **15.44** |
| | **(2.36)** | **(9.05)** | **(7.98)** | **(4.68)** |
| **YEAR02** | 1.24 | **9.98** | **8.45** | **19.65** |
| | (0.42) | **(8.79)** | **(7.63)** | **(5.83)** |
| **YEAR03** | **3.56** | **14.38** | **11.80** | **24.22** |
| | **(1.19)** | **(12.83)** | **(10.72)** | **(7.33)** |
| **R-squared** | **0.30** | **0.20** | **0.26** | **0.44** |
| **Adj R-squared** | **0.28** | **0.195** | **0.25** | **0.40** |

6.3.b. The Juhn-Murphy-Pierce Decomposition of Average Cost

Applying the Juhn-Murphy-Pierce decomposition, we estimate the proportion of the change in average costs over time due to changes in observable quantities, observable prices and changes in the distribution of unobservables (i.e., changes in unmeasured prices and quantities). The reference year is 1998, the year during which the first state, California, officially deregulated its electricity sector. In order to analyze the impact of deregulation on electric utilities, the reference average cost was set as the average cost of deregulated privately or publically owned electric companies.

Table 20 shows the observable and unobservable components of changes in average costs by IOUs and POUs in 2003 compared to 1996 and 1998. In general, average costs increased from 1996 and 1998 to 2003. Changes in observable prices over time accounted for most of the changes in average cost difference in Panels A, C and D for utilities in the 25th, 50th, 75th and 90th percentiles. Changes in observable quantities and unobservable quantities and prices explain most of the changes in average cost differences in the percentile differentials (below and above the mean). For example, changes in unobservable quantities and prices account for 85% (i.e. -6.01/-7.03) of the total change in the percentile differentials in cost in Panel D while changes in observable quantities account for over 100 percent of the total change in the percentile differentials in cost in Panels A (i.e. -8.77/-6.13 or143%), B (i.e. -8.84/-6.57 or 134%) and C (i.e. -272.58/-7.58 or 3595%). A change in quantities over time greater than 100% means that the change in quantities exceeds the change in average cost differences. Changes with opposite signs occurred over time for changes in prices and changes in unobservable quantities and prices which offset the changes in quantities.

Table 21 illustrates the change in observable quantities (total sales, net generation and the interaction between total sales and net generation) for IOUs and POUs in 2003 compared to 1996 and 1998. The changes in observable quantities over time (in Table 21) explain partially the total change in observable quantities in Table 20. For example, the sum of all the quantity effect of changes in average cost differences in Panel A equals -9.02 which more than explains the change in observable quantities in Table 20, Panel A of -8.77. This means that other changes in observable quantities occurred which account for the difference of -0.25. For all the percentiles in the table, except for net generation in Panel B, at the mean, the quantity effects in Panels A, B and D are similar in 1996, 1998 and 2003. For example, Panel D shows that on average, the changes in total sales and net generation were small (totaling 0.74) in 2003 compared to 1998 and do not fully explain the change in total observable quantities of -1.52. This finding substantiates the result explained above that change in observable input prices accounted for most of the changes in average costs across the electric industry.

Table 20: Observable and Unobservable Components of Changes in Average Costs of Electric Utilities: 1996 and 1998 Compared to 2003

| Differential | Total Change | Observable Quantities | Observable Prices | Unobservable Quantities and Prices |
|---|---|---|---|---|
| Panel A: 1996 and 2003 (Private electric companies) | | | | |
| 25 | -4.3 | 2.3 | -8.59 | 1.99 |
| 50 | -8.64 | -1.69 | -8.04 | 1.09 |
| 75 | -10.73 | -2.69 | -8.58 | 0.54 |
| 90 | -12.76 | -6.5 | -6.54 | 0.28 |
| Average | -9.11 | -2.15 | -7.94 | 0.98 |
| 90-10 | -9.04 | -15.05 | 8 | -2 |
| 90-50 | -4.12 | -4.8 | 1.5 | -0.81 |
| 50-10 | -4.92 | -10.25 | 6.5 | -1.18 |
| 75-25 | -6.43 | -4.99 | 0.011 | -1.44 |
| Average | -6.13 | -8.77 | 4.00 | -1.36 |
| Panel B: 1998 and 2003 (Private electric companies) | | | | |
| 25 | -1.606 | 2.1 | -5.32 | 1.62 |
| 50 | -7.72 | -5.29 | -3.85 | 1.42 |
| 75 | -9.12 | -7.57 | -1.11 | -0.44 |
| 90 | -10.54 | -9.21 | -1.87 | 0.54 |
| Average | -7.25 | -4.99 | -3.04 | 0.79 |
| 90-10 | -9.39 | -12.84 | 4.09 | -0.64 |
| 90-50 | -2.82 | -3.92 | 1.99 | -0.88 |
| 50-10 | -6.57 | -8.91 | 2.1 | 0.24 |
| 75-25 | -7.51 | -9.67 | 4.21 | -2.05 |
| Average | -6.57 | -8.84 | 3.10 | -0.83 |
| Panel C: 1996 and 2003 (Public electric companies) | | | | |
| 25 | -11.77 | 30.28 | 148.26 | -190.31 |
| 50 | -12.84 | -32.35 | 171.72 | -152.21 |
| 75 | -20.35 | -163.09 | 172.31 | -29.58 |
| 90 | -19.61 | -289.67 | 257.56 | 12.51 |
| Average | -16.14 | -113.71 | 187.46 | -89.90 |
| 90-10 | -10.88 | -448.48 | 219.36 | 218.24 |
| 90-50 | -6.76 | -257.32 | 85.85 | 164.72 |
| 50-10 | -4.11 | -191.16 | 133.52 | 53.53 |
| 75-25 | -8.58 | -193.36 | 24.05 | 160.73 |
| Average | -7.58 | -272.58 | 115.70 | 149.31 |
| Panel D: 1998 and 2003 (Public electric companies) | | | | |
| 25 | -12.43 | 0.56 | -15.68 | 2.7 |
| 50 | -12.13 | 0.06 | -14.29 | 2.11 |
| 75 | -20.26 | -0.19 | -15.23 | -4.84 |
| 90 | -19.69 | -0.21 | -15.64 | -3.84 |
| Average | -16.13 | 0.06 | -15.21 | -0.97 |
| 90-10 | -10.14 | -2.67 | 0.78 | -8.25 |
| 90-50 | -7.56 | -0.27 | -1.35 | -5.94 |
| 50-10 | -2.58 | -2.4 | 2.13 | -2.3 |
| 75-25 | -7.83 | -0.75 | 0.46 | -7.54 |
| Average | -7.03 | -1.52 | 0.51 | -6.01 |

Table 21: Quantity Effect of Changes in Average Costs of Electric Utilities: 1996 and 1998 Compared to 2003

| Differential | Total Sales | Net Generation | Distr.Gen |
|---|---|---|---|
| Panel A: 1996 and 2003 (Private electric companies) | | | |
| 25 | 11.12 | 4.92 | -5.03 |
| 50 | 6 | 1.17 | -3.56 |
| 75 | -0.61 | 1.14 | -1.47 |
| 90 | -1.26 | -0.37 | 0.34 |
| Average | 3.81 | 1.72 | -2.43 |
| 90-10 | -44.06 | -29.93 | 62.04 |
| 90-50 | -7.26 | -1.54 | 3.89 |
| 50-10 | -36.8 | -28.38 | 58.14 |
| 75-25 | -11.72 | -3.78 | 3.56 |
| Average | -24.96 | -15.91 | 31.91 |
| Panel B: 1998 and 2003 (Private electric companies) | | | |
| 25 | -0.5 | 0.36 | -0.94 |
| 50 | -1.7 | -4.02 | -1.14 |
| 75 | -0.93 | -2.61 | -1.97 |
| 90 | 6.66 | -16.61 | 6.96 |
| Average | 0.88 | -5.72 | 0.73 |
| 90-10 | 8.25 | -20.56 | 5.72 |
| 90-50 | 8.36 | -12.59 | 8.09 |
| 50-10 | -0.11 | -7.96 | -2.37 |
| 75-25 | -0.43 | -2.97 | -1.03 |
| Average | 4.02 | -11.02 | 2.60 |
| Panel C: 1996 and 2003 (Public electric companies) | | | |
| 25 | 6.8 | -6.64 | -0.45 |
| 50 | -8.84 | -10.28 | -1.52 |
| 75 | 1.26 | 0.75 | -4.13 |
| 90 | -9.54 | -21.8 | 7.47 |
| Average | -2.58 | -9.49 | 0.34 |
| 90-10 | -33.13 | -5.12 | 6.8 |
| 90-50 | -0.71 | -11.53 | 8.99 |
| 50-10 | -32.42 | 6.4 | -2.2 |
| 75-25 | -5.54 | 7.39 | -3.68 |
| Average | -17.95 | -0.72 | 2.48 |
| Panel D: 1998 and 2003 (Public electric companies) | | | |
| 25 | -0.04 | 0.24 | -0.08 |
| 50 | 0.17 | -0.59 | 0.16 |
| 75 | 0.52 | -0.41 | 0.11 |
| 90 | 0.84 | -0.18 | 0.72 |
| Average | 0.37 | -0.24 | 0.23 |
| 90-10 | 0.63 | 0.37 | 0.42 |
| 90-50 | 0.67 | 0.41 | 0.56 |
| 50-10 | -0.03 | -0.04 | -0.14 |
| 75-25 | 0.56 | -0.66 | 0.18 |
| Average | 0.46 | 0.02 | 0.26 |

Panels A and B of Table 22 below show that for the period from 1998 to 2003, average costs in IOUs, COOPs and POUs operating in deregulated states increased more than their counterparts in regulated states. This is true for all the firms in all percentiles and percentile differentials. Panel C illustrates that average costs for municipal electric utilities in deregulated states increased more than average costs for deregulated IOUs and COOPs in those states in all the percentiles considered. However, the same data show that average cost differences favored MUNIs over IOUs and COOPs when we consider the average cost differences between percentile differentials. Panel D demonstrates that average costs increased more for IOUs and COOPs in deregulated states than federal, state, and subdivision owned electric utilities, except for only the twenty-fifth percentile and for the ninetieth-fiftieth percentile differential.

For all the panels in Table 22, changes in observable prices explain most of the changes in average costs of deregulated electric utilities, positively contributing to the total change in average cost for the four considered percentiles of 47% (or 7.82/16.50) in deregulated private utilities (Panel A), 87% (or 18.75/21.60) in deregulated public utilities (Panel B), 96% (or -9.99/-10.43) in MUNIs in competitive states (Panel C), and reducing substantially total change in cost by -1468% (or -16.37/1.12). This means that changes in average costs of MUNIs in deregulated states were greater than changes in average costs of IOUs and COOPs due primarily to change in observable prices (higher prices for deregulated MUNIs) combined with greater changes in observable quantities in favor of deregulated IOUs and COOPs (i.e. 13.92/1.12 or 1248% change in observable quantities). For the 25$^{th}$, 50$^{th}$, 75$^{th}$, and 90$^{th}$ percentiles, unobservable quantities and prices account for a significant portion of the total change in average cost (9% in Panel A, 11% in Panel B, and 320% in Panel D); in Panel C the contribution of unobservable prices and quantities is negative and small. However, even for this period, unobservable quantities and prices remain important factors in explaining the percentile cost differentials, accounting for 91% in Panel B, 71% in Panel D, 21% in Panel A and -34% in Panel C.

Table 23 illustrating the quantity effect of changes in average costs of electric utilities over time by ownership shows that the quantity effects of deregulation are minimal for POUs (Panel B) and significant for IOUs and COOPs (Panel A).

The results in Panel C, Table 22 support the hypothesis that electricity deregulation decreases average cost of privately owned electric utilities compared to POUs. This is not surprising given that deregulation often affects privately-owned electric utilities under the jurisdiction of a state regulatory commission.[46] Thus, deregulation will only impact non-regulated electric utilities if electric competition brings in new competitors offering services which are good substitutes for the services offered by these utilities and utilities become more competitive and cost efficient. Compared to MUNIs which have higher changes in average costs than IOUs and COOPs (see Panel C, Table 22 above) net generation contributed to decreasing average cost while total sales contributed to increasing average costs, with the net effect being a better cost efficiency for deregulated private firms.

In conclusion, the results of the average cost decomposition analysis show that, on average:

(1) Electric companies operating in states with electricity deregulation are characterized by greater increases in average costs than their counterpart in regulated states, regardless of the type of ownership;

(2) Changes in observable prices and unobservable quantities and prices account for most of the changes in the differences in average cost at all the percentiles and in the percentile differentials (below and above the mean);

(3) Changes over time in observable quantities reduce (offset) the magnitude of the changes in the difference in average costs between firms in deregulated states and firms in regulated states; and

[46] Almost a quarter of all states regulate MUNIs and COOPs.

(4) Changes in the differences in cost of MUNIs in deregulated states exceed changes in the differences in costs of IOUs and COOPs, which is a disadvantage for deregulated MUNIs over time.

These results confirm the suspicion that deregulation occurred in those states where high electricity prices, and hence, high average electricity costs, existed before deregulation and may have been the leading force behind electricity restructuring (Kwoka, 2006). Therefore, future research into the effects of deregulation of the electric utilities in the United States should include a correction of the selection bias embedded in the sample of deregulated electric utilities. In addition, the results suggest that any state policy or management policy aimed at improving cost efficiency of electric utilities should focus on the price component of the policy; input prices such as fuel costs should be analyzed to determine the proper policy to reduce specific input prices and improve cost efficiency. Finally, the results confirm the cost efficiency advantage of privately owned electric utilities in deregulated states over MUNIs in deregulated states. Future research should focus on the analysis of the differences in deregulation policy approaches among deregulated states and other non-policy factors that affect electric utility costs.

Table 22: Observable and Unobservable Components of Changes in Average Costs of Electric Utilities by Ownership: 1998 to 2003 (compared to deregulated firms)

| Percentile and Differential | Total Change | Observable Quantities | Observable Prices | Unobservable Quantities and Prices |
|---|---|---|---|---|
| Panel A: 1998 to 2003 (reference = deregulated private electric companies) | | | | |
| 25 | 1.18 | 8.1 | -5.17 | -1.75 |
| 50 | 14.34 | 11.56 | 1.13 | 1.65 |
| 75 | 22.86 | 4.62 | 15.5 | 2.74 |
| 90 | 27.61 | 4.39 | 19.81 | 3.41 |
| Average | 16.50 | 7.17 | 7.82 | 1.51 |
| 90-10 | 29.33 | -6.07 | 29.01 | 6.39 |
| 90-50 | 13.27 | -7.17 | 18.67 | 1.76 |
| 50-10 | 16.07 | 1.1 | 10.33 | 4.63 |
| 75-25 | 21.69 | -3.48 | 20.68 | 4.49 |
| Average | 20.09 | -3.91 | 19.67 | 4.32 |
| Panel B: 1998 to 2003 (reference = deregulated public electric companies) | | | | |
| 25 | 12 | 1.55 | 17.11 | -6.66 |
| 50 | 19.64 | 0.03 | 18.93 | 0.69 |
| 75 | 26.87 | 1.17 | 19.84 | 5.86 |
| 90 | 27.89 | -0.55 | 19.13 | 9.31 |
| Average | 21.60 | 0.55 | 18.75 | 2.30 |
| 90-10 | 21.41 | -2.92 | 4.23 | 20.1 |
| 90-50 | 8.25 | -0.57 | 0.2 | 8.63 |
| 50-10 | 13.16 | -2.35 | 4.03 | 11.48 |
| 75-25 | 14.87 | -0.38 | 2.73 | 12.52 |
| Average | 14.42 | -1.56 | 2.80 | 13.18 |
| Panel C: 1998 to 2003 (deregulated private electric companies – MUNIs in competitive states) | | | | |
| 25 | -18.88 | -10.54 | -11.2 | 2.86 |
| 50 | -13.35 | -3.95 | -10.81 | 1.4 |
| 75 | -9.04 | 2.06 | -10.38 | -0.73 |
| 90 | -0.43 | 10.13 | -7.56 | -3 |
| Average | -10.43 | -0.57 | -9.99 | 0.13 |
| 90-10 | 15.76 | 18.71 | 2.3 | -5.25 |
| 90-50 | 12.93 | 14.08 | 3.24 | -4.4 |
| 50-10 | 2.84 | 4.63 | -0.94 | -0.85 |
| 75-25 | 9.83 | 12.61 | 0.83 | -3.6 |
| Average | 10.34 | 12.51 | 1.36 | -3.53 |
| Panel D: 1998 and 2003 (deregulated IOUs and COOPs – Other Public non-MUNIs in competitive states) | | | | |
| 25 | -7.54 | 9.11 | -14.91 | -1.73 |
| 50 | 3.83 | 13.78 | -12.19 | 2.24 |
| 75 | 5.14 | 14.04 | -13.96 | 5.05 |
| 90 | 3.03 | 18.75 | -24.42 | 8.7 |
| Average | 1.12 | 13.92 | -16.37 | 3.57 |
| 90-10 | 13.92 | -7.77 | 10.66 | 11.03 |
| 90-50 | -0.8 | 4.97 | -12.23 | 6.46 |
| 50-10 | 14.72 | -12.75 | 22.89 | 4.57 |
| 75-25 | 12.67 | 4.93 | 0.95 | 6.79 |
| Average | 10.13 | -2.66 | 5.57 | 7.21 |

Table 23: Quantity Effect of Changes in Average Costs of Electric Utilities Over Time by Ownership: 1998 to 2003

| Percentile and Differential | Total Sales | Net Generation | Distr.Gen |
|---|---|---|---|
| Panel A: 1998 to 2003 (reference = deregulated private electric companies) | | | |
| 25 | 0.71 | 28.27 | -4.72 |
| 50 | -0.12 | 23.44 | -0.85 |
| 75 | -4.19 | 22.37 | -0.12 |
| 90 | -6.07 | 13.17 | 0.25 |
| Average | -2.42 | 21.81 | -1.36 |
| 90-10 | -4.03 | -8.96 | 3.74 |
| 90-50 | -5.95 | -10.27 | 1.1 |
| 50-10 | 1.92 | 1.31 | 2.65 |
| 75-25 | -4.9 | -5.9 | 4.61 |
| Average | -3.24 | -5.96 | 3.03 |
| Panel B: 1998 to 2003 (reference = deregulated public electric companies) | | | |
| 25 | -2.21 | -0.06 | -0.39 |
| 50 | -1.58 | -1 | -0.15 |
| 75 | -0.21 | 0.28 | -0.37 |
| 90 | 1.54 | 0.44 | -0.36 |
| Average | -0.62 | -0.09 | -0.32 |
| 90-10 | 0.65 | -0.89 | 1.85 |
| 90-50 | 3.12 | 1.44 | -0.22 |
| 50-10 | -2.47 | -2.32 | 2.06 |
| 75-25 | 1.99 | 0.34 | 0.02 |
| Average | 0.82 | -0.36 | 0.93 |
| Panel C: 1998 to 2003 (deregulated IOUs and COOPs - MUNIs) | | | |
| 25 | 6.04 | -35.22 | 2 |
| 50 | 6.91 | -25.34 | 2.43 |
| 75 | 5.77 | -11.36 | 0.51 |
| 90 | 8.56 | -13.43 | 1.11 |
| Average | 6.82 | -21.34 | 1.51 |
| 90-10 | 6.03 | 44.61 | -15.68 |
| 90-50 | 1.65 | 11.91 | -1.33 |
| 50-10 | 4.38 | 32.69 | -14.35 |
| 75-25 | -0.28 | 23.86 | -1.49 |
| Average | 2.95 | 28.27 | -8.21 |
| Panel D: 1998 to 2003 (deregulated IOUs and COOPs – Other Public non-MUNIs) | | | |
| 25 | 3.59 | 7.2 | -1.49 |
| 50 | 3.32 | -8.28 | 2.43 |
| 75 | -1.97 | 3.99 | 0.48 |
| 90 | 5.04 | -4.02 | 1.11 |
| Average | 2.50 | -0.28 | 0.63 |
| 90-10 | 6.57 | -13.95 | -12.22 |
| 90-50 | 1.72 | 4.26 | -1.32 |
| 50-10 | 4.85 | -18.21 | -10.9 |
| 75-25 | -5.56 | -3.2 | 1.97 |
| Average | 1.90 | -7.78 | -5.62 |

### 6.4. Results of the Wealth Effect Analysis

In order to test the impact of deregulation on the returns on equity, we test a modified CAPM which includes technological changes and change in total factor productivity scores obtained from DEA Malmquist TFP Index analysis. The effects of deregulation on shareholder wealth is examined using monthly common stock returns for IOUs from 1997 to 2003, a period during which most deregulatory changes took place. The sample is constructed by matching electric utility subsidiary companies to their publicly traded corporate parent companies using information from FERC Form 1 and the Center for Research in Security Prices (CRSP).

Consistent with Johnston (1984) and Akhigbe et al. (2001), the Seemingly Unrelated Regression (SUR) model is used. We perform two regression analyses for deregulated and regulated IOUs. Because it is expected that the residuals from these two models would be correlated since all of the values of the variables are collected on the same set of observations, the SUR analysis generate more efficient estimates of the coefficients and standard errors.

Table 24 Panel A and B below shows descriptive means and standard deviations of the sample of regulated and deregulated distribution and generation utilities in the sample. Data in Panel A shows that on average, deregulated IOUs (for all combined utility functions, generation, transmission and distribution) performed better than the total sample and regulated IOUs, with 14.17% annual return compared to 13.05% for total sample and 11.89% return for regulated utilities. There are no differences in stock performance and technological and TFP changes of generation power plants. Overall, deregulated IOUs realized a better TFP scores than regulated IOUs. Because some deregulated IOUs are affiliated with regulated IOUs in states which have not enacted deregulation laws, we created another category of IOUs, the hybrid IOUs which include IOUs such as American Electric Power Company (AEP) whose subsidiaries are found in deregulated states (Ohio, Texas and Virginia) and in regulated states (Indiana, Kentucky, Oklahoma, Tennessee, West Virginia). Data in Panel B shows that deregulated IOUs attained high average annual returns on their stocks, 15.76% for integrated IOUs and 13.52% for generation plants compared to 13.38% and 13.07% for regulated IOUs and 8.37% and 8.51% for hybrid IOUs.  Panel B also shows that technological changes were similar across the sample, but that deregulated and hybrid IOUs realized higher TFP change scores than regulated IOUs.

Table 24: Sample characteristics for all IOUs in the sample

Panel A

| | COMPETE | RETURN | TECHCH | TFPCH | SAMPLE SIZE |
|---|---|---|---|---|---|
| All IOUs - COMBINED FUNCTIONS | 51.65% | 13.05% | 1.031 | 1.040 | 637 |
| DEREGULATED | | 14.17% | 1.033 | 1.077 | 329 |
| REGULATED | | 11.89% | 1.029 | 1.001 | 308 |
| | | | | | |
| ALL IOUs- GENERATION | 41.43% | 11.87% | 0.970 | 1.003 | 490 |
| DEREGULATED | | 11.55% | 0.971 | 1.011 | 203 |
| REGULATED | | 12.10% | 0.970 | 0.999 | 287 |
| | Market Return | Long-term Risk Free | Short-term Risk Free | SMB | HML |
| | 9.03% | 5.83% | 3.88% | 4.60% | 6.17% |

Panel B

| | COMPETE | RETURN | TECHCH | TFPCH | SAMPLE SIZE |
|---|---|---|---|---|---|
| All IOUs - COMBINED FUNCTIONS | 51.65% | 13.05% | 1.031 | 1.040 | 637 |
| DEREGULATED | | 15.76% | 1.033 | 1.071 | 280 |
| REGULATED | | 13.38% | 1.030 | 0.981 | 189 |
| HYBRID | | 8.37% | 1.030 | 1.057 | 168 |
| | | | | | |
| ALL IOUs- GENERATION | 41.43% | 11.87% | 0.970 | 1.004 | 490 |
| DEREGULATED | | 13.52% | 0.972 | 0.991 | 133 |
| REGULATED | | 13.07% | 0.971 | 1.000 | 217 |
| HYBRID | | 8.51% | 0.968 | 1.022 | 140 |
| | Market Return | Long-term Risk Free | Short-term Risk Free | SMB | HML |
| | 9.03% | 5.83% | 3.88% | 4.60% | 6.17% |

Table 25 below shows the results of the SUR analysis. It also reports the results of an ordinary least square regression analysis for the samples of integrated electric utilities and generation power companies owned by private investors.

Table 25: Wealth effects of deregulation of electric utilities.[47]
Panel A:

| | | | Seemingly Unrelated Regression | | | |
|---|---|---|---|---|---|---|
| | Regression Analysis | | COMBINED | | GENERATION | |
| **Variables** | **COMBINED** | **GENERATION** | **Deregulated** | **Regulated** | **Deregulated** | **Regulated** |
| Intercept | -20.62 | -5.47 | -20.98 | -16.64 | -4.47 | 13.25 |
| | (-2.21)** | (-0.74) | (-1.29) | (-1.58) | (-0.39) | (1.07) |
| Market Return | 0.75 | 0.82 | 0.81 | 0.70 | 0.95 | 0.71 |
| | (10.48)*** | (13.44)*** | (6.44)*** | (10.23)*** | (9.27)*** | (9.81)*** |
| SMB | -0.25 | -0.08 | -0.36 | -0.14 | -0.07 | -0.12 |
| | (-2.57)*** | (-1.35) | (-1.98)** | (-1.58) | (-0.69) | (-1.66)* |
| HML | 1.15 | 1.16 | 1.10 | 1.20 | 1.12 | 1.18 |
| | (17.02)*** | (18.63)*** | (9.43)*** | (18.75)*** | (10.55)*** | (15.75)*** |
| TECHCH | **18.76** | 3.75 | 20.42 | **16.18** | -1.71 | 6.05 |
| | **(2.10)**** | (0.61) | (1.26) | **(1.95)**** | (-0.17) | (0.83) |
| TFPCH | -0.17 | -1.71 | -0.06 | -3.10 | 2.06 | **-22.04** |
| | (-0.06) | (-0.44) | (-0.02) | (-0.58) | (0.45) | **(-2.41)**** |
| | | | | | | |
| $R^2$ | 0.3278 | 0.4902 | 0.238 | 0.5447 | 0.4595 | 0.5438 |
| Adj-$R^2$ | 0.3224 | 0.485 | | | | |
| F-Value | 61.53*** | 93.09*** | | | | |
| Sample | 637 | 490 | 323 | 307 | 202 | 286 |

* Significant at the 10% level.

** Significant at the 5% level.

*** Significant at the 1% level.

t-values in parenthesis

[47] The analysis used interest rates on 20-year government bonds as the risk-free interest rate. The results obtained using the short-term risk-free interest rate were similar that we decided not to report them.

Panel B

| Seemingly Unrelated Regression | | | | | | |
|---|---|---|---|---|---|---|
| | **COMBINED** | | | **GENERATION** | | |
| **Variables** | **Deregulated** | **Regulated** | **Hybrid** | **Deregulated** | **Regulated** | **Hybrid** |
| Intercept | -17.25 | -6.58 | -34.48 | 6.56 | 28.55 | -24.84 |
| | (-0.92) | (-0.43) | (-3.66) | (0.40) | (1.82)** | (-2.95)** |
| Market Return | **0.72** | **0.65** | **0.93** | **0.90** | **0.61** | **1.04** |
| | **(4.88)*** ** | **(6.97)*** ** | **(15.09)*** ** | **(6.29)*** ** | **(7.05)*** ** | **(14.18)*** ** |
| SMB | -0.38 | -0.12 | -0.19 | -0.09 | -0.17 | -0.03 |
| | (-1.82)** | (-0.97) | (-2.21)** | (-0.63) | (-1.90)* | (-0.43) |
| **HML** | **0.99** | **1.1** | **1.48** | **0.89** | **1.07** | **1.51** |
| | **(7.18)*** ** | **(12.49)*** ** | **(25.80)*** ** | **(6.03)*** ** | **(11.81)*** ** | **(20.44)*** ** |
| TECHCH | 19.98 | 10.32 | **25.26** | -10.76 | 4.20 | **14.62** |
| | (1.05) | (0.92) | **(3.19)*** ** | (-0.74) | (0.47) | **(2.05)** ** |
| TFPCH | -0.70 | -5.19 | -0.24 | 3.33 | **-33.43** | 0.83 |
| | (-0.15) | (-0.51) | (-0.08) | (0.50) | **(-2.82)** ** | (0.20) |
| | | | | | | |
| $R^2$ | 0.1796 | 0.4736 | **0.8079** | 0.3512 | 0.4931 | **0.7983** |
| Sample | 280 | 189 | 168 | 133 | 217 | 140 |

* Significant at the 10% level.

** Significant at the 5% level.

*** Significant at the 1% level.

t-values in parenthesis

We concluded from the following from these results:

(1) Regulated generation companies outperformed the market after controlling for the market, size, book-to-market, and technical and productivity changes.48

(2) Deregulated and hybrid electric utilities performed worse than the market and regulated electric utilities after controlling for the market, size, book-to-market, and technical and productivity changes. This means that shareholders lost value of their investments in deregulated and hybrid electric utilities relative to the market and regulation.

(3) Deregulated electric utilities faced higher systematic risks than their regulated peers, but lower risk than the market. Given the market risk (β) of 1, the coefficients on the expected market risk premium for deregulated integrated electric utilities and deregulated generation companies are respectively 0.81 and 0.95 compared to the β of their regulated peer companies of 0.70 and 0.71. This represents an increase in risk of deregulated electric utilities of 15.71% for integrated utilities and 33.80% for generation companies. Hybrid IOUs performed worse than regulated and deregulated IOUs, with a systematic risk higher than regulated IOUs by 43.08% (integrated IOUs) and 70.49% (generation companies).

(4) Higher book-to-market IOUs realized significantly higher stock returns regardless of the regulatory regime.

(5) Technological and total factor productivity changes were only significant for regulated and hybrid IOUs.

(6) Finally, even though stock returns are inversely related to the size of electric utilities, our findings are mixed: our results are not different for regulated and deregulated electric

[48] Although the sign of the coefficient for the intercept is positive for deregulated investor-owned generation firms, it is not statistically significant.

integrated or generation utilities. Therefore, they were not important determinant of the stock performance and of changes in shareholder wealth for deregulated IOUs.

(7) In conclusion, the results reject hypothesis (H1) that firms in states with restructuring laws experience higher positive wealth effects than firms in states without restructuring laws and fail to reject hypothesis (H2) that firms in deregulated states experienced higher systematic risk than regulated firms in the post- major deregulation events.

### 6.5. Summary of Empirical Findings

The results of DEA show no significant difference in efficiency between privately owned utilities and POUs. However, the results show the following:

(1) Integrated IOUs and COOPs are more cost efficient than integrated POUs;

(2) IOUs and COOPs have higher efficiency scores than POUs, both in generation and vertically integrated operations;

(3) Integrated IOUs and COOPs in deregulated states have higher allocative and cost efficiency scores than integrated POUs in deregulated states;

(4) Privately owned generation plants in deregulated states were less efficient than privately owned generation plants in regulated states;

(5) Publicly owned generation plants in deregulated states were more technically efficient than publicly owned generation plants in regulated states; and

(6) Integrated IOUs and COOPs in deregulated states generally improved technical, allocative and cost efficiencies respectively by 7%, 5.7% and 11.3% while the technical, allocative and cost efficiencies of integrated POUs in deregulated states regressed by 20.5%, 2.7% and 25.6% during the same time period.

The results of the DEA Malmquist TFP analysis show that on average POUs realized a 2.9% improvement in TFP in generation from 1997 to 2003 while the TFP decreased by 4.6% for the generation plants owned by IOUS and COOPs during the same period. However, looking at the combined operations of the utilities, TFP remained virtually unchanged. The analysis also shows that on average TFP improved for deregulated IOUs and COOPs by 3% over regulated IOUs and COOPs, while there was no difference in TFP change between deregulated and regulated POUs. Finally, generation power plants owned by IOUs and COOPs in deregulated states experienced a decrease in TFP change of 2.6% while power generation plants owned by POUs improved their TFP change by 1.3% in deregulated states. These differences in TFP change are small and need to be confirmed by future studies. It is possible that the differences are simply due to the speed and stage of deregulation as well as the fact that IOUs are in a transition stage from regulation to competition and need to adjust to a different business environment.

Assuming constant returns to scale, technical efficiency improved on average by 8.3% for privately owned electric utilities, but regressed by 7.9% for POUs. However, in the generation function only, technical efficiency declined respectively by 4.5% for privately owned generation plants and 4.9% for publicly owned generation plants. If variable returns to scale are assumed, technical efficiency improved by 4.3% for POUs and remained unchanged on average for IOUs and COOPs. Looking at the generation function only, technical efficiency declined by 1.5% for IOUs and COOPs and by 0.6% for POUs.

The results of the SFA show the following for all IOUs, COOPs and POUs:

(1) More power generation is associated with lower average costs;

(2) More purchased power to supplement their own generation lowers average costs;

(3) Serving more customers increases average costs;

(4) Nuclear power generation increases average costs; and

(5) Steam power generation is associated with lower average costs; and

(6) While more distribution is associated with lower costs for POUs, it is associated with higher average costs for IOUs and COOPs.

For POUs, a negative coefficient of the variable COMPETE supports the hypothesis that deregulation improves efficiency of POUs while a positive coefficient on COMPETE in the stochastic frontier analysis of IOUs and COOPs means that deregulation decreases efficiency of IOUs and COOPs. This result is consistent with our FTP change findings and DEA results for generation power plants, but contrary to our DEA results for vertically integrated electric utilities. The implication of these results is that more analysis of the effects of electricity deregulation should be conducted separating the generation, transmission, distribution and general expenses functions of the utilities. Finally, our SFA results show that for all electric utilities, increasing supply market share (market power in generation) and having generation power plants increase efficiency. The results also show that the existence of market power in distribution decreases efficiency of privately owned utilities but improves the efficiency of POUs. This result implies that increasing the size of distribution POUs is associated with increased efficiency. The efficiency results from our analysis are summarized in Table 26 below:

Table 26: Comparison of actual and expected outcomes from DEA and SFA analyses.

| | | | **IOUs and COOPs** | **POUs** | **Deregulation** |
|---|---|---|---|---|---|
| **DEA** | **Expected Efficiency** | **IOUs > POUs** | **Deregulated > Regulated** | **Deregulated > Regulated** | **Private > Public** |
| Generation | Cost efficiency | YES | NO | NO | YES |
| | Technical efficiency | YES | NO | YES | NO |
| | Allocative efficiency | YES | YES | NO | YES |
| Integrated Utility | Cost efficiency | YES | YES | NO | YES |
| | Technical efficiency | YES | YES | NO | YES |
| | Allocative efficiency | YES | YES | NO | YES |
| **DEA-MPI** | **Expected Efficiency** | **IOUs > POUs** | **Deregulated > Regulated** | **Deregulated > Regulated** | **Private > Public** |
| Generation | EFFCH | YES | NO | YES | NO |
| | TECHCH | YES | YES | NO | YES |
| | PECH | NO | NO | YES | NO |
| | SECH | YES | YES | NO | YES |
| | TFPCH | YES | NO | YES | NO |
| Integrated Utility | EFFCH | NO | YES | YES | NO |
| | TECHCH | YES | YES | NO | YES |
| | PECH | NO | YES | YES | NO |
| | SECH | NO | YES | NO | YES |
| | TFPCH | YES | YES | YES | YES |
| SFA | **Expected Efficiency** | IOUs > POUs | Deregulated > Regulated | Deregulated > Regulated | Private > Public |
| Generation | Cost efficiency | NO | YES | YES | NO |
| Integrated Utility | Cost efficiency | POUS > IOUs | NO | YES | POUs > IOUs |

The results of the cost decomposition analysis show that on average:

(1) As expected, electric companies operating in states with electricity deregulation are characterized by greater increases in average costs than their counterpart in regulated states, regardless of the type of ownership;

(2) Changes in observable prices and unobservable quantities and prices account for most of the changes in the differences in average cost at all the percentiles and in the percentile differentials (below and above the mean);

(3) Changes over time in observable quantities reduce (offset) the magnitude of the changes in the difference in average costs between firms in deregulated states and firms in regulated states; and

(4) Changes in the differences in cost of MUNIs in deregulated states exceed changes in the differences in costs of IOUs and COOPs, which is a disadvantage for deregulated MUNIs over time. This result is consistent with DEA results that IOUs and COOPs in deregulated states have higher allocative and cost efficiency scores than POUs in deregulated states.

The results of the wealth and risk effects of deregulation of the U.S. electric utilities show that deregulated and hybrid electric utilities performed worse than the market and regulated electric utilities after controlling for the market, size, book-to-market, and technical and productivity changes and faced higher systematic risks (by 15.71% for integrated utilities and 33.80% for generation companies) than their regulated peers, but lower risk than the market; higher book-to-market IOUs realized significantly higher stock returns regardless of the regulatory regime; and technological and total factor productivity changes were only significant for regulated and hybrid IOUs. In conclusion, the results reject hypothesis (H1) that firms in states with restructuring laws experience higher positive wealth effects than firms in states without restructuring laws and fail to reject hypothesis (H2) that firms in deregulated states experienced higher systematic risk than regulated firms. Therefore, for deregulation to benefit electric utility customers and shareholders, deregulation legislation should include measures to lower systematic risk, increase cost efficiency, and improve financial performance.

# CHAPTER VII

# CONCLUSIONS AND POLICY IMPLICATIONS

This study examined the effects of deregulation of the U.S. electric utilities on cost efficiencies, technological changes, stock performance and the impact of deregulation and ownership on the success or failure of deregulatory policies to produce intended results.

Several studies have examined the effects of regulatory changes on the cost efficiency and stock performance of a firm. However, an analysis of past studies of the electricity deregulation in the United States fails to provide sufficient, unequivocal evidence that deregulation generally increased the cost efficiency or the stock return of electric utilities in the United States.

Many recent studies generally used data envelopment analysis (DEA) or the stochastic frontier analysis (SFA) and found that in other countries, deregulation resulted in significant efficiency gains in the electricity industry, but the evidence is mixed in the United States with some studies finding that firms located in advanced deregulation states were less efficient in generation (Goto and Tsutsui, 2008). A review of recent empirical research into electricity deregulation in the United States provides no evidence of gains in efficiency or benefits due to electricity deregulation. Kwoka (2006), Blumsack et al. (2006) and Spinner (2006) reviewed these recent studies and concluded that they suffered from methodological deficiencies, which cast doubt on their results. They concluded that more research into the benefits of electricity deregulation in the United States was needed. Kwoka (2006) raised an important analytical issue which should be addressed by any serious study of the effect of deregulation of the U.S. electric utilities: the potential selection bias and endogeneity problem. It is evident that almost all high-cost/high-price states have enacted electric restructuring legislation with the exception of Alaska, Hawaii and Vermont. A few low-cost/low-price states like Arkansas, Oklahoma, Montana, Nevada, Oregon, Virginia and West Virginia enacted restructuring legislation but ultimately did not implement any form of restructuring. The Juhn-Murphy-Pierce decomposition of the change in average costs of regulated and deregulated electric utilities over time controls for selection effects in observable characteristics of firms, but we do not explicitly include a test for non-random selection based on unobservables in the model that we estimate. The JMP methodology allowed us to decompose the change in average costs into changes in their characteristics over time, changes in price over time, and changes in unexplained differences over time. Doing this analysis allowed us to determine the cost, price and quantity differentials between the regulated and deregulated firms. Future research should include additional modeling of non-random sample selection.

Past studies of the effects of deregulation on shareholder wealth relied primarily on event history analysis, focusing on short-term wealth effects rather than the long-term more permanent effects of deregulation. These studies failed to consider any size or book-to-market adjustments in their analyses. In addition, by focusing on major federal regulatory reforms, these studies failed to consider the differences in deregulatory policies and legislation across the country. Our study relies on state specific deregulatory policies and combines the market specific information on stock returns, technological efficiency data, size and book-to-to market data to determine the existence of long-term wealth effects from deregulation.

The main findings in our analysis are the following:

(1) Our DEA cost efficiency results suggest that IOUs, COOPs and POUs are in general cost inefficient and could increase efficiency levels by reducing their average costs in distribution and in generation. Vertically integrated IOUs and COOPs in deregulated states achieved greater technical, allocative and cost efficiencies than their peers in regulated states. Vertically integrated POUs in deregulated states achieved lower

technical, allocative and cost efficiencies than their peers in regulated states. The results also show that private and public generation plant efficiency was worse in deregulated states than in regulated states, but that privately owned deregulated power generation plants had higher allocative and cost efficiency scores than publicly owned power generation plants

(2) The results of the DEA Malmquist TFP show that on average, the total productivity decreased for IOUs and COOPs and for POUs. The analysis also shows that TFP Index improved for deregulated privately owned electric utilities more than it did for deregulated POUs. These results provide further evidence that deregulation improved the TFP index of privately owned electric utilities but did not affect the TFP index of POUs.

(3) The results of the stochastic frontier analysis indicate that deregulation improved efficiency of POUs but that IOUs and COOPs became less efficient with deregulation. However, deregulated IOUs and COOPs were more cost efficient in power generation and with increased share in generation relative to their state's electricity supply.

(4) The results of the Juhn-Murphy-Pierce decomposition of electric utilities' average cost confirms the cost efficiency advantage of privately owned electric utilities in deregulated states over POUs.

(5) The results support the existence of selection bias and endogeneity problems and show that changes in observable prices and unobservable quantities and prices account for most of the changes in the differences in average costs at all levels of costs.

(6) The results of the modified CAPM and Fama-French seemingly unrelated regressions analysis of the wealth and systematic risk long-term effects of deregulation of the U.S. electric utilities show deregulated and hybrid electric utilities realized lower stock returns relative to the market and to regulation and that deregulated electric utilities faced higher systematic risks than their regulated peers, but lower risk than the market.

(7) Technological and total factor productivity changes were not important determinants of the stock performance and of changes in shareholder wealth for deregulated IOUs.

The major finding of this study results from the JMP decomposition analysis: changes in observable prices and unobservable quantities and prices account for most of the changes in the differences in average costs at all levels of costs. The policy implication from this finding is that future deregulatory policy should require that rates reflect marginal costs of providing electric service so that consumers and suppliers can make economically efficient decisions (consumers need to maximize utility), suppliers can reduce capital costs over time and increase efficiency (and maximize profits). Deregulatory policies built on marginal cost pricing will promote economically efficient decision-making by including differentiated pricing or dynamic pricing in order to closely align retail rates and wholesale rates; improve system reliability, encourage customers to hedge against high rates (by adopting demand response programs) and suppliers to hedge high costs (by diversifying their inputs).

The policy implications of these results are that any state deregulatory policy aimed at improving the cost efficiency and reducing rates of electric utilities should focus on the input costs and output price components of the policy. For example, input prices such as fuel costs, costs of environmental policy changes, production and maintenance costs and administrative costs should be center of any deregulatory policy.

For that to happen, differentiated output prices should replace administratively set prices and regulators should not impede competitive market forces by maintaining a regulatory lag for the recovery of production costs.

Because unobservable quantities and prices are an important factor in explaining the differences in average costs between regulated and deregulated electric utilities, future studies should focus on factors other than prices and quantities such as differences in deregulatory policies, process and speed of deregulatory policies, and differences in costs and prices before implementation of any deregulation law or policy. In addition, future studies should include a correction for the selection bias embedded in the sample of deregulated electric utilities.

Future studies should concentrate on determining whether or not these findings hold true in the post-2003 time period and analyzing further the relationship between technical and productivity improvements on stock return performance. Future studies should also determine what factors should any deregulatory policy include in order to reduce the higher systematic risks faced by deregulated IOUs.

In general, our results show that deregulation of the U.S. electric utilities resulted in cost, technical and allocative efficiency advantage and in improved total factor productivity of privately owned electric utilities in deregulated states over POUs. However, looking only at the generation function, the results of the DEA and SFA provide contradictory evidence regarding the impact of deregulation on power generation efficiency. The implication of these results is that electric utilities which integrate all the production functions could be more efficient as a whole following deregulation even though one or more functions are not more efficient. Thus, future analysis of the effects of electricity deregulation should be conducted separating the generation, transmission, distribution and general expenses functions of the utilities.

Future studies should include data on peak demand quantities and prices in the analysis of the impact of deregulation of the U.S. electric utilities. It is possible that deregulated electric utilities face more incentives to make power available for peak demands in order to maximize profits when prices are at the highest levels. Regulated electric utilities do not face the same incentives as prices are administratively set by regulators. Since deregulated electric utilities are able to set differentiated prices (hourly prices, peak, off-peak, critical peak prices), they are better able to compensate for increased risk under deregulation and increase efficiencies.

## APPENDIX

| Appendix A: Average Residential Electricity Price by State, 1996-2006 (Cents per kilowatthour) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **1996** | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2006** | **2003 % Change** | **2006 % Change** |
| **AK** | 11.36 | 11.44 | 11.5 | 11.16 | 11.45 | 12.12 | 12.05 | 11.98 | 14.83 | 5.50% | 30.50% |
| **AL** | 6.63 | 6.74 | 6.94 | 7.03 | 7.05 | 7.01 | 7.12 | 7.39 | 8.75 | 11.50% | 32.00% |
| **AR** | 7.77 | 7.8 | 7.51 | 7.43 | 7.45 | 7.72 | 7.25 | 7.24 | 8.85 | -6.80% | 13.90% |
| **AZ** | 8.95 | 8.82 | 8.68 | 8.53 | 8.44 | 8.3 | 8.27 | 8.35 | 9.4 | -6.70% | 5.00% |
| **CA** | 11.33 | 11.5 | 10.6 | 10.64 | 10.89 | 12.09 | 12.64 | 12.23 | 14.33 | 7.90% | 26.50% |
| **CO** | 7.49 | 7.42 | 7.45 | 7.38 | 7.31 | 7.47 | 7.37 | 8.14 | 9.02 | 8.70% | 20.40% |
| **CT** | 12.05 | 12.13 | 11.95 | 11.46 | 10.86 | 10.9 | 10.96 | 11.31 | 16.86 | -6.10% | 39.90% |
| **DC** | 7.77 | 7.87 | 8 | 8 | 8.03 | 7.79 | 7.98 | 7.84 | 9.88 | 0.90% | 27.20% |
| **DE** | 8.97 | 9.22 | 9.13 | 9.17 | 8.54 | 8.61 | 8.7 | 8.59 | 11.85 | -4.20% | 32.10% |
| **FL** | 7.99 | 8.08 | 7.89 | 7.73 | 7.77 | 8.59 | 8.16 | 8.55 | 11.33 | 7.00% | 41.80% |
| **GA** | 7.66 | 7.74 | 7.67 | 7.56 | 7.6 | 7.72 | 7.63 | 7.7 | 8.91 | 0.50% | 16.30% |
| **HI** | 14.26 | 14.8 | 13.82 | 14.3 | 16.41 | 16.34 | 15.63 | 16.73 | 23.35 | 17.30% | 63.70% |
| **IA** | 8.16 | 8.21 | 8.38 | 8.35 | 8.37 | 8.41 | 8.35 | 8.57 | 9.63 | 5.00% | 18.00% |
| **ID** | 5.28 | 5.15 | 5.28 | 5.26 | 5.39 | 6.01 | 6.59 | 6.24 | 6.21 | 18.20% | 17.60% |
| **IL** | 10.34 | 10.43 | 9.85 | 8.83 | 8.83 | 8.71 | 8.39 | 8.38 | 8.42 | -19.00% | -18.60% |
| **IN** | 6.77 | 6.94 | 7.01 | 6.96 | 6.87 | 6.92 | 6.91 | 7.04 | 8.22 | 4.00% | 21.40% |
| **KS** | 7.86 | 7.71 | 7.65 | 7.64 | 7.65 | 7.66 | 7.67 | 7.71 | 8.25 | -1.90% | 5.00% |
| **KY** | 5.55 | 5.58 | 5.61 | 5.58 | 5.47 | 5.58 | 5.65 | 5.81 | 7.02 | 4.70% | 26.50% |
| **LA** | 7.55 | 7.39 | 7.07 | 7.12 | 7.67 | 7.92 | 7.1 | 7.84 | 9.14 | 3.80% | 21.10% |
| **MA** | 11.25 | 11.59 | 10.6 | 10.09 | 10.53 | 12.47 | 10.93 | 11.6 | 16.6 | 3.10% | 47.60% |
| **MD** | 8.26 | 8.33 | 8.44 | 8.39 | 7.95 | 7.67 | 7.74 | 7.73 | 9.71 | -6.40% | 17.60% |
| **ME** | 12.58 | 12.75 | 13.02 | 13.07 | 12.49 | 13.13 | 12.74 | 12.37 | 13.8 | -1.70% | 9.70% |
| **MI** | 8.47 | 8.57 | 8.67 | 8.73 | 8.52 | 8.26 | 8.28 | 8.35 | 9.77 | -1.40% | 15.30% |
| **MN** | 7.13 | 7.23 | 7.33 | 7.41 | 7.52 | 7.61 | 7.49 | 7.65 | 8.7 | 7.30% | 22.00% |
| **MO** | 7.08 | 7.09 | 7.08 | 7.12 | 7.04 | 7 | 7.06 | 6.96 | 7.44 | -1.70% | 5.10% |
| **MS** | 7.04 | 7.02 | 7.03 | 6.75 | 6.93 | 7.37 | 7.28 | 7.6 | 9.66 | 8.00% | 37.20% |
| **MT** | 6.22 | 6.4 | 6.5 | 6.78 | 6.49 | 6.88 | 7.23 | 7.56 | 8.28 | 21.50% | 33.10% |
| **NC** | 8.05 | 8.03 | 8.01 | 7.99 | 7.97 | 8.12 | 8.19 | 8.32 | 9.12 | 3.40% | 13.30% |
| **ND** | 6.19 | 6.27 | 6.49 | 6.5 | 6.44 | 6.47 | 6.39 | 6.49 | 7.14 | 4.80% | 15.30% |
| **NE** | 6.29 | 6.38 | 6.46 | 6.52 | 6.53 | 6.5 | 6.73 | 6.87 | 7.41 | 9.20% | 17.80% |
| **NH** | 13.44 | 13.67 | 13.92 | 13.64 | 13.15 | 12.49 | 11.89 | 11.98 | 14.68 | -10.90% | 9.20% |
| **NJ** | 11.99 | 12.08 | 11.39 | 11.4 | 10.27 | 10.21 | 10.38 | 10.67 | 12.84 | -11.00% | 7.10% |
| **NM** | 8.93 | 8.92 | 8.85 | 8.62 | 8.36 | 8.74 | 8.5 | 8.69 | 9.06 | -2.70% | 1.50% |
| **NV** | 6.9 | 6.77 | 7 | 7.13 | 7.28 | 9.08 | 9.43 | 9.02 | 11.08 | 30.70% | 60.60% |
| **NY** | 14.04 | 14.12 | 13.66 | 13.23 | 13.97 | 14.04 | 13.55 | 14.31 | 16.89 | 1.90% | 20.30% |
| **OH** | 8.6 | 8.63 | 8.7 | 8.68 | 8.61 | 8.37 | 8.24 | 8.26 | 9.34 | -4.00% | 8.60% |
| **OK** | 6.71 | 6.63 | 6.57 | 6.6 | 7.03 | 7.27 | 6.73 | 7.47 | 8.55 | 11.30% | 27.40% |
| **OR** | 5.69 | 5.56 | 5.82 | 5.75 | 5.88 | 6.29 | 7.12 | 7.06 | 7.48 | 24.10% | 31.50% |
| **PA** | 9.73 | 9.9 | 9.93 | 8.86 | 9.53 | 9.68 | 9.74 | 9.59 | 10.35 | -1.40% | 6.40% |
| **RI** | 11.81 | 12.12 | 10.91 | 10.12 | 11.28 | 12.13 | 10.2 | 11.61 | 15.12 | -1.70% | 28.00% |
| **SC** | 7.5 | 7.51 | 7.5 | 7.55 | 7.58 | 7.69 | 7.72 | 8.01 | 9.03 | 6.80% | 20.40% |
| **SD** | 7 | 7.08 | 7.27 | 7.42 | 7.42 | 7.42 | 7.4 | 7.47 | 7.83 | 6.70% | 11.90% |
| **TN** | 5.88 | 6.03 | 6.32 | 6.34 | 6.33 | 6.32 | 6.41 | 6.55 | 7.75 | 11.40% | 31.80% |
| **TX** | 7.77 | 7.82 | 7.65 | 7.55 | 7.96 | 8.86 | 8.05 | 9.16 | 12.86 | 17.90% | 65.50% |
| **UT** | 6.96 | 6.89 | 6.84 | 6.27 | 6.29 | 6.72 | 6.79 | 6.9 | 7.59 | -0.90% | 9.10% |
| **VA** | 7.6 | 7.75 | 7.51 | 7.48 | 7.52 | 7.79 | 7.79 | 7.76 | 8.49 | 2.10% | 11.70% |
| **VT** | 10.99 | 11.45 | 11.61 | 12.17 | 12.3 | 12.67 | 12.78 | 12.82 | 13.39 | 16.70% | 21.80% |
| **WA** | 5.03 | 4.95 | 5.03 | 5.1 | 5.13 | 5.7 | 6.29 | 6.31 | 6.82 | 25.40% | 35.60% |
| **WI** | 6.88 | 6.88 | 7.17 | 7.31 | 7.53 | 7.9 | 8.18 | 8.67 | 10.51 | 26.00% | 52.80% |
| **WV** | 6.38 | 6.26 | 6.29 | 6.27 | 6.27 | 6.26 | 6.23 | 6.24 | 6.35 | -2.20% | -0.50% |
| **WY** | 6.13 | 6.22 | 6.28 | 6.34 | 6.5 | 6.77 | 6.97 | 7.04 | 7.75 | 14.80% | 26.40% |
| **US-TOTAL** | 8.36 | 8.43 | 8.26 | 8.16 | 8.24 | 8.58 | 8.44 | 8.72 | 10.4 | 4.30% | 24.40% |
| **Average Change Deregulated States** | | | | | | | | | | -2.30% | 20.00% |
| Average Change Regulated States | | | | | | | | | | 9.00% | 24.30% |
| TTEST, 2-tails, unequal variance, Prob > \|T\| | | | | | | | | | | 0.00005 | 0.4061 |

Source: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

**Appendix B: Average Commercial Electricity Price by State, 1996-2006**
**(Cents per kilowatthour)**

| State | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2006 | 2003 % Change | 2006 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AK | 9.58 | 9.51 | 9.48 | 9.2 | 9.77 | 10.29 | 10.13 | 10.49 | 11.93 | 9.50% | 24.50% |
| AL | 6.49 | 6.34 | 6.54 | 6.54 | 6.58 | 6.53 | 6.63 | 6.85 | 8.18 | 5.50% | 26.00% |
| AR | 6.74 | 6.78 | 5.9 | 5.82 | 5.93 | 6.19 | 5.68 | 5.54 | 6.96 | -17.80% | 3.30% |
| AZ | 7.97 | 7.83 | 7.76 | 7.51 | 7.34 | 7.37 | 7.28 | 7.09 | 8.02 | -11.00% | 0.60% |
| CA | 9.83 | 9.98 | 9.66 | 9.44 | 10.25 | 12.15 | 13.36 | 12.48 | 12.9 | 27.00% | 31.20% |
| CO | 5.93 | 5.77 | 5.67 | 5.61 | 5.55 | 5.67 | 5.67 | 6.6 | 7.5 | 11.30% | 26.50% |
| CT | 10.29 | 10.28 | 10.01 | 9.69 | 9.27 | 9.26 | 9.32 | 9.93 | 14.03 | -3.50% | 36.30% |
| DC | 7.4 | 7.43 | 7.43 | 7.47 | 7.55 | 7.45 | 7.32 | 7.35 | 11.17 | -0.70% | 50.90% |
| DE | 7 | 7.19 | 7.07 | 7.39 | 5.89 | 7 | 7.15 | 7.31 | 10.21 | 4.40% | 45.90% |
| FL | 6.63 | 6.62 | 6.38 | 6.22 | 6.25 | 7.08 | 6.64 | 7.13 | 9.91 | 7.50% | 49.50% |
| GA | 7.17 | 7.11 | 7.01 | 6.67 | 6.5 | 6.61 | 6.46 | 6.66 | 7.81 | -7.10% | 8.90% |
| HI | 12.99 | 13.26 | 12.31 | 12.74 | 14.81 | 14.81 | 14.11 | 15.02 | 21.42 | 15.60% | 64.90% |
| IA | 6.53 | 6.61 | 6.67 | 6.45 | 6.57 | 6.69 | 6.56 | 6.24 | 7.29 | -4.40% | 11.60% |
| ID | 4.26 | 4.17 | 4.34 | 4.2 | 4.24 | 5.13 | 5.71 | 5.56 | 5.16 | 30.50% | 21.10% |
| IL | 7.97 | 7.93 | 7.77 | 7.38 | 7.31 | 7.4 | 7.52 | 7.3 | 7.95 | -8.40% | -0.30% |
| IN | 5.94 | 6.04 | 6.08 | 6.05 | 5.93 | 5.29 | 5.98 | 6.12 | 7.21 | 3.00% | 21.40% |
| KS | 6.67 | 6.47 | 6.34 | 6.25 | 6.25 | 6.2 | 6.28 | 6.42 | 6.96 | -3.70% | 4.30% |
| KY | 5.19 | 5.29 | 5.3 | 5.27 | 5.14 | 5.2 | 5.3 | 5.37 | 6.44 | 3.50% | 24.10% |
| LA | 7.12 | 6.99 | 6.56 | 6.59 | 7.18 | 7.58 | 6.64 | 7.42 | 9.03 | 4.20% | 26.80% |
| MA | 9.94 | 10.29 | 9.35 | 8.64 | 9.13 | 11.64 | 10.02 | 10.48 | 15.54 | 5.40% | 56.30% |
| MD | 6.83 | 6.86 | 6.82 | 6.82 | 6.55 | 6.36 | 6.31 | 6.95 | 10.56 | 1.80% | 54.60% |
| ME | 10.35 | 10.39 | 10.33 | 10.51 | 10.23 | 11.64 | 10.68 | 10.34 | 12.42 | -0.10% | 20.00% |
| MI | 7.94 | 7.84 | 7.81 | 7.85 | 7.9 | 7.54 | 7.79 | 7.55 | 8.51 | -4.90% | 7.20% |
| MN | 6.14 | 6.23 | 6.28 | 6.31 | 6.36 | 6.03 | 5.88 | 6.12 | 7.02 | -0.30% | 14.30% |
| MO | 6.04 | 6 | 5.99 | 5.96 | 5.83 | 5.89 | 5.88 | 5.78 | 6.08 | -4.30% | 0.70% |
| MS | 7.09 | 6.69 | 6.62 | 6.19 | 6.41 | 6.94 | 6.83 | 7.25 | 9.37 | 2.30% | 32.20% |
| MT | 5.51 | 5.8 | 5.87 | 6.35 | 5.6 | 5.91 | 6.28 | 6.85 | 7.44 | 24.30% | 35.00% |
| NC | 6.39 | 6.43 | 6.35 | 6.33 | 6.36 | 6.42 | 6.51 | 6.65 | 7.17 | 4.10% | 12.20% |
| ND | 6.07 | 6.15 | 6.2 | 6.19 | 6.08 | 5.99 | 5.85 | 5.64 | 6.3 | -7.10% | 3.80% |
| NE | 5.49 | 5.46 | 5.45 | 5.44 | 5.42 | 5.48 | 5.62 | 5.81 | 6.19 | 5.80% | 12.80% |
| NH | 11.32 | 11.35 | 11.64 | 11.18 | 10.81 | 10.53 | 10.06 | 10.3 | 14.07 | -9.00% | 24.30% |
| NJ | 10.32 | 10.35 | 10.09 | 9.73 | 9.14 | 9.09 | 8.9 | 9.11 | 11.62 | -11.70% | 12.60% |
| NM | 7.93 | 7.92 | 7.8 | 7.52 | 7.06 | 7.5 | 7.22 | 7.36 | 7.61 | -7.20% | -4.00% |
| NV | 6.61 | 6.31 | 6.5 | 6.66 | 6.74 | 8.45 | 9.06 | 8.79 | 10.12 | 33.00% | 53.10% |
| NY | 12.08 | 12.13 | 11.63 | 10.11 | 12.65 | 12.87 | 12.33 | 12.93 | 15.51 | 7.00% | 28.40% |
| OH | 7.71 | 7.67 | 7.67 | 7.67 | 7.61 | 8.46 | 7.81 | 7.55 | 8.44 | -2.10% | 9.50% |
| OK | 5.8 | 5.73 | 5.66 | 5.58 | 6.14 | 6.35 | 5.75 | 6.38 | 7.34 | 10.00% | 26.60% |
| OR | 5.15 | 4.97 | 5 | 4.94 | 5.06 | 5.45 | 6.59 | 6.38 | 6.77 | 23.90% | 31.50% |
| PA | 8.34 | 8.41 | 8.26 | 6.53 | 7.71 | 8.62 | 8.5 | 8.62 | 8.94 | 3.40% | 7.20% |
| RI | 10.14 | 10.4 | 9.26 | 7.73 | 9.5 | 11.54 | 8.65 | 10.09 | 13.51 | -0.50% | 33.20% |
| SC | 6.38 | 6.33 | 6.24 | 6.3 | 6.35 | 6.45 | 6.48 | 6.81 | 7.6 | 6.70% | 19.10% |
| SD | 6.57 | 6.63 | 6.62 | 6.7 | 6.64 | 6.55 | 6.24 | 6.04 | 6.47 | -8.10% | -1.50% |
| TN | 6.64 | 5.91 | 6.28 | 6.29 | 6.28 | 6.31 | 6.45 | 6.68 | 8 | 0.60% | 20.50% |
| TX | 6.71 | 6.74 | 6.57 | 6.52 | 6.88 | 7.74 | 6.95 | 7.84 | 9.85 | 16.80% | 46.80% |
| UT | 5.9 | 5.72 | 5.71 | 5.29 | 5.23 | 5.58 | 5.6 | 5.59 | 6.15 | -5.30% | 4.20% |
| VA | 5.91 | 5.97 | 5.61 | 5.55 | 5.65 | 5.85 | 5.87 | 5.74 | 6.21 | -2.90% | 5.10% |
| VT | 10.14 | 10.33 | 10.12 | 10.67 | 10.61 | 11.28 | 11.1 | 11.29 | 11.67 | 11.30% | 15.10% |
| WA | 4.88 | 4.79 | 4.81 | 4.86 | 4.86 | 5.45 | 6.11 | 6.07 | 6.63 | 24.40% | 35.90% |
| WI | 5.68 | 5.6 | 5.87 | 5.88 | 6.03 | 6.34 | 6.54 | 6.97 | 8.37 | 22.70% | 47.40% |
| WV | 5.71 | 5.54 | 5.56 | 5.53 | 5.46 | 5.44 | 5.41 | 5.45 | 5.59 | -4.60% | -2.10% |
| WY | 5.08 | 5.27 | 5.25 | 5.28 | 5.29 | 5.41 | 5.71 | 5.74 | 6.28 | 13.00% | 23.60% |
| US-TOTAL | 7.64 | 7.59 | 7.41 | 7.26 | 7.43 | 7.92 | 7.89 | 8.03 | 9.46 | 5.10% | 23.80% |
| **Average Change Deregulated States** | | | | | | | | | | 0.60% | 26.10% |
| Average Change Regulated States | | | | | | | | | | 6.20% | 21.00% |
| TTEST, 2-tails, unequal variance, Prob > \|T\| | | | | | | | | | | 0.0822 | 0.3538 |

Source: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

| Appendix C: Average Industrial Electricity Price by State, 1996-2006 (Cents per kilowatthour) | | | | | | | | | | 2003 % Change | 2006 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **1996** | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2006** | | |
| **AK** | 8.47 | 7.48 | 7.17 | 7.32 | 7.56 | 7.61 | 7.65 | 7.86 | 11.54 | -7.20% | 36.20% |
| **AL** | 3.9 | 3.71 | 3.89 | 3.82 | 3.87 | 3.79 | 3.82 | 3.98 | 4.9 | 2.10% | 25.60% |
| **AR** | 4.47 | 4.45 | 4.16 | 4.12 | 4.2 | 4.43 | 4.01 | 4.04 | 5.24 | -9.60% | 17.20% |
| **AZ** | 5.19 | 5.05 | 5.12 | 5.04 | 5.27 | 5.24 | 5.2 | 5.37 | 5.69 | 3.50% | 9.60% |
| **CA** | 6.97 | 6.95 | 6.59 | 6.27 | 7.14 | 9.23 | 9.81 | 9.59 | 10.09 | 37.60% | 44.80% |
| **CO** | 4.35 | 4.28 | 4.34 | 4.38 | 4.25 | 4.48 | 4.52 | 5.1 | 5.88 | 17.20% | 35.20% |
| **CT** | 7.86 | 7.76 | 7.7 | 7.42 | 7.32 | 7.62 | 7.68 | 7.99 | 11.71 | 1.70% | 49.00% |
| **DC** | 4.36 | 4.42 | 4.38 | 4.59 | 4.74 | 4.81 | 4.95 | 5.57 | 17.43 | 27.80% | **299.80%** |
| **DE** | 4.68 | 4.82 | 4.65 | 4.71 | 3.73 | 4.81 | 4.85 | 5.15 | 7.67 | 10.00% | 63.90% |
| **FL** | 5.11 | 5.04 | 4.81 | 4.77 | 4.84 | 5.18 | 5.23 | 5.41 | 7.71 | 5.90% | 50.90% |
| **GA** | 4.29 | 4.13 | 4.23 | 4.15 | 4.1 | 4.28 | 3.95 | 4.02 | 5.38 | -6.30% | 25.40% |
| **HI** | 10.03 | 10.32 | 9.41 | 9.7 | 11.69 | 11.68 | 11.02 | 12.2 | 17.96 | 21.60% | 79.10% |
| **IA** | 3.91 | 3.95 | 3.99 | 3.89 | 3.89 | 4.18 | 4.06 | 4.16 | 4.92 | 6.40% | 25.80% |
| **ID** | 2.68 | 2.6 | 2.77 | 2.63 | 3.11 | 3.71 | 4.34 | 4.16 | 3.61 | 55.20% | 34.70% |
| **IL** | 5.24 | 5.29 | 5.11 | 4.99 | 4.99 | 4.65 | 4.89 | 4.86 | 4.69 | -7.30% | -10.50% |
| **IN** | 3.93 | 3.91 | 3.95 | 3.89 | 3.81 | 4.11 | 3.95 | 3.92 | 4.95 | -0.30% | 26.00% |
| **KS** | 4.7 | 4.51 | 4.46 | 4.47 | 4.55 | 4.55 | 4.53 | 4.61 | 5.2 | -1.90% | 10.60% |
| **KY** | 2.92 | 2.8 | 2.91 | 2.99 | 3.01 | 3.04 | 3.09 | 3.21 | 4.05 | 9.90% | 38.70% |
| **LA** | 4.32 | 4.39 | 4.15 | 4.25 | 5 | 5.58 | 4.42 | 5.57 | 6.87 | 28.90% | 59.00% |
| **MA** | 8.43 | 8.78 | 8.18 | 7.53 | 8.2 | 9.37 | 8.34 | 8.93 | 13.04 | 5.90% | 54.70% |
| **MD** | 4.15 | 4.21 | 4.14 | 4.26 | 4.14 | 4.37 | 4.01 | 4.89 | 8.14 | 17.80% | 96.10% |
| **ME** | 6.26 | 6.36 | 6.61 | 6.42 | 6.89 | 7.15 | 7.05 | 6.35 | 8.83 | 1.40% | 41.10% |
| **MI** | 5.08 | 4.97 | 5.03 | 5.03 | 5.09 | 5.08 | 5.02 | 4.96 | 6.05 | -2.40% | 19.10% |
| **MN** | 4.26 | 4.33 | 4.45 | 4.56 | 4.57 | 4.34 | 4.07 | 4.36 | 5.29 | 2.30% | 24.20% |
| **MO** | 4.44 | 4.46 | 4.43 | 4.38 | 4.43 | 4.39 | 4.42 | 4.49 | 4.58 | 1.10% | 3.20% |
| **MS** | 4.41 | 4.12 | 4.22 | 4.02 | 4.14 | 4.4 | 4.4 | 4.48 | 5.94 | 1.60% | 34.70% |
| **MT** | 3.3 | 3.66 | 3.19 | 2.74 | 3.97 | 6.59 | 3.71 | 4.03 | 5.12 | 22.10% | 55.20% |
| **NC** | 4.79 | 4.71 | 4.63 | 4.57 | 4.58 | 4.61 | 4.7 | 4.79 | 5.23 | 0.00% | 9.20% |
| **ND** | 4.44 | 4.38 | 4.3 | 4.04 | 3.98 | 3.98 | 3.98 | 3.96 | 5 | -10.80% | 12.60% |
| **NE** | 3.68 | 3.61 | 3.6 | 3.57 | 3.61 | 3.76 | 3.89 | 4.18 | 4.56 | 13.60% | 23.90% |
| **NH** | 9.16 | 9.06 | 9.42 | 9.19 | 9.17 | 9.11 | 9.09 | 9.75 | 11.62 | 6.40% | 26.90% |
| **NJ** | 8.15 | 8.11 | 7.94 | 7.67 | 8.58 | 8.33 | 7.72 | 7.99 | 10.42 | -2.00% | 27.90% |
| **NM** | 4.35 | 4.42 | 4.47 | 4.24 | 4.69 | 5.45 | 4.48 | 4.95 | 5.57 | 13.80% | 28.00% |
| **NV** | 4.9 | 4.48 | 4.57 | 4.77 | 4.98 | 6.56 | 7.25 | 7.3 | 8.03 | 49.00% | 63.90% |
| **NY** | 5.62 | 5.2 | 4.95 | 4.74 | 5.37 | 5.56 | 5.18 | 7.14 | 9.39 | 27.00% | 67.10% |
| **OH** | 4.21 | 4.16 | 4.3 | 4.33 | 4.37 | 4.27 | 4.87 | 4.79 | 5.61 | 13.80% | 33.30% |
| **OK** | 3.78 | 3.63 | 3.65 | 3.6 | 4.09 | 4.29 | 3.81 | 4.59 | 5.46 | 21.40% | 44.40% |
| **OR** | 3.41 | 3.23 | 3.5 | 3.48 | 3.56 | 4.21 | 4.72 | 4.63 | 4.85 | 35.80% | 42.20% |
| **PA** | 5.93 | 5.89 | 5.63 | 4.71 | 5.63 | 5.76 | 5.83 | 5.8 | 6.63 | -2.20% | 11.80% |
| **RI** | 8.51 | 8.52 | 7.61 | 7.31 | 8.76 | 9.36 | 7.96 | 8.88 | 12.51 | 4.30% | 47.00% |
| **SC** | 3.89 | 3.71 | 3.69 | 3.72 | 3.74 | 3.86 | 3.85 | 4 | 4.71 | 2.80% | 21.10% |
| **SD** | 4.45 | 4.42 | 4.44 | 4.55 | 4.49 | 4.46 | 4.54 | 4.51 | 4.84 | 1.30% | 8.80% |
| **TN** | 4.52 | 3.81 | 4.17 | 4.19 | 4.09 | 4.05 | 4.15 | 4.29 | 5.17 | -5.10% | 14.40% |
| **TX** | 4.03 | 4.05 | 3.94 | 3.97 | 4.42 | 5.27 | 4.66 | 5.27 | 7.82 | 30.80% | 94.00% |
| **UT** | 3.7 | 3.49 | 3.45 | 3.36 | 3.35 | 3.53 | 3.84 | 3.79 | 4.21 | 2.40% | 13.80% |
| **VA** | 3.99 | 4 | 3.82 | 3.84 | 3.9 | 4.16 | 4.13 | 4.23 | 4.69 | 6.00% | 17.50% |
| **VT** | 7.58 | 7.44 | 7.27 | 7.35 | 7.31 | 7.89 | 7.9 | 8.05 | 8.33 | 6.20% | 9.90% |
| **WA** | 2.85 | 2.59 | 2.64 | 2.65 | 3.3 | 4.75 | 4.88 | 4.76 | 4.44 | 67.00% | 55.80% |
| **WI** | 3.66 | 3.72 | 3.86 | 3.89 | 4.04 | 4.36 | 4.43 | 4.71 | 5.85 | 28.70% | 59.80% |
| **WV** | 3.91 | 3.71 | 3.78 | 3.8 | 3.76 | 3.74 | 3.81 | 3.81 | 3.71 | -2.60% | -5.10% |
| **WY** | 3.45 | 3.46 | 3.38 | 3.34 | 3.36 | 3.43 | 3.55 | 3.65 | 4.04 | 5.80% | 17.10% |
| **US-TOTAL** | 4.6 | 4.53 | 4.48 | 4.43 | 4.64 | 5.05 | 4.88 | 5.11 | 6.16 | 11.10% | 33.90% |
| **Average Change Deregulated States** | | | | | | | | | | 10.00% | 55.20% |
| Average Change Regulated States | | | | | | | | | | 11.50% | 30.30% |
| TTEST, 2-tails, unequal variance, Prob > \|T\| | | | | | | | | | | 0.7463 | 0.1422 |

Source: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

| Appendix D: Average United States Electricity Price by State, 1996-2006 (Cents per kilowatthour) | | | | | | | | | | 2003 % Change | 2006 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **1996** | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2006** | | |
| **AK** | 10.24 | 10.07 | 9.97 | 9.78 | 10.08 | 10.54 | 10.46 | 10.5 | 12.84 | 2.50% | 25.40% |
| **AL** | 5.35 | 5.33 | 5.56 | 5.54 | 5.61 | 5.6 | 5.71 | 5.88 | 7.07 | 9.90% | 32.10% |
| **AR** | 6.15 | 6.15 | 5.78 | 5.68 | 5.77 | 6.05 | 5.61 | 5.57 | 6.99 | -9.40% | 13.70% |
| **AZ** | 7.54 | 7.38 | 7.33 | 7.23 | 7.25 | 7.27 | 7.21 | 7.34 | 8.24 | -2.70% | 9.30% |
| **CA** | 9.48 | 9.54 | 9.03 | 8.75 | 9.47 | 11.22 | 12.19 | 11.78 | 12.82 | 24.30% | 35.20% |
| **CO** | 6.05 | 5.95 | 5.95 | 5.95 | 5.88 | 6.02 | 6 | 6.77 | 7.61 | 11.90% | 25.80% |
| **CT** | 10.51 | 10.52 | 10.3 | 9.96 | 9.52 | 9.62 | 9.71 | 10.16 | 14.83 | -3.30% | 41.10% |
| **DC** | 7.35 | 7.39 | 7.41 | 7.45 | 7.52 | 7.4 | 7.34 | 7.4 | 11.08 | 0.70% | 50.70% |
| **DE** | 6.88 | 7 | 6.88 | 7.1 | 6.08 | 6.8 | 6.91 | 6.96 | 10.13 | 1.20% | 47.20% |
| **FL** | 7.18 | 7.19 | 7.01 | 6.85 | 6.91 | 7.67 | 7.31 | 7.72 | 10.45 | 7.50% | 45.50% |
| **GA** | 6.43 | 6.37 | 6.4 | 6.24 | 6.21 | 6.39 | 6.24 | 6.32 | 7.63 | -1.70% | 18.70% |
| **HI** | 12.12 | 12.49 | 11.56 | 11.97 | 14.03 | 14.05 | 13.39 | 14.47 | 20.72 | 19.40% | 71.00% |
| **IA** | 5.94 | 5.97 | 6.04 | 5.93 | 5.93 | 6.14 | 6.01 | 6.11 | 7.01 | 2.90% | 18.00% |
| **ID** | 3.96 | 3.87 | 4.02 | 3.89 | 4.17 | 4.92 | 5.58 | 5.22 | 4.92 | 31.80% | 24.20% |
| **IL** | 7.69 | 7.71 | 7.46 | 6.96 | 6.94 | 6.9 | 6.94 | 6.86 | 7.07 | -10.80% | -8.10% |
| **IN** | 5.23 | 5.29 | 5.34 | 5.29 | 5.18 | 5.3 | 5.34 | 5.37 | 6.46 | 2.70% | 23.50% |
| **KS** | 6.52 | 6.31 | 6.28 | 6.22 | 6.27 | 6.24 | 6.31 | 6.35 | 6.89 | -2.60% | 5.70% |
| **KY** | 4.03 | 4.03 | 4.16 | 4.17 | 4.18 | 4.24 | 4.26 | 4.42 | 5.43 | 9.70% | 34.70% |
| **LA** | 6.07 | 5.99 | 5.78 | 5.81 | 6.48 | 6.96 | 5.99 | 6.93 | 8.3 | 14.20% | 36.70% |
| **MA** | 10.13 | 10.48 | 9.59 | 8.99 | 9.49 | 11.55 | 10.06 | 10.56 | 15.45 | 4.20% | 52.50% |
| **MD** | 6.96 | 6.98 | 6.99 | 7.04 | 6.74 | 6.6 | 6.18 | 6.45 | 9.95 | -7.30% | 43.00% |
| **ME** | 9.46 | 9.51 | 9.75 | 9.77 | 9.69 | 10.55 | 10.35 | 9.79 | 11.8 | 3.50% | 24.70% |
| **MI** | 7.1 | 7.04 | 7.09 | 7.12 | 7.11 | 6.97 | 7.09 | 6.85 | 8.14 | -3.50% | 14.60% |
| **MN** | 5.54 | 5.61 | 5.71 | 5.83 | 5.87 | 5.97 | 5.8 | 6.01 | 6.98 | 8.50% | 26.00% |
| **MO** | 6.11 | 6.09 | 6.08 | 6.06 | 6.02 | 6.03 | 6.09 | 6.02 | 6.3 | -1.50% | 3.10% |
| **MS** | 6.01 | 5.91 | 5.98 | 5.65 | 5.85 | 6.26 | 6.24 | 6.46 | 8.33 | 7.50% | 38.60% |
| **MT** | 4.72 | 5.2 | 4.8 | 4.77 | 5 | 6.48 | 5.7 | 6.14 | 6.91 | 30.10% | 46.40% |
| **NC** | 6.53 | 6.48 | 6.45 | 6.44 | 6.48 | 6.58 | 6.74 | 6.86 | 7.53 | 5.10% | 15.30% |
| **ND** | 5.65 | 5.65 | 5.7 | 5.49 | 5.44 | 5.48 | 5.45 | 5.47 | 6.21 | -3.20% | 9.90% |
| **NE** | 5.32 | 5.3 | 5.3 | 5.31 | 5.31 | 5.39 | 5.55 | 5.64 | 6.07 | 6.00% | 14.10% |
| **NH** | 11.59 | 11.66 | 11.93 | 11.6 | 11.25 | 10.95 | 10.6 | 10.83 | 13.84 | -6.60% | 19.40% |
| **NJ** | 10.5 | 10.54 | 10.17 | 9.98 | 9.47 | 9.36 | 9.3 | 9.48 | 11.88 | -9.70% | 13.10% |
| **NM** | 6.76 | 6.8 | 6.78 | 6.57 | 6.58 | 7.16 | 6.73 | 7 | 7.37 | 3.60% | 9.00% |
| **NV** | 5.95 | 5.6 | 5.76 | 5.93 | 6.17 | 7.86 | 8.42 | 8.29 | 9.63 | 39.30% | 61.80% |
| **NY** | 11.13 | 11.13 | 10.71 | 9.95 | 11.38 | 11.55 | 11.16 | 12.44 | 15.27 | 11.80% | 37.20% |
| **OH** | 6.3 | 6.25 | 6.38 | 6.4 | 6.41 | 6.62 | 6.77 | 6.73 | 7.71 | 6.80% | 22.40% |
| **OK** | 5.56 | 5.42 | 5.43 | 5.37 | 5.88 | 6.1 | 5.59 | 6.35 | 7.3 | 14.20% | 31.30% |
| **OR** | 4.77 | 4.61 | 4.9 | 4.83 | 4.89 | 5.44 | 6.32 | 6.18 | 6.53 | 29.60% | 36.90% |
| **PA** | 7.96 | 7.99 | 7.86 | 6.71 | 7.65 | 8.01 | 8.06 | 8.02 | 8.68 | 0.80% | 9.00% |
| **RI** | 10.48 | 10.7 | 9.58 | 8.62 | 10.18 | 11.45 | 9.2 | 10.47 | 13.98 | -0.10% | 33.40% |
| **SC** | 5.67 | 5.5 | 5.53 | 5.57 | 5.62 | 5.77 | 5.83 | 6.08 | 6.98 | 7.20% | 23.10% |
| **SD** | 6.18 | 6.22 | 6.26 | 6.35 | 6.32 | 6.35 | 6.26 | 6.35 | 6.7 | 2.80% | 8.40% |
| **TN** | 5.24 | 5.31 | 5.62 | 5.63 | 5.58 | 5.59 | 5.72 | 5.84 | 6.97 | 11.50% | 33.00% |
| **TX** | 6.16 | 6.17 | 6.07 | 6.04 | 6.49 | 7.38 | 6.62 | 7.5 | 10.34 | 21.80% | 67.90% |
| **UT** | 5.28 | 5.17 | 5.16 | 4.86 | 4.84 | 5.21 | 5.39 | 5.41 | 5.99 | 2.50% | 13.40% |
| **VA** | 6.09 | 6.14 | 5.88 | 5.86 | 5.94 | 6.18 | 6.23 | 6.27 | 6.86 | 3.00% | 12.60% |
| **VT** | 9.74 | 9.89 | 9.83 | 10.28 | 10.27 | 10.86 | 10.87 | 10.98 | 11.37 | 12.70% | 16.70% |
| **WA** | 4.19 | 4.04 | 4.03 | 4.01 | 4.33 | 5.34 | 5.88 | 5.86 | 6.14 | 39.90% | 46.50% |
| **WI** | 5.25 | 5.22 | 5.44 | 5.53 | 5.71 | 6.08 | 6.28 | 6.64 | 8.13 | 26.50% | 54.90% |
| **WV** | 5.21 | 5.02 | 5.07 | 5.09 | 5.07 | 5.07 | 5.11 | 5.13 | 5.04 | -1.50% | -3.30% |
| **WY** | 4.31 | 4.33 | 4.31 | 4.3 | 4.34 | 4.46 | 4.68 | 4.76 | 5.27 | 10.40% | 22.30% |
| **US-TOTAL** | 6.86 | 6.85 | 6.74 | 6.64 | 6.81 | 7.29 | 7.2 | 7.44 | 8.9 | 8.50% | 29.70% |
| **Average Change Deregulated States** | | | | | | | | | | 1.90% | 29.20% |
| Average Change Regulated States | | | | | | | | | | 10.60% | 26.70% |
| TTEST, 2-tails, unequal variance, Prob > \|T\| | | | | | | | | | | 0.0078 | 0.6578 |

Source: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

Appendix E. Summary of State Electric Restructuring Activities

| State | Beginning Of Restructuring | Restructuring Details | Actual Status | Comments |
|---|---|---|---|---|
| AZ | Since 1999 | 09/99: The ACC approved a settlement agreement with Arizona Public Service for restructuring. The APS was required to open 20 percent of its retail territory to competition by October 1, 1999, and all of it by January 1, 2001. Residential rates were to be reduced 7.5 percent over 4 years, with large users' rates cut 5 percent over 3 years. | On hold since 2004 | 10/04: Restructuring in Arizona was essentially placed on hold due to a variety of regulatory orders. |
| CA | Since 1998 | 04/98: The CPUC issued the final order officially opening the electric industry market to competition as of March 31, 1998 for all consumers in investor-owned utilities' service territories. Control of 70 percent of the State's transmission lines was transferred to the California ISO. | Suspended since 2002 | 10/01: The CPUC suspended retail choice in California. The CPUC estimated that about 5 percent of the State's peak load of 46,000 MW was then under direct access contracts, mostly with large industrial customers. |
| CT | 7/1/2000 | 04/98: House Bill 5005, An Act Concerning Electric Restructuring, was signed into law on April 29, 1998. The bill would allow access to competitive suppliers for 35 percent of consumers by January 2000 and for all consumers by July 2000. | Active | The bill also required a 5.5-percent renewable portfolio standard, environmental protections, and a 10-percent rate reduction beginning January 2000, and a rate cap at the December 31, 1996 level from July 1, 1998 until January 1, 2000. |
| DC | 01/01/2001 | 01/01: The District of Columbia began allowing customers direct access to competitive electricity suppliers on January 1, 2001. | Active | The PSC established interim shopping credits ranging from 3.68 to 5.18 cents/kWh. |

| State | Beginning Of Restructuring | Restructuring Details | Actual Status | Comments |
|---|---|---|---|---|
| DE | 10/1999 | 03/99: House Bill 10, "The Electric Utility Restructuring Act of 1999," was enacted on March 31, 1999. The law's provisions included: a phase-in of retail competition beginning on October 1, 1999 for large customers in Conectiv's service territory and ending on April 1, 2001 | Active | 04/99: The act was intended to bring competition to Delaware's electricity generation. Rate caps were imposed for non-residential consumers of Conectiv from October 1999 through September 2002; caps for residences were imposed between October 1999 through September 2002. |
| IL | 1999 | 12/97: House Bill 362, "The Electric Service Customer Choice and Rate Relief Act of 1997," was enacted. The bill proposed rate cuts for ComEd and Illinois Power effective August 1998. The law also proposed some commercial and industrial customers choice by October 1999, and all customers, including residential, choice for their generation supplier by May 2002. | Active | Under H.B. 362, residential customers were given a 15% rate cut in August 1998 and an additional 5% reduction in October 2001, the largest rate reductions in the country. Residential customers who stay with their utility after May 2002 will have their rates frozen until 2005. |
| MA | 3/01/1998 | 01/97: The Department of Telecommunications and Energy's final decision stated that it would officially open the retail electricity market to competition by March 1, 1998. | Active | 11/97: The law required retail access by March 1998, rate cuts of 10 percent by March 1998 and another 5 percent 18 months later, encourages divestiture of generation assets, and allowed full recovery of stranded costs over a 10-year transition period. |

| State | Beginning Of Restructuring | Restructuring Details | Actual Status | Comments |
|---|---|---|---|---|
| ME | 2000 | 12/96: The PUC issued a plan requiring utility functional unbundling, divestiture of generation assets by March 2000, and retail competition by 2000. | Active | |
| MD | 7/01/2000 | 04/99: With House Bill 703 (HB 703) and Senate Bill (SB 300), “Maryland Customer Choice and Competition Act,” restructuring legislation was enacted. The legislation included at least a 3 percent rate reduction for residential consumers, and a 3-year phase-in for competition beginning in July 2000 and becoming complete by July 2002. | Active | |
| MI | 5/01/2000 | 01/98: The PSC adopted a phase-in schedule allowing 2.5 percent of Consumer’s Energy and Detroit Edison customers retail access as early as March 1998, adding another 2.5 percent on June 1998, January 1999, January 2000, and January 2001 and all consumers by 2002. | Active | 06/00: Public Act 141 of 2000 and companion Public Act 142 were signed into law on June 3, 2000. The comprehensive restructuring legislation proposed that all consumers have retail choice by January 2002. |
| NH | 1998; 2001 | 05/96: House Bill 1392 was enacted, requiring the PUC to implement retail choice for all customers of electric utilities under its jurisdiction by January 1, 1998 or at the earliest date which the Commission determined to be in the public interest, but not later than July 1, 1998. | Active | 01/01: The New Hampshire Supreme Court upheld Public Service of New Hampshire's (PSNH) restructuring plan, clearing the way for competition to begin for the majority of consumers in New Hampshire. The PSNH planned to implement retail choice by April 2001. |

| State | Beginning Of Restructuring | Restructuring Details | Actual Status | Comments |
|---|---|---|---|---|
| NJ | 11/1999 | 12/99: Due to procedural delays, New Jersey consumers did not start receiving power from their suppliers of choice until November 14, 1999. Legislation was passed in February 1999, allowing retail choice for all consumers on August 1, 1999. | Active | 04/97: The BPU's final report for the Energy Master Plan accelerated the time line for retail competition to begin: phase-in should have begun with 10 percent by October 1998, 35 percent by April 1999, 50 percent by October 1999, 75 percent by April 2000, and all by July 2000. |
| NY | Since 1998 | 05/96: The PSC issued its opinion and order regarding competitive opportunities for electric service that restructured New York's electric power industry. The competitive retail market started in May 1998 | Active | 05/98: Orange and Rockland became the first utility in New York to offer retail choice through its Power Pick program as customers began to receive power from their suppliers of choice on May 1, 1998. |
| OH | Since 2001 | 01/01: Retail direct access to competitive electricity suppliers began on January 1, 2001, in the State. The first month saw about 97,622 customers in First Energy territories switch suppliers. Standard Offer Rates ranged from 3.6 to 4.9 cents/kWh in the three FirstEnergy subsidiary territories of Toledo Edison, Ohio Edison, and Cleveland Illuminating. | Active | 01/03: The Ohio Consumers' Counsel (OCC) published its 2002 End-of-Year Update on Ohio's Electric Market that reviewed the past two years of competition in Ohio, showing that "813,000 residential consumers statewide – or about 20 percent of those who were eligible to participate in electric choice-actually switched electric suppliers. |

| State | Beginning Of Restructuring | Restructuring Details | Actual Status | Comments |
|---|---|---|---|---|
| PA | Since 1999 | 12/96: House Bill 1509, the Electricity Generation Customer Choice and Competition Act, was enacted. The law proposed a schedule for consumers to begin choosing among competitive generation suppliers, beginning with one third of the State's consumers, by January 1999, two thirds by January 2000, and all consumers by January 2001. | Active | 01/99: Retail access was made available to two-thirds of the State's customers. |
| RI | 1998 | 08/96: House Bill 8124, allowed retail choice to be phased-in starting July 1997. In July 1997, Rhode Island became the first state to begin phase-in of statewide retail wheeling (for industrial customers). Residential consumers were scheduled to have retail access by July 1998. | Active | 12/97: The Rhode Island Public Utilities Commission (PUC) issued an order accepting interim rates and approving retail choice for all Rhode Island consumers on January 1, 1998. |
| TX | 1/01/2002 | 06/99: Restructuring legislation, Senate Bill 7, was enacted to restructure the Texas electric industry allowing retail competition. The bill requires retail competition to begin by January 2002. | Active | 05/03: The Texas PUC has delayed retail choice in Northern Texas, which comes under the jurisdiction of the Southwest Power Pool (SPP) Regional Transmission Organization, until 2011. |
| VA | 1/01/2002 | 04/98: Restructuring legislation, House Bill 1172, was signed into law. The law establishes a schedule for retail competition beginning January 2002 and completion by January 2004. | Suspended February 2008 | 03/99: Senate Bill 1269 was signed into law by the Governor. The bill includes: creation of a regional transmission entity by January 1, 2001; deregulation of generation by January 1, 2002; phase-in of consumer choice between January 1, 2002 and January 1, 2004; rates capped through July 2007 for those who remain with the incumbent utility. |

## BIBLIOGRAPHY


Abbott, M. 2005. “Determining Levels of Productivity and Efficiency in the Electricity Industry.” *The Electricity Journal*, 18(9): 62-72.

Abbott, M. 2006. “The Productivity and Efficiency of the Australian Electricity Supply Industry.” *Energy Economics*, 28: 444-454.

Aharony, J. and Swary, I. 1981. “Effects of the 1970 Bank Holding Company Act: Evidence from Capital Markets.” *Journal of Finance*, 36: 841-853.

Aharony, J., Saunders, A. and Swary, I. 1986. “The Effects of a Shift in Monetary Policy Regime on the Profitability and Risk of Commercial Banks.” *Journal of Monetary Economics*, 17: 363-377.

Aharony, J., Saunders, A. and Swary, I. 1988. “The Effects of Didmca on Bank Stockholders’ returns and Risk.” *Journal of Banking and Finance*, 12: 317-331.

Akhigbe, A. and Whyte, A.M. 2001. “The Impact of Fdicia on Bank Returns and Risk: Evidence from the Capital Markets.” *Journal of Banking and Finance*, 25: 393-417.

Alchian, A.A. 1965. “Some Economics of Property Rights.” *Il Politico*, 30: 816-819. Reprinted In: Alchian, A.A. 1977. “Economic Forces at Work.” Indianapolis: Liberty Press.

Amoako-Adu, B. and Smith, F.B. 1995. “The Wealth Effects of Deregulation of Canadian Financial Institutions.” *Journal of Banking and Finance*, 19: 1211-1236.

Arocena, P. 2008. “Cost and Quality Gains from Diversification and Vertical Integration in the Electricity Industry: A DEA Approach.” *Energy Economics*, 30: 39-58.

Arocena, P. and Waddams-Price, C. 2002. “Generating Efficiency: Economic and Environmental Regulation of Public and Private Generators in Spain.” *International Journal of Industrial Organization*, 20(1): 41-69.

Apt, Jay. 2005. “Competition Has Not Lowered U.S. Industrial Electricity Prices.” *The Electricity Journal*, 18(2): 52-61.

Atkinson, S. and Halvorsen, R. 1986. “The Relative Efficiency of Public and Private Firms in a Regulated Environment: The Case of U.S. Electric Utilities.” *Journal of Public Economics*, 29: 281-291.

Averch, H. and Johnson, L. L. 1962. “Behavior of the Firm under Regulatory Constraint.” *American Economic Review*, 52(5): 1052 - 1069.

Banker, R.D. 1984. “Estimating Most Productive Scale Size Using Data Envelopment Analysis.” *European Journal of Operational Research*, 17: 35-44.

Banker, R., Charnes, A. and Cooper, W. 1984. "Some Models for Estimating Technical and Scale Efficiencies in Data Envelopment Analysis." *Management Sciences*, 30: 1078–1092.

Banker, R.D., Gadh, V.M. and Gore, W.L. 1992. "Maximum Likelihood Estimation of Monotone and Concave Production Frontiers." *Journal of Productivity Analysis*, 3: 401–416.

Banker, R. D., Das, S. and Ou, C.S. 1997. "Stockholder Wealth Effects of Legislative Events: The Case of Airline Deregulation." *Public Choice,* 91: 301-331.

Barber, B.M. and Lyon, J.D. 1997. "Detecting Long-Run Abnormal Stock Returns: The Empirical Power and Specification of Test Statistics." *Journal of Financial Economics,* 43: 341-372.

Barr, R., Seiford, L. M. and Siems, T. F. 1993. "An Envelopment-Analysis Approach to Measuring the Managerial Efficiency of Banks." *Annals of Operations Research*, 43: 1-19.

Barros, C. P. 2008. "Efficiency Analysis of Hydroelectric Generating Plants: A Case Study for Portugal." *Energy Economics,* 30: 59-75.

Battese, G.E. and Broca, S.S. 1997. "Functional Forms of Stochastic Frontier Production Functions and Models for Technical Inefficiency Effects: A Comparative Study for Wheat Farmers in Pakistan." *Journal of Productivity Analysis,* 8: 395-414.

Battese, G.E. and Coelli, T. J. 1995. "A Model for Technical Inefficiency Effects in a Stochastic Frontier Function for Panel Data." *Empirical Economics,* 20: 325-332.

Bauer, J.M**.** 1997. "Competitive Processes In Network Industries: Toward an Evolutionary Perspective." Unpublished Draft. Presented for Presentation at the Meeting of the Transportation and Public Utilities Group of the American Economic Association. New Orleans, Louisiana.

Baum, E., ed. 1996. "Perspectives in Electric Utility Restructuring." A Compilation of Papers Prepared by The Regulatory Assistance Project. http://www.raponline.org/showpdf.asp?PDF_URL=%22/pubs/general/perspect.pdf%22

Berger, A.N. and Mester, L.J. 2001. "Explaining the Dramatic Changes in Performance of U.S. Banks: Technological Change, Deregulation and Dynamic Changes in Competition." The Wharton Financial Institutions Center, Working Paper No. 01-6.

Berry, S.K. 2000. "Excess Returns in Electric Utility Mergers during Transition to Competition." *Journal of Regulatory Economics,* September 2000, 18(2): 175-88.

Berry, D. M. 1994. "Private Ownership Form and Productive Efficiency: Electric Cooperatives versus Investor-Owned Utilities." *Journal of Regulatory Economics*, 6: 399-420.

Besanko, D., D'souza, J. and Thiagarajan, S.R. 2001. "The Effect of Wholesale Market Deregulation on Shareholder Wealth in the Electric Power Industry." *Journal of Law and Economics,* 44(1): 65-88.

Binder, J. and Summer J. 1985. "Measuring the Effects of Regulation with Stock Price Data." *Rand Journal of Economics,* 16(2): 167-183.

Blacconiere, W.G. and Patten, D.M. 1994. "Environmental Disclosures, Regulatory Costs, and Changes in Firm Value", *Journal of Accounting and Economics*, 18: 357-377.

Blacconiere, G.W., Johnson, F.M. and Johnson, S.M. 2000. "Market Valuation and Deregulation of Electric Utilities." *Journal of Accounting and Economics*, 29: 231-260.

Blumsack, S. A., Jay, A. and Lave L. B. 2006. "Lessons from the Failure of U.S. Electricity Restructuring." *The Electricity Journal*, 19(2): 15-32.

Boardman, A. E. and Vining, A. R. 1989. "Ownership and Performance in Competitive Environments: A Comparison of the Performance of Private, Mixed, and State-Owned Enterprises." *Journal of Law & Economics*, 32: 1-33.

Boardman, A. E. and Vining, A. R. 1992. "Ownership Versus Competition: Efficiency in Public Enterprise", *Public Choice*, 73(2): 205-239.

Bopp, A. E. and Costello, D. 1990. "The Economics of Fuel Choice at US Electric Utilities." *Energy Economics*, 12(2): 82-88

Brown, M.H. 2000. "Slow Transition to Competition." *State Legislatures*, May, 28-31.

Brown, S.J. and Wagner, J.B. 1980. "Measuring Security Price Performance." *Journal of Financial Economics*, 8(3): 205-258.

Brown, S.J. and Wagner, J.B. 1985. "Using Daily Stock Returns: The Case of Event Studies." *Journal of Financial Economics*, 8(3): 205-258.

Cambridge Energy Research Associates. 2005. "Beyond the Crossroads: The Future Direction of Power Industry Restructuring."
http://www.cera.com/aspx/cda/client/MCS/MCSChapter.aspx?KID=170&CID=7691

Carow, A.K. and Heron, A.R. 1998. "The Interstate Banking and Branching Efficiency Act of 1994: A Wealth Event for Acquisition Targets." *Journal of Banking and Finance*, 22(2): 175-96.

Center for the Advancement of Energy Markets. 2003. "Estimating the Benefits of Restructuring Electricity Markets: An Application To The PJM Region."
www.caem.org/website/pdf/**PJM**.pdf

Charnes, A. and Cooper, W.W, 1962. "Programming With Linear Fractional Functionals." *Naval Research Logistics Quarterly*, 9: 181-186.

Charnes, A., Cooper, W.W., Lewin, A.Y. and Seiford, L.M. (Eds.) 1994. *Data Envelopment Analysis: Theory, Methodology, and Application.* Boston: Kluwer Academic Publishers.

Charnes, A., Cooper, W. and Rhodes, E. 1978. "Measuring the Efficiency of Decision Making Units." *European Journal of Operational Research*, 2(6): 429-444.

Charnes A, Cooper, W.W, Seiford L. and Stutz J. 1982. "A Multiplicative Model for Efficiency Analysis." *Socio-Economic Planning Sciences*. 16: 223-224.

Charnes, A., Cooper, W.W., Golany, B., Seiford, L.M. and Stutz, J. 1985. "Foundations of Data Envelopment Analysis for Pareto-Koopmans Efficient Empirical Production Functions." *Journal of Econometrics*, 30: 91-107.

Charnes, A., Cooper, W. and Thrall, R.M. 1991. "A Structure for Classifying and Characterizing Efficiency and Inefficiency in Data Envelopment Analysis." *Journal of Productivity Analysis*, 2: 197–237.

Charnes, A., Cooper, W.W., Wei, Q.L. and Huang, Z.M. 1989. "Cone Ratio Data Envelopment Analysis and Multi-Objective Programming." *International Journal of Systems Science*, 20 (7): 1099-1118.

Christensen, L.R. and Greene, W. 1976. "Economies of Scale in U.S. Electric Power Generation." *Journal of Political Economy*, 84: 655-676.

Coase, R. H. 1960. "The Problem of Social Cost." *Journal of Law and Economics,* 3: 1-44.

Coelli, T. 1996. "A Guide to Deap Version 2.1: A Data Envelopment Analysis (Computer) Program." Centre for Efficiency and Productivity Analysis (CEPA), Working Paper 96/08.

Coelli, T. 1996. "A Guide to Frontier Version 4.1: A Computer Program for Stochastic Frontier Production and Cost Function Estimation." Centre for Efficiency and Productivity Analysis (Cepa), Working Paper 96/07.

Coelli, T., Rao, D.S. and Battese, G. 1998. *An Introduction to Efficiency and Productivity Analysis.* Kluwer, London.

Cooper, W.W. and Gallegos, A. 2000. "Combined DEA - Stochastic Frontier Approach To Latin American Airline Efficiency Evaluations." Working Paper, Graduate School of Business, The University Of Texas at Austin, TX. Working Paper 91-08-01.

Cornett, M.M. and Tehranian, H. 1990. "An Examination of the Impact of the Garn-St. Germain Depository Institutions Act of 1982 on Commercial Banks and Savings and Loans." *Journal of Finance*, 45(1): 95-111.

Cote, D. O. 1989. "Firm Efficiency and Ownership Structure – The Case of U.S. Electric Utilities Using Panel Data." *Annals of Public and Cooperative Economy*, 60: 432-450.

Cowing, T. G. and Smith, V. K. 1978. "The Estimation of a Production Technology: A Survey of Econometric Analyses of Steam-Electric Generation." *Land Economics*, 54 (2): 156-186

Cowling, K. and Mueller, D.C. 1978. "The Social Costs of Monopoly Power." *The Economic Journal*, 88(352): 727-748

Crain, W. M. and Zardkoohi, A. 1980. "X-Inefficiency and Nonpecuniary Rewards in a Rent Seeking Society: A Neglected Issue in the Property Rights Theory of the Firm." *American Economic Review*, 70: 784-792.

Dann, L. Y. and James, C.M.  1982. “An Analysis of the Impact of Deposit Rate Ceilings on the Market Values of Thrift Institutions.” *Journal of Finance*, 37: 1259-1275.

De Alessi, L.  1974a. “An Economic Analysis of Government Ownership and Regulation: Theory and the Evidence from the Electric Power Industry.” *Public Choice*, 19: 1-42.

De Alessi, L.  1974b. “Mangerial Tenure under Private and Government Ownership in the Electric Power Industry.”  *The Journal of Political Economy*, 82(3): 645-653

De Alessi, L. 1977. “Ownership and Peak-Load Pricing In the Electric Power Industry.” *Quarterly Review of Economics and Business*, 17: 7-26.

De Alessi, L. 1980. “The Economics of Property Rights: A Review of Evidence.” *Research in Law and Economics*, 2: 1-47.

Debreu, G. 1951. “The Coefficient of Resource Utilization.” *Econometrica*, 19: 273-292.

De Fraja, G. 1991. “Efficiency and Privatisation in Imperfectly Competitive Industries.” *Journal of Industrial Economics*, 39(3): 311-321.

Demsetz, H.  1968. “Why Regulate Utilities?” *Journal of Law and Economics*, 11: 55-65.

Eckert, R. D. 1973. “On the Incentives of Regulators: The Case of Taxicabs.” *Public Choice*, 14: 83-100.

Dilorenzo, T.J. and Robinson, R. 1982. “Managerial Objectives Subject To Political Market Constraints:  Electric Utilities in the U.S.”  *Quarterly Review of Economics and Business*, 22: 113-125.

Dow Theory Forecasts. May 4, 2000. Featured Report. Http://www.Dowtheory.Com/ (Subscription Required)

Energy Information Administration.  2000. The Changing Structure Of The Electric Power Industry 2000: An Update, October (EIA, 2000) Http://Www.Eia.Doe.Gov/Cneaf/Electricity/Chg_Stru_Update/Toc.Html

Energy Information Administration. 2000. *Electric Power Annual 1999*, Vol. Ii. Washington, D.C., October.

Energy Security Analysis, Inc. 2005. Impacts of the PJM RTO Market Expansion. November.

Emmons, W.M., Iii. 1997. “Implications of Ownership, Regulation, and Market Structure For Performance: Evidence from the U.S. Electric Utility Industry before and After the New Deal.” *The Review of Economics and Statistics*, 279-289.

Estache, A., Tovar, B. and Trujillo, L.  2008. “How Efficient Are African Electricity Companies? Evidence from the Southern African Countries.”  *Energy Policy*, 36(6): 1969-1979.

Fagan, M. 2006. “Measuring and Explaining Electricity Price Changes In Restructured States.” *The Electricity Journal*, 19(5): 35-42

Fama, E., 1976. *Foundations of Finance*. Basic Books, New York.

Fama, E.F., 1990. “Stock Returns, Expected Returns, and Real Activity.” *Journal of Finance,* 1990, 45: 1089-1108.

Fama, E.F. and French, K. 1992. “The Cross-Section of Expected Stock Returns.” *Journal of Finance*, 47: 427-465.

Fare, R. Grosskopf, S. and Kokkelenberg, E.C. 1989a. “Measuring Plant Capacity, Utilization and Technical Change: A Nonparametric Approach.” *International Economic Review,* 30: 655-666.

Färe, R., Grosskopf, S. and Logan, J. 1987. “The Comparative Efficiency of Western Coal-Fired Steam-Electric Generating Plants: 1977-1979.” *Engineering Costs and Production Economics*, 11: 21-30.

Färe, R, Grosskopf, S. and Logan, J. 1983. “The Relative Efficiency of Illinois Electric Utilities.” *Resources and Energy*, 5(4): 349-367.

Färe, R, Grosskopf, S. and Logan, J. 1985(A). “The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities.” *Journal of Public Economics*, 26: 89-106.

Färe, R., Grosskopf, S. Logan, J. and Lovell, C.A., Knox, 1985(B). Measuring Efficiency In Production: With An Application To Electric Utilities. *The Measurement of Efficiency of Production.* Rolf Färe, S. Grosskopf, and C.A. Knox Lovell Kluwer-Nijhoff Publishing, Kluwer Academic Publishers, Boston. 185-214.

Färe, R**.,** Grosskopf, S. and Lovell, C.A.K. 1994. Production Frontiers. Cambridge University Press.

Färe, R., Grosskopf, S. and Pasurka, C. 1989. “The Effect of Environmental Regulations on the Efficiency of Electric Utilities: 1969 versus 1975.” *Applied Economics*, 21: 225-235.

Färe, R., Grosskopf, S. and Pasurka, C. 1986. “Effects on Relative Efficiency in Electric Power Generation Due To Environmental Controls.” *Resources and Energy*, 8: 167-184.

Farrell, M.J. 1957. “The Measurement of Productive Efficiency.” *Journal of The Royal Statistical Society (A, General),* 120: 253-281.

Ferson, W.E. and Harvey, C.R. 1991. “Sources of Predictability in Portfolio Returns.” *Financial Analysts Journal,* 3: 49-56.

Flannery, M.J. and James, C.M. 1984. “The Effect of Interest Rate Changes on the Common Stock Return of Financial Institutions.” *Journal of Finance,* 39: 1141-1153.

Fukuyama, H., Guerra, R. and Weber, W. L. 1999. “Efficiency and Ownership: Evidence From Japanese Credit Cooperatives.” *Journal of Economics and Business*, 51(6): 473-487

Fuss, M. 1994. “Productivity Growth in Canadian Telecommunications.” *Canadian Journal of Economics*, 2: 371–392.

Global Energy Decisions. Putting Competitive Power Markets To The Test: The Benefits of Competition in America’s Electric Grid. 2005. July.

Goto, M. and Tsutsui, M. 1998. “Comparison of Productive and Cost Efficiencies among Japanese and Us Electric Utilities.” *Omega, Int. J. Mgnt Science,* 26: 177-194.

Goto, M. and Tsutsui, M. 2008. “Technical Efficiency and Impacts of Deregulation: An Analysis of Three Functions in U.S. Electric Power Utilities during the Period from 1992 through 2000.” *Energy Economics,* 30: 15-38.

Greene, W. 1990. “A Gamma-Distributed Stochastic Frontier Model.” *Journal of Econometrics,* 46: 141-163.

Green, R. 1998.”England and Wales – A Competitive Electricity Market?” University Of Cambridge Working Paper Pwp-060.

Hanoch, G., and Rothschild, M. 1972. “Testing the Assumptions of Production Theory: A Nonparametric Approach.” *The Journal of Political Economy,* 80(2): 256-275.

Harberger, A. C. 1954. “Monopoly and Resource Allocation.” *The American Economic Review*, 44 (2), Papers and Proceedings of the Sixty-Sixth Annual Meeting of the American Economic Association, 77-87

Haussman, W. and J. Neufeld. 1991. “Property Rights Versus Public Spirit: Ownership and Efficiency of U.S. Electric Utilities Prior To Rate-Of-Return Regulation.” *The Review of Economics and Statistics,* 73: 414-423.

Hempling, S. 1995. “Electric Utility Holding Companies: The New Regulatory Challenges.” *Land Economics*, 71(3): 343-353.

Henderson, J. S. ed. 1985. “Cost Estimation For Vertically Integrated Firms: The Case Of Electricity In Analyzing The Impact Of Regulatory Change In Public Utilities.” M. A. Crew, Lexington Books Lexington, Ma.

Hjalmarsson, L. and Veiderpass, A. 1922a. “Efficiency and Ownership in Swedish Electricity Retail Distribution.” *The Journal of Productivity Analysis,* 3(1/2): 7-23.

Hjalmarsson, L., Veiderpass, A. and Mork, K. A. 1992b. “Productivity in Swedish Electricity Retail Distribution: Comment.” *Scandinavian Journal of Economics*, 94 (Supplement).

Hollas, D.R. and Stansell, S. R. 1988. “An Examination of the Effects of Ownership Form on Price Efficiency: Proprietary, Cooperative and Municipal Electric Utilities.” Southern Economic Journal, 336-350

Hughes, J.S., Magat, W.A. and Ricks, W.E. 1986. "The Economic Consequences of the Osha Dust Standards: An Analysis of Stock Price Behavior." *Journal of Law and Economics*, 29(4): 29-59.

Huettner, D. A. and Landon, J. H. 1978. "Electric Utilities: Scale Economies and Diseconomies." *Southern Economic Journal*, 44(4): 883-912

ISO/RTO Council. 2005. The Value of Independent Regional Grid Operators. November.

Jarrell, G.A. 1978. "The Demand for State Regulation of the Electric Utility Industry." *Journal of Law and Economics,* 21: 269-295.

Jarrell, G. and Peltzman, S. 1985. "The Impact of Product Recalls on the Wealth of Sellers." *Journal of Political Economics*, 93(3): 512-536.

Jenny, F. and Weber, A.P. 1983. "Aggregate Welfare Loss Due To Monopoly Power in the French Economy: Some Tentative Estimates." *The Journal of Industrial Economics*, 32(2): 113-130

Johnson, M.S., Mittelhammer, R.C. and Blayney, D.P. 1991. "The Impact of Regulation on Shareholder Wealth in the Tobacco Industry: An Event Study Approach." *Agricultural Finance Review,* 51: 21-34.

Johnson, M.S., Niles, M.S. and Suydam, S.L. 1998. "Regulatory Changes in the Electricity Utility Industry: Investigation of Effects on Shareholder Wealth." *Journal of Accounting and Public Policy,* 17: 285-309.

Joskow, P. L. and Schumalensee, R. 1983. "Markets for Power: An Analysis of Electric Utility Deregulation." Massachusetts Inst. Of Technology Press, Cambridge, Ma

Joskow, P. 1997. "Restructuring, Competition, and Regulatory Reform in the U.S. Electricity Sector." *Journal of Economic Perspectives,* 11: 119-138.

Joskow, P. 2006. "Markets for Power in the United States: An Interim Assessment." *The Energy Journal*, 27(1): 1-36.

Juhn, C., Murphy, K.M. and Pierce, B. 1993. "Wage Inequality and the Rise in Returns to Skill." *Journal of Political Economy,* 101(5): 410-442.

Junker, J.A. 1975. "Economic Performance of Public and Private Utilities: The Case of U.S. Electric Utilities." *Journal of Economics and Business,* 28: 60-67.

Kamerschen, D. R. 1966. "An Estimation of the 'Welfare Losses' From Monopoly in the American Economy." *Western Economic Journal*, 4(3): 221-236

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

Kaserman, D. and Mayo, J. 1991. "The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Industry." *Journal of Industrial Economics,* 39: 483-502.

Kerkvleit, J. 1991. "Efficiency and Vertical Integration: The Case of Mine-Mouth Electric Generating Plants." *Journal of Industrial Economics,* 39(5):467-482.

Kleit, A. N. and Tecrell, D. 2001. "Measuring Potential Efficiency Gains From Deregulation Of Electricity Generation: A Bayesian Approach." *The Review of Economics and Statistics*, 83(3): 523-530

Knight, F., 1933. *The Economic Organization*. Harper and Row, New York.

Knittel, C. 1999. "The Origins of State Electricity Regulation: Revisiting an Unsettled Topic." SSN Working Paper. Pwp-048

Knittel, C. R. 2002. "Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry." *The Review of Economics and Statistics*, 84(3): 530-540.

Koopmans, T.C. 1951. "An Analysis of Production as Efficient Combination of Activities." In: T.C. Koopmans (Ed.), *Activity Analysis of Production and Allocation,* Cowles Commission for Research in Economics, New York.

Kumar, V., Ramaswami, S.N. and Srivastava, R.K. 2000. "A Model To Explain Shareholder Returns: Marketing Implications." *Journal of Business Research,* 50: 157-167.

Kwoka, J. E., Jr. 1996. *Power Structure: Ownership, Integration, and Competition in the U.S. Electricity Industry.* Kluwer Academic Publishers, Boston.

Kwoka, J.E., Jr. 2005. "The Comparative Advantage of Public Ownership: Evidence from U.S. Electric Utilities." *Canadian Journal of Economics*, 38(2): 622-640.

Kwoka, J.E., Jr. 2006. Restructuring the U.S. Electric Power Sector: A Review of Recent Studies. Report Prepared For The American Public Power Association, 84.

Laffont, J.-J. 1994. "The New Economics of Regulation Ten Years After." *Econometrica,* 62(3): 507-537.

Liang, Y., Mahonty, S. and Song, F. 1996. "The Effect of the Federal Deposit Insurance Corporation Improvement Act (Fdicia) Of 1991 on Bank Stocks." *Journal of Financial Research,* 19: 229-242.

Lien, D. and Peng, Y. 2001. "Competition and Production Efficiency Telecommunications in OECD Countries." *Information Economics and Policy,* 13: 51-76.

Lintner, John. 1965. "The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets." *Review of Economics and Statistics*, 47: 13-37.

Maddala, G.S. and Nelson, F. 1975. "Switching Regression Models with Exogenous and Endogenous Switching." *Proceedings of The American Statistical Association,* 423-426.

Madura, J. and Bartunek, K.  1995. “Valuation Effects of the FDIC Improvement Act.” *Applied Financial Economics,* 5: 191-198.

Majumdar, S.K.  1998. “On the Utilization of Resources: Perspectives from the U.S. Telecommunications Industry.”  *Strategic Management Journal*, 19(9): 809-831.

Markiewicz, K., Rose, N. L. and Wolfram, C.  2004. “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency.”  Nber Working Paper 11001.

McCormick, R.E., Shughart, W. F, Ii and Tollison, R. D. 1984. “The Disinterest in Deregulation.” *American Economic Review*, 74(5): 1075-1079.

Meyer, R.A. 1975. “Public Owned Vs. Privately Owned Utilities:  A Policy Choice.”  *Review of Economics and Statistics,* 57: 391-399.

Miliotis, Panayotis A. 1992. “Data Envelopment Analysis Applied To Electricity Distribution Districts.”  *Journal of Operational Research Society*, 43(5):549-555.

Moore, T. G.  1970. “The Effectiveness of Regulation of Electric Utility Prices.” *Southern Economic Journal,* 36: 365-375.

Murillo-Zamorano, L.R. and Vega-Cervera, J. A. 2001. “The Use of Parametric and Non-Parametric Frontier Methods to Measure the Productive Efficiency in the Industrial Sector: A Comparative Study.” *Int. J. Production Economics*, 69: 265-275.

Nakano, M. and Managi, S. 2008. “Regulatory Reforms and Productivity: An Empirical Analysis of the Japanese Electricity Industry.”  *Energy Policy*, 36: 201-209.

Nerlove**,** M. 1963. *Returns to Scale in Electricity Supply*. Stanford University Press, Stanford, Ca.

Neuberg, L.G. 1977. “Two Issues in the Municipal Ownership of Electric Power Distribution Systems.” *Bell J. Econ.,* 8: 302-322.

New York State Department of Public Service. 2006. Staff Report On The State Of Competitive Energy Markets: Progress To Date And Future Opportunities.

Niskanen, W.A. 1971.  *Bureaucracy and Representative Government*. Chicago: Aldine-Atherton.

Noll, R.  1971. “The Economics and Politics of Regulation.” *Virginia Law Review,* 57.
Seitz, W. D.  1971. “Productive Efficiency in the Steam-Electric Generating Industry.” *Journal of Political Economy,* 79(4): 878-886.

Nunez, Karen.  2007. “Electric Utility Deregulation: Stranded Costs vs. Stranded Benefits.” *Journal of Accounting and Public Policy,* 26: 193-211.

Nwaeze, E.T. 2000. “Deregulation of the Electric Power Industry: The Earnings, Risk, and Return Effects.”  *Journal of Regulatory Economics*, 17(1): 49-67.

Olatubi, W. O. and Dismukes, D. E. 2000. "A Data Envelopment Analysis of the Levels and Determinants of Coal-Fired Electric Power Generation Performance." *Utilities Policy*, 9: 47-59.

Or, I. and Sarica, K. 2007. "Efficiency Assessment of Turkish Power Plants Using Data Envelopment Analysis." *Energy*, 32: 1484-1499.

Park, S.-U. and Lesourd, J.-B. 2000. "The Efficiency of Conventional Fuel Power Plants in South Korea: A Comparison of Parametric and Non-Parametric Approaches." *International Journal of Production Economics*, 63: 59-67.

Peltzman, S. 1971. "Pricing In Public and Private Enterprises and Electric Utilities in the United States." *Journal of Law and Economics*, 14: 109-147.

Peltzman, S. and Winston, C. Editors. 2000. *Deregulation of Network Industries: What's Next?* Washington, D.C.: AEI- Brookings Joint Center for Regulatory Studies.

Picot, A. and Kaulman, T. 1998. "Comparative Performance of Government-Owned and Privately-Owned Industrial Corporations – Empirical Results from Six Countries." *Journal of Institutional and Theoretical Economics*, 145(2): 298-316.

Pigou, A. C. 1932. *The Economics of Welfare*. 4th Edition. Reprinted 1950. London: Macmillan.

Poitras, M. and Sutter, D. 1997. "The Efficiency Gains from Deregulation." *Journal of Regulatory Economics*, 12: 81-89.

Pollitt, G. M. 1995. *Ownership and Performance in Electric Utilities: The International Evidence on Privatization and Efficiency*. Oxford University Press: Oxford Institute for Energy Studies.

Prescatrice, D.R. and Trapani, J.M. 1980. "The Performance and Objectives of Public and Private Utilities Operating In the United States." *Journal of Public Economics*, 13: 259-276.

Primeaux, W.J. and Nelson, R.A. 1980. "An Examination of Price Discrimination and Internal Subsidization of Electric Utilities", Southern Economic Journal, 47: 84-99.

Rhodes, E. and Southwick, L. 1986. "Variations in Public and Private University Efficiency." *Applications of Management Science*, 7: 145–170.

Roberts, M.J. 1986. "Economies of Density and Size in the Transmission and Distribution of Electric Power." *Land Econ*., 62: 378-387.

Ross, T. W. 1986. "The Costs of Regulating Price Differences." *The Journal of Business*, 59(1): 143-156.

Schipper, K. and Thompson, R. 1983. "The Impact of Merger-Related Regulations on the Shareholders of Acquiring Firms" *Journal of Accounting Research*, 21:184-221

Schmidt, P. and Lovell, C.A.K. 1979. "Estimating Technical and Allocative Inefficiency Relative to Stochastic Production and Cost Frontiers." *Journal of Econometrics*, 9: 343-366.

Schmidt, P. and Lovell, C.A.K. 1980. "Estimating Stochastic Production and Cost Frontiers When Technical and Allocative Inefficiency Are Correlated." *Journal of Econometrics*, 13: 83-100.

Schwert, G.W. 1990. "Stock Returns and Real Economic Activity: A Century of Evidence." *Journal of Finance*, 45: 1237-1257.

Sharpe, William F. "Capital Asset Prices: A Theory of Market Equilibrium under Condition of Risk." *Journal of Finance*, 19: 425-442.

Shephard, R. W. 1953. *Cost and Production Functions*. Princeton University Press, Princeton, NJ.

Sherman, R. 1989. *The Regulation of Monopoly*. 40 West 20th Street, New York, NY 10011 - USA: Cambridge University Press

Seiford, L.M. 1996. "Data Envelopment Analysis: The Evolution of the State Of The Art (1978-1995)." *Journal of Productivity Analysis*, 7: 99-137.

Sengupta, J.K. 1989. *Efficiency Analysis by Production Frontiers*. Kluwer Academic, Dordrecht.

Sengupta, J.K. 1991. "The Influence Curve Approach to Data Envelopment Analysis." *Mathematical Programming*, 52: 147–166.

Sengupta, J.T. 1987. "Data Envelopment Analysis for Efficiency Measurement in the Stochastic Case." *Computers and Operations Research*, 14: 117-169.

Sengupta, J.T. 1999. "A Dynamic Efficiency Model Using Data Envelopment Analysis." *International Journal of Production Economics*, 62(3): 209-218.

Sengupta, J.T. 1995. *Dynamics of Data Envelopment Analysis: Theory of Systems Efficiency*. Boston: Kluwer Academic Publishers.

Sioshansi, F. P. 2006. "Electricity Market Reform: What Have We Learned? What Have We Gained?" *The Electricity Journal*, 19(9): 70-83.

Smirlock, M. 1984. "An Analysis of Bank Risk and Deposit Rate Ceilings: Evidence Form the Capital Markets." *Journal of Monetary Economics*, 13: 195-210.

Spinner, H. M. 2006. "A Response to Two Recent Studies That Purport To Calculate Electric Utility Restructuring Benefits Captured By Consumers." *The Electricity Journal*, 19(1): 42-47.

Staranczak, G.A., Edgardo, R., Sepulveda, R.E., Dilworth, A.P. and Shaikh, A.S. 1994. "Industry Structure, Productivity and International Competitiveness: The Case of Telecommunications." *Information Economics and Policy*, 6: 121–142.

Stevenson, R.E. and David W. P. 1995. "Discretionary Evolution: Restructuring the Electric Utility Industry." *Land Economics*, August, 71(3): 354-367.

Stewart, J.F. 1979. "Plant Size, Plant Factor, and the Shape of the Average Cost Function in Electric Power Generation: A Nonhomogeneous Capital Approach." *Bell Journal of Economics*, 10: 549-565.

Stigler, J. 1971. "The Theory of Economic Regulation." *Bell Journal of Economics and Management Science*, 2: 3-21.

Stigler, G. and Friedland, C. 1962. "What Can Regulators Regulate? The Case of Electricity." *Journal of Law and Economics*, October, 5: 1-16.

Sueyoshi, T. 1997. "Measuring Efficiencies and Returns to Scale Of Nippon Telegraph & Telephone in Production and Cost Analyses." *Management Science*, *43:* 779-796.

Sueyoshi, T. 1994. "Stochastic Frontier Production Analysis: Measuring Performance of Public Telecommunications in 24 OECD Countries." *European Journal of Operational Research*, 74: 466–478.

Sueyoshi, T. 1995. "Production Analysis in Different Time Periods: An Application of Data Envelopment Analysis." *European Journal Of Operational Research*, 86: 216–230.

Sueyoshi, T. 1998. "DEA-Bilateral Performance Comparison: An Application to Japan Agricultural Co-Operatives (Nokyo)." *Omega, Int. J. Mgmt Sci.*, 26(2): 233-248.

Sueyoshi, T. 1999a"Tariff Structure Of Japanese Electric Power Companies: An Empirical Analysis Using DEA." *European Journal of Operational Research*, 118: 350-374.

Sueyoshi, T. 1999b"Dea Non-Parametric Ranking Test and Index Measurement: Slack-Adjusted DEA and an Application to Japanese Agriculture Cooperatives." *Omega, Int. J. Mgmt Sc.*, 27: 315-326.

Sueyoshi, T. 2000. "Stochastic DEA for Restructure Strategy: An Application to Japanese Petroleum Company." *Omega, The International Journal of Management Science*, 28: 385-398.

Synapse Energy Economics. 2004. Electricity Prices In PJM: A Comparison Of Wholesale Power Costs In The PJM Market To Indexed Generation Service Costs, June.

Schwert, G.W. 1981. "The Adjustment of Stock Prices to Inflation," *Journal of Finance*, 36: 15-29.

Taber, J., Chapman, D. and Mount, T. 2006. "Examining the Effects of Deregulation on Retail Electricity Prices." Cornell University Working Paper Wp 2005–14.

Thakur, T., Deshmukh, S. G. and Kaushik, S.C. 2006. "Efficiency Evaluation of State Owned Electric Utilities in India." *Energy Policy*, 34: 2788-2804.

Thomas, D.L. 1985. "Auditing the Efficiency of Regulated Companies Through the Use of Data Envelopment Analysis: An Application to Electric Cooperatives." Ph.D. Dissertation, Graduate School of Business, University Of Texas, Austin, TX.

Thompson, H. G., Jr. and Wolf, L. 1993. “Regional Differences in Nuclear and Fossil-Fuel Generation of Electricity.” *Land Economics*, 69: 234-48.

Tollison, R.D. and Wagner, RE. 1991. “'Romance, Realism and Economic Reform”. *Kyklos* 44, 57-70

Tullock, G., 1967. “The Welfare Cost of Tariffs, Monopoly and Theft.” *Western Economic Journal*, V, 224-32.

United States General Accounting Office. 2002. *Lessons Learned From Electricity Restructuring*, December, Gao-03-271.

Vaninsky, A. 2006. “Efficiency of Electric Power Generation in the United States: Analysis and Forecast Based On Data Envelopment Analysis.” *Energy Economics*, 28, 326-338.

Vetsuypens, M.R. and Helmuth, J.A. 1988. “Airline Deregulation: Additional Evidence from the Capital Markets.” *Quarterly Journal of Business and Economics*, 27(2): 117-138.

Vides De Andrade, A.R. 1998. *Determination of Wage Inequalities in the Urban Labor Market of El Salvador: A Segmented and Decomposition Analysis*. Thesis (Ph.D. In Economics)--Vanderbilt University.

Wallace, R. L. and Junk, P. E. 1970. “Economic Inefficiency of Small Municipal Electric Generating Systems.” *Land Economics*, 46(1): 98-104

Weaver, J. 2004. “Can Energy Markets Be Trusted? The Effect of the Rise and Fall of Enron on Energy Markets.” *Houston Business and Tax Law Journal*.

Wenders, J.T. “Economic Efficiency and Income Distribution in the Electric Utility Industry.” *Southern Economic Journal*, 52(4): 1056-1067.

White, M. W. 1996. “Power Struggles: Explaining Deregulatory Reforms in Electricity Markets.” *Brookings Papers on Economic Activity: Microeconomics*, 201-250.

Yatchew, A. 2000. “Scale Economies in Electricity Distribution: A Semiparametric Analysis.” *Journal of Applied Econometrics*, 15: 187-2000.

Zhou, P., Ang, B.W. and Poh, K.L. 2008. “A Survey of Data Envelopment Analysis in Energy and Environmental Studies.” *European Journal of Operational Research*, 189: 1-18.