

January 01, 2008

## Three essays on U.S. electricity restructuring

Sanem I. Sergici  
*Northeastern University*

---

### Recommended Citation

Sergici, Sanem I., "Three essays on U.S. electricity restructuring" (2008). *Economics Dissertations*. Paper 1. <http://hdl.handle.net/2047/d1001634x>

This work is available open access, hosted by Northeastern University.

**THREE ESSAYS ON U.S. ELECTRICITY RESTRUCTURING**

A dissertation presented

by

Sanem I. Sergici

to

The Department of Economics

In partial fulfillment of requirements for the degree of  
Doctor of Philosophy

in the field of

Economics

Northeastern University  
Boston, Massachusetts  
June, 2008

Dedicated to my parents, Semra and Ahmet

**THREE ESSAYS ON U.S. ELECTRICITY RESTRUCTURING**

by

Sanem I. Sergici

ABSTRACT OF DISSERTATION

Submitted in partial fulfillment of the requirements  
for the degree of Doctor of Philosophy in Economics  
in the Graduate School of Arts and Sciences of  
Northeastern University, June 2008.

The traditional structure of the electricity sector in the U.S. has been that of large vertically integrated companies with sole responsibility for distributing power to end users within a franchise area. The restructuring of this sector that has occurred in the past 10-20 years has profoundly altered this picture. This dissertation examines three aspects of that restructuring process.

First chapter of my dissertation investigates the impacts of divestitures of generation, an important part of the process of restructuring, on the efficiency of distribution systems. We find that while all divestitures as a group do not significantly affect distribution efficiency, those mandated by state public utility commissions have resulted in large and statistically significant adverse effects on distribution efficiency.

Second chapter of my dissertation explores whether independent system operator (ISO) formation in New York has led to operating efficiencies at the unit and the system level. ISOs oversee the centralized management of the grid and the energy market and are expected to promote more efficient power generation. We test these efficiencies focusing on the generation units in New York ISO region from 1998 to 2004 and find that the NYISO formation has introduced limited efficiencies at the unit and the system level.

Restructuring in the electricity industry has spawned a new wave of mergers, both raising questions and providing opportunities to examine these mergers. Third chapter of my dissertation investigates the drivers of electric utility mergers consummated between 1992 and 2004. My results provide support for disturbance theory of mergers, size hypothesis, and inefficient management hypothesis as drivers of electric utility mergers. I also find that the adjacency of the service territories is the most noteworthy determinant of the pairings between IOUs.

## **Acknowledgements**

I would like to express my gratitude to Professor John Kwoka for his excellent supervision, valuable suggestions, and encouragement throughout my study. I will be forever indebted to him for what I have learnt from him, his constant and selfless support and most of all, for the guidance he never denied when I needed it.

I would like to thank other members of my committee, Dr. Michael G. Pollitt and Professor James Dana, for their invaluable suggestions and contributions. I have been privileged to benefit from their expertise and unique points of view.

Many people on the faculty and staff of the Department of Economics assisted and encouraged me in various ways during the course of my studies. I would like to thank all of them for their support.

I would like to thank my parents, Semra and Ahmet, and my brother, Mehmet, for their endless love and support. They have always been my most instant morale and inspiration sources even when they are an ocean away from me.

Finally, I can not thank my husband, Onur, enough for his understanding, endless patience and encouragement. He has been the closest witness of all my hardwork and also the bearer of all my burdens.

## TABLE OF CONTENTS

	Page
ABSTRACT	4
ACKNOWLEDGEMENTS	5
TABLE OF CONTENTS	6
CHAPTER-1	8
I. Introduction	9
II. Background to the Industry and Issues	11
III. Data, Methodology, and Model	17
IV. Results and Discussion	25
V. Summary and Conclusions	32
Bibliography	34
Tables and Figures	35
Appendix	42
CHAPTER-2	44
I. Introduction	45
II. Why might ISO formation affect the generation efficiency?	48
III. Review of Literature	55
IV. Data	57
V. Methodology	58
VI. Results	65
VII- Summary and Conclusion	74
Bibliography	75
Tables and Figures	77

## TABLE OF CONTENTS (Cont'd)

	Page
CHAPTER-3	85
I. Introduction	86
II. Merger Motives: What does the literature say?	88
III. Data	94
IV. Part 1- Data, Methodology, and Results	95
V. Part 2- Data, Methodology, and Results	105
VI. Summary and Conclusion	110
Bibliography	112
Tables and Figures	115

## **CHAPTER 1**

### **Divestiture Policy and Operating Efficiency in U.S. Electric Power Distribution<sup>4</sup>**

---

<sup>4</sup> This chapter is based on an essay that has been coauthored with John Kwoka of Northeastern University and Michael G. Pollitt of University of Cambridge.

## **I. Introduction**

Over the past fifteen years a vast restructuring of the electric power sectors in the U.S. and many other countries has taken place. In the U.S. one of the key components of restructuring has been the divestiture of generation assets from distribution and transmission companies. Also important have been the divestiture of control (but not ownership) of transmission assets to independent system operators and regional transmission organizations, and in some states the further divestiture of marketing/supply from the infrastructure wires business of traditional distribution companies. The divestiture of generation facilities was intended, along with entry, to help create a standalone generation sector that would compete for the business of downstream marketers and distributors of power to final customers. The shifting of control of transmission assets to independent system operators (ISOs) and regional transmission organizations (RTOs) was designed to prevent discriminatory use of the grid and also to facilitate more efficient operation of the transmission grid. The purpose of separating marketing from wires was to spur entry of and competition among the marketers, leaving only the wires business for continued regulation as a natural monopoly.

The common thread running through these and other reforms in the electricity sector has been the effort to inject competition wherever possible, with the expectation that stronger competition would result in lower overall costs of producing and delivering power and ultimately lower prices to consumers. Evidence has now begun to address whether these expectations have been met. At the sectoral level, a few studies find evidence of improvements in the operating efficiency of the post-divestiture generation sector. Notably, studies by Bushnell and Wolfram (2005) and by Fabrizio et al (2007)

report an increase in several measures of fuel and/or non-fuel efficiency of power plants after divestiture.

These latter studies are important in that they suggest the very real possibility of efficiency improvements from divestiture in the generation sector. But divestiture actually created two standalone industries— distribution as well as generation. There appears to have been no commonly held or understood hypotheses concerning the effects of restructuring on distribution, nor have there been any studies of the effects of divestiture policy on the distribution sector. This omission is notable for two reasons. First, the distribution sector represents fully 35 percent of the value added in the industry, so any effect of divestiture on distribution is likely to be quantitatively significant. Second, the overall assessment of divestiture policy must consider its effects not only on generation, but also on the simultaneously created standalone distribution sector. Indeed, a sufficient decline in distribution efficiency might even outweigh gains to generation and result in an adverse judgment about divestiture policy overall.

This study examines the effects of divestiture policy on the operating efficiency of distribution utilities. We focus on the decisive 1994-2003 period when state utility commissions required or pressured utilities to create standalone generation facilities, and thereby almost incidentally standalone distribution systems. We examine major divestitures both in general and also with particular respect to those that were forced upon utilities by state public utility commissions or legislative action. The possibility of an adverse effect from divestiture policy is most obvious in these latter cases which were least likely to correspond to utilities' perceived self-interest.

The analytical foundation of this study is the measurement of the operating efficiency of 73 distribution units of major U.S. electric utilities in each of those ten years through the use of data envelopment analysis (DEA). DEA generates a numerical score for each distribution utility in each year, a score that represents its efficiency of input use relative to best practice in that year. Using this panel of data and controlling for other possible influences, we then evaluate the effects on measured efficiency from the divestitures that many of the utilities underwent during the study period. We find that while all divestitures as a group do not significantly affect distribution efficiency, those mandated by state public utility commissions have resulted in large and statistically significant adverse effects on efficiency.

This chapter is organized as follows. The next section provides some further background on these industry changes and on the literature that has previously examined them. Section III discusses the data and modeling. Results and implications are set out in Section IV, while Section V concludes.

## **II. Background to the Industry and Issues**

Traditionally, U.S. electric power industry was structured as vertically integrated utilities in which generation plants were integrated with transmission and distribution systems<sup>5</sup>. This structure of the industry relied on the economic theory that generation and delivery were natural monopolies and therefore the integrated systems are the most efficient structure for power procurement. However, advances in generation and

---

<sup>5</sup> Generation is defined as the production of electric energy using other energy sources. Transmission is the delivery of electric energy from generation to distribution systems over high-voltage electric lines. Lastly, distribution is the delivery of electric energy from transmission system to the end use customers over low voltage lines using transformers and substations (EIA, 2000).

transmission technology led U.S. electric power industry to go through extensive structural changes over the past 25 years.

Divestitures in the electricity sector were the logical outgrowth of the Energy Policy Act of 1992, which sought to promote wholesale market competition through a policy of open access to transmission lines owned by large vertically integrated utilities. Those utilities often impeded transactions between buyers and independent or outside sellers who needed transmission services. In response, the Federal Energy Regulatory Commission in 1996 issued an order requiring so-called “functional separation” of integrated utilities’ operations, with separate administrative units for generation and transmission, and with separately priced transmission services.

Functional separation was intended to achieve the objective of open access in the least intrusive manner, but in practice it failed to prevent vertically integrated utilities from exploiting their ownership and control of the transmission grid. This prompted a further FERC order in 1999 that sought to remove control of transmission from vertically integrated utilities by transferring grid operating decisions to ISOs and RTOs. These latter institutions were charged with running the transmission grid on a nondiscriminatory basis, as well as performing a number of other tasks normally associated with traditional integrated utilities. Exactly how well ISOs and RTOs have executed these tasks, and at what costs, are important, and controversial, issues.

Simultaneous with and supportive of these reforms, many states sought to have the traditional utilities within their jurisdictions divest their generation plant and thus become pure or nearly-pure distribution utilities. Such divestiture, it was believed, would help create broader and deeper markets for wholesale power. Divestiture occurred in a

variety of different manners. In states such as New Hampshire and Connecticut, state laws or orders of the public utility commissions simply mandated divestiture. An alternative scenario involved utilities being coaxed into divestitures in trade for regulatory approval of other measures they sought, for example, permission to merge, recovery of stranded costs, or adoption of incentive regulation to replace cost of service. For example, AEP's proposal to acquire Central and SouthWest Corp. was approved only on the condition that the parties divest more than 1000 MW of generation capacity in Texas. Finally, in some states such as Pennsylvania, New Jersey, and Maryland, utilities undertook divestiture apparently by themselves. Whether this was truly voluntary is open to debate, since little happened during these years that was not conditioned by actual or prospective regulatory action.

The resulting shift of generation assets was truly massive. Between 1992 and 2000, some 300 plants constituting 22 percent of all generation capacity in the U.S. had been sold or transferred to non-utility subsidiaries of investor-owned utilities (EIA, 2000). That percentage had been expected to double in the following decade, although subsequent problems in California and other markets that had undergone restructuring fueled doubts about further reforms. Mirroring the emergence of standalone generation, of course, has been the creation of a substantial number of new distribution utilities. While pure distribution utilities had previously existed, the vast majority of those were publicly owned utilities or rural electric coops. The new distribution utilities are investor-owned and profit-oriented. They usually are in name, personnel, and operations continuations of the vertically integrated utilities from which they sprang.

It should be noted, however, that a significant number of investor-owned utilities remained vertically integrated to some considerable degree throughout this period of active restructuring. This was due to the fact that some operated in regions less committed to a policy of de-integration, while others simply resisted state and federal pressures. Those utilities' experiences provide a benchmark for evaluating the performance of those utilities undergoing divestiture.

Our focus will be on the effects of major divestitures on the efficiency of standalone distribution utilities. The reasons that divestiture might affect distribution efficiency follow from the arguments concerning vertical integration, of which divestiture is a uniquely large and involuntary example.<sup>1</sup> In principle, vertically integrated utilities might benefit from economies of at least three classic sorts.<sup>2</sup> First, there may be interdependencies between stages of production in the form of coordination of scheduled shutdowns, joint optimization of generation and transmission investment, and better information flows between stages for real-time operation, among others. Second, these advantages may be reinforced by transactional economies resulting from contractual incompleteness, asset specificity, and opportunistic behavior. Third, vertically integrated firms may avoid double marginalization, as firms with pricing discretion at each stage engage in successive mark-ups (although this effect may be attenuated by regulation).

On the other hand, deintegration and divestiture may also have some efficiency benefits. After shedding generation plant, deintegrated utilities remain only in the distribution business. Since this becomes their only source of income, they may focus

---

<sup>1</sup> A search for literature on the effects of divestitures in general produced surprisingly little, most of which involved the rather special case of the AT&T divestiture. See, for example, Chen and Melville (1986) and Cho and Cohen (1997). Much of the rest of what exists can be found in Ravenscraft and Scherer (1987).

<sup>2</sup> For a standard discussion of such vertical economies, see Church and Ware (2000), ch. 22.

more intensively on it and perform more efficiently than before. In addition, to the extent that certain aspects of their distribution business may be subject to some retail competition, competitive forces may drive them to achieve greater efficiency after divestiture. And finally, it is possible that vertical integration is simply a neutral factor, creating neither benefits nor costs.

These conflicting tendencies of vertical integration have been subject to empirical test in electricity. Studies by Henderson (1985) and Hayashi (1997), for example, estimate cost functions that permit testing for the mathematical separability of generation from the transmission and distribution stages. Both reject separability, indicating likely vertical economies. Closely related to this are studies by Gilsdorf (1994) and by Lee (1995) examining cost complementarity between generation, transmission, and distribution. These reject cost complementarity, although that condition is sufficient but not necessary for economies of scope or vertical economies. Tests for overall vertical economies strengthen these findings. Kaserman and Mayo (1991) and Kwoka (2002) estimate multi-stage cost functions which allow for direct tests of overall vertical economies, finding significant economies between the generation and transmission/distribution stages for all but the smallest utilities.<sup>3</sup>

In a study with some similarities to our own, Delmas and Tokat (2005) report that a greater degree of integration by electric utilities is associated with higher efficiency, as measured by data envelopment analysis, whereas a separate variable for divestiture is

---

<sup>3</sup> Two recent international studies deserve note as well. Nemoto and Goto (2004) test the technological externality effects of generation assets on the costs of transmission and distribution stages in their study of vertically integrated Japanese utilities. Their results show that downstream costs depend on the generation capital, suggesting significant economies of vertical integration. Fraquelli et al (2005) analysis of Italian municipal electric utilities finds significant vertical economies for average-size and large utilities while failing to find any significant effects for smaller than average-size utilities. Efficiencies associated with vertical integration are largest for fully integrated utilities, confirming results found in most other studies. See also the survey by Michaels (2006).

associated with lower efficiency. Both variables, however, are defined in ways that obscure interpretation.<sup>4</sup> Mansur's study (2007) of PJM utilities concludes that vertical integration results in greater control of upstream market power, while divestiture permits generators in some markets to lower output and extract excess profit. Similar concerns over market power in a deintegrated setting underlie findings in Bushnell et al (2008).

These results concerning vertical economies provide a context in which to view previously-noted studies suggesting efficiency benefits from divestiture on the generation stage. Bushnell and Wolfram (2005) reports improvements in fuel efficiency of about two percent for those generating units that underwent divestiture to non-utility ownership. Notably, however, gains of essentially the same magnitude also resulted from incentive regulation of non-divested units, leading the authors to conclude that incentives rather than ownership changes were responsible for performance improvements. The Fabrizio et al study (2007) finds that labor and non-fuel expenses—but not fuel expenses—for generating plants in restructuring markets fell by about three to five percent. Interestingly, this improvement took place before divestiture, a fact which they interpret as indicating anticipatory action by the utility.

While this evidence is not entirely unambiguous, it does suggest that divestiture may well improve generator efficiency but that overall diseconomies attend vertical deintegration. Together these findings imply that offsetting losses must arise elsewhere

---

<sup>4</sup> They find that a high degree of integration is associated with greatest efficiency, but they also report a U-shaped relationship through the range of vertical integration. The latter seems likely an artifact of their use of a demeaned measure of vertical integration, together with positive coefficients on both the linear and quadratic terms for the degree of integration. Also problematic is their measure of divestiture, which is defined as 0 if there is no deregulation of any kind, 1 if there is deregulation, and 2 if there is deregulation plus divestiture. This scaling does not distinguish the effect of simple deregulation but without divestiture (the change in value from 0 to 1) from that divestiture (the change from 1 to 2—or perhaps from 0 to 2). Moreover, these are state-level variables and may therefore not capture the status of all utilities in the jurisdiction.

in the vertical chain. The present study can be viewed as an effort to determine whether such diseconomies manifest themselves at the distribution stage and, if so, whether they might outweigh any gains within generation. These questions in turn serve as the foundation for evaluating divestiture policy in the electricity sector.

### **III. Data, Methodology, and Model**

This section begins with a discussion of the data used in this study. It then describes the two-step process of analysis, first using data envelopment analysis to measure efficiency, and then regression analysis to test for causal relationships affecting efficiency. We take these up in turn.

#### **A. DATA**

The database used in this study consists of 73 distribution utilities, all subsidiaries of the major U.S. investor owned utilities for the period 1994-2003. We have some information on a total of 305 such utilities, but several considerations reduce the number of usable observations. Some are pure generators, which are not the focus of this study and hence are excluded. Also excluded are a number of observations involving non-responses or irresolvable data inconsistencies, typically involving relatively small utilities. Finally, we seek a balanced panel and thus do not use observations that do not represent a continuous series. Nonetheless, the utilities that are included in our data base account for well over half of total MWH of distribution in each year (for example, 57% for the typical year 2000).

For each such utility we have comprehensive data on its finances and operations derived from FERC Form 1 filings<sup>5</sup> together with supplementary information extracted from Electrical World Directory of Electric Utilities. These include but not limited to net generation, total generation plant, total sales, residential sales, total customers, residential customers, distribution line length, total distribution costs, total administrative costs, and customer service costs. Definitions and sources of the data are provided in Appendix. These data have distinctive strengths. Since distribution has been relatively unchanged in function, and since these utilities have had unchanged FERC reporting requirements, the data represent a consistent basis for measuring performance at the level of the individual operating unit before and after deintegration or divestiture. By contrast, generation now involves numerous independent suppliers that are not required to report on their operations and finances, while transmission is notoriously difficult to compare and assess. Our data avoid these problems.

One major complication is that by the end of 2003 approximately 20 states had partially deregulated their retail markets, so that customers could choose their suppliers. In those states the traditional distribution utility performed only the local transport function, rather than transport and product supply, although most served as default suppliers as well. This arrangement affects the local distribution utilities' reported customer numbers, output, and costs, which are recorded separately for bundled and unbundled services. Consistent records for each affected utility in the sample were reconstructed from data from a different utility report—namely, Form 861—with additional information as necessary from direct contacts with state utility commission staff.

---

<sup>5</sup> Federal Energy Regulatory Commission Form No. 1 is a comprehensive financial and operating report submitted annually by all investor-owned utilities. We employ a version processed by Platts.

For the 73 utilities in the data base, our focus is on major policy-induced divestitures. We utilize total year end cost of the generation plants (herein, generation plant) to define our divestiture variable. Defining a “major divestiture” and identifying the year in which it occurred are important threshold issues since the extent of generation plant owned and the degree of vertical integration vary to modest degrees in many years. These routine variations need to be distinguished from the major policy divestitures that constitute our focus. Our methodology involved detailed examination of the actual divestitures undertaken by each of the utilities in the data base. State PUC records, primarily on commission websites, constituted the primary source of information, although in a number of cases telephone contact with PUC personnel was required for clarification or confirmation. Based on this examination, we define a major divestiture as a year-to-year decline in a utility’s generation plant of at least one-half its initial amount, where that initial amount had to represent a substantial fraction of its requirements.<sup>6</sup> In some cases divestitures occurred over a period in excess of a single year, in which case the divestiture was associated with the initial year.<sup>7</sup>

From this process, we establish that 28 of the 73 firms in the data base underwent a major divestiture during the sample period, while 45 of them did not. As shown in Table 1, these major divestitures resulted in a decline from 69.1 percent to 18.8 percent in the proportion of electricity requirements that these utilities self-supplied. This fraction—a measure of the extent of vertical integration—makes clear that these utilities were

---

<sup>6</sup> This latter criterion is intended to exclude, for example, a utility whose generation plant declined from meeting 5 percent of its requirements to 2 percent—a greater-than-one-half decline that nonetheless does not constitute a major divestiture. What constituted a substantial decline and therefore a major divestiture was in all cases clear from the data.

<sup>7</sup> That is, if generation plant went from 40 to 20 percent in the first year, and then 20 to 10 percent, the first reduction was taken as the major divestiture. Controlling for the second such year made little difference in the results.

transformed from largely integrated to substantially deintegrated in a very few years. By contrast, the degree of deintegration by non-divesting utilities declined only modestly—from 70.0 percent to 61.3 percent—during the study period. Figure 1 shows the precipitous nature of the decline in the degree of integration for all 73 utilities, for those that divested, and for those that did not.

We are interested in comparing the efficiency of divesting utilities with that of comparable non-divesting utilities. We also distinguish the experience of utilities for which divestiture was mandated by the state public utility commission or legislative action, versus those undertaken at the utility's own discretion or at most involving a *quid pro quo*. This distinction was made based on analyses of the public utilities commission records and in some instances direct inquiry to the PUCs. Of the 28 divesting utilities, eight involved mandatory divestitures, the remaining twenty non-mandatory. Some descriptive statistics for utilities in these categories are also reported in Table 1.

## B. DATA ENVELOPMENT ANALYSIS

The analytical methodology used in this study is data envelopment analysis.<sup>8</sup> DEA uses observed inputs and outputs of decision making units (DMUs) or firms in the sample to construct a best practice frontier. Operation of each actual firm is then compared to a linear combination of best practice firms which can produce the same amount of output as the firm in question, but generally with lesser amount of inputs. Figure 2 illustrates relationship between firm 1's input utilization relative to best practice production of output amount X. The radial distance from the best practice frontier to non-frontier firm 1's input usage measures the technical inefficiency for firm 1.

---

<sup>8</sup> See Coelli et al (1998) for a detailed discussion of data envelopment analysis.

Specifically, the ratio OD/OR measures the relative efficiency for all firms outside the frontier, with a “1” denoting a best practice firm and “0” the lowest efficiency score possible (although no actual utility approached this lower bound).

Mathematically, the efficiency scores are calculated by solving linear programs of the form shown in Equation (1) below.<sup>9</sup> Assuming that the firm uses  $K$  inputs and  $M$  outputs,  $X$  and  $Y$  represent  $K \times N$  input and  $M \times N$  output matrices, respectively. The input and output column vectors for the  $i$ th firm are represented by  $x_i$  and  $y_i$ , respectively, and  $\lambda$  represents an  $N \times 1$  vector of constants. Then for the  $i$ th firm in a sample of  $N$  firms, the program solves for a scalar  $\theta$  that equals the efficiency score, as follows:

$$\begin{aligned} \min_{\theta, \lambda} \theta \quad \text{s.t.} & \tag{1} \\ & -y_i + Y \lambda \geq 0 \\ & \theta x_{i,D} - X_D \lambda \geq 0 \\ & \lambda \geq 0 \end{aligned}$$

This optimization is solved once for each firm to calculate the efficiency of the firm with respect to all other firms in the sample. The DEA scores calculated in this manner represent technical efficiency.<sup>10</sup>

Relative to other techniques for measuring efficiency, DEA has several advantages (Jamasb and Pollitt, 2001). It is non-parametric, so that it avoids the need to choose the functional form. It handles multiple outputs quite readily, a useful capability in the present context. And it allows for a straightforward calculation of technical efficiency. Alternative techniques such as corrected ordinary least squares and stochastic frontier analysis also have their distinctive merits, but in comparing the performance of

---

<sup>9</sup> This discussion of the linear program draws from Hattori et al (2005).

<sup>10</sup> Cost as well as allocative inefficiency requires input prices, beyond the scope of the present inquiry.

these three techniques, Jamasb and Pollitt (2001) find that results are highly correlated. We therefore take advantage of DEA, with the expectation that other techniques would show similar results.

Application of data envelopment analysis requires two additional choices—input vs. output orientation, and constant vs. variable returns to scale. We employ what is termed input oriented DEA in order to measure the efficiency of firm operation in minimizing inputs to produce a given level of output. This is more suitable to the nature of distribution utilities that meet largely exogenous demand, than would be output oriented DEA which measures the efficiency of firms in maximizing outputs from a given level of inputs. Also, we assume constant returns to scale in the belief that units undergoing divestitures or other structural changes are making precisely the kinds of decisions that ensure they remain at optimum scale. Moreover, many of these distribution utilities are subsidiaries of holding companies that help ensure realization of any scale economies not readily achieved at the unit level. Finally, the variable returns to scale assumption compares each firm to different best practice firms, tending thereby to attribute any efficiency differences to scale differences and obscuring underlying relative performance.

Our DEA model specifies three output variables—MWH sales, number of customers, and distribution network length. Each of these represents a cost-causal feature of distribution utility operations: Costs rise with output, but they also rise with the number of customers to whom that output is delivered and sold, and with a greater number of distribution miles over which that output is supplied.<sup>11</sup> These factors have been found to be important in previous empirical studies in the literature (e.g., Jamasb

---

<sup>11</sup> We use the number of residential customers, which account for the vast majority of total customers.

and Pollitt (2001); Kwoka (2006)). Two alternative input measures are employed—one for short-run variable costs, the other capturing longer-run cost considerations. Both use a single variable—the value of input cost—as the relevant measure, thus aggregating fuel, labor, materials, and (in the case of long run costs) capital expenses. This aggregation is appropriate so long as input tradeoffs are weak, as they surely are between fuel and labor costs, fuel and materials costs, and labor and materials costs (Jamash and Pollitt (2003)). On this assumption, such measures have been found to be a sound basis for comparison of real resource usage.

The short-run variable cost *OPEX* measure consists of total non-capital costs of distribution, defined as the sum of distribution costs, plus customer service costs, plus a prorated share of total administration costs. The prorating factor is the ratio of wages in distribution plus service, to total wages in operations and maintenance.<sup>12</sup> Longer run costs should include some measure of capital costs. The most obvious measure—imputed capital costs—has a number of significant deficiencies in the present context. It is sensitive to assumptions concerning capital valuation and rate of return. In electricity, imputed costs can be so large as to dwarf operating expenses, making their sensitivity to assumptions a potentially serious flaw. And perhaps most importantly for our purposes, since distribution capital—wires, etc.—is so long-lived, it can scarcely be altered by a utility in the relevant period of time.

Accordingly, we take as a measure of long-run costs the sum of operating costs plus the utility's *current* capital expenditures. The use of current capital expenditures has two advantages as a measure of relevant costs: It is indisputably a controllable expenditure in the relevant time frame, and it is clearly related to the capital investment

---

<sup>12</sup> For a similar approach, see Jamash and Pollitt (2003).

program of the utility. Of course, current capital decisions are influenced by factors other than efficiency, including such things as market conditions, investment opportunities, and strategic decisions. For all these reasons, the results on total controllable costs *TCEX*, while illuminating, should be interpreted with caution.

### C. REGRESSION MODEL

The second step involves the regression analysis of the computed DEA scores for 1994-2003, to test for the impact on distribution utilities of major divestitures of their generation plant. Our dependent variable is the DEA-based efficiency score ranging from 0 to 1. The independent variables of interest include a variable for the post-divestiture years for those utilities that underwent major divestiture during this period. These results compare divesting utilities' post-divestiture experience to the control group that underwent no major divestitures. Alternative specifications of two kinds follow. The first includes two variables for divesting utilities, one for those that underwent mandated divestitures and a second for divestitures that were not mandated. The former are less likely to represent utilities' own preferences and perceived self-interests and thus more likely to sacrifice efficiency of performance. The second variation introduces a set of post-divestiture year dummies, instead of a single post-divestiture variable, in order to test for time-dependent effects from divestiture. Other models examine separate subsets of the data for each type of divestiture. Finally, the regression controls for the ratio of residential sales to total sales, denoted *RES-PCT*, since the provision of residential sales is particularly costly due to additional infrastructure and service requirements. We shall discuss the definitions of these variables as they arise in particular regression models.

The structure of our data and our model raise some issues of the appropriate estimation technique. We note in particular that DEA scores are censored at 1, a characteristic that might suggest use of tobit analysis. In the present case, however, this censoring is not a constraint on the observed outcomes of a behavioral relationship that might logically produce values in excess of 1, for example, excess demand for a good or service which is not observed due to fixed supply. Rather, the upper bound of 1 is the result of the fact that DEA scores are definitionally bounded at 0 and 1. Since this is not the data generating process that underlies tobit, that technique is neither necessary nor appropriate. Moreover, none of the observations involving the divesting firms that are our primary focus involve values of 1.

Accordingly, the regression analysis proceeds using GLS estimation with fixed effects. Fixed effects control for any unobserved differences among the utilities, thus helping to ensure that the reported results are not simply reflecting such other characteristics. Controlling for fixed effects also addresses the endogeneity concerns due to potential correlation between unobserved time-invariant firm characteristics and explanatory variables of the model. Results using random effects -arguably useful given the fact that our sample does not include many utilities- are not substantially different and are available upon request.<sup>13</sup>

#### **IV. Results and Discussion**

We begin by examining the effects of major divestitures of generation on short-run operating efficiency of distribution utilities, and then turn to longer run efficiency as measured by controllable costs. In each case we examine alternative specifications and

---

<sup>13</sup> For discussion, see Greene (1993), pp 469-471.

subsets of the data in order to determine the importance of the type of divestiture and the time path of effects.

#### A. OPERATING EFFICIENCY AND DIVESTITURE TYPE AND TIMING

The initial cut into the data is simply a regression of DEA scores of operating efficiency *OPEX* on two variables—the dummy variable *POST-DIVEST* that takes on a value of one for each post-divestiture year for the 28 utilities that experienced a major divestiture, and a variable for the percent residential sales of the utility (*RES-PCT*). The results of estimating this model are given in Table 2, Column (a). With respect to *RES-PCT*, we note that here and in most results, this variable behaves predictably: DEA-measured efficiency is lower for utilities whose customer base is more heavily residential. Hence, we will not discuss this variable further.<sup>14</sup> In this most general form, the coefficient on *POST-DIVEST* is negative but lacks statistical significance ( $t = .67$ ). This result obviously does not suggest an important effect of divestiture, although the next two specifications reveal more of the actual effects. .

The specification in column (b) replaces the variable *POST-DIVEST* for all divesting utilities with two variables. *POST-MAND* is a dummy variable that takes on a value of one for the post-divestiture years of those eight utilities whose divestiture was mandated, while the dummy variable *POST-NON* is the analogous dummy variable for the twenty utilities that divested but not under a mandate to do so. A clear difference now emerges in the post-divestiture efficiency experience of these types of divestiture. Mandated divestitures are associated with a .029 point drop in efficiency relative to the

---

<sup>14</sup> Elimination of this control variable does not affect the results in any substantial way. Nor does the inclusion of other possible controls.

base group of non-divesting utilities, whereas non-mandated divestitures had essentially no effect on measured efficiency scores. Despite the uncertain statistical significance of *POST-MAND*, this does indicate some negative effect from divestiture policy for the subset of utilities that had divestiture forced upon them by state action. The estimated effect of  $-.029$  points represents about four percent of the overall average DEA efficiency in the data base of  $.69$ . In contrast, divestitures that were strictly voluntary or involved some *quid pro quo* exhibit no real difference from the control group of non-divesting utilities. The coefficient on *POST-NON* is  $.001$  with a t-statistic of  $.09$ .

A further variation on the initial specification takes into account the fact that divestiture policy, like many others, is unlikely to have its full effect immediately. Accordingly, we define a series of timing dummies *POST1*, *POST2*, ...*POST6* for successive years after the particular utility's major divestiture. *POST1* equals one for the first year after divestiture, *POST2* for the second year, and so forth. These variables effectively disaggregate the single variable *POST-DIVEST* in the earlier model. Column (c) reports the results of this estimation.

While none of the estimated coefficients achieves statistical significance, the results suggest that timing may well matter. Initially efficiency appears essentially unchanged, as indicated by the small and insignificant coefficient on *POST1*. This is probably due to the fact that the very first year is a transition period in which both operations and accounting reflect the utility's immediate past history. Beginning with the second post-divestiture year, however, suggestions of possible effects of divestiture emerge. Measured efficiency in that second year is  $.015$  lower than prior to divestiture, with subsequent years  $.022$ ,  $.005$ , and  $.027$  lower. The year-six results indicate an

efficiency improvement, but this result is based on exactly two data points where *POST6* equals one. Since this is likely a small numbers quirk rather than a meaningful substantive phenomenon, we do not focus on this result here or in later results.

The results in column (b) and those in column (c) reinforce the conviction that divestiture type and timing matter. This becomes yet more apparent in the results in Table 3, which splits the sample into utilities that divested under a mandate, versus those that divested but not as a result of a mandate.<sup>15</sup> Their efficiency performance is now starkly and significantly different. Column (a) re-estimates the model in the last column of the preceding table, which utilized the dummy variables *POST1*, ...*POST6* to capture the time path of divestiture effects on efficiency. For these utilities that divested under mandate, after the transition year *POST1*, their measured efficiency declines precipitously—by .160 points in year 2, followed by .125 points, .243 points, and .244 points. All of these estimates are statistically significant, with t-values no less than 2.80. Quite clearly, mandated divestitures have adversely affected utilities' operating efficiency.

Column (b) respecifies the previous model in a manner intended to summarize the post-divestiture experience of utilities undergoing mandatory divestiture. Specifically, we define *POST26* as a dummy variable taking on a value of 1 for the second through sixth post-divestiture year.<sup>16</sup> Together with *POST1* (held separate based on past results), this model is estimated and the results reported in column (b). As before, *POST1* is insignificant both in magnitude and statistical reliability. *POST26*, however, is highly

---

<sup>15</sup> Splitting the sample examines the effects of divestiture on each sample separately, given that such divestiture has occurred to those utilities. This avoids possibly biased estimates from any endogeneity.

<sup>16</sup>Since *POST6* is based on exactly two observations, it should not be interpreted as truly indicative of a sixth year effect. We nonetheless include it in *POST26*.

significant, and its magnitude implies that across all post-divestiture years starting with year 2, measured efficiency of distribution utilities falls by .148 points, or about twenty percent, as a result of mandatory divestitures.

As might be expected from previous results, the post-divestiture efficiency experience of non-mandated divestitures is quite different. Column (c) of Table 3 reports the results of estimating a model analogous to that in column (a) for mandatory divestitures, but in contrast to those results, the estimated coefficients on *POST1*, ...*POST5* are all small, positive-valued, and statistically insignificant.<sup>17</sup> It seems clear that where utilities choose to divest or are willing to do so as part of a larger bargain with the regulatory agency, their efficiency experience was quite different—not necessarily positive, but certainly avoiding the sharp declines experienced by mandated divestitures.

For symmetry with the column (b) specification, column (d) aggregates all the post-divestiture effects (including in this case that in the first year) into the single variable *POST15*. Given column (c) results, it is not surprising that the estimated coefficient on *POST15* is small, positive, and statistically insignificant. The operating efficiency of utilities undergoing non-mandatory divestitures is essentially unchanged by that divestiture. Their efficiency is little different after divestiture versus before—but quite different from that of utilities undergoing mandated divestiture.

Overall, we conclude that divestiture has a substantial adverse effect on the operating efficiency of utilities that were required to divest their generation assets. This adverse effect does not arise in the case of non-mandatory divestitures. We next turn to the issue of the effects of these same divestitures on total controllable costs.

---

<sup>17</sup> The only two observations on *POST6* are for mandated divestitures, so that variable drops out of this regression on non-mandatory divestitures.

## B. TOTAL CONTROLLABLE COSTS AND DIVESTITURE TYPE AND TIMING

As discussed previously, total controllable costs are a broader measure of utility efficiency than operating expenses insofar as they include current capital expenditures to represent discretionary capital costs. Data envelopment analysis of total controllable costs *TCEX* generates a set of efficiency scores for all 73 utilities for the years 1994-2003, much as for *OPEX*. This section reports the results of regression analyses of those scores.

Regression analysis of *TCEX* scores utilizes the same model specifications and estimation method as in the case of *OPEX*. The results largely track the findings of the earlier analysis, as well. Table 4 examines the full sample of utilities, while Table 5 splits the sample into utilities that underwent mandatory divestitures vs. those with non-mandatory divestitures. Column (a) of Table 4 estimates the sparsest model, with just *POST-DIVEST* and the control variable *PCT-RES* as explanatory variables. There is no indication from the estimated coefficient on *POST-DIVEST* that divestitures overall altered the efficiency of utilities, as measured by *TCEX*.

That conclusion is subject to revision based on column (b) results. This specification finds significantly lower efficiency scores for utilities undergoing mandatory divestitures (*POST-MAND*) but no significant effect—albeit a slightly positive coefficient—for those which undertook divestiture largely at their own initiative (*POST-NON*). As with *OPEX*, it seems clear that mandated divestitures represent structural changes that are not in the interests of the affected distribution utilities. The final set of results in this table, in column (c), reports on the efficiency effects of divestitures on a

year-by-year basis. The results are broadly similar, though weaker, than those found for *OPEX*. *POST1*, the variable for the first post-divestiture year, has a positive but insignificant coefficient, followed by a series of year dummies with negative coefficients. Only one of the latter approaches statistical significance, so as with *OPEX*, there is only modest indication of time-dependent effects for divesting utilities.

Table 5 disaggregates those utilities into those for which divestiture were mandated vs. those that divested largely at their own discretion. The model in column (a) estimates the year-by-year model for mandatory divestitures. Apart from the first year after divestiture, which again has a weakly positive coefficient, efficiency is lower in all years from the second through the sixth after divestiture. Four of those five estimated yearly effects are significant or nearly so, with magnitudes in the range of .119 through .182. As with *OPEX*, mandated divestitures have adverse effects on distribution utilities. This result is corroborated in column (b), which combines *POST2* through *POST6* into a single summary variable for those years. *POST26* emerges with a negative and statistically significant coefficient of .109, leaving little doubt about the reduction in efficiency following such divestitures.

Non-mandated divestitures are examined in columns (c) and (d) of Table 5. Since there is little evidence of effect—either positive or negative—from such divestitures in the preceding table, or for that matter with respect to *OPEX*, a reasonable expectation here would again be for little if any effect. Indeed, that is the case. Column (c) indicates a negative but generally small and insignificant effect of non-mandatory divestitures on a year-by-year basis. Only one year dummy out of five—specifically, *POST3*--carries a t-value in excess of one. Column (d) reports the results of combining these five year

dummies into a single post-divestiture variable *POST15*. While the coefficient is negative, its t-value is only .73, leading again to the conclusion that non-mandated divestitures do not have a clear effect on utility performance.

In summary, we conclude that with respect to our measure of overall costs, the results are quite similar to those for operating costs only. Specifically, divestitures that were mandated by state regulatory authorities after the first year reduce utility efficiency by a substantial amount and for a significant period of time. In contrast, divestitures undertaken largely at the utilities' own initiative are not associated with such adverse effects.

## **V. Summary and Conclusions**

The large number of divestitures in a relatively short period of time is nearly unprecedented in any single industry. In the U.S. electricity sector, these divestitures were largely the result of public policy that sought to foster competition among independent generators. Considerably less attention was paid to the possible effects of this policy on the simultaneously created standalone distribution utilities. This study represents the first evaluation of the latter sector in light of divestiture policy.

We have found that divestitures mandated by state regulatory authorities had adverse effects on efficiency, measured both by operating costs and also by total costs including capital expenditures. These effects have been both large and significant, casting considerable doubt on the policy of forced divestiture. Notably, however, utilities that undertook divestitures that were not the result of mandate did not experience any adverse effects on their efficiency.

These results raise questions about the merits of a centerpiece of electricity restructuring namely, mandated divestitures in order to create standalone generation sector. The resulting standalone distribution utilities suffer from significant and persistent reduced efficiency. Taken by itself, this represents a cost of divestiture policy, but it also raises a question about the overall benefits of the policy. Whatever the benefits at the generation stage, these must be weighed against the costs to distribution utilities in order to arrive at a comprehensive judgment about divestiture policy as a whole. That judgment is not rendered here, but is certainly a subject that needs to be on the policy agenda.

## BIBLIOGRAPHY

Bushnell, J., and Catherine Wolfram (2005). "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Generation Plants," University of California Energy Institute, Working Paper, No.140.

Bushnell, James, Erin Mansur, and Celeste Saravia (2008). "Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured US Electricity Markets," *American Economic Review, American Economic Association*, Vol. 98(1), pp. 237-66.

Chen, Andrew and L.J. Merville (1986). "An Analysis of Divestiture Effects Resulting from Deregulation," *Journal of Finance*, Vol. XLI, No. 5.

Cho, Myeong-Hyeon and M. A. Cohen (1997). "The Economic Causes and Consequences of Corporate Divestiture," *Managerial and Decision Economics*, Vol. 18, pp. 367-374.

Church, Jeffrey, and Roger Ware (2000). *Industrial Organization: A Strategic Approach*. McGraw-Hill: New York.

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

Delmas, M., and Y. Tokat (2005). "Deregulation, Governance Structures and Efficiency: The U.S. Electric Utility Sector," *Strategic Management Journal*, Vol. 26, pp. 441-460.

Energy Information Agency (2000). *The Changing Structure of the Electric Power Industry 2000: An Update*. U.S. Department of Energy, Washington, DC.

Fabrizio, K, Nancy Rose, and Catherine Wolfram (2007). "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," *American Economic Review*, 97 (4), pp. 1250-1277.

Fraquaelli, G., M. Piancenza, and D. Vannoni (2005). "Cost Savings from Generation and Distribution with an Application to Italian Electric Utilities." *Journal of Regulatory Economics*, 28:3, pp. 289-308.

Gilsdorf, K. (1994). "Vertical Integration Efficiencies and Electric Utilities: A Cost Complementarily Perspective," *Quarterly Review of Economics and Finance* 34, pp. 261-282.

Greene, Richard (1993). *Econometric Analysis*. Macmillan, New York.

- Hattori, T., T. Jamasb, and M. Pollitt, (2005). "Electricity Distribution in the UK and Japan: A Comparative Efficiency Analysis 1985-1998," *Energy Journal*, Vol.26, No.2, pp. 23-47.
- Hayashi, P., J. Goo, and W. C. Chamberlain (1997). "Vertical Economies: The Case of the U.S. Electric Industry, 1983-87," *Southern Economic Journal* 63, pp. 710-725.
- Henderson, S. (1985). "Cost Estimation for Vertically Integrated Firms: The Case of Electricity," in *Analyzing the Impact of Regulatory Change in Public Utilities*, M. Crew, ed. Lexington Books, Lexington.
- Jamasb, T., and M. Pollitt (2001). "Benchmarking and Regulation: International Electricity Experience," *Utilities Policy* 9, pp. 107-130.
- Jamasb, T., and M. Pollitt (2003), "International Benchmarking and Regulation: An Application to European Electricity Distribution Utilities," *Energy Policy* 31(15), pp. 1609-1622.
- Kaserman, D., and J. Mayo (1991). "The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Industry," *Journal of Industrial Economics* 39, pp. 483-502.
- Kwoka, J. (2002). "Vertical Economies in Electric Power: Evidence on Integration and Its Alternatives," *International Journal of Industrial Organization* 20, pp.653- 671.
- Kwoka, J. (2006). "Electric Power Distribution: Economies of Scale, Mergers and Restructuring," *Applied Economics*, Vol. 37, Issue 20, pp. 2373-2386.
- Lee, Byung-Joo. (1995). "Separability Test for the Electricity Supply Industry," *Journal of Applied Econometrics* 10, pp. 49-60.
- Mansur, Erin (2007) "Upstream Competition and Vertical Integration in Electricity Markets," *Journal of Law and Economics* 50, no. 1.
- Michaels, R.J. (2006). "Vertical Integration and the Restructuring of the U.S. Electricity Industry," *Policy Analysis*, No. 572, pp. 1-31.
- Nemoto, J., and M. Goto (2004). "Technological Externalities and Economies of Vertical Integration in the Electric Utility Industry," *International Journal of Industrial Organization* 22, pp. 676-81.
- Ravenscraft, D.J. and F. M. Scherer (1987). *Mergers, Sell-offs and Economic Efficiency*. Washington, D.C., Brookings Institution.

## TABLES AND FIGURES

**Table 1**  
**Descriptive Statistics**

Category	Number	Mean Total Sales (M MWh)	Degree of Vertical Integration	
			1994	2003
All	73	22,200	0.696	0.450
Non-Divesting	45	19,900	0.700	0.613
Divesting	28	25,900	0.691	0.188
Mandatory	8	17,200	0.621	0.288
Non-mandatory	20	29,300	0.719	0.148

**Figure 1**

### Degree of Average Vertical Integration

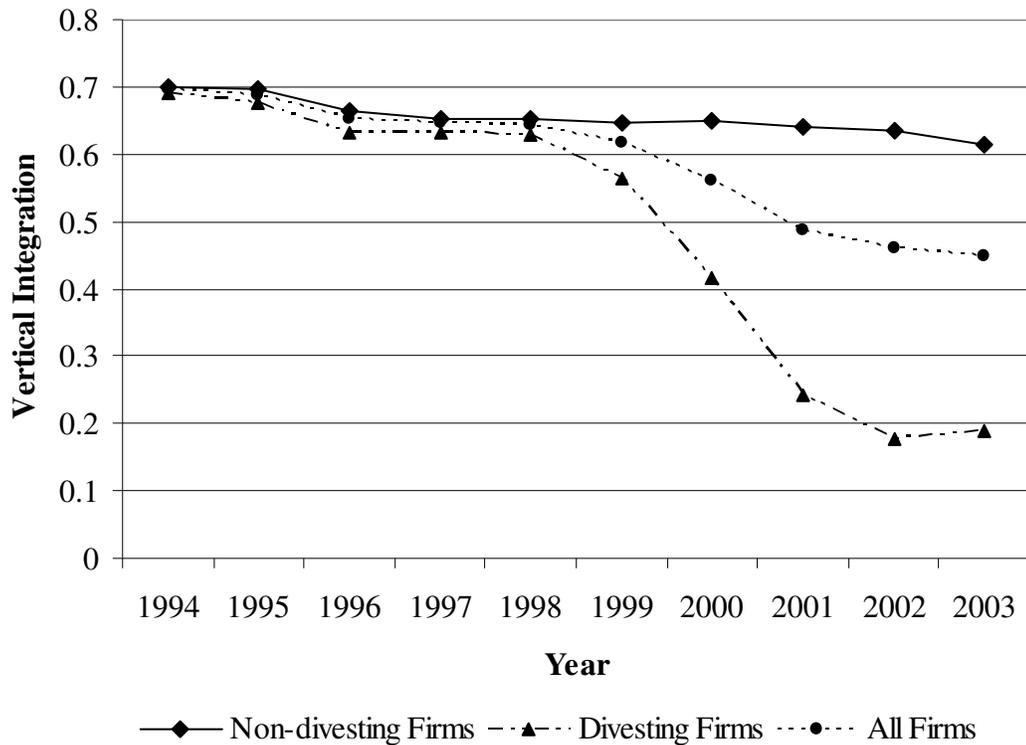
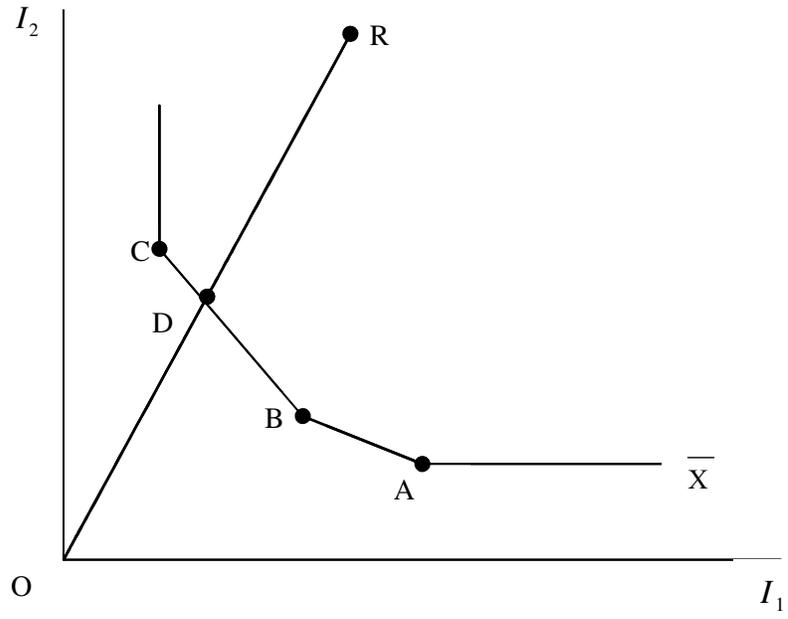


Figure 2

Input Oriented DEA Demonstration



**Table 2**  
**Regression Analysis on OPEX: Full Sample**  
**Dependent Variable: DEA Score**

	(a)	(b)	(c)
POST-DIVEST	-.008 (.67)		
POST-MAND		-.029 (1.45)	
POST-NON		.001 (.09)	
POST1			.001 (.08)
POST2			-.015 (.82)
POST3			-.022 (1.05)
POST4			-.005 (.22)
POST5			-.027 (.85)
POST6			.150 (2.47)
RES-PCT	-.198 (2.56)	-.209 (2.69)	-.187 (2.37)
CONSTANT	.740 (32.0)	.743 (32.0)	.737 (31.2)
R2	.03	.03	.04
F	8.15	7.63	6.20
N	730	730	730

Notes:

- 1- Absolute value of t-statistics are provided in parenthesis
- 2- Firm fixed effects are controlled for in the estimation.
- 3- Estimated coefficients for year dummies are suppressed.

**Table 3**  
**Regression Analysis on OPEX: Split Samples**

**Dependent Variable: DEA Score**

	Mandatory		Non-Mandatory	
	(a)	(b)	(c)	(d)
POST1	.014 (.44)	.016 (.53)	.017 (.66)	
POST2	-.160 (4.93)		.026 (.89)	
POST3	-.125 (2.80)		.051 (1.51)	
POST4	-.243 (5.38)		.067 (1.66)	
POST5	-.244 (3.79)		.086 (1.63)	
POST6	-.206 (3.07)			
POST26		-.148 (4.92)		
POST15				.023 (1.01)
RES-PCT	-.698 (3.68)	-.553 (2.98)	.236 (1.51)	.153 (1.03)
CONSTANT	.829 (15.9)	.792 (15.3)	.581 (12.8)	.603 (13.9)
R2	.35	.35	.05	.06
F	7.98	8.50	1.92	2.38
N	80	80	200	200

Notes:

- 1- Absolute value of t-statistics are provided in parenthesis
- 2- Firm fixed effects are controlled for in the estimation.
- 3- Estimated coefficients for year dummies are suppressed.

**Table 4**  
**Regression Analysis on TCEX: Full Sample**  
**Dependent Variable: DEA Score**

	(a)	(b)	(c)
POST-DIVEST	-.003 (.22)		
POST-MAND		-.055 (2.16)	
POST-NON		.020 (1.10)	
POST1			.018 (.84)
POST2			-.004 (.18)
POST3			-.042 (1.57)
POST4			-.004 (.13)
POST5			-.036 (.88)
POST6			.100 (1.30)
RES-PCT	-.150 (1.53)	-.178 (1.82)	-.162 (1.61)
CONSTANT	.784 (26.8)	.792 (27.0)	.787 (26.3)
R2	0.08	0.08	0.10
F	12.2	11.8	8.8
N	730	730	730

Notes:

- 1- Absolute value of t-statistics are provided in parenthesis
- 2- Firm fixed effects are controlled for in the estimation.
- 3- Estimated coefficients for year dummies are suppressed.

**Table 5**  
**Regression Analysis on TCEX: Split Samples**  
**Dependent Variable: DEA Score**

	Mandatory		Non-Mandatory	
	(a)	(b)	(c)	(d)
POST1	.055 (1.32)	.023 (.62)	-.015 (.42)	
POST2	-.146 (3.52)		-.017 (.41)	
POST3	-.014 (.25)		-.078 (1.59)	
POST4	-.182 (3.16)		-.033 (.57)	
POST5	-.130 (1.58)		-.063 (.82)	
POST6	-.119 (1.40)			
POST26		-.109 (2.89)		
POST15				-.024 (.73)
RES-PCT	-.807 (3.33)	-.754 (3.25)	.220 (.97)	.276 (1.29)
CONSTANT	1.01 (15.1)	.992 (15.3)	.653 (9.94)	.638 (10.2)
R2	.43	.40	.06	.07
F	6.63	7.40	2.50	3.22
N	80	80	200	200

Notes:

- 1- Absolute value of t-statistics are provided in parenthesis.
- 2- Firm fixed effects are controlled for in the estimation.
- 3- Estimated coefficients for year dummies are suppressed.

## APPENDIX

VARIABLE and DEFINITION	FERC PAGES [1]	FERC ACCOUNT NAME / NOTES
Total Distribution Costs (D)	322-126b	TOTAL Distribution Expenses (US\$)
Total Administration Costs (A)	322-168b	TOTAL Administration & General Expenses (US\$)
Total Customer Service Costs (Cu)	322-134b	TOTAL Customer Accounts Expenses (US\$)
“322-134b” + “322-141b” + “322-148b”	322-141b 322-148b	TOTAL Customer. Service and Information Expenses (US\$) TOTAL Sales Expenses (US\$)
S: Share of Distribution Business in Administration	S1(a) / S1 (b)	
S (a): Numerator (wages of distribution and customer)	354-20b	Distribution (US\$)
"354-20b"+ "354-21b" + “354-22b” + “354-23b”	354-21b 354-22b 354-23b	Customer Accounts (US\$) Customer Service and Informational (US\$) Sales (US\$)
S (b) :Denominator (wages)	354-25b	TOTAL Operations and Maintenance (US\$)
“354-25b”-“354-24b”	354-24b	Administrative and General (US\$)
Total Sales (MWh)	301-12d	TOTAL Unit Sales (MWH)
Residential Sales	301-2d	Unit Sales to Residential Consumers (MWH)
Total Customers (#)	301-12f	TOTAL Sales to Consumers (#)
Residential Customers	301-10f	Unit sales to Residential Consumer (#)
Distribution Line Length	Platts	TOTAL Network Length (Miles)

### APPENDIX (Cont'd)

VARIABLE and DEFINITION	FERC PAGES [1]	FERC ACCOUNT NAME / NOTES
Capital Cost Share of Distribution (CC)		
	207-42g	EOY Total Production Plant (US\$)
("207-69g")/("207-42g"+"207-53g"+"207-69g")	207-53g	EOY Total Transmission Plant (US\$)
	207-69g	EOY Total Distribution Plant (US\$)
Additions to Total Distribution Plant	206-69c	Add Dist Plant-Total Distribution Plant (US\$)
Additions to Total General Plant	206-83g	Add Gen Plant-Total General Plant (US\$)
Current Capital Expenditures on Distribution (CAPEX)	"206-69c"+CC * "206-83g"	
OPEX- (Operating costs)	D + Cu + S1 * A	O& M Costs of Distribution (US\$)
TCEX- (Total Controllable Costs)	OPEX+ CAPEX	
Generation Plant	207-42g	TOTAL Production Plant (US\$)
Net Generation	401-9a	Net Generation (kWh)

[1] Data are based on FERC Form 1 filings.

## **CHAPTER 2**

### **Independent System Operator (ISO) Formation in New York and the Impacts on Generation Efficiency<sup>15</sup>**

---

<sup>15</sup> This chapter is based on an essay coauthored with James D. Reitzes of The Brattle Group.

## **I. Introduction**

Following the introduction of competition in the wholesale power markets, Federal Energy Regulatory Commission (FERC) has taken several actions to advance the pace of competition and eliminate the discriminatory practices typically concerning the access to the transmission grid. FERC Order 888<sup>16</sup> called for voluntary formation of ISOs, providing for centralized management of the grid and the energy market. In response to FERC orders, coordinated markets have started in many regions across the country and have been operating for several years now.

ISO formation has been expected to spawn various types of efficiencies. Some of these are unit-level operating efficiencies; others are system efficiencies. The unit-level operating efficiencies derive from improved operation of individual generators. This might occur to the extent that the centralized unit commitment and dispatch coordinated by the ISO puts more units in competition with each other, and that competition enforces stronger cost discipline on the operating efficiency of each unit. Moreover, elimination of pan-caked<sup>17</sup> transmission rates makes it economically worthwhile to move power over longer distances for units that otherwise wouldn't find it economic to make supply offers, thereby introducing these units as additional competitors.

At the system level, the efficiencies might be due to central management of the transmission grid (e.g. congestion management, reliability) or to centralized commitment of a larger fleet of generators. With open access and centralized commitment, the system

---

<sup>16</sup> FERC Order 888 was later reincarnated as Order 2000 that promotes the formation of regional transmission organizations (RTOs). ISOs and RTOs perform equivalent services but ISOs tend to be smaller in geographic size than RTOs, or may not be subject to FERC jurisdiction

<sup>17</sup> Under pan-caked rates, a transmission customer is charged separate fees every time power crosses the service territory of a different utility. This practice harms the competition in the generation business since it increases the price of electricity which could otherwise be cheaper and competitive. (EIA 2000)

operator has a wider range of units to choose from and therefore can more often find low cost units to displace high-cost units in the dispatch order. These efficiencies would manifest themselves not at the unit level but at the system level in the form of greater output from the same set of inputs.

In this chapter, we test both of these possible sources of efficiency focusing on the generation units in New York ISO (NYISO) region from 1998 to 2004. Our unit-level analysis involves investigating the impacts of increased competition after the formation of NYISO on the fuel efficiency of generation units. Detailed information on fuel consumption and power production come from the Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS). We examine the impacts separately for each fuel type due to inherent differences in operation and production technologies of different fuels. Moreover we control for several changes that have happened in the industry concurrently with the formation of NYISO, as part of the larger process of restructuring. We also address the potential simultaneity problem between fuel efficiency and output using an instrumental variable approach.

Next, we analyze the system-level production relationship in NYISO region and explore whether the portfolio of generation assets are utilized more efficiently after the formation of NYISO. In order to observe the system level changes in productivity; we design an aggregate level approach that involves aggregating outputs and inputs of generating resources in the NYISO region into *generation portfolios* at each point in time. By estimating production functions for the constructed generation portfolios; we can observe whether the portfolio of generation assets used to meet the regional needs has become more productive and the centralized commitment and dispatch has lead to more

efficient allocation of the resources to load needs. Isolating the types of efficiencies is imperative for a better understanding of the benefits that the ISOs—and the NYISO in particular—yields.

We find that coal fueled units in NYISO region experience significant efficiency improvements in the post-ISO period. We don't observe similar efficiency improvements for gas, petroleum, and nuclear units in the post-ISO period although the gas units show significant improvements associated with the ownership changes. At the system level; we find that while one of the historically transmission constrained regions in the area exhibits system level efficiency gains, the other one with similar constraints suffers system level efficiency losses. Locational peculiarities and the differences in the rules governing power procurement in these regions may affect the extent to which centralized dispatch element of ISO is operational. Moreover, different market power mitigation mechanisms implemented in these regions may also contribute explaining the divergence in the system level efficiencies between the two otherwise similar regions. We also find that the relatively transmission unconstrained regions of NYISO have not experienced efficiency improvements during our sample period indicating that centralization of unit commitment and dispatch has not been superior to the non-centralized commitment and dispatch, in allocating resources more efficiently in these regions.

Overall, our results suggest that the formation of NYISO and the consolidation of unit commitment areas introduce limited efficiencies at the unit level and at the system level. However, one should be careful not to generalize our results to other regions with ISO/RTO formations. It is important to note that our analysis compares the generation efficiency under NYISO to that under NYPP which was organized differently than

NYISO but was still coordinated to some extent to achieve reliable and efficient trades in its control area. Consequently, the potential for efficiency gains arising from centralized commitment and dispatch might be relatively limited in the case of NYISO compared to what would result in another region that did not have any form of a coordinated market prior to the formation of ISO/RTO. Moreover, we should also note that our analysis only looks at dispatch efficiencies which are only one facet of ISO/RTO benefits. Other potential benefits of ISO/RTOs, such as incentives provided for more efficient generation and transmission investments and innovative pricing mechanisms for effectively dealing with congestion are not the subject of this chapter and will not be discussed further.

The remainder of the chapter is organized as follows. Section II provides some background on the efficiency effects of restructuring in U.S. electricity industry. Section III discusses the data and the empirical models while Section IV discusses the empirical findings. Finally, Section V concludes the chapter.

## **II. Why might ISO formation affect the generation efficiency?**

In order to have a better understanding of how ISO formation might affect the incentives of plant owners and thus the generation efficiency in New York; it is useful to describe the market structure in the state before NYISO has started its operations.

NYISO took over the control of the region's power grid and wholesale electric markets on Dec. 1, 1999 from New York Power Pool (NYPP), the coordinating entity in the region at the time. NYPP was created soon after the Great Northeast Blackout of 1965 to enhance the reliability of the electric system. An alternative raised at the time for the form of this coordinating entity involved fully computerizing and centrally coordinating

the whole system. However utilities did not support this alternative as it meant losing control over their own generation fleet (Pechman 1992). As a result; eight utilities voluntarily formed NYPP, structured as a tight power pool<sup>18</sup> with six control areas in which the individual utilities were responsible for commitment and dispatch of their own units. However unit commitment and dispatch was non-centralized in NYPP differentiating it from the other tight power pools operating at the time (i.e., New England Power Pool). In NYPP, units would only be dispatched system-wide to balance pool-wide supply and demand after the individual utilities in the pool had decided which units they would commit to meet the loads of their own customers (Tierney and Kahn 2007).

NYISO formally assumed the control of the region's power grid and consolidated the unit commitment areas and thereby the dispatch operations in New York on December 1, 1999. Yet, the formation of an ISO in New York State was only a facet of larger process of electricity restructuring which was in full swing at the time. The Energy Policy Act of 1992 opened wholesale markets to competition and made it easier for non-utility suppliers to enter the market. Following the EPACT, FERC issued Order 888 in 1996 to eliminate discriminatory practices in accessing the transmission grid and to facilitate the development of competition. In addition to the series of federal legislatives, many states issued their own restructuring programs. On May 1996, the New York Public Service Commission (PSC) issued its "Competitive Opportunities Case," that set the goal of having a competitive wholesale market by 1997 and a competitive retail market by 1998. During 1996 and 1997, PSC approved restructuring orders for six utilities in the state

---

<sup>18</sup> A tight power pool is a centralized reliability organization responsible for grid management as well as economic dispatch of the power plants in a region

(EIA 2000). PSC also encouraged the divestiture of generation assets and included provisions in utility restructuring orders regarding the sale of assets. Considering the course of the restructuring efforts; it would be fair to say that since 1996, New York State has been actively engaged in liberalization of its power industry through eliminating cost-plus regulation, introducing wholesale and retail competition, encouraging divestitures, and finally forming a centrally coordinated market. And it would be reasonable to expect that these substantial changes in market structure will improve the incentives of the generation plant owners for more efficient operation.

As early as 1992, utilities started to face competition from non-utility power producers and other utilities. Increasing this pressure further, many utilities are no longer subject to cost-of-service regulation that guaranteed them a service territory and recovery of their costs. Under the cost-of-service regulation, utilities have only limited incentives to minimize their costs as they are virtually isolated from competition for their native load and able to pass their capital and operations and maintenance (O&M) costs to their customers through rates determined by regulators (Wolfram 2004). After the elimination of cost-of-service regulation, utilities, being the residual claimants of any profits, had stronger incentives to reduce costs.

Cost minimization incentives on the part of plant operators are expected to improve even more after the implementation of competitive wholesale markets that operationalize the economic dispatch mechanism. Economic dispatch is the optimization process that determines a set of generators and output from these generators to meet the demand at the lowest cost given the operational constraints of the transmission system and the generation fleet (DOE 2005). First part of the economic dispatch is to determine which

units will be turned on the next day depending on their operating costs and characteristics. Second part involves determining the output levels that will be produced by each committed unit. Economic dispatch is ideally determined through ordering the bids of plant owners from least to most until the total supply meets total demand. The lower the average variable cost of production, the lower the unit can afford to bid and thus higher the likelihood that it will be included in the dispatch schedule. Units have more powerful incentives to minimize costs under this framework as they will have to compete with other generators to secure their place in the dispatch order. Moreover, since the dispatch is the only way to recover production costs and the cost recovery is not guaranteed anymore; many units will be more aggressive to minimize their costs under the competitive wholesale markets.

There are three main structures through which the commitment and the dispatch of the units are carried out. On one end of the spectrum, there is traditionally regulated utility system where each utility commits its own units to meet the native load. On the other end of the spectrum, there is centrally coordinated tight power pool where the pool operator carries on pool-wide commitment and dispatch to find the least-cost mix of plants –conditional on their costs- to meet the load in the region. In the middle, there is tight power pool with commitment and dispatch at the sub-area level, although units may be dispatched pool-wide to balance the excess supply and demand in the region. NYPP can be given as a unique example of the latter and was more efficient in unit commitment and dispatch compared to traditionally regulated systems. However, it may not be obvious to see how an organization with centralized commitment and dispatch, NYISO in our context, will be more efficient- at least in theory- than NYPP.

Operation of the power system under both NYPP and NYISO follows a natural sequencing. “Unit commitment” function is implemented first to determine which units to turn on the next day to serve the load. “Unit dispatch” function follows this step and determines how much production to call from each committed unit (DOE 2005). Units are committed on the basis of expected load, transmission constraints and unit specific operational considerations while unit dispatch is carried to find the least cost production mix from the committed resources.

Although these functions have existed under both of NYPP and NYISO organizations; they differed in terms of their execution. NYPP carried a non-centralized unit commitment function where each control area only committed its own units to meet the load in its control area. However, commitment function is centralized under NYISO in the sense that the universe of the units in the entire region is considered for commitment to meet the expected load in the region. This implies that a less-efficient unit is more likely to be left uncommitted and replaced with a more efficient unit under centralized commitment (where the choice set is larger) of NYISO than it is under the non-centralized dispatch of NYPP where a given control area may not have much choices other than committing the less efficient unit to meet the load. In other words, non-centralized dispatch may lead to turning on the less efficient units that would not be turned on under centralized unit commitment.

Similar argument also applies to the unit dispatch functions under NYPP and NYISO. NYISO centrally determines how much each committed unit needs to produce to meet the load in the region. Then these units are dispatched in a least-cost fashion that is starting from the least-cost source and dispatching in an ascending cost order until the

load needs are met. Under NYPP, units would only be centrally dispatched if there is need to balance supply and demand in the region, and only after each control area dispatched its own units (Tierney and Kahn 2007). In other words, more efficient power is more likely to replace less efficient power under NYISO organization where, again, the system operator's choice set is larger compared to that of individual control area operators' under NYPP. One might argue that the centralized dispatch for balancing supply and demand may produce outcomes similar to NYISO's centralized dispatch. However, this is not very likely since the remaining resources after each control area met their own needs are not necessarily the most efficient resources; since if they were, individual control areas in which they resided would take full advantage of them.

Size and geographic scope of the dispatch area are important determinants of how strong the cost minimization incentives of plant owners are. In the context of unit commitment and dispatch functions, a broader commitment area implies a wider range of units that the market operator may choose from –depending on their costs- to determine the dispatch schedule. As the commitment area gets broader and includes more units, competitive pressures for certain units increase. For instance, a given unit X operating in NYPP only competes with other units that are in the same control area with X. It doesn't compete with the units located in five other commitment areas due to the structure of NYPP. However, competitive conditions change after all six commitment areas of NYPP are consolidated into a single unit commitment area with the formation of NYISO. Unit X now has to compete with all units controlled by NYISO. In other words; consolidation of unit commitment areas, as in the formation of NYISO from NYPP, leads to a broader market in which units compete for commitment and dispatch. Intensified competition and

thus stronger incentives for cost minimization are expected to exhibit themselves in the improved performances of individual units and will be captured in our unit-level analysis.

Economic dispatch is defined as “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities” (EPAAct 2005, Sec. 1234 (b)). Therefore, dispatch problem is actually a cost minimization problem subject to several generation and transmission related constraints. Geographic scope of the dispatch area is an important determinant of the solution to this problem since it determines the choice set over which the minimization is performed. Economic theory suggest that the sum of separate cost-minimizing dispatch solutions for several independent but adjacent dispatch regions is likely to give a larger cost figure than the cost minimizing solution that would result if the entire area is combined and dispatched as one system. An economic dispatch area which is larger in scope allows the dispatcher to utilize the load diversity across the area and leads to a better allocation of resources to the load needs (DOE 2005).

In fact several cost-benefit studies for northeastern ISO/RTOs show that global optimization produces lower energy costs and greater savings from efficiency improvements than local optimization (i.e. PJM 2002). One survey participant in Department of Energy’s Report to Congress on economic dispatch states:

...Economic dispatch is optimized when it is coordinated over as large an area as possible, with the participation of as many resource options as possible given transmission constraints (DOE 2005, 28).

These efficiencies associated with the better use of system resources (i.e. more frequent substitution of more efficient generation for less efficient generation) are

expected to exhibit themselves at the system level in the form of greater output from given inputs and will be captured in our system level analysis.

### **III. Review of Literature**

Several authors in different contexts have examined the operating efficiencies of electric generating plants, but only a few have examined the impact of restructuring on the performance of generating units in the context of the U.S. electricity industry. Knittel (2002) investigate the effect of alternative regulatory programs on the technical efficiency of a large set of coal and natural gas generation units. Wolfram (2004) provides a comprehensive discussion of the impacts of the restructuring on the generation unit efficiency and summarizes the current state of knowledge. Joskow (1997) argues that medium-run efficiency gains from restructuring may be possible with improving the operating performance of the existing stock of generating facilities and increasing the productivity of labor operating these facilities. Kleit and Reitzes (2004) examine how the formation of ISOs has influenced the efficiency of interregional energy trading. Borenstein, Bushnell and Stoft (2000) show that relatively small investments in transmission capacity can give large payoffs in terms of increased competition. Joskow (2006) indicates that competition has provided incentives to increase generation unit performance.

A 2005 report prepared by Energy Security Analysis Inc. for PJM investigate the question whether electric markets under PJM's expanding footprint have become more efficient. Their review of the heat rate trends reveals the competitive activity in the PJM markets. They find that the average market heat rate of PJM Western Hub declines from 11MMbtu/MWh to 7.3MMbtu/MWh between 1999 and 2004. They attribute these

improvements to the competitive forces which are fueled by PJM's centralized dispatch and more efficient management of the transmission grid.

The s most closely related to this one are Fabrizio, Rose, and Wolfram (hereafter FRW) (2007) and Bushnell and Wolfram (hereafter BW) (2005). FRW utilize an annual plant-level dataset on a sample of fossil-fueled generation plants to investigate the impacts of *restructuring* on the fuel and non-fuel expenses of these plants. They find that investor owned utility (IOU) plants in restructuring states experienced the largest reductions in non-fuel expenses while municipally (MUNI) owned utilities experienced the least gains. They find no evidence of improved fuel efficiency from restructuring and reason that the level of aggregation of their data is not fine enough to capture fuel efficiency changes. They also address the simultaneity problem in the input-output choice through instrumental variables analysis.

BW concentrate on the question of fuel efficiency and investigate the impacts of *divestitures* on the fuel efficiency of a sample of fossil-fueled generation units. They find that divested plants achieve 2% efficiency gains compared to the non-divested utility owned plants. However, they also find efficiency gains of similar magnitude for non-divested plants which are subject to a form of incentive regulation. They conclude that efficiency gains should be attributed to the incentive changes rather than ownership changes.

In this paper, despite using a similar methodology to those of FRW and BW; we seek an answer to a different question: whether the *formation of an organized power market* in a region *further* enhances the fuel efficiency through stimulating the competition that is already in place? Moreover, our analysis of fuel efficiencies is at the hourly and the unit-

level and the disaggregated structure of our data is expected to give more accurate estimations of the fuel efficiency changes compared to FRW's annual plant-level and BW's monthly unit-level analyses. We also introduce a system level approach to the analysis of efficiencies where the goal is to capture efficiencies which are due to the substitution of less efficient units with more efficient units and are not readily captured by a unit level analysis.

#### **IV. Data**

In this analysis, we restrict our attention to generation units in NYISO region operating in the period 1998 through 2004. Our data come from the Environmental Protection Agency (EPA)'s Continuous Emissions Monitoring System (CEMS), which collects hourly data on emissions, fuel usage, and power production. The major purpose of CEMS data collection is to monitor the enforcement of EPA's Acid Rain Program (ARP). EPA requires Continuous Emissions Monitoring (CEM) of pollutants only for units<sup>19</sup> that are regulated under the ARP. This leaves us with an unbalanced panel of 288 generating units that are located in NYISO. Nonetheless, our sample covers 82 percent of the total nameplate capacity<sup>20</sup> in NYISO for the year 2003. Table 1 summarizes the number of all generating units located in NYISO as well as the units that are included in our sample. Our sample covers fossil (i.e. coal, gas, and petroleum) and nuclear fueled units while excluding hydro and renewable generation resources. In 2005, 82 percent of

---

<sup>19</sup> All units over 25 megawatts and new units under 25 megawatts that use fuel with a sulfur content greater than .05 percent by weight are required to measure and report emissions under the Acid Rain Program. The new units under 25 megawatts using clean fuels are required to certify their eligibility for an exemption every five years.

<sup>20</sup> Nameplate capacity refers to the maximum output a generator can produce under certain conditions designated by the manufacturer and is measured in megawatts (MW). Our sample represents 32,851 MWs while the total nameplate capacity in NYISO in 2003 is 40,007MWs. (EIA, Electric Generating Units in the United States, 2003).

total NYISO generation originated from nuclear and fossil fuels while only 18 percent of total generation can be attributed to hydro and renewable resources (NYSERDA 2005). As we can see from these numbers, nuclear and fossil fueled units together comprise the majority of NYISO generation portfolio and therefore even minor changes in fuel efficiency may lead to significant cost savings.

As we mentioned in the previous section, our sample corresponds to a time frame during which many units have changed hands. Majority of units were divested to non-utility generation companies by their utility owners. Some non-utility owned generation companies sold their assets to other non-utility generators. In order to be able to control the impacts of ownership changes on the fuel efficiency of generation units, we gather ownership information from EIA-906 and EIA-920 forms. We use the CEMS data at the hourly aggregation level as this chapter focuses on the impact of coordinated markets on fuel efficiency which is probably affected on an hourly level with the associated changes in the dispatch function. Hourly estimations should provide more precise coefficient estimates as the portrayal of heat rate relationship at the hourly level is more purposeful compared to the more aggregated representations (i.e. monthly averages).

## **V. Methodology**

In this section, we discuss our empirical strategy, model variables and several issues pertaining to the model estimations. First part of our analysis involves examination of the unit-level efficiency of fuel use in the period following the introduction of the ISO (hereafter post-ISO period). Our focus is restricted to the fuel efficiency of the generation units as the required data on non-fuel inputs (i.e. labor and other materials) for a more inclusive operating performance measure are not readily available to us. Following FRW

(2007), we assume that power production technology is Leontief and therefore elasticity of factor substitution between fuel and other inputs is zero. This allows us to be able to model fuel efficiency independently of other inputs of power production. Moreover, improvements or deteriorations in fuel efficiencies translate into more important overall consequences for society since fuel costs constitute around 80 percent of the total operations and maintenance costs of a generation plant (Beamon and Leckey 1999).

In this chapter fuel efficiency of the generating units is measured by “Heat Rate” following the practice in literature. Heat Rate is expressed as the number of MMBTUs<sup>21</sup> of heat required to produce a megawatt-hour of energy and shows how efficiently a generator converts the fuel into electrical energy. In other words; lower heat rate implies more fuel efficient production. Data are utilized at the hourly level to better capture the heat rate relationship at the individual units. We employ ordinary least squares to estimate how the unit-level fuel efficiency changes as a function of ISO status. In this estimation; Heat Rate is regressed on post-ISO dummy, output that is the total generation, ownership change dummies, year trend, quarter fixed effects, hour fixed effects, and unit fixed effects. More explicitly, our model takes the following form:

$$\ln(\text{HeatRate}_{it}) = \alpha_0 + \alpha_1 \text{PostISO} + \alpha_2 \ln(Q_{it}) + \alpha_3 \text{UtoNU} + \alpha_4 \text{NUtoNU} + \alpha_5 \text{YearTrend} + \beta \text{Qtr} + \theta \text{Hour} + u_{it} \quad (1)$$

Post-ISO is a dummy variable that takes the value of 1 starting from December 1, 1999 and extends through the time period following the formation of NYISO. It is 0 for all points in time before December 1, 1999. In our set-up,  $\alpha_1$  gives the efficiency changes

---

<sup>21</sup> A BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. It is a standard unit of measurement used to denote both the amount of heat energy in fuels and the ability of systems to produce energy.

associated with the implementation of the ISO that provided centralized unit-commitment and grid coordination in New York. We introduce output (Q) as an explanatory variable since the heat rate of a generation unit is affected by the level of production<sup>22</sup>. We expect to observe a negative relationship between *HeatRate* and the level of output due to the nature of power generation<sup>23</sup>. Many generation units have changed hands during our sample period. We introduce two dummy variables to control for the impact of ownership changes: *UtoNU* takes the value of 1 following the sale of a utility owned generation unit to a non-utility owner while *NUtoNU* takes the value of 1 following the sale of non-utility owned generation unit to another non-utility. We expect that ownership changes will have significant impacts on the fuel efficiency as they lead to changes in the incentives of plant operators. We don't have an a priori expectation for the sign of *NUtoNU* , but *UtoNU* is expected to be positively associated with the fuel efficiency since non-utilities have higher powered incentives for cost minimization as generation is their sole source of revenues and they have the focused expertise on plant operation. *YearTrend*<sup>24</sup> captures the industry trend in the fuel efficiency, if any, over the course of the years in our sample period. *Qtr* is a vector of quarter fixed effects to capture the seasonal trends while *Hour* is a vector of hourly fixed effects to control for the impact of hourly load profile on the fuel efficiency of a given unit. It's important to note once again

---

<sup>22</sup> We also estimate a slightly different version of the equation above where output is introduced in intervals to be able to capture any non-linearities in the production. These results are not reported as all coefficients but the output coefficients remain essentially unchanged.

<sup>23</sup> Fuel use becomes more efficient after the production increases from very low levels.

<sup>24</sup> We also introduced yearly dummies in the regressions to explicitly control for year-fixed effects. However, some year dummies drop out of the equation and are pooled in the constant due to collinearity problems with the post-ISO dummy. Therefore we opted to use trend variable as an imperfect substitute for year dummies.

that we estimate equation (1) separately for each fuel type as operation and production technologies are likely to differ for alternative production technologies.

Error term  $u_{it}$  can be decomposed as follows:

$$u_{it} = \theta_i + \varepsilon_{it} \quad (2)$$

In the equation above  $\theta_i$  represents time invariant unit-fixed effects (i.e. unit site, year of construction, idiosyncratic design features, and other unobservable fixed characteristics) that are expected to affect the fuel efficiency of the generation units.  $\varepsilon_{it}$  is an unobserved random shock to the unit fuel efficiency and normally distributed with mean zero. In our context, it is not realistic to assume that  $\varepsilon_{it}$  is independently distributed over time for a given unit. A random shock may persist over time - usually without a predictable time structure- indicating serially correlated errors. Therefore, we cluster standard errors by generation unit to obtain standard errors that are robust to arbitrary within-group autocorrelation rather than assuming  $n^{\text{th}}$  order autoregressive process and correcting for it.

An important issue in the estimations is potential simultaneity of output and heat rate if units adjust their output levels in response to shocks to their efficiency levels. In this situation, error term ( $\varepsilon_{it}$ ) would be correlated with the output (Q) variable and the coefficient estimates obtained from the model would be inconsistent. For this reason, we also report instrumental variable or the two-stage least squares (2SLS) estimation results that account for the likely simultaneity between the level of output and plant efficiency. First step of the 2SLS involves explaining the endogenous variable with excluded and included instruments. Included instruments are the exogenous regressors of equation (1). Excluded instruments should be at least as many as the endogenous regressors for

identification in the original model and must satisfy certain conditions to be valid and relevant instruments.<sup>25</sup> We use system level load (total demand in the region), average and maximum load to instrument for unit level output following Bushnell and Wolfram (2005). We also employ several statistics to determine whether our instruments satisfy relevancy and validity conditions for a proper instrumental variable estimation and our potentially endogenous variable  $-Q-$  is indeed endogenous. Our results indicate that there is no endogeneity involved in the unit-level regressions and therefore OLS estimations provide consistent and unbiased parameter estimates.

Second part of our analysis involves a system level analysis of New York generation supply in the post-ISO period. Formation of NYISO represents a consolidation of unit commitment areas and a centralization of unit commitment function that was decentralized under NYPP. In order to observe the system level changes in productivity after the NYISO formation, we design an aggregate level approach which involves aggregating outputs and inputs of all generating resources in the NYISO region into a single *generation portfolio* at each point in time. However, a single portfolio of generation sources for NYISO is hard to defend in practice due to substantial transmission constraints parting the region into three natural sub-markets. Historically, there are severe transmission constraints into New York City (Zone J) and Long Island<sup>26</sup> (Zone K), making these zones major load pockets in NYISO region (FERC 2006). When a region is a load pocket, transmission constraints do not allow bringing in power from other regions and unsettled load can only be met by own zone resources. In this case,

---

<sup>25</sup> For a detailed discussion of instrumental variable estimation; see Baum, Schaffer and Stillman (2002).

<sup>26</sup> Constraints into Long Island have become comparatively more important with the recent addition of new plants in New York City (FERC 2006).

system operator can only dispatch units located in the zone as the set of units to choose from virtually narrows down to the local units. Consequently, we aggregate output and inputs of units in NYISO into three different generation portfolios rather than a single portfolio in our system-level analysis. Figure 1 represents the zones under NYISO. “Portfolio J” covers the generation activity in Zone J- New York City; “Portfolio K” covers the generation activity in Zone K- Long Island; and “Portfolio Rest” covers all other regions in New York ISO region. For each portfolio, we estimate an equation to observe how the system level productivity has changed in the post-ISO period. In this framework, output is the total generation of a given portfolio at a given time while input is the total of MMBTUs from all fuels used in generation. More explicitly, our model takes the following form:

$$TotalGeneration_t = \alpha_0 + \alpha_1 TotalBTU_t + \alpha_2 PostISO + \alpha_3 YearTrend + \beta Qtr + \theta Hour + \varepsilon_t$$

where (3)

$$\varepsilon_t \sim N(0, \sigma_\varepsilon) \text{ and } E(\mathbf{X} \varepsilon_t) = 0$$

$TotalGeneration_t$  is the aggregate output produced by a given portfolio at time  $t$ .  $TotalBTU_t$  represents the aggregated heat content (in terms of BTUs) of all inputs that are used in the production of  $TotalGeneration_t$ . Post-ISO is the dummy variable defined above in the unit-level regressions, but this time capturing the impact of ISO formation on the aggregate productivity of the generation resources. More explicitly,  $\alpha_3$  shows the change in total output of a given portfolio in the post-ISO period, ceteris paribus. We expect to find that the generation portfolios will exhibit productivity gains in the post-ISO period to the extent that centralized unit commitment and coordination introduce

more effective resource sharing and more frequent replacement of more expensive power with cheaper power.  $\varepsilon_t$  is a normally distributed unobserved random error but  $E(\varepsilon_t \varepsilon_s) = 0$  is violated and equation (3) errors suffer from autocorrelation. We detect the presence of first order autocorrelation using the Durbin Watson<sup>27</sup> (DW) test. Accordingly, we employ FGLS estimation of the AR (1) model since FGLS estimator is more efficient than the OLS estimator when error term follows an AR (1) process (Wooldridge 2003).

One might think that simultaneity may also pose a potential problem for the estimation of equation (3). However due to construction, equation (3) is similar to a transformation function and doesn't suffer from simultaneity. It may help our understanding to envision this equation as the second stage of a two-stage decision process. In the first stage, generation units submit their bids that incorporate their marginal cost and quantity they are willing to produce. It is this stage where the simultaneity may arise since a random shock to the total load translates as a shock to the production of each unit, and this may in turn affect their input use. However, when the second stage is reached; outcome of the first stage process is already known and inputs and the resulting output are now ex-post variables. What we investigate with equation (3) is whether this transformation has become more productive after the formation of ISO.

It is also possible that the decision to implement an ISO in a region is correlated with potential fuel efficiency improvements. One could ideally deal with this problem instrumenting for the ISO formation and explicitly testing whether endogeneity is a problem. We haven't managed to find a proper instrument for the ISO formation in New York which is made more difficult by the time series structure of the data and the

---

<sup>27</sup> DW statistics are around 0.2 before the AR (1) correction while they become very close to 2 after the AR (1) correction.

uniqueness of the event over time. Nevertheless, endogeneity of ISO formation is less troublesome in our context given that the emergence of ISOs is prompted by a larger movement towards more competitive power markets rather than concerns over the fuel efficiency of individual generation units (Bushnell and Wolfram 2005).

Another concern for both analyses is the potential for selection. Selection may lead to biased coefficient estimates if, for instance, units with poor fuel efficiency performance are systematically selected out of the sample, and the remaining units are the ones that have done well enough to survive the sample period. In this chapter, we rely on a traditional approach to detect the extent of sample selection affecting our sample. In this approach, every regression is estimated on two samples: an unbalanced panel and a balanced panel. Considering the argument above, significant differences in estimation results from different samples indicate a problem of selection and may require a formal treatment of the problem. Yet, we suspect that the random shocks to the fuel efficiency are likely to make a generation unit exit the industry as does Bushnell and Wolfram (2005). Moreover exits are not a common phenomenon during our sample period.

## **VI. Results**

### **A. UNIT-LEVEL ANALYSIS RESULTS:**

Tables 2 through 5 report the results from unit level regressions which are estimated separately for each fuel type. In all regressions, standard errors are clustered by unit to adjust for serial correlation. Parameter estimates from the balanced panels are largely consistent with their unbalanced counterparts indicating that our results do not suffer from sample selection bias. Log of output is significant and negatively associated with

heat rate in all regressions confirming our expectations and will not be discussed separately for each set of results.

First, we will look at 2SLS results and discuss several statistics to gauge the relevancy of instrumental variable estimation in our context. Yet, we won't discuss the 2SLS estimation results here as we dismiss the endogeneity concerns and conclude that OLS estimation is more appropriate. Following this discussion, we will introduce OLS estimation results.

In the presence of a correlation between the error term and one or more explanatory variables, instrumental variable estimation (IV) technique can be used to address the endogeneity problem. However, there are certain conditions that IV estimation should satisfy to be able to stand as a viable alternative to OLS. First of all; instruments should be correlated with the endogenous variable (i.e., relevant) and uncorrelated with the error term (i.e., valid). Hahn and Hausman (2002) show that 2SLS produces biased coefficients when the correlation between endogenous variable and instruments is only weak. In fact, 2SLS coefficients become inconsistent and as biased as OLS coefficients when the correlation between instrument and endogenous variable is zero. Therefore, it is essential to utilize relevant instruments in an IV estimation. It is also essential to make sure that instruments are valid and truly exogenous to the error process. Violation of any of these conditions negates the reliability of IV estimation in dealing with endogeneity and therefore should be tested to avoid incorrect inferences from estimations. Moreover, 2SLS is less efficient than OLS when explanatory variables are exogenous (Wooldridge 2003). Therefore it is important to test whether supposedly endogenous variable(s) can

actually be treated as exogenous after one finds valid and relevant instruments for this endogenous variable.

Columns [b] and [d] of Tables 2 through 5 report 2SLS estimation results.<sup>28</sup> Comparison of the estimations results between columns b and d for each table reveals that results based on the unbalanced and the balanced samples are not fundamentally different alleviating the concerns about sample selection. Moreover, balanced sample is too restricted in terms of coverage of the units for the purposes of our analysis. Therefore, we'll focus on the estimation results from the unbalanced sample. For coal and nuclear, estimations; output is instrumented by total and maximum load in NYISO region. For gas and petroleum estimations however; we instrument output with average and maximum load in NYISO since our tests show that total and maximum load do not satisfy the validity condition as instruments. Table 6 compiles the test statistics<sup>29</sup> for validity, relevancy, and endogeneity reported in column b of each Table 2 through 5. Looking into the test-statistics and their implications in Table 6; we conclude that OLS estimation is more appropriate than 2SLS in our context since OLS estimators are more efficient than those from 2SLS in the absence of endogeneity.

Column [a] of Table 2 reports OLS estimations for coal-fueled units. Our results suggest that the fuel efficiency has improved in coal fueled generating units in NYISO by 3.3 percent following the ISO formation and this effect is significant at 1% level. As the dispatch is centralized with the formation of NYISO ideally broadening the market generators competes in; more efficient generators are more likely to replace less efficient

---

<sup>28</sup>2SLS estimations in Tables 2 through 5 do not report R-squared numbers since R-squared is not useful in the context of IV estimation. When the error term and the explanatory variables are correlated, we can not decompose the variance of y into variance of from explanatory variables and variance from the error (Wooldridge, 2003).

<sup>29</sup> 5% level is adopted as the significance criterion for rejection of the null hypothesis in the tests.

plants in the dispatch order. Our estimations show that resulting competitive pressures improve the incentives of the coal plant operators and coal units operate more efficiently after the formation of NYISO. Supporting our results for coal units, Douglas (2006) shows that the market reforms in PJM and the Northeast between 1996 and 2000 saved 1.5% to 3% of the costs of operating the coal-fired generator fleet. We do not observe a significant fuel efficiency improvement for utility- owned coal units that are sold to non-utilities. There are not any coal units in our sample which were owned by a non-utility and sold to another non-utility. Year trend is insignificant indicating that fuel efficiency in coal units does not follow a trend in time.

Column [b] of Table 3 reports the OLS estimation of fuel efficiency for gas-fueled units which are typically the marginal units setting the price of power. Our results suggest that fuel efficiency has not changed in gas-fueled units following the ISO formation. Year trend is -0.8% and significant at 5% level. This is expected since the gas technology improves progressively usually building upon the existing system in the form of upgrades. One interesting result from gas unit regressions is that fuel efficiency increases by 13% (significant at 1% level) for utility owned units that were sold to non-utilities. Fuel efficiency improvements in formerly utility owned units point out to the high-powered incentives provided by non-utilities for efficient production. Utilities have other lines of businesses which smooth the impact of foregone revenues in the event that a utility owned gas unit is not dispatched. However, generation is the only source of revenues for non-utilities and can be argued to provide them higher powered incentives to secure their order in the dispatch schedule. Therefore, after the transfer of their assets to non-utilities, the competition becomes particularly intense for gas utilities. As they are

generally the marginal units in the supply curve, their likelihood of dispatch increases more if they can reduce their marginal costs. Moreover, plants with lower variable cost will not only be more profitable when they are dispatched, but will also be dispatched more hours and produce more revenue. This may motivate plant management to focus on heat rate reductions. In contrast, coal units are base-load units and they have not been exposed to the pressure of being excluded from the dispatch schedule as much as gas units have. This may explain why this effect turns out to be significant for gas units but not for coal units.

Column [a] of Table 4 reports OLS estimation results for nuclear-fueled units. Results indicate that efficiency of nuclear units improve by 0.5% in the post-ISO period with the caveat that the estimated coefficient slightly falls short of 10% significance. This is reasonable since the dispatch of the nuclear units is minimally affected by the ISO formation because nuclear units have the must-run status and are always dispatched when they are available. Column [a] of Table 5 reports the OLS estimation of fuel efficiency for petroleum-fueled units. Post-ISO has a negative but an insignificant coefficient. However, much like the case of nuclear units, it slightly falls short of statistical significance. Year trend is -1.5% and significant indicating that efficiency of the petroleum fueled units improves progressively over time.

#### B. SYSTEM-LEVEL ANALYSIS RESULTS:

Table 7 reports the results from estimating the impacts of ISO formation on the system level productivity of NYISO generation portfolios. System level regressions are estimated separately for each of the generation portfolios and all estimations rely on the hourly data. All estimations in column [a] through column [c] suggest that  $\ln(\text{Total-}$

BTU) is significant and positively associated with  $\ln(\text{Total-MWH})$ . This is in line with our expectations since total generation increases with the total inputs used. DW statistics in all estimations are around 2, indicating that our estimations do not suffer from autocorrelation after the AR (1) corrections. TREND term is positive and significant in all estimations; therefore there is a trend for productivity improvements in all the portfolios.

Column [a] of Table 7 reports the estimation results for Portfolio J. Our results suggest that the portfolio J is associated with 1.7 percent productivity increase in the post-ISO period. In other words, total generation has increased by 1.7 percent after the formation of NYISO using the same amount of BTUs for output. It is important to note that this coefficient does not exclusively represent the “true system efficiencies”. Rather, it includes the true system efficiencies flowing from better allocation of resources as well as the unit level efficiencies now displaying themselves at the system level. As we readily have the estimates of unit level efficiencies and the productivity; we can isolate true system efficiencies through some algebra. Before moving onto this calculation, we shall summarize the total productivity estimates for the other portfolios.

Column [b] of Table 7 report the estimation results on Portfolio K. Estimations for portfolio K suggest that productivity decreases by 3.2 % in the post-ISO period. It is somewhat puzzling to see that the productivity of the generation portfolio gets worse for zone K while it improves for zone J despite the fact that they are both portrayed as the load pockets. Under NYPP; individual commitment areas dispatched their own units to meet native load in the area and would only be dispatched system-wide to balance the residual load in the pool. Zone J and Zone K operated as individual commitment areas

under NYPP (Tierney and Kahn 2007). After the consolidation of the commitment areas; dispatch function has not changed substantially for Zones J and K due to the binding transmission constraints in contrast to the rest of New York. These zones mostly continued relying on own resources<sup>30</sup> even though these resources may be less efficient compared to those outside the zone and available for dispatch. Moreover, Herfindahl-Hirschmann Index (HHI) which measures the market concentration is 1843 and 6317 respectively for Zones J and K indicating a high potential for market power<sup>31</sup>(NYDPS 2006). To address this problem; NYISO implements market power mitigation since 1998, though the nature of the mitigation differs between these zones. Market power in Zone J is mitigated through strict cost-based caps whereas in Zone K; Long Island Power Authority (LIPA), the major load serving entity in the area, procures power through long-term bilateral contracts<sup>32</sup> (NYDPS 2006). In fact, Zone K load is predominantly met through these long-term contracts and NYISO wholesale market is only relied on to meet the residual load that can not be procured through long-term contracts (*Comments of the LIPA on Case 06-M-1017*). As a result, exposure for zone K to the more efficient dispatch structure of NYISO has been relatively limited than it is for Zone J. This may explain why we observe an improvement in the productivity of portfolio J but not of portfolio K. However, decline in the total productivity in the post-ISO period is harder to explain. Negative coefficient for post-ISO implies that zone K relied on more efficient resources outside the zone less frequently after the ISO formation. We are still

---

<sup>30</sup> This issue is also reflected in our models as we take these constraints into account in creating our portfolios.

<sup>31</sup> According to the Department of Merger Guidelines, an HHI number greater than 1800 indicates a high potential for market power.

<sup>32</sup> Long-term bilateral contract refers to a power purchase agreement between parties and based on ex ante pricing where the sale price of the power is pre-agreed upon and does not change as the real time spot price varies (Ilic, Galiana, and Fink 2003).

investigating the rationale for this outcome however; increase in the severity of Zone K transmission constraints over time might be one possible explanation (FERC 2006). Moreover, increased reliance on long-term contracts might have slowed the development of the competitive markets in Zone K region and hurt competitive incentives. Also, procurement of long term contracts should be non-discriminatory and granted to the least cost-resource (*Comments of Keyspan Corporation on CASE 06-M-1017*). Deviations from the efficient contract design might lead to unfavorable consequences on productivity. Whenever a unit in a given zone is dispatched not because of efficiency per se, but because the transmission lines are congested or there is a long-term contract in effect, its impact on the total productivity of the zone is more likely to be negative. However, we don't have direct evidence whether these potential problems actually arise in Zone K.

Column c of Table 7 reports the estimation results for Portfolio REST. Representing the relatively unconstrained areas of the NYISO; Portfolio REST is associated with 0.7 percent productivity increase. In other words, total generation has increased by 0.7 percent after the formation of NYISO using the same amount of BTUs for output.

Going back to the discussion of true system efficiencies; if we can find the average share of each fuel input in a given portfolio, then we can calculate the weighted unit-level efficiency (weighted by the input shares) of that portfolio reflecting the unit level efficiency changes at the system level. Since we already have the system productivity impact from the ISO formation, the difference between system productivity estimates and the weighted unit-level efficiency numbers would represent the "true system efficiencies".

Our calculations indicate that there are no true system efficiencies for Portfolio REST. As the Portfolio REST represents the zones which have been relatively unconstrained in their transmission possibilities throughout the sample period and no true system efficiencies were achieved after the formation of NYISO, we can argue that the consolidation of the control areas with the formation of NYISO have not made the dispatch superior to that under NYPP.

We find that Portfolio K suffers 2.6 percent true system efficiency loss after the ISO formation. This is to say that even though multiple control areas were consolidated under the NYISO; benefits of this consolidation have not been realized in the form of more efficient allocation of the resources due to the binding transmission constraints and extensive reliance on long term contracts. Notwithstanding the centralized dispatch; Zone K load is most often met with Zone K resources not being able to turn to more efficient power available from elsewhere.

Finally, we find that Portfolio J experiences 2 percent true system efficiency gains after the formation of NYISO. In other words, Zone J utilizes 2 percent less input to produce the same amount of output due to more frequent substitution of more efficient power for less efficient power. We observe true system efficiencies for Zone J despite the fact that the transmission constraints have remained fairly stable during our sample period. This implies that Zone J was successful to take advantage of more efficient resources outside the zone whenever transmission constraints were not binding.

Our system level results indicate that NYISO formation has only been partially effective in improving the allocation of the resources in the region. Even though some type of units has become more efficient in their individual operations, substitution of the

more efficient units for less efficient ones has been relatively limited. Our finding that generation portfolios of unconstrained regions are not associated with true system efficiencies implies that non-centralized dispatch under NYPP was able to mimic the centralized dispatch outcome of NYISO for unconstrained regions.

## **VII. Summary and Conclusion**

This study investigates whether the ISO formation introduced efficiencies to the operations of the generation units and the power system as a whole in New York State. Our expectation has been that unit level efficiencies will arise from the increased competitive pressures induced by the centralized unit commitment and dispatch coordinated by the ISO. Likewise, system level efficiencies are expected as a result of the centralized commitment that gives the system operator opportunity to utilize the load diversity across the whole region and to more often substitute more efficient units for less efficient ones.

Our results reveal that the formation of NYISO and the consolidation of unit commitment areas introduced only limited efficiencies at both unit and the system levels. In the assessment of our results, it is important to keep in mind that the efficiencies due to NYISO formation are estimated relative to another form of coordinated market that existed in the region prior to NYISO. Our results therefore imply that the NYISO market design has not introduced substantial efficiencies over the market design it succeeded. One should also be careful not to generalize our results to other regions with ISO/RTO formations. Potential for efficiency gains arising from centralized commitment and dispatch might be more substantial in regions that did not have any form of a coordinated market prior to the formation of ISO/RTO.

## BIBLIOGRAPHY

Baum C. F., M. E. Schaffer and S. Stillman (2002). "Instrumental Variables and GMM: Estimation and Testing," Boston College Economics Working Paper No: 545.

Borenstein, S., J. B. Bushnell and S. Stoft (2000). "The Competitive Effects of Transmission Capacity in a Deregulated Electricity Industry," *RAND Journal of Economics*, 31 (2):294-325.

Bushnell, J. and C. Wolfram (2005). "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Generation Plants," University of California Energy Institute Working Paper No: 140.

Comments of the Long Island Power Authority (LIPA) on Case 06-M-1017 (2007). [http://www.dps.state.ny.us/06M1017/06M1017\\_LIPA\\_Comments.pdf](http://www.dps.state.ny.us/06M1017/06M1017_LIPA_Comments.pdf).

Comments of Keyspan Corporation on Case 06-M-1017 (2007). [http://www.dps.state.ny.us/06M1017/06M1017\\_Keyspan\\_comments.pdf](http://www.dps.state.ny.us/06M1017/06M1017_Keyspan_comments.pdf).

Douglas, S. (2006). "Measuring Gains from Regional Dispatch: Coal-fired Power Plant Utilization and Market Reforms," *The Energy Journal* 27, (1):119-138.

Energy Information Agency (2000). *The Changing Structure of the Electric Power Industry 2000: An Update*. U.S. Department of Energy, Washington, DC.

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

Fabrizio, K, Nancy Rose, and Catherine Wolfram (2007). "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," *American Economic Review*, 97 (4):1250-1277.

Federal Energy Regulatory Commission (FERC) (2006). *State of the Markets Report*.

Hahn J., and J.Hausman (2002). "Notes on Bias in Estimators for Simultaneous Equation Models," *Economics Letters*, 75 (2002): 237-241.

Joskow, P. L. (1997). "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *The Journal of Economic Perspectives*, 11 (3):119-138.

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

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

Leckey, Beamon J.A. and T.J. (1999). *Issues in Midterm Analysis and Forecasting 1999: Trends in Power Plant Operating Costs*: US Department of Energy, Washington, DC.  
[http://www.eia.doe.gov/oiaf/issues/power\\_plant.html](http://www.eia.doe.gov/oiaf/issues/power_plant.html).

New York State Department of Public Service (NYDPS) (2006). *Staff Report on the State of Competitive Energy Markets: Progress to Date and Future Opportunities*.

New York State Energy Research and Development Authority (NYSERDA) (2005). *Fast Facts* [http://www.nysERDA.org/energy\\_information/Fast%20facts.pdf](http://www.nysERDA.org/energy_information/Fast%20facts.pdf).

Pechman, C. (1993). *Regulating Power: The Economics of Electricity in the Information Age*. Kluwer Academic Publishers, Boston.

Pennsylvania, New Jersey, Maryland Interconnection (PJM) (2002). *Northeast Regional RTO Proposal Analysis of Impact on Spot Energy Prices*.

*Power Systems Restructuring : Engineering and Economics*. (1998). edited by F. G. Ilic M., L.Fink. Boston: Kluwer Academic Publishers.

Reitzes, J. D. and A. N. Kleit (2006). "Estimating the Economic Trade Value of Increased Transmission Capability," *The Electricity Journal*, 19 (2):69-78.

Tierney, S.T. and E. Kahn (2007). *A Cost-benefit Analysis of the New York Independent System Operator: The Initial Years*. Boston: Analysis Group.

United States Department of Energy (DOE) (2005). *The Value of Economic Dispatch*.  
<http://www.oe.energy.gov/DocumentsandMedia/value.pdf>.

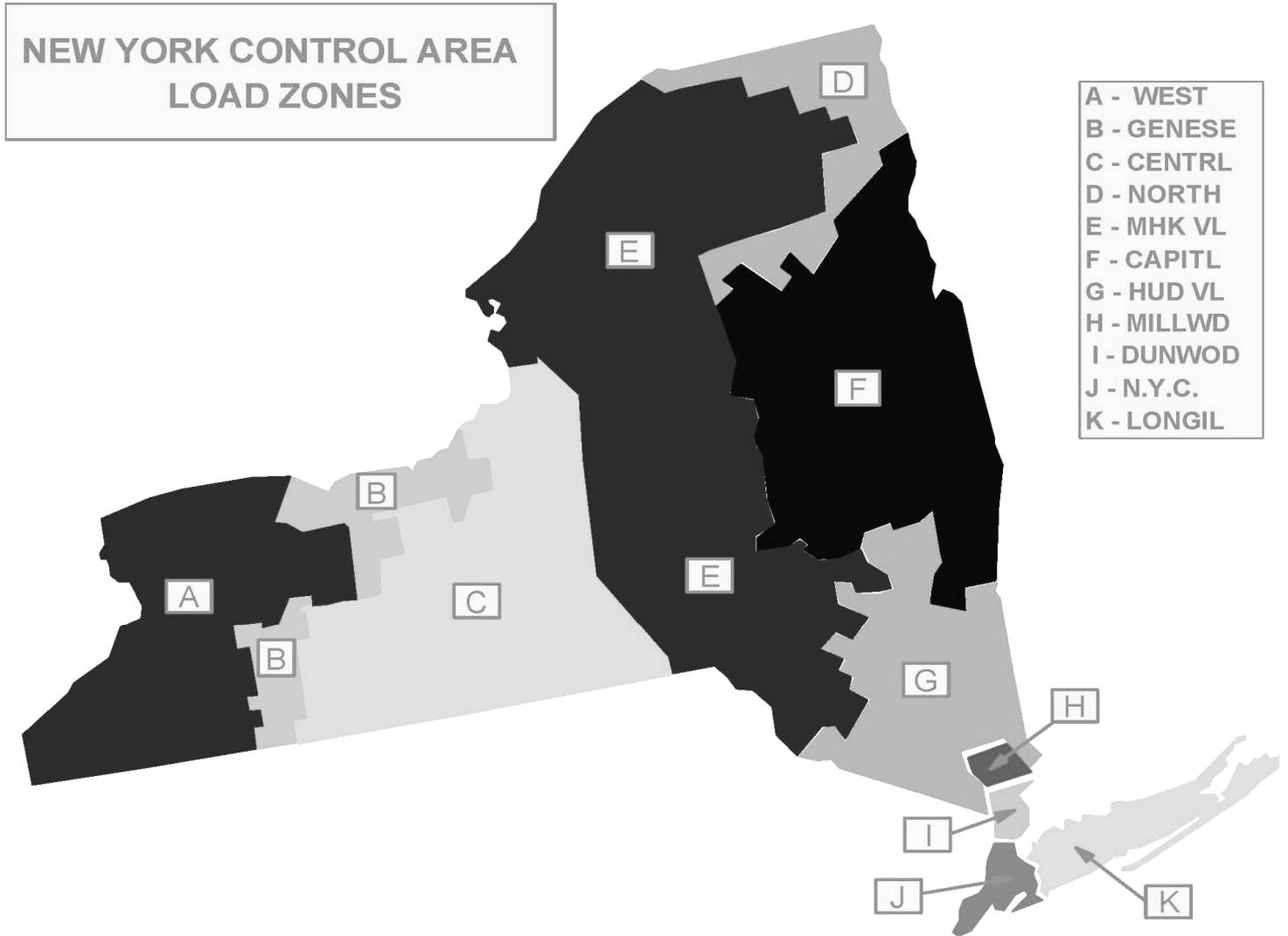
Wolfram, C. (2004). "The Efficiency of Electricity Generation in the U.S. after Restructuring," in *Electricity Deregulation: Where to from Here*, edited by J. Griffin and S. Puller: University of Chicago Press, Chicago.

Wooldridge, J. (2003). *Introductory Econometrics: A Modern Approach*, 2ed: South-Western College Publishing.

**TABLES AND FIGURES**

**Figure 1**

**NYISO Control Area Load Zones**



Source: NYISO

**Table 1: Total Number of Units**

<b>Year</b>	<b>Number of Units Covered by Sample</b>	<b>Number of Units Covered Under EPA's Acid Rain Program</b>	<b>Number of Units Covered Under EIA-906 and EIA-920</b>
1998	78	90	300
1999	195	311	355
2000	260	310	331
2001	269	323	400
2002	282	344	421
2003	288	351	514
2004	287	354	514

*Source* : EIA-906, EIA-920 Forms; EPA CEM data.

**Table 2**

**Fuel Efficiency of COAL Fueled Units in the Post-ISO Period**

<b>Dependent Variable: LN (HEAT_RATE)</b>				
	<b>[a]</b>	<b>[b]</b>	<b>[c]</b>	<b>[d]</b>
	<b>OLS</b>	<b>2SLS</b>	<b>OLS</b>	<b>2SLS</b>
	<b>Unbalanced</b>	<b>Unbalanced</b>	<b>Balanced</b>	<b>Balanced</b>
	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>
LN (OUTPUT)	-0.103** (7.85)	-0.069** (3.48)	-0.104** (6.86)	-0.064** (2.96)
U_to_NU	-0.002 (0.16)	0.01 (0.87)	-0.006 (0.39)	0.005 (0.42)
POST_ISO	-0.033* (2.29)	-0.054** (2.99)	-0.042 (1.74)	-0.051* (2.36)
QTR2	0 (0.07)	0.003 (0.75)	0.001 (0.13)	0.004 (1)
QTR3	0.015* (2.46)	0.012* (2.05)	0.018* (2.58)	0.015* (2.44)
QTR4	-0.004 (0.75)	-0.006 (1.46)	-0.001 (0.18)	-0.003 (0.62)
TREND	0.004 (0.86)	0.004 (0.86)	0.004 (0.83)	0.004 (0.87)
CONSTANT	2.823** (44.26)		2.819** (37.91)	
N	1147331	1146230	936669	935752
Number of unit_id	25	25	18	18
R-squared	0.17	0.17	0.17	0.17
F test of excluded Instruments		82.79		86.89
Prob>F		0.00		0.00
Anderson LR		46176.89		41305.98
Prob>chi		0.00		0.07
Hansen J		2.24		0.85
Prob>chi		0.13		0.36
Endog		2.42		3.24
Prob>chi		0.12		0.08

*Note:*

(1) Robust t statistics in parentheses. (2) Standard errors are clustered by unit and robust to serial correlation. (3) \* indicates significance at 5%; \*\* indicates significance at 1%

(4) Estimated coefficients for hour dummies are suppressed in OLS regressions.

(5) Constant term and hour dummies are partialled out in 2SLS regressions.

**Table 3**

**Fuel Efficiency of GAS Fueled Units in the Post-ISO Period**

<b>Dependent Variable: LN (HEAT_RATE)</b>				
	<b>[a]</b>	<b>[b]</b>	<b>[c]</b>	<b>[d]</b>
	<b>OLS</b>	<b>2SLS</b>	<b>OLS</b>	<b>2SLS</b>
	<b>Unbalanced</b>	<b>Unbalanced</b>	<b>Balanced</b>	<b>Balanced</b>
	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>
LN (OUTPUT)	-0.186** (26.66)	-0.076** (2.72)	-0.163** (13.87)	-0.112** (5.10)
U_to_NU	-0.131** (3.77)	-0.113** (3.19)	-0.139** (3.75)	-0.117** (3.49)
NU_to_NU	-0.049 (1.45)	-0.053 (1.35)	-0.048** (3.71)	-0.033* (2.12)
POST_ISO	0.022 (1.74)	0.023 (1.68)	0.013 (0.71)	0.008 (0.43)
QTR2	-0.003 (0.35)	-0.006 (0.8)	-0.006 (0.82)	-0.003 (0.4)
QTR3	0.001 (0.15)	-0.011 (1.33)	0.01 (1.14)	0.005 (0.51)
QTR4	-0.007 (1.09)	-0.009 (1.49)	0.001 (0.19)	0.003 (0.51)
TREND	-0.008* (2.28)	-0.007 (1.84)	-0.005 (0.98)	-0.004 (0.8)
CONSTANT	3.243** (87.35)		3.209** (49.07)	
N	1613725	1610812	604457	603869
Number of unit_id	162	162	14	14
R-squared	0.39	0.38	0.36	0.36
F test of excluded Instruments		24.28		20.76
Prob>F		0		0
Anderson LR		19195.72		26560.49
Prob>chi		0		0
Hansen J		0.96		1.76
Prob>chi		0.33		0.18
Endog		0.96		2.62
Prob>chi		0		0.10

*Note :*

- (1) Robust t statistics in parentheses. (2) Standard errors are clustered by unit and robust to serial correlation. (3) \* indicates significance at 5%; \*\* indicates significance at 1%
- (4) Estimated coefficients for hour dummies are suppressed in OLS regressions.
- (5) Constant term and hour dummies are partialled out in 2SLS regressions.

**Table 4**

**Fuel Efficiency of NUCLEAR Fueled Units in the Post-ISO Period**

<b>Dependent Variable: LN (HEAT_RATE)</b>				
	<b>[a]</b>	<b>[b]</b>	<b>[c]</b>	<b>[d]</b>
	<b>OLS</b>	<b>2SLS</b>	<b>OLS</b>	<b>2SLS</b>
	<b>Unbalanced</b>	<b>Unbalanced</b>	<b>Balanced</b>	<b>Balanced</b>
	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>
LN (OUTPUT)	0 (0.12)	-0.024* (2.27)	0 (0.12)	-0.024* (2.27)
U_to_NU	-0.003 (0.47)	-0.009 (1.83)	-0.003 (0.47)	-0.009 (1.83)
POST_ISO	-0.005 (1.76)	-0.003 (1.53)	-0.005 (1.76)	-0.003 (1.53)
QTR2	0 (1.74)		0 (1.74)	
QTR3	0 (0.58)		0 (0.58)	
QTR4	0.001 (2.38)		0.001 (2.38)	
TREND	-0.001 (1.15)		-0.001 (1.15)	
CONSTANT	2.343** (232.86)		2.343** (232.86)	
N	326832	326524	326832	326524
Number of unit_id	6	6	6	6
R-squared	0.21	0.20	0.21	0.20
F test of excluded Instruments		6.09		6.09
Prob>F		0.04		0.04
Anderson LR		185		185
Prob>chi		0.00		0.00
Hansen J		1.91		1.91
Prob>chi		0.17		0.17
Endog		0.03		0.03
Prob>chi		0.86		0.86

*Note:*

- (1) Robust t statistics in parentheses. (2) Standard errors are clustered by unit and robust to serial correlation. (3) \* indicates significance at 5%; \*\* indicates significance at 1%  
(4) Estimated coefficients for hour dummies are suppressed in OLS regressions.  
(5) Constant term, hour dummies, quarter dummies and trend are partialled out in 2SLS regressions

**Table 5**

**Fuel Efficiency of PETROLEUM Fueled Units in the Post-ISO Period**

<b>Dependent Variable: LN (HEAT_RATE)</b>				
	<b>[a]</b>	<b>[b]</b>	<b>[c]</b>	<b>[d]</b>
	<b>OLS</b>	<b>2SLS</b>	<b>OLS</b>	<b>2SLS</b>
	<b>Unbalanced</b>	<b>Unbalanced</b>	<b>Balanced</b>	<b>Balanced</b>
	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>	<b>Sample</b>
LN (OUTPUT)	-0.143** (20.55)	-0.109** (8.18)	-0.157** (24.09)	-0.103** (7.24)
U_to_NU	0.03 (1.65)	0.035 (1.87)	0.041 (1.27)	0.043* (2.40)
NU_to_NU	0.002 (0.07)	0.024 (0.81)	0.001 (0.02)	0.037 (1.230)
POST_ISO	-0.018 (1.75)	0.019 (1.85)	-0.025 (1.94)	0.027* (2.12)
QTR2	0.004 (0.48)	0.001 (0.09)	0.004 (0.57)	0.004 (0.51)
QTR3	0.01 (1.31)	0.004 (0.59)	0.014 (1.73)	0.007 (1.06)
QTR4	-0.006 (0.87)	-0.009 (1.35)	-0.006 (1.41)	-0.007 (1.5)
TREND	-0.014** (3.98)	-0.015** (4.37)	-0.016** (3.65)	-0.019** (4.43)
CONSTANT	3.202** (88.28)		3.309** (79.80)	
N	561624	560542	400403	399981
Number of unit_id	70	70	11	11
R-squared	0.31		0.31	
F test of excluded Instruments		96.2		322.3
Prob>F		0.00		0.00
Anderson LR		31717.6		35685.91
Prob>chi		0		0
Hansen J		1.39		2.58
Prob>chi		0.24		0.06
Endog		2.63		3.64
Prob>chi		0.1		0.11

*Note :*

- (1) Robust t statistics in parentheses. (2) Standard errors are clustered by unit and robust to serial correlation. (3) \* indicates significance at 5%; \*\* indicates significance at 1%
- (4) Estimated coefficients for hour dummies are suppressed.
- (4) Estimated coefficients for hour dummies are suppressed in OLS regressions.
- (5) Constant term and hour dummies are partialled out in 2SLS regressions.

**Table 6**

**Tests for Instrument Quality and Choice between OLS and 2SLS**

	COAL	GAS	PETROLEUM	NUCLEAR
<b>Relevance of Instruments</b>				
<i>i- F-test of Excluded Instruments</i>				
H0: Instrumenst are jointly insignificant	Prob > F= 0.0000	Prob > F= 0.0000	Prob > F= 0.0000	Prob > F= 0.04
<u>Conclusion of the test:</u>	Reject H0	Reject H0	Reject H0	Reject H0
<i>ii- Anderson Canonical Correlations Test</i>				
H0: Equation is not identified	Prob > chi= 0.0000	Prob > chi= 0.0000	Prob > chi= 0.0000	Prob > chi=0.0000
<u>Conclusion of the test:</u>	Reject H0	Reject H0	Reject H0	Reject H0
<b>Validity of Instruments</b>				
<i>i- Hansen J /Overidentification Test</i>				
H0: Instrumenst are uncorrelated with the error term	Prob > chi= 0.13	Prob > chi= 0.32	Prob > chi= 0.24	Prob > chi= 0.17
<u>Conclusion of the test:</u>	Do Not Reject H0	Do Not Reject H0	Do Not Reject H0	Do Not Reject H0
<b>Endogeneity of the Instrumented Variable</b>				
<i>i- Endogeneity Test</i>				
H0: Endogenous variable can be specified as exogenous	Prob > chi= 0.12	Prob > chi= 0.96	Prob > chi= 0.10	Prob > chi= 0.86
<u>Conclusion of the test:</u>	Do Not Reject H0	Do Not Reject H0	Do Not Reject H0	Do Not Reject H0
<b>2SLS or OLS ?</b>	OLS	OLS	OLS	OLS

**Table 7****System Level Productivity Analysis of Generation Portfolios**

<b>Dependent Variable: LN (TOTAL_MWH)</b>			
	<b>[a]</b>	<b>[b]</b>	<b>[c]</b>
	<b>Portfolio J</b>	<b>Portfolio K</b>	<b>Portfolio REST</b>
LN (TOTAL_BTU)	1.06** (373.54)	1.05** (526.72)	0.966** (451.35)
POST_ISO	0.017** (3.71)	-0.032** (14.98)	0.007** (5.02)
QTR2	-0.003 (0.76)	-0.012** (5.12)	-0.004** (2.99)
QTR3	-0.039** (9.78)	-0.019** (9.43)	-0.004** (2.65)
QTR4	0.003 (0.94)	0.001 (0.43)	0.004** (4.01)
TREND	0.005** (4.54)	0.011** (19.05)	0.005** (16.10)
CONSTANT	-3.085** (118.86)	-2.845** (155.18)	-1.978** (81.62)
N	61368	61368	61368
R-squared	0.96	0.98	0.97
Durbin-Watson	1.98	2.05	2.23

*Note :*

(1) Robust t statistics in parentheses. (2) \* indicates significance at 5%; \*\* indicates significance at 1%

(3) Estimated coefficients for hour dummies are suppressed

## **CHAPTER 3**

### **Electric Utility Mergers: Who Merges with Whom?**

## **I. Introduction**

Mergers, being a fundamental feature of modern market economies, have gained even more importance through the decades. Starting from 1980s, the value of U.S. mergers and acquisitions in the peak years of each decade equaled about one-fourth of gross national product (Trimath, 2002). The importance of mergers for the economy has spurred tremendous research efforts for unveiling the motives and impacts of mergers. Researchers in economics and finance have proposed several categories of explanations to the question why firms merge. One of the most fundamental motives that have emerged from this research is synergistic gains through mergers. Synergistic gains may realize in the form of cost efficiencies or revenue enhancements. Another important drive for mergers is acquiring market power through horizontal integration. Horizontal mergers increase market concentration and market power of the firm which in turn leads to higher profits. Economic disturbances, growth through mergers, avoiding uncertainty through vertical integration, and managerial motives can be listed as other important drivers alluring firms into the mergers.

As much as it is important to have a concrete understanding of the potential drivers of the mergers, it is also important to know which of these explanations better characterize the mergers taking place in a specific industry. This chapter will try to shed light on this less explored issue in the context of the mergers that have been consummated in U.S. electric power industry. More specifically, I plan to address two related questions: What are the characteristics of electric utilities that affect the likelihood of their involvement in a merger as an acquirer or a target? What characteristics of particular pairs of utilities affect the likelihood of the pair engaging in a merger? Despite

the voluminous research carried on in electric power industry in the past forty years; merger studies, especially descriptive studies of this nature is too few. This study aims to contribute to our knowledge of mergers in the context of electric power industry focusing on a large number of electric utility mergers consummated between 1992 and 2004.

However, information unveiled by this study is not exempt from several limitations. First of all, the literature is too vast to be able to test all possible firm characteristics, and thereby the merger motives. We therefore restrict ourselves to testing those characteristic and motives that are mostly agreed-upon in the literature. Secondly, we only have imperfect measures or proxies for testing the implications of some variables. Such results should be interpreted with caution. Finally, while it is possible to test some hypotheses directly, some others can only be inferred from the collection of results.

Chapter 3 starts with a discussion of the literature on merger motives. A master data set, subsections of which are utilized to answer the two main questions of the chapter, is described next. These two questions, despite being interrelated and complementary, rely on different data sets and analysis techniques. For that matter, following the discussion of the master dataset, each question is examined in its entirety including the descriptions of the data sets and analysis techniques used as well as the results of the analysis. The conclusion section summarizes the findings of the chapter and concludes.

## II. Merger Motives: What does the literature say?

The motives that inspire mergers have been extensively researched in the literature<sup>37</sup>. One of the most fundamental motives that have emerged from this research is *synergistic gains* through mergers. Synergies refer to the operational efficiencies that arise from the combination of two or more separate companies into a single company and may realize in the form of revenue enhancements or cost reductions. Revenue enhancements may arise from access to new marketing opportunities or extended distribution channels after the merger of separate companies. Cost reductions are generally portrayed as the biggest source of synergies which typically originate from elimination of duplicate operations, achieving economies of scale, and increased specialization through mergers. McGuckin and Nyugen (1995) find that ownership change is associated with the transfer of high productivity plants and conclude that synergies are important motives for ownership changes in their study of food manufacturing industry. Even though synergies are often portrayed as the main motivator for mergers, they are generally difficult to realize in practice. Incomplete integration of the parties - both culturally and operationally- often times impede the emergence of potential synergies.

Another commonly cited motivation for mergers is seeking *market power* through horizontal integration. Merger of two firms that operate in the same line of business increases their combined market share and thereby increases their market power. However, due to strict antitrust supervision, firms only rarely merge to increase their

---

<sup>37</sup> A detailed discussion of merger motives can be found in Gaughan (2002) and Perry (1989).

market power ruling it out as a significant motive for mergers. *Avoiding uncertainty through vertical integration* is another important motivation for mergers. A downstream firm may merge with its upstream supplier in order to secure its input supply or reduce transaction costs in the procurement of inputs. In this case, combined firm may gain a competitive advantage over its rivals who will still need to incur these input related transaction costs. Moreover, some production processes may require a specialized input that is only available from a limited number of suppliers. In these cases, producer may acquire its supplier to avoid the hold-up problem and guarantee an uninterrupted production cycle.

In addition to the merger motives discussed above; a review of the merger literature reveals a number of hypotheses that make firms more likely to be involved in mergers as acquirers or targets. First part of this chapter will test several of these hypotheses in the context of U.S. electric power industry and examine whether certain characteristics of acquirers and targets are significantly different from the non-merging firms. We shall now review these hypotheses in turn:

*Inefficient Management Hypothesis* implies that mergers serve as means to replace inefficient managements of poor performing firms and that these poor performers are more likely to be targets of mergers. An inefficient management that fails to maximize the market value of a firm makes it less costly for outsiders to gain control. In this case it is more likely that this inefficiently managed firm will be taken over by an outsider that can better manage target's resources. This mechanism is also known as the *Market for Corporate Control* which refers to the market for the right to manage company resources (Jarrell, Brickley, and Netter 1988). Singh (1975) finds a significant

degree of stock-market discipline for unprofitable firms. He also finds that increasing the profitability may be an inferior survival strategy compared to increasing the size to avoid becoming a target. Contrary to these findings; Kwoka and Pollitt (2007) show that acquirers are poor performers prior to the merger and buy better performing targets in their analysis of a sample of U.S. electric distribution companies.

*Economic Disturbance Theory of Mergers* was first proposed by Gort (1969). He argued that mergers stem from valuation differences between buyers and sellers that are set off by economic disturbances such as sudden changes in technology and regulatory framework. Likewise, firms often reposition themselves to more effectively deal with the uncertainty and risks associated with a given disturbance in an industry. Mitchell and Mulherin (1996) show that deregulation, price shocks, and foreign competition stand as major drivers of the takeover activity in the 1980s. In their cross-industry study; Andrade, Mitchell, and Stafford (2001) show that deregulation has motivated a significant portion of merger activity after the late 1980s and accounted for the half of the merger activity since then. Jensen (1986), Morck, Shleifer and Vishny (1988), and Jensen (1993) provides evidence for the economic disturbance theory of mergers. Cooke and Chapple (2000) look at the mergers in UK's waste disposal industry and estimate the degree to which increased regulations has lead to a rise in merger activity. They find that regulation increases the likelihood of being involved in a merger either as an acquirer or a target firm.

*Growth-Resource Mismatch Hypothesis* was first raised by Palepu (1986) who argued that firms with a mismatch between their resources and growth potentials are likely targets. One such target is low-growth, high-resource firms. These firms have the

needed financial resources (i.e. high-liquidity, low-leverage) in place, but they grow at a very slow pace and don't take the full advantage of the resources at their disposal. This situation makes them very attractive targets for other firms that have the necessary growth potential but missing the very much needed resources. Likewise, high-growth, low-resource firms are potential targets for those firms that have the resources in place but missing the growth potential (i.e. skilled labor, industry knowledge, learning by doing etc.) that will trigger the expansion of the firm. Palepu (1986) finds that firms with growth-resource imbalances are more likely to be takeover targets. He also individually tests the components of the mismatch hypothesis in order to identify which imbalance matters more to the takeover likelihood. He finds that while growth and leverage are significant and negatively associated with the acquisition likelihood, liquidity has an insignificant impact. Harris, Stewart, Guilkey, and Carlton (1982) find that high liquidity and low leverage increases the likelihood of acquisition in his study of mergers during 1974-1979 periods. Contrary to Palepu (1986) and Harris et al. (1982); Espahbodi and Espahbodi (2003) find that high leverage firms are more likely to be targets.

However, in some cases, relying on internal growth dynamics may not be feasible even if a firm has the necessary resources and grows at a reasonable pace. One such instance is the emergence of a short-lived opportunity that the firm can only take advantage of if it is of a certain size. In this situation firm cannot rely on internal growth since in the meantime competitors may act to seize this opportunity. Therefore only remaining growth solution is to acquire another company that has the required resources

in place and will provide the needed scale to take advantage of these opportunities<sup>38</sup>(Gaughan 2002).

*Size Hypothesis* suggests that small firms are more likely to be targets of mergers. As Palepu (1986) argues mergers are associated with several transaction costs most of which are related to the size of the merging parties. Small firms are more attractive targets since they tend to be much easier to integrate into the acquirer's organizational scheme. Singh (1971) and Meeks (1977) both find that size rather than profitability plays a major role in defining characteristics of takeover targets in U.K. manufacturing industry. Also, as argued in Gorton, Kahl and Rosen (2005), smaller firms are easier to finance while it is much difficult to raise funds for a large acquisition by issuing debt. Moreover, potential cultural clash between organizations are avoided to a large extent since small firms generally blend much better with the larger acquirer. Singh (1975) argues that the large unprofitable firms have incentives to increase their relative size rather than improving their profitability to avoid the take-over threat. He also suggests that a large firm can more readily acquire a smaller one than vice versa due to imperfect capital markets. Evidence in Palepu (1986), Hasbrouck (1985), Mikkelson and Partch (1989), and Song and Walkling (1993) suggest that smaller firms are indeed more likely to be targets.

It is important to identify certain characteristics of firms that make them more or less likely to be acquirers and targets. There is a vast literature seeking to answer this question although majority of these studies are cross-industry studies and may suffer from imprecision resulting from pooling different industries and their idiosyncrasies'

---

<sup>38</sup> As is stated in Andrade, Mitchell, and Stafford (2001), mergers often enable a firm to double its size in a matter of months.

together. In the first part of this study, I reexamine this much explored question focusing on a specific industry that has seen an extensive merger activity.

Second part of my study investigates a relatively less explored question of what determines the pairing decisions of firms in mergers. As the merger is a combination of two firms; analyzing both parties and interaction of their characteristics may help unveil motives that can not be detected by one-sided study designs. As is very well stated in Harris et al. (1982, 164):

“...Clearly certain characteristics make firms more attractive as merger partners. Unfortunately, empirical studies of such acquired firm characteristics do not yield a clear picture of factors leading to a takeover. The problem is confounded by the fact that a merger involves two firms simultaneously; thus there may be no single true effect of a firm’s characteristics on the probability of its being acquired. Specific characteristics (e.g. size) of a firm may have quite different effects on its desirability as merger partner, depending upon the characteristics and need of the other firm contemplating the merger. That is, beauty is in the eye of the beholder...”

An analysis of the sort Harris et al. (1992) calls for is undertaken in Brooks and Jones (1997). They examine a sample of hospital mergers and determine what characteristics of the particular hospitals and particular pairs of hospitals affect the likelihood of merger. They conclude that hospital mergers are mostly driven by the existence of specific merger opportunities in local hospital markets. Market overlap, relative performances and ownership characteristics are positively associated with the likelihood that a pair of hospitals will merge. Harrison (2006) also examines a sample of hospital mergers and finds that ownership status is the dominant determinant of merger pairs. In addition, hospitals are more likely to merge with a partner of similar size and close geographical proximity. In the second part of my analysis, I follow the methodologies employed in the Brooks and Jones (1997) and Harrison (2006) papers as I

ask and seek answers to the questions posed in these papers in the context of electric utility mergers.

### **III. Data**

This chapter employs a data set consisting of the operational and financial characteristics of 193 U.S. investor owned electric utilities (IOUs) for the period 1992 through 2004. Data are compiled from the utilities' Form-1 filings to FERC. List of electric utility mergers consummated between 1992 and 2004 is taken from a compilation of Edison Electric Institute, an industry trade association. The list includes information on the identity of the merging firms, merger announcement and completion dates, terms of the transaction, and type of the merger (i.e., merger involving two electric utilities; merger involving a gas utility and an electric utility, etc.). This study is restricted to the mergers between electric utilities and more specifically between IOUs. Within my sample period (1992-2004), 43 out of 80 completed electric utility mergers can be characterized as electric-electric IOU mergers<sup>39</sup>. Rest of the completed mergers involves parties that are pure gas utilities or independent power producers which are excluded from the study due to data limitations.

As mentioned before, the analysis in this chapter consists of two parts. We will introduce data and methodology, and results sections separately for each part of the analysis in the following.

---

<sup>39</sup> We should note that the utility mergers that were consummated during the time frame of our analysis were generally undertaken by the holding companies that control the utility subsidiaries. In those cases, our implicit assumption is that an operating subsidiary of a holding company accurately represents the financial health and other characteristics of the holding company that undertakes the merger.

## IV. Part 1- Data, Methodology, and Results

### A. DATA AND METHODOLOGY

First part of my analysis employs the data on 193 IOUs in my sample. Of these 193; 32 utilities are acquirers, 49<sup>40</sup> are targets, and 112 are non-merging firms during the study sample period. Palepu (1986) discusses an estimation bias due to state-based sampling that refers to sampling equal number of acquirers, targets, and non-merging firms. Although state-based sampling can be characterized as more efficient over random sampling; using state-based samples with estimators that assume random-sampling may lead to serious estimation problems. Palepu suggests modifications to the maximum likelihood estimator to account for the inconsistency between the model assumptions and sample selection. However, there are other ways to avoid this bias. Ohlson (1980) uses entire population of banks to estimate his bankruptcy model. Harris et al. (1982) employ a sample design that reflects the composition of the population in terms of the target, acquired, and non-merging firms. Following Harris et al. (1982) our sample is a proper representative of the underlying population<sup>41</sup>.

It is important to note that the estimations are carried on a cross-sectional dataset which is created by averaging the data in all 13 years for non-merging firms while averaging in only the pre-merger years<sup>42</sup> for targets and acquirers. This routine produces a single value for each variable which reflects the historical characteristics or

---

<sup>40</sup> It may seem somewhat puzzling that there are 49 targets while there is a total of 43 mergers during the sample period. Divergence can be explained by the fact that we employ the information on subsidiaries and in some cases a utility may have more than one subsidiary involved in the merger.

<sup>41</sup> According to APPA (2005), there are 219 IOUs operating as of 2005. Using this number and number of IOU mergers in our sample; composition of the population is 61% non-merging, 20% target, and 20% acquirer firms. These numbers are respectively 58%, 17%, and 25% for our sample.

<sup>42</sup> In this study we use all available pre-merger years for purposes of averaging the data. Different studies adopt different rules. For instance, Palepu (1986) takes the average over 3 pre-merger years.

performance for a given utility. This is reasonable in the sense that financial analyses performed by firms contemplating a merger incorporate firms' historical performances as well as projections of their business accounts into the future. These valuations are mostly based on average historical performance and rarely draw on individual years<sup>43</sup>.

In the first part of the study, I utilize a multinomial logit analysis to determine the certain characteristic of the firms that affect their likelihood of being involved in a merger as an acquirer or target (compared to non-merging firms). Multinomial logit model is based on random utility model where utility from each alternative in the choice set is expressed as a function of characteristics of the choice maker, of the alternatives, and an error term ( $\varepsilon$ ) (Kennedy 2003). Probability that an alternative will be chosen is determined by the probability that its utility is greater than that of the other alternative. This relationship between utility and the likelihood and the density function of the error term are then used to derive the log-likelihood function which is later maximized to estimate the parameters of the multinomial logit model. Random utility model error terms are assumed to be independently and identically distributed with extreme value distribution.

Another assumption of the multinomial logit model is the "Independence of Irrelevant Alternatives (IIA)". If this assumption holds, adding a new alternative to the choice set or dropping alternatives does not affect the odds of the alternatives that were originally included in the choice set. Violation of the IIA assumption leads to erroneous results from the estimation of multinomial logit model. We test and confirm the validity

---

<sup>43</sup> The caveat is that there are different numbers of pre-merger years, depending on when the merger occurred. This may introduce some biases to the extent that utilities' characteristics substantially vary over the relevant years absent the merger activity. However, there is no obvious reason why pre-merger or non-merging firm characteristics would substantially differ over the relevant years

of IIA assumption for our multinomial logit models using the Hausman Test, as presented in Table 2. In cases where IIA is violated, multinomial probit model may emerge as an alternative (as it doesn't require IIA) with the caveat that it is computationally intensive. It is also important to note that when multinomial dependent variable has an ordinal structure, ordered logit model may be econometrically more efficient. Our dependent variable doesn't have a natural ordering, and therefore doesn't call for an ordered logit model.

A multinomial logit model with a dependent variable taking on K values is actually a system of equations with K parameter vectors. However, for this system to be identifiable and produce a unique solution of the probabilities, only K-1 parameter vectors are required. In this case, one value is assigned to be the reference group and its parameter vector is set to zero. General model for K values can be expressed as follows where the parameters for the first of the K values are set to zero:

$$\ln\left(\frac{\Pr(Y = k)}{\Pr(Y = 1)}\right) = \alpha_k * X = Z_k \quad \text{where} \quad k=1,2,\dots,K. \quad (1)$$

$Z_k$  is called the log odd-ratio and refers to the log of the probability of k relative to a reference group (in this case 1).  $X$  is a vector of explanatory variables and  $\alpha_k$  is a vector of parameters. It is possible to calculate the predicted probabilities from log odd-ratios as follows:

$$\Pr(Y = k) = \frac{e^{Z_k}}{1 + \sum_{i=2}^K e^{Z_i}}$$

In our model, dependent variable takes three different values; 1, 2, or 0 depending on whether the utility i is respectively an acquirer, a target or a non-merging firm during

our sample period. Probabilities can be written as follows for our 3 choice multinomial logit model:

$$\Pr(Y = 0) = e^{\alpha_0 X} / e^{\alpha_0 X} + e^{\alpha_1 X} + e^{\alpha_2 X} = 1 / 1 + e^{\alpha_1 X} + e^{\alpha_2 X}$$

$$\Pr(Y = 1) = e^{\alpha_1 X} / e^{\alpha_0 X} + e^{\alpha_1 X} + e^{\alpha_2 X} = e^{\alpha_1 X} / 1 + e^{\alpha_1 X} + e^{\alpha_2 X}$$

$$\Pr(Y = 2) = e^{\alpha_2 X} / e^{\alpha_0 X} + e^{\alpha_1 X} + e^{\alpha_2 X} = e^{\alpha_2 X} / 1 + e^{\alpha_1 X} + e^{\alpha_2 X}$$

We select non-merging firms (0) as our reference group and therefore probabilities of being an acquirer or a target firm are defined relative to this group:

$$\Pr(Y = 1) / \Pr(Y = 0) = e^{\alpha_1 X} = e^{Z_1}$$

$$\Pr(Y = 2) / \Pr(Y = 0) = e^{\alpha_2 X} = e^{Z_2}$$

We can write the log-likelihood function for our model as follows:

$$\ln L = \sum_{i=1}^{193} \sum_{k=0}^2 d_{ik} \ln \Pr ob(Y_i = k) \quad \text{where} \quad k=0, 1, 2 \text{ and } i=1, \dots, 193$$

$d_{ik}$  takes the value of 1 if utility  $i$  chooses alternative  $k$ , and zero for all other outcomes.  $X$  includes explanatory variables based on the merger hypotheses widely accepted in the literature as well as certain characteristics of electric utilities which are thought to impact merger motives. We shall discuss the merger hypotheses tested in our model, the variables representing them and the expected signs for the variables in detail below:

1. According to the *disturbance theory of mergers*, economic shocks or innovations within an industry may create environments which are conducive to mergers. Restructuring of an industry is considered a shock since the operations as well as the rules governing the operations may change during this transformation. Electric power industry has been subject to massive and continuous restructuring in the past fifteen

years which span the entirety of our sample period. This restructuring movement was by no means homogenous across the country and showed significant differences among different states in terms of the timing and the nature of the changes. Nevertheless, several innovations during our sample period have widely impacted the electric power industry and had the potential to alter utility behaviors. In April 1996, FERC issued Order 888<sup>44</sup> which effectively introduced competition in the generation market by ordering all vertically integrated IOUs implement universal access to their transmission systems. Moreover, in December 1996, FERC instituted its new merger policy statement that was aimed at clarifying and expediting the commission's analysis of the mergers.<sup>45</sup> We capture the impact of these innovations on the merger likelihood with **SHOCK** dummy that takes the value of 1 for all years between 1997<sup>46</sup> and 2004. We expect that SHOCK will be positively associated with both of likelihoods of being an acquirer or a target.<sup>47</sup> One possible reason is that restructuring may create new business opportunities which could be better seized with joining forces with another company via sharing potential risks and the synergies. Another

---

<sup>44</sup> Energy Policy Act of 1992 was the first to call for open access to the transmission lines and introduce the competition from non-utility generators. However, competition was only slowly developing and discriminatory practices were very common until FERC ordered vertically integrated IOUs to file open access transmission tariff that provides universal access to the grid by all users (EIA 2000).

<sup>45</sup> FERC summarizes the purpose of the 1996 Merger Policy Statement along the following lines: "The Federal Energy Regulatory Commission (Commission) is amending its regulations to update and clarify the Commission's procedures, criteria and policies concerning public utility mergers in light of dramatic and continuing changes in the electric power industry and the regulation of that industry. The purpose of this Policy Statement is to ensure that mergers are consistent with the public interest and to provide greater certainty and expedition in the Commission's analysis of merger applications." (FERC Order No. 592, Docket No. RM96-6-000)

<sup>46</sup> 1997 is the first full calendar year after the issuance of 1996 Merger Policy Statement and Order 888.

<sup>47</sup> In December 1999, FERC issued another order, Order 2000, to encourage all transmission owners to join regional transmission organizations (RTOs) and address the potential discrimination problems in accessing the transmission grid. We tested impact of this innovation with an additional shock dummy that takes the value 1 for all years between 2000 and 2004. The resulting coefficient was not statistically significant.

- reason for this expectation is the implications of the new merger policy that have made the merger process progress more transparently and swiftly.
2. According to *size hypothesis* for mergers, large firms are less likely to be targets of the mergers. As Palepu (1986) argues, acquiring a large firm rather than a small firm generates more transaction costs for a given acquirer. We introduce the dummy variable **LARGE** to test this hypothesis in the context of electric mergers. **LARGE** takes the value 1 if total sales (MWHs) and net book value of assets are greater than the corresponding 75<sup>th</sup> percentiles and 0 otherwise. We expect that **LARGE** will be negatively associated with the probability of being a target while we don't have an a priori on the association between being an acquirer and **LARGE**.
  3. *Inefficient Management Hypothesis* implies that more efficient firms acquire other firms to spread their efficient management skills. We employ the variable **OPERATING-MARGIN** which represents the profitability<sup>48</sup> of a firm. Operating margin is defined as the ratio of net operating income divided by the net revenues and reflects the operating efficiency of a firm. In other words, it measures how much revenue is left over after paying the variable costs of production. A high operating margin implies that the resources of the firm are being efficiently used in generating revenue. **OPERATING-MARGIN** is expected to be positively (negatively) associated with the likelihood of being an acquirer (a target).

---

<sup>48</sup> Accounting profitability measures are widely used in the literature to proxy for the management efficiency. (i.e. Ravenscraft and Scherer 1989, Matsusaka 1993, etc. ) Palepu (1986) uses excess return on a firm's stock as an alternative to accounting profitability measures. Calculation of this variable requires stock return data which were not available to us.

4. *Growth-Resource Mismatch Hypothesis* implies that firms with imbalance between their finances and growth potentials are more likely to be targets<sup>49</sup>. Following the practice in the literature, availability of finances is measured by the degree of liquidity and the leverage<sup>50</sup> while growth potential is measured by the growth rate of sales. We look into two separate models that only differ in terms how the growth and financial ease variables are introduced to the models:

- a. In the first model; following Palepu (1986), we introduce a dummy variable **GROWTH-RESOURCE** which takes the value of 1 for the combinations (low leverage-high liquidity-low growth) or (high leverage-low liquidity-high growth), and 0 for any other combination. For each of the leverage, liquidity or growth variables; a dummy variable named LOW- <variable> is created and assigned the value 1 if it is smaller than or equal to the 25<sup>th</sup> percentile. In the same fashion, a HIGH- <variable> is created for each of these variables and assigned the value 1 if it is greater than or equal to the 75<sup>th</sup> percentile. **GROWTH-RESOURCE** is expected to have a positive relationship with the probability of being a target. We don't have a priori expectation about the association of this variable with the probability of being an acquirer. We also introduce **GROWTH**, **LIQUIDITY**, and **LEVERAGE** variables independently to the same model to determine whether they have additional effects on the likelihood of being an acquirer or a target as well as to identify the direction of these effects if they are determined to exist.

---

<sup>49</sup> This hypothesis should not be confused with the mismatch in cultures and goals of merger partners that in turn may lead to unconsummated mergers.

<sup>50</sup> Liquidity is the ratio of net liquid assets divided by total assets while leverage is defined as the ratio of debt to equity.

- b. In the second model, we introduce **HIGH-GROWTH**, **HIGH-LIQUIDITY**, and **LOW-LEVERAGE** dummy variables. This model is estimated as an alternative to the growth-mismatch imbalance hypothesis and tests whether growth, liquidity, and leverage are standalone determinants of the merger likelihood. **HIGH-GROWTH** is expected to be positively related to the likelihood of being a target as firms with high growth potentials are more attractive candidates for mergers. It is expected to be negatively associated with the likelihood of being an acquirer since firms may seek merger opportunities and look for targets when they exhaust their internal growth potential. **HIGH-LIQUIDITY** is expected to be positively related to the likelihood of being a target since the firms become more attractive for acquisitions when some of the acquisition costs can be internally met reducing the need for outside finance (Song and Walkling 1993). **LOW-LEVERAGE** is expected to be positively related to the likelihood of being a target as mergers involving low leverage firms are less costly to finance (Espahbodi and Espahbodi, 2003).

Both models incorporate **NEG-GROWTH** dummy variable that takes on the value of 1 if growth rate of sales is negative. We expect that negative growth will be negatively associated with both likelihoods of being an acquirer or a target as contracting firms are less attractive candidates for mergers. We also introduce **VERTICAL-INTEGRATION** variable to the models which is defined as the ratio of net generation to the total sales. We expect that the more integrated firms will be more likely acquirers

seeking to expand their operations further while less integrated firms will be more likely targets due to their ease of integration to the acquirer's system.

## B. RESULTS

Table 1 reports multinomial logit estimation results from two alternative models. Model 1 introduces the growth and resource availability variables in categorical forms while model 2 replaces these with continuous variables as well as introducing growth-mismatch variable to the analysis. Model 1 estimation results are presented in columns [a] and [b]. SHOCK variable is significant at 1% level and positively associated with both likelihoods of being an acquirer or a target in electric utility mergers. In other words, a firm is more likely to engage in a merger after the industry disturbance as an acquirer or a target firm than to remain as a non-merging firm. This is in line with our expectations and the literature presents substantial amount of evidence that industry disturbances motivate merger activity. Palepu (1986) finds a significant and negative association between an industry shock and likelihood of being a target, and considers his finding to be inconsistent. LARGE variable is insignificant for acquirer likelihood estimation, but it is significant at 1% level and negative for target likelihood estimation. This indicates that while a large firm is less likely to be a target than a non-merging firm confirming our expectations; being a large firm doesn't increase or decrease the likelihood of being an acquirer than a non-merging firm in the context of electric utility mergers.

We introduce two dummy variables to capture the growth related effects. First of these; NEGATIVE-GROWTH variable is negative and significant at 1 % and 5% levels respectively for acquirer and target estimations. This indicates that contracting firms are

less likely to engage in mergers as acquirers or targets than to remain as non-merging firms. This finding is intuitive in the sense that contracting firms are neither attractive targets nor are they successful candidates for acquirers as the contraction may signal problems related to the operations of the firm. In cases where the contraction is in fact a business strategy; merger doesn't stand as a viable option since mergers commonly serve as means of expansion. HIGH-GROWTH is significant at 5% level and positively related to the likelihood of being a target indicating that firms with high growth potentials are more preferred targets for mergers. This finding is in contrast to Palepu (1986) and Espahbodi and Espahbodi (2003) that find that low growth firms are more likely to be targets. We don't find a significant relationship between HIGH-GROWTH and likelihood of being an acquirer indicating that high-growth firms are not more likely to be acquirers than the non-merging firms.

HIGH-LIQUIDITY and LOW-LEVERAGE variables are both insignificant in explaining the likelihoods of being an acquirer or a target firm than to remain as a non-merging firm. This implies that a firm's debt position and internal finance possibilities do not play significant roles in explaining electric utility mergers. OPERATING-MARGIN is significant at 5% level and positively related to the likelihood of being an acquirer. This finding is in agreement with inefficient management hypothesis that conveys that more efficient firms are more likely to acquire others. VERTICAL-INTEGRATION is significant in neither of the acquirer or the target likelihood estimations. This implies that the degree of integration does not play a role in motivating firms or making them more attractive for mergers in the context of electric power industry.

Model 2 estimations are presented in columns [c] and [d]. In this model, we introduce GROWTH-RESOURCE dummy variable to test the growth-resource mismatch hypothesis in the context of electric utility mergers. We also replace HIGH-LIQUIDITY, LOW-LEVERAGE, and HIGH-GROWTH dummy variables with continuous variables LIQUIDITY, LEVERAGE, and GROWTH. We find that GROWTH-RESOURCE variable is not significant indicating that the growth-resource mismatch hypothesis doesn't hold for electric utility mergers. Moreover, neither of LIQUIDITY, LEVERAGE, and GROWTH variables is significant in explaining the likelihood of being an acquirer or a target. Rest of the variables in this model has the same signs and significance levels with their alikes in Model 1.

Our multinomial-logit estimations provide support for disturbance theory of mergers, size hypothesis, and inefficient management hypothesis in the context of electric-electric mergers. Neither growth-resource mismatch hypothesis nor the liquidity and leverage variables explain the likelihoods of being an acquirer or a target. We find evidence for the high-growth variable however only for explaining the likelihood of being a target.

## **V. Part 2- Data, Methodology, and Results**

### **A. DATA AND METHODOLOGY**

Second part of the analysis explores the factors that determine the likelihood of matching between two IOUs to realize a merger. As the question involves matching; this requires us to have both IOUs in our sample that are parties to a merger. Moreover, we include withdrawn mergers to the analysis as well as the completed mergers since our

goal is to identify the factors that bring two parties together with the intention of a merger regardless of whether the merger is eventually consummated or not<sup>51</sup>. During our analysis period; there are 12 completed and 15 withdrawn mergers with both sides included in our sample. Consequently; we have a total of 27 events as each matching between two IOUs constitutes an event in our framework. However, we also incorporate information on a number of “non-events” to identify the factors that determine the likelihood of matching between two IOUs. A non-event can be defined as a matching between any two IOUs in our sample that doesn’t represent an actual event covered by the sample. One problem is that with 193 IOUs in our sample, the number of non-events is very large<sup>52</sup>. With a small number of events and a very large number of nonevents; sampling all the events and nonevents will result in a rare events dataset<sup>53</sup>. It is costly to collect and manage data on each of 18,501 non-events given that ones are statistically more informative than zeros in rare events data. In this case, rather than collecting data on all events and non-events; one can choose to collect all available events and a random sample of nonevents without losing consistency and much efficiency relative to the full sample (King and Zeng, 2001a) One should also decide on the number of non-events to be sampled per event in the dataset. Laskey and Stolley (1993) find that relative precision of the estimates reaches around 90 percent of the theoretical maximum with a non-event over event ratio of 5. King and Zeng (2001b) recommend sampling two to five times more non-events than events as the marginal information content of each additional non-event diminishes after

---

<sup>51</sup> Mergers may be withdrawn due to several reasons. Conflicts of interest and culture clash are to name few.

<sup>52</sup> There are  $193! / 2! * (193-2)! = 18528$  unique combinations of IOUs. Since 27 of these combinations represent events; there are 18501 possible matchings that are non-events.

<sup>53</sup> A rare events dataset includes dozens to thousands of times more non-events than events (King and Zeng, 2001).

the number of non-events starts to exceed that of events. In our analysis, we decided to sample 7 non-events per event resulting in a sample of 216 observations. In this way, we form a choice-based sample where each event is matched with 7 non-events. Above sampling procedure is appropriate only if the resulting sample is used in an estimation routine that performs appropriate statistical corrections for selection on the dependent variable and rare events. We utilize a conditional logit model which is designed to work with the choice-based samples and correct for the aforementioned biases (King and Zeng, 2001b).

Following the notation in Green (2003), we can write the random utility model of a pair of IOUs faced with two choices (merging or not merging) as follows:

$$U_{ik} = z_{ik} \beta + \varepsilon_{ik} \quad \text{where} \quad i=1, \dots, 216 \quad \text{and} \quad k=0,1.$$

In this model;  $z$  is the vector of pair-specific attributes while  $\beta$  is the parameter vector of the estimates.  $i$  represents the total number of IOU pairs in the sample and  $k$  represents the choice set taking the value of 1 for events and 0 for non-events.

Since the error term is assumed to be independently and identically distributed with extreme value distribution, we can write the probability model as follows:

$$\Pr ob(Y_i = k | z_{i0}, z_{i1}) = \frac{e^{\beta z_{ik}}}{\sum_{k=0}^1 e^{\beta z_{ik}}}$$

Log-likelihood function can be written as follows:

$$\ln L = \sum_{i=1}^{216} \sum_{k=0}^1 d_{ik} \ln \Pr ob(Y_i = k)$$

In a conditional logit framework, matching each event with a set of nonevents, I will use adjacency of the service territories and differences operational performance, size,

resource availability, degree of vertical integration and sales growth as explanatory variables. Dependent variable takes the value of 1 for all events and 0 for all non-events in the sample. This representation will be helpful in revealing the factors that led to the realization of the actual event rather than any of the non-events. Variables of interest are discussed below in more detail:

- 1- **ADJACENT** is a dummy variable that takes the value of 1 if IOUs in a given pair have neighboring service territories. We expect that the adjacency of the utilities increases the likelihood of an event, as it might be easier to integrate physical infrastructure if the facilities are contiguous.
- 2- **DIF-OPER-MARGIN** is the absolute value of the difference between the operating margins of the two IOUs in a pair. If the firms pair up with other firms that have similar operating efficiencies, then this coefficient expected to be negative. However, if the pairing is a combination of a more efficient firm with a less efficient one, then this coefficient is expected to take on a positive sign.
- 3- **DIF-SIZE** is the absolute value of the difference between the total sales (in terms of MWHs) of the two IOUs in a pair. If the pairing for a merger is more likely for the firms of different sizes, this variable will take on a positive sign.
- 4- **DIF-LEVERAGE** is the absolute value of the difference between the leverages of the IOUs in the pair. This variable will take on a negative sign if the firms pair up with other firms with similar debt structures.
- 5- **DIF-LIQUIDITY** is the absolute value of the difference between the liquidities of the IOUs in the pair. This variable is expected to take on a positive sign if the mergers are more likely to realize between firms with different liquidities.

- 6- DIF-VI** is the absolute value of the difference between the vertical integration degrees of the IOUs in the pair. This variable is introduced to investigate whether the similarity in business focus affects the likelihood of pairing. It is expected to be positively associated with the likelihood of pairing if the IOUs merge to alter their business focus.
- 7- DIF-GROWTH** is the absolute value of the difference between the sales growth rates of the IOUs in the pair. This variable is expected to be positively related to the pairing decision as firms that have exhausted their internal growth sources seek for others with growth potentials.

Results of this analysis are expected to complement the first part where we study the factors that make firms more likely to merge, using information on one of the parties in a merger. Introducing information on both firms as is done in the second part of our analysis may disclose other important factors that explain the likelihood of a merger and contribute to our understanding of the mergers consummated in U.S electricity sector.

## B. RESULTS

Table 3 reports the conditional logit estimation results. **ADJACENT** is positive and significant at 1 percent level indicating that firms that have contiguous service territories are more likely to match to realize a merger. This outcome is in line with our expectations since proximity in the service areas may introduce several conveniences in the event of a merger such as easy integration of the infrastructure or elimination of redundant administrative functions. We find that **DIF-SIZE** variable is positive and significant at 10 percent level indicating that IOUs pair up with other IOUs of different

sizes. DIF-OPER-MARGIN represents the resemblance between two IOUs in terms of their operational performance. This variable is negative and significant at 10 percent level indicating that the more different the firms' operational performances are, the less likely they are to match for a merger. DIF-LEVERAGE and DIF-LIQUIDITY variables represent the degree to which IOUs in a pair are financially similar. These variables are insignificant in our model indicating that IOUs do not factor in their financial likeliness to their matching decisions with a potential merger partner. We also find that DIF-VI and DIF-GROWTH variables are insignificant in our model implying that neither the degree of vertical integration nor the sales growth differences between IOUs play a role in the decision to pair up for a merger.

One important conclusion arising from our conditional logit estimation is that the adjacency of the service territories is the most noteworthy determinant of the pairings between IOUs. While we have found limited evidence for operating performance and size variables as determinants of pairings between IOUs, our results suggests that differences in leverage, liquidity, vertical integration, and sales growth do not explain the likelihood of matching between two IOUs to engage in a merger.

## **VI. Summary and Conclusion**

In this chapter, we review the merger hypotheses most agreed-upon in the literature and identify the drivers of the electric utility mergers that were consummated between 1992 and 2004. We find that the utilities are more likely to be involved in mergers either as acquirers or targets in the face of an industry shock validating the industry disturbance hypothesis. Efficiently managed firms emerge as more likely

acquirers lending support to the inefficient management hypothesis. Our results support the size hypothesis in the context of electric utility mergers and the large firms are less likely to be merger targets. In contrast to Palepu (1986) and Espahbodi and Espahbodi (2003), we find that the high growth firms are more likely to be merger targets. This result implies that the drivers of mergers may show variations due to the idiosyncrasies involved when examined at the individual industry level compared to the cross-industry studies. We also shed light on a less explored question of what determines the merger pairings and find that the adjacency of the firms is the most significant factor that increases the likelihood of pairing for a merger. Similarity in operating performance and difference in size are found to increase the likelihood of pairing though the evidence for these findings is limited.

This study contributes to the literature by testing the fundamental motives for mergers in the context of a particular industry, namely electric utility industry. As our results indicate, not all the motives identified in the literature may be applicable to the mergers undertaken in a specific industry. Given the tremendous research efforts directed at understanding the consequences of mergers, it's essential to have a thorough understanding of the merger motives, most ideally at the industry level similar to the approach followed in this chapter.

## BIBLIOGRAPHY

- American Public Power Association (APPA) (2005). *2007-08 Annual Directory & Statistical Report*. <http://www.appanet.org/files/PDFs/Numelecproviderscust2005.pdf>.
- Andrade, G., M. Mitchell and E. Stafford (2001). "New Evidence and Perspective on Mergers," *Journal of Economic Perspectives*, 15 (2):103-120.
- Brooks, G. R., and V. G. Jones (1997). "Hospital Mergers and Market Overlap," *Health Services Research* 31, (6):701-722.
- Cooke A. and W. Chapple (2000). "Merger Activity in the Waste Disposal Industry: The Impact and the Implications of the Environmental Protection Act," *Applied Economics*, 32:749-755.
- Energy Information Agency (2000). *The Changing Structure of the Electric Power Industry 2000: An Update*. U.S. Department of Energy, Washington, DC.
- Espahbodi H. and P. Espahbodi (2003). "Binary Choice Models and Corporate Takeover," *Journal of Banking and Finance*, 27:549-574.
- Federal Energy Regulatory Commission (FERC) (1996). *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*. Docket No. RM96-6-000, Order No: 592.
- Gaughan, P. A. (2002). *Mergers, Acquisitions, and Corporate Restructurings, 3rd Ed.* New York: John Wiley & Sons Inc.
- Gort, M. (1969). "An Economic Disturbance Theory of Mergers," *The Quarterly Journal of Economics*, 83 (4):624-42.
- Gorton G., M. Kahl, and R. Rosen (2005). "Eat or Be Eaten: A Theory of Mergers and Merger Waves," NBER Working Paper 11364.
- Greene, W. (2003). *Econometric Analysis*. New Jersey: Prentice Hall.
- Harris R. S., J. F. Stewart, D. K. Guilkey, and W. T. Carleton. (1982). "Characteristics of Acquired Firms: Fixed and Random Coefficients Probit Analyses," *Southern Economic Journal*, 49 (1):164-184.
- Harrison, T. D. (2006). "Hospital Mergers: Who Merges with Whom?" *Applied Economics*, 38:637-647.
- Hasbrouck, J. (1985). "The Characteristics of Takeover Targets: Q and Other Measures," *Journal of Banking and Finance*, 9:351-362.

- Jarrell G. A., J. A. Brickley, and J. M. Netter. (1988). "The Market for Corporate Control: The Empirical Evidence since 1980," *Journal of Economic Perspectives*, 2 (1):49-68.
- Jensen, M. C. (1993). "The Modern Industrial Revolution, Exit, and the Failure of Internal Control Systems," *Journal of Finance*, 48 (3):831-80.
- Jensen, M. C. (1986). "Agency Costs of Free Cash Flow, Corporate Finance, and Takeovers," *American Economic Review*, 76 (2):323-29.
- Kennedy, Peter. (2003). *A Guide to Econometrics*. 5th Edition ed. Cambridge: MIT Press.
- King G., and L. Zeng. (2001a). "Explaining Rare Events in International Relations," *International Organization*, 55 (3):693-715.
- King, G., and Zeng, L. (2001b). "Logistic Regression in Rare Events Data," *Political Methodology*.
- Kwoka, J., and M. G. Pollitt. (2007). "Industry Restructuring, Mergers, and Efficiency: Evidence from Electric Power," Working Paper.
- Lasky, T., and P. D. Stolley. (1993). "Selection of Cases and Controls," *Epidemiologic Reviews*, 16:6-17.
- Matsusaka, J. G. (1993). "Target Profits and Managerial Discipline during the Conglomerate Merger Wave," *Journal of Industrial Economics*, 41 (a):179-189.
- McFadden, D. (1974). "Conditional Logit Analysis of Qualitative Choice Behavior," in *Frontiers in Econometrics*, edited by P. Zarembka. New York: Academic Press.
- McGuckin, R. and S.Nguyen (1995). "On Productivity and Plant Ownership Change: New Evidence from the Longitudinal Research Database," *Rand Journal of Economics*, 26:257- 76.
- Meeks, G. (1977). *Disappointing Marriage: A Study of the Gains from Merger*. Cambridge: Cambridge University Press.
- Mikkelson, W. and H. and M. M. Partch (1989). "Managers' Voting Rights and Corporate Control," *Journal of Financial Economics*, 25:263-290.
- Mitchell, M. and J. H. Mulherin (1996). "The Impact of Industry Shocks on Takeover and Restructuring Activity," *Journal of Financial Economics*, 41 (2):193-229.
- Morck, R., A. Shleifer, and R. W. Vishny (1988). "Characteristics of Targets of Hostile and Friendly Takeovers," in *Corporate takeovers: Causes and consequences*, edited by A. J. Auerbach. Chicago, Illinois: University of Chicago Press.

- Ohlson, J. (1980). "Financial Ratios and the Probabilistic Prediction of Bankruptcy," *Journal of Accounting Research*, 18:109-131.
- Palepu, K. G. (1986). "Predicting Takeover Targets: A Methodological and Empirical Analysis," *Journal of Accounting and Economics*, 8 (1):3-35.
- Perry, M. K. (1989). "Vertical Integration: Determinants and Effects," in *Handbook of Industrial Organization*, edited by Richard Schmalensee and Robert D. Willig. Amsterdam: North-Holland.
- Ravenscraft D. J., and F. M. Scherer (1989). "The Profitability of Mergers," *International Journal of Industrial Organization*, 7:101-116.
- Singh, A. J. (1971). *Takeovers: Their Relevance to the Stock Market and the Theory of the Firm*. Cambridge: Cambridge University Press.
- Singh, A. (1975). "Take-overs, Economic Natural Selection and the Theory of the Firm," *Economic Journal*, 85 (September): 497-515.
- Song, M.H., Walkling, R.A. (1993). "The Impact of Managerial Ownership on Acquisition Attempts and Target Shareholder Wealth," *Journal of Financial and Quantitative Analysis*, (December):439-457.
- Trimbath, Susanne. (2002). *Mergers and efficiency: Changes across time*. Boston: Kluwer Academic Publishers.

## TABLES AND FIGURES

**Table 1**

### Regression Results from the Multinomial Logit Model

	Model 1		Model 2	
	Acquirer	Target	Acquirer	Target
	[a]	[b]	[c]	[d]
SHOCK	5.304** (4.37)	6.432** (5.19)	5.251** (4.25)	6.188** (5.04)
LARGE	-0.266 (0.4)	-2.276** (2.65)	-0.334 (0.5)	-2.160** (2.6)
NEGATIVE-GROWTH	-2.389** (2.66)	-1.762* (1.99)	-3.730** (2.74)	-1.984* (1.97)
HIGH-GROWTH	0.145 (0.25)	1.278* (2.3)		
HIGH-LIQUIDITY	0.32 (0.54)	0.792 (1.32)		
LOW-LEVERAGE	0.247 (0.41)	-1.084 (1.55)		
LIQUIDITY			3.251 (0.58)	5.474 (1.02)
GROWTH			-5.194 (0.86)	2.591 (0.71)
LEVERAGE			-4.377 (1.66)	-0.729 (0.42)
GROWTH-RESOURCE			2.328 (1.36)	-36.164 (0.25)
OPERATING-MARGIN	8.002* (2.18)	-1.667 (0.32)	14.701* (2.48)	2.902 (0.58)
VERTICAL-INTEGRATION	-0.104 (0.13)	-0.433 (0.52)	-0.766 (0.83)	-0.302 (0.38)
Constant	-2.863** (3.75)	-1.235 (1.53)	-1.42 (1.22)	-0.743 (0.63)
Observations	193	193	193	193
Model chi-square	145.71	145.71	145.64	145.64
df	16	16	18	18
Loglikelihood	-112.77	-112.77	-112.81	-112.81
Pseudo R2	0.39	0.39	0.39	0.39
N of observations	193	193	193	193

Absolute value of z statistics in parentheses

\* significant at 5%; \*\* significant at 1%

**Table 2**  
**Hausman Test of IIA Assumption**

<b>H0: Odds (Outcome 1 and 2) are independent of other alternatives.</b>				
Omitted	Chi2	df	P>chi2	Evidence
1	0.396	9	1	Do not reject H0
2	-2.306	9	1	Do not reject H0

**Table 3**  
**Regression Results from the Conditional Logit Model**

	<b>Matching</b>
DIF-OPER-MARGIN	-11.771* (1.73)
DIF-SIZE (10 <sup>8</sup> )	2.148* (1.84)
DIF-LEVERAGE	-4.993 (1.28)
DIF-LIQUIDITY	1.317 (1.24)
DIF-VI	-9.7 (1.19)
DIF-GROWTH	-3.516 (0.66)
ADJACENT	1.867*** (3.59)
Observations	216
Model chi-square	41.35
df	7
Loglikelihood	-35.47
Pseudo R2	0.37
N of observations	216
Absolute value of z statistics in parentheses	
* significant at 10%; ** significant at 5%; *** significant at 1%	