Do Mergers really increase Efficiency?

A Cost Efficiency Analysis of Electricity Distributors in the US

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Abstract

Starting in mid-1990s, the US experienced a substantial merger wave in the electricity industry with more than 70 since then and a value of more than 180 bn US-$ for the period 1994-2002. This notable reconstructing of the electricity industry seems to have different sources. One argument, stated by theory, is that mergers can increase the firms' efficiency due to economies of scale and scope and customer can benefit from mergers by decreasing prices but evidence of the phenomenon of these mergers so far is scarce. In order to test this argument, we apply the parametric Stochastic Frontier Analysis (SFA) on a panel data set of 109 investor owned utilities (IOUs) from the US covering the years 1994-2001. Cost efficiency and merger effects on efficiency are estimated simultaneously in a one stage procedure. The results indicate that merger changes efficiency of the merging parties' significantly. While the buying firms gain from merging, the acquired firms loose in terms of efficiency; the overall effect of the merged firm remains ambiguous.

Keywords: Mergers and acquisitions, cost efficiency, stochastic frontier analysis, US
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1 INTRODUCTION

Starting in mid-1990s, the US experienced a substantial merger[1] wave in the electricity industry with more than 70 since then and a value of more than 180 bn US-$ for the period 1994-2002. (Edision Electric Institute, as cited in Kwoka and Pollitt 2005, p. 33). Also, the European Union is subject to a electricity industry consolidation.[2] This notable reconstructing of the electricity industry seems to have different sources. One argument, stated by theory, is that mergers can increase the firms' efficiency due to economies of scale and scope and customer can benefit from mergers by decreasing prices but evidence of the phenomenon of these mergers so far is scarce.

A very good overview about the literature being related to M&As and measuring efficiency in the US is given by Kwoka and Pollitt (2005) who reviewed three streams of relevant literature: (i) US electricity merger literature, (ii) mergers and productivity literature and (iii) measuring electricity distribution efficiency and productivity. Within the field of benchmarking efficiency of US electricity distributors, two main streams of applied techniques can be observed: the average-based, stochastic approach and the frontier-based, deterministic approach.

Kwoka (2005) used a rich static dataset of 436 electricity distribution utilities in the US (117 investor owned utilities (IOUs) and 319 publicly owned utilities) of the year 1989 to assess determinants of average costs and cost performance using Ordinary Least Squares (OLS) regression technique. He found economies of scale with respect to the outputs electricity units delivered and the customer numbers but the effect is small for the size of service territory; economies of scope and economies from vertical integration in the distribution business could not be stated. Thus, a reason for mergers can be found only in the scale effects. Additionally, the results indicated systematic savings in unit costs for public utilities by 14% on average.

Lowry, Getachew, and Hovde (2005) assessed the average-based cost performance and efficiency of 66 US electricity distributors for the period 1991-2002 and applied Feasible Generalized Least Squares (FGLS). The data used was from the Federal Energy Regulatory Commission (FERC) and modified to control for the age of the investment. Besides the finding of small scope effects, the

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[1] The term merger and acquisition will be used in this paper equivalently, meaning that one firm ('buyer') is acquiring ('seller') another firm.

[2] See Codognet et al. (2003) for a detailed survey of European M&A activities within the energy sector.

authors highlighted the number of customers to be the dominant cost driver and the fact that the age of investment had a significant positive effect on costs. The time variable showed a modest significant annual cost decrease of 0.6% to 0.8%.

A frontier approach with the non-parametric technique Data Envelopment Analysis (DEA) is used in Nillesen, Pollitt and Keats (2001) as well as in Nilllesen and Pollitt (2001) to estimate technical efficiency scores for a cross-section data set of over 130 US distributors from 1990. Mergers were analyzed in from of case studies. While in the first paper estimated the potential gains from three mergers by comparing pre-merger and post-merger potential cost savings, the latter one assessed the optimal customer base for one firm to achieve technical efficiency. The results of the paper suggested that M&A is a feasible instrument to increase a firm's efficiency.

Kwoka and Pollitt (2005) used DEA for estimating technical efficiency scores for US distributors and applied a two stage procedure on FERC data for 78 IOUs covering the eight years 1994-2001. Thereby, efficiency is calculated in a first stage and in a second stage, a Tobit regression is estimated to assess several merger effects on efficiency. The results indicate that the acquired distributors were more technically efficient than the control-group of non-merging firms before consolidation, while the buying firm faced lower efficiency scores than the target firms. After merging, the activities of merging parties were less efficient than those of the control firms. Thus, merging parties do not seem to increase efficiency.

Both streams of applied techniques have their drawbacks. While the average-based techniques do not explicitly consider the boundaries of the cost or production function, the deterministic frontier approach does not regard stochastic errors. Additionally, the two stage procedure used in Kwoka and Pollitt (2005) is subject to an inconsistency problem discussed by Simar and Wilson (2003) which developed a model to overcome this problem. Thus, we like to bring together both advantages and reduce the disadvantages of both types of methods in applying a stochastic frontier method – the Stochastic Frontier Analysis (SFA) to assess the effects of mergers on efficiency.

2 MARKET CONSOLIDATION IN THE US ELECTRICITY INDUSTRY

Industry reconstructing goes along with mergers and acquisition (M&A) activity within the industry for a long time. This section gives an overview about the evolution of the industry structure and reviews the regulatory framework mergers are subject to.

2.1 Merger Trends

2.1.1 Industry Structure and Regulation

The electricity industry in the US is characterized by a large number of market participants; approximately 5,000 in 1998. Generation of electricity is performed by utilities and independent power producers (IPPs). The approximately 3,000 electric utilities are firms that are engaged in the generation, transmission, and/or distribution of electricity that are given a monopoly franchise over a specific geographic area. Due to the monopoly franchise, the utilities are regulated by State and Federal agencies. Beside the power marketers, the utilities can be classified by ownership: investor owned utilities (IOUs), federally owned utilities, other publicly owned utilities, and cooperatively owned utilities. (EIA 1999, pp. 3-4).

Although there are only about 200 IOUs, they account for about 2/3 of total generation and capacity in 1998. The share of IPPs is quite low but increasing over time by purchasing of generation assets due to the divesture activities of utilities; this share rose from 12% to 36% in the period 1998 to 2004. Most IOUs are vertically integrated utilities but currently there is trend towards specialization either in generation or transmission/distribution by M&A. (EIA 1999, p. 5 and EIA 2005, p. 17). In 2004, there were 28 registered electricity, so called, top holding companies. (SEC 2006).

2.1.2 Merger Waves

The current wave of mergers and acquisitions follow a long tradition of concentration in the US electricity sector. The period 1917-1936 can be considered as a first merger wave of the industry which was also the greatest consolidation process in history with more than 200 mergers per year, peaking at over 300 mergers per year in the mid-1920s. Mainly small operating companies formed a few holding companies in order to pool engineering, operating, and financial resources to face particularly technological difficulties and capital constraints to large-scale interconnections. This trend came to an end in the early 1930s, when many of the holding companies collapsed financially. The Federal Trade Commission (FTC) followed a passage of The Public Utility Holding Company Act of 1935 (PUHCA) resulting in an investigation of the companies' situation at which FTC exposed a host of financial abuses. (Ray et al. 1992, pp. 3-5). As major consequences, the assets of many of the holding companies were subject to reorganization and divestiture while the remaining holding companies were limited to a single integrated electricity system. Between 1935 and 1950, more than 750 subsidiaries were spun off from the holding companies. (EIA 1999, p. 11).

Following the breakup of the large holding companies, the consolidation process continued but at a much lower rate. In the period 1936-1976 the number of mergers was 529, occurring with a rate of less than 15 per year. Between 1977 and 1989, only 40 mergers took place, about 3 mergers per year on average. (Ray et al. 1992, pp. 5-7).

The investor owned utilities played a dominant role in the consolidation process after 1965, where 76% of the acquired companies joined with an IOU. (Ray et al. 1992, p. 8). Another trend over time is the increasing relative size of merging firms. Smaller companies were acquired by larger ones during the mergers occurred early in the industry while nowadays large companies merge with other large companies. (EIA 1999, p. 11).

The liberalization and privatization process started in the early 1990s n the US. In this light, the current merger wave began in mid-1990s and is still going on, peaking in end-1990s and recovering since 2005. There are three major trends that can already be observed:

(1) an increasing size of IOUs and the concentration of generation capacity among IOUs;
(2) the disintegration of many vertical integrated IOUs which concentrate only on transmission and distribution businesses; and
(3) the opening up of IOUs which were dedicated only to the electricity sector to the natural gas sector ("convergence mergers"). (EIA 1999, pp. 20-21, 29-30).

The mergers approved by FERC and those are relevant for calculation purpose are shown in Appendix 1.

However, the consolidation activity in the electric utility industry contrasts the economy wide activity in the US. First, the industry participated only in the second and third of the four former merger waves observed in the economy (1892-1902, 1926-1930, 1966-1969, 1981-1986). Second, the consolidation activity of the industry is decreasing while the activity within the economy is increasing over time. These differences in the merger pattern suggest the existence of unique, industry-specific factors influencing mergers substantially. The regulatory framework including the competition policy in the electricity industry seems to be such a factor. (Ray et al. 1992, pp.15-19).

2.1.3 Reasons for M&A

The reasons for mergers and acquisitions are diverse. The work of Greer (1992) and Ray et al. (1992) discussed many of the causes. Diamond and Edwards (1997)[3] emphasized five major causes:

(1) **Economic efficiency** in form of cost savings by synergy effects;[4]

(2) **Defensive motives** to protect the company from being acquired by increasing the market value;

(3) **Diversification** in form of investment risk diversity and smoothing business cycle volatility (for non-electric acquisitions);

(4) **Growth and personal aggrandizement** to grow more than proportionally than the exogenous demand and to increase the personal responsibilities of the top manager (Wilson 1996); and

(5) **Market power** by increasing market share and monopoly/oligopoly profits.

In this paper we follow the first argument because we focus only on mergers within the electricity distribution industry[5] and the firms' efficiency development in terms of technical, cost and scale efficiency. The quantitative methods used will be described in detail in Section 3.

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[3] They followed thereby the classification of Greer (1992) who related the utilities' M&As to the nature and pace of deregulation. We do not relate to a sixth argument that deals with cost savings to overcome decreasing competitive pressure because cost savings are stressed under "economic efficiency".

[4] For most mergers, the major cost saving potential is seen in labor costs. Using a sample of five mergers, EIA (1999) concluded that over 50% of the expected saving will come from a reduction in corporate and operations labor. See also FERC (1981) for a detailed description of 15 sources of cost savings for generation and transmission by power pooling.

[5] See EIA (1999), p. 33, for an overview of strategic benefits of a combined electric and natural gas company over all natural gas supply-chain segments. For electricity distributors benefits emerge by cross-selling activities, expanding overhead over a larger customer base and combining administrative functions.

2.2 Regulatory Review

2.2.1 Competition Policy in the US

The competition policy in the US is generally concentrated within Federal and State antitrust laws for most industries that include both general competition laws and sector-specific laws and regulations. The general competition philosophy is based on the Federal Sherman Act of 1890 and the Clayton Act of 1914. While the first act prohibits trusts and monopolies, as well as collusion in restraint of trade, the latter act prohibits mergers or other combinations (like alliances and joint-ventures) that substantially lessen competition. Thus, the US antitrust policy has largely focused on preventing the formation of uncompetitive market structures (ex-ante) and the prosecution of explicit collusion of firms (ex-post). (Bushnell 2003, p. 4).

Concerning the electricity and natural gas industry, the FERC is responsible for antitrust and regulatory issues of IOUs; the authority come mainly from the Federal Power Act of 1935 (FPA). It has jurisdictional power on wholesale electricity transactions and their supporting transmission arrangements. It also determines "just and reasonable" rates due to its statutory mandate; at times FERC defined the rates in terms of the market environment rather than in terms of pricing levels or the cost basis. Until 1996, the evaluation of merger and applications for market-based rates went along with the analysis of gradually changes to the underlying market. Even the merger of large firms did not affect the wholesale market substantially because of three reasons: (1) the markets accounted only for residual transactions; (2) the majority of electricity was still produced by local utilities; and (3) most of the firms were vertically integrated and regulated by state regulators. (Bushnell 2003, pp. 4-5).

In 1992, the Energy Policy Act was enacted by Congress that gives FERC the power to introduce third party access (TPA) to the transmission grid in order to support a competitive wholesale electricity market. In 1996, FERC finished the rulemaking process and required each IOU to provide TPA on the one hand and on the other hand, it allowed them to make wholesales to unregulated prices. Additionally, FERC adopted the horizontal merger guidelines from the Federal antitrust agencies Department of Justice (DOJ) or the Federal Trade Commission (FTC) as its own because of the inherent experience with mergers and in order to minimize potential differences between the parties that share the jurisdiction over proposed M&A. (Pierce 2005, pp.7-11). The procedure of a merger review contains (1) the identification of the relevant products, (2) the relevant geographic market for those products, and (3) the estimation of the price effect of the proposed merger that is measured by its impact on the concentration of suppliers in the relevant geographic market. Thus, the relevant products determined are non-firm energy, short-term capacity (firm energy), and long-term capacity because they are most frequently traded between not-restructured vertically integrated utilities in the periphery of the "spot" energy market.[6] (Bushnell 2003, p. 6).

2.2.2 Regulatory Agencies

Mergers and acquisitions in the electricity industry of a substantial size are subject to a review process involving different Federal and State governmental agencies. At the State level, the public utility commission (or equivalent agencies) focuses mainly on antitrust issues and the potential cost savings of the merger. The intensity can vary widely between States depending on the expected impact of the merger and the resources available for the review. (EIA 2000, p. 103)

At the Federal level, up to five agencies can be involved in the reviewing process. Concerning antitrust issues, either the Department of Justice (DOJ) or the Federal Trade Commission (FTC) can prove the consistence of the merger with antitrust laws; their antitrust authority come primarily from the Clayton Act of 1914 an the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The Federal Energy Regulatory Commission (FERC) is frequently involved in the reviewing process of M&As in order to assure markets and access to reliable service at reasonable prices. Recently, DOJ relies often on the FERC analysis on the competitive effects and plays a more passive role. FERC's authority is based on The Federal Power Act of 1935, the Department of Energy Reorganization Act of 1977 and the Energy Act of 1992. According to the Public Utility Holding Company Act of 1935 (PUHCA), the Securities and Exchange Commission (SEC) is responsible for assuring compliance with the PUHCA and the protection of shareholder interests when a holding company gains control of at least 10% of the voting securities of another company. The Nuclear Regulatory Commission (NRC) reviews proposed M&As that goes along with a transfer of a nuclear power plant operating licence. (EIA 2000, pp. 103-104).

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[6] See Pierce (2005) for an excellent overview about the development of FERC's work and policy. See also Bushnell (2003)

3 METHODS

This section describes the approach of measurement cost efficiency and total factor productivity (TFP) using SFA on panel data and additionally, the approach to assess the impact of merger characteristics on the efficiency scores.

3.1 Specification of the cost function

As discussed in the introduction, this paper combines the advantages of the methods applied in previous research on merger analyses in the US electricity distribution industry. Therefore and because we like to asses the overall or cost efficiency (CE), we use the parametric, stochastic frontier technique SFA in a cost function framework. This allows for random unobserved heterogeneity among the different firms but a specification of a functional form is needed. The cost efficiency is the product of technical efficiency (TE) and allocative efficiency (AE); the first term describes the efficiency in the use of production technology, while the second term displays the efficiency in production factor allocation.[7]

The original stochastic frontier model was developed by Aigner, Lovell and Schmidt (1977) and Meeusen and van den Broeck (1977) in the form:

$$\ln Y_i = X_i^{\prime} \beta + v_i - u_i \tag{1}$$

where Y_i represents the output vector of company i, X_i is a vector that contains the logarithms of inputs, β is a vector of parameters to be estimated, v_i is a random error term accounting for statistical noise and assumed to have a normal distribution, and u_i is a non-negative random variable associated with technical inefficiency (often assumed to be half-normal or truncated-normal distribution). The maximum likelihood estimated method is used to calculate here the technical inefficiency parameter u_i for a one output case.

for a detailed description of the merger review process.

[7] See Coelli at al. (2005) and Kumbhakar and Lovell (2000) for a detailed discussion of the components of cost efficiency.

An alternative approach of the basic model, a frontier cost model, is used in this paper on a panel data set. Pitt and Lee (1981) extended the original SFA approach, shown in (1), to a panel data framework.[8] Their model can be formulated as:

$$\ln C_{it} = \ln C(Y_{it}, W_{it}) + v_{it} + u_i \qquad (2)$$

with C_{it} displaying the observed total costs of firm i in year t, the cost function C, the vector of outputs Y_{it} and the input price vector W_{it}. The underlying assumption of the cost function is that it defines minimum costs at a given output level, input prices and the existing production technology with the corresponding properties of linear homogeneity and concavity in input prices and monotonicity in input prices and output.[9]

Electricity distribution utilities can be considered to operate in a given network with the objective to deliver electricity to an exogenous defined area. Therefore, they transform capital and labor into electricity delivery outputs; in this paper those outputs are the amount of electricity delivered and the number of connected customers. The heterogeneity of different service areas is often considered by additional network characteristics. We control for this by using a network density parameter ND_{it} that is the logarithm of customers per unit of distribution assets. Thus, we expect a distributor to have lower costs when it acts in a densely populated area that is indicated by a higher value of the variable. In addition, a time trend t is used to assess the technological change for the whole industry.

A translog (transcendental logarithmic) function is chosen for estimating the cost function given in (2). Its flexible form places no restrictions on the elasticity of substitution at the outset and the economies of scale are allowed to differ with the level of output. Two alternative approaches can be taken for estimating purpose of a translog function. One approach is to see the translog function as a local second-order logarithmic approximation to any arbitrary twice-differentiable cost function. The sample mean is often used as an approximation point (mean correction).[10] Moving away from this point any implicit approximation errors will grow. The second approach considers the function as an exact representation of the minimum cost function and there is no need for a definition of an approximation point. (Berechmann 1993, p. 138). We choose the first approach and correct the sample

[8] A good discussion about the alternative frontier cost models is given by Farsi and Filippini (2004).
[9] See Coelli et al. (2005), pp. 21-30, and Kumbhakar and Lovell (2000), pp. 32-35, for more details concerning the properties of a cost function.

variables by their means due to the advantages of reduced effects of outlier without affecting the data structure and the convenient interpretation of first order coefficients as elasticities at sample means (Coelli et al. 2003). The total cost function can therefore be written as:

$$\begin{aligned}
\ln\left(\frac{C_{it}}{W_{L\,it}}\right) &= \beta_0 + \beta_{Y_E} \ln Y_{E\,it} + \beta_{Y_{NC}} \ln Y_{NC\,it} + \beta_{W_K} \ln \frac{W_{K_{it}}}{W_{L_{it}}} \\
&+ \frac{1}{2}\beta_{Y_E Y_E} \left(\ln Y_{E\,it}\right)^2 + \frac{1}{2}\beta_{Y_{NC} Y_{NC}} \left(\ln Y_{NC\,it}\right)^2 + \frac{1}{2}\beta_{W_K W_K} \left(\ln \frac{W_{K_{it}}}{W_{L_{it}}}\right)^2 \\
&+ \beta_{Y_E Y_{NC}} \ln Y_{E\,it} \ln Y_{NC\,it} + \beta_{Y_E W_K} \ln Y_{E\,it} \ln \frac{W_{K_{it}}}{W_{L_{it}}} + \beta_{Y_{NC} W_K} \ln Y_{NC\,it} \ln \frac{W_{K_{it}}}{W_{L_{it}}} \\
&+ \beta_t t + \beta_{ND} \ln ND_{it} + \beta_{NDND} \left(\ln ND_{it}\right)^2 + \beta_{Y_E ND} \ln Y_{E\,it} \ln ND_{it} \\
&+ \beta_{Y_{NC} ND} \ln Y_{NC\,it} \ln ND_{it} + \beta_{W_K ND} \ln \frac{W_{K_{it}}}{W_{L_{it}}} \ln ND_{it} + u_{it} + v_{it}
\end{aligned} \qquad (3)$$

where the output variables Y_E and Y_{NC} represent the quantity of electricity delivered and the number of customers respectively, W_C and W_L are the input price variables of capital and labor respectively. The t displays the time trend and ND_{it} is the network density and the β are the coefficients to be estimated. The linear homogeneity condition is imposed by normalizing the costs and the capital price by the labor price W_L.

3.2 Explaining efficiency

Apart from calculating only efficiency scores of the utilities, we are interested in explaining the efficiency. In a wide range of papers, a two stage approach was used, where in the first stage the inefficiencies were calculated by a frontier model omitting environmental (or structural) variables and in a second stage; the estimated inefficiencies were regressed on those exogenous, environmental variables to assess their impact on efficiency.

This two stage approach was criticized due to econometrical inconsistence in the assumptions about the distribution of the inefficiencies, first of all by Kumbhakar, Ghosh and McGukin (1991) and Reifschneider and Stevenson (1991). In the first stage, the inefficiency effects are assumed to be independently and identically distributed but in the second stage, the predicted inefficiencies are assumed to be a function of firm-specific effects, which implied that these are not identically

[10] For an example, see Farsi, Filippini and Kuenzle (2006) or Growitsch, Jamasb and Pollitt (2005).

distributed. As a solution for this problem, they proposed stochastic frontier models in which the inefficiency effects (u_i) are expressed as an explicit function of a vector of firm-specific variables and a random error. The model proposed by Battese and Coelli (1995) is similar to the specification of Kumbhakar, Ghosh and McGukin (1991) but they imposed allocative efficiency, removed the first-order conditions on profit maximization and extended it to panel data. The model assumes the inefficiency term u_{it} to be independently distributed as truncations at zero of the N(μ_{it},σ_U^2) with

$$\mu_{it} = \delta' z_{it} \tag{4}$$

where z_{it} is a vector of environmental variables and δ is a vector of coefficient to be estimated. (Coelli, Rao and Battese 1998, pp.207-209, Coelli, 1996).

To account for merger activities of a firm, we use certain factors that are likely to influence the environment of production. A set of dummies is proposed in Kwoka and Pollitt (2005) which captures the time path of a merger. Separate 'merger timing' dummies are introduced for each year before and each year after a merger and for 'buyers' and 'sellers' respectively. One of our two types of models follows their idea but also accounts for the year of merger. In contrast to Kwoka and Pollitt (2005), we capture the effect of being involved in two or three mergers as a 'buyer' or a 'seller' separately. The second model category does not account for the time path of a merger and uses dummies only describing the status of a firm: 'have acquired' and 'have been acquired' after a merger and 'will acquire' and 'will be acquired' before a merger. A firms involvement in more than one merger is treated as described above. All dummies can take on a value of 0 or for each year and firm.

In addition to the merger dummies we include a time trend t that captures the effect of systematic industry-wide improvement of efficiency that come from learning over time and a constant to be less restrictive.[11] Under the above specifications on the set of explanatory variables the mean of the inefficiency term can be describes by the equation:

$$\mu_{it} = \delta_0 + \delta_t t + \sum_m \delta_m d_{m\,it} \tag{5}$$

where d_{it} displays the dummies.

For calculation purpose we use the software "FRONTIER 4.1" developed by Tim Coelli.[12]

4 DATA

The data used as well as the calculation of variable is heavily based on the paper of Kwoka and Pollitt (2005) because of very similar research questions and the availability of data. Therefore the following description will be done very briefly and highlights the main differences between both papers. For our estimation procedure of cost efficiency, we require information of electricity distribution businesses only concerning the total expenditures (TOTEX), the operating and maintenance expenditures (O&M), the output quantities, the input quantities and input prices as well as structural variables.

All the data used come from the FERC Form 1 filings for the years 1994-2001 but the data for mergers come from the FERC website and they are dated from the year of issuing FERC's decision.[13] The original data set consists of 295 major investor owned utilities and reduced to 109 IOUs due to the lack of data[14] where the sample used account for 54% of total electricity sold and for 69% of total customers in the year 2000. These ratios are quite constant for all years in our sample period. Thus, we use a balanced panel of 872 observations. For three missing of the 872 observations, we calculated an average of the O&M and the number of employees using the previous and the following year.

The 109 IOUs are classified using three categories: there are 25 buying utilities, 21 acquired companies, and 67 non-merging utilities. The difference of 4 is due to firms that are buying as well as acquired utilities. The distribution of mergers over the period is displayed in Table 1.

[Insert Table 1 here]

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[11] The introduction of a time trend here is the easiest way to account for systematic change of inefficiency over time. See Kumbhakar and Lovell (2000) for a comparison of the more complex and common time-varying functions of Battese and Coelli (1992) and Kumbhakar (1990).

[12] See Coelli (1996) for a description of the software.

[13] In some cases there is a one year lag between the issuing of the final decision by FERC and the completion of the merger. This might appear because of additional merger reviews by state agencies.

[14] To some extend, the lack of data can be explained by merging itself. For example, the number of filings reduces from two to o one when two regulated firms merge and form a new entity afterwards.

The variables used and the corresponding sources and modification are displayed in Appendix 2. In contrast to the work of Kwoka and Pollitt (2005), we use calculated the Total Distribution Assets (TDA) as the sum of the distribution assets (DA) and the share of total distribution assets of all assets (S2) times other assets (OA):

TDA = DA+S2*OA.

Additionally, we calculated the total Number of Units Delivered (Nud) and a capital price variable (Average Capital Price - AvCP) that is the ratio of capital costs (CC) and Total Distribution Assets:

AvCP = CC / TDA = EBITDA / TOT

Equivalently, AvCP is the ratio of EBITDA and total assets that assumes a constant capital price for the whole supply chain. The number of employees in distribution (TDemp) is calculated as a product of total employees (Temp) times the share of distribution on total salaries (S1).

The deflating of costs and factor prices is not necessary because these variables are already divided by a factor price to achieve homogeneity of the cost function, as mentioned in the precious chapter. The summary statistics of the variables used are shown in Table 2.

[Insert Table 2 here]

5 ESTIMATION RESULTS

The estimation results of the two models are given in Table 3. Almost all models show significant positive coefficients of the outputs and the input prices.

[Insert Table 3 here]

Since total costs and all explanatory variables are in logarithms and normalized by their means, the coefficients of the first order derivatives can be interpreted as cost elasticities at the sample means. Thus, the cost elasticities of energy delivered are quite low on average with 0.13 to 0.15 but Model 1 shows a crucial slightly negative value. An increase of 1% in customer numbers will increase the costs by 0.81% to 0.96% depending on the specification chosen.

As expected, the impact of network density is significantly negative and equal among both models with a value of -0.68%. That means that a distributor operating in an urban area with a high density has a cost advantage compared to a rural company.[15]

Due to the homogeneity, the cost elasticities with respect to input prices are equal to their cost shares. Interestingly, we observe a high cost share of capital, ranging from 72% to 80% despite the fact that the data set used shows a cost share of only 58% on average. However, the results support the structure of a high capital/labor ratio that is typical for network industries with high capital investments.

The coefficient of the time trend is slightly negative and significant in two models. This indicates a positive technological change of 1% over time and shows that the technology used in electricity distribution has not much changed over time.

The results of the estimation of the coefficients of the structural variables show a significantly positive time effect on inefficiency over all specifications. This indicates a negative learning effect in terms of efficiency.

The coefficients of the merger dummies are significantly only in parts but the magnitude of the significant coefficients show that the differences between buyer, sellers, and non-merging distributors are notable.

The time path dummies in Model 1 and 1a indicate higher inefficiencies of the buying distributors before merging and big efficiency gains after merging. Thus, the bad-performing buyers improve remarkably in terms of cost efficiency by merging in comparison with the control group of non-merging distributors. Interestingly, the buyers which are involved in two acquisitions improve even more. This can be seen in Model 2.

On the other side, we can say little about the acquired firms in the pre-merging period. The insignificance of all related dummies can be interpreted cautiously as a cost performance that is similar to the control group. Additionally, Model 1 shows that those firms which are very good performer in terms of efficiency that are acquired more than once. If we decompose in two and three mergers (Models 2 and 2a), we observe good cost performance before the second acquisition (negative sign) but bad performance prior to the third merger (positive sign).[16] After the first merger, the sellers have higher cost inefficiencies than the control group. Only the firms that are acquired more than on time face a significant and notable increase in efficiency. This can be seen by a switch in the signs of the coefficients from positive to negative in Model 2 and 2a:

Concerning the overall evaluation of the models the γ coefficients which measure the share of the deviations from the cost function that are due to inefficiency are about 90%. The decision of including a network density variable can be evaluated by a likelihood-ratio test that proofs the network density variables to be zero at a given significance level. The results are shown in Table 4.

[Enter Table 4 here]

For both models we can reject the null hypothesis on a 99%-level in favor of the Models 1 and 2 with network density variables included.[17]

A summary of the inefficiency estimates is given in Table 5. The inefficiency measures can be interpreted as excess costs measured by the ratio of actual costs to efficient cost. The value can be equal or greater than one where a value of one indicates cost efficient firms. The inefficiency values show similarity within the pairs of models which contain (omit) network density variables in the cost function – Model 1 and 2 (Model 1a and 2a). Between the model pairs there are remarkable differences in the inefficiency values, where higher inefficiency can be observed by the models omitting the network density variables. That is reasonable because we control for network density in the first model pair. This displays the cost disadvantage of firms which operate in a less densely populated area not as inefficiency, resulting in a mean disadvantage of 10% to 15%. The mean inefficiency shows excess costs of 13% to 33% depending on the specification chosen. The quite small

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[15] Interestingly, the incorporation of the network density variably goes along with systematically higher cost elasticities of the customer numbers. That suggests that there might be a problem of multicollinearity because the customer number is also used in calculating the network density variable.

[16] There is only one firm in our sample that is acquired three times. Hence, there is doubt concerning the explanatory power of that coefficient despite its significance.

positive difference between mean and median, as well as the low 95 percentile value suggest that there are only a few very inefficient firms with a maximum value across all models of 330%.

[Enter Table 5 here]

[Enter Table 6 here]

The pair-wise correlation coefficients between the inefficiency estimates from different models are listed in Table 6. The basic result is the high correlation of over 97% of the inefficiency estimates between the model pair Model 1 and Model 2 and the pair Model 1a and Model 2a, respectively. Over all models, the correlation is at least 60%.

6 CONCLUSION

We applied the parametric stochastic frontier analysis on a panel data set of 109 investor owned utilities from the US covering the years 1994-2001. Cost efficiency and merger effects on efficiency are estimated simultaneously in a one stage procedure following Battese and Coelli (1995).

The estimation results of the cost function show relatively low cost elasticities with respect to the electricity delivered. The cost elasticities of the output 'number of customers' lie in the in the range of 80% to 100% that is in line with the literature. Over all model specifications, the results indicate that mergers change efficiencies of the merging parties' significantly. The buying firms were bad cost performer in the pre-merger period (more inefficient compared to the control group of non-merging utilities) and gain from merging by increasing efficiency becoming a good cost performer in the post-merger period. In contrast, the acquired firms were average cost performer (as inefficient as non-merging firms) prior to a merger and they loose in terms of efficiency becoming a bad performer.

[17] In addition, we tested the assumption of a Cobb Douglas cost function and the specification of a density variable that enter the equation only with a first order derivation. Both assumptions could be rejected for both models applying a likelihood-ration test on a 99%-level.

Hence, the overall effect of the merged firm remains ambiguous. Hence, we cannot confirm cost savings of a merger and their magnitude.

The parametric approach we applied does not allow for investigating the channels by which the efficiency can be transferred from one company to another. There are other issues that can be addressed in further research. Beside the implementation of further structural parameter to improve the cost function, such as transformer capacity ,the line length and quality, it might be of interest to decompose the cost inefficiency into its components of technical and allocative efficiency to reveal the sources of cost inefficiency more intensively. Concerning the merger issue, the rising number of convergence mergers combining electricity and natural gas businesses raises the question of economies of scope. Additionally, it will be interesting t figure out if mergers of adjacent network operators can gain from scale efficiency more than proportionally.

APPENDIX

Appendix 1: Mergers in the Electricity Sector – approved by FERC between 1995 and 2001

Merger status	Buyer	Seller/Aquired/Merged	In Panel
Completed in 2001	E.ON AG	Powergen plc	
	Potomac Electric Power Company	Conectiv	
	Energy East Corp.	RGS Energy Group	
	National Grid USA	Niagra Mohawk Holdings, Inc.	X
	The AES Corporation	IPALCO Enterprises, Inc.	
	FirstEnergy Corporation	GPU, Inc.	X
	Emera	Bangor-Hydro Electric Company	
Completed in 2000	Entergy Power Marketing Corp.	Koch Energy Trading, Inc.	
	UtiliCorp United, Inc.	St. Joseph Light & Power Company	X
	Carolina Power & Light (CP&L) Energy, Inc.	Florida Progress Corporation	X
	Interstate Power Company	IES Utilities, Inc.	
	PowerGen plc	LG&E Energy Corporation	X
	Black Hills Corporation	Indeck Capital, Inc.	
	Stora Enso Oyj (F/S)	Consolidated Water Power Company	
	Consolidated Edison, Inc.	Northeast Utilities	
	PECO Energy Co.	Commonwealth Edison Co.	X
	Energy East Corp.	CMP Group, Inc.	
	American Electric Power Company	Central and Southwest	X
	Northern States Power Co. (Minnesota)	New Century Energies, Inc.	X
Completed in 1999	Pennsylvania Enterprises	Southern Union Co.	
	New England Electric System	Eastern Utilities Associates	X
	BEC Energy	Commonwealth Energy System	X
	ScottishPower plc	PacifiCorp	
	National Grid Group plc	New England Electric System	X
	The AES Corporation	CILCORP Inc.	X
	Sierra Pacific Power Company	Nevada Power Company	X
	Consolidated Edison Company of New York, Inc.	Orange and Rockland Utilities, Inc.	X
Completed in 1998	CalEnergy Company, Inc.	MidAmerican Energy Holdings Company	
	Duke Energy Corporation	Nantahala Power and Light Company	X
	WPS Resources Corporation	Upper Peninsula Energy Corporation	X
	Wisconsin Energy Corporation, Inc.	Edison Sault Electric Company	X
	Louisville Gas and Electric Company	Kentucky Utilities Company	X
Completed in 1997	Wisconsin Power & Light Company	IES Utilities, Inc. Interstate Power Company	X
	Ohio Edison Company	Centerior	X
	Union Electric Company	Central Illinois Public Service Company	X
	Delmarva Power & Light Company	Atlantic City Electric Com	X
	Destec Energy, Inc.	NGC Corporation	
	Enova Energy, Inc.	San Diego Gas & Electric Company	X
	Public Service Company of Colorado	Southwestern Public Service Company	
1995	Delmarva Power & Light Company	Conowingo	X

Source: DOE, 1999. Changing structure of the electric power industry 1999: Mergers and Other Corporate Combinations, http://www.eia.doe.gov/cneaf/electricity/corp_str/corpcomb.pdf, and FERC website

Appendix 2: Variable Definition and Sources

Variable	Definition	FERC Pages	FERC Account Name/Notes
OPEX		**Electric Operation & Maintenance Expenses**	**FERC database table f1_elc_op_mnt_exp**
D	Total Distribution Costs (US$)	322-126b	TOTAL Distribution Expenses
A	Total Administration Costs (US$)	322-168b	TOTAL Administration 6 General Expenses
Cu	Total Customer Service Costs (US$)	Sum of 322-134b, 322-141b, 322-148b	
		322-134b	TOTAL Customer Accounts Expenses
		322-141b	TOTAL Customer, Service and Information Expenses
		322-148b	TOTAL Sales Expenses
T	Total Transmission Costs (US$)	321-100b	TOTAL Transmission Expenses
G+PP	Total Power Production Costs (US$)	321-80b	TOTAL Production Expenses
Wage distribution		**Distribution of Salaries & Wages**	**F1_slry_wg_dstrbtn**
S1	Share of Distribution Business in Administration	S1(a) / S1(b)	
S1(a)	Numerator (wages of distribution and customer)	Sum of 354-20b, 354-21b, 354-22b, 354-23b	
		354-20b	Distribution
		354-21b	Customer Account
		354-22b	Customer Services and Informational
		354-23b	Sales
S1(b)	Denominator (wages)	354-25b	TOTAL Operations and Maintenance
Assets		**Electric Plant in Service**	**F1_plant_in_srvce**
S2	Total Distribution Share of EBITDA	TDA / TOT = DA / (TOT-OA)	
DA	Distribution Assets (US$)	207-69g	TOTAL Distribution Plant
TA	Transmission Assets (US$)	207-53g	TOTAL Transmission Plant
PA	Production Assets (US$)	207-42g	TOTAL Production Plant
TOT	Total Assets (US$)	207-88g	TOTAL Plant in Service
OA	Other Assets (US$)	TOT - (DA+TA+PA)	
TDA	Total Distribution Assets	DA + OA*S2	
Revenues		**Electric Operation Revenues**	**F1_electrc_oper_rev**
R	Total Revenue (US$)	300-12b	TOTAL Sales of Electricity
Nud	Total Units Delivered (MWh)	301-12d	TOTAL Unit Sales (MWh)
Ncu	Total Customers (#)	301-12f	TOTAL Sales to Consumers (#)
Others			
EBITDA		R-D-Cu-T-(G+PP)-A	Earning before Interest, Taxes, Depreciation, Amortization
CC	Capital Costs in Distribution Business	S2*EBITDA	
NCC	Non-Capital Costs	D+Cu+S1*A	O&M of Distribution
TDC	Total Distribution Costs	CC+NCC	
Temp	Total Employees	323-4	TOTAL Employees (#)
TDemp	Total Employees in Distribution	S1*Temp	
AvW	Average Wages in Distribution	(354-25b) / Temp	
LEQ	Labor Equivalent O&M Costs	NCC / AvW	O&M Costs deflated by Labor Costs
AvCP	Average Price of Capital	CC / (DA+S2*OA) = EBITDA / TOT	

Table 1: Number of Electricity Mergers used in the Sample

Year	Buyer	Seller
1994	0	0
1995	1	0
1996	0	0
1997	4	6
1998	4	2
1999	5	5
2000	8	8
2001	4	1
SUM	**26**	**22**

Table 2: Summary Statistics

Variable	Explanation	Obs	Mean	Std. Dev.	Min	Max
C	Total Distribution Costs	872	283,000.000	350,000,000	2,299,131	2,660,000,000
Y_E	Total Electricity sold (MWh)	872	21,000,000	23,600,000	128,208	182,000,000
Y_{NC}	Total Number of Customers (#)	872	606,348	702,499	5,565	3,935,296
X_L	Total Employees in Distribution (#)	872	860	945	3	5.096
X_K	Total Distribution Assets ($)	872	1,250,000,000	1,590,000,000	8,390,768	16,500,000,000
W_L	Avg. Costs of Labor	872	47,691	109,182	15,197	1,892,592
W_K	Avg. Price of Capital	872	0.132	0.040	0.029	0.425

Table 3: Maximum Likelihood Estimation Results of the Models

Coefficient	Model 1	Model 1a (without ND)	Coefficient	Model 2	Model 2a (without ND)
β			β		
constant β_0	0.02 (1.25)	-0.12*** (-4.62)	constant β_0	0.01 (0.93)	-0.14*** (-5.41)
t	-0.01*** (-4.18)	0.00 (-0.58)	t	-0.01*** (-3.75)	-0.01 (-1.47)
Y_E	-0.03* (-1.80)	0.13*** (6.15)	Y_E	-0.02 (-1.25)	0.15*** (7.36)
Y_{NC}	0.97*** (62.21)	0.83*** (37.21)	Y_{NC}	0.96*** (61.37)	0.81*** (36.75)
W_K	0.79*** (43.67)	0.72*** (31.12)	W_K	0.80*** (48.71)	0.72*** (31.49)
Y_EY_E	0.09*** (3.18)	-0.46*** (18.64)	Y_EY_E	0.09*** (2.94)	-0.44*** (-18.88)
$Y_{NC}Y_{NC}$	0.12*** (3.30)	-0.58*** (19.88)	$Y_{NC}Y_{NC}$	0.11*** (2.96)	-0.56*** (-20.11)
W_KW_K	-0.20*** (-11.83)	-0.19*** (-7.91)	W_KW_K	-0.20*** (-11.79)	-0.19*** (-8.12)
Y_EY_{NC}	-0.11*** (-3.65)	0.51*** (22.05)	Y_EY_{NC}	-0.11*** (-3.32)	0.49*** (22.53)
Y_EW_K	-0.03 (-1.15)	-0.23*** (-5.35)	Y_EW_K	-0.03 (-1.18)	-0.20*** (-4.88)
$Y_{NC}W_K$	0.06** (1.99)	0.27*** (5.83)	$Y_{NC}W_K$	0.06** (1.99)	0.25*** (5.42)
ND	-0.68*** (-27.90)		ND	-0.68*** (-27.32)	
NDND	-0.26*** (-4.46)		NDND	-0.22*** (-3.81)	
Y_END	-0.02 (-0.65)		Y_END	0.00 (-0.09)	
Y_{NC}ND	-0.03 (-0.91)		Y_{NC}ND	-0.05 (-1.58)	
W_KND	0.06 (1.12)		W_KND	0.03 (0.68)	

continued					
Coefficient	**Model 1**	**Model 1a (without ND)**	**Coefficient**	**Model 2**	**Model 2a (without ND)**
δ			***δ***		
constant δ_0	-0.69***	-0.51**	constant δ_0	-0.71***	-0.19**
	(3.43)	(-2.42)		(-3.91)	(-2.04)
t	0.06***	0.08***	t	0.05***	0.06***
	(3.34)	(4.74)		(3.66)	(4.49)
More than once a buyer	-0.88	-0.87			
	(-1.09)	(-1.06)			
More than once a seller	-1.63**	-3.08*			
	(-2.02)	(-1.69)			
Buyer: 7 years before	0.46	0.80***	Buyer: before first merger	0.00	0.08*
	(1.14)	(3.02)		(-0.05)	(1.66)
Buyer: 6 years before	0.32*	0.23	Buyer: before second merger	0.52***	-0.48*
	(1.74)	(1.35)		(3.00)	(-1.82)
Buyer: 5 years before	0.34**	0.46***	Buyer: since first merger	-0.51***	-0.03
	(2.21)	(3.31)		(-5.13)	(-0.63)
Buyer: 4 years before	0.32**	0.31***	Buyer: since second merger	0.29	-0.18
	(2.43)	(2.57)		(1.01)	(-0.87)
Buyer: 3 years before	-0.26	-0.03			
	(-1.06)	(-0.24)			
Buyer: 2 years before	-0.15	-0.02			
	(-0.98)	(-0.16)			
Buyer: 1 years before	-0.29	-0.11			
	(-1.28)	(-1.04)			
Buyer: 1 year after	-0.80***	0.03			
	(-2.63)	(0.36)			
Buyer: 2 year after	-0.58	-0.12			
	(-1.53)	(-0.69)			
Buyer: 3 years after	-0.99*	-0.93**			
	(-1.70)	(-2.17)			
Buyer: 4 years after	-0.61	-0.94**			
	(-0.79	(-1.96)			
Buyer: 5 years after	0.12	0.41			
	(0.12)	(0.40)			
Buyer: 6 years after	1.23	0.97			
	(1.30)	(1.04)			
Seller: 7 years before	0.51	0.13	Seller: before first merger	0.03	0.03
	(1.15)	(0.19)		(0.46)	(0.52)
Seller: 6 years before	-0.36	-1.09	Seller: before second merger	-1.43***	-2.27**
	(-0.53)	(-1.67)		(-12.77)	(-2.42)
Seller: 5 years before	-1.09	0.00	Seller: before third merger	1.44***	1.20
	(-1.38)	(0.02)		(6.65)	(1.57)
Seller: 4 years before	-0.29	-0.15	Seller: since first merger	0.29***	0.15***
	(-0.68)	(-0.66)		(4.57)	(3.04)
Seller: 3 years before	0.08	-0.12	Seller: since second merger	-1.86***	-2.05**
	(0.55)	(-0.88)		(-3.00)	(-2.27)
Seller: 2 years before	-0.13	-0.20	Seller: since third merger	-0.07	0.73
	(-0.70)	(-1.30)		(-0.07)	(0.67)
Seller: 1 year before	0.13	0.03			
	(1.15)	(0.29)			
Seller: 1 year after	0.09	-0.01			
	(0.67)	(-0.07)			
Seller: 2 year after	0.27**	0.21**			
	(2.43)	(2.07)			
Seller: 3 year after	0.07	0.21			
	(0.32)	(1.47)			
Seller: 4 year after	0.35*	0.24			
	(1.91)	(1.52)			
σ^2	0.08***	0.13***	σ^2	0.09***	0.09***
	(5.45)	(5.02)		(6.06)	(9.88)
$\gamma = \sigma^2_u/\sigma^2$	0.91***	0.88***	$\gamma = \sigma^2_u/\sigma^2$	0.92***	0.88***
	(46.15)	(36.64)		(59.46)	(40.94)
Log Likelihood	539.54	126.22	Log Likelihood	537.09	132.27

Significance on 10%-, 5%-, and 1%-level: *, **, ***; t-statistics in parentheses.

Table 4: Likelihood-Ratio Test of the Models

Null hypothesis	Degrees of freedom	$\chi^2_{0.99}$	Test statistics	Decision
Model1: do not include ND $\beta_{ND} = \beta_{NDND} = \beta_{Y_E ND} = \beta_{Y_{NC} ND} = \beta_{NDW_K} = 0$	5	15.09	826.64	Reject H_o
Model2: do not include ND $\beta_{ND} = \beta_{NDND} = \beta_{Y_E ND} = \beta_{Y_{NC} ND} = \beta_{NDW_K} = 0$	5	15.09	809.64	Reject H_o

Table 5: Summary of Inefficiency Measures

	Model 1	Model 1a (without ND)	Model 2	Model 2a (without ND)
Mean	1.134	1.286	1.137	1.331
Median	1.091	1.200	1.093	1.249
Minimum	1.011	1.023	1.011	1.020
Maximum	2.655	3.147	2.715	3.303
95th Percentile	1.368	1.784	1.368	1.860

Table 6: Pair-wise Pearson Correlation between Inefficiency Estimates

	Model 1	Model 1a (without ND)	Model 2	Model 2a (without ND)
Model 1	1.000			
Model 1a (without ND)	0.631	1.000		
Model 2	0.977	0.623	1.000	
Model 2a (without ND)	0.604	0.995	0.615	1.000

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