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Examining the Effects of Deregulation on Retail Electricity Prices

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Examining the Effects of Deregulation on Retail Electricity Prices*

Abstract

A primary aim of deregulation is to reduce the customer cost of electricity. In this paper, we examine the degree of success in reaching that goal using a variety of methods. We examine rates for each of four customer classes; for regulated, deregulated and publicly owned utilities; and for three definitions of deregulation. We control for a variety of factors which may independently affect differences in electricity price: climate, fuel costs, and electricity generation by energy source. Taken as a whole, the results from our analysis do not support a conclusion that deregulation has led to lower electricity rates.

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I. INTRODUCTION

After the Federal Energy Regulatory Commission issued order number 888 in 1996, many states began to initiate programs designed to allow varying degrees of competition among privately-owned utilities. Briefly, there were four major components used to effect deregulation: the formation of Independent System Operators (ISO's), the establishment of wholesale auction-based markets for electricity, retail-choice programs, and the breakup of vertical electricity monopolies, usually through a divestiture of the generating assets of transmission and distribution companies. By encouraging competition, deregulation aimed to increase the efficiency of the electricity market, thus lowering retail electricity prices and improving the quality of service. By 2002, over 30% of the electricity sales (by kilowatt-hour) in the United States were occurring in deregulated states, serving customers in 13 states and the District of Columbia with almost 41% of the country's population. In those states, almost 80% of the power produced was generated by privately-owned companies (EIA, Form 861). In this paper, we are concerned with investigating the success of one of the goals of deregulation: lowering retail energy prices.

Deregulated markets, according to economic theory, were expected to be competitive, offering lower marginal costs and lower rates. "Has Restructuring Improved Operating Efficiency at US Electricity Generating Plants?" (Markiewicz et al, 2004) looks at the changes in non-fuel operating efficiencies and employment costs at municipally owned plants and investor owned plants in deregulated and regulated states. The results show that investor-owned plants in deregulated states reduced both costs by about 5% relative to investor-owned plants in still regulated states and reduced labor costs by 15% and non-fuel operating expenses by 20% when compared to municipal, federal and cooperative plants. A similar study, "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants" (Bushnell and Wolfram, 2005) shows similar results for fuel efficiency changes in deregulated plants. Controlling for output level, deregulated plants used 2% less fuel per MWh of electricity produced, averaged across different fuel types, than still-regulated plants, especially at high output. "Emissions Trading, Energy Restructuring, and Investment in Pollution Abatement" (Fowlie, 2005) finds that deregulated utilities choose less expensive pollution abatement options than still regulated utilities.

Finally, "Testing the Effects of Holding Forward Contracts On the Behavior of Suppliers in an Electricity Auction" (Oh and Mount, 2004) looks at the effect of different kinds of forward contracts and their usefulness in reducing high electricity spot prices, as well as the efficacy of computer agents for simulating interactions in such markets. Forward contracts which are held throughout the entire period offer lower prices than forward contracts which are periodically renewed or forward contracts purchased in an active trading market, which allows them to be influenced by high spot prices.

However, other factors such as the concentration of market power, poorly designed energy markets, unusual climate conditions, or high fuel costs may have had an opposite effect, possibly resulting in ultimately higher prices. "Market Efficiency, Competition, and Communication in Electric Power Markets: Experimental Results" (Chapman et al, 2004) looks at the minimum number of electricity producers in an auction market necessary to result in wholesale prices approximating a competitive level. Through empirical tests, the researchers tried to see if competitive prices were achieved with six, 12, and 24 suppliers if no communication of any sort was allowed among producers. Then, increasingly less restrictive behaviors were allowed. Generally, if prices in a market are within 10% of the competitive price, the auction market is considered to be workably competitive. Under the restrictive communications rules, only a market with 24 producers is not significantly above this benchmark (though it is significantly above the competitive price.) As restrictions on communication are lessened, prices approach those predicted under a monopoly, even though indexes of competition suggest the market is competitive. The article does not discuss what price level might be required to ensure sufficient investment in new capital. It might be possible, for instance, to have auction prices significantly above short-run marginal costs, but still below levels necessary to guarantee sufficient levels of capital investment.

"Simulating GenCo Bidding Strategies in Electricity Markets With an Agent-Based Model" (Botterud et al, 2005) examines the issue of market power in electricity markets. Specifically, by modeling the bidding strategies employed in auction-based electricity markets, the study finds that conventional measures used to assess market power, such as the HHI, prove inadequate as a measure for market concentration in the electric industry. Because they fail to take into account the unique limitations of the electric power industry, such as transmission limitations and local load pockets, they can understate the degree of market power held by a given supplier. The market power of a supplier can be best understood by studying the layout of the electric grid.

"Testing the Effects of Inter-Regional Transfers of Real Energy on the Performance of Electricity Markets" (Mount and Thomas, 2004) looks at the results of an experiment designed to test the interaction of market power, transmission constraints, and system reliability. Like the previous paper, this one found that estimating market power and system bottlenecks to be difficult, especially because inter-regional transfers can result in problems with the transmission system appearing in unexpected locations. Furthermore, the authors contend that the reliability of the electric system is a public good and thus, a market system an inefficient means for control – the owners of the grid should continue to be regulated. Finally, the widely-used bilateral contracts which pay wheeling charges across the expected flow route of the real energy are overly simplistic and discount the complex nature of flows across an AC network. Contracts are allowed only if the do not explicitly harm reliability across a path chosen for accounting means, but the path taken by energy in the real word as it flows from generator to consumer rarely follows this accounting path. Thus, different financial contracts such as futures hedging are a more effective means than physical bilateral contracts for the transfers of electricity and should be encouraged.

"Cost Savings from Generation and Distribution with an Application to Italian Electric Utilities" (Fraquelli et al, 2004) looks at the effects of deregulation on the cost of generation, particularly the effect of the breakup of vertical monopolies. By estimating cost functions for electric utilities in Italy, the study finds statistically significant cost savings resulting from vertical integration for average sized firms. Furthermore, there is an element of scale to these cost savings, as large operators see cost savings as high as 30% from vertical integration, versus savings of only 3% for small operators. Also, firms in which the amount of electricity generated and distributed is equal see even higher cost savings. Taken as a whole, these findings suggest that the divestiture included as a component of deregulation may actually lead to increasing costs.

Compared to the number of studies analyzing the effects of deregulation on wholesale prices, there have been relatively few studies that directly compare prices in regulated and deregulated states. "Competition Has Not Lowered US Industrial Electricity Prices" (Apt, 2005) examines the annual rate of change of nominal industrial electricity prices in restructured and regulated states. The study found that in states which initiated retail competition, restructuring of the electricity industry did not lead to lower industrial electricity prices, or reduce the rate at which those prices increase. Also, the study notes that the rate of increase of prices in deregulated states is greater after deregulation than before in twelve out of nineteen states. However, the study made no corrections for variables such as fuel costs or generation ratios, though those are noted as important factors affecting electricity prices.

Like the above paper, "Markets for Power in the United State: An Interim Assessment" (Joskow, 2006) primarily focuses on retail choice programs. He argues that they have the potential to offer lower rates to customers. However, due to political and technical issues, deregulation as a whole has not yet succeeded in its aim of providing reduced prices to consumers. Although real residential rates in states with retail competition decreased more than in states without, real industrial prices decreased less in states with retail competition. In addition, those states which had the greatest rates of switching providers actually saw rate increases. Controlling for other factors leads to more agreement on the effects of retail competition across customer classes: prices decreased about 5% to 10% at the means of the sample for industrial and residential customers. In recent years, many of the technical issues have been addressed (e.g. "seams problems", new generation and transmission incentives), and now Joskow says the largest obstacles to effective deregulation are political ones (e.g. “delays in implementing Order 2000 and the withdrawal of the proposed SMD rule in July 2005”).

Two other studies had conflicting results, though they were limited in their geographic scope. “Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs” (Biewald et al, 2004) examines wholesale power costs in the PJM market for selected companies and compared them to estimated generation costs under the former regulated regime. Essentially, hypothetical generation costs under the regulated regime were estimated by indexing a base year generation cost to fuel share and fuel cost figures for three utility companies. The study also acknowledges several flaws with this approach. First, the indexed costs include some cost components not included in the current wholesale power costs, such as “stranded costs” and transmission costs. Also, wholesale power costs may be different than retail power costs due to factors such as marketing costs and market power. The authors also posit that wholesale power costs have also been unusually low in the PJM market due to a surplus of new capacity in the region. Finally, only three companies in PJM were studied, and it might be possible that an analysis of other companies in the region would show different results. “Putting Competitive Power Markets to the Test - The Benefits of Competition in America’s Electric Grid: Cost Savings and Operating Efficiencies” (Global Energy Decisions, 2005) looks at the benefits to customers in the Eastern Interconnect realized through deregulation. Through a simulation of expected market prices had deregulation not occurred, Global Energy Decisions estimated that from 1999-2004, customers in that region saved $15.1 billion as a result of deregulation, attributed to increased operating efficiencies at power plants. Changes in ownership resulted in shorter refueling outages, better capacity factors and improved reliability. Furthermore, new territories added to the study area in 2004 realized an annualized savings of $85.4 million, and customers throughout the Eastern Interconnection also benefited, thanks to an elimination of seams in the market.

"CERA: N.A. Restructuring Only Gets Grade of C+" (Platts, 2005) summarizes the initial findings of a CERA study which finds mixed results from deregulation in the United States. The study claims that customers in the South and the Northeast saw significant savings from deregulation, mostly resulting from rate freezes and a competitive wholesale market, though customers in the West paid higher prices under deregulation than they would have under a regulated regime. Many states that are implementing deregulation are still and have not yet achieved full competition.

II. DEFINING RETAIL ELECTRICITY PRICES USED

To examine the effects of deregulation on retail electricity prices, we have used a variety of measures, including different customer classes and definitions of deregulation. We have included four different customer classes: average annual prices for residential, commercial, and industrial customers and total average annual electricity prices from 1990-2003. Additionally, we have separated electricity suppliers into three different categories: privately-owned utilities in regulated states, privately-owned utilities in deregulated states, and publicly-owned utilities. For the purposes of this paper, we are examining three variations in a definition of deregulation. For our primary definition, we consider as deregulated those utilities which belonged to an ISO with an auction-based market at the end of the period in 2002. As a second definition, we consider a utility to be deregulated only for those years in which it actually belonged to an ISO. Finally, we take a utility as deregulated only for the years it belonged to an ISO which had an auction-based market. For example, the New York ISO was formed in 1998 and initiated energy markets in 1999. Under the first definition, we would place privately-owned utilities in New York State in the deregulated category for the entire time period, because in 2002 it belonged to the NYISO, which had a wholesale market. Under the second definition, we would only consider privately-owned utilities in New York State to be deregulated from 1998 onward. Under the final definition, privately-owned utilities in New York State would only be defined as deregulated from 1999 onwards. Publicly-owned utilities in New York State would be classified separately for the entire time period, under all definitions of deregulation. For all of these categories (three definitions of deregulation and four definitions of customer class), we have examined electricity prices using both real and nominal prices. A map of deregulated states is shown in Figure 1.

III. TRENDS IN RETAIL ELECTRICITY PRICES

First, we will analyze electricity prices without correcting for other factors to gain some familiarity with the data. Although we have only chosen to highlight a few graphs below, we have analyzed the information for all twelve combinations of customer classes and definitions of deregulation as noted in the previous section. In general, patterns and results were similar.

Figure 2 shows nominal industrial electricity prices for the three institutional classes: deregulated privately-owned utilities, regulated privately-owned utilities, and publicly-owned utilities. In this figure, the prices in each institutional class are averaged for utilities in the lower 48 states. We are using our primary definition of deregulation for this, meaning that any privately-owned utility which belonged to an ISO with a functioning wholesale market in 2002 is considered deregulated for the purposes of this comparison. As Figure 2 illustrates, only customers of deregulated utilities saw an appreciable change in energy prices over the time period. In nominal terms, the rate

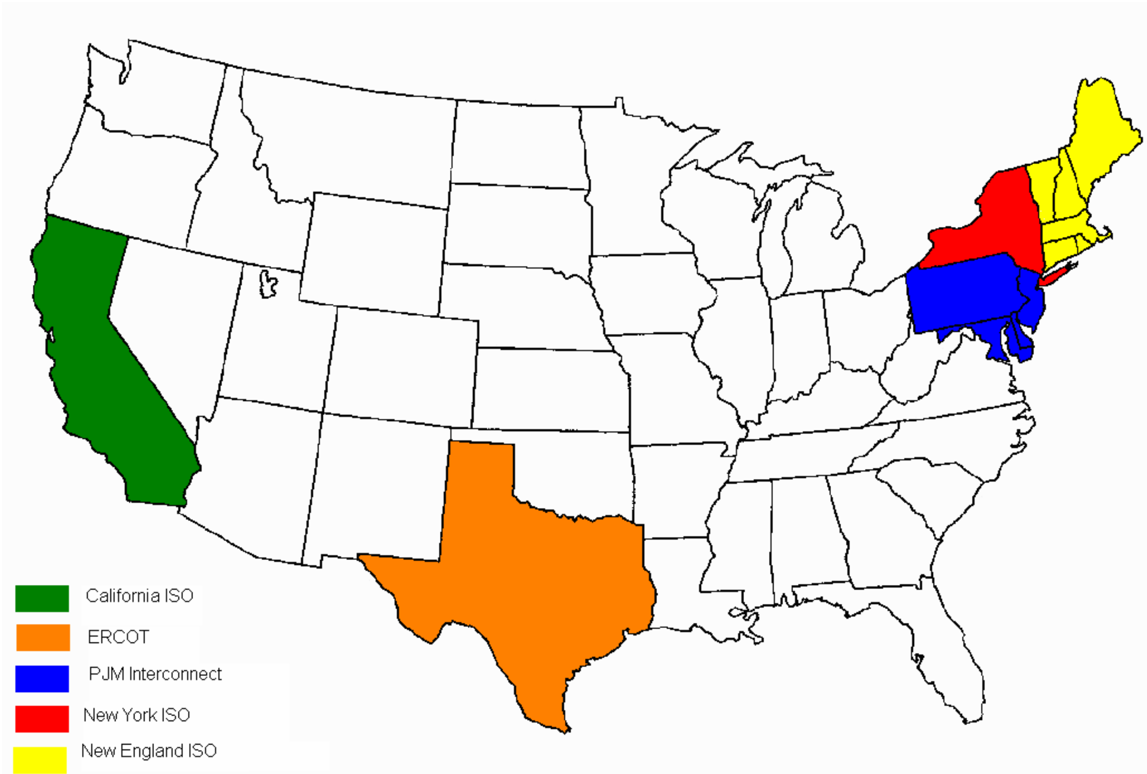

Figure 1. Deregulated States as of 2002

increase for deregulated customers was over one cent per kilowatt-hour, while the rate increases for the two other categories were less than a third of that: 0.18 cents per kilowatt-hour for customers of regulated, privately-owned utilities and 0.27 cents per kilowatt-hour for customers of publicly-owned utilities. (Figure 2 portrays industrial customer prices; the pattern is similar for all four customer classes.)

Figure 3 illustrates the difference in prices between privately-owned deregulated and regulated utilities in terms of a price gap, which is defined as

(Deregulated Prices – Regulated Prices)/(Regulated Prices) x 100 **(1)**

Results for industrial prices are thus equivalent, at least in sign, to trends for the other consumer classes. The difference in electricity prices between deregulated and regulated utilities increased over the study period.

Figure 4 repeats the analysis done in Figure 3, but this time broken down by ISO and only for total prices – the average cost of electricity across all customer classes. Using this analysis, it becomes obvious that the different ISO's have responded in different ways. Figure 4 suggests that most of the gap increases in Figure 3 can probably be attributed to the massive jump in the California ISO gap, especially given the large size of the California market as well as the large increase in relative prices. However, in Figure 4, New York and the states in the New England ISO followed the same general pattern, although the increase was not as pronounced as with California. Also notice that although Texas ended the period with deregulated prices below regulated prices, the advantage declined over the period. Like Figure 3, patterns for total consumer electricity prices are similar for all definitions of deregulation and all customer classes. (Incidentally, in Figure 4, the regulated average is calculated over all states not in an ISO; the deregulated average price is defined for each ISO.) With the exception of California and New York, deflated prices declined for all customers for all types of utilities, but at different rates. In California and New York, only residential customers saw a reduction in the real cost of electricity between 1990 and 2003.

It appears as though deregulation may not have succeeded in its aim of lower prices through the efficiencies generated by competition. However, there may be other important factors determining this pattern. Several are addressed in the next section.

IV. EXPLANATORY VARIABLES DEFINED

We have examined a number of explanatory variables to attempt to explain the differing prices of electricity between states and regulation class. Climate variables are the first possible explanation for price differences, as unusually hot or cold years could cause a high level of demand, and thus impact generating costs and prices. To examine this effect, we have created the delta degree day variables, defined as the actual number of heating or cooling degree days in a given year less the mean number in each state.

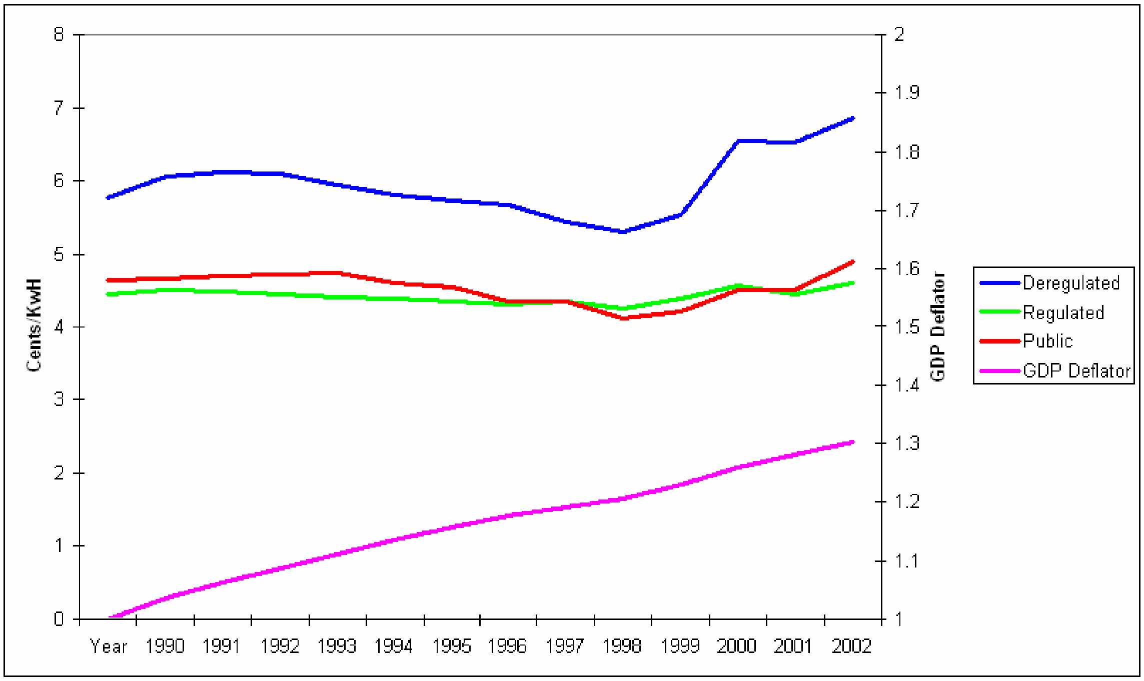

Figure 2. Nominal Industrial Electricity Prices and GDP Deflator

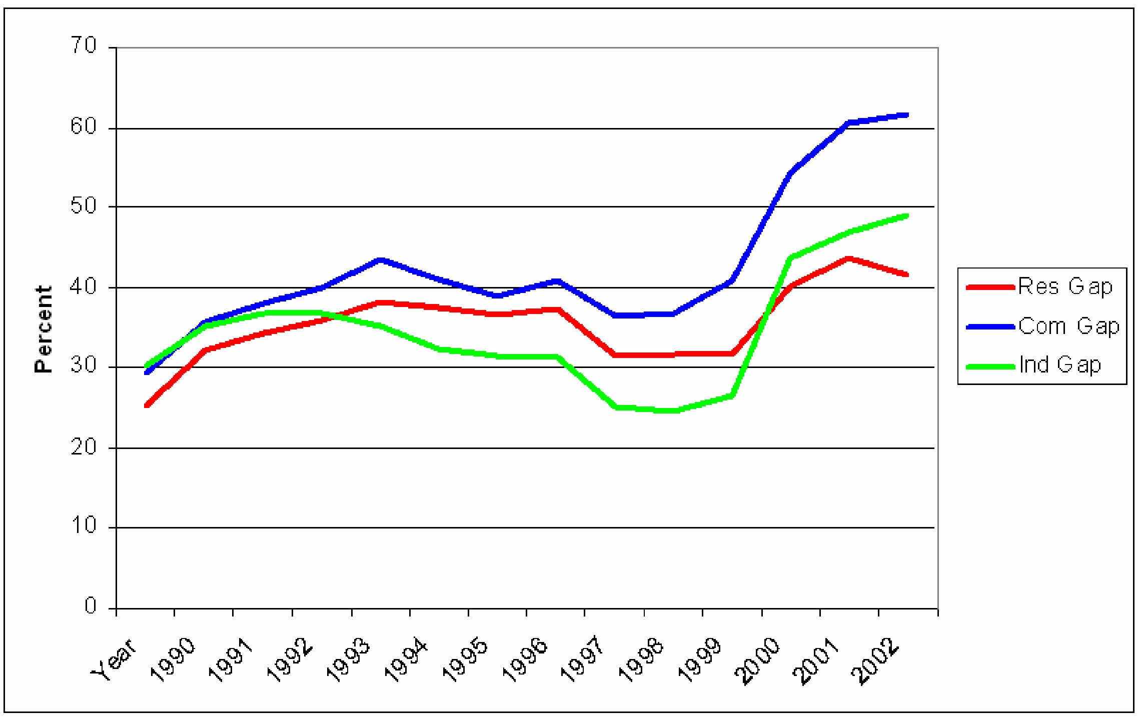

Figure 3. Price Gap for Privately-Owned Deregulated and Regulated Utilities

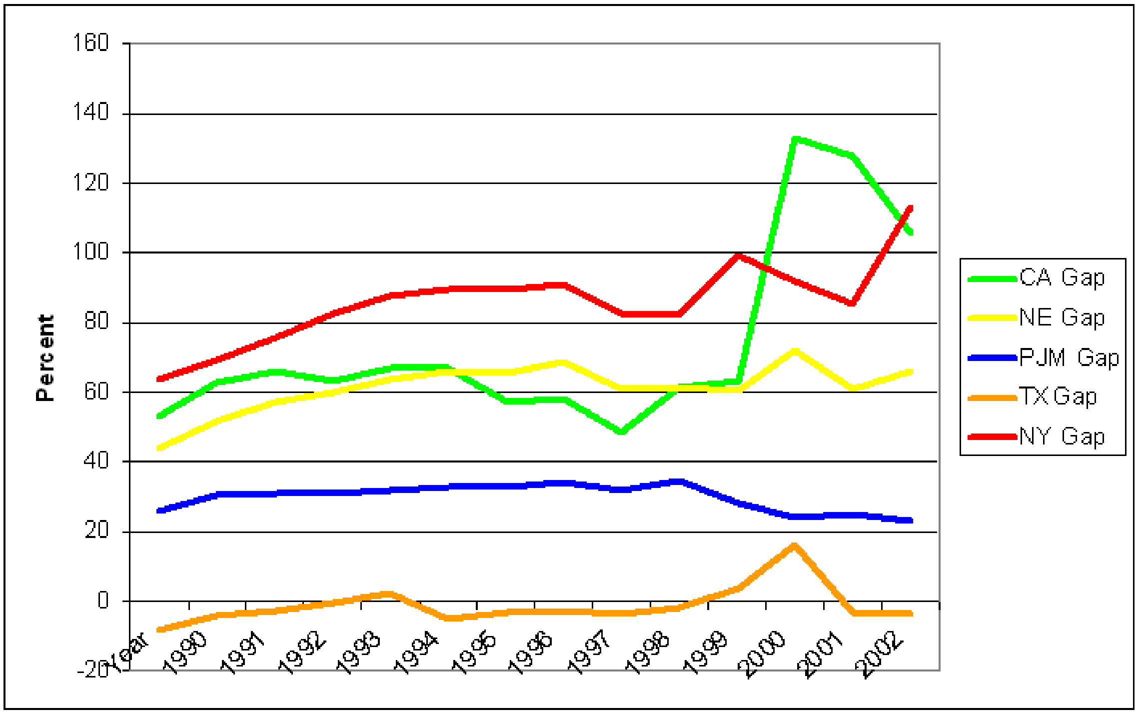

Figure 4. Price Gaps for Total Electricity Prices, Privately-Owned Deregulated and Regulated Utilities, by ISO

Also for each state, we have calculated the amount of electricity generated by six types of power plants: coal, oil, natural gas, nuclear, hydropower, and other renewables. We expect states with more low-cost generating capacity to have lower retail prices. For example, coal, hydropower, and nuclear generation all generally have much lower marginal costs than natural gas generation or electricity from other renewable sources. However, high capital costs for generating plants may result in higher retail prices through "stranded cost recovery." For instance, California utilities estimated their stranded costs to be between 21 and 25 billion dollars (Michaels 1997), to be paid by consumers through transition charges on electricity bills.

Of course, fuel costs matter as well as generation mix. We have also included average annual fuel costs per million BTU (MBTU) for coal, petroleum and natural gas. We expect that an increase in any of these prices will cause the price of electricity to increase. Our fuel data has problems because some of our data is missing and must be replaced with hopefully appropriate data from nearby states. In total, some price data for eighteen states is missing. In some cases, we are only missing data for a single year for a single type of fuel. For example, there is no data for the cost of natural gas in North Carolina in 1990. In other cases, we may be missing data on all fuel costs in a state for a given year or missing all the data on one fuel type, in the case of coal prices for California. California uses coal generation, but it is produced in other states. If a state is part of an ISO, we have used the average of the rest of the states in the ISO to fill in the missing fuel costs. If not, or the state is the only state in an ISO, we used data from nearby states which appear to have similar fuel costs. For full details, see the attached appendix A.

For all of the explanatory variables discussed so far, gap variables have also been constructed in a manner similar to electricity price gaps. In this case, the equation is:

(Deregulated Utility Value – Average Value for Regulated Utilities)/(Average Value for Regulated Utilities) x 100 **(2)**

Finally, we have constant terms for deregulation status. Each ISO is assigned a constant term, and there is a different term for regulated privately-owned utilities. Thus, we have six constant terms relating to regulation status: privately-owned regulated utility, California ISO, PJM Interconnect, Energy Reliability Council of Texas, New England ISO, and New York ISO. If deregulation has been effective at reducing retail electricity rates, the constant terms for ISO's should have a negative or zero coefficients. Publicly owned utilities are the default case because their prices are generally the lowest. In our final regression, we also include terms for NERC regions, shown in Figure 5.

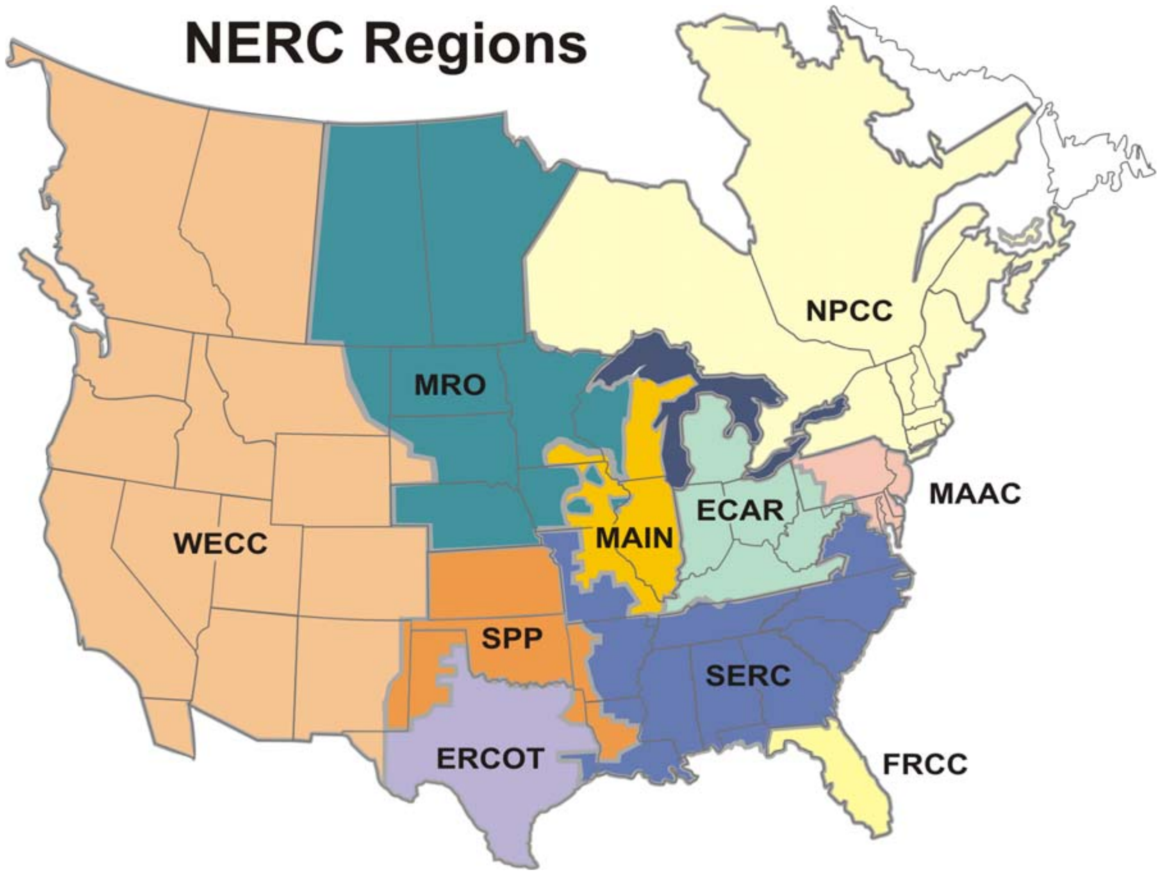

Figure 5. NERC Regions in North America (NERC)

V. TRENDS IN EXPLANATORY VARIABLES

Trends in our explanatory variables may explain the observed trends in electricity prices. Some factors in the data account for increasing costs outside of the realm of deregulation. For example, Figures 6 and 7 illustrate the difference in generation mix between regulated and deregulated states. Deregulated states tend to use more natural gas and nuclear power and less coal and hydropower. In general, hydropower is extremely cheap (and often controlled by publicly-owned utilities) so it is no surprise that states with ready supplies of hydropower can offer lower power rates.

In fact, one of the main arguments in favor of deregulation was that it would allow states with an abundance of cheap electricity to sell electricity to states with higher rates (Van Doren and Taylor 2004). Likewise, natural gas is usually more expensive than coal generation, and while nuclear power may be, in marginal terms, cheaper than fossil-fuel power reactors, its capital costs can amount to significant sums.

As Figure 8 demonstrates, fuel prices are often higher in deregulated states. In the New England states, for instance, they were sometimes over sixty cents per million BTU higher. The only reason that California coal costs are so close to the average coal costs for regulated states may be that California coal generation occurs in the four corners states and Arizona coal costs were used. Natural gas prices are more constant across the different regulation categories, although there are large spikes for New England in 1992 and California in 2001.

Now that the basic trends in the explanatory variables and the electricity prices are understood, we can move on to our preliminary regression results.

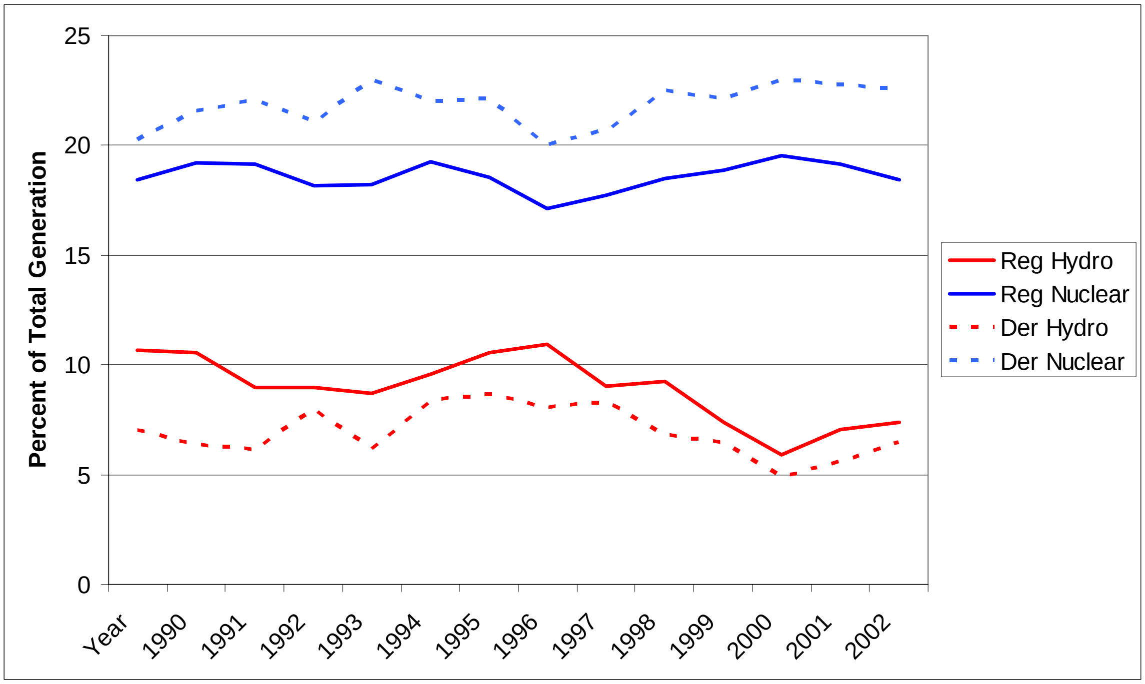

Figure 6. Fuel Sources in Regulated and Deregulated States: Hydropower and Nuclear Generation

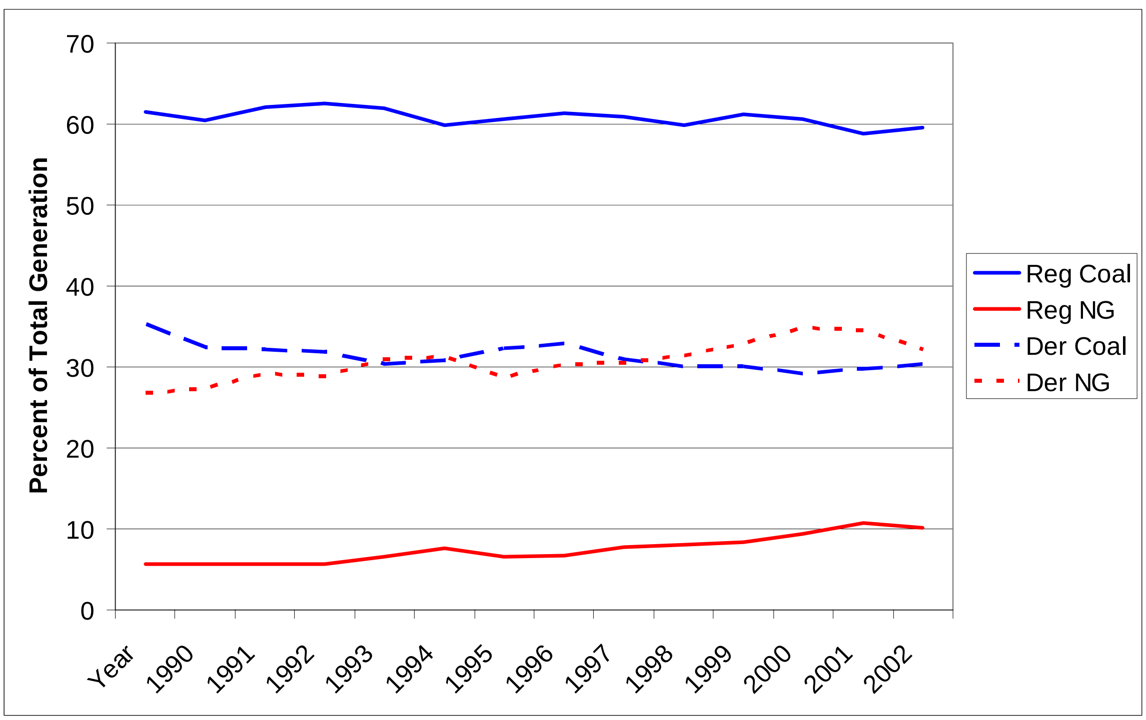

Figure 7. Fuel Sources in Regulated and Deregulated States: Coal and Natural Gas Generation

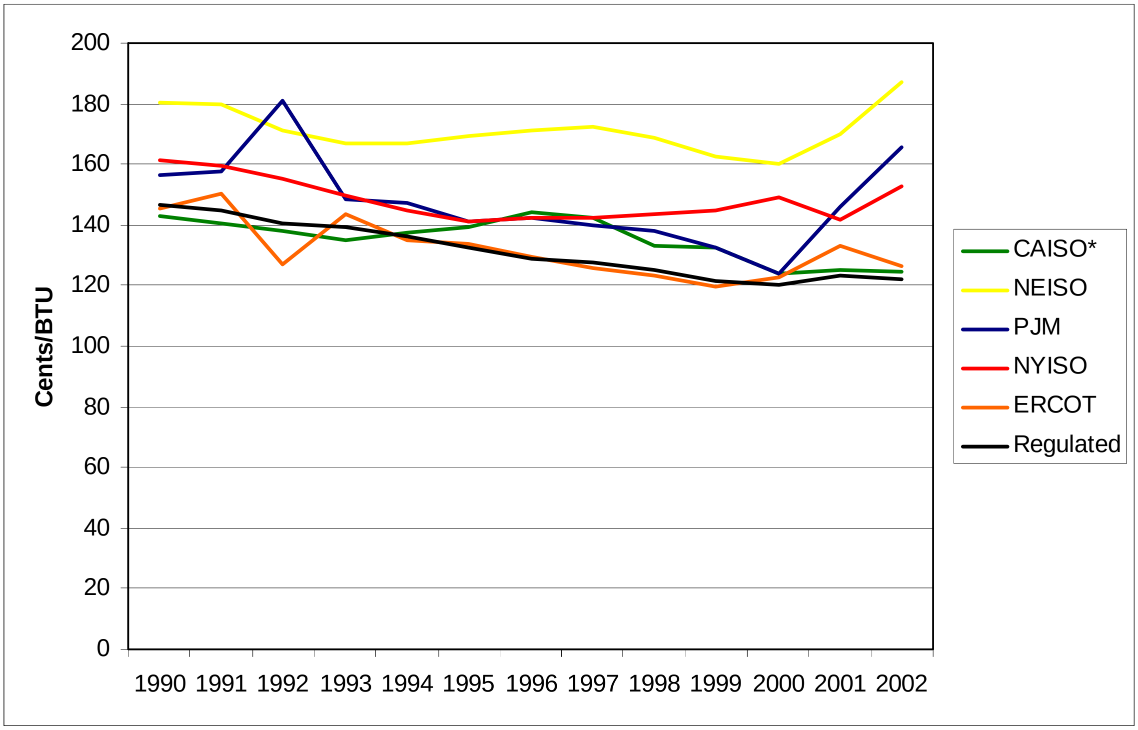

Figure 8. Comparison of Coal Costs for ISO's and Regulated States
MBTU are "Million British Thermal Units"

VI. RESULTS FROM ECONOMETRIC ANALYSIS

In section III, we found that rates (defined in real dollars) declined over the time period for most customers,[1] although that decline was less in deregulated states. In this section, we seek to understand how this pattern has been influenced by variations in fuel prices, types of generation, and climate. A variety of econometric models were used to test these effects, but break down into three broad classes. In the initial set of analyses, explained and summarized in Tables 1-4, we use customer prices as the dependent variables, and also compare results according to estimation method. The explanatory variables include climate, generation mix, fuel prices and constant terms for deregulation status.

The second set of analyses (Tables 5-12) all use price gaps (as defined in Equations (1) – (3)) as dependent variables, and are all undertaken with the GARCH method to correct for possible problems arising from heteroscedasticity and autocorrelation. Two price gap definitions are used: a deregulated/regulated gap, and a private/public gap. Additionally, each is modeled using both non-gap and gap explanatory variables.

In the final set of analyses (Tables 13 – 15), customer prices are again used as dependent variables (as in Tables 1-4). However, to the list of explanatory variables we add constant terms for NERC region, generation ratios and proportionality-weighted fuel prices. The final two explanatory variables replace fuel prices and generation mix in the regression. Finally, Table 15 summarizes the coefficients of the ISO constant terms across different definitions of deregulation.

[1] The exception: in New York and California, industrial and commercial rates (in real dollars) increased for customers of private utilities.

A) Electricity Prices vs. Climate, Generation Mix, Fuel Prices, Deregulation Status

Table 1 shows the results from a typical OLS regression, while Table 2 shows the results from a typical GARCH regression; both regressions (as well as all other typical regression results that follow) use nominal industrial electricity prices (or industrial electricity price gaps, in the case of the gap models) as the dependent variable. Tables 3 and 4 summarize the results from the 24 regressions performed for the OLS and GARCH model respectively. These 24 regressions include all possible permutations of deregulation definition, customer type, as well as real and nominal prices.

Taken together, Tables 1 and 2 show similar results for most explanatory variables. However, two of the delta heating and cooling degree day[2] coefficients are reversed in sign from our expectations. The delta cooling degree day coefficient is negative in the OLS model; in the GARCH model, the delta heating degree day coefficient is negative. In both cases, we would expect all degree day variables to be positive. We also expect all the fuel price coefficients to be positive, but the coefficient for coal price is negative under the GARCH model. But, with the exception of other renewable sources, the ranking of the generation coefficients seems to agree with our expectations. Taken together, they confirm that coal and hydropower provide the cheapest power sources, while nuclear, petroleum, natural gas and other renewable sources have increasingly positive impacts on customer rates. Finally, most of the deregulation status constant terms are unchanged between the two regressions. The coefficients for California, New England and New York are

[2] Delta degree days are defined as the actual number of heating or cooling degree days in a state for a given year minus the mean number of heating or cooling degree days for that state.

higher, while the coefficients for PJM and ERCOT are insignificant, close to zero, or negative.

Tables 3 and 4 mostly confirm this analysis. Some of the variables which give unexpected results for nominal industrial electricity prices are insignificant in most regressions, such as the delta heating and cooling degree day variables in the GARCH model, summarized in Table 4. The patterns discussed above for relative generation cost and deregulation status remain intact. CAISO and NYISO are significant and positive in every regression; NEISO is positive and significant in all but two, while the results ERCOT and PJM are more often negative and insignificant. As a last note, because the GARCH term is not significant in this model, it has been dropped from future regressions which correct for heteroscedasticity and autocorrelation; we will now be using ARCH estimation.

B) Electricity Prices Gaps vs. Gap and Non-Gap Explanatory Variables

Tables 5 through 12 show the results from four different gap regressions. The model summarized in Table 5 uses the price gap between deregulated and regulated industrial electricity prices as a dependent variable (as defined in Equation (1)) with a wide range of gap explanatory variables (as defined in Equation (2)): heating and cooling degree day gaps, fuel prices gaps, and generation gaps with constant terms for deregulation status. The model behind Table 6 has the same dependent variable, but the explanatory variables are expressed in their original units, as in the models summarized in section (A). Tables 9 and 10 repeat this analysis, but use the gap between private and public utilities as the dependent and gap explanatory variables. The equation used to generate gap variables for this model is:

(Privately-Owned Utility Value – Average Value for Public Utilities)/(Average Value for Public Utilities) x 100 **(3)**

As with Tables 5 and 6, the model summarized in Table 9 uses gap explanatory variables and that in Table 10 uses the variables in their original units.

Tables 7, 8, 11 and 12 summarize the results from twelve gap regressions for the previous models, again utilizing all combinations of customer classes and definitions of deregulation. With a gap model, there are only twelve permutations instead of 24 because the price gap is the same whether prices are expressed in nominal or real terms. As a whole, these results suggest that gap explanatory variables explain price differences between different regulation or ownership classes much better than the raw values for deregulated state or private-owned utilities. Price differences cannot be easily explained by any of these models, though customers of privately-owned utilities in many deregulated states have significantly higher retail costs of electricity than customers of publicly-owned utilities. For instance, Table 11 shows this price gap is higher for customers of every ISO except ERCOT.

C) Electricity Prices vs. Climate, Fuel Ratios, Proportionality-Weighted Fuel Prices, Deregulation Status, NERC Region

The final regression model examines generation ratios instead of generation in its natural units, to separate scale and generation mix effects. Like the first model, it uses electricity prices as the dependent variable, for four customer classes and both nominal and real prices:

$$P_e = HDD + CDD + TG + DER + NERC + \sum (w_i P_i + w_i) \qquad \textbf{(4)}$$

HDD and CDD are heating and cooling degree days, respectively. TG, the total generation of each state, is used to quantify scale effects. The constant terms DER and NERC are used to indicate the deregulation status of a state and to which NERC region(s) it belongs. Fuel costs are included for coal, oil and natural gas as the product of fuel costs and generation ratio for that fuel type – the proportionality weighted fuel price. The sum of these terms represents the average fossil fuel cost per million BTU for a state. Finally, the generation ratios for all major sources of power are included. Because these ratios sum to one for each state, the intercept is excluded to avoid problems with multicollinearity. Table 13 illustrates results from one regression, while Table 14 summarizes results for all 24 regressions. This model explains variations in electricity prices very well. The climate variables still behave differently than expected, but are not significant very often. Also, the coal cost ratio is the only fuel cost variable effective at explaining differences in electricity prices. However, almost all of the generation ratios are significant in every regression and suggest that coal and hydropower provide the cheapest electricity, while oil, nuclear, natural gas and other renewable sources are increasingly more expensive. It is interesting to note that, despite its low marginal costs, states which rely heavily on nuclear power see higher prices of electricity than those relying heavily on coal. This may be partially explained by the issue of stranded cost recovery. The negative coefficient on total generation suggests the findings of Fraquelli et al. hold for the United States: there are economies of scale in the electric power industry. The price effect from ISO's follows a familiar pattern: CAISO, NEISO and NYISO all have positive coefficients, while coefficients of ERCOT and PJM are close to zero of negative.

Finally, Tables 15 examines the coefficients of the constant terms for deregulation status across our three definitions of deregulation. For example, the entry is the "CAISO" row under column "1" is the average value of the coefficient from equation (3) from eight regressions, across all customer classes and real and nominal prices. With the exception of PJM, all the coefficients are positive. Except for Texas under definition two and California, all the coefficients are also greater than the Private Regulated coefficient in each definition. However, only 39 out of 60 coefficients from which these averages are generated are significant at the 5% level. Although the results in Table 15 are complex, they do not support a conclusion that in aggregate deregulation has lowered electricity rates relative to those rates in still-regulated states.

Table 1. Nominal Industrial Electricity Prices: Typical Regression Results, OLS[3]

Adjusted R^2: 0.42
Observations: 1177

Variables	Coefficients	T Statistic
Intercept	6.21	13.25
Delta Heating Degree Days	1.21E-04	1.12
Delta Cooling Degree Days	-2.56E-04	-2.47
Nominal Coal Price per MBTU	5.18E-03	4.14
Nominal Natural Gas Price per MBTU	1.94E-04	1.02
Nominal Oil Price per MBTU	9.78E-04	3.09
Coal Generation	-1.64E-08	-11.33
Hydropower Generation	-4.69E-08	-13.61
Natural Gas Generation	7.19E-09	3.53
Nuclear Generation	1.31E-08	4.82
Other Renewables Generation	7.19E-08	4.59
Petroleum Generation	3.47E-08	4.34
Private Regulated	-0.46	-5.09
CAISO	2.71	6.47
PJM	0.52	2.42
ERCOT	-0.97	-2.33
NEISO	2.76	15.37
NYISO	1.42	3.39

[3] Although data on electricity prices are available for 1990-2003, data on some of the explanatory variables are not. Thus, this regression is only for the years 1990-2002.

Table 2. Nominal Industrial Electricity Prices: Typical Regression Results, Corrected for Heteroscedasticity and Autocorrelation

Total R^2: 0.88

Observations: 1177

Variables	Coefficients	T Statistic
Intercept	5.23	48.35
Delta Heating Degree Days	-2.10E-05	-0.84
Delta Cooling Degree Days	1.29E-04	2.86
Nominal Coal Price per MBTU	-5.07E-04	-3.38
Nominal Natural Gas Price per MBTU	1.50E-04	3.64
Nominal Oil Price per MBTU	2.59E-04	4.85
Coal Generation	-5.85E-09	-9.44
Hydropower Generation	-3.71E-08	-20.76
Natural Gas Generation	7.93E-09	5.30
Nuclear Generation	4.44E-09	2.82
Other Renewables Generation	-2.52E-08	-1.63
Petroleum Generation	3.29E-09	0.79
Private Regulated	-0.59	-21.02
CAISO	5.08	13.26
PJM	-1.36	-14.17
ERCOT	-0.97	-2.73
NEISO	1.79	36.68
NYISO	4.10	9.64
AR(1)[4]	-0.91	-181.4
ARCH(0)	0.12	35.00
ARCH(1)	1.33	31.92
GARCH(1)	1.08E-18	0.00

[4] These coefficients represent ω (AR), α (ARCH), and γ (GARCH) in the following GARCH model:

$y^t = x^{t}{'}\beta + \nu^t$

$\nu^t = \varepsilon^t - \varsigma\nu^{t-1}\ldots$

$\varepsilon^t = \sqrt{(h^t e^t)}$

$h^t = \omega + \Sigma\, \alpha_i(\varepsilon_{t-i})^2 + \Sigma\, \gamma_j h_{t-j}$

As a whole, the ARCH and GARCH models correct for heteroscedasticity by modeling the variance of the error terms as the sum of a constant, a term which relates to the previous error terms and a term which relates to the pervious variances of the error term. The "AR(1)" term is the initial constant term. The "ARCH(0)" and "ARCH(1)" terms are the coefficients on the effect of the current and previous period's error term on the variance of the current period's error term. Finally, the "GARCH(1)" is the coefficient for the effect of last year's variance of the error term on the current variance of the error term. In Table 2, the significant coefficients for AR(1), ARCH(0) and ARCH(1) indicate that the error terms have been corrected by a process which corrects for time-dependent error terms. The low t-statistic for the GARCH(1) coefficient indicates that last year's error variance does not significantly affect the variance estimate for the current year. For more information see Pindyck and Rubinfeld, pp. 285-292.

Table 3. A Meta-Summary of 24 Regressions, OLS

Variable	Average Coefficient	Number of Regressions Significant at 5% Level
Intercept	6.78	24
Delta Heating Degree Days	-1.10E-04	12
Delta Cooling Degree Days	-9.76E-04	24
Coal Price Per MBTU*	1.07E-02	24
Natural Gas Price Per MBTU*	-2.10E-04	0
Oil Price Per MBTU*	6.68E-04	5
Coal Generation	-2.04E-08	24
Hydropower Generation	-4.60E-08	24
Natural Gas Generation	1.29E-08	24
Nuclear Generation	2.12E-08	24
Other Renewables Generation	4.63E-08	12
Petroleum Generation	4.32E-08	24
Private Regulated	2.11E-01	17
CAISO	3.64	24
PJM	7.03E-01	10
ERCOT	-4.23E-01	2
NEISO	2.92	24
NYISO	3.72	20

* These are treated the same with regards to inflation as the dependent variable. If the electricity cost variable is given in real terms, so are these.

Table 4. A Meta-Summary of 24 Regressions, Corrected for Heteroscedasticity and Autocorrelation

Variable	Average Coefficient	Number of Regressions With Significant Coefficient at 5% Level
Intercept	6.00	24
Delta Heating Degree Days	-4.28E-05	1
Delta Cooling Degree Days	-1.61E-05	8
Coal Price Per MBTU*	2.50E-03	21
Natural Gas Price Per MBTU*	4.56E-05	7
Oil Price Per MBTU*	4.78E-04	21
Coal Generation	-1.21E-08	23
Hydropower Generation	-2.25E-08	24
Natural Gas Generation	8.91E-09	19
Nuclear Generation	6.34E-09	15
Other Renewables Generation	2.42E-08	13
Petroleum Generation	1.42E-08	17
Private Regulated	-0.28	23
CAISO	3.93	24
PJM	-0.83	17
ERCOT	-0.56	7
NEISO	1.39	22
NYISO	3.84	24
AR(1)	-0.84	24
ARCH(0)	0.14	24
ARCH(1)	1.19	24
GARCH(1)	0.29	16

* These are treated the same with regards to inflation as the dependent variable. If the electricity cost variable is given in real terms, so are these.

Table 5. Deregulated/Regulated Industrial Electricity Price Gaps with Gap Explanatory Variables: Typical Regression Results, Corrected for Heteroscedasticity and Autocorrelation

Adjusted R^2: 0.95

Observations: 169

Variables	Coefficients	T Statistic
Heating Degree Day Gap	1.16	31.63
Cooling Degree Day Gap	-0.03	-0.25
Coal Price per MBTU Gap	-0.74	-1.02
Natural Gas Price per MBTU Gap	-0.14	-0.33
Oil Price per MBTU Gap	0.78	1.26
Coal Generation Gap	-0.91	-1.79
Hydropower Generation Gap	-0.29	-0.57
Natural Gas Generation Gap	0.02	0.31
Nuclear Generation Gap	0.48	1.67
Other Renewables Generation Gap	-0.15	-0.93
Petroleum Generation Gap	0.09	1.49
CAISO	370.61	0.99
PJM	-41.73	-0.52
ERCOT	106.40	0.44
NEISO	-16.93	-0.23
NYISO	-74.57	-0.34
AR1	0.02	0.07
AR2	-7.63E-03	-0.02
ARCH0	11035.00	9.03
ARCH1	0.00	0

Table 6. Deregulated/Regulated Industrial Electricity Price Gaps with Non-Gap Explanatory Variables: Typical Regression Results, Corrected for Heteroscedasticity and Autocorrelation

Adjusted R^2: 0.27

Observations: 169

Variable	Coefficient	T-Statistic
HDD	0.02	3.92
CDD	-0.20	-0.63
Real Coal Price	-0.49	-0.39
Real NG Price	-0.10	-0.14
Real Oil Price	0.38	0.54
Coal Generation	-6.46E-06	-1.00
Hydropower Generation	-2.53E-06	-0.03
Natural Gas Generation	4.97E-07	0.09
Nuclear Generation	6.32E-06	0.98
Other Renewables Generation	-2.50E-05	-0.38
Petroleum Generation	3.03E-05	2.17
CAISO	508.36	0.25
PJM	287.29	0.43
ERCOT	1015.00	3.92
NEISO	81.4492	0.12
NYISO	-259.29	-0.11
AR1	-0.19	1.10
AR2	0.17	0.68
ARCH0	160652.00	1335.96
ARCH1	1.12E-23	0.00

Table 7. A Meta-Summary of 12 Deregulated/Regulated Gap Regressions with Gap Explanatory Variables, Corrected for Heteroscedasticity and Autocorrelation

Variables	Average Coefficient	Number of Regressions With Significant Coefficient at 5% Level
Heating Degree Day Gap	1.03	12
Cooling Degree Day Gap	0.09	7
Coal Price per MBTU Gap	-0.25	0
Natural Gas Price per MBTU Gap	-0.03	0
Oil Price per MBTU Gap	0.49	1
Coal Generation Gap	-0.45	4
Hydropower Generation Gap	-0.08	0
Natural Gas Generation Gap	0.03	3
Nuclear Generation Gap	0.21	0
Other Renewables Generation Gap	-0.01	0
Petroleum Generation Gap	0.05	8
CAISO	92.16	0
PJM	-5.13	0
ERCOT	38.24	0
NEISO	-1.97	0
NYISO	-36.08	0
AR1	0.2	0
AR2	-0.04	0
ARCH0	5226.08	12
ARCH1	2.26E-23	0

Table 8. A Meta-Summary of 12 Deregulated/Regulated Gap Regressions with Non-Gap Explanatory Variables, Corrected for Heteroscedasticity and Autocorrelation

Variables	Average Coefficient	Number of Regressions With Significant Coefficient at 5% Level
HDD	0.01	0
CDD	0.02	0
Real Coal Price	0.12	0
Real NG Price	-0.12	0
Real Oil Price	0.20	0
Coal Generation	-4.2E-06	0
Hydropower Generation	-3.9E-06	0
Natural Gas Generation	1.28E-07	0
Nuclear Generation	4.56E-06	0
Other Renewables Generation	-7.50E-06	0
Petroleum Generation	1.90E-05	10
CAISO	101.86	0
PJM	45.23	0
ERCOT	234.72	4
NEISO	42.15	0
NYISO	-243.28	4
AR1	0.18	0
AR2	-.17	0
ARCH0	134271.90	12
ARCH1	-3.60E-24	0

Table 9. Private/Public Industrial Electricity Price Gaps with Gap Explanatory Variables: Typical Regression Results, Corrected for Heteroscedasticity and Autocorrelation

Adjusted R^2: 0.89
Observations: 582

Variables	Coefficients	T Statistic
Intercept	-22.25	-6.46
Heating Degree Day Gap	-0.04	-2.41
Cooling Degree Day Gap	0.02	1.39
Coal Price per MBTU Gap	-0.11	-5.16
Natural Gas Price per MBTU Gap	0.08	6.13
Oil Price per MBTU Gap	-0.01	-4.15
Coal Generation Gap	-0.05	-4.67
Hydropower Generation Gap	-0.02	-7.21
Natural Gas Generation Gap	0.02	3.08
Nuclear Generation Gap	0.01	2.13
Other Renewables Generation Gap	-0.04	-4.45
Petroleum Generation Gap	4.80E-03	1.98
CAISO	140.91	9.60
PJM	13.61	2.94
ERCOT	21.91	1.84
NEISO	69.34	15.00
NYISO	-0.23	-0.03
AR1	-0.88	-31.49
AR2	-0.02	-0.80
ARCH0	39.67	16.32
ARCH1	1.26	9.45

Table 10. Private/Public Industrial Electricity Price Gaps with Non-Gap Explanatory Variables: Typical Regression Results, Corrected for Heteroscedasticity and Autocorrelation

Adjusted R^2: 0.90

Observations: 582

Variable	Coefficient	T-Statistic
Intercept	-6.25	-0.50
HDD	-4.90E-04	-0.55
CDD	1.39E-03	0.61
Real Coal Price	-0.02	-0.59
Real NG Price	2.85E-03	1.06
Real Oil Price	4.84E-04	0.08
Coal Generation	-1.33E-07	-3.39
Hydropower Generation	-2.16E-07	-2.74
Natural Gas Generation	3.43E-07	3.92
Nuclear Generation	1.66E-07	2.07
Other Renewables Generation	-2.60E-06	-2.67
Petroleum Generation	1.22E-07	0.57
CAISO	121.85	5.05
PJM	15.90	1.88
ERCOT	-22.52	-1.25
NEISO	63.57	7.00
NYISO	7.67	0.53
AR1	-0.82	-12.46
AR2	-0.06	-0.94
ARCH0	103.69	15.53
ARCH1	0.42	4.06

Table 11. A Meta-Summary of 12 Private/Public Gap Regressions with Gap Explanatory Variables, Corrected for Heteroscedasticity and Autocorrelation

Variables	Average Coefficient	Number of Regressions With Significant Coefficient at 5% Level
Intercept	-9.65	7
Heating Degree Day Gap	-0.02	3
Cooling Degree Day Gap	2.50E-03	2
Coal Price per MBTU Gap	-0.07	8
Natural Gas Price per MBTU Gap	0.04	9
Oil Price per MBTU Gap	-0.01	10
Coal Generation Gap	-0.06	8
Hydropower Generation Gap	-9.17E-03	4
Natural Gas Generation Gap	0.01	5
Nuclear Generation Gap	0.02	7
Other Renewables Generation Gap	2.80	6
Petroleum Generation Gap	3.64E-03	6
CAISO	46.11	8
PJM	9.17	8
ERCOT	-1.17	0
NEISO	49.56	11
NYISO	28.56	9
AR1	-0.74	12
AR2	-0.09	8
ARCH0	131.77	12
ARCH1	1.23	12

Table 12. A Meta-Summary of 12 Private/Public Gap Regressions with Non-Gap Explanatory Variables, Corrected for Heteroscedasticity and Autocorrelation

Variables	Average Coefficient	Number of Regressions With Significant Coefficient at 5% Level
Intercept	-21.65	0
HDD	1.57E-03	0
CDD	-2.66E-03	0
Real Coal Price	0.17	8
Real NG Price	8.57E-04	0
Real Oil Price	-6.59E-03	0
Coal Generation	-2.1E-07	7
Hydropower Generation	-1.8E-07	3
Natural Gas Generation	1.94E-07	1
Nuclear Generation	2.12E-07	1
Other Renewables Generation	3.20E-07	4
Petroleum Generation	3.94E-07	0
CAISO	46.65	4
PJM	2.40	0
ERCOT	-3.56	0
NEISO	20.42	4
NYISO	14.85	1
AR1	-0.84	12
AR2	0.08	6
ARCH0	294.30	12
ARCH1	0.42	12

Table 13. Nominal Industrial Electricity Prices, with NERC Regions: Typical Regression Results, Corrected for Heteroscedasticity and Autocorrelation

Adjusted R2: 0.96

Observations: 1177

Variable	Coefficient	T-Stat
HDD	-3.80E-05	-1.29
CDD	-4.50E-04	-6.35
Coal Cost Ratio	2.40E-03	1.92
NG Cost Ratio	5.86E-04	0.71
Oil Cost Ratio	1.51E-03	0.63
Coal Ratio	5.10	15.04
Hydropower Ratio	4.35	14.56
NG Ratio	9.18	25.07
Nuclear Ratio	8.28	30.46
Other Renewables Ratio	7.82	10.22
Oil Ratio	6.35	6.22
Private Regulated	-0.39	-5.80
CAISO	0.54	1.27
ERCOT (ISO)	-0.48	-0.94
NEISO	0.86	7.80
NYISO	0.27	0.74
PJM	-1.00	-8.16
Total Generation	-1.76E-10	-0.23
ECAR	-0.15	-0.92
ERCOT (All Utilities)	-0.40	-0.82
FRCC	0.98	3.12
MAAC	-0.22	-1.09
MAIN	-0.98	-7.65
MRO	0.44	3.32
NPCC	0.15	0.92
SERC	-1.04	-7.08
SPP	-0.87	-8.50
WECC	-0.60	-4.36
AR1	-0.07	-1.96
ARCH0	0.48	10.97
ARCH1	0.79	8.21

Table 14. A Meta-Summary of 24 Regressions with NERC Region, Corrected for Heteroscedasticity and Autocorrelation

Variable	Average Coefficient	Number of Regressions With Significant Coefficient at 5% Level
HDD	6.16E-05	2
CDD	-1.52E-04	9
Coal Cost Ratio	1.03E-02	13
NG Cost Ratio	-3.22E-04	2
Oil Cost Ratio	9.79E-04	2
Coal Ratio	4.16	22
Hydropower Ratio	5.92	24
NG Ratio	8.70	24
Nuclear Ratio	8.59	24
Other Renewables Ratio	11.28	24
Oil Ratio	6.96	14
Private Regulated	0.19	10
CAISO	2.33	17
ERCOT (ISO)	0.20	0
NEISO	0.74	6
NYISO	3.11	8
PJM	-0.59	8
Total Generation	-1.99E-09	4
ECAR	0.48	4
ERCOT (All Utilities)	-0.38	1
FRCC	0.95	9
MAAC	0.39	3
MAIN	-1.02	14
MRO	0.33	8
NPCC	0.14	6
SERC	-1.27	20
SPP	-0.11	9
WECC	-0.60	8
AR1	-0.13	15
ARCH0	2.83	23
ARCH1	0.44	9

Table 15. Meta Summary of Coefficients For ISO Constant Terms For Three Definitions of Deregulation; Eight Regressions for Each Definition[5]

ISO/Definition	**1**	Number Significant at 5%	**2**	Number Significant at 5%	**3**	Number Significant at 5%
CAISO	**2.20**	4	**2.24**	6	**2.56**	7
ERCOT	**0.24**	0	**0.09**	0	**0.27**	0
NEISO	**0.95**	4	**0.69**	2	**0.57**	0
NYISO	**3.60**	4	**2.91**	2	**2.82**	2
PJM	**-0.46**	2	**-0.66**	3	**-0.65**	3
Private Regulated	**0.08**	4	**0.23**	3	**0.24**	3

[5] In the first definition, a state which was in an ISO with an operating auction-based market at the wholesale level in 2002 is considered a deregulated state for the entire time period. Under definition two, a state is considered deregulated for those years beginning with its admission to an ISO which has an auction-based market by the end of the period, 2002. For the third and final definition, a state is only considered deregulated for those years in which an active auction-based wholesale market functions in its ISO.

VII. SUMMARY

Overall, our research shows that there is no evidence to support the general expectation that deregulation would result in lower electricity prices. Most of our results, regardless of analysis method, showed that even though most customers in deregulated states saw declines in the real price of electricity, they faced higher prices relative to customers in still-regulated states. Furthermore, these price differences remain even after controlling for climate, generation mix, fuel prices and NERC region, as shown by the coefficients to the constant terms from the regressions discussed in Section VI.

An important area for future research would be involve investigating wholesale costs of power, as well as the differences between retail and wholesale prices. For deregulated states, we can look at the auction-clearing prices in the individual ISO, but no such market mechanism exists in still-regulated states. As a proxy, we might use generating costs for regulated states, but those are not immediately comparable to auction-clearing prices, as the latter would probably include some form of profit or risk premium.

We have examined price differences as affected by climate variables, fuel mix, fuel cost and ISO effects. We have used three definitions of regulatory status, four customer class groupings, and both real and nominal prices. We do not find empirical support for a generalized expectation that customers in deregulated states experienced lower rates than customers in still-regulated states.

Appendix A: Fuel Cost Data Substitutions

State	Fuel	Years	Replacement
California	Coal	1990-2002	Arizona
California	Oil	1995-1997	Arizona
Connecticut	All	2000-2002	Average NEISO
Delaware	Coal	2002	Average PJM
Idaho	All	1990,1991,1993-2002	Nevada
Massachusetts	Coal	2001	Average NEISO
Maryland	All	2001-2002	Average PJM
Maine	Coal,NG	1990,1991,1993-2002	Average NEISO
Maine	Oil	2000-2002	Average NEISO
Montana	Oil	2000-2001	Wyoming
North Carolina	NG	1990	South Carolina
New Hampshire	NG	1990,1991,1996,1998	Average NEISO
New Jersey	NG	2002	Average PJM
Oregon	NG	1990	Oregon
Oregon	Oil	1996	Oregon
Pennsylvania	NG	2002	Average PJM
Rhode Island	Coal	1990,1991,1993-2002	Average NEISO
Rhode Island	NG	1999-2002	Average NEISO
Rhode Island	Oil	1997-2002	Average NEISO
South Dakota	NG	1990,1997,1999-2002	Minnesota
South Dakota	Oil	1994,1995,1997-2002	Minnesota
Tennessee	NG	1990,1991,1993-2002	Kentucky
Vermont	All	1990	Average NEISO
Vermont	Oil	1990,1991,1999,2001,2002	Average NEISO
Washington	NG	1990,1999-2002	Nevada
Washington	All	2001,2002	Nevada

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