PRICE EFFECTS OF INDEPENDENT TRANSMISSION SYSTEM OPERATORS IN THE UNITED STATES ELECTRICITY MARKET

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Abstract

In 1996, the Federal Energy Regulatory Commission (FERC) sought to "remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers" through a series of market rules. A product of these rules was the establishment of regional transmission organizations (RTOs) and independent system operators (ISOs) charged with facilitating equal access to the transmission grid for electricity suppliers. Whether these changes in market structure have succeeded in achieving FERC's goal to provide "lower cost power to the Nation's electricity consumers" remains an open question.

This paper utilizes a panel data set of the 48 contiguous United States and a treatment effects model in first differences to determine whether there have been changes in delivered electric prices as a result of the establishment of ISOs and RTOs. To avoid the confounding effects of electric restructuring, the model is estimated with the full panel data set, and then again without the states that have restructured their electric markets. This estimation shows that electricity prices fall approximately 4.8% in the first 2 years of an ISO's operation and that this result is statistically significant. However, this result is dependent on the presence of states that restructured their electricity markets. When these restructured states are removed from the data set the price effects of RTOs become indistinguishable from zero. The paper concludes that rate agreements are the principal source of the observed decrease in prices and that RTOs have not had the desired effect on electricity prices.

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1 Introduction

Before the Federal Energy Regulatory Commission (FERC) issued its landmark Order 888 in April of 1996, the electricity generation, transmission, and distribution market in the United

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States had functioned largely within a vertically integrated monopoly structure for over 100 years. The opening paragraph of Order 888 reads:

> "Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers. The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce. A second critical aspect of the rules is to address recovery of the transition costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced."[2]

FERC appears to believe that the vertically integrated structure in which the generator of electricity also controls the transmission of electricity is inefficient, and that this inefficiency leads to higher prices. The issuance of this order paved the way for numerous states to introduce plans to restructure their electric markets, with varying degrees of success. This movement began most notably in California, Texas, and a number of states in the Northeast, with the separation of the utility's generation from the transmission and distribution functions. To facilitate non-discriminatory access for all generators to the transmission grid, FERC conditionally approved the formation of five independent system operators (ISO) in 1997 and 1998 to oversee the deregulated wholesale power markets.

In December of 1999, FERC issued Order 2000, which stated:

> "The Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act (FPA) to advance the formation of

[2] FERC Order 888, issued April 24, 1996, Page 1 (75 FERC ¶ 61,080)

> Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO. The Commission also codifies minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO. The Commission's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service."[3]

This Order suggests that FERC believed that the establishment of independent entities to control access to the electric transmission system would result in costs that are no greater than the costs that exist at the time of the order.

The focus of this paper is to identify tangible price effects as a result of the formation of RTOs and ISOs. These effects are critical to assessing the efficacy of this landmark regulatory policy. While there are structural differences[4] between the two types of organizations, their basic function of ensuring equal access for electric generators to the transmission grid and optimal dispatch of the generating system remain. Since that is the function analyzed in the paper, the terms ISO or RTO as used here are effectively indistinguishable.

An RTO can impart many benefits to the market in both the short term and long term. FERC Order 2000 identified five benefits that RTOs can offer: improved efficiencies in the management of the transmission grid, improved grid reliability, non-discriminatory transmission practices, improved market performance, and lighter-handed government regulation[5]. Through

[3] FERC Order 2000, issued December 20, 1999, Page 1 (89 FERC ¶ 61,285)
[4] For example, RTOs have been tasked by the FERC to ensure the long term reliability of the system by managing transmission investment. ISOs are nominally regulated by the Federal government, while RTOs govern themselves.
[5] FERC Order 2000, issued December 20, 1999, Page 70-71 (89 FERC ¶ 61,285)

the optimization of the daily and hourly decisions of system dispatch over a wider geographic area than the existing system, the RTO may lower the system costs required to serve electric load. By allowing non-discriminatory access to the transmission system, the RTO may also be able to incorporate lower priced resources that may not have enjoyed access to the market under a previous market regime, thus lowering system costs. Fabrizio, Rose, and Wolfram (2007) provide evidence that electric generators increase their operating efficiency in a market environment by reducing labor and nonfuel operating expenses, relative to operators in states that do not restructure their markets. An RTO may also be able to improve the reliability of the electric system by coordinating resource allocation and long term system planning. All of these benefits must be measured against the costs of operating and maintaining the RTO, and the costs incurred by market participants for compliance and regulation. However, since all costs related to the RTO are recovered through volumetric charges passed through to consumers of electricity served by that RTO, it is possible to assess the RTO's effect on system costs net of the RTO's own costs by examining the rates charged to customers. A change in prices, controlling for other factors, should signal either a net cost or net benefit associated with the RTO.

FERC is presently attempting to assess the costs and benefits of RTOs. In February of 2010, FERC issued a request for comments on a series of performance metrics for ISOs and RTOs[6]. This request for comment was the result of a 2008 report from the Government Accounting Office that requested that FERC work to develop metrics to track the performance of RTO operations and report this performance to the public. Once this data is collected, regulators will have better information with which to address the question, but the goal of this paper is to see if there is something that can be learned now, with the data available. Pricing metrics utilized by FERC include indicators of wholesale market price performance, but do not reflect the costs

[6] 75 Fed. Reg. 7581 (2010)

paid by retail utility customers. Any burden to the retail customer will include not only the wholesale market prices, but the utility's costs of compliance. As a result, FERC performance metrics account for some of the costs to retail customers, but do not address all of them. In an effort to assess the costs of maintaining a RTO, Greenfield and Kwoka (2010) have developed an econometric model of RTO costs dependent upon the geographic scale, scope of services provided, and age of the RTO. Such a model could be used to benchmark the relative cost effectiveness of these organizations. Kwoka, Pollitt, and Sergici (2010) have also presented evidence that forced divestiture as a result of electric restructuring has resulted in decreases in efficiency for electric distribution systems. Because these models do not address benefits, the question of whether RTOs have provided net benefits the consumers of electricity remains open.

This study employs a panel data set of the contiguous United States spanning the period 1990-2008 in an attempt to determine whether the establishment of RTOs has had an effect on the prices that consumers pay for electricity. The United States electricity market is particularly attractive for studying questions related to market structure. For roughly 100 years, most electric utilities in the United States were vertically integrated, providing generation, transmission, and distribution of electricity. Following the issuance of FERC Order 888, industry structure changed. Many states restructured their electricity markets, forcing the divestiture of the generation, transmission, and distribution components of the electric utilities in their state. Utilities in other states did not restructure, but ceded control of their transmission assets to independent entities, the RTOs and ISOs. A third group of states retained their vertically integrated structure. This paper exploits this diversity to study the effects of changes in market structure. The analysis concludes that the price effects of RTOs, when disentangled from the effects of electric restructuring, are not statistically significant, and these general results are robust to various specifications of the model. However, when the price effects for individual classes of customers are considered, there may be some slight reductions in price for residential and industrial customers.

The remainder of the paper is organized as follows: Section 2 consists of a review of the existing literature, Section 3 describes the data used in the analysis, Section 4 is a description of the estimation models used, Section 5 discusses the results of the analysis, and Section 6 contains some concluding remarks.

2 Existing Literature

Coase (1937) addressed the question of why individuals organize into firms, observing that the degree of vertical integration varied greatly among types of industries and types of firms. Since individuals were always free to interact with the market in the absence of firms, Coase concluded that firms arise when the costs of interacting with the market exceed the costs of interacting within an organization. So, if the regulators of a particular industry decided that the costs of interacting within an organization would exceed those of the market, they might restructure the firms in the industry in order to reduce transaction costs.

Grossman and Hart (1986) have argued that the literature on transaction costs emphasized the conclusion that nonintegrated relationships can be inferior to relationships with complete contracts. However, they assert that this is not due to the nature of the nonintegrated relationship itself, but because of the presence of incomplete contracts. They pointed out that this argument in the existing literature has assumed that integration leads to complete contracts, which may not be the case. They further argue that the proper comparison is that between contracts that allocate rights of ownership, residual rights, to one party and contracts that allocate them to another. They conclude that when it is too costly to specify a list of particular rights that one party desires over another party's assets, it may be optimal to purchase all rights.

Previous studies in the electricity area have focused on the question of whether restructuring of the electricity market itself has led to changes in delivered electricity prices. Kwoka (2006) presents a review of a number of these studies. He finds that all are plagued by two underlying problems: the endogeneity issues related to the decision to restructure the electricity market, and the confounding effects of settlement agreements between the states and the utilities in the state that were necessary to enable each state's restructuring plans. The particular terms of these settlement agreements varied considerably by state, but contained two common elements. The first element was some form of retail rate control, either a rate freeze that kept rates at current levels for a designated period of time, or a prescribed schedule of future rates based on current rates. Most often, the first year in the schedule mandated a rate decrease, and this decrease often persisted beyond the first year. The second element was a mechanism to recover the value of stranded assets, or to recover costs not recovered under the rate agreement. Restructuring in Pennsylvania, for example, was accompanied by the imposition of retail rate caps on the privately-owned utilities. The expiration of the rate caps for PPL Electric Utilities in January of 2010 was accompanied by rate increases of 30%. This dramatic increase in electric prices suggests that the realized prices in the years following the restructuring agreement did not reflect the market price for electricity in Pennsylvania. The states of Maryland and California experienced similar price increases upon the expiration of imposed price caps, so the experiences of the state of Pennsylvania are not unique. Clearly, some degree of 'cost savings' from electric restructuring was simply a temporal subsidy, though it is not yet clear how much, as this transition cost recovery continues in many states, and the methods used to impose this subsidy were heterogeneous across states. Because temporal subsidies have been used to shift costs, the full effect of these subsidies is unknown and the effect of restructuring on costs is difficult to determine. Therefore, any analysis utilizing electricity prices in restructured states will be tainted by those confounding effects, as well as by endogeneity issues related to the decision to restructure the electricity market.

The present study frames the question differently to avoid those confounding effects. Rather than attempt to explain the changes in price wrought by electric restructuring, which is composed of two inter-related effects[7], this paper focuses on whether there have been changes in price as a result of the formation of ISOs or RTOs. A map of the current footprint of these organizations is shown in Figure 1.

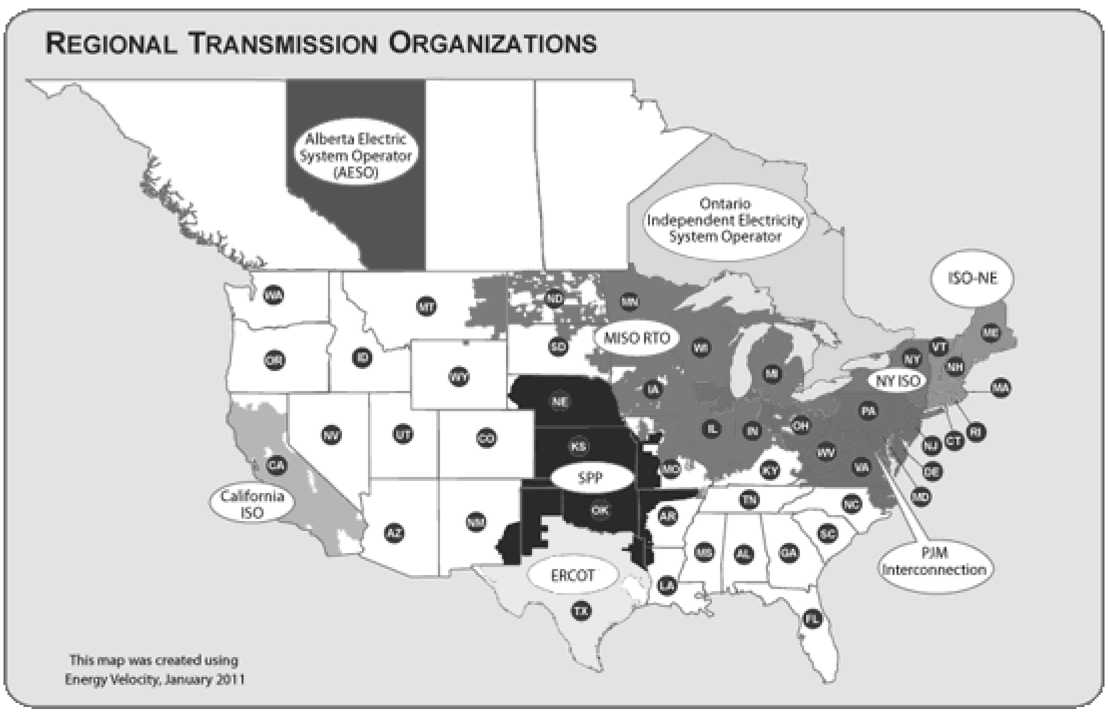

Figure 1. Regional Transmission Organizations in North America[8]

[7] The two effects are the effect of the change in market structure as well as the effect of the rate agreement used to facilitate electric restructuring.
[8] From http://www.ferc.gov/industries/electric/indus-act/rto.asp

Using a panel data set of the 48 contiguous United States, this paper utilizes a treatment effects model in first differences to determine whether there have been changes in delivered electric prices as a result of the establishment of RTOs. To avoid the confounding effects of electric restructuring, the model is initially estimated with the full panel data set as a benchmark, and then again without the 16 states that have restructured their electric markets. Of the remaining 32 states, 12 are served by one or more RTOs. Table 1 shows the average nominal price of electricity for each of these state groups.

Table 1. Mean and Standard Deviation of Nominal Electrcity Price for each State Group

Restructuring Status	**ISO Status**	**N**	**Nominal Price**
Restructured States	Before ISO Implementation	150	8.09 1.91
	After ISO Implementation	154	9.98 2.67
Non-Restructured States Served by ISOs	Before ISO Implementation	126	5.96 0.93
	After ISO Implementation	102	6.81 1.67
Non-Restructured States Not Served by ISOs		380	6.14 1.29

Table 1 illustrates the endogeneity issue raised by Kwoka. The states that restructured their electricity markets exhibited higher prices, on average, than the states that did not. However, among the states that did not restructure their electricity market, there is little difference, on average, in price level between the states that were eventually served by ISOs and those that were not. Therefore, by considering only the states that have not restructured their electric markets, this paper estimates whether there have been price effects due to the establishment of RTOs, in the absence of restructuring agreements.

3 Data

The data used in this paper are annual data for the 48 contiguous United States, spanning the period 1990 through 2008. The data for the study are primarily derived from reports and survey forms prepared by the United States Department of Energy's Energy Information Administration (EIA). The EIA is mandated by Congress to collect survey data from electric utilities in the United States. These data are collected on a variety of forms spanning electric utility operations. The EIA-860 report consists of generator-specific data such as generating capacity and energy sources. The EIA-861 and EIA-826 reports contain utility-specific data on sales and revenues by customer class. The EIA-923 report contains utility-specific data on electricity generation and fuel consumption. This utility- and generator-specific data is aggregated by state as a component of the EIA's State Energy Data System, the primary data source for statewide generation and prices in this study. Prices used in this study are average prices across customer classes, as well as for broad customer classes, calculated by dividing revenue by the sales volume. State-level data on annual heating and cooling degree days is available from the National Climatic Data Center, which population-weights the heating and cooling degree days collected from individual climate monitoring stations. Heating and cooling degree days are functions of average daily temperature often used to explain demand for electricity (Papalexopoulos and Hesterberg, 1990). They are the aggregate of the average daily temperatures either above (cooling) or below (heating) 65 degrees Fahrenheit. For example, if the average daily temperature is 70 degrees, then that day is said to have 5 cooling degrees[9]. These degree days are then aggregated annually or monthly. Data on annual population by state is from the U.S. Census Bureau. Data on per capita income by state is from the U.S. Department

[9] If, for example, half of a state's population experiences 70 degree temperatures and half of the population experiences 74 degree temperatures, then the National Climatic Data Center will record 7 cooling degrees for that state, for that day.

of Commerce, and is used as a proxy for heterogeneous economic conditions within each state. Data regarding state participation in electric restructuring activities is available from EIA[10], FERC, and the individual state regulatory agencies. Finally, the membership of state utilities in RTOs is available from EIA, FERC (as seen in Figure 1), and the individual RTOs.

4 The Model

The paper presents a model of the average electricity prices paid per kilowatthour (kWh) of consumption by the customers in each state, and tests the treatment effect of RTOs on that price. The effects of RTOs are not limited to prices, however. The centralization of dispatch and system planning decisions may have impacts beyond electricity revenues, such as on the overall system reliability. The effects of the RTOs on system reliability are much more difficult to assess, as most reliability data is proprietary. Further, the RTOs may be able to optimize the decisions regarding power plant investment within its region of responsibility, but its effects may not yet be seen. Thus, this paper studies the impact that RTOs have through the retail rates charged to customers. This is an important metric, as the portion of FERC Order 2000 cited above specifically states the Commission goal of lowest possible prices.

The average revenue per kWh of electricity for each state *i*, in a given year *t* can be expressed by the following panel equation:

$$Price_{it} = \alpha_i + \beta_0 Sales_{it} + \beta_1 PCoal_{it} + \beta_2 PGas_{it} + \beta_3 \%Hydro_{it} + \beta_4 \%Nuc_{it} + \beta_5 RTO_{it} + u_{it} \quad (1)$$

where:

Price	Nominal state electricity revenues per kWh in cents/kWh
Sales	Electricity sales in MWh

[10] For example, http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html

PCoal	Nominal state price of coal in $/MMBtu
PGas	Nominal state price of natural gas in $/MMBtu
%Hydro	Percent of electric generation from hydroelectric sources
%Nuc	Percent of electric generation from nuclear sources
RTO	Whether the majority of the electric customers in the state are served by a utility that belongs to an RTO

The mean and standard deviation for these variables is given for the entire sample, as well as three cohorts, in Table 2.

Table 2. Mean and Standard Deviation for Model Variables

	Entire Sample	Restructured States	States that Did Not Restructure Electric Industry	
			RTO States	Non-RTO States
Price (cents/kWh)	7.16 2.25	9.05 2.51	6.34 1.38	6.14 1.29
Sales	6.75e07 6.09e07	9.28e07 8.30e07	4.16e07 2.98e07	6.28e07 4.39e07
Coal Price	1.36 0.58	1.58 0.61	1.05 0.46	1.37 0.53
Natural Gas Price	4.31 2.42	4.31 2.49	4.45 2.39	4.22 2.38
% Hydro	11.10% 20.83%	9.84% 18.89%	8.68% 15.81%	13.56% 24.44%
% Nuclear	18.43% 18.53%	22.72% 18.80%	18.39% 21.36%	15.03% 15.58%
N	912	304	228	380

The variable α represents the fixed effects of the model, or the heterogeneous characteristics of the state that contribute to the prevailing electricity price in the state. The price of electricity in a state is influenced by factors such as the types of units used to generate electricity, the price and availability of fuel, the geographic proximity to these resources, the effects of geography on the costs of electricity transmission and distribution, heterogenous ratemaking standards that might apply to that state, or the degree to which ratemaking authority is centralized[11]. Because generating units are long-lived assets, the composition of the generating fleet will change little over time leading to stability in the structure used to produce electricity. As a result, price levels might be expected to differ by state, and these differences might be expected to persist. Figure 2 illustrates the electricity prices in the data set for three sample states. Idaho's low prices are the result of the abundance of inexpensive hydropower resources in the region. Georgia relies primarily on coal and nuclear generation and thus experiences higher prices than Idaho. Connecticut relies on nuclear and natural gas generation, with no access to lower priced coal generation, and therefore had the highest prices of the three states. The centralization of ratemaking authority is also a source of heterogeneity, with each state served by some combination of investor-owned, municipally-owned, and cooperative utilities. However, the ownership status of these utilities rarely changes, so this heterogeneity will be relatively stable over the sample period.

[11] State public utility commissions typically have ratemaking authority over only investor-owned utilities, while municipally-owned utilities are governed by the municipalities themselves, and cooperative utilities are governed by the customers they serve.

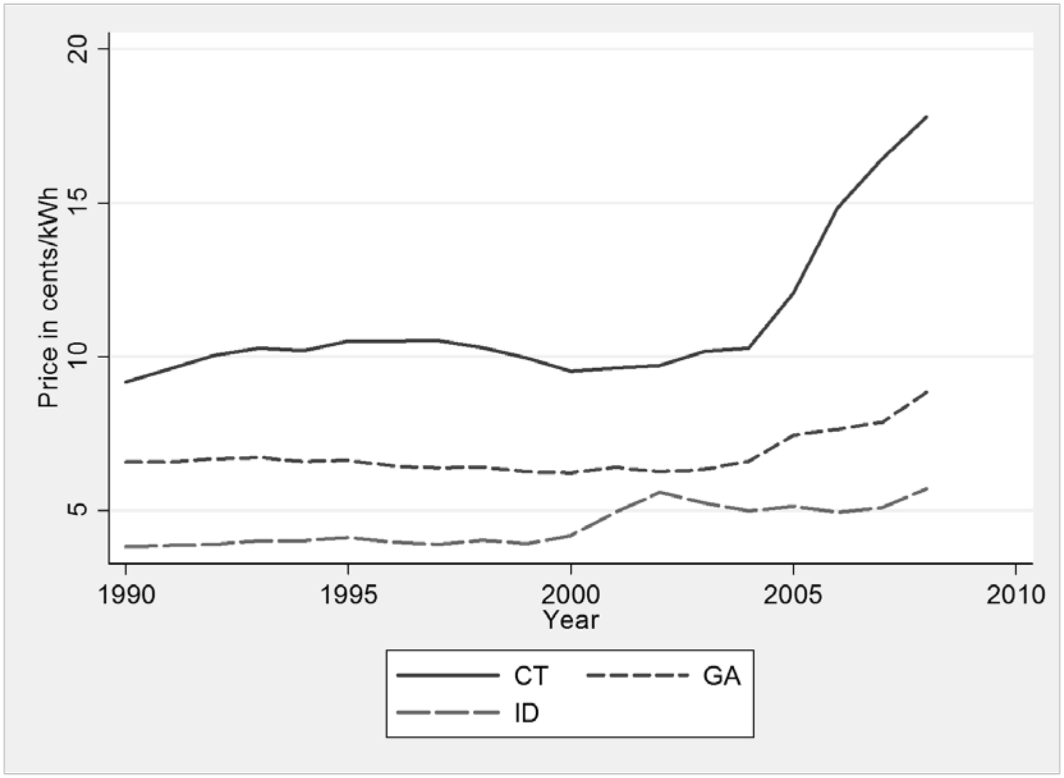

Figure 2. Comparative State Electricity Prices

The heterogeneous effects of this variable α are removed by estimating the model in first differences. Further, the variables *Price*, *Sales*, *PCoal*, and *PGas* are transformed by taking logs, so that the variables in the equation, with the exception of the treatment, all represent annual percent changes. The estimation equation then becomes:

$$\Delta lnPrice_{it} = \beta_0 \Delta lnSales_{it} + \beta_1 \Delta lnPCoal_{it} + \beta_2 \Delta lnPGas_{it} + \beta_3 \Delta\%Hydro_{it} + \beta_4 \Delta\%Nuc_{it} + \beta_5 \Delta RTO_{it} + \beta_6 \Delta RTO_{it-1} + \beta_7 \Delta RTO_{it-2} + u_{it} \quad (2)$$

Lagged observations of the RTO variable are also included in the estimated model, as the effects of the RTO may not materialize (or fully materialize) in the year of its inception. The first lag will be equal to 1 if the utilities in the state became members of an RTO in the previous year, and the second lag equals 1 if two years prior.

One further refinement to the model is necessary. Unless the price elasticity of electricity demand is zero, the electricity sales variable is endogenous in the price equation. While other authors have estimated the price elasticity of demand for electricity[12], that question is beyond the scope of this paper. As long as the price elasticity differs from zero, it is important for the specification of this model. Therefore, the endogeneity of the electricity sales variable is tested using the instrumental variables heating and cooling degree days, state per capita income, and state population. Even if the price of electricity has an effect on sales, it should not have an effect on the weather, income or the population of the state, so these variables are exogenous. The reduced form equation for *ΔlnSales* is estimated and the residuals are included as explanatory variables in equation (2). The coefficient on this variable is significant[13], and so equation (2) is estimated using 2SLS with the instrumental variables heating and cooling degree days, state per capita income and state population for *ΔlnSales*.

The sign of the *ΔlnSales* coefficient might be positive or negative. Increased demand for electricity increases the expenditure on fuels required to produce electricity and may result in the utilization of higher cost generating units, which would have the effect of increasing price. However, utilities generally recover some amount of fixed costs through variable charges, so a decrease in sales could also have the effect of raising prices overall, as any fixed costs need to be recovered over a smaller volume of sales. Increasing fuel prices, the primary variable cost of electricity production, should also cause prices to increase, so the signs on *ΔlnPCoal* and *ΔlnPGas* coefficients should be positive, as many utilities recover fuel expenditures as they are

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[12] See, for example, Bernstein and Griffin (2005)
[13] The details of the reduced form estimation are included in Appendix A

incurred through fuel adjustment charges in their retail rates. The variable costs associated with the production of hydroelectricity are very low, but the availability of hydroelectricity varies with year to year levels of precipitation, realized as either rainfall or accumulated snow pack. However, when the electricity is available, it is available at much lower variable costs. Therefore, the sign on *Δ%Hydro* is expected to be negative, as increased volumes of hydroelectricity should displace more expensive generating resources. The sign on *Δ%Nuc* should also be negative, as increased availability of low priced nuclear generation should result in lower electricity prices.

5 Results

The results of the estimation of equation (2) are shown in Table 3.

Table 3: 2SLS Estimates with Entire Sample

Variable	Coefficient
Constant	0.0180*** (0.0029)
ΔlnSales	-0.0504 (0.0899)
ΔlnPCoal	0.1650*** (0.0279)
ΔlnPGas	0.0209*** (0.0078)
Δ%Hydro	-0.1756*** (0.0553)
Δ%Nuc	-0.0143 (0.0183)
RTO	-0.0200** (0.0089)
RTO_{t-1}	-0.0284*** (0.0092)
RTO_{t-2}	-0.0043 (0.0126)

R-squared of 0.14
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The coefficient on sales is negative, but not significantly different from zero. Since the dependent variable represents the average cost curve, this suggests that the utilities are operating close to the minimum point on the curve. The coefficients for the fuel prices both have the expected signs and are statistically significant at the 1% level, though the electricity price is eight times more sensitive to a 1% increase in coal prices than to a natural gas price increase. The broad result that electricity prices are more responsive to changes in coal price than natural gas prices is consistent with Mohammadi (2009), although he finds that coal price elasticity is roughly twice that of natural gas. This result offers further insight into the problem of modeling electricity prices in general. It is a common approach, in modeling electricity prices, to form a fossil fuel price index[14] and use it as a proxy for fuel costs. The result that the coefficients for natural gas prices and coal prices are significant and distinct in this specification suggests that modeling fuel prices in this manner is conveying information that would be unavailable if the fossil fuel index approach is adopted. Increased availability of hydroelectricity causes the price to decrease, and this decrease is significant. Finally, as indicated by the sum of the coefficients on the RTO and RTO_{t-1} variables, electricity prices seem to fall by about 4.8% during the first two years of an RTO's existence. The coefficient associated with the RTO_{t-2} variable is not statistically significant, and further lags of the variable yield similar results. This indicates that if an RTO is going to have a price impact on consumers, it occurs in the first two years of its existence. This 4.8% decrease is statistically significant and interesting, because it is at the lower range identified by Joskow (2006), who estimates the price effects of electric restructuring, utilizing a different data set and methodology, to be 5% to 10%.

[14] This index is essentially a weighted average of coal and natural gas prices, as the states in the sample do not use appreciable quantities of petroleum to generate electricity.

However, as noted by Kwoka (2006), the effects of restructuring settlements and any imposed rate caps that accompanied those settlements can act as confounding factors, by masking the market prices that might otherwise exist if not for the restructuring agreement. That is, when the equation is estimated with the full sample, the effects of RTOs are indistinguishable from the effects of these rate agreements, if membership in an RTO accompanies the restructuring. It would be preferable to simply account for these rate agreements with additional variables, but the form of these agreements, such as the length of time that rate controls are put in place, the restrictiveness of these controls, and the period over which these deferred costs are recovered, differs greatly from state to state, making the quantification of their effects difficult. Therefore, the best way to control these effects is to remove them altogether.

To remove this confounding effect, the equation is estimated with only the sample of states that have not restructured their electric industry. This means that the sample is free of any of the confounding effects of rate agreements on electricity prices, and should truly reflect the effects of RTOs, controlling for other factors. Note that membership in an RTO does not require restructuring of the electric utility, as the RTO does not assume ownership of the transmission and distribution assets of the utility, so the sample includes states that are within RTOs, but have not restructured their electric industry. The results of the estimation of equation (2) with this restricted sample are shown in Table 4.

Table 4: 2SLS Estimates Excluding States that have Restructured their Electric Industry

Variable	**Coefficient**
Constant	0.0141*** (0.0033)
ΔlnSales	-0.0561 (0.1007)
ΔlnPCoal	0.1775*** (0.0366)

Δ lnPGas	0.0263*** (0.0081)
Δ%Hydro	-0.2053*** (0.0742)
Δ%Nuc	0.0549 (0.0553)
RTO	-0.0127 (0.0086)
RTO_{t-1}	-0.0127 (0.0106)
RTO_{t-2}	0.0043 (0.0095)
R-squared of 0.21 (Robust standard errors clustered by state in parentheses) * Statistically significant at the 10% level ** Statistically significant at the 5% level *** Statistically significant at the 1% level	

Notice that the signs and significance of most of the variables remains unchanged when the model is estimated with this subset of the data. The magnitudes of the coefficients are consistent as well. However, the variables corresponding to the establishment of an RTO and the effects of that RTO one year later have changed considerably. First, the magnitude of the variables related to the RTO has fallen by roughly half, and second, the precision of their measurement has decreased. Neither variable is significant at even the 10% level. Therefore, by eliminating from the sample those 16 states that have restructured their electric industry, the price effects of an RTO are reduced from approximately 4.8%, an effect significantly different from 0%, to 2.5%, but not significantly different from 0%. This suggests that most of the realized price reductions observed in the initial estimation are not due to the change in the market structure, but the form of the restructuring agreements in the states that chose to restructure their markets. Therefore, if there are any cost savings that result from the establishment of RTOs in the absence of electric restructuring, they are not significantly different from zero.

Alternate specifications of this model are tested, both as a check on the robustness of the results as well as a way to relax certain assumptions of the original specification of the model.

First, the effect of RTO membership on real prices instead of nominal prices is considered. Using the annual consumer price index from the Department of Labor's Bureau of Labor Statistics, all of the electricity and fuel prices are restated in real terms. Replacing nominal prices with real prices decreases the magnitude of the price effects, once the effects of inflation are removed, but does not change the results regarding statistical significance.[15]

Second, the original model, as specified, assumes that the marginal effect of changes in fuel price does not vary by state. However, because the availability of resources necessary to generate electricity varies with individual state geography, the degree to which each state relies on different types of fuels changes. Therefore, this assumption that marginal effects are constant across states may not be valid. Therefore, another specification of the model is estimated with interaction terms between each state and the annual change in the price of coal and natural gas in that state.

[15] Estimation details are available upon request from the author.

Table 5: 2SLS Estimates with Entire Sample and Interaction Terms between State and Fuel Price	
Variable	**Coefficient**
Constant	0.0175*** (0.0030)
ΔlnSales	-0.1015 (0.0955)
Δ%Hydro	-0.1819*** (0.0527)
Δ%Nuc	-0.0026 (0.0527)
RTO	-0.0288*** (0.0086)
RTO_{t-1}	-0.0325*** (0.0097)
RTO_{t-2}	0.0017 (0.0126)
R-squared of 0.38 (Robust standard errors clustered by state in parentheses) * Statistically significant at the 10% level ** Statistically significant at the 5% level *** Statistically significant at the 1% level	

The 96 coefficients for the state and fuel price interaction have been omitted from this table for the sake of parsimony, but a Wald test rejects the hypothesis that the coefficient of each state with respect to coal prices are equal at the 1% level, and a test of the coefficients on gas prices yields similar results. For illustrative purposes, selected coefficients are listed in Table 6[16].

[16] The coefficients for all 96 interaction terms are available from the author upon request.

Table 6: Selected Coefficients on the Interaction between State and Fuel Prices	
State	**Coefficient**
Change in Log Coal Prices	
Alabama	0.3910*** (0.0081)
Florida	0.4741*** (0.0136)
Georgia	0.5288*** (0.0226)
Minnesota	0.2633*** (0.0093)
Change in Log Natural Gas Prices	
Colorado	0.0678*** (0.0007)
Louisiana	0.2260*** (0.0015)
Oklahoma	0.1384*** (0.0101)
Texas	0.1717*** (0.0062)
(Robust standard errors clustered by state in parentheses) * Statistically significant at the 10% level ** Statistically significant at the 5% level *** Statistically significant at the 1% level	

This specification of the model controls for the heterogeneity of each state's sensitivity to fuel prices, and the coefficients are consistent with the degree to which these states rely on these fossil fuels. As of 2008, 37% of Alabama's generating capacity was coal-fired, as was 18% of Florida's generating capacity, and 36% of Georgia's and Minnesota's. Colorado relies on natural gas for 44% of its generating capacity, while Louisiana, Oklahoma, and Texas are much more reliant on gas for 76%, 65%, and 69% of their capacity, respectively. It is not surprising, then, that the electricity prices in these states would be sensitive to the prices of these fuels. The addition of these variables does not change the results of the analysis, however, as shown in the restricted sample regression results in Table 7.

Table 7: 2SLS Estimates with Restricted Sample and Interaction Terms between State and Fuel Price	
Variable	**Coefficient**
Constant	0.0191*** (0.0026)
ΔlnSales	-0.0848 (0.0957)
Δ%Hydro	-0.1853** (0.0752)
Δ%Nuc	0.0190 (0.0546)
RTO	-0.0152* (0.0089)
RTO_{t-1}	-0.0009 (0.0084)
RTO_{t-2}	0.0077 (0.0057)

R-squared of 0.44
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The individual state interaction terms change slightly, but remain largely consistent between the two samples. Once again, the effect of the RTO is reduced dramatically, as is the precision with which it is measured. However, with this specification, a reduction of approximately 1.5% in realized electricity prices is observed, and this result is significant at the 10% level.

Finally, the state data set also includes prices and sales reported by broad customer class (i.e. residential, commercial, and industrial customers). To see if benefits from RTOs have accrued to particular customer classes, the price equation (2) is estimated using the prices and sales for each class of customer and the results are reported in Table 8. The coefficients are similar in sign and magnitude to the ones in Table 4, but now there are two statistically significant results for the RTO variables. The first is a 1.44% decrease in prices for residential customers in the first year of the RTO's existence. The second is a 2.49% decrease in prices for industrial customers in the second year of the RTO's existence. This provides evidence that for certain types of customers, the change in market structure may be producing tangible cost benefits. Residential customers are typically voters, so this group exerts political influence, and industrial customers are important consumers of electricity, so the price benefits for these groups may not be surprising. However, given that roughly 35 different organizations representing large industrial users of electricity contributed to the final version of FERC Order 888, these customers have not seen a sizable reduction in price.

Table 8: 2SLS Estimates By Customer Class Excluding States that have Restructured their Electric Industry

Variable	Residential	Commercial	Industrial
Constant	0.0172*** (0.0028)	0.0160*** (0.0043)	0.0064 (0.0054)
ΔlnSales	-0.1175 (0.0830)	-0.2058* (0.1099)	0.0483 (0.1417)
ΔlnPCoal	0.1355*** (0.0325)	0.1523*** (0.0414)	0.2830*** (0.0897)
ΔlnPGas	0.0054 (0.0075)	0.0075 (0.0104)	0.0616*** (0.0195)
Δ%Hydro	-0.0302 (0.0539)	-0.0318 (0.0908)	-0.6212** (0.3020)
Δ%Nuc	0.0610 (0.0416)	0.0443 (0.0685)	0.0051 (0.0932)
RTO	-0.0144** (0.0070)	-0.0153 (0.0150)	-0.0031 (0.0135)
RTO_{t-1}	-0.0065 (0.0097)	-0.0186 (0.0139)	-0.0249* (0.0143)
RTO_{t-2}	0.0103 (0.0073)	0.0125 (0.0081)	0.0051 (0.0149)

(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

6 Conclusion

When FERC established rules to change the structure of the electricity market, it did so under the belief that the existing system was inefficient, and that the change in structure would provide benefits to consumers. Ten years after these original orders, the question regarding benefits of the changes in market structure was raised by the Government Accounting Office, leading to a FERC Request for Comment on the establishment of performance metrics for ISOs and RTOs. Once these data have been collected, greater insight into the net benefits of the establishment of ISOs and RTOs may be possible.

However, the present study provides some immediate insight into this important issue. Utilizing a panel data set of the United States over the past 18 years, this paper estimates equations for annual percentage changes in electricity price, and attempted to identify the degree to which membership in an RTO affects costs. There is a significant effect, a decrease of 4.8% over two years, when estimating these price changes with the entire data sample. However, the entire sample includes the effects of rate agreements that accompanied restructuring agreements in states that chose to restructure their market. When the equation is estimated excluding the states that restructured their electric industry, the significance of the price change disappears. Therefore, if ISOs and RTOs have led to changes in the price of electricity, then these changes are indistinguishable from zero or may only apply to certain classes of customer. However, there may be other benefits of RTOs relating to reliability of electricity service or the optimization of long term resource planning that are not estimated here. The question of whether RTOs have influenced system reliability or the long term planning process would be interesting avenues for further research. However, given the time and effort required to comply with the changes in market structure necessitated by FERC rules, it is worth asking the question whether all of this effort has provided tangible benefits to electricity consumers at least in terms of lower prices.

Appendix A

To test whether *ΔlnSales* is endogenous in equation (2), equation (3) is estimated

$$\Delta lnSales = \beta_0 \Delta lnPop + \beta_1 \Delta lnPCI + \beta_2 \Delta lnCDD + \beta_3 \Delta lnHDD + \beta_4 \Delta lnPCoal + \beta_5 \Delta lnPGas + \beta_6 \Delta \%Hydro + \beta_7 \Delta \%Nuc + \beta_8 \Delta RTO + \beta_9 \Delta RTO_{t-1} + \beta_{10} \Delta RTO_{t-2} + \varepsilon_{it} \quad (3)$$

Where:

Pop	State population
PCI	State per capita income
CDD	State population-weighted cooling degree days
HDD	State population-weighted heating degree days
Sales	Electricity sales
PCoal	Nominal price of coal
PGas	Nominal price of natural gas
%Hydro	Percent of electric generation from hydroelectric sources
%Nuc	Percent of electric generation from nuclear sources
RTO	Whether the majority of the electric customers in the state are served by a utility that belongs to an RTO

The results of this estimation are shown in Table A1. The residuals from this reduced form estimation are included as independent variables in the estimation of equation (2). The coefficient on the residuals was significant at the 1% level[17], indicating that the variable *Sales* is

[17] Coefficient was -0.6788 with a standard error of 0.1175

endogenous in equation (2). Therefore, equation (2) is estimated with the two stage least squares technique (2SLS) utilizing the variables *ΔlnHDD*, *ΔlnCDD*, *ΔlnPCI*, and *ΔlnPop* as instrumental variables for *ΔlnSales*.

Table A1: OLS Estimates of the Log Return of Electric Sales

Variable	**Coefficient**
Constant	0.0053 (0.0033)
ΔlnPop	0.5659*** (0.0802)
ΔlnPCI	0.2200*** (0.0512)
ΔlnCDD	0.0436*** (0.0052)
ΔlnHDD	0.0982*** (0.0152)
ΔlnPCoal	-0.0393*** (0.0141)
ΔlnPGas	-0.0131*** (0.0044)
Δ%Hydro	0.1431*** (0.0498)
Δ%Nuc	0.0042 (0.0276)
RTO	-0.0020 (0.0027)
RTO_{t-1}	-0.0017 (0.0034)
RTO_{t-2}	0.0070** (0.0035)

R-squared of 0.22
F-test statistic is 15.70 and significant at the 1% level
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

Appendix B

The results of the first stage regressions of the estimates of equation (2) are provided below. Table B1 is for the entire sample, Table B3 is for the restricted sample.

Table B1: First Stage Estimates of Log Return of Electricity Sales with Entire Sample	
Variable	**Coefficient**
Constant	0.0053 (0.0032)
ΔlnPCoal	-0.0393*** (0.0141)
ΔlnPGas	-0.0131*** (0.0044)
Δ%Hydro	0.1431*** (0.0498)
Δ%Nuc	0.0042 (0.0276)
RTO	-0.0020 (0.0027)
RTO_{t-1}	-0.0017 (0.0034)
RTO_{t-2}	0.0070** (0.0035)
ΔlnCDD	0.0436*** (0.0052)
ΔlnHDD	0.0982*** (0.0152)
ΔlnPop	0.5659*** (0.0802)
ΔlnPCI	0.2200*** (0.0512)
R-squared of 0.22 (Robust standard errors clustered by state in parentheses) * Statistically significant at the 10% level ** Statistically significant at the 5% level *** Statistically significant at the 1% level	

Table B2: Partial R^2 Values for Excluded Instruments	
Variable	**Partial R^2**
ΔlnCDD	0.1101
ΔlnHDD	0.0626
ΔlnPop	0.0394
ΔlnPCI	0.0171

All of the coefficients on my IV for sales are significant at the 1% level. Additionally, the Cragg-Donald Wald F-statistic for this regression is 47.83, and exceeds the 5% critical value from Stock and Yogo (2005) at the 5% level, so the null hypothesis that the instrumental variables are weak in this estimation is rejected.

Table B3: First Stage Estimates of Log Return of Electricity Sales Excluding Restructured States	
Variable	**Coefficient**
Constant	0.0092** (0.0041)
ΔlnPCoal	-0.0291 (0.0193)
ΔlnPGas	-0.0185*** (0.0053)
Δ%Hydro	0.1820*** (0.0678)
Δ%Nuc	0.0033 (0.0596)
RTO	-0.0049 (0.0032)
RTO_{t-1}	-0.0002 (0.0039)
RTO_{t-2}	0.0114*** (0.0040)
ΔlnCDD	0.0465*** (0.0072)
ΔlnHDD	0.0856*** (0.0167)
ΔlnPop	0.4930*** (0.1028)
ΔlnPCI	0.2116*** (0.0584)
R-squared of 0.21 (Robust standard errors clustered by state in parentheses) * Statistically significant at the 10% level ** Statistically significant at the 5% level *** Statistically significant at the 1% level	

Table B4: Partial R^2 Values for Excluded Instruments	
Variable	**Partial R^2**

ΔlnCDD	0.1154
ΔlnHDD	0.0475
ΔlnPop	0.0327
ΔlnPCI	0.0163

Again, all of the coefficients on the IVs for kWh sales are significant at the 1% level, and the Cragg-Donald Wald F-statistic for this regression is 30.04, and exceeds the 5% critical value from Stock and Yogo (2005) at the 5% level, so the null hypothesis that the instrumental variables are weak in this estimation is rejected.

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