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The impact of coordination on wholesale market participation: The case of the U.S. electricity industry

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ABSTRACT

Coordination costs in a wholesale electricity market are a relevant public policy consideration. The mitigation of coordination costs, all else equal, should increase participation in the marketplace. Since Federal Energy Regulatory Commission (FERC) Order 888 was issued in 1996, the level of trading activity in bulk electricity markets has increased significantly. In 1999, FERC issued Order 2000 to advance the role of regional transmission organizations (RTOs) in the restructured marketplace for wholesale electricity. RTOs have the potential to reduce the coordination costs, while also having the countervailing effect of causing market participants to incur compliance costs. This paper utilizes the diversity of the United States electricity market and a panel data set representing electric utilities for the period 1990–2009 to study the effects that RTOs have had on wholesale electricity exchange. The paper finds that the presence of a transparent wholesale marketplace for electricity has the effect of increasing participation, but this participation is uneven across types of electric utilities. Greater participation is seen for investor-owned and larger utilities. The results have important implications for policy aimed at wholesale markets and the transmission organizations, as the opportunities afforded by transparency may not be uniformly distributed across all market participants.

1. Introduction

On December 20, 1999, the Federal Energy Regulatory Commission (FERC or "the Commission") issued Order No. 2000 in Docket No. RM99-2-000, a docket opened to explore the role of Regional Transmission Organizations (RTOs) in the restructured electricity marketplace. The role of a RTO is to administer the electric transmission system, ensuring open access to the grid for all electricity generators. The FERC noted that since FERC Order 888 was issued in 1996, trade in the bulk electricity markets had increased significantly. FERC also noted that during the Notice of Proposed Rulemaking process for the instant docket, the Commission had "reviewed evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets, and that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets."[2] FERC further enjoined utilities, state officials, and affected interest groups to voluntarily develop RTOs. Despite the urging of FERC, there remain substantial portions of the United States electricity grid that are not administered by RTOs or Independent System Operators (ISOs). While there are structural differences[3] between the two types of organizations, the basic function of providing transparency in wholesale electricity pricing remains. Since that is the function analyzed in the paper, the terms ISOs or RTOs as used here are effectively indistinguishable.

Coase (1960) observed that there are costs involved in carrying out transactions in the market, such as the cost "to discover who it is that one wishes to deal with, to inform people that one wishes to deal and on what terms, to conduct negotiations leading up to the bargain, [and] to draw up the contract..."[4] Milgrom and Roberts

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[1] I wish to thank Sandy Berg, David Brown, Jonathan Hamilton, Mark Jamison, Chuck Moss, David Sappington, the editor and two anonymous referees for their valuable insight. All remaining errors are my own.

[2] FERC Order 2000, issued December 20, 1999, Page 2 (89 FERC ¶ 61,285).

[3] 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.

[4] Coase (1960) p. 15.

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(1992) categorize these costs as either coordination or motivation costs. They define coordination costs in terms of the need to determine the price and other parameters of transactions, make the existence of buyers and sellers known to one another, and bring buyers and sellers together. Motivation costs arise from incomplete and asymmetric information and imperfect commitment. The wholesale market for electricity, where the relevant product is electricity delivered to a particular location at a particular point in time, is prone to coordination costs,[5] as the product has an instantaneous useful life. RTOs and ISOs can have a direct explicit influence on coordination costs in the wholesale electricity market, but the direction of that influence is not always clear. One way in which RTOs can influence coordination costs is by publishing wholesale electricity prices in a manner that provides access to any party.[6] But since the costs of these organizations are recovered from all utilities in their market footprint (Greenfield and Kwoka, 2011), the distribution of benefits is important to assessing the cost-effectiveness and equity of these organizations. This paper employs a panel data set of United States electric utilities spanning the period 1990–2009 to investigate whether transparency increases the degree to which an electric utility participates in the wholesale market. The findings suggest that transparency increases the level of exchange of investor-owned utilities and larger utilities, regardless of ownership structure, but has no significant effect on the level of exchange of municipally owned and cooperative utilities, all else equal. This indicates that the distribution of the benefits afforded to participants in market administered by RTOs is not uniform across all market participants, while the costs are borne by all. The results of the analysis could be used to inform policy that could mitigate this inequity.

The remainder of the paper is organized as follows: Section 2 provides a discussion of the costs and benefits of RTOs, Section 3 provides a review of related literature, Section 4 describes the data utilized, Section 5 describes the empirical model and estimation methodology, Section 6 reports the results of the estimation, and Section 7 offers concluding remarks.

2. The costs and benefits of RTOs

RTOs 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.[7] One way that ISOs and RTOs can influence the performance of electricity markets is by providing a transparent wholesale market, which this paper defines as a market in which the prices for a unit of electricity delivered to a given location at a given point in time are publicized in a manner that is easily accessible by any interested party, such as a posting on a public web site.[8]

Consider the case of an electric utility, Alpha, operating as an island, isolated from the electricity transmission grid. The utility dispatches generating units to supply electricity to its customers and attempts to do so in a manner that optimizes performance, typically measured in terms of least cost relative to some standard of reliability. If electricity demand and the criteria under which the utility optimizes its portfolio (say, least cost) are taken as exogenous, then the utility's only task is to determine which of its generating units will be dispatched at any given time. To this end, Alpha assesses the hourly marginal costs of its generating units, considers any constraints related to the units' availability or operating characteristics, determines how much electricity to supply, and dispatches units sufficient to meet the prevailing demand at the lowest possible cost.

Now consider the existence of a neighboring electric utility, Beta, which becomes physically interconnected to Alpha. Operating as an island, Beta faces the same decision as Alpha. However, if both utilities seek to minimize costs and, in a particular hour, there is a difference between the utilities' marginal costs of generation that is greater than the cost of coordinated transmission between Beta and Alpha, then an opportunity for Pareto improvement exists. If Alpha has a higher marginal cost of generation than Beta in a given hour,[9] then Beta can generate that marginal kWh and sell to Alpha at a price somewhere between their respective marginal costs, and both utilities have lowered their effective average cost of generation; Alpha by buying the marginal kWh at less than it would cost to generate it with its own units and Beta by realizing a sales revenue offset to its cost to generate the marginal kWh.

But the costs that must be incurred in order to achieve this benefit are not limited to the cost of transmission and the transaction itself. As Milgrom and Roberts observe, coordination costs also arise. Each utility must expend resources to gather information about the electricity system around it. First, each must identify the number of potential trading partners. Second, each must be able to assess the costs and availability of electricity in any given hour and for every one of those potential trading partners, in order to identify profitable trading opportunities. Third, each must know how to make the arrangements necessary to have that electricity delivered to the purchasing utility system for agreed upon transactions. Before the advent of RTOs and ISOs, the first and third tasks were often performed in the U.S. by roughly 140 regional balancing authorities (Joskow, 2005), organizations registered by the National Electric Reliability Council (now the North American Electric Reliability Corporation or NERC) to integrate future resource plans; maintain the balance between load, interchange, and generation; and support real-time interconnection frequency for a given area. The second function was accomplished primarily through bi-lateral contacts between utilities, though confederations of utilities also existed. For example, before ISOs and RTOs existed, the Orlando Utilities Commission, the City of Lakeland, and the Florida Municipal Power Agency formed the Florida Municipal Power Pool in 1988 to centrally commit and dispatch all of the pool members' generating resources to meet the collective load obligations in the most economical manner.

Today, by establishing a transparent wholesale marketplace, the RTO can fulfill the second task either by maintaining a centralized databank of hourly prices, or by collecting hourly bids and offers from utilities and generators interested in participating in the market. While the RTO can lower the costs required to gather this information, other costs to participate in the market still exist. Utilities must incur costs in order to conform to the rules and procedures of wholesale markets and the ability to trade with utilities belonging to other RTOs may be constrained. In a survey of RTO cost-benefit studies, Eto et al. (2005) report that while utilities will incur market participation costs, these costs had not been

[5] Cave and Stern (2013) have explained the role that system operators play as coordinating entities in infrastructure industries.

[6] Further discussions of these costs and benefits follow in Section 2.

[7] FERC Order 2000, issued December 20, 1999, Page 70–71 (89 FERC ¶ 61,285).

[8] Per Bakos (1998). For an example from the Midwest ISO, see https://www.midwestiso.org/MARKETSOPERATIONS/REALTIMEMARKETDATA/Pages/LMPContourMap.aspx.

[9] This might be due to a difference in the fuel used to generate the electricity or the efficiency with which the fuel is used by the marginal generating unit of each utility.

explicitly studied. In another type of electricity market, Newell and Spees (2011) find that gaps in realized sales of electricity capacity[10] across the border between the PJM Interconnection (PJM) and the Midwest ISO (MISO) are caused by barriers, such as difficulty in obtaining long-term firm transmission service to support capacity sales and energy market must-offer requirements that impose risks on capacity importers.

Participation in these markets also imposes implementation burdens on utilities. In PJM, for example, the manuals describing the administrative, planning, operating, and accounting procedures for participating in the market number more than 3000 pages in 34 separate volumes. In 2013 alone, these manuals underwent 68 distinct revisions.[11] The steep learning curve and burden of market participation may prove a barrier to smaller utilities, which may not be able to employ or retain someone with the specialized expertise necessary to navigate these procedures. These countervailing factors may influence a utility's willingness to participate wholesale electricity markets.

3. Related literature

The majority of the existing literature on electricity market restructuring (that is, the separation of generation, transmission, and distribution) has focused on the impacts of restructuring as a whole. Kwoka (2006) reviewed a number of studies on the price effects of electricity restructuring, finding that they are plagued by the endogeneity of the treatment variable (restructuring) as the states with higher prices tended to restructure their electric industry. He also found it is difficult to disentangle the effect of the change in market structure from the effect of the temporary rate agreements that accompanied restructuring. Other researchers have reached conclusions regarding changes in efficiency. Fabrizio et al. (2007) examined the effects on restructured markets on electric generators and found increases in operating efficiency through reductions in labor and nonfuel operating expenses. Kwoka et al. (2010) studied electric distribution systems and found that forced divestiture from restructuring resulted in decreased efficiency in distribution. However, little empirical work has been conducted to assess the net benefits of the RTOs and ISOs themselves.

Fabrizio (2012) studied the 'make-or-buy' decisions of 240 investor-owned electric utilities from 1990 to 2007 and found that utilities in ISOs tended to meet growing demand with more purchased power and less self-generation than non-ISO members. Blumsack (2007) found that the metrics used to evaluate the efficacy of RTOs were incomplete and not objective. He proceeded to enumerate nine areas on which evaluation metrics should focus. Davis and Wolfram (2011) studied changes in operating efficiency of nuclear power plants in the United States and found that those operating in competitive wholesale markets had increased efficiency by 10%. Outside of the electricity industry, Garicano and Kaplan (2000) studied the changes in transaction costs resulting from business-to-business e-commerce and found that the Internet reduces coordination costs.

Kury (2013) examined the retail price effects of RTOs and ISOs in the United States electricity market, concluding that ISOs and RTOs did not have a significant effect on retail prices once the confounding effects of electric restructuring were removed from the data. However, that work also acknowledged that while lower prices are a stated goal of the FERC, they are not the only benefit of establishing these organizations. Chandley and Hogan (2009) point out that "part of the purpose of RTO design was to facilitate trading"[12] and show that the day-ahead net exports from the Midwest to the PJM region tripled when American Electric Power became a member of PJM in October 2004.[13]

This study examines whether utilities within RTOs participate more in the wholesale electricity markets, relative to utilities outside of RTOs, either due to improved efficiencies in grid management or non-discriminatory transmission practices. It expands on the scope of Fabrizio (2012) by considering utilities with different ownership structures, encompassing over 3000 utilities instead of 240. Note that there may be electricity market effects of RTOs and ISOs beyond market access. These organizations may improve grid reliability and investment decisions by reforming the long-term planning process, but these questions are beyond the scope of this paper.

4. Data

The primary data source for this study is the Form 861 database compiled by the U.S. Department of Energy's Energy Information Administration (EIA). Form 861 is an annual information reporting requirement for all privately and publicly owned electric utilities in the United States and its territories. Data collected includes the quantity of wholesale and retail purchases and sales, revenues, number of customers, and annual system peak load as well as information on demand-side management programs, green pricing and net metering programs, and distributed generation capacity. The utilities also report their control area operator on the form, which allows the identification of the time periods during which the utility is a part of a RTO and thus a transparent wholesale market. The transparency mechanism employed by the various RTOs (the posting of wholesale prices on a public website), is nearly identical, so the effect of this mechanism is treated as homogenous across RTOs. Total sources and disposition of energy reported on the form is disaggregated into several categories that are important for this study. Data include the annual generation for each utility net of the plant's own use (reported as net generation) and purchases from the wholesale market (reported as purchases). Together, these accounts are aggregated as total electricity sources for the utility. The total sources of electricity in a given year must always equal the total disposition of electricity, which is disaggregated into sales to ultimate consumers (retail sales), sales for resale (wholesale sales), and electricity losses (due to the transmission or distribution of electricity).

The data set consists of more than 64,000 data points, each representing the response of one electric utility to the EIA 861 survey for one year from 1990 through 2009. This data set is an unbalanced panel, with roughly 3000 to 4000 utilities responding in any given year. However, these utilities enter and exit the sample in a non-random fashion and the inclusion of all utilities in the sample can lead to selection bias (Heckman, 1979). Therefore, this analysis employs a balanced panel consisting only of those utilities that have submitted data over the entire 20-year data collection period.

The questions of whether utilities purchase or sell more electricity in the wholesale markets, in the presence of a RTO will be addressed separately. Measuring market participation by considering only net sales or purchases would distort the analysis, as a utility that purchases and sells 1000 MWh over the course of the

[10] The capacity product in the electricity industry is the ability to generate electricity on demand, but not the electricity itself.

[11] http://www.pjm.com/documents/manuals/manual-updates/2013-updates.aspx.

[12] Chandley and Hogan (2009), Page 33.

[13] Chandley and Hogan (2009), Page 34.

year would look identical to a utility that does not participate in the market at all. The Purchase 1 sample includes only utilities with positive sales to ultimate consumers, that is, utilities serving retail electric load. Further, utilities that do not themselves generate electricity in any year of the sample are excluded from the Purchase 1 sample. These utilities likely are 'all requirements customers'[14] of another utility, and therefore lack the discretion to serve their electric load by means other than purchasing electricity on the wholesale market. The wholesale market interactions of these utilities would therefore be unaffected by the presence of a transparent market because they are restricted to purchasing 100% of their electricity regardless of whether the wholesale market is transparent. The dependent variable for this sample is the percentage of the utility's total disposition of energy (wholesale and retail electricity sales) that is purchased from the wholesale market. The isolated utility Alpha in the initial example would purchase none of its energy requirements in the wholesale market, and its market participation may be limited by the coordination costs; as these coordination costs change, the utility may find participation beneficial. Initially, the utility may only participate in the market when necessary (i.e., when it has insufficient generation to meet its load obligations, perhaps due to unit outages) and the percentage of its energy that it purchases in the wholesale market may be very low. However, as coordination costs evolve, the utility may also look for economic opportunities to displace its own generation with market purchases. In this manner, the dependent variable might change for each utility over time with changes in coordination costs.

The Sales 1 sample includes all utilities with positive net electricity generation in a given year, with the exception of any utility that sold all of that generation in the wholesale market over the entire time period in the study. These utilities are likely wholesale generators and the presence of a transparent wholesale market will have no effect on the variability of their participation. The dependent variable in this case is the percentage of total sources of energy (generation and wholesale purchases of electricity) sold on the wholesale market.

Broader criteria may be used to derive the samples. Recall that the Purchase 1 sample excluded any utility that did not generate electricity in any year during the sample period. However, a transparent wholesale marketplace might afford utilities that do not generate electricity the opportunity to purchase electricity above load obligations and resell that electricity to another retail provider. Utilities that exploit this opportunity in the wholesale market are excluded from the initial sample. Therefore, the Purchase 2 sample includes all utilities in the Purchase 1 sample as well as all utilities that reported sales for resale during the sample period. This sample is much larger, and encompasses the majority of the data points. Similarly, the Sales 2 sample encompasses generating utilities that serve ultimate consumers during some period of the sample timeframe. Unlike the broader purchase criteria, this does not lead to a sizable increase in sample size.

5. Model

The model to be estimated considers the dependent variable (*DV*), which is either the fraction of the total disposition of energy that comes from the wholesale market (for the Purchase regressions), or the fraction of total sources of energy that is sold on the wholesale market (for the Sales regressions).

[14] These are utilities that serve retail electricity customers but purchase all of their requirements on the wholesale market.

$$
\begin{aligned}
DV_{it} = \; & \alpha_i + \gamma_t + \beta_1 ISOWhl_{it} + \beta_2 ISOYrs_{it} + \beta_3 Peak_{it} + \beta_4 Owner_i \\
& + \beta_5 PeakxISO + \beta_6 OwnerxISO + \beta_7 PeakxISOYrs \\
& + \beta_8 OwnerxISOYrs + \varepsilon_{it}
\end{aligned}
$$

$$\varepsilon_{it} = \rho\varepsilon_{it-1} + \eta_{it}$$

Changes in the dependent variable are explained by a utility-specific fixed effect α and a number of other factors. First, an indicator variable equal to 1 if the utility is a member of a RTO in that year (*ISOWhl*), the number of years that the utility has been in the market (*ISOYrs*), the size of the utility measured by its peak demand (*Peak*), and indicator variables equal to 1 (dummy variables) depending on the ownership (municipally owned utility, customer-owned cooperative, investor-owned utility, or other) structure of the utility (*Owner*). Finally, the analysis includes a series of annual indicator variables (dummy variables), an analytical technique to control for unobserved variables that are common to a particular year. The variables of interest include *ISOWhl* and *ISOYrs* as well as the interaction between these variables and the size and ownership variables. Finally, the error terms for each utility were found to exhibit first order serial correlation, and are thus modeled as AR(1) processes. Descriptive statistics for the Purchase and Sales samples are given in Tables 1 and 2, respectively.

Notably absent from the data set is the utility's cost relative to the costs of other utilities with which it might exchange. This variable is especially relevant because it is the catalyst for the interaction in the hypothetical example of utilities Alpha and Beta. However, hourly wholesale price data is not available for utilities that do not participate in transparent wholesale markets, the control group for this study. In lieu of these data, the effect of cost differentials were modeled with a variety of annual aggregated regional price differentials providing mean and maximum differentials. However, these variables failed to generate statistically significant coefficients at any reasonable level and did not affect the influence or statistical significance of other variables in the model. Moreover, the relatively high R^2 values in the regressions reported below suggest that the explanatory power of any omitted variables is relatively small.

The treatment effect in the model, whether the utility is a member of an organization that operates a transparent wholesale market, might be seen as endogenous, but it important to note that membership in a RTO or ISO was mandatory for utilities located in

Table 1
Mean and standard deviation of purchase samples.

Utilities included	All	Purchase 1	Purchase 2
		Serve retail customers and generate some portion of that electricity	Purchase 1 sample plus those reporting Sales for Resale
PurchasePct	0.92	0.83	0.94
	0.24	0.29	0.19
ISOWhl	0.15	0.17	0.15
	0.35	0.37	0.36
ISOYrs	0.61	0.74	0.62
	1.77	2.01	1.79
Peak	293.51	648.95	273.71
	2731.37	2518.59	2832.28
Muni	0.57	0.73	0.64
	0.49	0.44	0.48
IOU	0.07	0.13	0.05
	0.25	0.34	0.22
Coop	0.28	0.08	0.27
	0.45	0.27	0.45
N	63,266	19,558	55,998

Table 2
Mean and standard deviation of sales samples.

Utilities included	All	Sales 1	Sales 2
		All generators except exempt wholesale generators	All generators that sell some portion to consumers
SalesPct	0.09	0.23	0.26
	0.26	0.35	0.37
ISOWhl	0.15	0.15	0.16
	0.35	0.36	0.36
ISOYrs	0.61	0.65	0.67
	1.77	1.84	1.87
Peak	293.51	1107.86	1082.36
	2731.37	3068.35	3022.66
Muni	0.57	0.62	0.61
	0.49	0.48	0.49
IOU	0.07	0.21	0.21
	0.25	0.40	0.41
Coop	0.28	0.08	0.08
	0.45	0.27	0.27
N	57,168	9922	10,322

states that restructured their electricity markets and the decision to restructure was made by state legislatures and not utilities; although FERC Order 2000 strongly suggested that utilities join their regional organization, FERC could not compel them to do so. Further, utilities that operate within the control area of a larger utility may find it most practical to join a RTO if their control area operator does so. Finally, as argued in Kwoka (2006), the rationale for restructuring was based more on the desire to lower electricity prices than simply to create opportunities for market participation.

The utility-specific fixed effect accounts for the fact that utilities serve their load obligations with different combinations of owned generation and purchased power. Due to the long-lived nature of generating assets, this fixed effect simply reflects the average purchases and sales of the utility over time and is relatively stable. The remaining variables are of interest, although the null hypothesis suggests that the effects of the constraints imposed by transparent wholesale markets would be less than the effects of the reduced cost of information regarding electricity availability and price, and that the coefficients on these variables will be positive. A variable to quantify the utility's experience with the market is also included, to discern whether the participation is influenced by 'learning-by-doing' (Lucas, 1988).

6. Results

The results of the estimation with the Purchase samples are given in Table 3.

The coefficients for the annual indicator (dummy) variables are all significant, but not shown here. The interaction terms are far more interesting, indicating that investor-owned and larger utilities, regardless of ownership, purchase more in a transparent wholesale market and that this tendency increases with time. The coefficient on *PeakxISOWhl* implies that an electric utility in a city such as Knoxville, Tennessee, with an annual peak load of approximately 1000 MW, will purchase about 0.3% more in a transparent wholesale market, while the utility in a city such as Los Angeles, California, with an annual peak load of approximately 10,000 MW will purchase about 3% more. Further, the coefficient on *PeakxISOYrs* implies that purchases for a utility with a peak load of 1000 MW increase by 0.08%–0.1% per year of experience in a market (depending on the sample used). A utility with a peak load of 10,000 MW increases its purchases by 0.9%–1.1% with each year of experience (depending on the sample used). Meanwhile, interactions terms imply that investor-owned utilities increase their purchases by about 2.25%–2.75% with each year of experience with a transparent wholesale market.

So, larger utilities and investor-owned utilities seem to purchase more electricity in a transparent whole market, while municipally owned and cooperative utilities do not exhibit statistically significant differences in participation. These broad results are similar to the behavior identified by Rose and Joskow (1990), who concluded that larger utilities and investor-owned utilities adopted new gas-fired generating technologies sooner than smaller and municipally owned utilities. In this instance, market participation by utilities can be seen as an analog to technological innovation. These results for investor-owned utilities also are consistent with the results of Fabrizio (2012), who analyzed the make-or-buy decisions of investor-owned utilities in ISOs and RTOs.

Estimating the regression for the Sales samples affects some of the results related to larger utilities, as shown in Table 4. The coefficients for the two Sales samples are similar because the relaxed criterion for the Sales 2 sample only expands the Sales 1 sample by 20 utilities. The coefficient on *ISOWhl* indicates that the presence of a transparent wholesale market increases sales for all utilities by approximately 4%. However, the interaction terms counteract some

Table 3
Parameter estimates for purchase samples.

Variable	Purchase 1	Purchase 2
Constant	0.1783[c] (0.0158)	0.0491[c] (0.0051)
ISOWhl	−0.0122 (0.0352)	−0.0078 (0.0196)
Peak x ISOWhl	3.25e-06[a] (1.73e-06)	2.72e-06[c] (9.85e-07)
Muni x ISOWhl	0.0110 (0.0356)	0.0074 (0.0197)
IOU x ISOWhl	0.0316 (0.0357)	0.0264 (0.0199)
Coop x ISOWhl	0.0012 (0.0393)	0.0059 (0.0198)
ISOYrs	−0.0055 (0.0072)	−0.0041 (0.0041)
Peak x ISOYrs	9.12e-07[b] (4.18e-07)	1.16e-06[c] (2.38e-07)
Muni x ISOYrs	0.0017 (0.0073)	0.0027 (0.0041)
IOU x ISOYrs	0.0275[c] (0.0074)	0.0225[c] (0.0042)
Coop x ISOYrs	0.0071 (0.0084)	0.0033 (0.0042)
Peak	−2.56e-06[c] (5.83e-07)	−1.01e-07 (6.90e-08)
N	18,432	52,705
Number of clusters (utilities)	980	2802
R-squared	0.8747	0.8930
Rho	0.6777	0.6865

Standard errors in parentheses.
[a] Statistically significant at the 10% level.
[b] Statistically significant at the 5% level.
[c] Statistically significant at the 1% level.

Table 4
Parameter estimates for sales samples.

Variable	Sales 1	Sales 2
Constant	0.1381[b] (0.0074)	0.0800[b] (0.0070)
ISOWhl	0.0428[b] (0.0139)	0.0459[b] (0.0128)
Peak x ISOWhl	−3.08e-06[a] (1.26e-06)	−3.02e-06[a] (1.23e-06)
Muni x ISOWhl	−0.0469[b] (0.0144)	−0.0491[b] (0.0134)
IOU x ISOWhl	−0.0109 (0.0154)	−0.0154 (0.0144)
Coop x ISOWhl	−0.0403[a] (0.0184)	−0.0424[a] (0.0171)
ISOYrs	−0.0144[b] (0.0038)	−0.0134[b] (0.0035)
Peak x ISOYrs	1.11e-07 (3.36e-07)	7.91e-08 (3.29e-07)
Muni x ISOYrs	0.0152[b] (0.0039)	0.0136[b] (0.0037)
IOU x ISOYrs	0.0126[b] (0.0042)	0.0108[a] (0.0039)
Coop x ISOYrs	0.0161[b] (0.0054)	0.0142[a] (0.0050)
Peak	−1.00e-06[b] (3.64e-07)	−9.75e-07[b] (3.59e-07)
N	9295	9621
Number of clusters (utilities)	524	544
Rho	0.7784	0.7787
R-squared	0.9534	0.9604

Standard errors in parentheses.
[a] Statistically significant at the 5% level.
[b] Statistically significant at the 1% level.

of that gain. The coefficient on the *PeakxISOWhl* term indicates that a utility with a 1000 MW peak load will see lesser sales by approximately 0.3% in a transparent wholesale market. The coefficient on the *MunixISOWhl* variable indicates that municipal utilities in transparent wholesale markets will see approximately 5% lower sales, while the sales of cooperative utilities will be lesser by approximately 4%. So the presence of the transparent market has a statistically significant impact on the sales by utility type, but the result is only economically relevant for municipal utilities, cooperatives, and very large utilities. The coefficient for investor-owned utilities is negative, but not statistically different from zero, so investor-owned utilities seem to realize all of the gains from the *ISOWhl* term. Experience in the market also matters, as indicated by the statistical significance of the *ISOYrs* interaction terms. Investor-owned, municipal and cooperative utilities see slightly greater sales with each year of market experience. So while larger, municipal, and cooperative utilities all experience less sales initially, these differences are mitigated by experience. However, all three types of utilities sell less than investor-owned utilities, all else equal, which also do not experience the initial decrease.

As discussed earlier, the dependent variable for market participation could be thought of as endogenous. In order to evaluate whether this endogeneity might affect the results, the estimation is repeated using only states that restructured their electricity industry. Restructuring, enabled by FERC and legitimized by state legislatures, required utilities to either relinquish their transmission assets, or the control over the transmission assets, to a third party. For the utilities' transmission assets, this third party was the ISO or RTO. So restructuring requires participation in an ISO, but the converse does not hold. Thus, utilities in restructured states that relinquished control of their transmission assets did so not of their own accord, but because they were compelled by state legislation and regulation. As discussed in Kwoka (2006), the motivation for states to restructure was high electricity prices and not market participation (the dependent variable in this analysis), so a sample consisting only of restructured states should be free of these endogeneity concerns. The results of this estimation are shown in Table 5.

The coefficients in Table 5 differ from those in Tables 3 and 4, and the precision with which those coefficients are measured decreases with the smaller sample size, but the basic results of the analysis stand. Participation in the purchase market tends to increase for investor-owned and larger utilities. In the sales market, municipal utilities tend to sell less in transparent markets but the effect is mitigated over time. Therefore, the potential endogeneity of the dependent variable does not seem to be driving the results of the original analysis.

Since the results for restructured states are consistent with those for the entire sample, this might beg for the question of whether restructuring is solely responsible for the results. To test whether this is true, the estimation is repeated using the complement of the data set in Table 5, that is, only those states that did not restructure their electricity industry. In this case, utilities joined RTOs and ISOs absent any state effort to restructure the electricity market. The results of this estimation are shown in Table 6.

The observed pattern in the purchase market continues to hold, with larger utilities and investor-owned utilities tending to purchase more than municipal utilities and cooperatives. No variables of interest retain their statistical significance in the restricted sales sample, although the sign of the coefficients remains consistent with earlier results.

The results of this analysis raise two policy concerns. First is the basic fairness issue that arises when the costs of an initiative (e.g. a transparent market) are socialized across all participants, but the benefits accrue to a subset of those participants. The second is whether fewer participants in a market might lead to market power. Fortunately, these results also inform potential remedies for these concerns. As suggested, the learning curve for market participation may be too steep for smaller utilities to easily climb. This research suggests that experience in the market increases participation, so workshops allowing more experienced participants to share their insights with smaller utilities may be useful. Further, the market organizations themselves can education participants about market procedures, possibly in the form of virtual seminars. While there may be no substitute for experience in a market, these initiatives may help smaller participants enjoy the benefits of transparent wholesale markets.

7. Conclusions

It is clear that RTOs and ISOs can provide opportunities in the electricity sector that might not otherwise exist, particularly by facilitating transparent wholesale electricity markets. Transparency can reduce the coordination costs that limit utility participation in

Table 5
Parameter estimates for restructured states.

Variable	Purchase 2	Sales 2
Constant	0.2182[c] (0.0126)	−0.0832[c] (0.0144)
ISOWhl	0.0040 (0.0287)	0.0366[b] (0.0185)
Peak x ISOWhl	4.73e-06[c] (1.62e-06)	−5.76e-06[b] (2.53e-06)
Muni x ISOWhl	−0.0085 (0.0289)	−0.0430[b] (0.0201)
IOU x ISOWhl	0.0179 (0.0301)	0.0098 (0.0231)
Coop x ISOWhl	−0.0084 (0.0294)	−0.0301 (0.0312)
ISOYrs	−0.0037 (0.0061)	−0.0137[c] (0.0057)
Peak x ISOYrs	4.67e-07 (3.78e-07)	1.89e-07 (5.69e-07)
Muni x ISOYrs	0.0023 (0.0061)	0.0133[c] (0.0056)
IOU x ISOYrs	0.0270[c] (0.0064)	0.0119[b] (0.0060)
Coop x ISOYrs	0.0031 (0.0063)	0.0144[a] (0.0085)
Peak	−2.75e-07 (4.69e-07)	−8.38e-07 (4.91e-07)
N	12,678	2898
Number of clusters (utilities)	686	173
Rho	0.7423	0.8133
R-squared	0.8490	0.9252

Standard errors in parentheses.
[a] Statistically significant at the 10% level.
[b] Statistically significant at the 5% level.
[c] Statistically significant at the 1% level.

Table 6
Parameter estimates for non-restructured states.

Variable	Purchase 2	Sales 2
Constant	0.0405[c] (0.0055)	0.1519[c] (0.0066)
ISOWhl	0.0444 (0.0446)	0.0119 (0.0255)
Peak x ISOWhl	−3.77e-06[b] (1.70e-06)	−9.11e-07 (1.43e-06)
Muni x ISOWhl	−0.0434 (0.0446)	−0.0105 (0.0259)
IOU x ISOWhl	−0.0252 (0.0438)	0.0158 (0.0264)
Coop x ISOWhl	−0.0460 (0.0447)	−0.0097 (0.0273)
ISOYrs	−0.0226[a] (0.0119)	0.0036 (0.0073)
Peak x ISOYrs	2.03e-06[c] (4.74e-07)	−5.70e-08 (4.63e-07)
Muni x ISOYrs	0.0209[a] (0.0119)	−0.0034 (0.0075)
IOU x ISOYrs	0.0257[b] (0.0117)	−0.0064 (0.0076)
Coop x ISOYrs	0.0212[a] (0.0119)	−0.0036 (0.0083)
Peak	−9.46e-08 (6.31e-08)	−9.13e-07 (9.17e-07)
N	40,006	6704
Number of clusters (utilities)	2137	390
Rho	0.6090	0.7199
R-squared	0.9150	0.9770

Standard errors in parentheses.
[a] Statistically significant at the 10% level.
[b] Statistically significant at the 5% level.
[c] Statistically significant at the 1% level.

the marketplace, and thus limit the realized benefits. However, formal markets also impose transaction and other costs that may discourage participation.

This paper utilized a large data set to estimate the determinants of market participation, showing that the presence of a transparent wholesale marketplace for electricity has the effect of increasing market participation, but this participation is uneven across types of electric utilities. Greater participation is seen for investor-owned and larger utilities, reflecting both the results of Rose and Joskow, who found that investor-owned and larger electric utilities are more willing to adopt technological innovations, and Fabrizio, who found that investor-owned utilities in ISOs tend to meet more of their growing demand by purchasing electricity, as opposed to generating it themselves.

These results have important implications for public policy aimed at increasing transparency in wholesale electricity markets and the organizations that facilitate it. The opportunities afforded by markets may not be evenly distributed across all market participants. However, as experience in the market also appears to affect participation, communication and education efforts may be useful for ensuring that all market participants share in the benefits as well as the costs.

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