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Geographic Integration, Transmission Constraints, and Electricity Restructuring

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Abstract:

We examine the impact on inter-regional trade in eastern U.S. electricity markets arising from the FERC-supported creation of Independent System Operators (ISOs). Our analysis focuses on the PJM ISO (Pennsylvania, New Jersey, Maryland, and other states) and its trade with the New York ISO and ECAR (East Central Area of Reliability).

The formation of ISOs has been associated with two distinct impacts: (1) more centralized management of regional transmission resources; and (2) the formation of regional multi-party electricity exchange markets. We find that the former effect actually may have facilitated electricity trade between regions, since quantity constraints on trading volume occur with substantially greater likelihood when sending power into the loosely organized ECAR "reliability area" as compared with the more centrally administered PJM ISO. We attribute this to institutional impediments in obtaining a transmission path within ECAR that deter the use of physically available transmission capacity. This result supports FERC policy of encouraging the creation of ISOs.

As for the impact of PJM's creation of multi-party energy exchange markets, our evidence suggests that the formation of these markets initially reduced transaction costs for inter-regional trade by improving price discovery, but the overall impact has been to raise inter-regional transaction costs somewhat. Finally, our estimates of the shadow value of adding incremental transmission capability provide useful empirical evidence for the debate surrounding the adequacy of the U.S. electricity transmission system.

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1. Introduction

One rationale behind electricity restructuring and the Federal Energy Regulatory Commission's (FERC's) "Open Access" policy is to remove barriers to trade between electricity producing regions. To further the process, Independent System Operators (ISOs)—such as PJM Interconnection, the New York ISO, and ISO-New England in the eastern United States—have been created to independently manage the transmission system and institute formal multi-party exchange markets for trading electricity within their boundaries. FERC has favored the geographic expansion of ISOs, now known as Regional Transmission Organizations (RTOs), into new areas, as well as the creation of "super RTOs" from a combination of existing RTOs.

This paper examines how the formation of regional electricity exchange markets and the reliance on ISOs to independently manage available transmission capacity have influenced inter-regional electricity trading. We estimate the impact of these institutional changes on inter-regional electricity trading costs, both explicit transaction costs and implicit costs involved in identifying and exploiting profitable trading opportunities. Since our methodology estimates the likelihood that inter-regional electricity trading is affected by binding volume constraints, our analysis assesses whether transmission availability has been affected by ISO formation in comparison to more decentralized organizational structures for managing the transmission system. Our methodology also allows us to estimate the shadow value of incremental increases in electricity transfer capability (e.g., transmission capacity) between regions, which is quite important in light of the current policy debate regarding the adequacy of the U.S. transmission system.

The analysis examines trade between PJM Interconnection (covering New Jersey, Pennsylvania, Maryland, Delaware, District of Columbia, and parts of other states) and neighboring areas, including the New York ISO and the more loosely organized East Central

Area of Reliability (ECAR). Our results suggest that the cost of trading electricity between regions, as well as the shadow value of increasing inter-regional transfer capability, differs based on the direction of trade. We find that the formation of PJM's internal exchange market initially lowered transaction costs associated with certain types of inter-regional trade (e.g., between ECAR and PJM), perhaps due to improved price discovery. However, PJM's conversion from cost-based to market-based bidding in its internal exchange market is associated with substantially higher inter-regional transaction costs for sending power to New York from PJM (and to PJM from ECAR).

We estimate that the shadow value of increased transfer capability (e.g., transmission capacity) to PJM from New York is approximately $6,180 per MW annually. By contrast, the shadow value of increased transfer capability to New York from PJM is estimated at only $1,640 per MW annually. Over our sample period, we estimate that the probability of observing quantity-constrained trade between PJM and New York was approximately 7 percent when PJM was the higher-priced region, and 5 percent when New York was the higher-priced region.

For trade between PJM and ECAR, our results are quite curious. PJM is the higher-priced area in 77 percent of our observations. When prices are higher in PJM than ECAR, we estimate that the probability of observing quantity-constrained trade is about 3 percent, and the shadow value of increased transfer capability to PJM from ECAR is approximately $2,390 per MW annually.

Surprisingly, we estimate that when the ECAR price is greater than the PJM price, the probability of observing quantity-constrained trade is quite high—over 23 percent. Since a variety of evidence on electricity flows indicates that power movements to ECAR from PJM rarely exhaust the physical transfer limits of the transmission system, our finding regarding the prevalence of quantity-constrained trade is a bit unexpected. Given that PJM is a centrally coordinated ISO, while ECAR is a "reliability area" without centralized dispatch of its transmission system, prospective buyers and sellers may encounter difficulties in securing available transmission capacity within ECAR on high-priced days. It is also possible that incentives may exist to impede imports of generation at those particular times because some transmission owners within ECAR also own substantial amounts of generation. This behavior might be restrained more readily if the transmission system within ECAR were controlled instead by an ISO.

This paper is organized as follows. Section 2 briefly discusses issues of market integration and transmission adequacy in electricity markets. Section 3 provides some further institutional background. Section 4 presents our empirical methodology for analyzing market integration through the estimation of trading costs and identification of equilibrium states associated with autarky (i.e., no arbitrage), unconstrained trade (i.e., arbitrage), and quantity-constrained trade. Section 5 describes our data, while Section 6 contains our empirical findings. Finally, Section 7 offers concluding comments.

2. Market Integration and Transmission Adequacy in Electricity Markets

In general, formal empirical analysis has been lacking with respect to assessing the benefits or costs of FERC's policy designed to stimulate regional electricity markets, particularly as it relates to markets in the eastern United States. One study (Energy and Environmental Analysis Inc., 2001), which has been substantially criticized, contends that considerable gains would be realized by combining the PJM, New York, and New England ISOs into a single super-regional market. While the introduction of regional ISOs likely has lowered electricity trading costs within their internal boundaries, it is unclear to what extent ISOs facilitate external electricity trading between regions. Similar to a "free trade" area, the formation of an ISO may facilitate trading within its borders at the expense of trading electricity across its borders.

To date, virtually no attention has been devoted to assessing how institutional changes in electricity markets, such as the formation of ISOs, affect transaction costs associated with inter-regional electricity trading. In addition, very little attention has been paid to examining whether the expansion or combination of existing ISOs is likely to generate substantial additional gains from trade.[1] By estimating transactions costs arising from inter-regional electricity trade, this paper addresses both of these issues.

Finally, in the wake of past price "spikes" and the August 2003 blackout in the eastern United States, the adequacy of the U.S. transmission system has been the subject of intense public scrutiny by the Department of Energy, FERC, Congress, and state public service commissions.[2] By identifying the likelihood that observed inter-regional price differentials at a particular time stem from binding constraints on trading volume rather than unconstrained trade, and by comparing price differences under these two regimes, we can estimate the "shadow value" of adding transfer capability (e.g., transmission capacity) that facilitates electricity flows between regions of the United States. This value represents the cost savings that can be achieved if lower-cost generation in one region is allowed to satisfy more of the electricity demand in a higher-cost region where that demand is currently served by local generation.[3] If the estimated cost savings arising from increased transmission capability exceed the cost of providing that additional capability, then it would be worthwhile to increase transmission capability to facilitate electricity trading between the regions of interest.

We also can use this approach to compare how the likelihood of observing binding trade constraints is influenced by the organizational form used to manage the transmission system. That may shed additional light on whether ISOs lead to improved use of available transmission capacity relative to less centralized forms of transmission management.

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[1] One exception is the U.S. Department of Energy (2002) study of the national transmission grid, which examines economic gains from the trade of electricity and the costs of transmission congestion.

[2] See, for example, the U.S. Department of Energy's (2002) "National Transmission Grid Study," which states that "[t]here is growing evidence that the U.S. transmission system is in urgent need of modernization (Executive Summary, p. xi)." Recent press attention concerning underinvestment in the transmission grid includes *Business Week* (2004) and Dow Jones Newswires (2004).

[3] Overbye, Hale, Leckey, and Weber (2000) have examined the cost of transmission constraints in the eastern United States, using a simulation approach that optimally dispatches generation resources to minimize aggregate production costs subject to existing transmission limits.

3. Institutional Background

Our analysis focuses on inter-regional trading costs between the PJM Interconnection (covering New Jersey, Pennsylvania, Delaware, Maryland, and parts of other states) and two adjoining regions, the New York Independent System Operator (New York ISO) and the East Central Area of Reliability (ECAR). These are three important energy-trading regions in the eastern and east-central United States with different forms of internal organization pertaining to the control of their transmission systems and trading environments.

The PJM and New York ISOs both exercise centralized oversight over the dispatch of system resources to further the efficient use of available transmission capacity, where ECAR takes a more light-handed approach. As a "reliability area," ECAR typically allows its member utilities to determine how their transmission systems are used, subject to FERC's "Open Access" requirements (see FERC Order 888) and some co-ordination of dispatch schedules to mitigate regional transmission congestion and ensure reliability.

Both PJM Interconnection and the New York ISO offer a mixture of bilateral and multi-party "exchange" trading. In PJM, those entities needing to purchase electric power on the exchange market provide demand estimates, as well as a description of their existing bilateral purchase agreements and self-supply capabilities (if they own generation). From this, PJM formulates an estimate of "residual" electricity demand on a day-ahead basis. Electric generators can then bid their available power production into the PJM day-ahead market to serve the residual demand. Once approved by PJM to serve the market based on their bid schedule, resources are called into service through price signals and other information sent by PJM (using the aggregated bid schedules as the market supply curve). Transactions involving PJM entities and a purchaser or seller located outside of PJM are typically arranged on a bilateral basis, with the transaction requiring approval by PJM and any other relevant transmission system operator in order to insure that an available transmission path exists.

The day-ahead PJM "exchange" market began operations on April 1, 1998 with mandated "cost-based" bidding. However, no explicit mechanism existed for monitoring compliance with cost-based bids, and PJM members could still enter into bilateral transactions at mutually agreed rates to supply electricity inside and outside of PJM's service territory. Starting April 1, 1999, "market-based" bidding was allowed in PJM's energy exchange. Since our data covers the period from March 1997 through June 2002, we can analyze whether trading costs between PJM and neighboring regions were affected by the formation of the multi-party PJM exchange market and its switch from "cost-based" to "market-based" bidding.

The New York ISO (NYISO) began its power exchange on November 18, 1999 and operates both day-ahead and real-time energy markets. Prior to November 1999, NYISO relied exclusively on bilateral arrangements to clear the market. Similar to PJM, NYISO uses a location-based marginal pricing system to clear its internal market efficiently at particular "nodes" (or buses), subject to the transmission constraints that exist within its boundaries. To avoid pricing issues that arise as a result of internal congestion within ISOs, we use prices for two typically uncongested areas, PJM's Western hub and New York's Western zone (i.e., Zone A).

ECAR, covering all of Ohio and Indiana and portions of Kentucky, Michigan, West Virginia, and other states, relies exclusively on bilateral trading for internal and external transactions. Hence, the costs associated with price discovery within ECAR may be greater than PJM or New York where the ISO provides information publicly on the exchange's market-clearing prices. As mentioned previously, ECAR operates as a "reliability area" instead of an area with an "independent system operator" (ISO), implying that the use of its transmission system and generation resources is not centrally coordinated to the extent of PJM Interconnection and New York ISO. In all three markets (PJM, New York, and ECAR), day-ahead contracts are sold for 16-hour blocks of electricity. We focus on these particular prices in our study.

4. Empirical Methodology

This section extends the existing methodology to provide a more general specification for estimating transaction (i.e., arbitrage) costs. Previous arbitrage models, as mentioned above, consider that only two states of nature may explain observed price differences across geographic areas. One state reflects the presence of arbitrage, while the other state reflects the absence of arbitrage (i.e., "autarky").[4]

Since the capacity limits of the transmission system and institutional impediments may constrain the quantity of electricity traded between regions, our model necessarily considers three possible equilibrium states. These potential states are: (1) no arbitrage (i.e., autarky); (2) arbitrage (i.e., unconstrained trade); and (3) quantity-constrained trade.

The autarky state reflects the absence of significant (short-term) trade, while the arbitrage state is consistent with trading without a binding constraint on the volume traded. Finally, quantity-constrained trade represents a state where trade takes place up to some capacity constraint, such as transmission limits.

Besides considering the possibility of a quantity-constrained trading state, our model includes other modifications from prior attempts to estimate arbitrage costs. These include the following: (i) arbitrage cost is measured in both directions based on the observed price differences across regions; (ii) structural factors are included that may affect regional price differences in the

[4] The approach of estimating arbitrage costs to assess the extent of market integration contrasts with time-series approaches often used in the literature. Several studies (including Spulber and Doane, 1994, in natural gas; Woo, Lloyd-Zannetti, and Horowitz, 1997, and De Vany and Walls, 1999a and 1999b, in electricity; and, Gulen, 1999 in oil) have used correlation, Granger causality, or co-integration analysis to determine whether energy markets have grown more "unified" over time. In general, these tests consider two or more regions to be an "integrated market" if the evidence shows: (i) that prices across regions are highly correlated, (ii) prices are co-integrated, or (iii) Granger causality exists between the price series. Of course, among other issues, these approaches may show that two regions are integrated if they are subject to common exogenous supply and demand shocks. Rather than assessing the extent of market integration, these tests also are constructed to indicate that markets are either integrated, or not. For a critique of time-series approaches to market integration, see Kleit (2001).

autarky (and constrained trade) state; and, (iii) adjustments are made for autocorrelation in estimating the autarky price difference.

4.1. The Model

Let P_{1i} and P_{2i} represent product prices in regions 1 and 2, respectively, in period *i*. We define the <u>observed</u> price difference between the two regions as $Y_i \equiv P_{1i} - P_{2i}$. This observed difference is consistent with three possible equilibrium states, as described below.

4.1.1. No Arbitrage (Autarky)

The observed difference in regional prices may reflect an absence of arbitrage behavior, otherwise known as autarky. Note that the autarky state in our model does not necessarily imply the complete absence of trade between regions in a real-world context. For instance, a relatively constant commodity flow may move between regions under long-term contracts, but there may be limited commodity movement in response to short-term regional price differences.

In autarky, we assume that the inter-regional price difference is determined by the relationship,

$$\Delta P_i^N = A_i + \varepsilon_i,\ where\ \varepsilon_i \sim N\left(0, \sigma^2\right), \tag{1}$$

where A_i is the mean autarky price. Note that ΔP_i^N represents what the price difference would be in the absence of arbitrage, which may differ from the actually observed price difference. Temporarily, we assume w.l.o.g. that $\Delta P_i^N \geq 0$, implying that region 1's price is greater than (or equal to) region 2's price.

4.1.2. Arbitrage (Unconstrained Trade)

Alternatively, if the price in region 1 becomes "much" higher than the price in region 2, consumers in region 1 will "arbitrage" the difference by purchasing the good in region 2 and shipping it to region 1.[5] This, in turn, limits the price differential between regions 1 and 2. However, arbitrage should not arise unless the price difference between the two regions in the absence of trade exceeds the transaction (i.e., arbitrage) cost of trading the good from the lower-priced region to the higher-priced region.

Now define the transaction cost of shipping the good from region 2 to region 1 as

$$T_{1i} = \underline{T}_1 + \varepsilon_{1i}, \textit{ where } \varepsilon_{1i} \sim N\left(0, \sigma_1^2\right) \textit{ and truncated below } -\underline{T}_1. \tag{2}$$

The reason for the truncation is that transaction costs cannot be negative. Based on the assumed distribution of ε_{1i}, the expected value of T_{1i} equals:

$$E\left(T_{1i}\right) = \underline{T}_1 + \sigma_1 f\left(-\underline{T}_1/\sigma_1\right)/F\left(\underline{T}_1/\sigma_1\right), \tag{3}$$

where f is the probability density function and F is the cumulative distribution function for a standard normal variable. For proof, see among others, Johnson and Kotz (1970).

4.1.3. Quantity-Constrained (Transmission-Constrained) Trade

Without constraints, trade continues between regions 1 and 2 until the price difference between the two markets equals the associated transaction (i.e., arbitrage) cost. If, however, a limit exists on the possible quantity traded, the inter-regional price difference may remain greater than transaction costs under conditions where the quantity constraint becomes binding. Thus, when trade is quantity-constrained in equilibrium, the price difference between regions is

[5] Alternatively, the arbitrage process can be viewed as one where producers in region 2 recognize a profit opportunity in selling into region 1. They search for buyers in region 1, and ship the good into that region to the buyers that they identify.

above the level associated with unconstrained trade, but below the level that would arise under autarky. In electricity markets, this result may be observed when electricity trade occurs up to the physical limits of the transmission system, or up to quantity constraints that arise from institutional limits on transmission access.

We therefore express the price differential between regions 1 and 2 under quantity-constrained trade as:

$$C_{1i} = A_i - FLOW_1 + \varepsilon_i,\ \ where\ FLOW_1 > 0. \tag{4}$$

In this equation, *$FLOW_1$* is a "flow parameter" representing the change in the price difference induced by the flow of electricity from one region to another up to the allowed quantity limit. Compare equations (1) and (4). In contrast to the no-arbitrage (i.e., autarky) case, the inter-regional price differential is lower by *$FLOW_1$* when trade occurs up to the physical transmission limits. In other words,

$$C_{1i} = \Delta P_i^N - FLOW_1\,. \tag{5}$$

4.1.4. Deriving the Basic Likelihood Function

In basic terms, the likelihood of observing the inter-regional price difference, Y_i, is the sum of the probabilities associated with observing this price differential in any of the three possible equilibrium states. Based on the above model, this likelihood can be expressed as follows when $Y_i \geq 0$:

$$\begin{aligned} L^+(Y_i) = {} & [\Pr(\Delta P_i^N = Y_i) * \Pr(Y_i \leq T_{1i})] + [\Pr(T_{1i} = Y_i) * \Pr(C_{1i} \leq Y_i < \Delta P_i^N)] \\ & + [\Pr(C_{1i} = Y_i) * \Pr(T_{1i} < Y_i < \Delta P_i^N)]. \end{aligned} \tag{6}$$

The first bracketed expression represents the probability that autarky results in the observed inter-regional price difference (i.e., $\Delta P_i^N = Y_i$), multiplied by the probability that we are observing the autarky equilibrium state. The second bracketed expression represents the probability that arbitrage results in the observed price difference (i.e., $T_{1i} = Y_i$), multiplied by the probability that we are observing the arbitrage equilibrium state. The third bracketed expression represents the probability that quantity-constrained trade results in the observed price difference (i.e., $C_{1i} = Y_i$), multiplied by the probability that we are observing the constrained-trade equilibrium state.

Substituting equations (1), (2), and (4) into equation (6), and making use of the symmetry of the normal distribution function, we obtain the following result:[6]

$$
\begin{aligned}
L^{+}(Y_i) = {} & (1/\sigma) f\left((Y_i - A_i)/\sigma\right) * \left(F\left((\underline{T}_1 - Y_i)/\sigma_1\right)/F(\underline{T}_1/\sigma_1)\right) \\
& + (1/\sigma_1)\left(f\left((Y_i - \underline{T}_1)/\sigma_1\right)/F(\underline{T}_1/\sigma_1)\right) * \left[F\left((Y_i - \underline{A}_i + FLOW_1)/\sigma\right) - F\left((Y_i - \underline{A}_i)/\sigma\right)\right] \qquad (7) \\
& + (1/\sigma) f\left((Y_i - A_i + FLOW_1)/\sigma\right) * \left[\left(F(\underline{T}_1/\sigma_1) - F\left((\underline{T}_1 - Y_i)/\sigma_1\right)\right)/F(\underline{T}_1/\sigma_1)\right],
\end{aligned}
$$

where f is the probability distribution function for a standard normal, and F is the cumulative distribution function.

Having previously assumed that region 1 was the higher-priced region, we now consider the opposite case where region 2 is the higher-priced region (i.e., $Y_i < 0$). Our autarky specification remains unchanged. However, under this circumstance, it is possible that the good will move from region 1 to region 2 if transaction costs are sufficiently low to accommodate trade. Allowing for the possibility that arbitrage costs may differ depending on the direction of trade, we define the arbitrage cost of shipping the good from region 1 to region 2 as

[6] In the quantity-constrained trade state, it necessarily holds that if $Y_i = C_{1i}$, then $Y_i < \Delta P_i^N$ (see equations (1) and (4)).

$$T_{2i} = \underline{T}_2 + \varepsilon_{2i}, \textit{ where } \varepsilon_{2i} \sim N\left(0, \sigma_2^2\right) \textit{ and truncated below } -\underline{T}_2. \tag{8}$$

Based on the distribution of ε_{2i}, $E(T_{2i})$ equals $\underline{T}_2 + \sigma_2 f\left(-\underline{T}_2/\sigma_2\right)/F\left(\underline{T}_2/\sigma_2\right)$.

Also, in contrast to the autarky state, we assume that the inter-regional price difference is reduced by $FLOW_2$ when electricity flows from region 1 to region 2 up to the quantity constraints imposed by transmission availability. In other words, when $Y_i < 0$, the price difference between regions 1 and 2 under quantity-constrained trade can be expressed as:

$$C_{2i} = A_i + FLOW_2 + \varepsilon_i, \textit{ where } FLOW_2 > 0, \tag{9}$$

or

$$C_{2i} = \Delta P_i^N + FLOW_2. \tag{10}$$

Based on the above description, the likelihood function can be expressed as follows when the price in region 2 exceeds the price in region 1 (i.e., $Y_i < 0$):

$$\begin{aligned} L^-(Y_i) = {} & (1/\sigma) f\left(\left(Y_i - A_i\right)/\sigma\right) * \left(F\left(\left(\underline{T}_2 + Y_i\right)/\sigma_2\right)/F\left(\underline{T}_2/\sigma_2\right)\right) \\ & + (1/\sigma_2)\left(f\left(\left(-Y_i - \underline{T}_2\right)/\sigma_2\right)/F\left(\underline{T}_2/\sigma_2\right)\right) * \left[F\left(\left(Y_i - \underline{A}_i\right)/\sigma\right) - F\left(\left(Y_i - \underline{A}_i - FLOW_2\right)/\sigma\right)\right] \\ & + (1/\sigma) f\left(\left(Y_i - A_i - FLOW_2\right)/\sigma\right) * \left[\left(F\left(\underline{T}_2/\sigma_2\right) - \left(F\left(\underline{T}_2 + Y_i\right)/\sigma_2\right)\right)/F\left(\underline{T}_2/\sigma_2\right)\right]. \end{aligned} \tag{11}$$

We now have a function that describes the likelihood of observing a given price difference between regions 1 and 2, whether that difference is nonnegative, as described by $L^+(Y_i)$, or negative, as described by $L^-(Y_i)$. Thus, the likelihood function for observing any value Y_i, whether that value is positive or negative, is described as follows:

$$L(Y_i) = \left(L^+(Y_i)\right)^{I_i} * \left(L^-(Y_i)\right)^{(1-I_i)}, \tag{12}$$

where I_i = *1* if $Y_i \geq 0$ and I_i = *0* if $Y_i < 0$.

4.2. Additional Modifications

The above model can be modified to improve the generality and reliability of the specification. The price difference between regions 1 and 2 under autarky should depend on regional supply and demand factors. Thus, we modify equation (1) by assuming that $A_i = Z_i'\theta$, where Z represents a *(k x 1)* vector of explanatory variables for the autarky state, and θ represents a *(k x 1)* vector of coefficient values for these variables. Consequently, the autarky price difference is now represented as follows:

$$\Delta P_i^N = Z_i'\theta + \varepsilon_i, \ where \ \varepsilon_i \sim N\left(0, \sigma^2\right). \tag{13}$$

Inserting equation (5) into the above specification, we can describe the inter-regional price difference when electricity flows into region 1 from region 2 up to the transmission system's limits:

$$C_{1i} = Z_i'\theta - FLOW_1 + \varepsilon_i, \ where \ \varepsilon_i \sim N\left(0, \sigma^2\right). \tag{14}$$

When region 1 has a higher price than region 2, the estimated coefficient $FLOW_1$ again describes the change in the regional price differential under constrained trade as compared with autarky.

With the above modifications, our more general specification has the following likelihood function (for $Y_i \geq 0$):

$$L^{+}(Y_i) = (1/\sigma) f((Y_i - Z_i'\theta)/\sigma) * (F((\underline{T}_1 - Y_i)/\sigma_1)/F(\underline{T}_1/\sigma_1))$$

$$\begin{aligned} &+ (1/\sigma_1)(f((Y_i - \underline{T}_1)/\sigma_1)/F(\underline{T}_1/\sigma_1)) \\ &\qquad * [F((Y_i - Z_i'\theta + FLOW_1)/\sigma) - F((Y_i - Z_i'\theta)/\sigma)] \end{aligned} \tag{15}$$

$$+ (1/\sigma) f((Y_i - Z_i'\theta + FLOW_1)/\sigma) * [(F(\underline{T}_1/\sigma_1) - F((\underline{T}_1 - Y_i)/\sigma_1))/F(\underline{T}_1/\sigma_1)].$$

An analogous specification applies when $Y_i < 0$.

The estimation maximizes the likelihood,

$$\prod_{i=1}^{T} L(Y_i) = (L^{+}(Y_i))^{I_i} * (L^{-}(Y_i))^{(1-I_i)}, \tag{16}$$

where $L^{+}(Y_i)$ is described by equation (15), $L^{-}(Y_i)$ is an analogous specification ($\underline{T}_2$ replaces $\underline{T}_1$, F_2 replaces F_1, and σ_2 replaces σ_1), and $I_i = 1$ if $Y_i \geq 0$ (else zero).

4.3. Autocorrelation Adjustment

It is possible that the price difference under autarky could be subject to (first-order) autoregressive error behavior. If so, the autarky price series has the following underlying process,

$$\Delta P_i^N = A_i + \rho(\Delta P_{i-1}^N - A_{i-1}) + \mu_i, \tag{17}$$

where $\mu_i \sim N(0, \sigma^2)$ and $A_i = Z_i'\theta$ in the more general case. Here, the extent of autocorrelation is described by the coefficient, ρ, where $|\rho| < 1$.

Since we are unable to directly distinguish the "autarky" state from either the "arbitrage" or "constrained trade" state, ΔP_{i-1}^N is not observed directly. Instead, ΔP_{i-1}^N is calculated by estimating the (expected) autarky price difference, conditional on the observed price difference being associated with a particular equilibrium state (i.e., autarky, unconstrained trade, or constrained trade). These state-dependent estimates of the autarky price difference are then multiplied (i.e., weighted) by the estimated probability that a given state is being observed.

By incorporating equation (17) into our more general specification (as described by equation (15)), we are able to correct for the effects of autocorrelation. Through maximum likelihood techniques, we now can estimate the parameter ρ along with the other parameters.

5. Data

The data used to perform the regression analyses include three key inputs: (i) electricity prices, (ii) temperatures, and (iii) fuel costs. The electricity prices ($ per MWh) are volume-weighted averages of the contract prices for pre-scheduled, day-ahead 16-hour blocks of electricity, as reported by *Power Markets Week* for weekdays.[7] The data are for the period from March 1997 through June 2002, comprising 1350 observations for PJM, NYISO and ECAR.

The PJM price series is for power bought and sold at its Western Hub, while the New York price series is for power bought and sold in Western New York (Zone A, which excludes New York City and Long Island). ECAR prices are for power delivered into Cinergy's transmission system, which serves portions of Indiana and Ohio. We used this price series to represent ECAR since it represents an area close to PJM's western boundary.[8]

Our analysis uses temperature as the crucial demand shifter for electric power. Electric power consumption increases substantially at high temperatures, particularly through increased demand for air conditioning and other cooling processes. At particularly low temperatures, electricity demand for heating purposes potentially increases.

[7] This publication conducts an independent review of transaction data as reported by energy traders and then compiles the results.
[8] PJM has recently expanded into parts of Illinois, Indiana, Ohio, and Kentucky, and will soon expand into Virginia.

The regions analyzed in this paper, PJM Interconnection, New York ISO, and ECAR, cover relatively broad geographic areas. A weighted-average temperature for each region was therefore calculated using the daily maximum temperature in major cities, where the weights equaled the population of the corresponding metropolitan area. Daily maximum temperatures were obtained from the National Climatic Data Center.[9] The following cities were used to calculate the average temperature in each respective region:

<u>PJM Interconnection:</u> Baltimore, MD; Newark, NJ; Philadelphia, PA; Washington, DC; Wilmington, DE.

<u>New York ISO:</u> Buffalo, NY; New York City, NY.

<u>ECAR:</u> Cincinnati, OH; Cleveland, OH; Indianapolis, IN.[10]

We then take the weighted-average high temperature for a given day and convert it into cooling and heating degree days, where "cooling degree days" equals *max(0, temperature-65)*, and "heating degree days" equals *max(0, 65-temperature)*.

Natural gas constitutes an important fuel source, and consequently an important short-run cost, for many power generators. We rely on the daily cash-market closing price at Henry Hub (a major trading point in Louisiana), as recorded in the Bridge/CRB Historical Data CD-ROM.

Although coal is also an important fuel source for some generators, it is typically purchased on a contract basis, with substantial regional differences in prices. Since there is no day-ahead spot market for coal transactions, we assume that the coal price on a given day is related to the gas price on that day. Certainly, for an operator of a coal-fired power plant, its willingness to pay

[9] For further description, see http://lwf.ncdc.noaa.gov/oa/ncdc.html.

[10] Although the ECAR average temperature in our reported regressions is constructed only from temperature readings in Ohio and Indiana, our results were not substantively affected by including readings from Kentucky, Michigan, West Virginia, and other parts of ECAR. Since ECAR, as an "area of reliability," does not coordinate its transmission operations as tightly as an ISO, we decided to use temperature readings from areas of ECAR in relatively close proximity to PJM.

for coal on a given day is influenced by the price of electricity on that day, and the latter is influenced by the price of natural gas facing its competitors.[11]

6. Results

We estimate transaction costs between PJM and New York as well as between PJM and ECAR. As described previously, our methodology uses maximum-likelihood techniques to estimate the following simultaneously: (i) the autarky price-difference equation; (ii) the transaction-cost equation (for trade in each direction), and (iii) the price difference under constrained trade (for trade in each direction). Our likelihood specification is described generally by equations (15) and (16) (where an equation analogous to (15) applies for $Y_i < 0$). Our estimation corrects for autocorrelation in the errors affecting the autarky equilibrium, using the procedure described previously in section 4.3.

When the two regions behave effectively as separate markets (i.e., in the autarky and constrained-trade states), the structural variables used to describe the inter-regional price difference (i.e., the vector Z_i in equation (15)) include the price of natural gas and the difference in cooling and heating degree days between the two regions, where the difference in cooling and heating degree days enters by itself and as a squared term.

In the transaction-cost specification, two indicator variables were included. One variable denotes the period beginning in April 1998 when PJM commenced its internal multi-party exchange market, and another variable denotes the period beginning in April 1999 when the energy exchange became subject to market-based bidding rather than cost-based bidding.

[11] This potentially raises the issue that the regional price of coal and natural gas may be endogenously determined. To mitigate this potential problem, we use prices for natural gas delivered to Henry Hub (Louisiana), a major trading point. Prices at Henry Hub are not likely to be substantially influenced by conditions affecting electricity markets in the eastern United States.

6.1. Interpretation of Results

6.1.1. PJM and New York

Table 1 provides our coefficient estimates for the model explaining inter-regional price differences between the PJM and New York ISOs. The table shows coefficient estimates with and without an autocorrelation adjustment. The dependent variable is the PJM price less the New York price, where the prices are for pre-scheduled, day-ahead 16-hour blocks of electricity.

In the specification describing price differences under autarky, the coefficient for the natural gas price is negative and statistically significant, indicating that an increase in the price of natural gas is associated with a reduced PJM-New York price difference (i.e., PJM's price less New York's price) in the absence of arbitrage. This result is quite plausible, since a larger percentage of electric power is supplied by gas-fired plants in New York, as compared to PJM, which has a larger percentage of coal-fired generation. Hence, an increase in natural gas prices may have a greater impact on (marginal) supply costs within New York than within PJM.

While the coefficient for the difference in cooling degree days is negative in our autarky specification, the coefficient for the squared difference in cooling degree days is positive and statistically significant. This suggests that when average high temperatures are substantially greater in PJM than in New York (e.g., by more than 13 degrees), the difference increases between PJM and New York electricity prices due to PJM's increased electricity demand (for air conditioning and cooling purposes). The coefficient for the difference in heating degree days is positive and statistically significant in our specification containing an autocorrelation adjustment, implying that autarky prices may increase in PJM relative to New York when PJM temperatures are substantially cooler than New York temperatures.

Table 1: Coefficient Estimates – PJM/NY

1350 observations: 694 (656) observations where PJM (NY) has higher price
t-statistics in parenthesis — ** (*) denotes 5 (10) percent significance in two-tailed test

	Without Autocorrelation Adjustment	With Autocorrelation Adjustment
Autarky Parameters		
Constant	11.27** (3.42)	11.63** (3.11)
σ	38.66** (4.84)	39.02** (3.20)
ρ		0.300** (14.12)
Price of Natural Gas	-3.32** (-3.80)	-3.87** (-3.41)
(Δ Cooling Degree Days)	-2.79** (-3.21)	-3.01** (-3.00)
(Δ Cooling Degree Days)^2	0.217** (8.07)	0.230** (6.00)
(Δ Heating Degree Days)	1.18 (1.36)	1.14** (1.99)
(Δ Heating Degree Days)^2	0.00413 (0.15)	0.00147 (0.90)
Transaction Cost to PJM from NY		
Constant	-18.07** (-3.91)	-18.79** (-7.34)
April 1998 Indicator	1.31 (0.34)	1.19 (0.50)
April 1999 Indicator	-4.00* (-1.91)	-3.77* (-1.81)
σ_1	8.84** (14.83)	9.34** (35.03)
Transaction Cost to NY from PJM		
Constant	-10.67** (-2.71)	-12.94** (-2.69)
April 1998 Indicator	-4.05 (-1.17)	-4.38 (-1.33)
April 1999 Indicator	14.48** (3.74)	15.45** (3.77)
σ_2	4.84** (16.18)	5.18** (14.08)
Flow Parameters		
Flow to PJM from NY	72.86** (11.26)	82.51** (11.67)
Flow to NY from PJM	72.69** (11.72)	81.36** (8.82)
Log-Likelihood	-1049.26	-940.31

Transaction Cost Estimates: PJM and New York

Table 2 indicates that the estimated mean transaction cost when PJM is the higher-priced region is between approximately \$3 and \$4 per MWh over our sample period. According to our estimates, the combined effect of starting the PJM internal exchange market (in April 1998), and then switching from cost-based to market-based bidding in that market (in April 1999), has been to slightly lower the cost of trading power to PJM from New York. However, these two indicator variables are not statistically significant together.[12]

As for trade in the other direction, the estimated mean transaction cost when New York is the higher-priced market varies from less than \$2 per MWh to more than \$3 per MWh over our sample period. The introduction of the PJM exchange market in 1998 is initially associated with a lower transaction cost for sending power to New York from PJM, although this result is not statistically significant. However, the subsequent switch in 1999 from cost-based to market-based bidding within PJM is associated with a statistically significant increase of more than \$2 per MWh in the cost of trading power to New York. Together, these institutional changes within PJM's market have a positive and statistically significant impact on the transaction cost for sending power to New York.[13]

Perhaps PJM market participants found it more attractive to sell power within the PJM region, as opposed to outside of the region, once PJM switched from cost-based to market-based bidding in its energy exchange. PJM protocols during this period also may have increased the

[12] The likelihood-ratio test statistic for including both indicator variables is 1.30 (in the specification without an autocorrelation adjustment), which is not statistically significant at the 5-percent level according to the $\chi^2(2)$ distribution for the test.
[13] The likelihood-ratio test statistic for including both indicator variables is 107.96, which is easily statistically significant at the 5-percent level.

Table 2: Transaction Cost Estimates – PJM/NY

($ per MWh)

	Model Without Autocorrelation Adjustment	Model With Autocorrelation Adjustment
Mean Transaction Cost to PJM from NY		
Before April 1998	3.25	3.47
April 1998 – April 1999	3.40	3.61
After April 1999	2.97	3.20
Mean Transaction Cost to NY from PJM		
Before April 1998	1.70	1.67
April 1998 – April 1999	1.36	1.35
After April 1999	3.78	3.52

Table 3: Estimated Average State Probabilities PJM/NY

	Model Without Autocorrelation Adjustment	Model With Autocorrelation Adjustment
When PJM Price Is Higher Than NY Price		
Autarky	12.1%	11.4%
Unconstrained Trade	80.1%	81.7%
Quantity Constrained Trade	7.8%	6.9%
When NY Price Is Higher Than PJM Price		
Autarky	6.3%	5.3%
Unconstrained Trade	88.3%	89.4%
Quantity Constrained Trade	5.4%	5.3%

difficulty of sending power out of the region into New York. Alternatively, given that New York began its exchange market in November 1999, the formation of the internal PJM and New York ISO exchange markets subject to different power trading and dispatch protocols may have created "seams" issues that inhibited trade to New York from PJM. The appearance of seams issues associated with ISO formation has been discussed frequently in the electricity trade press (see, for example, the discussion in *Public Utilities Fortnightly,* September 1, 2001).

Thus, the formation of regional ISOs did not appear to raise transaction costs for trading power to PJM from New York. However, some evidence suggests that PJM's switch from cost-based to market-based exchange bidding may have raised the cost of trading power to New York from PJM.

Quantity-Constrained Trade: PJM and New York

The coefficients for the "flow" variables estimate the impact on the price difference between PJM and New York if trade occurs up to the volume limits imposed by the transmission system, as compared to the autarky state. As reported in Table 1, our model estimates that when PJM is the higher-priced region, the impact of allowing trade flows that exhaust transmission capabilities is to reduce the price difference between PJM and New York by $73 per MWh (or $83 per MWh, adjusted for autocorrelation), as compared to the autarky state. If New York is the higher-priced region, we estimate that the impact of allowing trade up to the transmission system's limits, as compared to autarky, is to reduce the price difference between PJM and New York by $73 per MWh (or $81 per MWh, adjusted for autocorrelation).

At a cursory glance, the "flow parameter" estimates appear large in magnitude, when one considers that the average daily PJM price in our data sample is about $35 per MWh. The estimation, however, assigns more weight to those observations where the probability is relatively large that the quantity-constrained trading state is being observed. Since the model estimates that the probability of observing quantity-constrained trade is small in general, it places a large weight on a few specific observations. Of course, we are more likely to observe quantity-constrained trading on those days when temperatures are quite hot, and, so-called electricity "price spikes" arise occasionally under those conditions. For example, prices above $180 per MWh were observed in PJM on two days in July 1998, six days in July 1999, one day in August 1999, one day in May 2000, and two days in August 2001.

As reported in Table 3, our model (without an autocorrelation adjustment) estimates that on those days when PJM has a higher price than New York, the probability of observing quantity-constrained trade is 7.8 percent in our sample. The probability of observing unconstrained trade is 80.1 percent, while the probability of observing autarky is 12.1 percent.

When New York has higher prices than PJM, our model estimates that the probability of observing quantity-constrained trade is 5.4 percent. The probability of observing unconstrained trade is 88.3 percent, and the probability of observing autarky is 6.3 percent.

6.1.2. PJM and ECAR

Table 4 provides our coefficient estimates for the model explaining inter-regional price differences between PJM and ECAR. In the autarky specification, we observe that the natural gas price is not a statistically significant determinant of the electricity price difference between PJM and ECAR, since both regions have substantial coal-fired generation along with gas-fired generation. The coefficient for the difference in cooling degree days (i.e., PJM cooling degree days less ECAR cooling degree days) enters negatively into our autarky price specification, but it is not statistically significant. The coefficient for the squared difference in cooling degree days is positive and statistically significant. This suggests that when average high temperatures are greater in PJM than in ECAR, the difference increases between PJM and ECAR electricity prices.

Table 4: Coefficient Estimates – PJM/ECAR

1350 observations: 1036 (314) observations where PJM (ECAR) has higher price
t-statistics in parenthesis — ** (*) denotes 5 (10) percent significance in two-tailed test

	Without Autocorrelation Adjustment	With Autocorrelation Adjustment
Autarky Parameters		
Constant	43.77** (7.39)	42.89** (8.03)
σ	56.79** (3.18)	58.50** (3.93)
ρ		0.325** (50.59)
Price of Natural Gas	-0.540 (-0.36)	-0.534 (-0.56)
(Δ Cooling Degree Days)	-0.312 (-0.29)	-0.225 (-0.20)
(Δ Cooling Degree Days)^2	0.0833** (2.98)	0.0666** (2.00)
(Δ Heating Degree Days)	-0.527 (-0.59)	-0.396 (-0.41)
(Δ Heating Degree Days)^2	0.0398* (1.96)	0.0405* (1.81)
Transaction Cost to PJM from ECAR		
Constant	2.00** (4.61)	1.55** (3.50)
April 1998 Indicator	-2.11** (-2.75)	-2.41** (-3.48)
April 1999 Indicator	4.44** (6.60)	5.95** (9.23)
σ_1	3.29** (72.44)	3.33** (75.48)
Transaction Cost to ECAR from PJM		
Constant	-3.41 (-0.54)	-2.95 (-1.07)
April 1998 Indicator	-3.01 (-0.75)	-3.43** (-2.31)
April 1999 Indicator	-0.325 (-0.14)	0.605 (0.55)
σ_2	5.47** (4.48)	6.10** (13.44)
Flow Parameters		
Flow to PJM from ECAR	148.34** (12.93)	170.50** (14.04)
Flow to ECAR from PJM	41.37** (7.39)	50.28** (8.52)
Log-Likelihood	-1248.38	-1133.65

Transaction Cost Estimates: PJM and ECAR

Table 5 indicates that when PJM is the higher-priced region, the estimated mean transaction cost between PJM and ECAR varies approximately from $2 to $5 (or $6, adjusted for autocorrelation) per MWh over the sample period. According to our estimates, the transaction cost for sending power to PJM from ECAR fell after the formation of PJM's internal exchange market in April 1998. However, this transaction cost increased substantially after PJM's exchange market switched from cost-based to market-based bidding in April 1999. The combined effect of these PJM institutional changes is positive and statistically significant with respect to this transaction cost.[14]

Perhaps the formation of the PJM exchange market led to improved price discovery regarding PJM's internal prices, thereby reducing the information-cost component of transaction costs for sending power to PJM from ECAR. That could explain the initial drop in transaction costs after the energy exchange began operations. It is more difficult, however, to explain why PJM's switch from cost-based to market-based exchange bidding is associated with higher transaction costs for importing power into PJM.

As for trade in the other direction, we estimate that when ECAR is the higher-priced region, the mean transaction cost between PJM and ECAR varies approximately from $2 to $4 per MWh over our sample period (or, from $3 to $4 per MWh, adjusted for autocorrelation). Our results suggest that the transaction cost in sending power to ECAR from PJM may have fallen after PJM formed its internal exchange market in April 1998. However, no statistically significant impact on this transaction cost is associated with PJM's switch from cost-based to market-based bidding.

[14] The likelihood-ratio test statistic for including both indicator variables is 109.32 (in the regression without an autocorrelation adjustment), which is statistically significant at the 5-percent level.

Table 5: Transaction Cost Estimates – PJM/ECAR
($ per MWh)

	Model Without Autocorrelation Adjustment	Model With Autocorrelation Adjustment
Mean Transaction Cost to PJM from ECAR		
Before April 1998	3.50	3.31
April 1998 – April 1999	2.59	2.37
After April 1999	4.94	5.53
Mean Transaction Cost to ECAR from PJM		
Before April 1998	3.34	3.94
April 1998 – April 1999	2.70	3.15
After April 1999	2.64	3.27

Table 6: Estimated Average State Probabilities PJM/ECAR

	Model Without Autocorrelation Adjustment	Model With Autocorrelation Adjustment
When PJM Price Is Higher Than ECAR Price		
Autarky	3.3%	3.2%
Unconstrained Trade	92.9%	93.7%
Quantity Constrained Trade	3.8%	3.1%
When ECAR Price Is Higher Than PJM Price		
Autarky	7.3%	7.8%
Unconstrained Trade	65.4%	68.6%
Quantity Constrained Trade	27.3%	23.6%

Quantity-Constrained Trade: PJM and ECAR

As reported in Table 4, the coefficient for our "flow" variables represents the reduction in the inter-regional price difference that arises when trade occurs up to the transmission system's limits as compared with autarky. This parameter estimate is approximately $148 per MWh (or $170 per MWh, adjusted for autocorrelation) when PJM is the higher-price region. The estimate is a more modest $41 per MWh (or $50 per MWh, adjusted for autocorrelation) when ECAR is the higher-priced region.

Although these numbers appear quite large compared to a mean PJM(ECAR) energy price of $35($39) per MWh, one must note again that the estimation assigns substantially more weight to particular observations where the probability is relatively large that the quantity-constrained trading state is being observed. On those days where high temperatures produced a greater probability of observing quantity-constrained trade, extreme prices have arisen in both PJM and ECAR. For example, ECAR prices reached $2,040 and $1,892 per MWh on June 26 and June 29, 1998, respectively. ECAR prices reached $1,493 and $572 per MWh on July 21 and July 22, 1998; and, they reached $2,017 and $1,758 per MWh on July 29 and July 30, 1999. Electricity trade on these days is potentially quite valuable.

As described in Table 6, our model (without an autocorrelation adjustment) estimates that on those days when PJM has a higher price than ECAR, the probability of observing quantity-constrained trade in our sample is about 3.8 percent. The probability of observing unconstrained trade is about 92.9 percent, while the probability of observing autarky is about 3.3 percent.

Surprisingly, on those days when ECAR has a higher price than PJM, we estimate that the probability of observing quantity-constrained trade is about 27.3 percent (or 23.6 percent, adjusted for autocorrelation). The probability of observing unconstrained trade is 65.4 percent, and the probability of observing autarky is 7.3 percent.

Based on evidence describing actual electricity flows (see, for example, U.S. Department of Energy, 2002), it is unlikely that the transmission system's physical limits for sending power to ECAR from PJM are exhausted to the extent estimated by our model. Our model, though, attempts to estimate the probability that the two regions, ECAR and PJM, show price divergence consistent with quantity-constrained trade. The quantity restriction could represent an actual physical limitation on trade volume, such as exhausting the physical capacity of the transmission system. Alternatively, the restriction can be in the form of an "institutional" quantitative barrier, such as greater difficulty in obtaining available physical transmission capacity within a loosely organized "reliability" region (e.g., ECAR) as opposed to a centrally dispatched ISO (e.g., PJM and New York ISO).

Indeed, complaints have been lodged in the past that available transmission capacity within ECAR is difficult to obtain, or that it is hard to put together a transmission path on short notice for sending power from a given supply source to the buyer's specified delivery location. It is possible that transmission owners in ECAR, some of whom own substantial amounts of generation capacity, have incentive to withhold available transmission capacity when prices in ECAR are relatively high.

6.1.3. Estimating the Shadow Cost of Quantitative Trade Constraints

With the 2003 blackout in the east-central United States, and with the continuing deregulation of wholesale electricity markets, much attention has focused on the adequacy of the U.S. transmission system in handling inter-regional electricity flows. Little research has attempted, however, to measure the efficiency losses imposed by existing quantity constraints on electricity flows. Measuring the "shadow cost" of quantity constraints in terms of their marginal contribution to inter-regional price differences represents a means of assessing the value that additional transfer capability (e.g., transmission capacity) could provide in terms of reduced energy supply costs.

Even with available data on physical electricity flows along particular transmission lines, it is frequently difficult to determine when quantity constraints are "binding." Since thermal limits constrain the amount of electricity that can flow across a particular transmission line, available transmission capacity changes as temperature conditions vary. Other issues, like dynamic flow instability, may constrain use of the transmission system. Thus, problems arise in using physical data on electricity flows to determine when transmission limits are potentially binding. Moreover, as our previous results regarding trade from PJM into ECAR suggest, quantity constraints on electricity flows could arise not only from reaching physical transmission limits, but also from institutional obstacles, such as co-ordination, control, and informational impediments that keep available transmission capacity from being used effectively.

For the above reasons, we do not rely on physical flow data in estimating the (marginal) "shadow cost" of existing quantity constraints. Instead, we use a two-stage process to estimate the "shadow cost" arising from quantity constraints on electricity flows. First, we take the observed inter-regional price difference on each day and subtract our estimated mean transaction cost. If a state of quantity-constrained trade is actually being observed, an incremental increase in electricity flows from a lower-priced region to a higher-priced region will reduce energy procurement costs by the observed price difference, less the applicable transaction cost.

Second, we take the estimated shadow cost conditional on quantity-constrained trade being observed (as described above), and multiply this amount by our estimated probability that the observed inter-regional price difference on that day represents a state of quantity-constrained trade. In this fashion, we derive an estimate of the "expected" shadow cost that is used in our aggregate calculations. Since the estimated shadow cost is based on the observed inter-regional price difference per MWh for the sale of a 16-hour block of electricity, we multiply our estimated shadow cost per MWh by sixteen to arrive at a daily shadow cost estimate.[15]

[15] Since we do not have price data for the remaining 8-hour block (or weekends), representing off-peak hours, our estimated shadow cost does not include these hours. Thus, our analysis

The estimated (marginal) shadow costs for each month are presented in Figures 1 through 3. Figure 1 shows the estimated monthly shadow costs associated with quantity restrictions on electricity flows to PJM from New York, and in the opposite direction. Due to substantial differences in estimated shadow costs depending on the direction of PJM-ECAR trade, Figure 2 shows the shadow costs associated with quantity restrictions on electricity flows to PJM from ECAR, while Figure 3 shows the shadow costs associated with quantity-restricted electricity flows to ECAR from PJM.

Note that, as expected, shadow costs are higher in summer months, where transmission constraints are more likely to be binding as a result of the increased electricity demand created by high temperatures. Since constrained trade is observed relatively infrequently in our model, our results are driven by the extremely high inter-regional price differences observed on a few key dates. For example, the expansion of transfer capability between New York and PJM is only likely to reduce electricity supply costs substantially on a small number of summer days, provided that weather conditions on those days are similar to those experienced in July and August of 1998 and 1999.

assumes that quantity constraints (e.g., transmission limits) are not binding during this off-peak period, which is consistent with industry information regarding off-peak electricity flows.

Figure 1: Monthly Shadow Cost (per MW) of Quantitative Trade Constraints
- Flows between PJM and NYISO -

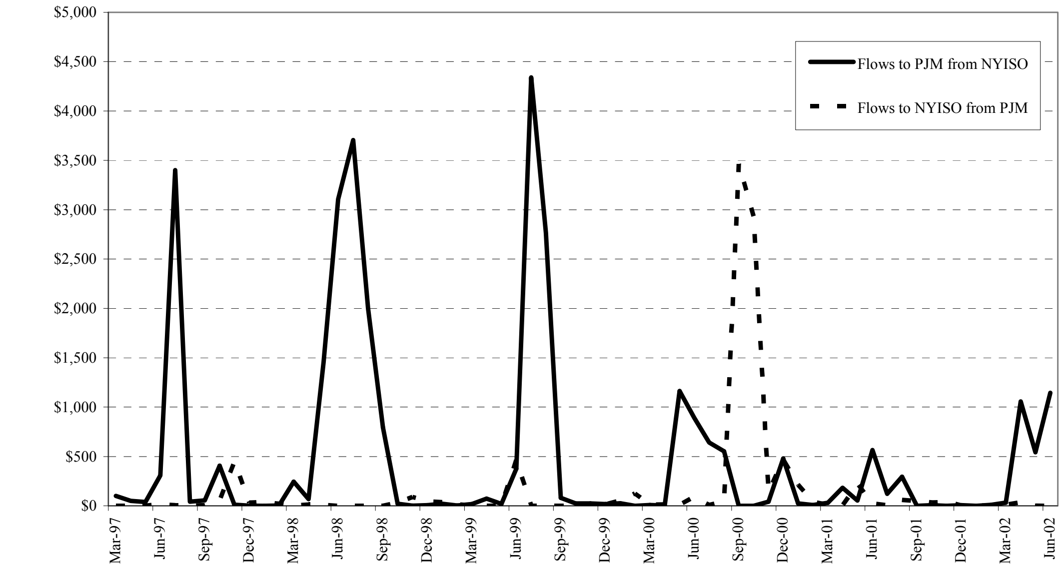

Figure 2: Monthly Shadow Cost (per MW) of Quantitative Trade Constraints
- Flows to PJM from ECAR -

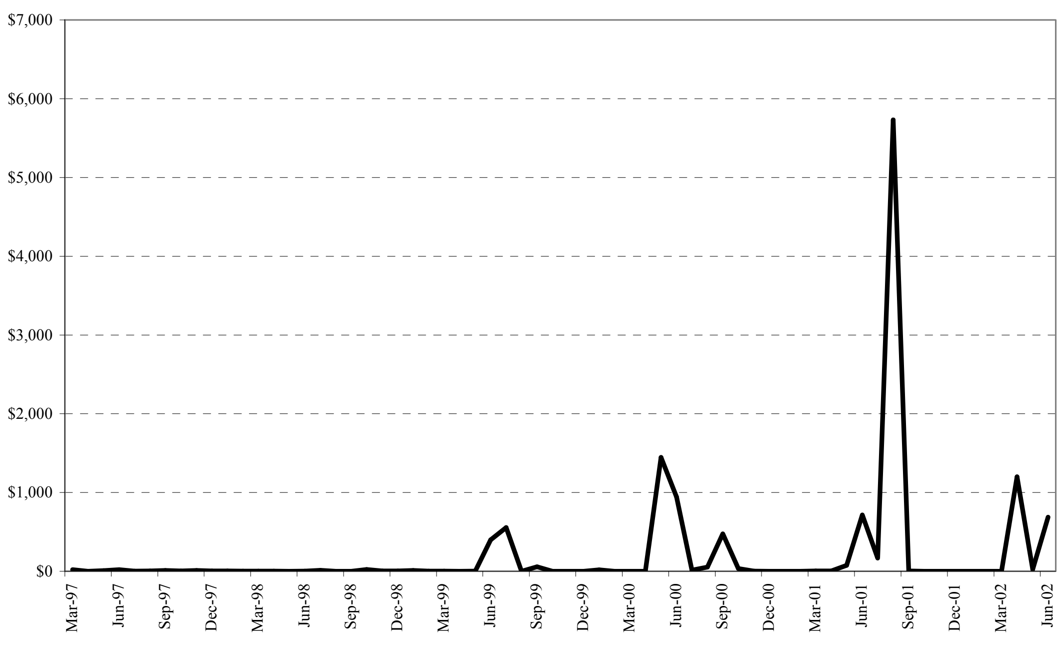

Figure 3: Monthly Shadow Cost (per MW) of Quantitative Trade Constraints
- Flows to ECAR from PJM -

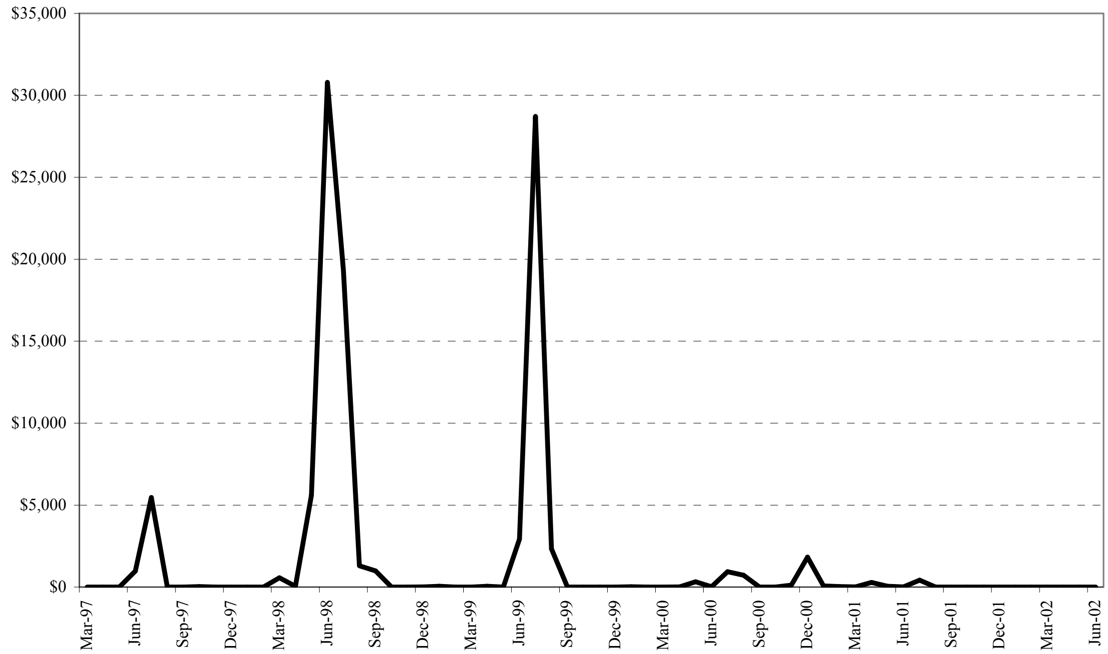

Table 7 presents our annualized estimates of marginal shadow costs. These estimates take the total shadow costs calculated over our entire sample, and then divide by the five years (and four months) covered by our data.

Our estimates indicate that the shadow cost imposed by quantity constraints (e.g., transmission limits) is larger for sending power to PJM from New York, rather than in the opposite direction. In particular, the estimated annual shadow cost over our sample period is $6,182 per MW for sending power to PJM from New York. The annual shadow cost for sending power from New York to PJM is estimated at $1,638 per MW (using our results without the autocorrelation adjustment).

Our shadow cost estimate for sending power to PJM from ECAR is approximately $2,390 per MW annually. By contrast, our marginal shadow cost estimate for sending power to ECAR from

Table 7: Estimated Annual "Shadow Cost" (per MW) of Quantity Trade Constraint (Annual Average: March 1997 – June 2002)				
To: **From:**	**PJM** **New York ISO**	**New York ISO** **PJM**	**PJM** **ECAR**	**ECAR** **PJM**
Without Autocorrelation Adjustment	\$6,182	\$1,638	\$2,389	\$18,961
With Autocorrelation Adjustment	\$5,901	\$1,781	\$2,394	\$19,529
Annual Shadow Cost = (Total Shadow Cost)/5.33 years Total Shadow Cost = Σ [(Actual Daily Observed Price Difference - Estimated Mean Transaction Cost) * (Probability That Observed State Is Quantity-Constrained Trade)].				

PJM is $18,961 per MW annually (based on our results without the autocorrelation adjustment). As mentioned previously, this shadow cost estimate may not reflect the value of marginally increasing physical transmission capacity to ECAR from PJM, since electricity flow data indicate that the transmission system is rarely constrained in sending power in this direction. However, it does suggest that substantial economic value may result from institutional changes which improve market participants' ability to access available transmission capacity. Note though, that over the five-year period covered by our data, over 70 percent of the estimated total shadow cost is derived from inter-regional price differences arising on fewer than thirty days.

7. Conclusion

We have used maximum-likelihood techniques to estimate transaction costs in trading electricity between regions in the eastern United States. Our methodology advances the approach for measuring trading costs, offering a more general specification which also estimates the probability that a quantity restriction is binding on the volume of trade. This refinement allows us to form estimates of the "shadow cost" imposed by existing quantitative constraints, such as transmission capacity limitations, which is important in the current electricity regulatory environment where transmission adequacy is a prominent issue.

We find some evidence to suggest that introducing Independent System Operators (ISOs) to centrally control the use of a regional transmission system and organize multi-party, intra-regional "exchange" markets (where power is traded through a formal auction mechanism as opposed to bilateral transactions), is associated with lower transaction costs initially for inter-regional trade, perhaps due to lower costs involved in price discovery. However, the evidence also indicates that the PJM ISO's switch from cost-based to market-based bidding in its "internal" energy exchange is associated with higher costs for trades involving PJM members and "outside" parties.

Our estimation finds that on those days where the more loosely controlled ECAR "reliability region" has higher prices than the more centrally administered PJM ISO, quantity-constrained trade arises with a relatively high probability. Based on this finding, a binding constraint often exists on trade volume, although evidence on electricity flows indicates that the physical limits of the transmission system are rarely being exhausted. On high-priced days, ECAR's institutional features may make it difficult to access available internal transmission capacity for purposes of selling PJM-supplied power. If so, FERC's policy of encouraging ISO formation and expansion is likely to induce more efficient energy trading.

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