I. TECHNICAL APPENDIX

Our approach to measuring RTO efficiency benefits involves the statistical estimation of the generation cost savings and productive efficiency gains that are collectively achieved by plants operating within a specified geographic area after an RTO has formed, and after that RTO has changed its design from a Day 1 to a Day 2 market. If the elimination of transmission rate pancaking, improvement in electricity trading, and better use of transmission facilities associated with a Day 1 RTO causes more efficient plants to expand their output and less efficient plants to reduce their output, then the cost of producing a fixed amount of power within a given region should fall after that region becomes a Day 1 RTO. Additionally, if a specified RTO moves from a Day 1 design to a Day 2 design, where there is centralized unit commitment, least-cost dispatch, and transmission usage (along with its reliance upon day-ahead and real-time energy trading markets), then there is the potential for further reductions in electric generation costs. Using established statistical techniques, we examine whether these cost reductions have occurred, and the extent to which they have occurred.

Our analytical techniques expand on prior empirical work by Bushnell and Wolfram (2005), Wolfram (2003), and Fabrizio, Rose, and Wolfram (2007), who have estimated how individual generating plants have improved their productivity under different forms of electricity restructuring. These reductions in operating costs at the individual plant level have arisen from the divestiture of generation accompanying electricity deregulation, including that associated with the advent of retail competition in particular states.[1]

[1] See James Bushnell and Catherine Wolfram, 2005, “Ownership Change, Incentives and Plant Efficiency: The Divestiture of US Electric Generation Plants,” University of California Energy Institute, Center for the Study of Energy Markets, Paper CSEMWP No. 140; Catherine Wolfram, 2003, “The Efficiency of Electricity Generation in the U.S. after Restructuring,” in James Griffin and Steve Puller, eds., *Electricity Deregulation: Choices and Challenges* (Chicago: University of Chicago Press); and, Kira Fabrizio, Nancy Rose, and Catherine Wolfram, 2007, “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency,” *American Economic Review*, Vol. 97, 1250-1277.

Our analysis, by contrast, estimates specifically how a group of generating plants serving a geographic region has collectively improved its productivity subsequent to RTO formation and changes in RTO operating rules. In our case, the productivity gains may stem either from efficiency improvements at the plant level due to the improved competitive environment fostered by an RTO, or more significantly, efficiency improvements at the system level arising from the movement of output from higher-cost plants to lower cost plants. Unlike prior studies, any improvements in plant-level productivity are not readily attributable to the divestiture of utility-owned plants into the hands of unregulated entities, as the vast majority of plants in our sample remain utility-owned during the period of our analysis.

It is important to note that our methodology focuses only on efficiency improvements in the generating sector, rather than changes in wholesale prices or retail electric rates (or other dimensions of markets and competition). However, achieving efficiency gains in generation is a pre-requisite to nearly all other types of benefits that may flow from organized competitive markets. Moreover, the process of forming RTOs and changing their design features is oriented toward improving wholesale market efficiency, which should manifest itself in lower system-wide generation costs. We are testing whether these theoretical sources of efficiency gains have led to efficiency gains in actuality.

A. Our Statistical Approach

To estimate cost reductions (or cost increases) associated with RTO formation and changes in RTO design, we use unit-specific generation output and fuel consumption data collected by the Environmental Protection Agency ("EPA") and the Nuclear Regulatory Commission ("NRC") for generating units located within the geographic area administered by the Midwest Independent Transmission System Operator ("MISO"). We aggregate this unit-level data to determine the total fuel consumption and generation output for a group (*i.e.*, system) of power plants operating within a specified geographic area within MISO. Combining this information with fuel price data, we were able to identify both the dollar value and quantity of fuel consumed to produce a given amount of generation.

We estimate two different relationships: (i) a production relationship and (ii) a cost relationship.

Production Relationship

In its simplest form, the equation describing the production relationship is as follows:

$$MWh_t = \alpha_0 + \alpha_1 BTUs_{Nuclear_t} + \alpha_2 BTUs_{Coal_t} + \alpha_3 BTUs_{Gas_t} + \alpha_4 BTUs_{Oil} + \alpha_5 Tons_{SO_2} + \alpha_{Day1} Day\,1 + \alpha_{Day2} Day\,2 + \varepsilon_t, \qquad (1)$$

where α denotes coefficient values, and ε_t is a noise term.

All variables, except for the *Day 1* and *Day 2* dummy variables, are expressed as logarithms (*i.e.*, "logs"). Note that, in addition to fuels such as nuclear, coal, gas, and oil, our production relationship also includes "environmental" inputs, such as the tons of SO_2 that are released as part of the generation process. Due to environmental regulations, the emissions of SO_2 are limited (and the rights to emit SO_2 are tradable under a market arrangement).

In the production relationship, we use the total megawatt hours ("MWhs") generated in a given day (denoted by time *t*) as the so-called dependent variable, where we perform separate analyses for the peak and off-peak periods of the day. Our analysis uses regression techniques to estimate the coefficient values that best describe the underlying statistical relationship between the MWhs of electric generation produced, the amount of each fuel type (*e.g.*, nuclear, coal, gas, and oil) needed to produce that output level, the amount of SO_2 emissions needed to produce that output level, and the relevant institutional regime governing the region (*i.e.*, pre-RTO, Day 1 RTO, and Day 2 RTO). Besides the terms described in equation (1), our estimated statistical specification also includes the squared log value of each fuel input amount.[2]

We include the dummy (*i.e.*, indicator) variable *Day 1* to indicate whether the specified day was in the period after MISO initially formed as a Day 1 RTO market (*i.e.*, after February 1, 2002). The dummy variable *Day 2* denotes whether the specified day also was in the period after MISO became a *Day 2* market (*i.e.*, after April 1, 2005). The coefficients for these variables, denoted

[2] While the squared log terms are frequently statistically significant, their inclusion does not substantively alter our qualitative findings and has limited quantitative impact.

above as α_{Day1} and α_{Day2}, measure the extent to which the production relationship changes under Day 1 and Day 2, respectively.

These coefficients are interpreted as follows. A positive value for the coefficient α_{Day1}, where the coefficient is also statistically significant, indicates that the same combination of fuel inputs was associated with greater system-wide generation output during the Day 1 period relative to the pre-RTO period. This necessarily implies that the same amount of generation output can be produced with less fuel input during the Day 1 period, which represents a clear source of efficiency gains. Similarly, a positive value for the coefficient α_{Day2}, where the coefficient is statistically significant, indicates that the same combination of fuel inputs was associated with greater system-wide generation output during the Day 2 period relative to the Day 1 period.

By contrast, if the coefficients, α_{Day1} and α_{Day2}, are negative rather than positive in value (and statistically significant), then the movements to a Day 1 and a Day 2 RTO design are associated with reduced system-wide generation output for a specified set of fuel inputs. Such a result would suggest that these institutional changes are associated with a loss of generation efficiency.

Cost Relationship

For expositional simplicity, the cost relationship is characterized as follows:

$$\begin{aligned} Cost_t \;=\; & \beta_0 + \beta_1 P_{Nuclear_t} + \beta_2 P_{Coal_t} + \beta_3 P_{Gas_t} + \beta_4 P_{Oil_t} + \beta_5 P_{SO_{2t}} + \beta_6 MWh_t \\ & + \beta_{Day1} Day\,1 + \beta_{Day2} Day\,2 + \varepsilon_t , \end{aligned} \tag{2}$$

where β denotes coefficient values, P denotes price, and ε_t is a noise term.

All variables, except for the Day 1 and Day 2 dummy variables, are expressed as logarithms.

In the cost relationship, the dependent variable is the dollar fuel cost associated with producing a given number of MWhs of electric generation during the peak period (or off-peak period) of a given day. We use regression techniques to estimate the coefficient values that best describe the underlying statistical relationship between this dollar fuel cost, the price of the individual fuels, the MWhs of electricity generated, and the institutional regime governing the region (*i.e.*, pre-RTO, Day 1 RTO, and Day 2 RTO). The coefficients for the institutional-regime variables, denoted $\beta_{Day\,1}$ and $\beta_{Day\,2}$, measure the extent to which this cost relationship changes under Day 1 and Day 2, respectively.

The coefficients for these variables are interpreted as follows. A negative value for the coefficient β_{Day1}, where the coefficient is also statistically significant, indicates that a specified system-wide generation output level can be produced at a lower fuel cost during the Day 1 period relative to the pre-RTO period (holding the prices of each fuel type constant). This result indicates that the generation sector is producing power more efficiently after RTO formation, suggesting that RTO formation is associated with system-wide cost-savings in the generation sector.

Similarly, a negative value for the Day 2 coefficient, where the coefficient is statistically significant, indicates that a specified system-wide generation output level can be produced at a lower fuel cost (holding the prices of each fuel type constant) during the Day 2 period relative to the Day 1 period. This result indicates that the generation sector is producing power more efficiently after the formation of Day 2 RTO markets, suggesting that movement from a Day 1 to a Day 2 RTO design results in system-wide cost savings in the generation sector.

If the coefficients for these variables were instead positive in value and statistically significant, then one would associate the movements to a Day 1 design and a Day 2 design with higher system-wide generation costs.

Differences between the Production Relationship and the Cost Relationship

The production relationship identifies the physical relationship between fuel (and environmental) inputs and electric power output, and whether this input-output relationship is affected by RTO formation and design changes. By contrast, the cost relationship identifies the relationship between fuel prices and the cost of producing a given amount of electric power, and whether this relationship is affected by RTO formation and design changes.

Both relationships will capture productivity gains made by individual plants as the institutional regime changes, since these productivity gains will lead to both reduced fuel usage and reduced dollar cost. Both relationships also will capture productivity gains made by shifting output from less-productive to more-productive generation resources of the same fuel type. So, if, hypothetically, output shifts from coal plants with higher heat rates to those with lower heat rates as a result of implementing a Day 2 RTO market design, then one should observe both reduced fuel usage and reduced dollar cost.

Only the cost relationship, however, will capture productivity gains that arise from switching production from higher cost plants of one fuel type to lower cost plants of another fuel type. So, if hypothetically, output shifts from higher cost gas plants to lower cost coal plants as a result of shifting to a Day 2 market design, only the cost relationship will identify that source of efficiency improvement.

B. IMPLEMENTATION DETAILS

Our analysis was applied only to the group of MISO generating units that were present over the entire period from December 1, 1999 through November 30, 2007. By focusing on a set group of generating units, we avoided the difficult issue of trying to empirically identify whether the addition of a new generating unit was, or was not, directly attributable to the implementation of a Day 1 or Day 2 market design.

To assess system efficiency properly, we needed to identify groups of generating plants within MISO that are in largely separate geographic areas, where that separation results from frequently binding transmission constraints internal to MISO. We consider "narrow constrained areas" ("NCAs") in MISO to be separate regions because they are treated as such in monitoring the MISO market. Accordingly, we consider WUMS ("Wisconsin - Upper Michigan System"), Northern WUMS, and Minnesota to each constitute a separate region, with the substantially larger remaining area designated as the Rest of MISO.

Also, since electric generation production and cost relationships can be influenced by ambient temperatures and other seasonal factors, we ran separate statistical analyses for each season. Not surprisingly, daily system generation output was substantially higher in the "summer" (*i.e.*, June-

September) and "winter" (*i.e.*, December-March) seasons than in the "spring" (*i.e.*, April-May) and "autumn" (*i.e.*, October-November) seasons.

Data Sources

All data on electric power generation, fuel input usage, and SO_2 emissions are taken from Ventyx's Velocity Suite, which compiles information from EPA's Continuous Emissions Monitoring Systems ("CEMS") database. Data on nuclear generating units are obtained from the NRC, as compiled in Velocity Suite. Some combined-cycle co-generation units do not report data on the amount of electric power produced by their heat recovery steam generators ("HRSGs"). To ensure that our data set was accurate, we removed certain combined-cycle units that reported unusually low generation output relative to their fuel input usage.

Fuel prices are obtained from various sources. MISO coal prices are based on a weighted average of the Powder River Basin and Illinois Basin price series provided by Exelon (applying a 0.8 weighting factor to Powder River Basin and a 0.2 weighting factor to the Illinois Basin). MISO gas prices are based upon the Chicago Citygate day-ahead price, as reflected in the Intercontinental Exchange market data available from Velocity Suite. SO_2 prices are based on weekly allowance prices provided by Exelon. Oil prices are based on the delivered residual fuel oil price series found in the Energy Information Administration's Monthly Energy Report (see the table, "Cost of Fossil-Fuel Receipts at Electric Generating Plants"). Nuclear fuel prices are assumed to be $0.40 per million btus in 1999 and $0.50 per million btus in 2008, where a linear annual growth rate is applied to the interim years. These nuclear fuel prices are based on our experience with actual delivered nuclear fuel costs for major market participants.

Translog Cost Specification

The above discussion represents a generalized description of our cost relationship. To improve the quality of our coefficient estimates, we rely upon the so-called transcendental logarithmic (*i.e.*, "translog") cost function, introduced by Berndt, Christensen, Jorgenson, Lau, and Wood in the 1970s and refined in various other academic papers.[3] In particular, we used a translog cost function of the following form:

$$Cost_t = \beta_0 + \sum_i \beta_i P_{it} + \sum_i \sum_j \beta_{ij} P_{it} P_{jt} + \beta_M MWh_t + \sum_i \beta_{iM} P_{it} MWh_t + \beta_{Day1} Day1 + \beta_{Day2} Day2 + \varepsilon_t, \tag{3}$$

where β denotes coefficient values, $P_{it}\,(P_{jt})$ denotes the price of input $i\,(j)$ (*e.g.*, nuclear, coal, gas, oil, SO_2) at time t, and ε_t is a noise term.

Once again, all variables except for the Day 1 and Day 2 dummy variables are expressed as logarithms. Also, note that $\beta_{ij} = \beta_{ji}$ (*i.e.*, $\beta_{gas,coal} = \beta_{coal,gas}$).

Since cost functions describe a relationship between input prices and output costs, they can frequently be used to derive a functional relationship between the demand for a specified input (sometimes expressed as the input's share of total cost) and the prices of that input and other relevant inputs.[4] By log differentiating the translog cost function specified in equation (3) with respect to the price of a specified input, we obtain a very convenient representation of each input's share of total cost as a function of the overall output level and the price levels of all inputs:

$$\frac{\partial Cost_t}{\partial P_{kt}} = S_k = \beta_k + 2\sum_j \beta_{kj} P_{jt} + \beta_{kM} MWh_t, \tag{4}$$

where S_k = input k's share of total costs.

3 See, for example, Ernst Berndt and Laurits Christensen, 1973, "The Translog Function and the Substitution of Equipment, Structures, and Labor in U.S. Manufacturing, 1929-1968," *Journal of Econometrics*, Vol. 1, 81-114; Laurits Christensen, Dale Jorgenson, and Lawrence Lau, 1975, "Transcendental Logarithmic Utility Functions," *American Economic Review*, Vol. 65, 367-383; Ernst Berndt and David Wood, 1975, "Technology, Prices, and the Derived Demand for Energy," *The Review of Economics and Statistics*, Vol. 57, 259-268; and, Laurits Christensen and William Greene, 1976, "Economies of Scale in U.S. Electric Power Generation," *Journal of Political Economy*, Vol. 84, 655-676.

4 Among others, see Angus Deaton, 1983, "Demand Analysis," in Zvi Griliches and Michael Intriligator, eds., *Handbook of Econometrics, Volume 1* (Amsterdam: North Holland).

A well-behaved cost function must be homogeneous of degree one in prices, and the resulting input share functions must be homogenous of degree zero in prices. This implies two relevant restrictions. First, if each input price increases by *x* percent, then total cost also must increase by *x* percent, holding output fixed. Second, if each input price increases by *x* percent, then each input's cost share should remain the same (holding output fixed). The latter result occurs because, under cost-minimizing behavior, each input will be used in the same quantity as long as relative prices remain the same (*i.e.*, input prices rise or fall by the same percentage amounts). These results impose certain restrictions on the coefficients in equations (3) and (4), as described below:

$$\sum_i \beta_i = 1, \ \sum_j \beta_{ij} = \sum_i \beta_{ij} = 0, \ \sum_i \beta_{iM} = 0. \tag{5}$$

By estimating the coefficients for the translog cost function and the individual input share equations together, and imposing linear restrictions on the coefficients as described above in equation (5), an internally consistent set of coefficient estimates can be obtained.

The translog cost function places few limitations on the substitution possibilities involving the various inputs needed to make the specified product (in this case, electric power), and it allows scale economies to vary with the level of output. Thus, the translog cost function is relatively straightforward to estimate, yet highly flexible.

C. Estimation Method and Results

The production relationship is estimated using the Yule-Walker method to adjust for first-order autocorrelation of the residuals (*i.e.*, noise) term.

The cost relationship consists of the translog cost equation and corresponding input share equations (see equations (3) and (4) above), along with restrictions on the sums of coefficients within and across these equations (see equation (5)). Further restrictions are imposed to ensure that certain coefficient estimates in the translog cost equation are consistent with the corresponding coefficient estimates in the input share equations (also described in equations (3) and (4) above). The system of equations is estimated using seemingly unrelated regression ("SUR") methods, which adjusts for correlation in the residuals.

Since the full system of input share equations necessarily sums to one, a single share equation must be dropped to avoid singularity of the covariance matrix. Moreover, to impose the coefficient restrictions identified in equation (5), the prices in the remaining input share equations are divided by the price of the input that lacks a corresponding share equation. In order to produce coefficient estimates that are invariant to which share equation is being dropped, we follow Christensen and Green (1976) and employ an iterated SUR procedure, which has been shown to converge to the maximum likelihood estimates of the equation coefficients.

As mentioned previously, we performed separate regression analyses for each season. These seasons are defined as follows: "summer" (*i.e.*, June-September), "autumn" (*i.e.*, October-November), "winter" (*i.e.*, December-March), and "spring" (*i.e.*, April-May).

Results

Our statistical results using the input-output production relationship approach are contained in Appendix Tables 1 and 2, which show the system-wide productivity gains or losses associated with the creation of the MISO Day 1 market and the switch to a Day 2 market design.

Our results from the cost-relationship approach are contained in Appendix Tables 3 and 4. Appendix Table 5 shows our estimates of the dollar cost savings in generation production that are associated with the creation of a Day 1 market and the switch to a Day 2 market design.

Finally, Attachment A includes tables containing the detailed coefficient estimates underlying our regression results. Highlighted coefficient estimates in these tables are those that are statistically significant at the 5 percent level (in a two-tailed test).

As mentioned previously, the existence of frequently binding transmission constraints within MISO effectively creates different sub-regional geographic markets. For that reason, and consistent with the identification of Narrowly Constrained Areas identified in MISO's State of the Market Report, we have broken MISO into the following sub-regions: (i) Minnesota; (ii) WUMS; (iii) NWUMS; and, (iv) the Rest of MISO.

Our results show that substantial generation cost savings have been associated with the formation of the MISO Day 1 RTO, and its subsequent conversion to a Day 2 RTO. Among the various sub-regions, we find that the preponderance of the savings has been achieved within the area designated as Rest of MISO, which excludes Minnesota, Wisconsin, and Upper Michigan. We further find that the annual cost savings associated with the Day 2 period is 90 percent greater than that associated with the Day 1 period.

The results are broken down in further detail by sub-region below, where our commentary focuses on results that are statistically significant.

Rest of MISO

The rest of MISO, which is a significantly larger area than the three previous regions, shows statistically significant gains in generation input-output production efficiency associated with both MISO Day 1 and Day 2. The peak-hour productivity gains during the Day 1 period range from 0.7% to 2.0%, while the productivity gains during the Day 2 period range from 1.0% to 2.0% (see Appendix Table 1). The off-peak productivity gains are both qualitatively and quantitatively similar to those achieved in peak hours (see Appendix Table 2).

When moving to the actual estimate of generation cost savings, as opposed to the productivity improvement measured by input-output relationships, the benefits arising from the introduction of the Day 2 market design are greatly enhanced. We observe cost savings between 2.9% and 3.3% during peak hours, and between 2.4% and 4.1% during off-peak hours, associated with Day 2. The cost savings associated with the Day 1 period are typically smaller in magnitude, with the exception of off-peak winter hours.

Appendix Table 1

Estimated Change in Generation Production Efficiency by MISO Subregion (On-Peak Hours Only)

	Summer	Autumn	Winter	Spring
Minnesota Hub				
Day 1 vs. Day 0	0.2%	0.4%	-0.3%	0.0%
Day 2 vs. Day 1	**1.6%**	0.4%	0.5%	1.0%
Combined	*1.8%*	*0.9%*	*0.2%*	*1.0%*
WUMS				
Day 1 vs. Day 0	0.1%	0.4%	**1.8%**	**1.8%**
Day 2 vs. Day 1	**-0.6%**	**-2.5%**	**-2.8%**	-0.2%
Combined	*-0.6%*	*-2.1%*	*-1.1%*	*1.6%*
NWUMS				
Day 1 vs. Day 0	**1.9%**	0.0%	**0.9%**	**1.1%**
Day 2 vs. Day 1	**1.2%**	**2.3%**	**1.2%**	**1.0%**
Combined	*3.1%*	*2.3%*	*2.2%*	*2.0%*
Rest of MISO				
Day 1 vs. Day 0	**1.1%**	**0.7%**	**2.0%**	**1.5%**
Day 2 vs. Day 1	**1.2%**	**1.6%**	**1.0%**	**2.0%**
Combined	*2.3%*	*2.3%*	*3.0%*	*3.4%*

Note:
Estimates which are significant at the 5% level are in bold type and highlighted.

Appendix Table 2

Estimated Change in Generation Production Efficiency by MISO Subregion (Off-Peak Hours Only)

	Summer	Autumn	Winter	Spring
Minnesota Hub				
Day 1 vs. Day 0	0.3%	0.1%	0.4%	1.1%
Day 2 vs. Day 1	**1.5%**	**1.2%**	-0.5%	1.4%
Combined	*1.8%*	*1.4%*	*-0.2%*	*2.5%*
WUMS				
Day 1 vs. Day 0	0.3%	0.6%	**1.8%**	**2.0%**
Day 2 vs. Day 1	**-0.5%**	-0.3%	**-2.2%**	-0.6%
Combined	*-0.2%*	*0.2%*	*-0.4%*	*1.5%*
NWUMS				
Day 1 vs. Day 0	**2.0%**	0.9%	**1.0%**	1.1%
Day 2 vs. Day 1	**2.7%**	**5.1%**	**0.8%**	**2.4%**
Combined	*4.7%*	*6.0%*	*1.8%*	*3.5%*
Rest of MISO				
Day 1 vs. Day 0	**1.5%**	**1.0%**	**2.3%**	**1.7%**
Day 2 vs. Day 1	**1.3%**	**1.4%**	**0.8%**	**1.5%**
Combined	*2.7%*	*2.4%*	*3.2%*	*3.2%*

Note:
Estimates which are significant at the 5% level are in bold type and highlighted.

Appendix Table 3

Estimated Change in Generation Cost Efficiency by MISO Subregion (On-Peak Hours Only)

	Summer	Autumn	Winter	Spring
Minnesota Hub				
Day 1 vs. Day 0	**-0.3%**	**-1.5%**	**0.8%**	0.7%
Day 2 vs. Day 1	**-3.8%**	**-2.3%**	-0.5%	0.8%
Combined	*-4.1%*	*-3.8%*	*0.3%*	*1.5%*
WUMS				
Day 1 vs. Day 0	**1.3%**	0.1%	**-4.3%**	**-1.7%**
Day 2 vs. Day 1	-0.1%	**1.4%**	**1.2%**	**-3.3%**
Combined	*1.1%*	*1.5%*	*-3.1%*	*-5.0%*
NWUMS				
Day 1 vs. Day 0	**-1.2%**	**-2.0%**	**1.2%**	-0.8%
Day 2 vs. Day 1	**-0.9%**	**-1.8%**	**-0.9%**	-0.6%
Combined	*-2.1%*	*-3.8%*	*0.2%*	*-1.4%*
Rest of MISO				
Day 1 vs. Day 0	**-1.0%**	-0.2%	**-2.3%**	**-1.4%**
Day 2 vs. Day 1	**-3.3%**	**-3.1%**	**-3.1%**	**-2.9%**
Combined	*-4.3%*	*-3.3%*	*-5.4%*	*-4.3%*

Note:
Estimates which are significant at the 5% level are in bold type and highlighted.

Appendix Table 4

Estimated Change in Generation Cost Efficiency by MISO Subregion (Off-Peak Hours Only)

	Summer	Autumn	Winter	Spring
Minnesota Hub				
Day 1 vs. Day 0	**-0.3%**	**-2.1%**	-0.1%	0.5%
Day 2 vs. Day 1	**-3.3%**	**-3.0%**	0.1%	0.4%
Combined	*-3.7%*	*-5.1%*	*0.0%*	*0.9%*
WUMS				
Day 1 vs. Day 0	**-0.6%**	**-1.2%**	**-1.7%**	0.0%
Day 2 vs. Day 1	0.2%	0.5%	-0.3%	**-3.2%**
Combined	*-0.4%*	*-0.7%*	*-2.0%*	*-3.2%*
NWUMS				
Day 1 vs. Day 0	-0.1%	0.6%	**0.7%**	0.4%
Day 2 vs. Day 1	**-1.3%**	**-1.2%**	**-1.3%**	1.3%
Combined	*-1.3%*	*-0.7%*	*-0.6%*	*1.7%*
Rest of MISO				
Day 1 vs. Day 0	**-1.8%**	**-2.0%**	**-2.9%**	**-2.1%**
Day 2 vs. Day 1	**-3.0%**	**-2.4%**	**-2.5%**	**-4.1%**
Combined	*-4.7%*	*-4.4%*	*-5.4%*	*-6.2%*

Note:
Estimates which are significant at the 5% level are in bold type and highlighted.

Appendix Table 5

Cost Savings - Including SO2 Costs

	Day-1 Cost Savings			Day-2 Cost Savings		
	On Peak	Off Peak	Total	On Peak	Off Peak	Total
Minnesota	368,284	1,403,413	1,771,697	7,546,422	5,140,209	12,686,631
Northern WUMS	1,081,834	917,763	1,999,597	-122,517	435,487	312,970
WUMS	1,378,552	-596,580	781,972	3,298,917	2,641,809	5,940,726
Rest of MISO	33,669,077	50,776,609	84,445,686	86,217,098	66,838,393	153,055,490
Total	***36,497,747***	***52,501,205***	***88,998,952***	***96,939,920***	***75,055,898***	***171,995,818***

The percentage decline in generation costs observed under Day 2 is associated with substantial dollar cost savings, as shown in Appendix Table 5. The creation of the MISO Day 1 RTO was associated with system-wide generation cost savings of approximately $84.4 million, while the shift in market design to Day 2 was associated with approximately $153.1 million in additional savings. Our savings estimates are based on generation costs observed in 2007.[5]

Minnesota

As described in Appendix Table 1, the production-relationship approach indicates that there were no statistically significant improvements in the efficiency of electric power generation in Minnesota during peak hours of the Day 1 period (as compared with the pre-RTO period). However, productivity improvements of approximately 1.6% were sustained in summer peak hours during Day 2 (as compared with the Day 1 period). For off-peak hours, system-wide productivity improvements of 1.5% and 1.2% were sustained in the summer and autumn seasons respectively under Day 2 (see Appendix Table 2).

Referring to Appendix Table 3, the Minnesota sub-region shows statistically significant generation cost savings during summer and autumn peak hours during Day 1. However, modest cost increases are observed during the winter season. By contrast, larger cost savings are associated with the Day 2 period, where cost decreases of 3.8% and 2.3% are associated with the

5 Note that, in constructing Appendix Table 5, no cost savings were calculated for MISO sub-regions and seasons where the relevant coefficient estimate was not statistically significant. The estimated cost savings are based on fuel and SO_2 costs in MISO from December 2006 through November 2007.

summer and autumn peak hours, respectively (see Appendix Table 3). A similar pattern prevails during off-peak hours (see Appendix Table 4).

Overall, as summarized in Appendix Table 5, we estimate that the creation of the MISO Day 1 RTO was associated with system-wide generation cost savings in Minnesota of about $1.8 million (relative to the pre-RTO period), while the change in market design to Day 2 was associated with additional system-wide generation cost savings of approximately $12.7 million (relative to the Day 1 period).

WUMS

According to Appendix Table 1, WUMS sustained a statistically significant improvement in system-wide generation productivity of 1.8% during peak hours of the winter and spring seasons under Day 1, while there was a statistically significant decline in productivity in the summer, autumn, and winter seasons under Day 2. A largely similar pattern prevails for off-peak hours (see Appendix Table 2).

In terms of system-wide generation costs in WUMS during peak hours, the creation of the MISO Day 1 RTO was associated with cost decreases of 4.3% and 1.7% in the winter and spring seasons, respectively (see Appendix Table 3). The movement to Day 2 was associated with a 1.4% cost increase in autumn, a 1.2% cost increase in winter, and a 3.3% cost decrease in the spring during peak hours. As for off-peak hours, cost decreases were associated with the creation of the MISO Day 1 RTO during the summer, autumn, and winter seasons in WUMS, while the movement to Day 2 was associated with a 3.2% cost reduction in the spring season.

As summarized in Appendix Table 5, we estimate that the creation of the MISO Day 1 RTO was associated with system-wide generation cost savings in WUMS of approximately $0.8 million, while the shift in market design to Day 2 was associated with approximately $5.9 million in additional savings.

NWUMS

According to Appendix Table 1, NWUMS experienced statistically significant increases in peak-hours generation productivity during the Day 1 period of 1.9% in summer, 0.9% in winter, and 1.1% in spring. During the Day 2 period, NWUMS experienced a further improvement of at least 1% in peak-hours generation productivity during all seasons. In off-peak hours, the movement to a Day 2 market design was again associated with improved generation productivity in all seasons (see Appendix Table 2).

Moving to the cost results, we find that the introduction of MISO Day 1 RTO was associated with reduced generation costs in the summer and autumn peak hours of 1.2% and 2.0%, respectively. In winter peak hours, generation costs increased by approximately 1.2%. After the Day 2 market was introduced, additional cost savings was achieved for peak hours during all seasons except spring, ranging from 0.9% to 1.8%. The cost reductions in off-peak hours largely mirror those experienced during peak hours under Day 2.

According to Appendix Table 5, the creation of the MISO Day 1 RTO was associated with system-wide generation cost savings in NWUMS of approximately $2.0 million, while the shift in market design to Day 2 was associated with approximately $0.3 million in additional savings.

Total MISO System-Wide Generation Cost Savings Associated with Implementation of Day 1 and Day 2

As summarized in Appendix Table 5, the creation of the MISO Day 1 RTO was associated with system-wide generation cost savings of approximately $89.0 million across all regions, while the shift in market design to Day 2 was associated with approximately $172.0 million in savings.

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ATTACHMENT A - DETAILED REGRESSION RESULTS

On-Peak Generation Production Efficiency -- Regression Coefficient Estimates

(t-statistics reported in parentheses -- results in bold type are significant at the 5% level)

Independent Variables	Minnesota Hub				WUMS				NWUMS				Rest of MISO			
	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring
	Dependent Variable = ln Net Generation															
Intercept	**24.5004**	**42.5474**	**-16.4083**	**48.2210**	5.4549	**54.5852**	**34.1903**	**14.0387**	**31.7058**	**39.2611**	**34.1154**	**43.2301**	28.9539	-17.5457	0.5034	-6.9220
	(2.98)	**(7.05)**	**-(3.01)**	**(6.00)**	(0.99)	**(6.08)**	**(7.48)**	**(3.01)**	**(11.73)**	**(10.59)**	**(7.98)**	**(9.42)**	(1.69)	-(0.90)	(0.02)	-(0.22)
ln BTUs $_{COAL}$	-0.2432	**-3.5159**	**4.8438**	**-4.4803**	0.3564	**-7.1061**	**-5.1494**	**-1.1636**	**-1.3694**	**-2.7911**	**-2.6006**	**-3.4642**	-1.5505	5.0928	0.8419	4.5428
	-(0.24)	**-(4.08)**	**(5.96)**	**-(3.62)**	(0.42)	**-(5.03)**	**-(6.57)**	**-(1.59)**	**-(3.10)**	**-(4.56)**	**-(4.40)**	**-(4.45)**	-(0.68)	(1.93)	(0.29)	(1.14)
ln BTUs $_{COAL}^{2}$	0.0348	**0.1541**	**-0.1514**	**0.1920**	0.0224	**0.3058**	**0.2321**	**0.0798**	**0.0734**	**0.1339**	**0.1226**	**0.1628**	0.0762	-0.1352	0.0016	-0.1170
	(0.94)	**(4.86)**	**-(5.08)**	**(4.20)**	(0.70)	**(5.69)**	**(7.75)**	**(2.85)**	**(4.06)**	**(5.31)**	**(5.04)**	**(5.06)**	(1.06)	-(1.60)	(0.02)	-(0.92)
ln BTUs $_{GAS}$					**-0.6592**	**-0.6621**	**-0.0678**	**-0.7214**	**-0.0065**	**-0.0071**	**-0.0069**	**-0.0071**	**-0.0035**	**-0.0021**	**-0.0019**	**-0.0020**
					-(24.55)	**-(6.55)**	**-(24.96)**	**-(12.84)**	**-(15.07)**	**-(10.67)**	**-(17.47)**	**-(6.97)**	**-(12.25)**	**-(6.33)**	**-(6.73)**	**-(5.87)**
ln BTUs $_{GAS}^{2}$					**0.0336**	**0.0339**	**0.0069**	**0.0368**	**0.0009**	**0.0010**	**0.0010**	**0.0010**	**0.0004**	**0.0002**	**0.0002**	**0.0002**
					(28.04)	**(7.27)**	**(34.58)**	**(14.31)**	**(18.69)**	**(13.03)**	**(21.02)**	**(8.88)**	**(15.90)**	**(8.35)**	**(7.94)**	**(7.77)**
ln BTUs $_{NUCLEAR}$	**-2.7603**	**-2.1766**	**-1.7661**	**-2.0753**					**-2.9651**	**-2.9020**	**-2.2356**	**-2.8851**	**-0.6380**	**-2.0020**	**-0.8497**	**-0.5672**
	-(3.67)	**-(5.90)**	**-(10.65)**	**-(11.23)**					**-(18.43)**	**-(18.48)**	**-(5.46)**	**-(14.98)**	**-(2.34)**	**-(4.68)**	**-(5.91)**	**-(5.98)**
ln BTUs $_{NUCLEAR}^{2}$	**0.1193**	**0.0963**	**0.0803**	**0.0941**					**0.1423**	**0.1399**	**0.1119**	**0.1399**	**0.0267**	**0.0774**	**0.0348**	**0.0242**
	(4.00)	**(6.54)**	**(11.98)**	**(12.45)**					**(21.42)**	**(21.21)**	**(6.70)**	**(17.34)**	**(2.64)**	**(4.88)**	**(6.47)**	**(6.72)**
ln BTUs $_{OIL}$	**-0.0014**	-0.0007	**-0.0017**	**-0.0021**									**-0.0051**	-0.0015	**-0.0021**	**-0.0026**
	-(3.45)	-(1.25)	**-(2.88)**	**-(2.22)**									**-(11.21)**	-(1.77)	**-(3.72)**	**-(4.69)**
ln BTUs $_{OIL}^{2}$	**0.0002**	0.0001	**0.0002**	**0.0003**									**0.0005**	**0.0002**	**0.0003**	**0.0003**
	(4.25)	(1.84)	**(3.17)**	**(3.03)**									**(12.30)**	**(2.35)**	**(4.85)**	**(5.96)**
ln TONS $_{SO2}$	-0.1192	0.1418	-0.1831	-0.0501	0.0246	0.0681	**1.5962**	**0.6848**	**-0.2476**	-0.0394	0.2002	-0.1947	**-1.5385**	-0.7022	1.1051	**-4.7264**
	-(0.86)	(0.76)	-(0.90)	-(0.21)	(0.23)	(0.26)	**(5.36)**	**(2.71)**	**-(3.60)**	-(0.46)	(1.35)	-(1.54)	**-(3.21)**	-(0.99)	(1.86)	**-(4.66)**
ln TONS $_{SO2}^{2}$	0.0121	-0.0122	0.0186	0.0059	-0.0061	-0.0139	**-0.1557**	**-0.0673**	**0.0297**	0.0025	-0.0237	0.0235	**0.0953**	0.0449	-0.0685	**0.2955**
	(0.95)	-(0.70)	(0.98)	(0.26)	-(0.60)	-(0.54)	**-(5.53)**	**-(2.78)**	**(3.67)**	(0.26)	-(1.35)	(1.52)	**(3.27)**	(1.02)	-(1.88)	**(4.72)**
Day1	0.0020	0.0044	-0.0028	0.0002	0.0008	0.0044	**0.0177**	**0.0179**	**0.0189**	0.0000	**0.0094**	**0.0107**	**0.0109**	**0.0075**	**0.0199**	**0.0146**
	(1.51)	(1.76)	-(0.74)	(0.03)	(0.36)	(1.20)	**(4.86)**	**(3.44)**	**(6.60)**	(0.00)	**(4.42)**	**(2.46)**	**(7.93)**	**(4.12)**	**(13.08)**	**(7.91)**
Day2	**0.0163**	0.0043	0.0047	0.0095	**-0.0065**	**-0.0258**	**-0.0289**	-0.0017	**0.0121**	**0.0227**	**0.0120**	**0.0097**	**0.0115**	**0.0158**	**0.0096**	**0.0195**
	(13.07)	(1.64)	(1.21)	(1.30)	**-(2.73)**	**-(6.09)**	**-(7.40)**	-(0.32)	**(4.51)**	**(6.05)**	**(5.63)**	**(2.33)**	**(7.51)**	**(8.90)**	**(5.50)**	**(9.33)**
Degrees of Freedom	667	331	646	329	669	333	648	331	667	331	646	329	665	329	644	327
Total R-Square	0.9907	0.9923	0.9917	0.9923	0.994	0.9854	0.9928	0.9932	0.9976	0.9959	0.9946	0.996	0.9919	0.9856	0.9884	0.99

Off-Peak Generation Production Efficiency -- Regression Coefficient Estimates

(t-statistics reported in parentheses -- results in bold type are significant at the 5% level)

Independent	Minnesota Hub				WUMS				NWUMS				Rest of MISO			
Variables	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring
	Dependent Variable = ln Net Generation															
Intercept	**-1.3592**	**2.6772**	0.6469	1.2570	**-2.8432**	**-2.8258**	**-1.7018**	**-2.3151**	**-3.5522**	**2.2542**	0.4175	-2.4557	**-4.9387**	**-1.7192**	-1.1304	**-2.7759**
	-(2.58)	**(3.14)**	(1.16)	(1.21)	**-(6.80)**	**-(4.60)**	**-(2.70)**	**-(4.73)**	**-(4.11)**	**(2.86)**	(0.88)	-(1.57)	**-(9.65)**	**-(2.20)**	-(1.43)	**-(2.93)**
ln BTUs $_{COAL}$	**0.5723**	**0.2947**	**0.5646**	**0.4471**	**1.1241**	**1.0271**	**0.9533**	**1.0010**	**1.0773**	0.0993	**0.3182**	**0.8485**	**1.2527**	**0.8682**	**0.8899**	**0.9997**
	(7.96)	**(2.64)**	**(7.08)**	**(2.85)**	**(16.36)**	**(10.67)**	**(8.59)**	**(13.11)**	**(7.05)**	(0.87)	**(4.49)**	**(3.26)**	**(16.19)**	**(7.77)**	**(7.47)**	**(7.69)**
ln BTUs $_{COAL}^{\ 2}$	0.0052	**0.0150**	**0.0061**	0.0104	**-0.0056**	-0.0020	0.0006	-0.0024	**-0.0253**	**0.0190**	0.0033	-0.0124	**-0.0120**	0.0005	0.0011	-0.0031
	(1.92)	**(3.58)**	**(2.05)**	(1.74)	**-(2.08)**	-(0.53)	(0.14)	-(0.80)	**-(3.91)**	**(4.00)**	(1.10)	-(1.12)	**-(4.74)**	(0.14)	(0.28)	-(0.73)
ln BTUs $_{GAS}$					**-0.0515**	**0.0764**	**-0.0359**	-0.0089	**-0.0023**	**-0.0028**	**-0.0036**	**-0.0037**	**-0.0013**	**-0.0007**	-0.0003	-0.0005
					-(2.51)	**(2.07)**	**-(12.17)**	-(0.31)	**-(3.26)**	**-(2.77)**	**-(8.43)**	**-(2.22)**	**-(8.16)**	**-(2.91)**	-(1.39)	-(1.58)
ln BTUs $_{GAS}^{\ 2}$					**0.0054**	-0.0002	**0.0048**	**0.0040**	**0.0004**	**0.0004**	**0.0006**	**0.0007**	**0.0002**	**0.0001**	0.0000	0.0001
					(5.59)	-(0.14)	**(22.40)**	**(2.88)**	**(4.98)**	**(3.38)**	**(9.96)**	**(2.96)**	**(9.50)**	**(3.19)**	(1.47)	(1.74)
ln BTUs $_{NUCLEAR}$	**0.3639**	0.0425	0.0531	0.0685					**0.2654**	**0.2133**	**0.3483**	**0.3131**	**0.1460**	**0.1116**	-0.0313	**0.0765**
	(8.94)	(0.78)	(1.61)	(1.28)					**(6.40)**	**(4.83)**	**(10.38)**	**(5.26)**	**(5.37)**	**(3.58)**	-(1.20)	**(3.01)**
ln BTUs $_{NUCLEAR}^{\ 2}$	-0.0030	**0.0097**	**0.0084**	**0.0081**					**0.0124**	**0.0117**	**0.0095**	**0.0085**	**-0.0021**	-0.0005	**0.0048**	-0.0001
	-(1.82)	**(4.42)**	**(6.22)**	**(3.69)**					**(7.14)**	**(6.24)**	**(6.92)**	**(3.37)**	**-(2.05)**	-(0.42)	**(4.73)**	-(0.15)
ln BTUs $_{OIL}$	**-0.0010**	-0.0007	-0.0010	0.0016									**-0.0016**	**-0.0014**	**-0.0016**	-0.0007
	-(2.87)	-(1.04)	-(1.90)	(0.97)									**-(4.70)**	**-(2.33)**	**-(3.79)**	-(0.84)
ln BTUs $_{OIL}^{\ 2}$	**0.0002**	0.0001	0.0001	-0.0003									**0.0002**	**0.0002**	**0.0002**	0.0001
	(3.69)	(1.10)	(1.55)	-(1.29)									**(5.58)**	**(2.77)**	**(4.42)**	(1.30)
ln TONS $_{SO2}$	-0.0003	-0.0328	0.0101	0.0256	**-0.0655**	**-0.0913**	**-0.1023**	0.0022	**-0.2023**	**-0.0517**	-0.0401	**-0.2771**	-0.0130	-0.0226	-0.0083	0.0459
	-(0.02)	-(1.17)	(0.44)	(0.62)	**-(4.95)**	**-(4.09)**	**-(2.71)**	(0.11)	**-(5.18)**	**-(2.23)**	-(1.82)	**-(4.15)**	-(0.43)	-(0.53)	-(0.20)	(0.82)
ln TONS $_{SO2}^{\ 2}$	-0.0001	0.0046	-0.0004	-0.0019	**0.0028**	**0.0048**	0.0067	-0.0014	**0.0206**	0.0003	**0.0074**	**0.0264**	0.0026	0.0026	-0.0008	-0.0016
	-(0.04)	(1.65)	-(0.16)	-(0.46)	**(1.96)**	**(1.99)**	(1.71)	-(0.66)	**(3.94)**	(0.13)	**(2.64)**	**(3.02)**	(1.36)	(0.92)	-(0.30)	-(0.44)
Day1	0.0028	0.0014	0.0038	0.0106	0.0035	0.0056	**0.0176**	**0.0200**	**0.0197**	0.0089	**0.0097**	0.0113	**0.0147**	**0.0095**	**0.0231**	**0.0172**
	(1.77)	(0.62)	(1.08)	(1.32)	(1.50)	(1.34)	**(5.65)**	**(3.56)**	**(6.52)**	(1.73)	**(4.38)**	(1.77)	**(9.10)**	**(4.35)**	**(15.02)**	**(9.59)**
Day2	**0.0151**	**0.0124**	-0.0054	0.0141	**-0.0053**	-0.0033	**-0.0219**	-0.0056	**0.0271**	**0.0496**	**0.0078**	**0.0237**	**0.0125**	**0.0140**	**0.0083**	**0.0145**
	(10.48)	**(5.29)**	-(1.51)	(1.81)	**-(2.20)**	-(0.80)	**-(6.55)**	-(1.02)	**(9.69)**	**(9.90)**	**(3.52)**	**(4.02)**	**(7.56)**	**(6.76)**	**(4.97)**	**(6.90)**
Degrees of Freedom	964	476	927	476	966	478	929	478	964	476	927	476	962	474	925	474
Total R-Square	0.9999	0.9998	0.9997	0.9993	0.9997	0.9996	0.9993	0.9996	0.9993	0.9994	0.9998	0.9986	0.9999	0.9999	0.9999	0.9999

Generation Cost Efficiency -- Regression Coefficient Estimates
Minnesota
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	On-Peak Summer	On-Peak Autumn	On-Peak Winter	On-Peak Spring	Off-Peak Summer	Off-Peak Autumn	Off-Peak Winter	Off-Peak Spring
	***Dependent Variable = ln* (Cost)**							
ln(MWh)	*0.560*	*0.579*	*0.827*	*0.975*	*0.987*	*0.990*	*1.003*	*1.003*
	(12.39)	(7.42)	(20.93)	(23.28)	(213.36)	(103.73)	(165.01)	(131.13)
lnPc	*1.530*	*-2.064*	*1.313*	*0.585*	*0.853*	*0.970*	*0.974*	*0.868*
	(8.88)	(-7.08)	(8.26)	(3.36)	(54.20)	(28.20)	(40.44)	(26.21)
lnPc*lnPc	*0.208*	*0.240*	*0.173*	*0.199*	*0.207*	*0.241*	*0.178*	*0.202*
	(92.10)	(43.89)	(51.84)	(40.04)	(102.12)	(47.44)	(59.18)	(50.35)
ln(MWh)*lnPc	*-0.044*	*0.272*	-0.023	*0.035*	*0.010*	*0.012*	*0.005*	*0.007*
	(-2.95)	(10.96)	(-1.71)	(2.32)	(7.57)	(4.26)	(2.51)	(2.60)
lnPo	*-0.782*	*0.947*	*0.465*	*0.726*	*0.070*	*0.068*	*0.078*	*0.080*
	(-3.55)	(3.84)	(3.34)	(4.89)	(5.59)	(4.35)	(6.51)	(4.91)
lnPo*lnPo	*0.023*	*-0.015*	0.007	*0.080*	-0.002	*-0.016*	0.001	*0.035*
	(5.67)	(-4.09)	(1.78)	(10.37)	(-0.85)	(-7.13)	(0.29)	(7.74)
ln(MWh)*lnPo	*0.072*	*-0.076*	*-0.039*	*-0.067*	-0.001	*-0.003*	*-0.005*	*-0.007*
	(3.78)	(-3.59)	(-3.23)	(-5.18)	(-1.24)	(-2.10)	(-5.55)	(-5.13)
lnPn	*1.443*	*3.809*	0.042	0.197	*0.547*	*0.517*	*0.454*	*0.540*
	(9.35)	(15.58)	(0.25)	(0.88)	(31.58)	(15.04)	(19.07)	(12.56)
lnPn*lnPn	*0.141*	*0.167*	*0.145*	*0.206*	*0.165*	*0.175*	*0.153*	*0.198*
	(47.39)	(30.92)	(42.19)	(29.30)	(64.62)	(35.03)	(55.15)	(36.08)
ln(MWh)*lnPn	*-0.093*	*-0.295*	*0.034*	0.029	*-0.012*	*-0.012*	0.000	-0.001
	(-7.02)	(-14.16)	(2.39)	(1.52)	(-8.06)	(-4.29)	(-0.16)	(-0.29)
lnPs	*-1.191*	*-1.693*	*-0.820*	*-0.509*	*-0.470*	*-0.555*	*-0.506*	*-0.489*
	(-12.87)	(-10.43)	(-10.33)	(-7.20)	(-46.05)	(-25.54)	(-38.85)	(-31.87)
lnPs*lnPs	*0.088*	*0.103*	*0.096*	*0.099*	*0.087*	*0.099*	*0.097*	*0.096*
	(75.91)	(45.84)	(74.35)	(69.70)	(93.48)	(53.79)	(90.98)	(77.42)
ln(MWh)*lnPs	*0.065*	*0.099*	*0.028*	0.002	*0.003*	0.003	0.000	0.000
	(8.21)	(7.31)	(4.05)	(0.39)	(3.29)	(1.59)	(0.27)	(0.20)
lnPc*lnPo	*-0.025*	*-0.010*	0.001	*-0.015*	*-0.004*	*0.005*	*0.007*	*-0.004*
	(-13.38)	(-3.09)	(0.40)	(-4.12)	(-2.99)	(2.74)	(4.89)	(-2.16)

Generation Cost Efficiency -- Regression Coefficient Estimates
Minnesota
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak**				**Off-Peak**			
	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring
lnPc*lnPs	*-0.054*	*-0.069*	*-0.064*	*-0.051*	*-0.054*	*-0.080*	*-0.066*	*-0.050*
	(-44.73)	(-24.21)	(-42.30)	(-27.95)	(-58.63)	(-35.29)	(-49.70)	(-32.59)
lnPo*lnPs	*-0.010*	-0.002	-0.002	*-0.020*	*-0.006*	0.001	*-0.003*	*-0.013*
	(-7.03)	(-0.91)	(-1.39)	(-7.48)	(-5.28)	(1.17)	(-3.01)	(-7.55)
lnPc*lnPn	*-0.129*	*-0.161*	*-0.110*	*-0.133*	*-0.149*	*-0.165*	*-0.119*	*-0.147*
	(-68.59)	(-35.82)	(-37.36)	(-30.27)	(-81.12)	(-36.93)	(-45.80)	(-37.15)
lnPo*lnPn	*0.012*	*0.027*	*-0.006*	*-0.045*	*0.012*	*0.010*	*-0.005*	*-0.018*
	(3.67)	(8.23)	(-2.15)	(-7.65)	(5.81)	(4.78)	(-3.27)	(-5.52)
lnPs*lnPn	*-0.024*	*-0.032*	*-0.029*	*-0.028*	*-0.028*	*-0.020*	*-0.028*	*-0.033*
	(-18.99)	(-14.15)	(-19.72)	(-11.33)	(-25.82)	(-9.43)	(-24.22)	(-17.22)
Day1	*-0.003*	*-0.015*	*0.008*	0.007	*-0.003*	*-0.021*	-0.001	0.005
	(-2.00)	(-6.36)	(3.55)	(1.74)	(-2.48)	(-8.23)	(-0.38)	(1.49)
Day2	*-0.039*	*-0.023*	-0.005	0.008	*-0.034*	*-0.031*	0.001	0.004
	(-19.30)	(-8.96)	(-1.76)	(1.66)	(-21.27)	(-12.18)	(0.37)	(0.97)
constant	*8.627*	*8.707*	*5.745*	*4.068*	*3.685*	*3.926*	*3.728*	*3.705*
	(16.37)	(9.50)	(12.58)	(8.48)	(68.45)	(35.23)	(52.87)	(42.45)
				Dependent Variable = Share of Coal				
ln(MWh)	*-0.044*	*0.272*	-0.023	*0.035*	*0.010*	*0.012*	*0.005*	*0.007*
	(-2.95)	(10.96)	(-1.71)	(2.32)	(7.57)	(4.26)	(2.51)	(2.60)
ln(Pc/Pn)	*0.208*	*0.240*	*0.173*	*0.199*	*0.207*	*0.241*	*0.178*	*0.202*
	(92.10)	(43.89)	(51.84)	(40.04)	(102.12)	(47.44)	(59.18)	(50.35)
ln(Po/Pn)	*-0.025*	*-0.010*	0.001	*-0.015*	*-0.004*	*0.005*	*0.007*	*-0.004*
	(-13.38)	(-3.09)	(0.40)	(-4.12)	(-2.99)	(2.74)	(4.89)	(-2.16)
ln(Ps/Pn)	*-0.054*	*-0.069*	*-0.064*	*-0.051*	*-0.054*	*-0.080*	*-0.066*	*-0.050*
	(-44.73)	(-24.21)	(-42.30)	(-27.95)	(-58.63)	(-35.29)	(-49.70)	(-32.59)
constant	*1.530*	*-2.064*	*1.313*	*0.585*	*0.853*	*0.970*	*0.974*	*0.868*
	(8.88)	(-7.08)	(8.26)	(3.36)	(54.20)	(28.20)	(40.44)	(26.21)

Generation Cost Efficiency -- Regression Coefficient Estimates
Minnesota
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak** Summer	**On-Peak** Autumn	**On-Peak** Winter	**On-Peak** Spring	**Off-Peak** Summer	**Off-Peak** Autumn	**Off-Peak** Winter	**Off-Peak** Spring
	Dependent Variable = Share of Oil							
ln(MWh)	*0.072*	*-0.076*	*-0.039*	*-0.067*	-0.001	*-0.003*	*-0.005*	*-0.007*
	(3.78)	(-3.59)	(-3.23)	(-5.18)	(-1.24)	(-2.10)	(-5.55)	(-5.13)
ln(Pc/Pn)	*-0.025*	*-0.010*	0.001	*-0.015*	*-0.004*	*0.005*	*0.007*	*-0.004*
	(-13.38)	(-3.09)	(0.40)	(-4.12)	(-2.99)	(2.74)	(4.89)	(-2.16)
ln(Po/Pn)	*0.023*	*-0.015*	0.007	*0.080*	-0.002	*-0.016*	0.001	*0.035*
	(5.67)	(-4.09)	(1.78)	(10.37)	(-0.85)	(-7.13)	(0.29)	(7.74)
ln(Ps/Pn)	*-0.010*	-0.002	-0.002	*-0.020*	*-0.006*	0.001	*-0.003*	*-0.013*
	(-7.03)	(-0.91)	(-1.39)	(-7.48)	(-5.28)	(1.17)	(-3.01)	(-7.55)
constant	*-0.782*	*0.947*	*0.465*	*0.726*	*0.070*	*0.068*	*0.078*	*0.080*
	(-3.55)	(3.84)	(3.34)	(4.89)	(5.59)	(4.35)	(6.51)	(4.91)
	Dependent Variable = Share of SO2							
ln(MWh)	*0.065*	*0.099*	*0.028*	0.002	*0.003*	0.003	0.000	0.000
	(8.21)	(7.31)	(4.05)	(0.39)	(3.29)	(1.59)	(0.27)	(0.20)
ln(Pc/Pn)	*-0.054*	*-0.069*	*-0.064*	*-0.051*	*-0.054*	*-0.080*	*-0.066*	*-0.050*
	(-44.73)	(-24.21)	(-42.30)	(-27.95)	(-58.63)	(-35.29)	(-49.70)	(-32.59)
ln(Po/Pn)	*-0.010*	-0.002	-0.002	*-0.020*	*-0.006*	0.001	*-0.003*	*-0.013*
	(-7.03)	(-0.91)	(-1.39)	(-7.48)	(-5.28)	(1.17)	(-3.01)	(-7.55)
ln(Ps/Pn)	*0.088*	*0.103*	*0.096*	*0.099*	*0.087*	*0.099*	*0.097*	*0.096*
	(75.91)	(45.84)	(74.35)	(69.70)	(93.48)	(53.79)	(90.98)	(77.42)
constant	*-1.191*	*-1.693*	*-0.820*	*-0.509*	*-0.470*	*-0.555*	*-0.506*	*-0.489*
	(-12.87)	(-10.43)	(-10.33)	(-7.20)	(-46.05)	(-25.54)	(-38.85)	(-31.87)
Observations	679	681	343	341	976	970	488	488

Notes: Subscripts denote input types (c = coal; o = oil; g = gas; n = nuclear; s = SO_2).
Within our sample, not all regions contain generating units of all input types.

Generation Cost Efficiency -- Regression Coefficient Estimates
WUMS
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak** Summer	Autumn	Winter	Spring	**Off-Peak** Summer	Autumn	Winter	Spring
				***Dependent Variable = ln* (Cost)**				
ln(MWh)	*1.317*	*0.929*	*0.989*	*1.233*	*0.998*	*0.995*	*0.984*	*1.003*
	(35.84)	(16.74)	(39.30)	(31.80)	(212.48)	(119.77)	(196.79)	(131.27)
lnPc	*5.452*	-0.036	*0.366*	*0.653*	*1.185*	*1.185*	*1.024*	*1.203*
	(22.32)	(-0.13)	(2.21)	(2.06)	(53.53)	(33.11)	(35.93)	(28.59)
lnPc*lnPc	*0.229*	*0.233*	*0.231*	*0.251*	*0.235*	*0.238*	*0.236*	*0.254*
	(91.14)	(71.56)	(74.36)	(53.04)	(182.85)	(113.56)	(116.69)	(94.35)
ln(MWh)*lnPc	*-0.391*	*0.118*	*0.071*	0.052	*0.005*	*0.008*	*0.016*	0.004
	(-17.61)	(4.80)	(4.66)	(1.77)	(2.16)	(2.40)	(6.11)	(0.94)
lnPg	*-5.115*	*1.854*	*1.170*	0.291	*0.135*	*0.251*	*0.380*	*0.140*
	(-17.00)	(5.85)	(5.90)	(0.78)	(4.87)	(6.14)	(11.41)	(2.91)
lnPg*lnPg	*0.205*	*0.220*	*0.238*	*0.250*	*0.207*	*0.222*	*0.234*	*0.249*
	(38.58)	(36.21)	(61.33)	(31.95)	(59.00)	(50.60)	(85.90)	(49.93)
ln(MWh)*lnPg	*0.478*	*-0.154*	*-0.088*	-0.015	*-0.006*	*-0.010*	*-0.021*	-0.004
	(17.44)	(-5.31)	(-4.84)	(-0.43)	(-2.48)	(-2.65)	(-6.72)	(-0.89)
lnPs	*0.663*	*-0.818*	*-0.536*	0.056	*-0.320*	*-0.435*	*-0.404*	*-0.342*
	(7.43)	(-6.22)	(-9.67)	(0.61)	(-23.08)	(-19.20)	(-32.09)	(-17.12)
lnPs*lnPs	*0.070*	*0.101*	*0.091*	*0.086*	*0.072*	*0.097*	*0.089*	*0.085*
	(38.82)	(33.34)	(75.09)	(42.38)	(47.41)	(43.81)	(89.32)	(42.45)
ln(MWh)*lnPs	*-0.087*	*0.036*	*0.017*	*-0.037*	0.002	0.002	*0.005*	0.000
	(-10.73)	(3.07)	(3.32)	(-4.33)	(1.60)	(1.00)	(4.44)	(0.18)
lnPg*lnPs	*-0.023*	*-0.044*	*-0.049*	*-0.042*	*-0.022*	*-0.041*	*-0.043*	*-0.040*
	(-8.58)	(-12.40)	(-32.12)	(-12.71)	(-10.66)	(-15.37)	(-37.27)	(-15.34)
lnPg*lnPc	*-0.182*	*-0.176*	*-0.189*	*-0.207*	*-0.185*	*-0.181*	*-0.190*	*-0.209*
	(-53.43)	(-45.33)	(-59.97)	(-36.47)	(-95.16)	(-69.01)	(-89.63)	(-62.07)
lnPs*lnPc	*-0.047*	*-0.057*	*-0.042*	*-0.044*	*-0.050*	*-0.057*	*-0.046*	*-0.045*
	(-27.97)	(-24.63)	(-27.81)	(-16.13)	(-47.07)	(-38.12)	(-44.79)	(-24.43)
Day1	*0.012*	0.001	*-0.044*	*-0.018*	*-0.006*	*-0.012*	*-0.017*	0.000
	(2.98)	(0.13)	(-8.96)	(-2.79)	(-3.36)	(-4.27)	(-7.48)	(0.03)
Day2	-0.001	*0.014*	*0.012*	*-0.033*	0.002	0.005	-0.003	*-0.033*
	(-0.33)	(2.25)	(2.23)	(-4.14)	(1.09)	(1.84)	(-1.09)	(-9.21)
constant	-0.380	*4.189*	*3.347*	0.771	*3.194*	*3.486*	*3.414*	*3.243*
	(-0.94)	(6.86)	(12.41)	(1.84)	(63.24)	(39.05)	(63.64)	(39.76)

Generation Cost Efficiency -- Regression Coefficient Estimates
WUMS
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	On-Peak Summer	On-Peak Autumn	On-Peak Winter	On-Peak Spring	Off-Peak Summer	Off-Peak Autumn	Off-Peak Winter	Off-Peak Spring
				Dependent Variable = Share of Gas				
ln(MWh)	*0.478*	*-0.154*	*-0.088*	-0.015	*-0.006*	*-0.010*	*-0.021*	-0.004
	(17.44)	(-5.31)	(-4.84)	(-0.43)	(-2.48)	(-2.65)	(-6.72)	(-0.89)
ln(Pg/Pc)	*0.205*	*0.220*	*0.238*	*0.250*	*0.207*	*0.222*	*0.234*	*0.249*
	(38.58)	(36.21)	(61.33)	(31.95)	(59.00)	(50.60)	(85.90)	(49.93)
ln(Ps/Pc)	*-0.023*	*-0.044*	*-0.049*	*-0.042*	*-0.022*	*-0.041*	*-0.043*	*-0.040*
	(-8.58)	(-12.40)	(-32.12)	(-12.71)	(-10.66)	(-15.37)	(-37.27)	(-15.34)
constant	*-5.115*	*1.854*	*1.170*	0.291	*0.135*	*0.251*	*0.380*	*0.140*
	(-17.00)	(5.85)	(5.90)	(0.78)	(4.87)	(6.14)	(11.41)	(2.91)
				Dependent Variable = Share of SO2				
ln(MWh)	*-0.087*	*0.036*	*0.017*	*-0.037*	0.002	0.002	*0.005*	0.000
	(-10.73)	(3.07)	(3.32)	(-4.33)	(1.60)	(1.00)	(4.44)	(0.18)
ln(Pg/Pc)	*-0.023*	*-0.044*	*-0.049*	*-0.042*	*-0.022*	*-0.041*	*-0.043*	*-0.040*
	(-8.58)	(-12.40)	(-32.12)	(-12.71)	(-10.66)	(-15.37)	(-37.27)	(-15.34)
ln(Ps/Pc)	*0.070*	*0.101*	*0.091*	*0.086*	*0.072*	*0.097*	*0.089*	*0.085*
	(38.82)	(33.34)	(75.09)	(42.38)	(47.41)	(43.81)	(89.32)	(42.45)
constant	*0.663*	*-0.818*	*-0.536*	0.056	*-0.320*	*-0.435*	*-0.404*	*-0.342*
	(7.43)	(-6.22)	(-9.67)	(0.61)	(-23.08)	(-19.20)	(-32.09)	(-17.12)
Observations	679	681	343	341	976	970	488	488

Notes: Subscripts denote input types (c = coal; o = oil; g = gas; n = nuclear; s = SO_2).
Within our sample, not all regions contain generating units of all input types.

Generation Cost Efficiency -- Regression Coefficient Estimates
NWUMS
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	On-Peak Summer	On-Peak Autumn	On-Peak Winter	On-Peak Spring	Off-Peak Summer	Off-Peak Autumn	Off-Peak Winter	Off-Peak Spring
				Dependent Variable = ln(Cost)				
ln(MWh)	*1.213*	*0.870*	*1.312*	*1.647*	*0.998*	*0.996*	*1.005*	*1.040*
	(45.34)	(11.90)	(35.72)	(35.06)	(213.39)	(81.85)	(225.88)	(99.80)
lnPc	*1.448*	*4.677*	*2.243*	*2.439*	*0.704*	*0.909*	*0.633*	*0.845*
	(9.89)	(18.87)	(13.29)	(10.32)	(28.38)	(19.60)	(29.73)	(15.15)
lnPc*lnPc	*0.245*	*0.236*	*0.213*	*0.237*	*0.242*	*0.252*	*0.206*	*0.206*
	(54.19)	(29.98)	(66.22)	(23.05)	(64.33)	(30.57)	(72.19)	(26.83)
ln(MWh)*lnPc	*-0.073*	*-0.367*	*-0.157*	*-0.182*	*-0.011*	*-0.015*	*-0.009*	*-0.029*
	(-5.29)	(-15.55)	(-9.86)	(-8.08)	(-4.78)	(-3.41)	(-4.45)	(-5.42)
lnPg	*0.787*	-0.172	*1.107*	*1.675*	*-0.151*	-0.021	*-0.043*	-0.066
	(4.01)	(-0.60)	(4.44)	(5.17)	(-6.45)	(-0.82)	(-1.97)	(-1.52)
lnPg*lnPg	*0.050*	0.009	*0.064*	*0.082*	0.001	-0.007	*0.020*	*0.035*
	(9.09)	(1.27)	(16.72)	(5.16)	(0.15)	(-1.93)	(9.22)	(3.52)
ln(MWh)*lnPg	*-0.079*	0.025	*-0.109*	*-0.151*	*0.013*	0.005	0.002	0.005
	(-4.26)	(0.90)	(-4.64)	(-4.96)	(5.77)	(1.92)	(0.86)	(1.48)
lnPn	*-1.311*	*-2.727*	*-2.283*	*-3.609*	*0.834*	*0.723*	*0.838*	*0.562*
	(-8.27)	(-10.63)	(-11.92)	(-12.26)	(28.12)	(15.84)	(35.32)	(7.78)
lnPn*lnPn	*0.230*	*0.176*	*0.253*	*0.244*	*0.256*	*0.242*	*0.252*	*0.263*
	(51.18)	(22.36)	(82.36)	(23.15)	(70.85)	(30.92)	(85.46)	(27.12)
ln(MWh)*lnPn	*0.199*	*0.328*	*0.302*	*0.421*	0.003	*0.011*	*0.009*	*0.033*
	(13.24)	(13.57)	(16.65)	(15.06)	(0.90)	(2.68)	(3.86)	(4.80)
lnPs	0.076	*-0.779*	-0.067	*0.495*	*-0.387*	*-0.610*	*-0.428*	*-0.341*
	(1.64)	(-5.31)	(-1.15)	(7.65)	(-39.86)	(-22.46)	(-52.74)	(-17.43)
lnPs*lnPs	*0.077*	*0.120*	*0.085*	*0.094*	*0.078*	*0.114*	*0.084*	*0.087*
	(63.13)	(32.66)	(107.33)	(57.33)	(87.30)	(45.16)	(131.03)	(63.12)
ln(MWh)*lnPs	*-0.046*	0.014	*-0.036*	*-0.088*	*-0.004*	-0.001	*-0.002*	*-0.010*
	(-10.64)	(1.00)	(-6.50)	(-14.69)	(-4.63)	(-0.38)	(-2.36)	(-5.71)
lnPc*lnPg	*-0.045*	*-0.030*	*-0.027*	*-0.041*	*-0.012*	*-0.010*	*-0.004*	-0.006
	(-12.25)	(-4.54)	(-10.14)	(-4.51)	(-4.72)	(-2.78)	(-2.16)	(-1.08)

Generation Cost Efficiency -- Regression Coefficient Estimates
NWUMS
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak** Summer	Autumn	Winter	Spring	**Off-Peak** Summer	Autumn	Winter	Spring
lnPc*lnPs	*-0.028*	*-0.056*	*-0.022*	*-0.006*	*-0.027*	*-0.050*	*-0.023*	*-0.018*
	(-19.09)	(-13.86)	(-18.96)	(-1.99)	(-25.17)	(-16.41)	(-24.71)	(-8.34)
lnPg*lnPs	0.002	-0.008	*-0.006*	*-0.038*	*0.006*	0.001	*-0.002*	*-0.009*
	(1.10)	(-1.82)	(-5.34)	(-8.45)	(3.93)	(0.35)	(-1.98)	(-3.10)
lnPc*lnPn	*-0.171*	*-0.149*	*-0.164*	*-0.190*	*-0.204*	*-0.193*	*-0.179*	*-0.183*
	(-49.90)	(-22.75)	(-61.90)	(-21.86)	(-68.97)	(-26.78)	(-70.97)	(-23.60)
lnPg*lnPn	-0.007	*0.029*	*-0.031*	-0.003	*0.005*	*0.016*	*-0.014*	*-0.020*
	(-1.90)	(5.52)	(-13.07)	(-0.30)	(2.20)	(4.94)	(-8.86)	(-3.07)
lnPs*lnPn	*-0.052*	*-0.056*	*-0.058*	*-0.050*	*-0.057*	*-0.065*	*-0.059*	*-0.060*
	(-31.68)	(-15.02)	(-55.81)	(-15.62)	(-44.92)	(-22.11)	(-67.86)	(-21.65)
Day1	*-0.012*	*-0.020*	*0.012*	-0.008	-0.001	0.006	*0.007*	0.004
	(-4.36)	(-4.46)	(5.82)	(-1.26)	(-0.23)	(1.53)	(4.26)	(0.73)
Day2	*-0.009*	*-0.018*	*-0.009*	-0.006	*-0.013*	*-0.013*	*-0.013*	0.012
	(-3.47)	(-5.10)	(-3.81)	(-0.87)	(-5.45)	(-4.00)	(-6.54)	(1.87)
constant	*1.404*	*5.503*	0.419	*-3.251*	*3.678*	*4.187*	*3.648*	*3.258*
	(4.96)	(7.12)	(1.08)	(-6.45)	(74.67)	(33.01)	(77.48)	(28.97)

Dependent Variable = Share of Coal

	On-Peak Summer	Autumn	Winter	Spring	Off-Peak Summer	Autumn	Winter	Spring
ln(MWh)	*-0.073*	*-0.367*	*-0.157*	*-0.182*	*-0.011*	*-0.015*	*-0.009*	*-0.029*
	(-5.29)	(-15.55)	(-9.86)	(-8.08)	(-4.78)	(-3.41)	(-4.45)	(-5.42)
ln(Pc/Pn)	*0.245*	*0.236*	*0.213*	*0.237*	*0.242*	*0.252*	*0.206*	*0.206*
	(54.19)	(29.98)	(66.22)	(23.05)	(64.33)	(30.57)	(72.19)	(26.83)
ln(Pg/Pn)	*-0.045*	*-0.030*	*-0.027*	*-0.041*	*-0.012*	*-0.010*	*-0.004*	-0.006
	(-12.25)	(-4.54)	(-10.14)	(-4.51)	(-4.72)	(-2.78)	(-2.16)	(-1.08)
ln(Ps/Pn)	*-0.028*	*-0.056*	*-0.022*	*-0.006*	*-0.027*	*-0.050*	*-0.023*	*-0.018*
	(-19.09)	(-13.86)	(-18.96)	(-1.99)	(-25.17)	(-16.41)	(-24.71)	(-8.34)
constant	*1.448*	*4.677*	*2.243*	*2.439*	*0.704*	*0.909*	*0.633*	*0.845*
	(9.89)	(18.87)	(13.29)	(10.32)	(28.38)	(19.60)	(29.73)	(15.15)

Generation Cost Efficiency -- Regression Coefficient Estimates
NWUMS
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	On-Peak Summer	On-Peak Autumn	On-Peak Winter	On-Peak Spring	Off-Peak Summer	Off-Peak Autumn	Off-Peak Winter	Off-Peak Spring
				Dependent Variable = Share of Gas				
ln(MWh)	*-0.079*	0.025	*-0.109*	*-0.151*	*0.013*	0.005	0.002	0.005
	(-4.26)	(0.90)	(-4.64)	(-4.96)	(5.77)	(1.92)	(0.86)	(1.48)
ln(Pc/Pn)	*-0.045*	*-0.030*	*-0.027*	*-0.041*	*-0.012*	*-0.010*	*-0.004*	-0.006
	(-12.25)	(-4.54)	(-10.14)	(-4.51)	(-4.72)	(-2.78)	(-2.16)	(-1.08)
ln(Pg/Pn)	*0.050*	0.009	*0.064*	*0.082*	0.001	-0.007	*0.020*	*0.035*
	(9.09)	(1.27)	(16.72)	(5.16)	(0.15)	(-1.93)	(9.22)	(3.52)
ln(Ps/Pn)	0.002	-0.008	*-0.006*	*-0.038*	*0.006*	0.001	*-0.002*	*-0.009*
	(1.10)	(-1.82)	(-5.34)	(-8.45)	(3.93)	(0.35)	(-1.98)	(-3.10)
constant	*0.787*	-0.172	*1.107*	*1.675*	*-0.151*	-0.021	*-0.043*	-0.066
	(4.01)	(-0.60)	(4.44)	(5.17)	(-6.45)	(-0.82)	(-1.97)	(-1.52)
				Dependent Variable = Share of SO2				
ln(MWh)	*-0.046*	0.014	*-0.036*	*-0.088*	*-0.004*	-0.001	*-0.002*	*-0.010*
	(-10.64)	(1.00)	(-6.50)	(-14.69)	(-4.63)	(-0.38)	(-2.36)	(-5.71)
ln(Pc/Pn)	*-0.028*	*-0.056*	*-0.022*	*-0.006*	*-0.027*	*-0.050*	*-0.023*	*-0.018*
	(-19.09)	(-13.86)	(-18.96)	(-1.99)	(-25.17)	(-16.41)	(-24.71)	(-8.34)
ln(Pg/Pn)	0.002	-0.008	*-0.006*	*-0.038*	*0.006*	0.001	*-0.002*	*-0.009*
	(1.10)	(-1.82)	(-5.34)	(-8.45)	(3.93)	(0.35)	(-1.98)	(-3.10)
ln(Ps/Pn)	*0.077*	*0.120*	*0.085*	*0.094*	*0.078*	*0.114*	*0.084*	*0.087*
	(63.13)	(32.66)	(107.33)	(57.33)	(87.30)	(45.16)	(131.03)	(63.12)
constant	0.076	*-0.779*	-0.067	*0.495*	*-0.387*	*-0.610*	*-0.428*	*-0.341*
	(1.64)	(-5.31)	(-1.15)	(7.65)	(-39.86)	(-22.46)	(-52.74)	(-17.43)
Observations	679	681	343	341	976	970	488	488

Notes: Subscripts denote input types (c = coal; o = oil; g = gas; n = nuclear; s = SO_2).
Within our sample, not all regions contain generating units of all input types.

Generation Cost Efficiency -- Regression Coefficient Estimates
Rest of MISO
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak** Summer	Autumn	Winter	Spring	**Off-Peak** Summer	Autumn	Winter	Spring
				***Dependent Variable = ln* (Cost)**				
ln(MWh)	*0.879*	*1.325*	*0.730*	*1.306*	*0.988*	*1.008*	*1.004*	*1.011*
	(17.63)	(500.47)	(11.26)	(580.41)	(206.97)	(128.71)	(155.91)	(143.77)
lnPc	*4.508*	*2.353*	*1.732*	*2.527*	*1.400*	*1.415*	*1.381*	*1.392*
	(21.24)	(6.36)	(5.46)	(5.88)	(80.51)	(54.12)	(59.70)	(48.50)
lnPc*lnPc	*0.206*	*0.189*	*0.187*	*0.207*	*0.191*	*0.178*	*0.179*	*0.202*
	(104.79)	(68.92)	(72.75)	(54.66)	(140.64)	(71.35)	(91.73)	(64.31)
ln(MWh)*lnPc	*-0.226*	*-0.061*	-0.020	*-0.077*	0.002	*0.006*	*0.007*	*0.005*
	(-14.44)	(-2.21)	(-0.84)	(-2.40)	(1.80)	(3.13)	(4.21)	(2.50)
lnPo	*-1.299*	*0.775*	0.236	-0.647	*0.068*	*0.075*	*0.167*	*0.136*
	(-8.34)	(2.72)	(1.01)	(-1.56)	(5.26)	(5.28)	(10.67)	(5.56)
lnPo*lnPo	*0.017*	-0.006	0.009	*0.090*	*0.005*	*-0.008*	*-0.017*	*0.035*
	(4.63)	(-1.63)	(1.70)	(10.01)	(2.22)	(-3.63)	(-5.70)	(6.92)
ln(MWh)*lnPo	*0.099*	*-0.054*	-0.008	0.057	*-0.004*	*-0.003*	*-0.006*	*-0.007*
	(8.61)	(-2.53)	(-0.48)	(1.81)	(-4.05)	(-2.63)	(-5.73)	(-4.10)
lnPg	*-2.632*	*-2.777*	0.571	-0.609	*-0.041*	*0.074*	0.004	-0.038
	(-10.84)	(-6.62)	(1.87)	(-1.13)	(-2.52)	(4.22)	(0.28)	(-1.71)
lnPg*lnPg	*0.025*	*0.023*	*0.058*	*0.079*	*-0.005*	*0.005*	*0.018*	*0.025*
	(6.75)	(5.29)	(17.70)	(9.62)	(-2.73)	(2.42)	(13.39)	(7.10)
ln(MWh)*lnPg	*0.192*	*0.209*	*-0.045*	0.036	*0.002*	*-0.004*	*-0.002*	0.000
	(10.72)	(6.67)	(-2.01)	(0.88)	(2.05)	(-3.10)	(-2.17)	(0.04)
lnPn	*0.709*	0.276	-0.081	*-0.715*	*0.256*	*0.223*	*0.196*	*0.142*
	(8.81)	(1.32)	(-0.63)	(-3.25)	(24.23)	(13.97)	(14.20)	(6.44)
lnPn*lnPn	*0.053*	*0.055*	*0.057*	*0.091*	*0.071*	*0.064*	*0.070*	*0.096*
	(36.66)	(21.56)	(34.20)	(29.20)	(50.81)	(29.07)	(50.95)	(32.85)
ln(MWh)*lnPn	*-0.041*	-0.007	0.018	*0.068*	*-0.003*	0.001	0.000	0.002
	(-6.79)	(-0.44)	(1.86)	(4.05)	(-4.50)	(0.64)	(0.49)	(1.32)
lnPs	*-0.286*	*0.373*	*-1.458*	*0.443*	*-0.683*	*-0.787*	*-0.748*	*-0.632*
	(-2.10)	(3.69)	(-9.30)	(3.49)	(-52.50)	(-36.66)	(-47.06)	(-37.62)
lnPs*lnPs	*0.133*	*0.163*	*0.149*	*0.148*	*0.134*	*0.158*	*0.150*	*0.139*
	(85.94)	(64.56)	(97.47)	(91.14)	(110.84)	(77.47)	(119.31)	(97.50)
ln(MWh)*lnPs	*-0.025*	*-0.087*	*0.055*	*-0.083*	*0.003*	0.000	0.001	0.000
	(-2.49)	(-11.53)	(4.74)	(-8.71)	(2.83)	(0.03)	(0.98)	(-0.15)
lnPc*lnPo	*-0.012*	*0.011*	0.004	*-0.014*	*-0.005*	*0.006*	*0.010*	*-0.011*
	(-7.34)	(5.17)	(1.73)	(-3.56)	(-4.65)	(4.25)	(6.87)	(-4.71)
lnPc*lnPg	*-0.039*	*-0.022*	*-0.017*	*-0.025*	*-0.013*	*-0.006*	*-0.004*	*-0.004*
	(-17.56)	(-7.15)	(-7.31)	(-5.96)	(-10.91)	(-3.41)	(-3.47)	(-2.00)

Generation Cost Efficiency -- Regression Coefficient Estimates
Rest of MISO
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	On-Peak				Off-Peak			
	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring
lnPc*lnPs	*-0.109*	*-0.134*	*-0.123*	*-0.117*	*-0.113*	*-0.128*	*-0.128*	*-0.118*
	(-79.52)	(-62.01)	(-91.99)	(-58.03)	(-106.92)	(-68.07)	(-117.65)	(-70.48)
lnPo*lnPg	0.003	-0.004	*-0.026*	*-0.035*	0.002	-0.003	-0.003	-0.003
	(1.14)	(-1.22)	(-8.53)	(-4.62)	(1.08)	(-1.74)	(-1.81)	(-1.08)
lnPo*lnPs	*-0.011*	-0.002	*-0.009*	*-0.034*	*-0.003*	-0.001	*-0.004*	*-0.016*
	(-8.01)	(-1.43)	(-5.93)	(-12.19)	(-3.77)	(-1.47)	(-5.04)	(-9.34)
lnPg*lnPs	*0.004*	*-0.007*	-0.001	*0.009*	*0.005*	*-0.003*	-0.001	-0.001
	(2.24)	(-2.88)	(-0.74)	(3.16)	(5.10)	(-2.14)	(-0.71)	(-0.69)
lnPc*lnPn	*-0.046*	*-0.045*	*-0.051*	*-0.051*	*-0.061*	*-0.050*	*-0.056*	*-0.070*
	(-51.78)	(-25.18)	(-34.55)	(-22.98)	(-68.53)	(-26.68)	(-41.93)	(-32.23)
lnPo*lnPn	0.002	0.001	*0.022*	-0.006	0.001	*0.006*	*0.014*	-0.005
	(1.28)	(0.59)	(9.16)	(-1.53)	(0.72)	(3.85)	(8.65)	(-1.60)
lnPg*lnPn	*0.007*	*0.009*	*-0.013*	*-0.028*	*0.011*	*0.006*	*-0.011*	*-0.016*
	(5.19)	(4.23)	(-10.11)	(-9.67)	(10.33)	(4.27)	(-11.78)	(-7.75)
lnPs*lnPn	*-0.017*	*-0.020*	*-0.015*	*-0.006*	*-0.022*	*-0.026*	*-0.017*	*-0.004*
	(-20.11)	(-15.43)	(-16.85)	(-4.17)	(-29.21)	(-20.69)	(-19.96)	(-3.07)
Day1	*-0.010*	-0.002	*-0.023*	*-0.014*	*-0.018*	*-0.020*	*-0.030*	*-0.021*
	(-7.77)	(-1.28)	(-14.88)	(-7.61)	(-17.62)	(-13.52)	(-24.55)	(-13.26)
Day2	*-0.034*	*-0.031*	*-0.032*	*-0.029*	*-0.030*	*-0.025*	*-0.025*	*-0.041*
	(-18.30)	(-14.87)	(-14.76)	(-8.73)	(-22.36)	(-15.84)	(-15.87)	(-17.07)
constant	*5.561*	*0.000*	*7.748*	*0.000*	*4.183*	*4.272*	*4.163*	*3.827*
	(8.25)	(0.01)	(8.89)	(0.01)	(65.12)	(40.98)	(48.40)	(41.41)
				Dependent Variable = Share of Coal				
ln(MWh)	*-0.226*	*-0.061*	-0.020	*-0.077*	0.002	*0.006*	*0.007*	*0.005*
	(-14.44)	(-2.21)	(-0.84)	(-2.40)	(1.80)	(3.13)	(4.21)	(2.50)
ln(Pc/Pn)	*0.206*	*0.189*	*0.187*	*0.207*	*0.191*	*0.178*	*0.179*	*0.202*
	(104.79)	(68.92)	(72.75)	(54.66)	(140.64)	(71.35)	(91.73)	(64.31)
ln(Po/Pn)	*-0.012*	*0.011*	0.004	*-0.014*	*-0.005*	*0.006*	*0.010*	*-0.011*
	(-7.34)	(5.17)	(1.73)	(-3.56)	(-4.65)	(4.25)	(6.87)	(-4.71)
ln(Pg/Pn)	*-0.039*	*-0.022*	*-0.017*	*-0.025*	*-0.013*	*-0.006*	*-0.004*	*-0.004*
	(-17.56)	(-7.15)	(-7.31)	(-5.96)	(-10.91)	(-3.41)	(-3.47)	(-2.00)
ln(Ps/Pn)	*-0.109*	*-0.134*	*-0.123*	*-0.117*	*-0.113*	*-0.128*	*-0.128*	*-0.118*
	(-79.52)	(-62.01)	(-91.99)	(-58.03)	(-106.92)	(-68.07)	(-117.65)	(-70.48)
constant	*4.508*	*2.353*	*1.732*	*2.527*	*1.400*	*1.415*	*1.381*	*1.392*
	(21.24)	(6.36)	(5.46)	(5.88)	(80.51)	(54.12)	(59.70)	(48.50)

Generation Cost Efficiency -- Regression Coefficient Estimates
Rest of MISO
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak** Summer	**On-Peak** Autumn	**On-Peak** Winter	**On-Peak** Spring	**Off-Peak** Summer	**Off-Peak** Autumn	**Off-Peak** Winter	**Off-Peak** Spring
				Dependent Variable = Share of Oil				
ln(MWh)	*0.099*	*-0.054*	-0.008	0.057	*-0.004*	*-0.003*	*-0.006*	*-0.007*
	(8.61)	(-2.53)	(-0.48)	(1.81)	(-4.05)	(-2.63)	(-5.73)	(-4.10)
ln(Pc/Pn)	*-0.012*	*0.011*	0.004	*-0.014*	*-0.005*	*0.006*	*0.010*	*-0.011*
	(-7.34)	(5.17)	(1.73)	(-3.56)	(-4.65)	(4.25)	(6.87)	(-4.71)
ln(Po/Pn)	*0.017*	-0.006	0.009	*0.090*	*0.005*	*-0.008*	*-0.017*	*0.035*
	(4.63)	(-1.63)	(1.70)	(10.01)	(2.22)	(-3.63)	(-5.70)	(6.92)
ln(Pg/Pn)	0.003	-0.004	*-0.026*	*-0.035*	0.002	-0.003	-0.003	-0.003
	(1.14)	(-1.22)	(-8.53)	(-4.62)	(1.08)	(-1.74)	(-1.81)	(-1.08)
ln(Ps/Pn)	*-0.011*	-0.002	*-0.009*	*-0.034*	*-0.003*	-0.001	*-0.004*	*-0.016*
	(-8.01)	(-1.43)	(-5.93)	(-12.19)	(-3.77)	(-1.47)	(-5.04)	(-9.34)
constant	*-1.299*	*0.775*	0.236	-0.647	*0.068*	*0.075*	*0.167*	*0.136*
	(-8.34)	(2.72)	(1.01)	(-1.56)	(5.26)	(5.28)	(10.67)	(5.56)
				Dependent Variable = Share of Gas				
ln(MWh)	*0.192*	*0.209*	*-0.045*	0.036	*0.002*	*-0.004*	*-0.002*	0.000
	(10.72)	(6.67)	(-2.01)	(0.88)	(2.05)	(-3.10)	(-2.17)	(0.04)
ln(Pc/Pn)	*-0.039*	*-0.022*	*-0.017*	*-0.025*	*-0.013*	*-0.006*	*-0.004*	*-0.004*
	(-17.56)	(-7.15)	(-7.31)	(-5.96)	(-10.91)	(-3.41)	(-3.47)	(-2.00)
ln(Po/Pn)	0.003	-0.004	*-0.026*	*-0.035*	0.002	-0.003	-0.003	-0.003
	(1.14)	(-1.22)	(-8.53)	(-4.62)	(1.08)	(-1.74)	(-1.81)	(-1.08)
ln(Pg/Pn)	*0.025*	*0.023*	*0.058*	*0.079*	*-0.005*	*0.005*	*0.018*	*0.025*
	(6.75)	(5.29)	(17.70)	(9.62)	(-2.73)	(2.42)	(13.39)	(7.10)
ln(Ps/Pn)	*0.004*	*-0.007*	-0.001	*0.009*	*0.005*	*-0.003*	-0.001	-0.001
	(2.24)	(-2.88)	(-0.74)	(3.16)	(5.10)	(-2.14)	(-0.71)	(-0.69)
constant	*-2.632*	*-2.777*	0.571	-0.609	*-0.041*	*0.074*	0.004	-0.038
	(-10.84)	(-6.62)	(1.87)	(-1.13)	(-2.52)	(4.22)	(0.28)	(-1.71)

Generation Cost Efficiency -- Regression Coefficient Estimates
Rest of MISO
(z-statistics reported in parentheses -- results in highlighted type are significant at the 5% level)

Independent Variables	**On-Peak** Summer	**On-Peak** Autumn	**On-Peak** Winter	**On-Peak** Spring	**Off-Peak** Summer	**Off-Peak** Autumn	**Off-Peak** Winter	**Off-Peak** Spring
				Dependent Variable = Share of SO2				
ln(MWh)	*-0.025*	*-0.087*	*0.055*	*-0.083*	*0.003*	0.000	0.001	0.000
	(-2.49)	(-11.53)	(4.74)	(-8.71)	(2.83)	(0.03)	(0.98)	(-0.15)
ln(Pc/Pn)	*-0.109*	*-0.134*	*-0.123*	*-0.117*	*-0.113*	*-0.128*	*-0.128*	*-0.118*
	(-79.52)	(-62.01)	(-91.99)	(-58.03)	(-106.92)	(-68.07)	(-117.65)	(-70.48)
ln(Po/Pn)	*-0.011*	-0.002	*-0.009*	*-0.034*	*-0.003*	-0.001	*-0.004*	*-0.016*
	(-8.01)	(-1.43)	(-5.93)	(-12.19)	(-3.77)	(-1.47)	(-5.04)	(-9.34)
ln(Pg/Pn)	*0.004*	*-0.007*	-0.001	*0.009*	*0.005*	*-0.003*	-0.001	-0.001
	(2.24)	(-2.88)	(-0.74)	(3.16)	(5.10)	(-2.14)	(-0.71)	(-0.69)
ln(Ps/Pn)	*0.133*	*0.163*	*0.149*	*0.148*	*0.134*	*0.158*	*0.150*	*0.139*
	(85.94)	(64.56)	(97.47)	(91.14)	(110.84)	(77.47)	(119.31)	(97.50)
constant	*-0.286*	*0.373*	*-1.458*	*0.443*	*-0.683*	*-0.787*	*-0.748*	*-0.632*
	(-2.10)	(3.69)	(-9.30)	(3.49)	(-52.50)	(-36.66)	(-47.06)	(-37.62)
Observations	679	681	343	341	976	970	488	488

Notes: Subscripts denote input types (c = coal; o = oil; g = gas; n = nuclear; s = SO_2).
Within our sample, not all regions contain generating units of all input types.