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Generation Cost Savings From Day 1 and Day 2 RTO Market Designs

October 1, 2009

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I. INTRODUCTION AND EXECUTIVE SUMMARY

Competition has been introduced in many forms into the electric power sector in the United States and around the world. Throughout the United States, every transmission system offers access to other power generators, and wholesale power marketers and generating companies can trade bulk power at market rates. Seven Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) have been formed that operate centralized bulk power markets,¹ and in many cases, the states within these regions have enabled retail competition, allowing customers to choose their electricity supplier at market-determined prices.

This diverse set of market designs has sparked a considerable debate over the benefits and costs of electric competition. A number of studies have attempted to measure costs and benefits of electric restructuring as a whole or of certain aspects of restructuring. This study adds to this body of work by examining the reductions in power production costs experienced when RTO-operated electric markets change from a less-centralized form known as "Day 1" to a more centralized and organized "Day 2" design. In Day 2 markets, all power plants in a region become part of centralized market-driven unit commitment and dispatch process. In order to facilitate the centralized dispatch process, regional power exchanges are created for buying and selling power on a day-ahead and hour(s)-ahead basis.²

	Pre-Day One	Day One	Day Two
Tariff Administration & Design		Х	Х
Congestion Management			
Redispatch		Х	
Market-Based			Х
Parallel Path Flow		Х	Х
Ancillary Services		Х	Х
OASIS	Х	Х	Х
Market Monitoring		Х	Х
Transmission Planning		Х	Х
Interregional Coordination		Х	Х
Day-Ahead Energy Market			Х
Same-Day Energy Market			Х
Ancillary Services Market			Х
Capacity Market			Х

¹ As noted by FERC on its website, "the primary difference between an ISO and an RTO is that there is no 'scope' requirement associated with ISO status." For simplicity, we refer to all markets operated by either ISOs or RTOs simply as "RTO-operated" or equivalently as "centralized" or "organized" markets.

² Day 2 markets often contain other features, but they are less standard across the various Day 2 RTOs.



Our analysis compares the costs of operating the same group of electric power plants, which we refer to as "systems," under Day 1 and Day 2 market designs. Because initial implementation of Day 1 markets is easier than the implementation of a Day 2 design, certain organized markets began in a Day 1 form and subsequently added the features necessary to become a Day 2 design. This sets up a natural experiment in which we can examine the same market -- buyers, sellers, power plants, and transmission lines -- operating under different market designs.

Using econometric methods, we measured the savings in fuel (and environmental) costs in the Midwest ISO ("MISO") during its Day 1 period and its Day 2 period to date. Our results show that the costs of operating a system of generating plants declines significantly as a market transitions from no organized regional markets (*i.e.*, "pre-RTO" or "Day 0") to Day 1, and it continues to gain cost efficiency going from Day 1 to Day 2 operation.³

Overall, our analysis suggests that power production costs declined by an average of 1.35% going from Day 0 to Day 1 and 2.61% from Day 1 to Day 2, or almost 4% overall. Applying this to the entire RTO, the annual savings in fuel and SO₂ costs in MISO is about \$261 million per year between Day 0 and Day 2 (based on 2007 data), with approximately \$172 million of that annual savings attributable to the change from Day 1 to Day 2. While individual plants or systems of generation plants would be expected to get more efficient over time even without market changes, it is extremely unlikely that evolutionary cost improvements of this magnitude would arise over only eight years (*i.e.*, the 2000-07 period covered by our analysis) based on the performance of a fixed set of generation plants.

Our estimated MISO-wide savings of \$261 million per year in fuel and SO_2 costs associated with the full transition from Day 0 to Day 2 is greater than the \$227 million "adder" that MISO charged to recover its 2007 operating costs (of which \$127 million was for market facilitation,

³ The features of Day 1 and Day 2 markets are summarized in the table on page 1, and discussed in further detail in the next section of the report. In a Day 0 state, no RTO is in operation, and transmission charges are aggregated (*i.e.*, "pancaked") when sending electric power across multiple utility control areas. Under a Day 1 RTO, transmission rate pancaking is eliminated, and the RTO coordinates use of the transmission system within its boundaries to facilitate bilateral energy trading and increase system reliability. Under a Day 2 RTO, there is centralized trading where generators bid in supply in order that the least-cost generation resources are committed and dispatched to meet regional load obligations.



monitoring, and compliance services and \$94 million was for scheduling, system control, and dispatch).⁴

As energy usage increases, the fuel cost savings associated with the transition from Day 0 to Day 2 market design would only be expected to grow over time. However, holding the annual cost savings constant (to be "conservative"), our results imply that the fuel cost savings over ten years associated with moving from Day 0 to a Day 1 market design would amount to \$0.89 billion. The ten-year savings associated with moving from Day 1 to a Day 2 market design would amount to \$1.72 billion.

Note that the above cost-savings estimates assume that no plant-level or system-level efficiency improvements would have occurred among <u>existing</u> MISO generation resources if the MISO region had remained in a pre-RTO (*i.e.*, Day 0) state. While improvements in plant-level and system-level generation efficiency would be expected to occur even if MISO had remained as a Day 0 or Day 1 market, it is also true that our estimates omit any cost savings arising from more effective generation investment spurred by the movement to a Day 1 or Day 2 market design.

One additional feature of Day 2 markets is that they interrupt wholesale transmission transactions to preserve system reliability far less often than occurs in Day 1 markets. These transaction-canceling interruptions occur suddenly, and can be costly to wholesale buyers or sellers when they must quickly find alternative supplies or pay liquidated damages. A review of reliability-based interruptions (known as "Transmission Loading Reliefs"), while reflecting a somewhat informal approach to examining system reliability, suggests that the use of centralized security-constrained dispatch and re-dispatch associated with Day 2 market design may have reliability advantages over less-centralized electricity market designs.

These results do not constitute a complete benefit-cost analysis of wholesale or retail competition in the power industry. To do this, we would need to consider the costs associated with alternative market designs, longer-term product (or capacity) markets, and other public and private benefits and costs. Nevertheless, our results show that the short-run production efficiencies that have long been associated with centralized markets and power pools provide a

⁴ In the absence of an RTO (*i.e.*, under Day 0), one would expect that individual transmission providers would bear additional costs related to scheduling, system control, and dispatch, and that regional reliability entities also may bear greater costs involved in managing regional transmission resources.



substantial cost savings to the region. Harvesting these cost savings provides an opportunity to share the production efficiencies enabled by Day 1 and Day 2 markets with all market participants through lower prices, higher reliability, and other benefits.

II. ELECTRIC MARKET DESIGN AND PRODUCTION EFFICIENCIES

For many decades it has been known that the coordinated use of all power plants in a single region leads to the lowest-cost power supply. Individual utilities have always used the principle of centralized least-cost dispatch, where total electric demand is met by the cheapest combination of power plants owned by that utility, supplemented by purchased power when it is available and cheaper than self-production. Traditional power pools extended this idea across the service territories of multiple cost-based regulated utilities.⁵

In areas where there are no organized markets or pools, or where the markets have only a Day 1 design, all plants in a region are not centrally dispatched. Instead, individual generation companies and power distributors (known as load-serving entities, or "LSEs") make their own trades – a market system often called bilateral trading. These trades increase production efficiency, but on a case-by-case basis. In addition, bilateral traders in Day 1 markets do not have access to the centralized spot markets that are part of the Day 2 design, which allow them to supplement their bilateral purchases with spot power supplies that might be temporarily cheaper. Day 1 markets also cannot use the transmission system as efficiently as in Day 2 markets.

As a result, one of the main expected advantages of Day 2 markets is that all power plants in a region that participate in the market will act so as to become part of a region-wide least-cost dispatch. In Day 2 markets, owners of generating units bid those units into the market through a centralized auction process. Based on those bids, the lowest priced units are "committed" and dispatched to meet the remaining load requirements of the region, subject to transmission constraints that limit power movements within and into the region. In this fashion, market forces will cause the lowest-cost plant to be fully subscribed even if its owner does not need all of its power for its own use. Similarly, the second-cheapest plant also will be fully subscribed, and so on, in order of the lowest to highest cost plant. The market process will naturally lead buyers to

⁵ The value of increased regional generator coordination to achieve cost savings was mentioned prominently in the Department of Energy's 1980 National Grid Study (DOE/ERA0056/1, Chapter 4) and in Paul Joskow and Richard Schmalensee's seminal work, "Markets for Power" (MIT Press, 1985) at 82.



purchase from the combination of power plants that has the lowest total production cost, subject to reliability and transmission limitations.

Other features of Day 2 markets enhance the production cost savings from least-cost centralized dispatch. Under alternative market designs, market operators cannot dispatch a plant unless it is <u>committed</u> to the market in advance – roughly the equivalent of warming up a power plant in advance so that it can be dispatched. In Day 2 markets, generators bid to supply their generating units to the market, and the lowest-priced bids determine which units are committed to serve market demand. If the lowest-cost units make the lowest-priced bids, then that will result in lower overall costs relative to other potential market designs. In addition, transparent markets for purchasing power on a day-ahead or hour(s)-ahead basis are available to all buyers, allowing them to optimize their purchasing, and the transmission system can be more fully utilized without interruptions.

In summary, the introduction of Day 1 markets (which incorporate a more streamlined regional transmission tariff and improved regional transmission usage) should reduce regional power production costs relative to a decentralized Day 0 state. In addition, further significant cost reductions would be expected to arise in Day 2 markets, where generation resources are centrally committed and dispatched to meet regional load requirements. That is exactly what our study confirms.

III. OUR STUDY

Our approach for measuring RTO efficiency benefits involves the statistical estimation of a production function and a cost function for a constant set of generators within the Midwest Independent System Operator (MISO) RTO. The MISO RTO covers all or part of the following states: Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, Ohio, Pennsylvania, South Dakota, and Wisconsin, as shown in Figure 1.⁶

⁶ The Canadian province of Manitoba is also part of MISO's reliability footprint.







Source: http://www.midwestiso.org/

The MISO market contains 130,000 MW of generation capacity, and its peak load (set July 31, 2006) amounted to nearly 110,000 MW. MISO has over 93,600 miles of transmission lines, nearly 5,400 generating units, and approximately 36,000 network buses. MISO membership includes 30 transmission owners, with approximately \$14.4 billion in transmission assets, and approximately 90 other market participants.⁷

Within MISO there are different subregions, which periodically become economically separated from other parts of MISO as a result of binding transmission constraints. MISO has defined several "narrow constrained areas" (NCAs), which are chronically transmission-constrained areas where there are limited supply options. These NCAs are known as WUMS (Wisconsin -

⁷ For further detail, see <u>http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-</u> <u>7ba50a48324a/FactSheet_0510f%20(2).pdf</u>.



Upper Michigan System) Northern WUMS and Minnesota. For purposes of analyzing the efficiency gains associated with RTO Day 1 and Day 2 markets, we analyze each of these areas separately. What we expect to find, and our results confirm, is that cost savings are low or even negative in these areas because there is limited scope for efficiency gains. However, the remaining portion of MISO is much larger, and holds the potential for significant efficiency gains associated with the introduction of Day 1 and Day 2 market designs. We refer to this remaining area as the "Rest of the MISO."

MISO became a Day 1 RTO in January 2002 and then converted to a Day 2 RTO design (in April 2005). Because we are looking for changes in market performance that are associated with changes in market design features, we only examine generating plants that have been operating in this region continuously since December 1999. We analyze these continuously operating plants as a group (*i.e.*, a production "system").

The power plants included in our study constitute all 302 large power units in MISO that operated throughout our sample period, December 1999 through November 2007.⁸ The vast majority of these plants are owned by utilities, and remained under utility ownership through the entire sample period. By using a consistent set of plants, our study can focus entirely on efficiencies that may arise from the improved coordination of plant usage, rather than efficiencies arising from new plant additions or changes in plant ownership. It is possible that centralized market designs lead to the choice of more cost-effective technologies for new generating plants and more efficient use of those plants, but our study is not designed to answer this question.

For our system-level analysis, we first estimate a production function and then a cost function, testing whether these functional relationships change when the MISO area went to a Day 1 design (*i.e.*, created a bilateral trading market with regional open access) and also when it went from Day 1 to Day 2 (*i.e.* adopted a more centralized market design).

⁸ The plants we examine are those monitored continuously by EPA, as we require the detailed data from the EPA CEMS data set. CEMS-monitored units comprise over 90 percent of MISO's capacity. We supplemented these data with information on nuclear power plants provided by the Nuclear Regulatory Commission.



Production functions measure the physical inputs needed to make one unit of physical system output. A generation production function will tell you how many units of power you can produce with a given number of tons of coal, cubic feet of natural gas, gallons of oil, and other inputs.⁹ It describes the physical relationship between generator inputs and outputs. Our production relationship also includes "environmental" inputs, such as the tons of SO₂ that are released as part of the generation process.

Production functions show how efficient the generator system is at using fuels and other inputs to produce power. If the implementation of a Day 1 or Day 2 market design made the group of generators more efficient, we should see the production function change so that the same amount of power can be made by a smaller amount of fuel (or conversely, the same amount of fuel can make more power). As a purely hypothetical example, if it took 100,000 tons of coal and 100 million cubic feet of natural gas to make 1 million megawatt-hours ("MWh") before a Day 1 market starts, our estimation process should show that, after Day 1, less than 100,000 tons of coal and 100 million cubic feet of gas were needed to make the same 1 million MWh. If market efficiency declined instead, we would see more than 100,000 tons of coal and 100 million cubic feet used.

We also estimate system cost functions for the MISO area. Cost functions are like production functions, except that instead of measuring the physical input-output relationship, cost functions measure the combined dollar amount of inputs (including fuel and SO₂ allowances in our particular case) needed to produce a specified amount of output. For example, it might take \$11 million of fuel, including \$5 million dollars worth of coal and \$6 million dollars of natural gas, to produce 300,000 MWh of electric power. If efficiency improvements occur as a result of implementing a Day 2 market design, then the total dollar cost of fuel needed to produce the same amount of electric power will fall, after controlling for changes in fuel prices. Because cost functions take into account the prices of inputs as well as quantities, they are a slightly better indicator of economic efficiency improvements.

Tables 1 and 2 display the results of our production and cost function estimates, respectively. Table 1 shows that the transition to the Day 1 open access/bilateral trading structure was

⁹ Technically, we convert these different units (*e.g.*, tons, cubic feet, gallons) into million btus, using standard conversion factors. This conversion has no effect on our results.



associated with increased production efficiency of 1.20% on average.¹⁰ Similarly, movement from a Day 1 to Day 2 market structure increased production efficiency by an average of 1.10%. The combined average increase in efficiency from Day 0 to Day 2 was approximately 2.30%. This is a statistically and economically significant productivity improvement.

For the Minnesota, WUMS, and NWUMS constrained areas within MISO, we expected lower efficiency gains relative to the rest of MISO due to the limited nature of competition and supply options in these regions. As expected, the average productivity gains in these areas are generally smaller, more variable, less statistically significant, and occasionally even estimated as negative. The average productivity increases for Minnesota, WUMS, and Northern WUMS for the transition from Day 0 to Day 1 were 0%, 1.17%, and 0.86%, respectively. For the transition from Day 2, the productivity changes were 0.59%, 1.35%, and -1.59%, respectively.

Table 1 also shows the percentage reduction in generation costs (*i.e.*, fuel and SO₂ allowances) for the constant set of MISO generating units that we examined. On average, these "system-level" generation costs diminish 1.35% between Day 0 and Day 1 and 2.61% between Day 1 and Day 2. Similar to the input-output productivity improvements, the majority of the cost savings occur in the larger "Rest of MISO" region and are much smaller for the constrained subregions.

Table 2 translates these percentage improvements into annual dollar cost savings. We assume that the percentage cost reductions resulting from market design improvements (*e.g.*, Day 1 and Day 2 design changes) are sustained for as long as those design features remain in place. However, the annual dollar value of this efficiency boost changes each year as fuel and environmental costs change over time. Using generator expenditures for fuel and SO₂ allowances in 2007¹¹ as our base year, Table 2 shows that the MISO-wide decrease in generation production costs associated with the transition from Day 0 to Day 1 was approximately \$89 million, and the additional savings associated with the transition from Day 1 and Day 2 was

¹¹ Technically, this analysis is for the period from December 2006 through November 2007, since we estimate cost savings by season and the winter season begins in December.



¹⁰ The averaging occurs across separate regression analyses conducted for peak and off-peak periods and the four seasons of the year (*i.e.* eight cases in total). Coefficients that are not statistically significant within cases are treated as zeros. For the complete results, see the Technical Appendix available at <u>www.brattle.com</u>.

approximately \$172 million. The combined savings of moving from Day 0 to Day 2 is \$261 million for that year.

Table 1

Avera	e Productivity	Gain and	Cost Savings	Associated with	MISO Da	v 1 and Da	v 2 Markets
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	Day 0 to Day 1		Day 1 to Day 2	
	Productivity		Productivity	
	Improvement	Cost savings	Improvement	Cost savings
Rest of MISO	1.40%	1.68%	1.30%	3.04%
Minnesota	0.00%	0.23%	0.59%	1.68%
WUMS	1.17%	0.13%	1.35%	0.99%
Northern WUMS	0.86%	0.99%	-1.59%	0.16%
Total MISO	1.20%	1.35%	1.10%	2.61%

Table 2

Annual Cost Savings Associated with MISO Day 1 and Day 2 Markets (In \$ Millions, based on 2007 MISO fuel and SO2 costs)

	Day 0 to Day 1	Day 1 to Day 2	Day 0 to Day 2
Rest of MISO	\$84.4	\$153.1	\$237.5
Minnesota	\$1.8	\$12.7	\$14.5
WUMS	\$0.8	\$5.9	\$6.7
Northern WUMS	\$2.0	\$0.3	\$2.3
Total MISO	\$89.0	\$172.0	\$261.0

Notes:

Technically, this analysis is for the period from December 2006 through November 2007, as cost savings were estimated by season and the winter season begins in December.

As energy usage increases, the fuel cost savings associated with the transition from Day 0 to Day 2 market design would be expected to increase over time. However, holding the annual savings level constant, our results imply that the fuel cost savings over ten years associated with moving from Day 0 to a Day 1 market design would amount to approximately \$0.89 billion (see Table 3). The ten-year savings associated with moving from Day 1 to a Day 2 market design would amount to approximately \$1.72 billion.



Table 3

Ten Year Cost Savings Associated with MISO Day 1 and Day 2 Markets (In \$ Millions, based on 2007 MISO fuel and SO2 costs)

	Day 0 to Day 1	Day 1 to Day 2	Day 0 to Day 2
Total MISO	\$890	\$1,720	\$2,610

Notes:

Technically, this analysis is for the period from December 2006 through November 2007, as cost savings were estimated by season and the winter season begins in December.

Note that the above cost-savings estimates assume that no plant-level or system-level efficiency improvements would have occurred among <u>existing</u> MISO generation resources if the MISO region had remained in a pre-RTO (*i.e.*, Day 0) state. While improvements in plant-level and system-level generation efficiency would have occurred even if MISO had remained as a Day 0 or Day 1 market, it is also true that our estimates omit any cost savings arising from more effective generation investment which might be spurred by the movement to a Day 1 or Day 2 market design.

A more detailed description of our econometric analysis is provided in the Technical Appendix available at <u>www.brattle.com</u>.

IV. REDUCTIONS IN TRANSMISSION INTERRUPTIONS IN DAY 2 MARKETS

In addition to system-wide cost-related efficiencies associated with RTO formation, we also examined whether the quality of service offered by RTOs changes when a Day 2 market design is introduced. One of the most important elements of the quality of wholesale power service is reliability.

Prior to Day 2 RTO markets, transmission congestion management in the Eastern Interconnection was achieved with a heavy reliance on Transmission Loading Relief ("TLR") procedures, which allow reliability coordinators to prevent transmission security-limit violations as they attempt to maintain transmission-service reservation priorities. Within Day 2 RTO markets such as MISO, congestion management is achieved simultaneously with the security-constrained economic dispatch and re-dispatch of generation. Arguably, the more



centralized deployment of transmission associated with this market design could lead to fewer "emergency" events, such as the use of more severe forms of Transmission Loading Relief.

In Day 2 RTOs that border regions where economic re-dispatch is not possible, TLRs are still utilized to manage congestion resulting from the actions of market participants outside of the RTO. Although significant quantities of TLR events are still invoked in these markets, economic redispatch has become the primary means for managing congestion. To examine whether the implementation of Day 2 RTOs was associated with the more reliable provision of wholesale electric power, we compared the reported use of TLRs in MISO with that of SPP, which was approved by FERC as a Day 1 RTO in October 2004 and covers eight states including Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas (see Figure 2).



Source: <u>http://www.spp.org/section.asp?pageID=28</u>.

SPP's footprint includes 26 different balancing authorities, and over 47,000 miles of transmission lines. SPP has a system peak load in 2007 of approximately 43,000 MW, and contains 493 generating plants. According to its website,¹² SPP's generation mix, by output share, is 40 percent coal, 45 percent gas/oil, 4 percent nuclear, 4 percent hydro, 1 percent wind, and 6 percent other. SPP's membership consists of 12 investor-owned utilities, 9 municipal

¹² For further detail, see <u>http://www.spp.org</u>.



systems, 11 generation and transmission cooperatives, 4 state authorities, 5 independent power producers, 11 power marketers, and 2 independent transmission companies.¹³

SPP administers an Open Access Transmission Tariff and processes an average of 17,000 transmission requests per month. In February 2007, SPP initiated an exchange-based Energy Imbalance Services (EIS) market intended to rectify within-day supply and demand imbalances, so that "less expensive power is used to serve load before expensive power, as long as system reliability is met."¹⁴ Except for this exchange-based, ancillary-service-type market which is subject to locational pricing, SPP operates similarly to a Day 1 RTO, where electricity is traded through bilateral transactions and load-serving entities submit schedules for RTO approval. There is neither least-cost centralized dispatch within SPP, nor locational marginal pricing (except for the EIS market).

As indicated in Figure 3 below, TLRs have dropped steadily in MISO since the beginning of Day 2 operations in 2005, particularly during summer months when the transmission system faces greater stress. By contrast, as indicated in Figure 4, TLRs have increased markedly in SPP over the same time period. This surge has occurred despite SPP's institution of a real-time energy imbalance services (EIS) market in 2007. The increase in TLRs in SPP may be linked to increased trading activity brought on by SPP's formation as a Day 1 RTO (with a subsequent EIS market), combined with the lack of centralized security-constrained economic dispatch to deal with congestion management. These findings, while reflecting a somewhat informal approach to the examination of system reliability, nevertheless suggest that the use of centralized security-constrained dispatch and re-dispatch has reliability advantages over less-centralized electricity market designs.

¹⁴ See <u>http://www.spp.org/section.asp?pageID=23</u>.



¹³ See <u>http://www.spp.org/publications/SPP_Fast_Facts.pdf</u>.



MISO Transmission Line-Loading Relief Logs, 2005-2008



Figure 4



SPP Transmission Line-Loading Relief Logs, 2005-2008



V. SUMMARY AND CONCLUSION

We have conducted an econometric analysis of the production cost efficiencies and savings arising out of the reorganization of the MISO area into "Day 1" and then "Day 2" markets. Based on actual MISO production and cost data, we find that overall production efficiency increases by an average of 1.35% going from Day 0 to Day 1 and 2.61% from Day 1 to Day 2, or nearly 4% in total.

Assuming these savings apply to the entire MISO system, the annual reduction in fuel and SO₂ costs due to the full transition from Day 0 to Day 2 is about \$261 million per year, based on 2007 fuel cost data. These savings are significantly greater than the \$227 million "adder" that MISO charged to recover its 2007 operating costs (of which \$127 million was for market facilitation, monitoring, and compliance services and \$94 million was for scheduling, system control, and dispatch). As energy usage increases, the fuel cost savings associated with the transition from Day 0 to Day 2 market design would only be expected to grow over time. However, assuming no growth in annual fuel cost savings, we estimate that this transition in market design will lead to \$2.61 billion in cost savings over a ten-year period.

Our results are in line with what theory would predict. Economic theory would predict that key features of Day 2 markets, such as centralized power trading, transmission management, and least-cost unit commitment and dispatch, are likely to reduce system-level electricity generation costs when compared to bilateral trading and other less centralized generation system designs. Accordingly, we find that the implementation of both Day 1 and Day 2 market design features are associated with a decrease in system-level costs, where that decline results in part from the shifting of output to more-efficient generation plants from less-efficient plants. These cost savings were found among a fixed group of generating plants, the vast majority of which remained under utility ownership during our period of analysis.

As we noted earlier, our estimates combine the evolutionary cost savings one expects over time with efficiencies triggered by the introduction of Day 1 and Day 2 market designs. However, we believe that the observed savings are larger than would be expected to occur over time (particularly for a fixed group of generating plants), and that our econometric analysis captures much of the design-related cost impact.



This analysis does not represent a complete cost-benefit analysis of any particular form of wholesale or retail electric competition. Moreover, our analysis does not identify all of the benefits of Day 1 and Day 2 markets, as we have concentrated only on the efficiency gains manifested by a defined group of generating plants and have not estimated the benefits that these market designs may produce in terms of more cost-effective investment in new generation technology and capacity. Our findings suggest, nevertheless, that Day 1 and Day 2 market designs are unlocking system-level production efficiencies that were not realized in bilateral markets and are of considerable size and value. It also suggests that Day 2 markets are reducing the need for disruptive reliability procedures and are maintaining reliability at lower total cost.



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