

---

**2008 STATE OF THE MARKET REPORT  
FOR THE MIDWEST ISO**

Prepared by:



**INDEPENDENT MARKET MONITOR  
FOR THE MIDWEST ISO**

---

**Table of Contents**

<b>I.</b>	<b>Executive Summary.....</b>	<b>i</b>
<b>II.</b>	<b>Prices and Revenues .....</b>	<b>1</b>
	A. Prices.....	1
	B. Net Revenue Analysis.....	9
<b>III.</b>	<b>Load and Resources .....</b>	<b>12</b>
	A. Load Patterns .....	12
	B. Generation Capacity .....	15
	C. Generator Availability and Outages.....	17
	D. Resource Margins and Generation Adequacy.....	20
	E. Demand Response Resources .....	22
<b>IV.</b>	<b>Day-Ahead and Real-Time Market Performance .....</b>	<b>24</b>
	A. Day-Ahead Market Performance .....	24
	B. Real-Time Market Outcomes.....	43
	C. Revenue Sufficiency Guarantee Payments .....	50
	D. Dispatch of Peaking Resources.....	54
	E. Ex Ante and Ex Post Prices .....	56
	F. Wind Generation.....	59
	G. Market Outcomes Conclusions and Recommendations .....	61
<b>V.</b>	<b>Transmission Congestion and Financial Transmission Rights .....</b>	<b>65</b>
	A. Real-Time Congestion Costs .....	66
	B. Day-Ahead Congestion and FTR Obligations .....	68
	C. Value of Congestion in the Real-Time Market.....	72
	D. Market-to-Market Coordination with PJM .....	74
	E. TLR Events .....	82
	F. Congestion Manageability .....	84
	G. FTR Auction Prices and Congestion.....	90
<b>VI.</b>	<b>Competitive Assessment.....</b>	<b>99</b>
	A. Market Structure .....	99
	B. Participant Conduct.....	105
	C. Market Power Mitigation.....	115
<b>VII.</b>	<b>Demand Response Programs.....</b>	<b>120</b>
	A. DR Resources in the Midwest ISO .....	121
	B. Inter-ISO Comparison of DR Programs .....	124
	C. Improving DR Integration in Midwest ISO / Overcoming Barriers .....	125
	D. Conclusions.....	128
<b>VIII.</b>	<b>External Transactions .....</b>	<b>129</b>
	A. Import and Export Quantities.....	129
	B. Lake Erie Loop Flow .....	134
	C. Convergence of Prices Between the Midwest ISO and Adjacent Markets.....	138
	D. Intra-Hour Scheduling at PJM Interface .....	141
	E. Resource Adequacy and External Transactions.....	142

---

**List of Figures**

Figure 1: All-In Price of Wholesale Electricity .....	1
Figure 2-3: Real-Time Price-Duration Curve .....	3
Figure 4: Midwest ISO Fuel Prices.....	5
Figure 5: Implied Heat Rate of Real-Time Energy Prices .....	6
Figure 6: Implied Heat Rate Duration Curve.....	7
Figure 7: Price Setting by Unit Type .....	8
Figure 8: Net Revenue and Operating Hours.....	10
Figure 9: Load Duration Curves .....	13
Figure 10: Heating and Cooling Duration Curves .....	14
Figure 11: Generation Capacity in MW by Coordination Region .....	15
Figure 12: Distribution of Generation Capacity by Region.....	16
Figure 13: Availability of Capacity during Peak Hours.....	17
Figure 14: Capacity Unavailable during Peak Hours.....	18
Figure 15: Generator Outage Rates in 2007-2008 .....	19
Figure 16-17: Day-Ahead Hub Prices and Load.....	25
Figure 18-19: Average Daily Day-Ahead and Real-Time Price Differences .....	28
Figure 20-23: Day-Ahead and Real-Time Prices.....	30
Figure 24: Peak Hour Day-Ahead Scheduled Load versus Actual Load.....	36
Figure 25: Virtual Load and Supply in the Day-Ahead Market.....	37
Figure 26: Profitability of Day-Ahead Virtual Trading .....	38
Figure 27: Virtual Transaction Volumes .....	40
Figure 28: Virtual Supply Cleared .....	42
Figure 29: Daily Day-Ahead Forecast Error in Peak Hour.....	43
Figure 30-31: Real-Time Hub Prices and Load .....	44
Figure 32: Real-Time Prices and Headroom by Time of Day .....	46
Figure 34: Five-Minute Real-Time Price Volatility.....	48
Figure 35: Day-Ahead and Real-Time Generation .....	49
Figure 36: Total Day-Ahead RSG Payment Distribution .....	51
Figure 37: Total Real-Time RSG Payment Distribution.....	51
Figure 38: Weekly RSG Payment Distribution by Region .....	52
Figure 39: Drivers of Real-Time RSG Payments .....	53
Figure 40: Average Daily Peaker Dispatch and Prices .....	55
Figure 41: Ex Ante and Ex Post Price Differences .....	57
Figure 42: Scheduling of Wind Generation in the Real-Time and Day-Ahead Markets.....	60
Figure 43: Wind Generation versus Load .....	61
Figure 44: Total Congestion Costs.....	66
Figure 44: Real-Time Balancing Congestion Costs.....	68
Figure 45: Day-Ahead Congestion Revenue and Payments to FTR Holders .....	70
Figure 46: Payments to FTR Holders .....	71
Figure 47: Value of Real-Time Congestion by Coordination Region .....	72
Figure 48: Value of Real-Time Congestion by Type of Constraint.....	74
Figure 49: Market-to-Market Events .....	76
Figure 50: Market-to-Market Settlements.....	77
Figure 51: PJM Market-to-Market Constraints.....	79
Figure 52: Midwest ISO Market-to-Market Constraints.....	80
Figure 53: Monthly TLR Activity.....	83
Figure 54: Unmanageable Constraints.....	85

---

---

Figure 55: Value of Real-Time Congestion by Path.....	86
Figure 56: Congestion Relief Unavailable Due to Offer Parameters.....	88
Figure 57: Balancing Congestion Costs.....	90
Figure 58: FTR Purchases.....	91
Figure 59-60: FTR Profitability .....	92
Figure 61-66: Comparison of FTR Auction Prices and Congestion Value.....	94
Figure 67: Market Shares and Market Concentration by Region .....	100
Figure 68: Pivotal Supplier Frequency by Load Levels.....	101
Figure 69: Percentage of Active Constraints with a Pivotal Supplier.....	103
Figure 70: Percent of Intervals with at Least One Pivotal Supplier.....	104
Figure 71: Monthly Average Output Gap: Real-Time Market .....	109
Figure 72-75: Real-Time Market Output Gap .....	110
Figure 76-79: Real-Time Deratings and Forced Outages .....	113
Figure 80: Real-Time Mitigation by Month .....	117
Figure 81: Real-Time RSG Payment Mitigation by Month.....	118
Figure 82: Average Hourly Day-Ahead Imports .....	129
Figure 83: Average Hourly Real-Time Imports.....	130
Figure 84: Hourly Average Real-Time Imports from PJM.....	131
Figure 85: Hourly Average Real-Time Imports from Canada .....	132
Figure 86: Net Imports over the Manitoba Hydro Interface .....	133
Figure 87-88: Actual Flows Around Lake Erie .....	135
Figure 89-90: Real-Time Prices and Interface Schedules.....	139

---

### List of Tables

Table 1: Capacity, Load, and Reserve Margins for each Midwest ISO Region .....	20
Table 2: Planned Capacity Additions from Summer 2008 to Summer 2009.....	22
Table 3: Price Convergence in Midwest ISO and Other RTO Markets in 2008.....	34
Table 4: Virtual Transaction Volumes.....	41
Table 5: Comparison of DR Programs Across RTOs. ....	124
Table 6: Comparison of Participation in ISO DR Programs.....	125

### Guide to Acronyms

AMI	Advanced Metering Infrastructure
ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Market
BCA	Broad Constrained Area
C&I	Commercial & Industrial
CC	Combined Cycle
CDD	Cooling Degree Day
CSP	Curtailment Service Provider
CT	Combustion Turbine
DR	Demand Response
EDR	Emergency Demand Response
FFE	Firm Flow Entitlement
FTR	Financial Transmission Rights
GSF	Generation Shift Factors
GW	Gigawatt (1 GW = 1,000 MW)
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
IESO	Ontario Independent Electricity System Operator
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	ISO New England, Inc.
JOA	Joint Operating Agreement
LMP	Locational Marginal Price
LSE	Load-Serving Entity
MHEB	Manitoba Hydro Electricity Board
Midwest ISO	Midwest Independent Transmission System Operator
MMBtu	Million British Thermal Units, a measure of energy content
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corporation
NPPD	Nebraska Public Power District
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
O&M	Operations & Maintenance
OPPD	Omaha Public Power District
PAR	Phase Angle Regulator
PJM	PJM Interconnection, Inc.
PVMWP	Price Volatility Make Whole Payment
RDI	Residual Demand Index
RMR	Reliability Must-Run
RSG	Revenue Sufficiency Guarantee

---

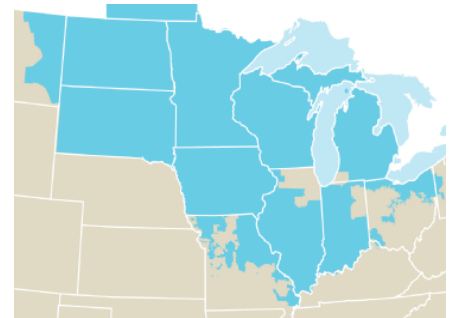
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
TLR	Transmission Loading Relief
TOU	Time-of-Use
UDS	Unit Dispatch System
WUMS	Wisconsin-Upper Michigan System

---

### I. Executive Summary

As the Independent Market Monitor (“IMM”) for the Midwest Independent Transmission System Operator (“Midwest ISO”), Potomac Economics is responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by the Midwest ISO. In this State of the Market Report, we provide our annual evaluation of the Midwest ISO’s markets and our recommendations for future improvements.

The Midwest ISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include day-ahead and real-time energy markets that produce prices that vary across the region to reflect the marginal cost of supply, transmission congestion, and losses. These markets are designed to generate benefits by facilitating an efficient daily commitment of generation, dispatching the lowest-cost resources to satisfy the system’s demands without overloading the transmission network, and providing transparent economic signals to guide short-run and long-run decisions by participants and regulators. The Midwest ISO also operates a market for Financial Transmission Rights (“FTRs”) that allows participants to hedge the congestion risk associated with serving load or engaging in other market transactions.<sup>1</sup>



The Midwest ISO markets were augmented by the introduction of contingency reserve and regulation markets (Ancillary Services Markets or “ASM”) in January 2009. These markets optimize the allocation of the Midwest ISO’s resources between the energy and ancillary services markets, and allow prices to reflect shortage conditions more efficiently when resources are insufficient to satisfy market demands. This project was a massive undertaking that required changes to virtually all of the Midwest ISO’s systems. Despite the scope and complexity of this project, the ASM markets were introduced smoothly and have operated as expected.

---

<sup>1</sup> FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market. Hence, they allow participants to hedge congestion costs on the network.



The Midwest ISO also clarified the capacity provisions under Module E of its Tariff, which should ensure that long-run economic signals support adequate supply and demand resources.

### **A. Summary of Findings**

Overall, we found that the market performed competitively in 2008. Our analysis raised no competitive concerns that suppliers withheld resources to raise prices. Nonetheless, prices in the day-ahead and real-time energy markets in 2008 rose by five and four percent, respectively.

However, these increases were modest given the sharp fuel price increases during 2008.

Average natural gas and oil prices increased by 28 and 34 percent, respectively. Similarly, coal prices rose by 30 to 110 percent depending on the type of coal. Since fuel is the dominant input cost for producing electricity, one would normally expect electricity prices to track fuel price increases more closely. After accounting for fuel price changes, we find that “fuel-price-adjusted” energy prices decreased substantially in 2008, particularly in the fourth quarter. This occurred because higher fuel prices were offset by several factors that lower energy prices.

First, average load decreased by 2.2 percent due to mild weather and deteriorating economic conditions. Therefore, conditions were generally not tight in the energy market and real-time shortages (which produce sharp transitory price increases) were infrequent. Second, lower outage rates increased the amount of generation that was available to serve load. Lastly, the Midwest ISO experienced a sharp increase in intermittent generation from wind resources that led to surplus generation in real-time and low energy prices.

These supply and demand trends in 2008, together with transmission upgrades and operating improvements, also contributed to lower levels of transmission congestion and Revenue Sufficiency Guarantee (“RSG”) costs. This is notable because rising fuel prices would normally increase these types of costs. Increased supply availability and reduced load also limit the need for the Midwest ISO to invoke its emergency operating procedures. In 2008, the Midwest ISO did not call for any load interruptions. Nonetheless, the Midwest ISO is working to develop changes to its market design and operating procedures to integrate more fully both dispatchable and non-dispatchable Demand Response (“DR”) resources into its markets.

An additional two gigawatts (“GW”) of new wind generating capacity is expected in 2009. Although wind provides substantial environmental benefits, its intermittent nature limits its contribution to reliability and resource adequacy and creates significant operational challenges that the Midwest ISO is working to address.

The additional wind capacity and limited amounts of other new generation, together with the forecasted reduction in annual peak load, have contributed to a market-wide planning reserve margins ranging from 15 percent to 23 percent (depending on whether interruptible load is included). This is a significant increase over the planning reserve levels that have prevailed over the past two years and suggests that the system will not require significant new entry in the short-run to maintain adequate resources. This is fortunate because the economic signals in 2008 would not have supported investment in new natural gas-fired generation. Regardless, the implementation of ASM (which include efficient shortage pricing provisions) and the revisions to the capacity rules in Module E should improve the long-run economic signals that govern new investment.

The Midwest ISO relies heavily on imports from adjacent areas, averaging 4.4 GW in peak hours in 2008 and 2.1 GW in off-peak hours. Given the importance of external transactions and the extensive network interactions in the Midwest, our report evaluates the interchange and coordination with neighboring areas. Based on these analyses, we find:

- The prices at the border between the markets are well arbitrated in most hours, but could be improved by optimizing the net interchange with PJM Interconnection (“PJM”). The Midwest ISO has developed a conceptual approach for implementing this change.
- Two patterns of schedules around Lake Erie emerged in 2008 that raise efficiency concerns because the scheduled path (i.e., the “contract path”) that is the basis for the settlements is not consistent with the actual power flows (these deviations are known as “loop flows”). To address these issues, we recommend that the Regional Transmission Organizations (“RTOs”) around Lake Erie work together to modify their scheduling and settlement rules.
- Our report also evaluates the market-to-market coordination between the Midwest ISO and PJM that has been generally effective in managing constraints affected by both RTOs. On the basis of our analysis, we recommend specific improvements to the market-to-market process. Additionally, the Midwest ISO identified an issue that may have caused PJM to understate its market flows and the associated settlements.

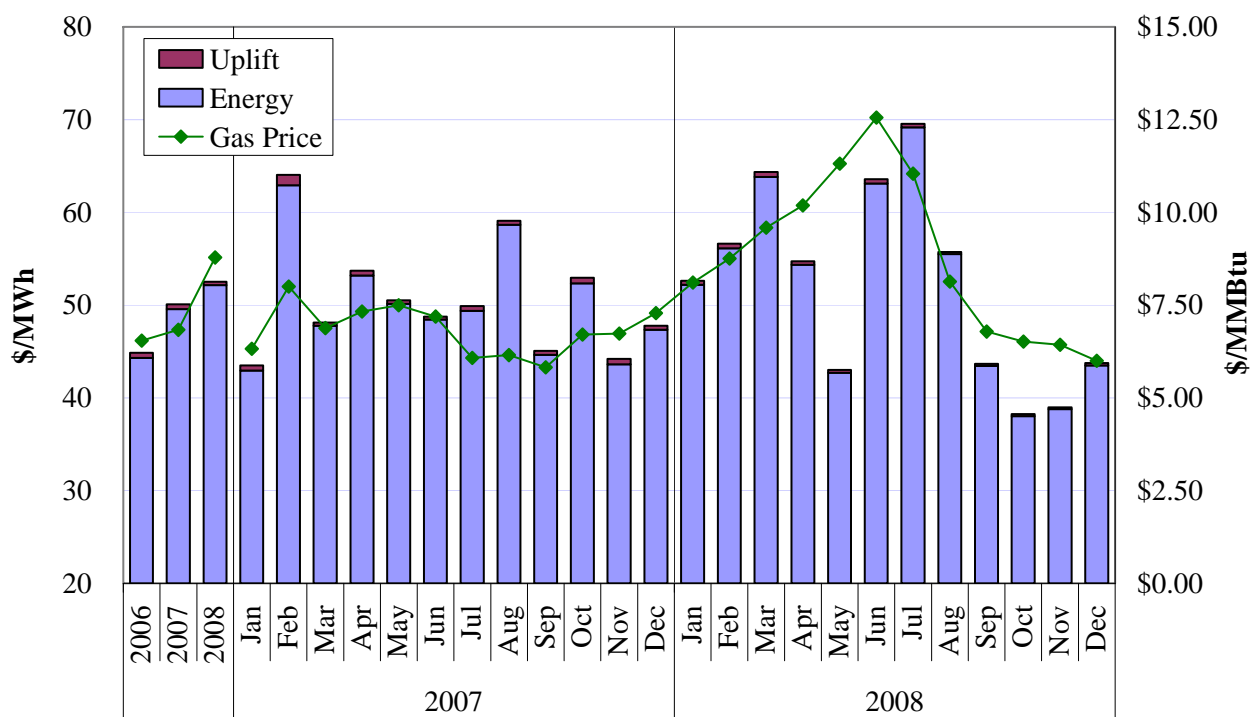
In addition to the recommendations addressing external transactions and market-to-market coordination, this report identifies a number of other recommended changes in the areas of energy pricing, congestion management, operating procedures, demand response development, and wind integration that should improve the performance of the market. Work is underway by the Midwest ISO to address many of these issues.

In the remainder of this executive summary, we provide a more detailed discussion of the market outcomes and issues in 2008, along with a description of each of our recommendations to improve the performance of the Midwest ISO markets.

### 1. Short-term Prices and Long-Term Economic Signals

We summarize changes in prices and costs in Figure E-1, which shows an “all-in” price of electricity. This represents the total costs of serving load. The all-in price of electricity is equal to the load-weighted average real-time energy price plus average real-time RSG per megawatt (“MW”) of real-time load.

**Figure E-1: All-In Price of Electricity**



The all-in price was approximately \$52.50 per megawatt-hour (“MWh”) in 2008, a 3.5 percent increase over 2007. The figure shows that price fluctuations are generally driven by changes in fuel prices as one would expect in a well-functioning market. This relationship exists because fuel costs represent the majority of most suppliers’ variable production costs (i.e., marginal costs) so changes in fuel prices directly translate into changes in offer prices. However, prices increased much less than the fuel prices increases that occurred in 2008 because the higher fuel prices were offset by other factors that tended to lower electricity prices, including lower average load levels.

The figure also shows that in April and May 2008, low load levels and planned generator outages resulted in low real-time energy prices. Uplift costs continue to be a small share of the all-in price (less than one percent).

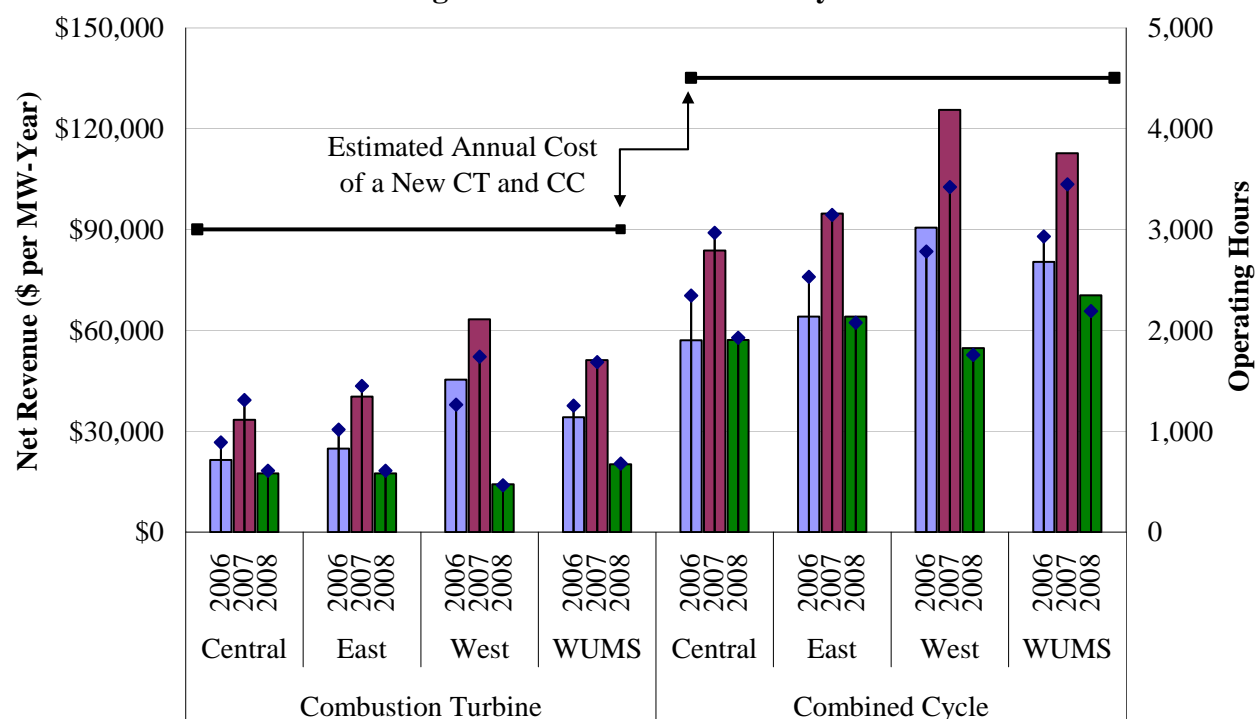
One of the most important assessments of the Midwest ISO markets is our evaluation of wholesale prices as signals for investment in new resources and transmission capability. We evaluate wholesale price signals by estimating the “net revenue” that a new generating unit would have earned from the market under prevailing prices.<sup>2</sup> Net revenue is the revenue that a new generator would earn above its variable production costs if it runs when it is economic and does not run when it is not economic. A well-designed market should produce net revenues sufficient to finance new investment when the available resources are not sufficient to meet the needs of the system.

Figure E-2 shows estimated net revenues for a hypothetical new combustion turbine (“CT”) and combined cycle (“CC”) generator for the years 2006 through 2008. The figure also shows the estimated annual cost of each unit type, which is the minimum net revenue that would be needed to make these investments profitable.

---

2 Net revenue results are discussed in Subsection II.B.

Figure E-2: Net Revenue Analysis



The net revenue analysis indicates that net revenues for a new CC unit and CT unit were substantially less than the annual entry cost for both types of units in 2008. These results are consistent with expectations because the Midwest ISO currently has a capacity surplus that, together with the mild load, resulted in rare instances of shortage in 2008. Furthermore, when shortage conditions did occur in 2008, market prices did not fully reflect prevailing conditions because operating reserve shortages and emergency actions did not contribute to setting prices. Finally, because the capacity requirements and enforcement provision in Module E of the Tariff had not yet been clarified, our net revenue estimates did not include capacity revenues.

The AS markets introduced in January 2009 have improved shortage pricing because they integrate operating reserve demand curves that reflect the economic value of forgone reserves. The Midwest ISO is working on other pricing changes to allow interruptible load, other types of demand response resources, and other emergency actions to set prices. These changes will produce efficient shortage prices that will cause net revenue to rise when new capacity is needed.

The Midwest ISO also introduced changes to Module E of its Tariff that are intended to clarify capacity requirements and establish clear, effective enforcement of capacity requirements. These changes also introduce a voluntary, monthly capacity auction that allows deficient Load-Serving Entities (“LSEs”) to purchase capacity to satisfy their obligations. These changes should improve the long-term market signals needed to maintain adequate resources.

## **B. Day-Ahead and Real-Time Market Performance**

### **1. Day-Ahead Market**

The performance of the day-ahead market is important for three reasons:

- The day-ahead market determines most of the generator commitments in the Midwest ISO; hence, efficient commitment requires efficient day-ahead market outcomes;
- Most wholesale energy bought or sold through the Midwest ISO markets is settled in the day-ahead market; and
- The entitlements of firm transmission rights are determined by the outcomes of the day-ahead market (the payment to an FTR holder is based on day-ahead congestion).

The Midwest ISO markets have substantially improved the commitment and dispatch of generating resources in the Midwest. The improved commitment is largely due to the day-ahead market, which provides a market-based process to commit generating resources and supply load.

Good convergence between day-ahead and real-time prices facilitates efficient commitment decisions. Based on our analysis in this report, we find price convergence in the Midwest ISO has been similar to convergence in other RTO markets, which generally exhibit modest day-ahead premiums as well.<sup>3</sup> These day-ahead premiums can be attributed to the higher volatility, risk, and RSG cost associated with buying in the real-time market. The day-ahead premiums are generally larger in the Midwest ISO than in other RTOs due to higher RSG allocations to real-time purchases.

---

3 See Subsection IV.A.

By arbitraging price differences, active virtual supply and demand participation in the day-ahead market also contributed to good price convergence in the Midwest ISO. However, virtual trading levels decreased substantially late in the year and into 2009. These reductions are attributable to RSG allocation decisions made by the Federal Energy Regulatory Commission (the “Commission”) in November 2009 and to poor financial market conditions. Price convergence during this period deteriorated, but it has shown signs of improvement since the spring of 2009.

## **2. Real-Time Market**

Prices in the real-time market were substantially more volatile than prices in the day-ahead market. Real-time price volatility in the Midwest ISO was nearly double that of other RTOs in 2008.<sup>4</sup> Unlike some of the other RTOs, the Midwest ISO runs a true five-minute real-time market that produces a new dispatch and prices every five minutes. Since the real-time market software is limited in its ability to look ahead, the system is frequently “ramp constrained” (i.e., generators are moving as quickly as they can up or down). This results in transitory spikes in prices up or down. Ramp constraints can also bind and cause price volatility when large changes in the Net Scheduled Interchange (“NSI”) occur or when several generators are either started or shutdown. Volatility has decreased under ASM because the real-time market now has the flexibility to jointly optimize resources to satisfy the energy and ancillary service needs of the system. This report also includes recommendations to improve management of ramp capability.

## **3. RSG Payments**

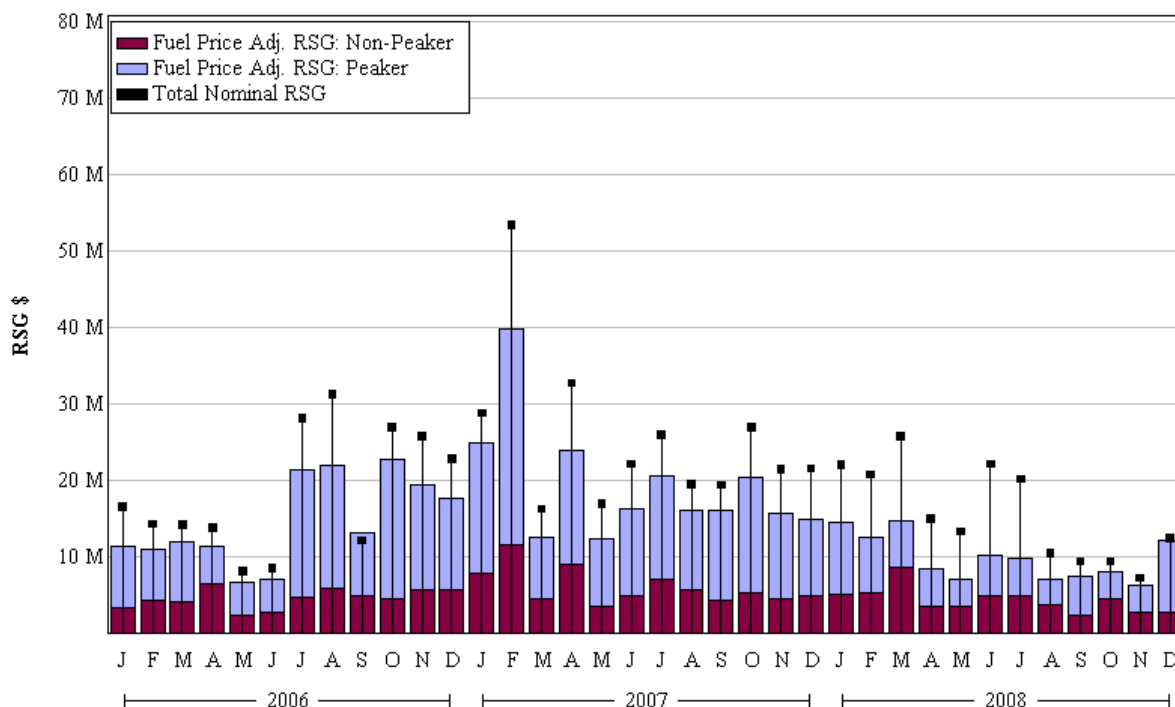
RSG payments ensure that the total market revenue a generator receives when its offer is accepted at least equals its as-offered costs. Resources committed by the Midwest ISO after the day-ahead market receive “real-time” RSG payments when their costs are not covered by Locational Marginal Price (“LMP”) payments in the real-time market. Because the day-ahead market is a financial market, it generates minimal RSG costs. Figure E-3 shows RSG payments generated in the real-time market. Due to the significant influence of fuel prices, the figure

---

4 See Subsection IV.B.

shows RSG in both nominal terms and adjusted for fuel price changes. It also separately shows the fuel price-adjusted RSG payments to peaking units and non-peaking units.<sup>5</sup>

**Figure E-3: Real-Time RSG Payments**



Most RSG costs (over 92 percent) are generated in the real-time market and are paid to peaking resources. Even though they produced less than one percent of the energy generated in the Midwest ISO, peaking resources received 59 percent of RSG payments in 2008. This is not surprising because peaking resources are generally the highest-cost resources and must be relied upon in real time to meet the reliability needs of the system.

This figure shows that real-time RSG costs declined from 2007 levels, decreasing from \$331 million to \$216 million. This real-time market decrease contributed to an overall reduction in total RSG costs by 35 percent in 2008. The real-time RSG reduction was primarily due to reduced dispatch of peaking resources resulting from higher levels of net load scheduling in the

<sup>5</sup> Analyses of RSG are detailed in Subsection IV.C.



day-ahead market (which causes the day-ahead commitments to more fully satisfy the load) and from lower load levels. A decrease in the need for commitments in the West to manage congestion into the Minnesota Narrow Constrained Area (“NCA”) also contributed to the reduction in RSG in 2008.

#### **4. Dispatch of Peaking Resources**

The dispatch of peaking resources is an important component of the real-time market because they are a primary source of RSG costs and a critical determinant of efficient price signals.<sup>6</sup> The dispatch of peaking resources decreased substantially in 2008. On average, 270 MW of peaking resources were dispatched per hour in 2008, down from 433 per hour in 2007. As described above, this reduction is primarily due to higher levels of load scheduling in the day-ahead market, fewer congestion-related commitments, and lower peak load levels.

Our analysis also shows that a large share of the peaking resources were dispatched out-of-merit. A resource is out-of-merit when its offer price is greater than the LMP. A peaking resource that is dispatched out-of-merit does not indicate it was dispatched inappropriately. When a peaking resource is committed for reliability, if the LMP is set by a lower-cost resource, the peaking resource will be out-of-merit. A large share of peaking resources being out-of-merit indicates that they frequently do not set the energy price and results in higher RSG costs to ensure the peaking resources recover their as-offered costs. Out-of-merit dispatch of peaking resources also contributes to the under-scheduling of load in the day-ahead market. Peaking resources are generally the only resources that can be committed in real time to serve the load not scheduled day-ahead. Hence, if real-time prices are not set by the peaking resources, real-time prices will be lower and create a disincentive to purchase day-ahead. The Midwest ISO is actively working on a pricing method to address this issue that will allow inflexible units and demand to set prices.

---

<sup>6</sup> The dispatch of peaking resources is analyzed in Subsection IV.D.

## **5. Generating Capacity and Reserve Margins**

Total generating resources in the Midwest ISO market exceeded 131 GW in 2008.<sup>7</sup> This is measured in nameplate capacity and does not include typical deratings (i.e., reductions in generators' capability). These deratings tend to be particularly large during periods of hot weather. When we fully account for deratings and outages, we project a reserve margin for Midwest ISO of 15 to 23 percent for 2009.<sup>8</sup> The high end of this range is based on the unrealistic assumption that all interruptible load will respond when called upon. Assuming no response from interruptible load (which is also unrealistic), the reserve margin is estimated to be at the lower end of the range, near 15 percent. These margins have increased over the last three years as forecasted peak loads have fallen and new resources have entered.

Despite the surplus of capacity that currently exists, more than 3500 MW of new capacity is scheduled to enter in 2009, of which almost 2000 MW is wind-powered. Only 235 MW of generation is scheduled to retire. Relative to other technologies, the intermittent nature of wind power causes it to provide less reliable capacity to the system than indicated by its nameplate capacity. Therefore, it has a larger effect on overall energy production than on planning reserve margins. The western areas in the Midwest ISO have substantial natural wind resources. The rapid development of wind resources provides substantial environmental benefits, although it also creates significant operational challenges that the Midwest ISO is working to address.

## **6. Transmission Congestion**

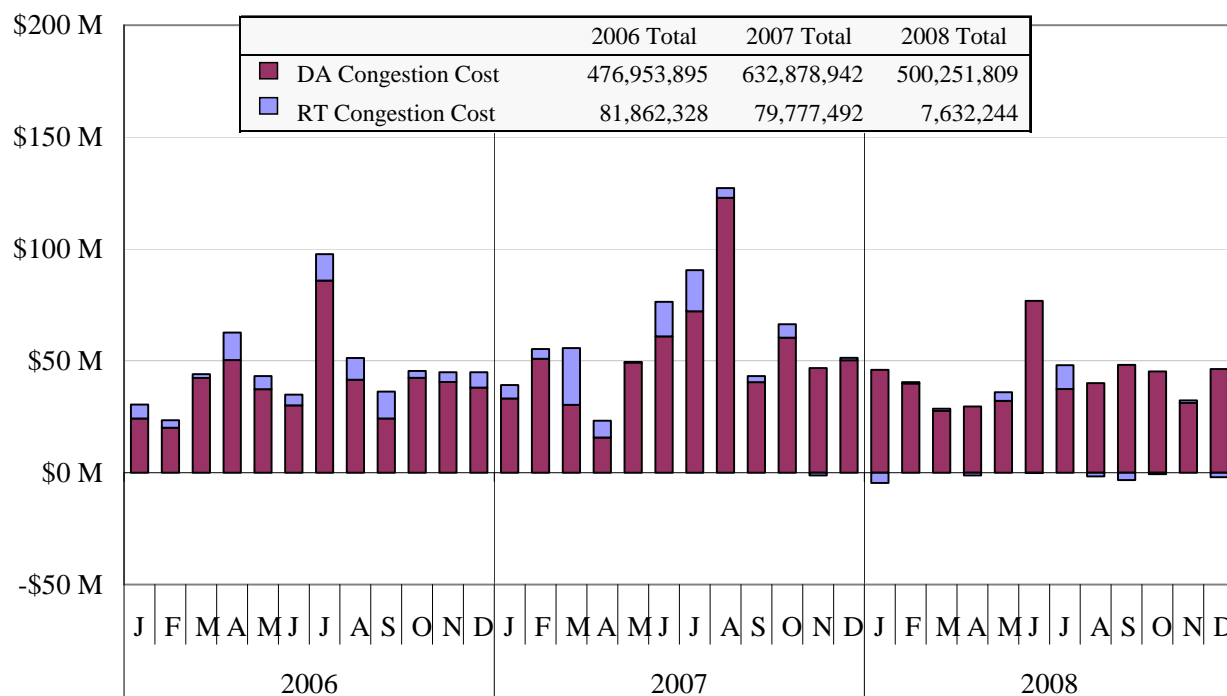
One of the most significant benefits of the Midwest ISO energy markets is that they provide accurate and transparent locational price signals that reflect congestion on the network. Additionally, Figure E-4 below shows the total congestion costs in the day-ahead and real-time markets.<sup>9</sup>

---

<sup>7</sup> Analysis and discussion of the Midwest ISO's generating capacity is contained in Subsection III.B.

<sup>8</sup> See Subsection III.C.

<sup>9</sup> Congestion costs are evaluated in Subsection V.B.

**Figure E-4: Day-Ahead and Real-Time Congestion Costs**

Additionally, Figure E-4 shows that total congestion costs shown in this figure were \$500 million in 2008, a decrease of more than 20 percent from 2007. The decrease was the primarily the result of lower load, higher net imports into the West from Manitoba, and transmission upgrades that reduced congestion into WUMS.

Additionally, over 98 percent of total congestion was captured in the day-ahead market in 2008. This is a significant improvement from 2006 and 2007. Residual real-time congestion costs generally arise when the day-ahead modeling of the network is not consistent with the real-time system. Hence, the reduction in residual real-time congestion indicates that the Midwest ISO's day-ahead modeling has improved.

One of the significant issues in the area of congestion management is the frequency with which the real-time market model was unable to reduce the flow below the transmission limit.<sup>10</sup> Indeed, more than 28 percent of binding transmission constraints could not be managed on a

<sup>10</sup> These instances are evaluated in Subsection V.E.

five-minute basis (real-time redispatch could not reduce flow below the limit). The presence of an unmanageable constraint does not mean the system is unreliable (reliability standards require the flow to be less than the limit within 30 minutes). When a constraint is unmanageable, an algorithm is used to “relax” the constraint’s limit for the purpose of calculating LMPs. Our analysis of the market outcomes suggests that this relaxation algorithm produces some inefficient results and is the subject of one of our recommendations.

The primary causes of unmanageable congestion are generator inflexibility (offer parameters that provide little redispatch capability) and a modeling parameter that causes the market software not to redispatch resources that have small effects on the transmission constraints. Our report includes a recommendation to address the latter issue.

Our report also evaluates the market-to-market coordination used by the Midwest ISO and PJM to manage transmission constraints that are affected by both markets.<sup>11</sup> This process has been important in allowing constraints that affect both markets to be managed efficiently. The Midwest ISO and PJM have made process improvements over the past two years to continually improve the performance of the market-to-market coordination. However, our analysis shows that the process can be further improved and we recommend specific improvements. Additionally, the Midwest ISO identified an issue with PJM’s market flow calculations that may have understated PJM’s market flows and affected past settlements.

## **7. Financial Transmission Rights**

FTRs are important in an LMP-based energy market because they provide a hedge for congestion. We analyze performance of the FTR market by evaluating how FTR prices reflect the value of their entitlements (i.e., the value of day-ahead congestion associated with the FTRs).<sup>12</sup> Our evaluation shows that FTR pricing has improved substantially since 2005, which indicates that market liquidity has improved and participants have gained experience with the LMP market.

---

<sup>11</sup> The market-to-market process is evaluated in Subsection VII.B.

<sup>12</sup> See Subsection V.F.

Day-ahead congestion in 2008 was 14 percent less than the obligations due to FTR holders. This compares to a 19 percent shortfall in 2007. Three main factors contributed to the shortfall in 2008: (1) continued difficulties in accurately forecasting loop flow on the Midwest ISO network in the FTR modeling; (2) significant unplanned unit and line outages that reduced transfer capability assumed in the FTR auctions; and (3) storm-related damage to the transmission system in June 2008 that led to the most significant instances of FTR funding shortfalls. To address the under-funding of FTRs, the Midwest ISO has introduced more conservative assumptions regarding loop flow and transmission limits used in the FTR auctions. However, these 2008 results indicate that significant improvements are still possible.

## **8. External Transactions**

The Midwest ISO relies heavily on imports from adjacent areas. On average, the Midwest ISO imported almost 4.4 GW in peak hours and over 2.1 GW in off-peak hours.<sup>13</sup> Although power can flow in either direction depending on prevailing prices, the Midwest ISO generally imports power from PJM and Manitoba and exports power to IESO. The net import levels can fluctuate substantially. On many days, for example, the average net imports decreased by more than 1,000 MW per hour between the day-ahead and real-time markets. These NSI changes introduce reliability issues that the Midwest ISO must manage and contribute to increased price volatility. Large changes in real-time net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources. We recommend changes in the scheduling and settlement rules to reduce inefficient variability in net imports.

Our analysis indicates that prices between Midwest ISO and PJM are well arbitrated in most hours. The current rules rely on participants increasing or decreasing their net imports to cause prices to converge. Given the uncertainties regarding relative prices when transactions are scheduled (30 minutes in advance), many hours exhibit large price differences between the Midwest ISO and PJM. To achieve better price convergence with PJM, we continue to recommend that the RTOs expand their Joint Operating Agreement (“JOA”) to optimize net

---

13 External transactions are evaluated in Subsection VII.A.

interchange between the two areas. This change would achieve the majority of any potential savings associated with jointly dispatching generation in the two regions. The Midwest ISO has developed a conceptual approach for implementing this change.

In 2008, a number of issues arose related to “contract path” transaction scheduling around Lake Erie. The underlying problem in each of the cases was that settlements occurred based on the scheduled path (i.e., the “contract path”), but the actual power flows occurred on other paths (these flows are generally referred to as “loop flows”). This inconsistency distorts participants’ incentives and can lead to inefficient scheduling. Our report evaluates the two scheduling patterns that become prevalent in 2008. To address these issues, we recommend that the RTOs around Lake Erie work together to modify their scheduling and settlement rules.

Finally, given the importance of imports in meeting the Midwest ISO’s energy needs, our report also includes a recommendation to ensure that external resources are not unreasonably restricted in satisfying the Midwest ISO’s capacity needs under Module E of its Tariff.

## **9. Competitive Assessment and Market Power Mitigation**

Section VI of our report is a competitive assessment of the Midwest ISO markets that includes a review of potential market power indicators, an evaluation of participants’ conduct, and a summary of the imposition of mitigation measures in 2008.<sup>14</sup> Our analysis shows that market concentration is low for the overall Midwest ISO region and moderate-to-high in the various subregions.<sup>15</sup> However, a more reliable indicator of potential market power is whether a supplier is “pivotal”. A supplier is pivotal when its resources are necessary to satisfy load or manage a constraint.

We focus particular attention on the two types of constrained areas that are defined for purposes of market power mitigation: Narrow Constrained Areas and Broad Constrained Areas (“BCA”). NCAs are chronically constrained areas that raise more severe potential local market power

---

<sup>14</sup> See Section VI.

<sup>15</sup> See Subsection VI.A.

concerns (so tighter market power mitigation measures are employed), while BCAs include all other areas within the Midwest ISO that are isolated by a transmission constraint.

Fifty-nine percent of the active Broad Constrained Area (“BCA”) constraints have a pivotal supplier. BCA constraints are all constraints other than the NCA constraints defined in WUMS and SE Minnesota. Seventy-nine percent of the active NCA constraints into WUMS have a pivotal supplier, as do 69 percent of the active NCA constraints into Minnesota. Based on these and other results, we find substantial local market power in constrained areas. However, evaluation of participants’ conduct provides little evidence of attempts to withhold resources (either physically or economically) to exercise market power.<sup>16</sup>

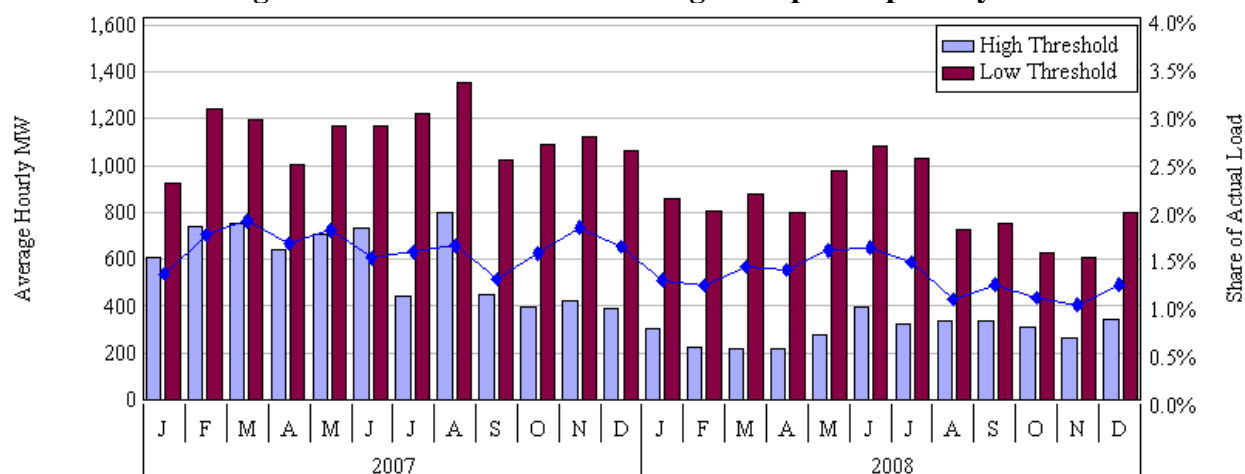
Figure E-5 shows our “output gap” metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using a higher threshold (the mitigation threshold) and a lower threshold (one-half of the mitigation threshold).

Overall, the output gap levels generally declined from 2007 to 2008. On a monthly-average basis, the output gap ranges from 1 to 1.5 percent of actual load. These results and others in our report provide little indication of significant economic or physical withholding in 2008. Nonetheless, we monitor these levels on an hourly basis and regularly investigate instances of potential withholding.

---

16 See Section VI.B.

Figure E-5: Economic Withholding – Output Gap Analysis



High Thresh	Low Thresh	Commit	36	150	44	112	217	61	127	102	79	141	36	5	35	35	47	91	89	112	130	102	84	146	126	222
		On-Line	886	1,092	1,154	892	951	1,111	1,094	1,254	944	947	1,084	1,060	825	771	828	708	888	971	897	625	671	484	479	579
	High Thresh	Commit	13	60	20	56	127	36	42	35	34	56	9	21	17	10	25	16	31	26	73	79	65	124	83	110
		On-Line	597	682	733	586	580	697	401	767	416	341	411	366	289	213	194	203	244	373	250	257	273	189	181	235

In addition to these screens for potential withholding, we calculate a “price-cost mark-up” that compares the system marginal price based on actual offers to a simulated system marginal price based on the assumption that all suppliers submitted offers at their estimated marginal costs. Based on this metric we found an average “mark-up” of the system marginal price of roughly one percent, indicating that the market outcomes in 2008 were highly competitive.

Finally, market power mitigation in the Midwest ISO’s energy market continues to occur pursuant to automated conduct and impact tests that utilize clearly specified criteria.<sup>17</sup> Because conduct has generally been competitive, market power mitigation has been imposed infrequently.

## 10. Demand Response

Demand participation in the market is beneficial in many ways. It improves reliability in the short-term, contributes to resource adequacy in the long-term, reduces price volatility and other

<sup>17</sup> Market power mitigation measures are reviewed in Subsection VI.C.



market costs, and mitigates supplier market power. Accordingly, the development of demand response in the Midwest ISO should be a high priority. When all forms of demand response (both passive and active) are included, the Midwest ISO has more than 8,000 MW, an amount greater than a third of the total demand response capability in all U.S. RTOs. Most of this is interruptible load which was developed under regulated utility programs and is only curtailable for reliability purposes. This interruptible load is not price-responsive. Only modest amounts of this demand response capability participates in the Midwest ISO's markets:

- 48 MW of dispatchable demand response resources directly participate in the Midwest ISO's energy and ancillary services markets;
- 1603 MW of non-dispatchable demand response resources sell supplemental reserves and emergency energy to the Midwest ISO; and
- Other emergency demand response capability is used to satisfy an LSE's capacity requirements under Module E.

Integrating this capability into the market is challenging and work has been underway by the Midwest ISO to develop plans to utilize it efficiently. This work has included:

- Establishing a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements;
- Filing Tariff changes to allow retail aggregators to participate in the Midwest ISO markets; and
- Considering Tariff modifications that would be necessary to allow load interruptions and other emergency actions to set prices in energy and reserve markets.

We recommend the Midwest ISO also consider changes to allow non-dispatchable demand response resources to participate in a real-time economic demand response program.

## **11. Recent Market Improvements**

The Midwest ISO has implemented two major changes that have substantially improved the performance of its markets and the economic signals the markets provide. The first change was the introduction of ASM in January 2009, which has led to improved system flexibility and reduced price volatility. The ASM have been designed to produce more efficient prices that reflect the economic trade-offs between operating reserves and energy, particularly during

shortage conditions when resources are insufficient to satisfy market demands. The ASM implementation was smooth and the markets have operated as expected in 2009.

The second major change was the clarification of capacity requirements in Module E of the Tariff and the development of enforcement provisions. With these changes, Module E will support a decentralized contract market to help satisfy the Midwest ISO's capacity requirements. This will improve the market signals that govern investment and retirement decisions.

## **12. Summary of Recommendations**

Although the markets have performed well and will perform better with the implementation of ASM, we recommend the Midwest ISO:

**1. *Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set energy prices.***

This change would improve the efficiency of real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs. To set prices correctly, the market must distinguish between gas turbines that are needed versus those that would be shut-down if they were flexible and dispatched optimally. The Midwest ISO has developed promising research in this area and should be in a position to test the practical feasibility of its approach later in 2009.

**2. *Develop provisions that allow non-dispatchable demand response (or interruptible load) to set energy prices in the real-time market when they are called upon in a shortage.***

Like the first recommendation, this recommendation also would improve price signals in the highest-demand hours, which are important for ensuring that the markets send efficient economic signals to maintain adequate supply resources and to develop additional demand response capability. We believe it is possible to address this recommendation in conjunction with the prior recommendation associated with the role of gas turbines in setting energy prices.

3. ***Develop improved “look-ahead” capabilities in the real-time that would improve the commitment of quick-starting gas turbines and the management of ramp capability on slow-ramping units.***
  - In the short-run, this involves improving the tool that determines the recommended “offset” parameter used to make incremental adjustments to load modeled in the real-time market.
  - In the long-run, this recommendation involves developing a model to assist in the economic commitment of peaking resources, which should reduce out-of-merit quantities and RSG payments.
4. ***Discontinue the constraint-relaxation procedure and use the constraint penalty factor to set LMPs when a transmission constraint is unmanageable.***

This change will allow prices to reflect more efficiently the binding constraint, particularly in cases when the constraint-relaxation procedure causes the market software to calculate outcomes as though congestion is not present. This is particularly important for low-voltage and market-to-market constraints.

5. ***Allow generating resources with lower effects on a constraint to be redispatched (i.e., setting Generation Shift Factors (“GSFs”) lower than the current cutoff).***

In addition to increasing the manageability of transmission constraints, this will tend to reduce price volatility by providing the market with more redispatch options.

6. ***Improve the market-to-market process with PJM by implementing the following three changes:***
  - Instituting a process to more closely monitor the information being exchanged with PJM in order to quickly identify cases where the process is not operating correctly;
  - Optimizing the real-time net interchange between the two RTO areas; and
  - Developing a process to coordinate external transactions with non-Midwest ISO/PJM areas within the JOA.
7. ***Develop a joint agreement with the Ontario Independent Electricity System Operator (“IESO”), New York Independent System Operator (“NYISO”), and PJM to modify scheduling and settlement provisions to better align settlements with physical flows around Lake Erie.***

Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.

**8. *Improve the scheduling of intra-hour imports and exports by:***

- Evaluating its scheduling limits to determine whether they are generally consistent with the available capability to ramp internal generation up or down in support of transactions; and
- Modifying scheduling deadlines to ensure that prior to scheduling a transaction no participant will observe prices that will be included in that transaction's hourly settlement.

**9. *Continue its work to improve the integration of demand response in the energy and ancillary services markets.***

This will improve the incentives and opportunities for the development of new demand response resources and allow the Midwest ISO to send more efficient long-term economic signals.

**10. *Improve the integration of wind resources into the Midwest ISO system by:***

- Allowing wind resources to be curtailable at a specified offer price and allowing that offer price to be eligible to set energy market LMPs; and
- Developing allocation rules for RSG and other costs (e.g., reserves and regulation) that assign the costs to intermittent resources to the extent these resources cause such costs.

**11. *Modify deliverability requirements for external resources to establish a maximum amount that can be utilized to satisfy LSEs' capacity requirements under Module E.***

Because exports and imports from adjacent markets are supported by their real-time dispatch processes, facility-specific deliverability studies should not be needed. Given the Midwest ISO's heavy reliance on net imports in real time, it is important for this source of supply to be available to the Midwest ISO capacity market

## II. Prices and Revenues

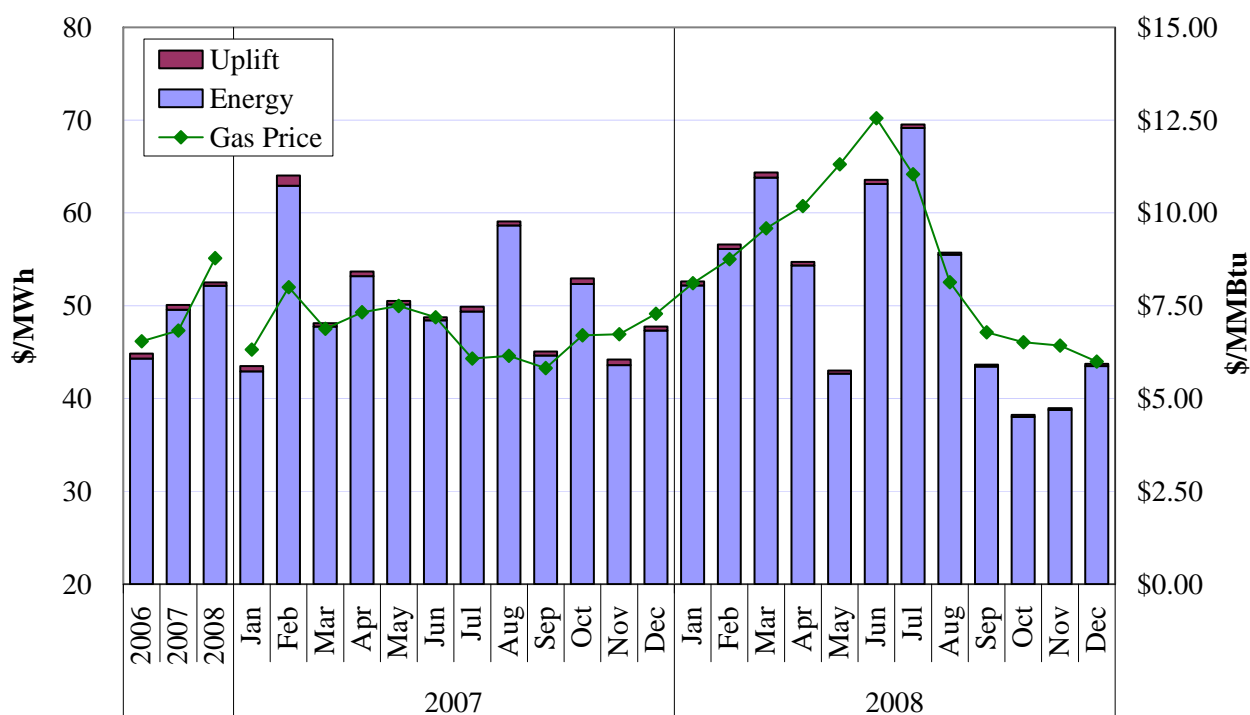
The Midwest ISO has operated competitive wholesale electricity markets since 2005. The Midwest ISO operates markets for day-ahead and real-time energy and markets for FTRs. The ASM markets were successfully launched on January 6, 2009 and are performing well based on our preliminary assessments. In this section, we evaluate prices and revenues associated with the day-ahead and real-time energy markets.

### A. Prices

Our first analysis is an overview of electricity and fuel prices for the Midwest ISO markets.

Figure 1 shows the “all-in” price of wholesale electricity and the price of natural gas. The all-in price includes both energy prices and “uplift” cost (the average RSG costs per MWh). The all-in price of electricity is equal to the load-weighted average real-time price plus average real-time RSG cost per MW of real-time load. The all-in price does not include ancillary services or capacity costs because the Midwest ISO did not have those markets in place in 2008.

**Figure 1: All-In Price of Wholesale Electricity**  
2007-2008

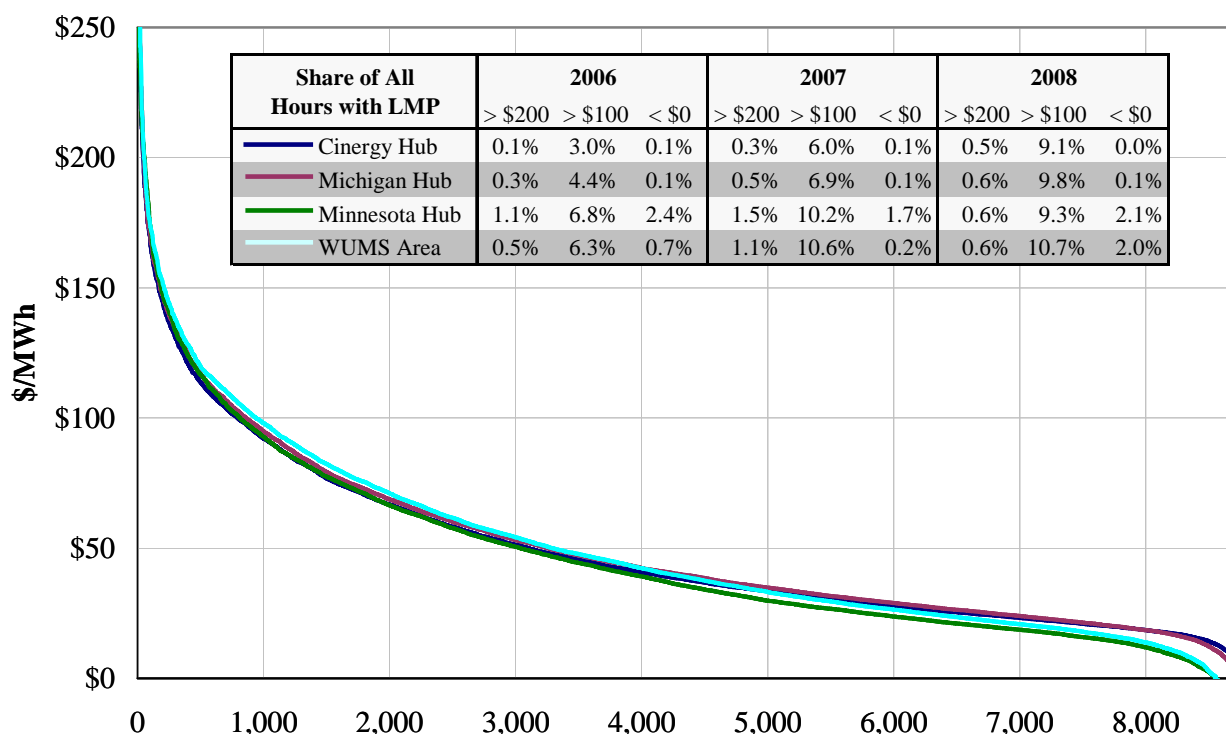


The all-in price was approximately \$52.50 per MWh in 2008, a 3.5 percent increase over 2007. The figure shows that price fluctuations are generally driven by changes in fuel prices as one would expect in a well-functioning market. This relationship exists because fuel costs represent the majority of most suppliers' variable production costs (i.e., marginal costs) so changes in fuel prices directly translate into changes in offer prices. However, prices increased much less than the fuel prices increases that occurred in 2008 because the higher fuel prices were offset by other factors that tended to lower electricity prices, including lower average load levels. The figure also shows that in April and May 2008, low load levels and planned generator outages resulted in low real-time energy prices. In June, storm damage to the transmission network caused congestion-related prices to increase from lower levels in May. Uplift costs continue to be a small share of the all-in price—less than one percent of the average all-in price.

The figure shows that prices were correlated positively with natural gas prices, except in the April to June period when low load levels and high generation availability resulted in fewer hours with natural gas units on the margin. We expect this correlation because fuel costs represent the majority of most suppliers' variable production costs (i.e., marginal costs) and natural gas units are often on the margin. In a competitive market, generation owners have incentives to offer energy at marginal cost. Hence, generators' energy-offer prices should rise as fuel costs rise. Although only about 28 percent of the capacity in the Midwest ISO region is fueled by natural gas, these units are on the margin in a large share of the peak load hours. Therefore, the correlation of fuel prices and electricity prices is an indication that the markets are performing efficiently.

Our next analysis shows the range of hourly prices in the real-time market in the form of a price-duration curve. A price-duration curve shows the number of hours (horizontal axis) when the LMP is greater than or equal to a particular price level (vertical axis). For example, the curve for the Minnesota Hub crosses \$50 per MWh on the vertical axis at approximately the 3000-hour level. Therefore, in approximately 3000 hours during 2008, the Minnesota Hub price exceeded \$50 per MWh. Figure 2 shows the real-time price-duration curves for four representative Midwest ISO Hubs.

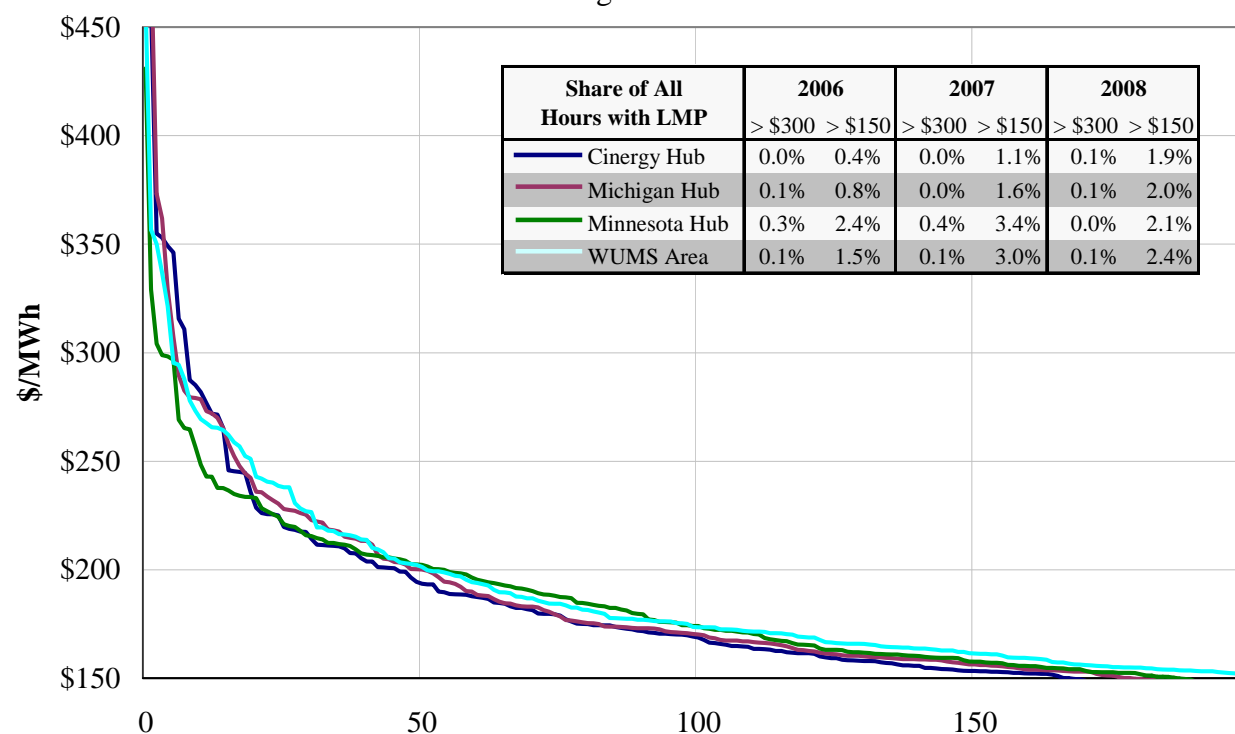
**Figure 2: Real-Time Price-Duration Curve**  
2008: All Hours



The differences between these curves are due to congestion and losses that cause prices to vary by location. In prior years, the Wisconsin-Upper Michigan System (“WUMS”) and Minnesota prices were the highest due to frequent congestion into these areas, but in 2008 congestion patterns caused prices to be more uniform across the Midwest ISO hubs. The number of hours exceeding \$200 per MWh and \$100 per MWh were comparable for all hubs, although congestion affected the Minnesota Hub and WUMS area more in the winter months and affected Cinergy more in the summer months. Compared to 2007, the number of hours exceeding \$200 per MWh in 2008 declined significantly for Minnesota and WUMS due to lower congestion and increased substantially for Cinergy and Michigan, owing to extensive storm damage to key transmission facilities in June. As a result of this storm-related congestion, there was an increase in the number of hours with prices less than zero (two percent of total hours) in Minnesota and WUMS.

Prices in peak hours play a critical role in sending the economic signals that govern investment and retirement decisions. Figure 3 shows the real-time price-duration curve for the highest-priced hours (over \$150 per MWh) for each hub.

**Figure 3: Real-Time Price-Duration Curve**  
2008: High Price Hours



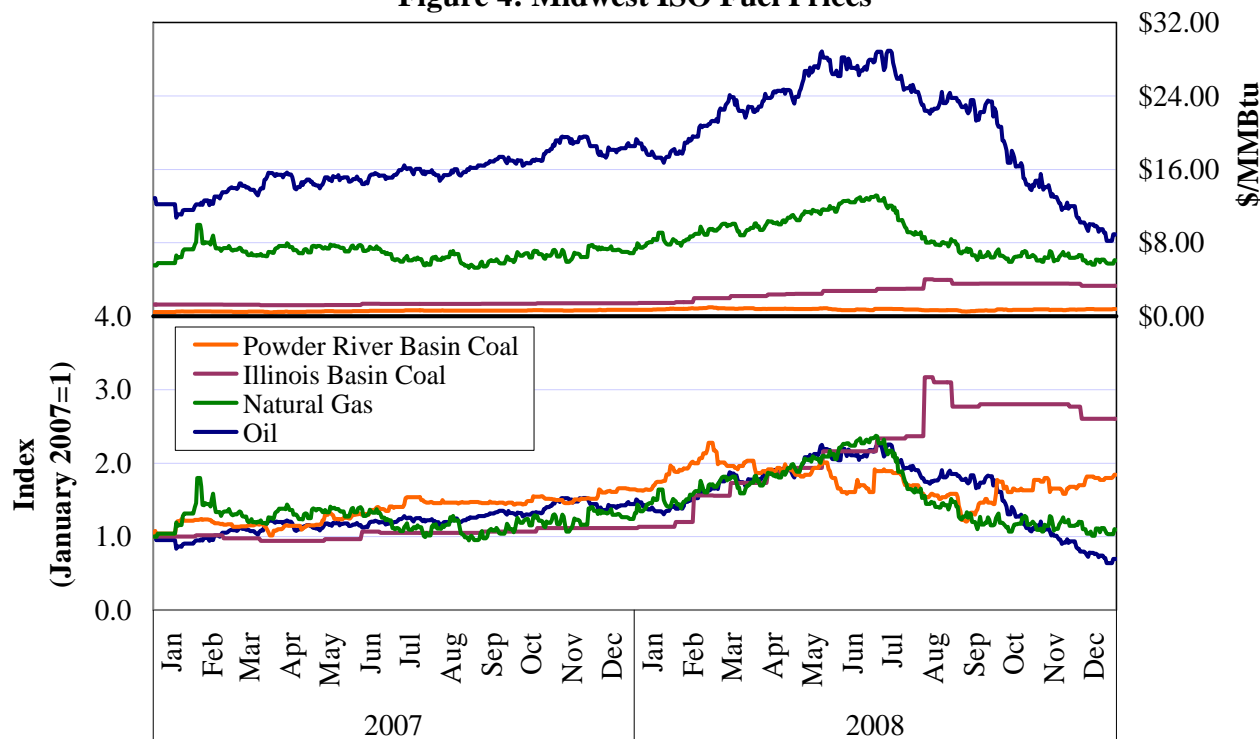
Peak pricing was particularly consistent across the Midwest ISO in 2008, with the WUMS area exhibiting extreme prices slightly more frequently than the Cinergy, Minnesota, and Michigan Hubs. In prior years, Minnesota and WUMS had significantly more high-priced hours due to congestion. Prices across all Midwest ISO hub locations were above \$300 per MWh in a very small number of hours—ranging from three to eight hours out (less than 0.1 percent of total hours) at each hub. In the long run, these relatively high prices during shortage conditions are needed to support investment in the region. Improvements in the peak energy pricing provisions and related market rules and revenues from ancillary services will improve the economic signals and contribute to resource adequacy. This is further explored in the net revenue analysis later in this section.

Fuel prices are the largest component of most generators' marginal cost and, therefore, are a primary determinant of the overall price of energy. As shown in Figure 4 below, fluctuations in fuel prices, particularly for natural gas units that are often on the margin, were particularly severe in 2008 and contributed to similar volatility in electricity prices. The figure also shows that fuel



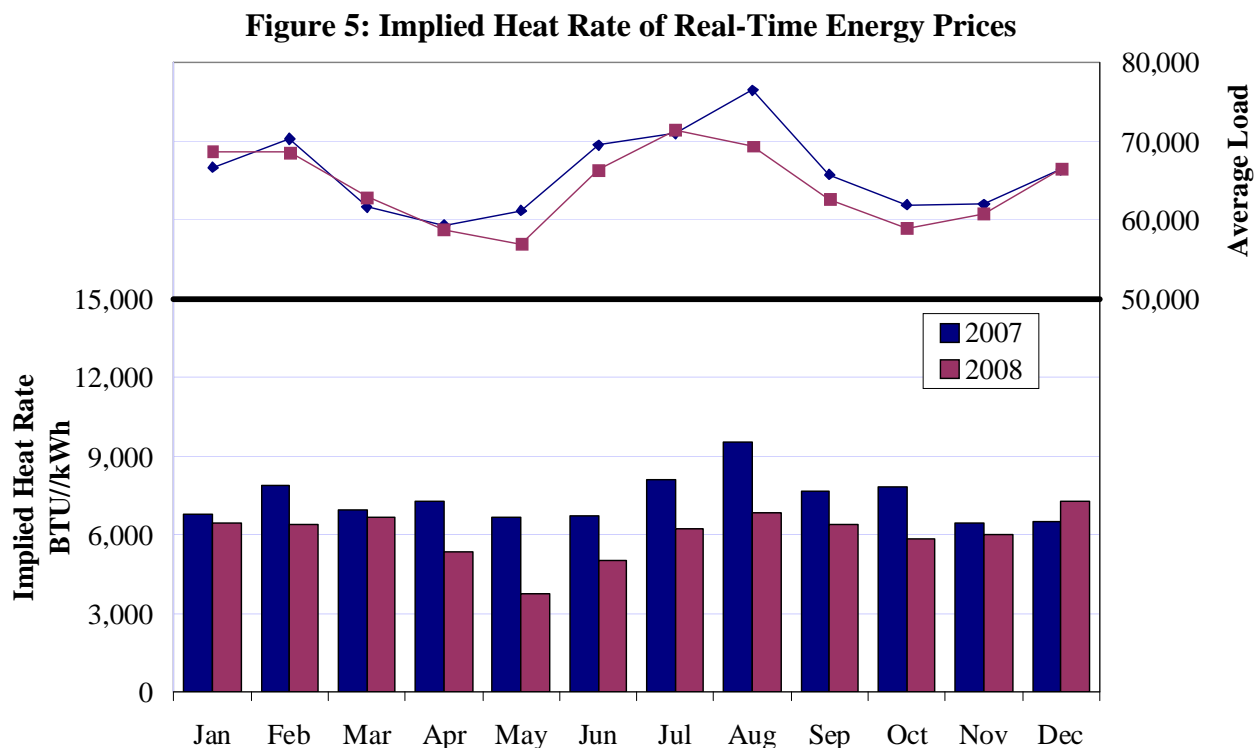
prices increased substantially in the first half of 2008, while oil and natural gas prices decreased even more sharply during the remainder of the year.

**Figure 4: Midwest ISO Fuel Prices**



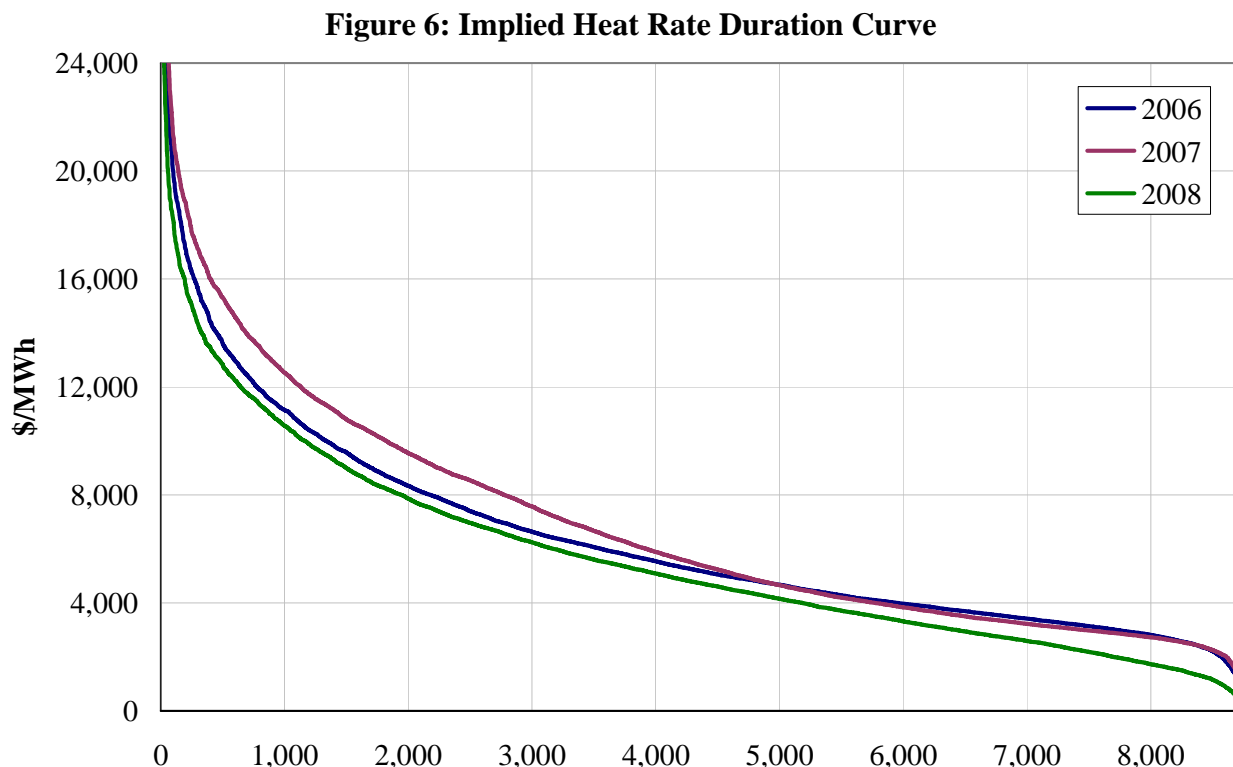
Overall, natural gas and oil prices rose by 28 and 30 percent from 2007 to 2008, respectively. After beginning the year at \$7.30 per million British thermal units (“MMBtu”), the price of natural gas rose steadily and peaked above \$13 per MMBtu in early July. The price then declined sharply to end the year at \$6 per MMBtu. Oil prices also fluctuated throughout the year, beginning the year at \$18.50 per MMBtu, rising to nearly \$29 per MMBtu by mid-July and finishing the year below \$9 per MMBtu. Illinois Basin coal prices rose through most of the year, peaking in August and ending the year at \$3.30 per MMBtu, more than double the price at the start of year. Power River Basin coal prices averaged \$0.74 per MMBtu in 2008 and ended the year at \$0.72 per MMBtu, only slightly above the January 2008 price of \$0.69 per MMBtu. Overall, higher fossil fuel prices allow investments in other forms of generation—in particular wind—to compete more favorably with hydrocarbon generation.

The impact of fluctuations in marginal fuel prices can obscure the underlying electricity market performance. Hence, we use an implied heat rate metric calculated as the real-time energy price divided by the natural gas price. This measure highlights variations in electricity prices that are due to factors other than fluctuations in natural gas prices, such as the price of coal, changes in load, or congestion costs. Figure 5 shows the implied heat rates and average load levels for 2007 and 2008.



The figure clearly shows that the implied heat rate rises and falls in close correlation with monthly load levels. Average implied heat rates were substantially lower in 2008 than in 2007, owing to significantly higher natural gas prices and lower load levels in 2008. The only anomaly was in December 2008, when implied heat rates were higher than in 2007 due to lower natural gas prices, higher load, and higher coal prices. Volatility in non-natural gas fuel prices (particularly coal, which was on the margin 73 percent of the time in 2008) eroded some of the typical consistency displayed between load and implied heat rates. Generally for each month, the year with the higher average load will also exhibit the higher implied heat rate. In 2008 this relationship did not hold in January, March, July, or December.

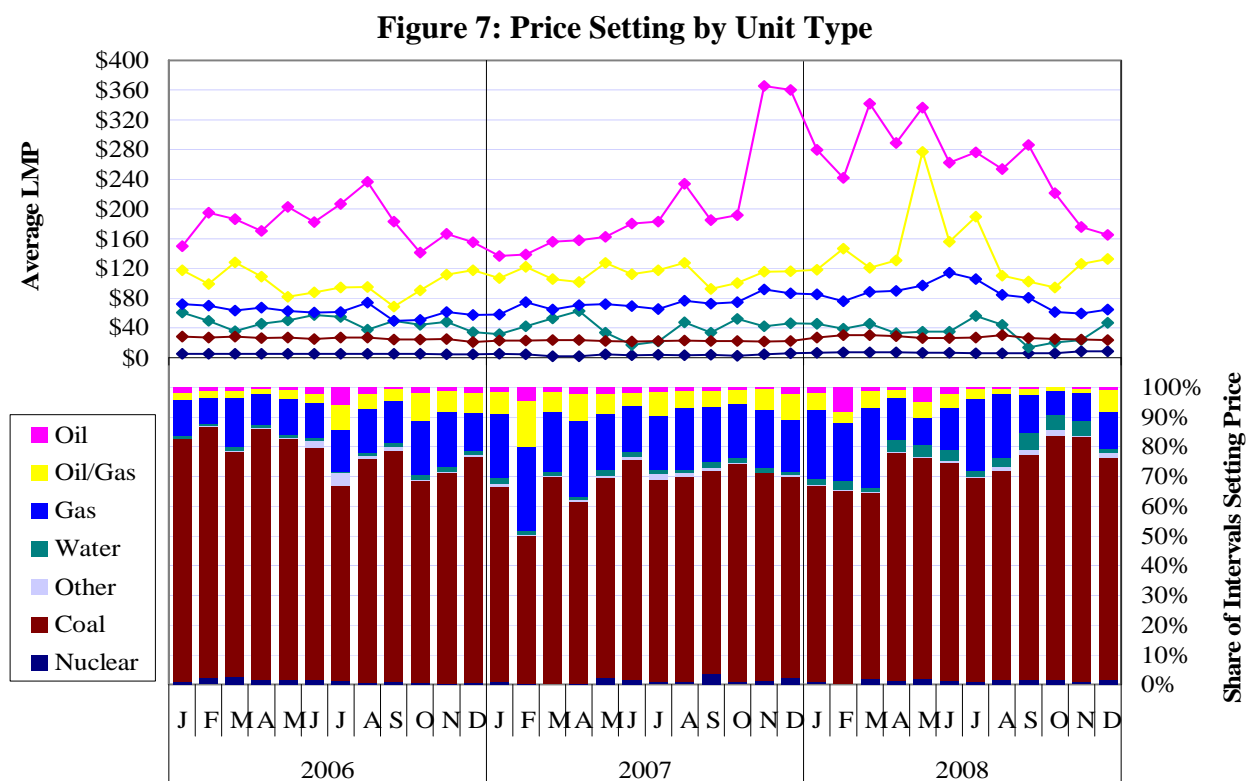
The implied heat rate duration curves illustrated in Figure 6 represent the average load-weighted real-time (ex post) price during each hour in 2006, 2007, and 2008 divided by prevailing natural gas prices.



This figure shows that the implied heat rate is markedly lower in 2008 compared to previous years. This is primarily due to reduced overall peak and average load in 2008. In addition, the system increasingly relied upon coal, rather than natural gas or oil-fired resources, to set the marginal price (discussed in detail below), which serves to lower the implied heat rate. Finally, non-firm natural gas transportation issues were less significant in 2008 than in 2007 when they compelled many dual-fueled resources to burn oil during the winter.

Next, we analyze the frequency with which different types of units are on the margin in the Midwest ISO. When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained areas). For the purposes of our analysis, we show only the price-setter in the unconstrained areas—thus, higher cost units may set prices in constrained areas more often than suggested in our analysis.

Figure 7 shows the average prices that prevail when each type of unit is on the margin and how often each type of unit sets the real-time clearing price.



This figure shows that coal units set prices in 73 percent of the hours (including 87 percent of the off-peak hours), up from 67 percent in 2007. This is due to a decrease in average load and a 556 MW increase in average wind generation, which reduces the need for natural gas-fired generation. In addition, high fuel costs made natural gas and oil units comparatively less economic during intermediate load hours.

Natural gas and oil units set prices during the highest-load hours, particularly in the winter months. Hence, these fuel prices have a larger effect on the load-weighted average prices than the percentages would suggest. Natural gas, oil-fired, and dual-fueled resources set prices in only 23 percent of hours during 2008 (a significant decline from 29.5 percent in 2007). However, nearly half of all real-time energy load occurred when these resources were on the margin.

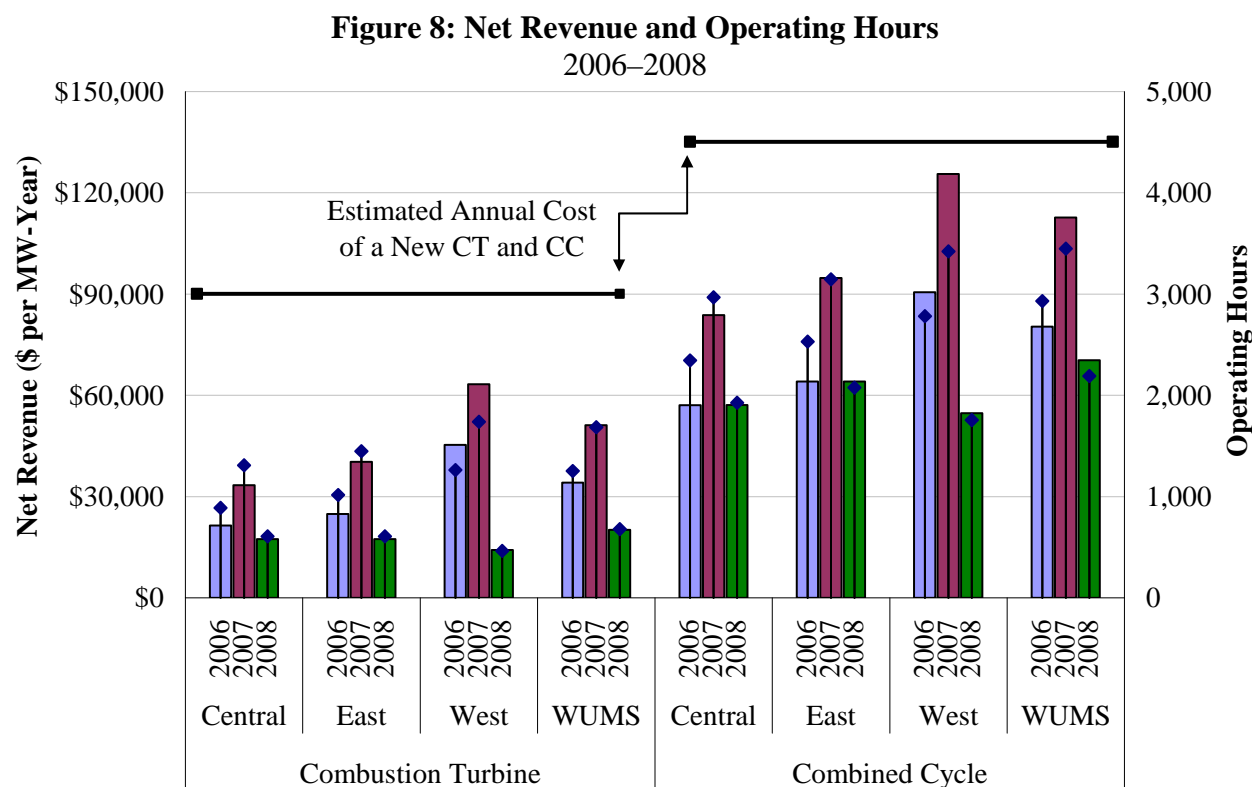
**B. Net Revenue Analysis**

In the previous subsection, we provided a summary of the Midwest ISO energy market prices in 2008. We now evaluate the resulting economic signals associated with these prices. Our evaluation uses the “net revenue” metric, which measures the revenue that a new generator would earn above its variable production costs if it were to operate only when its variable production costs were less than the energy price.

A well-designed market should allow a new entrant to earn a level of net revenue that is sufficient to finance new investment when new resources are needed. However, even if the system is in long-run equilibrium, random factors in each year will cause the net revenue to be higher or lower than the equilibrium value (e.g., weather conditions, generator availability, competing fuel prices, etc.). In other RTO markets, net revenues from energy markets are augmented by net revenues from capacity and ancillary services markets. These are not included in our analysis because the Midwest ISO markets did not operate capacity or ancillary services markets in 2008.

Our analysis examines the economics of two types of new units: a natural gas CC unit with an assumed heat rate of 7,000 Btu per kWh and a natural gas CT unit with an assumed heat rate of 10,500 Btu per kWh. We also incorporate standardized assumptions for calculating net revenues put forth by the Commission that account for variable Operations and Maintenance (“O&M”) costs, fuel costs, and forced outages. However, the analysis does not consider startup costs, minimum run-times, or other physical limitations.

Figure 8 shows net revenue provided by the Midwest ISO market from 2006 to 2008. To determine whether these net revenue levels would support investment in new resources, the figure also shows the estimated annualized cost of a new unit (which equals the annual net revenue a new unit would need to earn to make the investment economic).



Because CC generators have substantially lower production costs than simple-cycle CT generators, they run more frequently (nearly 23 percent of all hours in 2008, compared to 6.7 percent for CT units). Hence, a new CC generator would receive higher net revenues ranging from more than \$55,000 to \$70,000 per MW-year for various locations. In contrast, the net revenues for CT generators in 2008 ranged from \$14,000 to \$20,000. Compared to 2007, operating hours and net revenues were estimated to be significantly lower in 2008 for both types of resources due to lower load levels and reduced congestion.<sup>18</sup>

To check the reasonableness of the net revenue estimates, we compared the actual operating statistics of existing CC and CT generating units in 2008 to the estimated run hours in the net revenue analysis. We found that actual operating hours were slightly lower than the estimated

<sup>18</sup> Specifically, operating hours dropped from 37 percent to 23 percent of all hours for CC generators and from nearly 18 percent to 6.7 percent for CT generators. Net revenues dropped accordingly, from \$105,000 to \$61,000 for CC generators, and from \$47,000 to \$17,000 for CT generators.

run hours. For example, run hours for the most efficient Midwest ISO CT unit were lower in the WUMS area (7.2 percent of actual hours versus 7.7 percent estimated), where turbines generally run the most. In general, CT net revenue hours exceed actual hours due to startup costs and physical restrictions that prevent units from running in all profitable hours. CC generator run hours, however, were slightly higher in the East and WUMS area (25.8 and 27.1 percent, respectively, of actual hours versus 24 and 25 percent in the net revenue calculation). These differences in run hours for CCs are attributable to the multiple hour minimum runtimes which are honored by the market but not enforced in the net revenue metric.

The net revenue analysis indicates that net revenues for a newly placed-in-service CC or CT unit would fall short of the threshold required to justify new investment. This is consistent with expectations because the Midwest ISO footprint has a capacity surplus currently and did not experience significant periods of shortage in 2008. Furthermore, when shortage conditions do occur, market prices do not fully reflect them because operating reserve shortages and interrupted load do not contribute to setting prices. The ASM markets that were introduced in January 2009 will improve shortage pricing because it includes operating reserve demand curves that reflect the economic value of foregone reserves. When resources are not sufficient to satisfy reserve requirements, the operating reserve demand curve will indicate reserve prices and consequently improve energy price signals. The Midwest ISO is working on other pricing changes to allow interruptible load to set prices. Together, these changes will produce efficient shortage prices and increase net revenues.

Changes introduced to Module E of the Midwest ISO's Tariff in early 2009 also improved the long-run market signals needed to maintain adequate resources. The Midwest ISO clarified the capacity requirements and introduced enforcement provisions that should allow a decentralized market to develop to meet the Midwest ISO's capacity requirements. Our analysis does not include revenues earned through Module E transactions, which were likely modest in 2008. We will include such revenues in our analysis as this market develops in the future.

As excess capacity in the region declines, it will be important that the Midwest ISO's markets send efficient long-term signals. The introduction of ASM and the proposed changes to Module E of the Tariff should reinforce these priorities.

### III. Load and Resources

In this section, we provide an overview of the basic supply and demand conditions in the Midwest ISO markets. We summarize load and generation within the Midwest ISO region and evaluate the resource balance in light of available transmission capability on the Midwest ISO network.

In delineating the Midwest ISO geographic boundaries, we confine our analysis to the participants in the Midwest ISO markets. There are more than 75 owners of generation resources in the Midwest ISO market “footprint”. This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

For our analysis, we generally divide the Midwest ISO geographic boundaries into four regions based upon the geographic areas the Midwest ISO uses to operate the system. These regions are:

- East — generally includes the Midwest ISO control areas that had been located in the North American Electric Reliability Corporation’s (“NERC”) ECAR region;
- West — generally includes the Midwest ISO control areas that had been located in the NERC MAPP region;
- Central — generally includes the Midwest ISO control areas that had been located in the NERC MAIN region, but excluding MAIN utilities located in the WUMS area; and
- WUMS — the Midwest ISO control areas located in the WUMS area.

These four regions should not be viewed as distinct geographic markets, particularly with respect to generation ownership concentration. Concentration in these regions does not allow one to draw reliable competitive conclusions. An accurate market power analysis requires analyses beyond calculating market share and concentration statistics. This is discussed at length in Section VI.

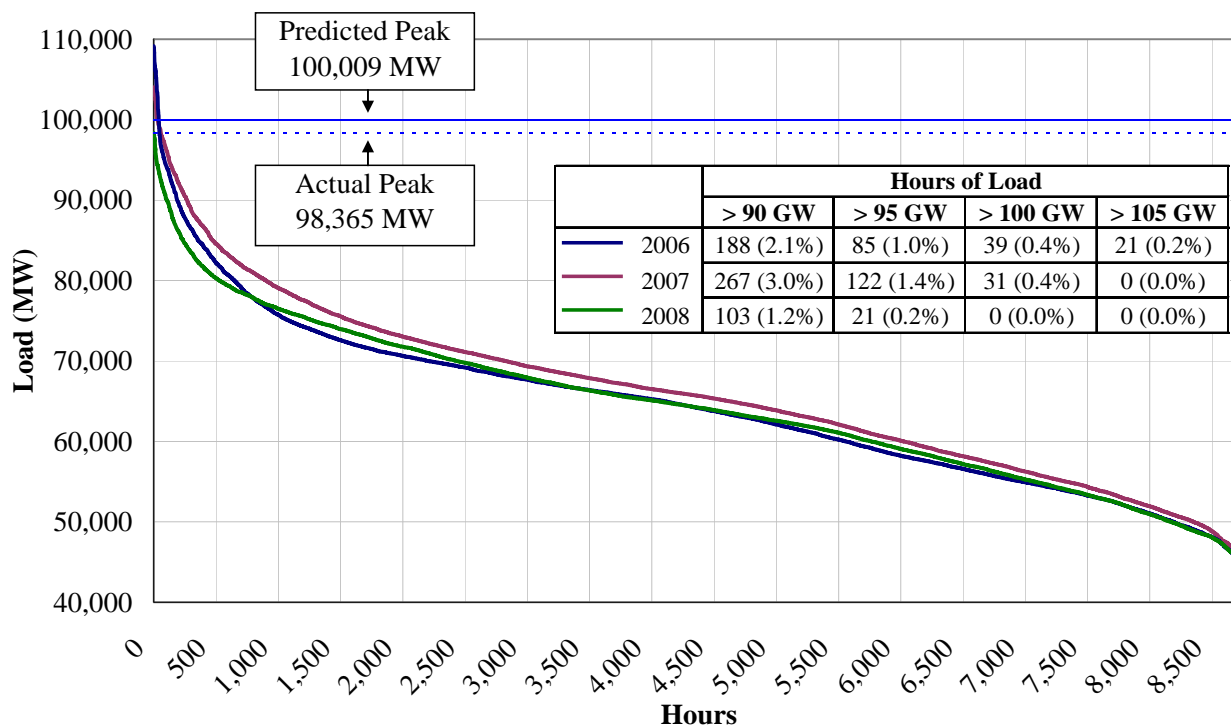
#### A. Load Patterns

Our first analysis in this section summarizes load patterns throughout the Midwest ISO region in 2008. The Midwest ISO is a summer peaking region. The peak load in 2008 was 98.6 GW, below the predicted peak load of 100 GW.



Figure 9 depicts hourly load duration curves for 2006, 2007, and 2008. A load duration curve, similar to a price duration curve, is a figure showing the number of hours (horizontal axis) in which load is greater than an indicated level (vertical axis).

**Figure 9: Load Duration Curves**  
2006-2008

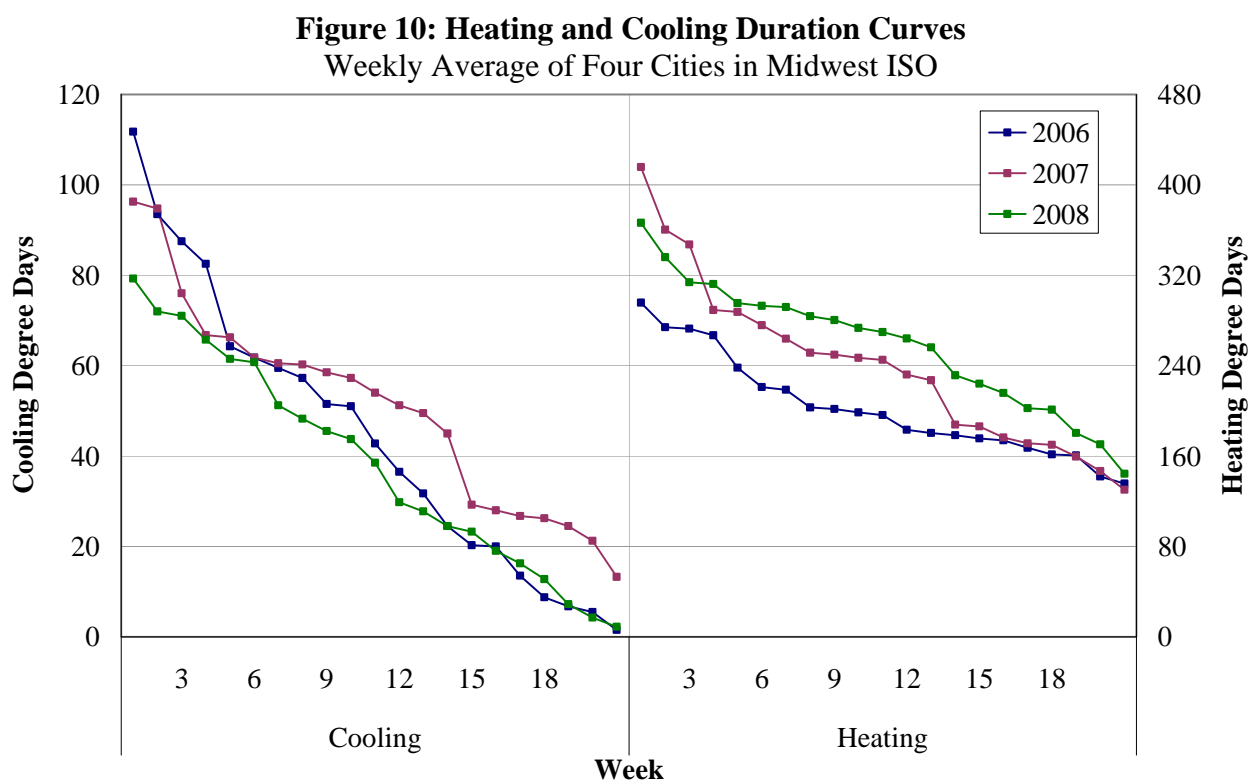


The figure shows that peak and average load declined in 2008 versus 2007. In particular, actual loads never exceeded the 100 GW mark in 2008, compared to 39 and 31 hours in 2006 and 2007, respectively. Additionally, the total hours of load above 90 GW and 95 GW decreased 61.4 and 82.7 percent year-over-year, respectively. Finally, the actual peak load in 2008 was 1.4 percent below the predicted peak demand of just over 100 GW. The load reductions that were evident in 2008 were primarily due to mild summer weather and the contraction in economic activity.

The load duration curves clearly show the sharp increase in load in the highest-demand hours. Our analysis indicates that close to 30 percent of the resources are needed only to meet the energy and operating reserve requirements of the region in the highest three percent of load

hours. These results underscore the importance of efficient pricing during the highest load conditions in order to maintain adequate peaking resources to satisfy demand.

Figure 10 shows the contribution of weather patterns to differences in load from 2006 to 2008. The figure depicts heating and cooling degree day duration curves, which shows the number of weeks in which the heating or cooling degree days are higher than the quantity shown on the vertical axis.<sup>19</sup>



The winter of 2008 was colder than both the winter of 2006 and 2007 on average, although the winter of 2007 had a particularly cold week in February that registered 415 Heating Degree Days (“HDDs”). The low average load observed in 2006 (as depicted on the load duration curve in Figure 9) was a direct result of the mild winter weather. The summer of 2008, meanwhile, was

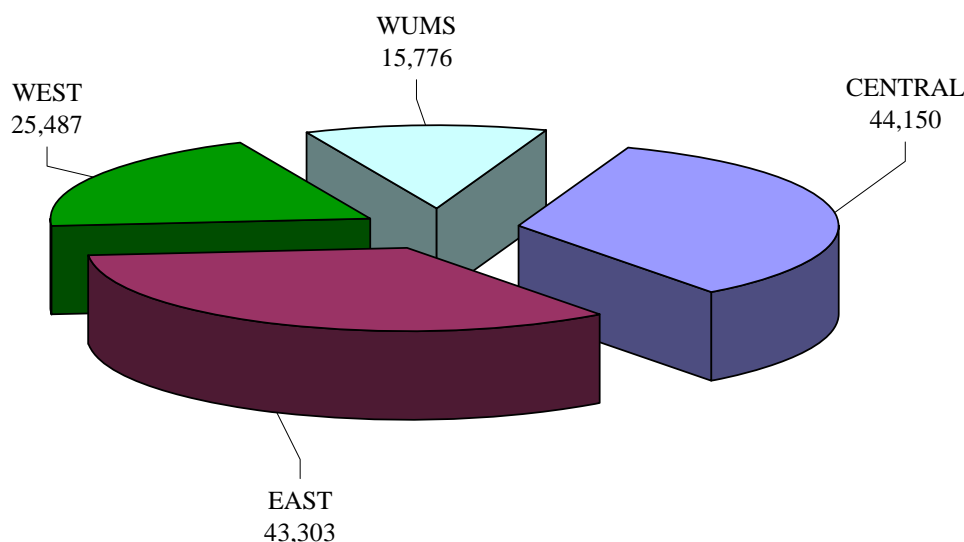
<sup>19</sup> HDDs and CDDs are defined using aggregate daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). For example, a mean temperature of 25 degrees Fahrenheit in a particular week in Minneapolis results in  $(65-25) * 7 \text{ days} = 280 \text{ HDDs}$ .

markedly milder than either 2006 or 2007, and contributed significantly to the relatively low peak load. The warmest week in 2008 resulted in 79 Cooling Degree Days (“CDDs”) versus 96 in 2007 and 112 in 2006.

## B. Generation Capacity

Generating resources in the Midwest ISO market footprint totaled 128.8 GW by the end of 2008. Figure 11 shows the distribution of this capacity by coordination region.

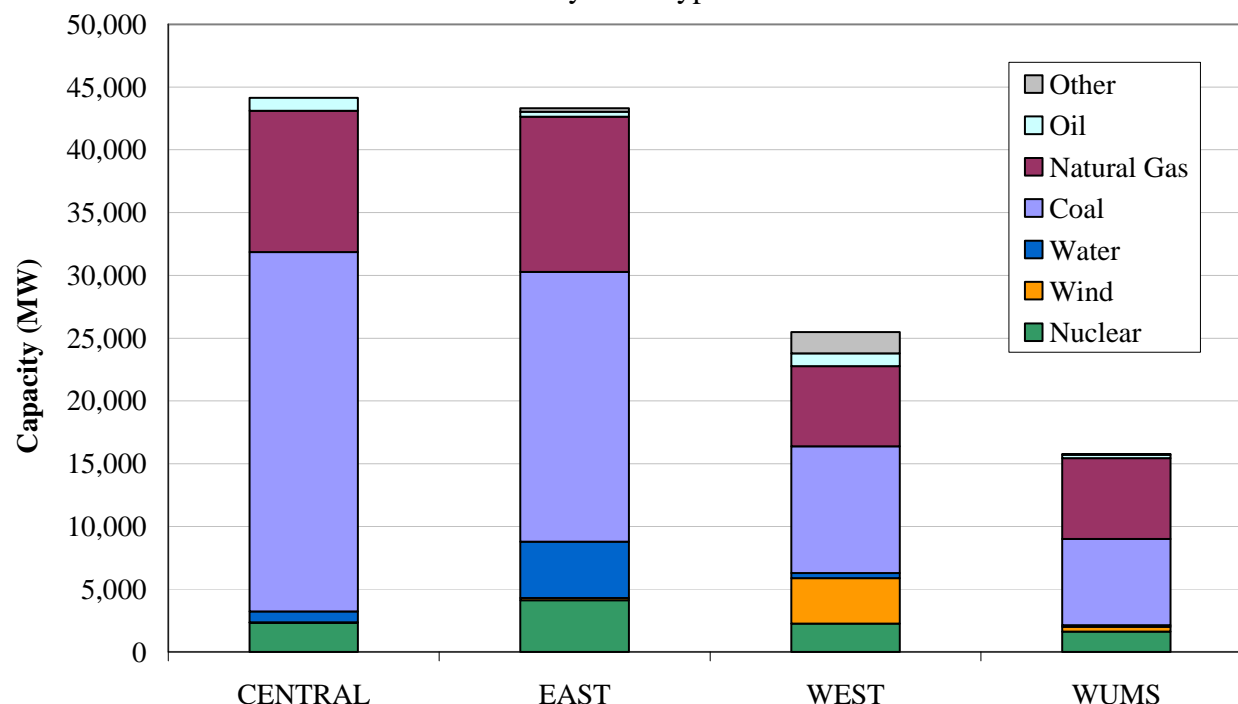
**Figure 11: Generation Capacity in MW by Coordination Region**



Consistent with the location of the load in the Midwest, more than 70 percent of the generating resources are located in the East and Central regions. Because it is a frequently congested area, we show the WUMS area separately from the rest of the East coordination region of the Midwest ISO. The capacity in the figure includes only capacity owned by entities that are participants in the Midwest ISO markets. This figure excludes the Midwest ISO reliability-only members (e.g., Nebraska Public Power District (“NPPD”), Omaha Public Power District (“OPPD”)). The Midwest ISO serves as the Reliability Coordinator for these entities, but they do not submit bids and offers in the Midwest ISO energy markets. Including the resources of the reliability-only members, the total generating capacity for the Midwest ISO exceeded 170 GW by the end of 2008, although this figure declined when OPPD, NPPD, and Lincoln Electric System left the Midwest ISO for the Southwest Power Pool (“SPP”) in April 2009.

In addition to the location of generation, the fuel used by the Midwest ISO generators is important because it determines marginal costs and, ultimately, the patterns of prices in the Midwest ISO region. Our next analysis shows the generating capacity by fuel type in the four primary regions of the Midwest ISO.

**Figure 12: Distribution of Generation Capacity by Region**  
By Fuel Type



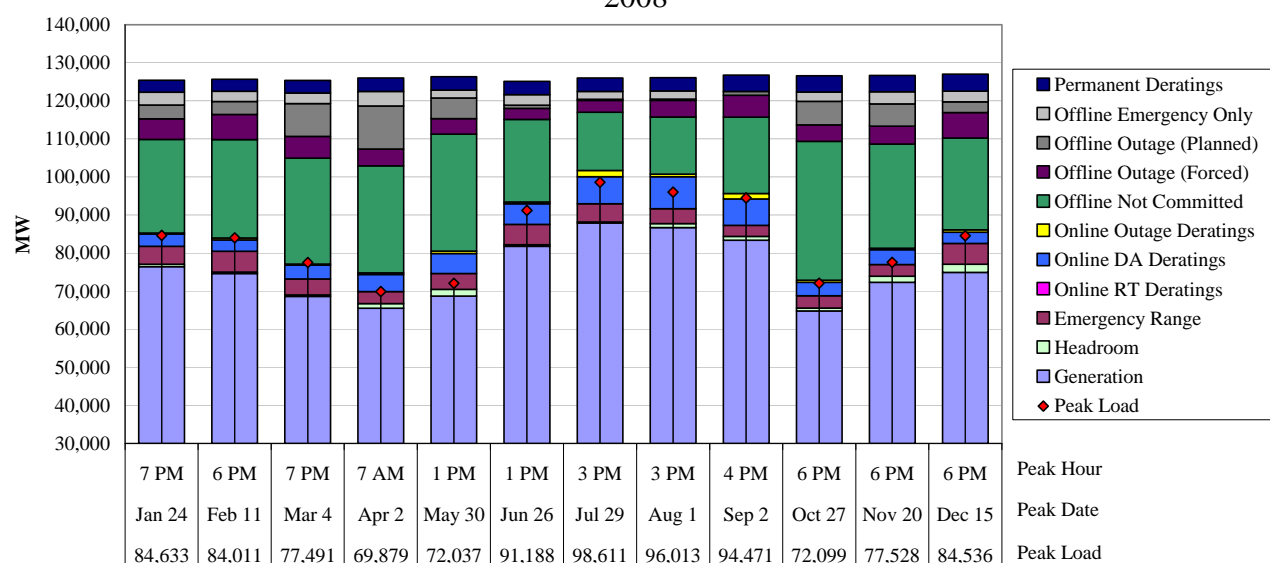
The Midwest ISO continues to rely on coal-fired generating resources for the majority of its installed capacity (52 percent). Because coal units are generally baseloaded, coal-fired resources generate an even larger proportion (77 percent) of the total energy produced. The second most common fuel type is natural gas, which accounts for almost 28 percent of the generating resources in the Midwest ISO. These resources are more expensive than most of the other resources in the region and are dispatched sparingly, producing less than five percent of the energy in the region. However, they frequently set the price in peak hours. Nuclear units account for 7.3 percent of capacity but produce 15 percent of the generation because they are the lowest-cost resources and run in all hours. Finally, wind generation accounts for three percent of capacity, bolstered by a large influx of new wind resources in 2008. While the mix of generation is fairly homogeneous across the Midwest ISO footprint, certain regions are more conducive than

others to particular generator types. The West region, for example, contains the vast majority of total wind generation (86 percent) due to the relatively attractive wind conditions in the area.

### C. Generator Availability and Outages

In this section, we examine the availability of generation capacity, particularly in peak-load hours when resource availability is most important. Figure 13 shows the status of generation capacity during the peak load hour of each month in 2008.

**Figure 13: Availability of Capacity during Peak Hours  
2008**

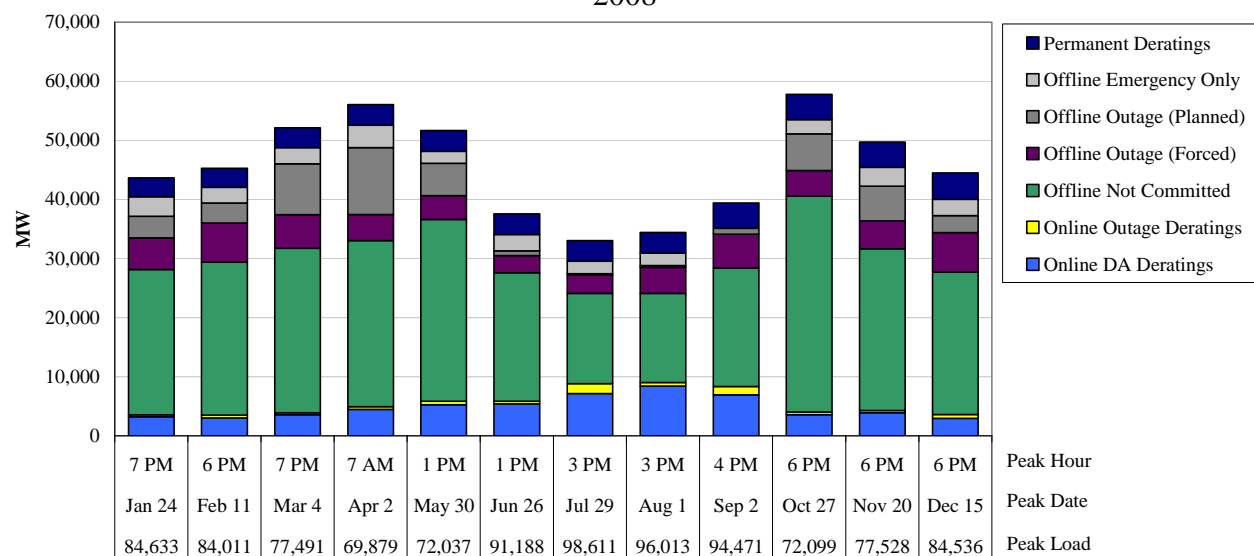


For reference, the peak load in each hour is shown as a red diamond. Most of the load is served by Midwest ISO generation, as indicated by the bottom (blue) segment of each bar. The next two segments are (1) “headroom”, which is the amount of capacity remaining on the committed units above their dispatch point, and (2) the emergency output range. These three segments together represent the total online capacity. The other segments comprise the remaining total capacity that is unavailable for various reasons. The figure shows that peak load was generally higher than the total online capacity, which is consistent with the fact that the Midwest ISO relies heavily upon imports to satisfy its demands for energy and operating reserves. The figure also shows that headroom on the highest load days was generally low and near the expected dispatch margins. During most months, headroom in the peak hour was less than one percent of total

demand, indicating the market was generally not over-committed (which can suppress peak pricing). There were no conditions that required demand side management during the summer peak periods.

To better depict the unavailable capacity in the peak hours, Figure 14 shows deratings, outages, and other offline capacity.

**Figure 14: Capacity Unavailable during Peak Hours**  
2008

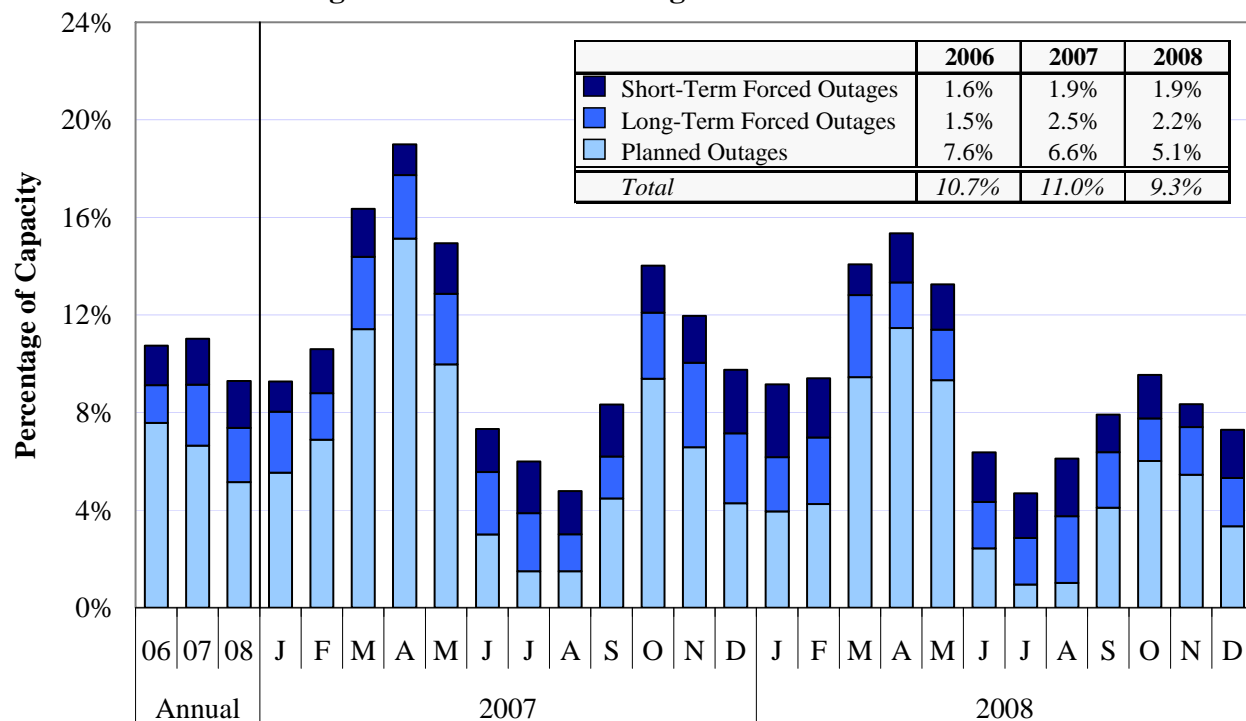


The figure indicates that deratings in the day-ahead market (shown in bright blue) were highest during July and August, which is largely attributable to high ambient temperatures that reduce the capability of some types of generators. Summer deratings were less in 2008 than in previous years due to milder temperatures. In addition, roughly 4.4 GW of capacity is permanently derated (relative to nameplate capacity ratings) and unavailable for dispatch in any hour. This represents an increase of 0.8 GW over 2007 and is attributable to both aging baseload capacity and new wind resources that do not operate at nameplate capacity (Midwest ISO wind generation had an average capacity factor of 28 percent in 2008).

Finally, we review forced and planned generator outages for 2008. Figure 15 shows the different types of generator outages on a monthly basis. The values in the figure include only full outages—they do not include partial outages or deratings shown above in Figure 14. The

analysis in the figure divides the forced outages between short-term (less than seven days) and long-term (seven days or longer).

**Figure 15: Generator Outage Rates in 2007-2008**



The annual combined outage rate declined considerably in 2008 to 9.3 percent, a 1.7 percentage-point drop from 2007, predominantly due to a decrease in planned outages. The figure shows that the largest total outage levels occurred in the spring and fall. This is expected because most planned outages are scheduled during periods of low load. Planned outages were 10 percent of capacity during the spring and 5.5 percent in the fall. Total planned and forced outages peaked in April at almost 15.3 percent, down from 19 percent in 2007. Planned outages were lowest (one percent) in the peak load months of July and August. Forced outage rates were constant throughout the year, with slightly higher rates (of about five percent) in January, February and August. The relatively low planned outage rates could be a concern if it indicates that suppliers are deferring maintenance due to the poor economic conditions that have prevailed over the past year. Outages and deratings are evaluated from a competitive perspective in Section VI.

## D. Resource Margins and Generation Adequacy

We review the capacity levels in the Midwest in this section of the report, assessing whether they are adequate to cover the forecasted peak loads in the summer of 2009. We evaluate generator availability by analyzing outages in 2008. For purposes of evaluating resource adequacy, we note that the estimated reserve margins will be optimistic if all potential deratings are not fully reflected. In particular, many resources during peak-load events must be derated in response to environmental restrictions or due to the effect of high ambient temperatures. Capacity levels during high temperature conditions can therefore be significantly lower than typically assumed, leading to lower reserve margins in reality.

Table 1 shows our analysis of the Midwest ISO's capacity levels for the summer of 2008, given the forecasted peak load and the announced capacity additions and retirements.

**Table 1: Capacity, Load, and Reserve Margins for each Midwest ISO Region**

Region	Load	Firm Net Imports	Nameplate		Available Capacity <sup>1</sup>		High Temp. Capacity <sup>2</sup>	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin
East								
Internal Load	38,111	-	43,387	13.8%	41,836	9.8%	39,438	3.5%
Internal Demand <sup>3</sup>	35,416	-	43,387	22.5%	41,836	18.1%	39,438	11.4%
Central								
Internal Load	37,501	2,032	45,057	25.6%	42,636	19.1%	39,550	10.9%
Internal Demand	35,636	2,032	45,057	32.1%	42,636	25.3%	39,550	16.7%
West								
Internal Load	18,399	1,744	26,363	52.8%	21,821	28.1%	19,983	18.1%
Internal Demand	17,193	1,744	26,363	63.5%	21,821	37.1%	19,983	26.4%
WUMS								
Internal Load	13,137	556	16,501	29.8%	15,488	22.1%	14,643	15.7%
Internal Demand	12,315	556	16,501	38.5%	15,488	30.3%	14,643	23.4%
MISO								
Internal Load	102,472	4,332	131,308	32.4%	121,781	23.1%	113,614	15.1%
Internal Demand	95,884	4,332	131,308	41.5%	121,781	31.5%	113,614	23.0%

<sup>1</sup> Midwest ISO Summer-Rated Capacity from its 2009 Summer Assessment.

<sup>2</sup> High Temperature capacity is based upon temperature derates that occurred in the Day-Ahead market of August 1, 2006.

<sup>3</sup> Net Internal Demand estimate excludes interruptible load and behind the meter generation.

<sup>4</sup> Our planning reserve margins differ from the Midwest ISO's because: a) we include temperature-related deratings (reduces our margins), b) we include all physical capacity, not only those designated as capacity (increases our margins), c) we calculate our margins based on internal load and internal demand while the Midwest ISO's is generally based on internal demand.



The table includes separate reserve margins calculated based upon internal demand and internal load. We define internal demand as internal load less the sum of behind-the-meter generation, interruptible load, and other demand side response capability. Hence, the statistics based upon internal demand will include the effects of DR capability and those based upon internal load will not. We calculate the reserve margin as follows:

$$\text{Reserve margin} = [(\text{Capacity} + \text{Firm Imports}) \div \text{Internal Demand or Load}] - 1.$$

Table 1 shows that reserve margins are highly sensitive to the assumed maximum-capacity levels and whether interruptible demand is included. Using nameplate capacity levels and the projected capacity changes for 2008, we find the reserve margin for the Midwest ISO region is 32 percent based upon internal load and almost 42 percent based upon internal demand. This reserve margin varies within Midwest ISO subregions from 13.8 percent to 52.8 percent based upon internal load and from 22.5 percent to 63.5 percent based upon internal demand.

These reserve margins are notably higher than in previous years due to lower peak load levels in 2008, and would lead one to conclude that the Midwest ISO has a substantial surplus. However, when the typical deratings and the temperature-sensitive capacity that is unavailable under peak-demand conditions are removed, the reserve margin projected for 2008 for the Midwest ISO region is 15 percent based upon internal load and 23 percent based upon internal demand. In individual regions, the reserve margin varies from 3.5 percent to 18.1 percent based upon internal load and from 11.4 percent to 26.4 percent based upon internal demand. However, because 10 percent or more of the capacity can be unavailable due to forced outages or set aside for operating reserves, real-time conditions may be tight on some peak days. Hence, interruptible load may need to be curtailed under extreme conditions or if forced outages are higher than average at peak times.<sup>20</sup>

---

20 The Midwest ISO's planning margins are slightly lower than the ones we estimate in Table 1. While it does remove high-temperature deratings as we do, the Midwest ISO removes capacity that is not needed to satisfy Load Serving Entities' ("LSEs") capacity obligations. Our estimate includes all physical capacity.

Although these results indicate that the system's resources are adequate for the summer of 2009, new resources will be needed over the longer term. The results of the net revenue analysis presented above indicate that the long-term economic signals do not currently support new entry. Consistent with these signals, little conventional capacity has been added in the last few years. The recommended pricing changes designed to improve the efficiency of the market's economic signals should ensure that these signals will support new investment when it is needed.

Table 2 shows the new capacity additions in the Midwest ISO's 2009 Summer Assessment that have been added since the 2008 Summer Assessment.<sup>21</sup> In total, 3,500 MW of additions and 237 MW of retirements are included in the 2009 Summer Assessment. Although the additional capacity appears substantial, more than half of it is in the form of wind generation, which contributes less to reliability than conventional supply or DR resources due to its intermittent nature. Large quantities of wind resources added in other markets have caused significant congestion management issues and other operational issues. Much of the remaining new capacity additions are in the form of natural gas and oil-fired resources located in congested regions, which should improve the Midwest ISO's ability to manage congestion in those areas.

**Table 2: Planned Capacity Additions from Summer 2008 to Summer 2009**

Region	Coal	Coal/Gas	Gas	Oil/Gas	Other	Waste	Water	Wind	Total
Central	220	0	53	0	0	0	0	101	373
East	0	0	578	0	8	0	0	5	591
West	0	15	6	688	15	6	0	1,714	2,444
WUMS	0	0	0	0	0	0	10	122	131
<b>Total</b>	<b>220</b>	<b>15</b>	<b>637</b>	<b>688</b>	<b>23</b>	<b>6</b>	<b>10</b>	<b>1,941</b>	<b>3,539</b>

## E. Demand Response Resources

Demand participation in the market allows end-users to reduce consumption during certain high-priced peak hours. Substantial DR capability exists in the Midwest ISO, primarily in the form of interruptible load programs implemented by regulated LSEs prior to the formation of the Midwest ISO. DR help maintain system reliability and address congestion concerns during

<sup>21</sup> Some of these additions occurred in 2008 after the MISO 2008 Summer Assessment.

emergency conditions. DR resources also improve the performance of the market by minimizing the costs of satisfying resource adequacy in the long term, reduce price volatility, and reduce supplier market power. There are a host of issues unique to DR implementation that require further work, particularly regarding barriers to integration with energy markets, price-setting, measurement and verification, and coordination with retail customers. We explore these topics in detail in Section VII.

## **IV. Day-Ahead and Real-Time Market Performance**

In this section, we evaluate the performance of the day-ahead and real-time markets. Our evaluation is focused on three main areas: (1) prices relative to load and other operating conditions; (2) the convergence of prices between the day-ahead and real-time energy markets; and (3) load scheduling and virtual trading.

We also address other market issues, including RSG payments, the dispatch of peaking resources in real-time, ex post pricing issues, and the integration of wind generation. We conclude this section with a number of suggested improvements intended to enhance efficiency and competitive performance of the markets.

### **A. Day-Ahead Market Performance**

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real-time. This market allows participants to hedge their portfolios and manage risk. For example, loads can insure against volatility in the real-time market by purchasing in the day-ahead market and using FTRs to hedge against congestion.

The performance of the day-ahead market is important because most of the power that is procured through the Midwest ISO markets is financially settled in the day-ahead market. In addition, FTRs are settled based upon day-ahead market results. The day-ahead market also plays a crucial role in coordinating generator commitments because most generator commitments are determined through the day-ahead market.

#### **1. Day-Ahead Prices and Load**

In this subsection, we review day-ahead peak-hour prices in each region relative to scheduled load. This overview of day-ahead market results is shown in Figure 16, which shows daily average day-ahead prices during peak hours (6:00 a.m. to 10:00 p.m. on weekdays) and the corresponding scheduled load (which includes net cleared virtual demand).

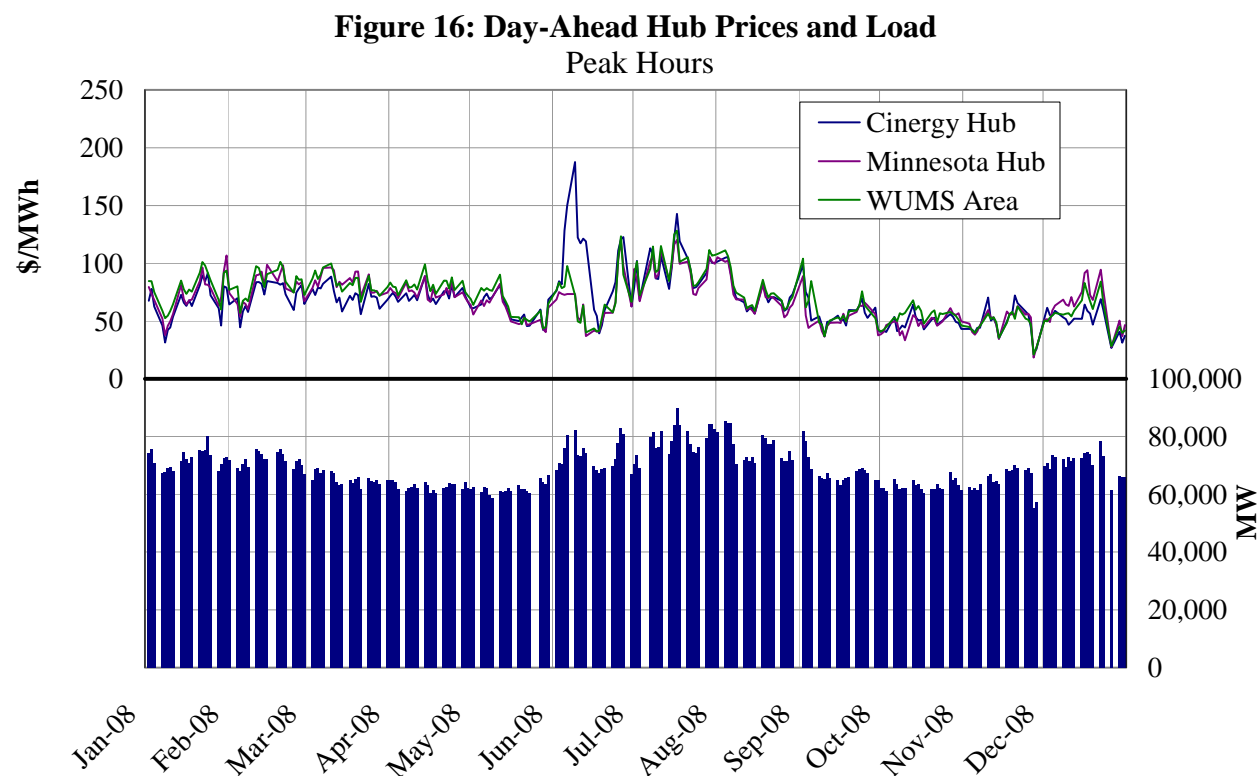
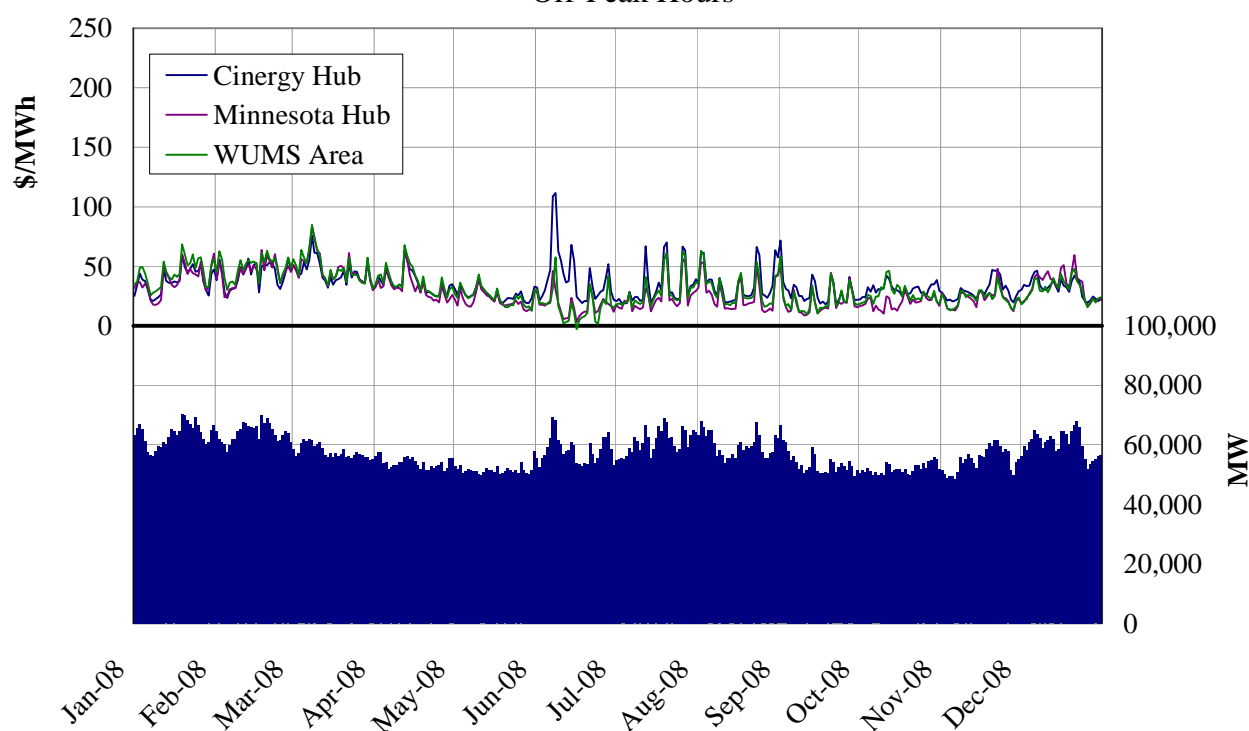


Figure 16 shows that hub prices generally correspond to prevailing load. This is expected because a well-functioning LMP market provides transparent signals regarding market conditions. Differences in prices among the hubs show the prevailing congestion patterns throughout the year (high prices in one location relative to another location indicate congestion from the low-price area to the high-price area). High load during both the winter peak and summer peak periods led to higher prices and seasonal volatility throughout the footprint. In the first five months of 2008, congestion was greatest into WUMS and the West due to the higher share of winter load in the cold northwestern portion of the footprint and non-firm natural gas transportation issues. In June, significant storm-related transmission outages east of Chicago caused West-to-East congestion and high prices at the Cinergy and Michigan Hubs (exceeding \$187 and \$168 per MWh, respectively, on June 9). Price volatility eased in the fall due to reduced overall load and, in the case of Minnesota, due to the return of high levels of imports over the Manitoba interface. Finally, wider inter-hub spreads prevailed in March and December due to planned and unplanned generator outages.

Overall, Michigan and WUMS experienced average prices about \$3 per MWh higher than Minnesota and Cinergy. In the case of Michigan, this was partially due to the residual effects of storm-related transmission outages and congestion on market-to-market flowgates that limit flows into Michigan. WUMS traditionally has the highest prices in the Midwest ISO due to transmission constraints that limit flows into the area from the South and West, although recent transmission investments have reduced this congestion. Figure 17 shows the same analysis for off-peak hours.

**Figure 17: Day-Ahead Hub Prices and Load  
Off-Peak Hours**



The maximum load levels during off-peak hours were comparable between the summer and winter months of 2008. This is somewhat surprising because the maximum load in off-peak hours usually occurs in the summer. Although the maximum off-peak daily load occurred in February (71.35 GW), the off-peak maximums for the months of January, June, July, August, September, and December were all within 4 GW (5.6 percent) of the February maximum. This is attributable to cold winter temperatures, generally mild summer temperatures and an unusually

warm start to September (peak load on September 1 was 23 percent above the September average daily peak load).

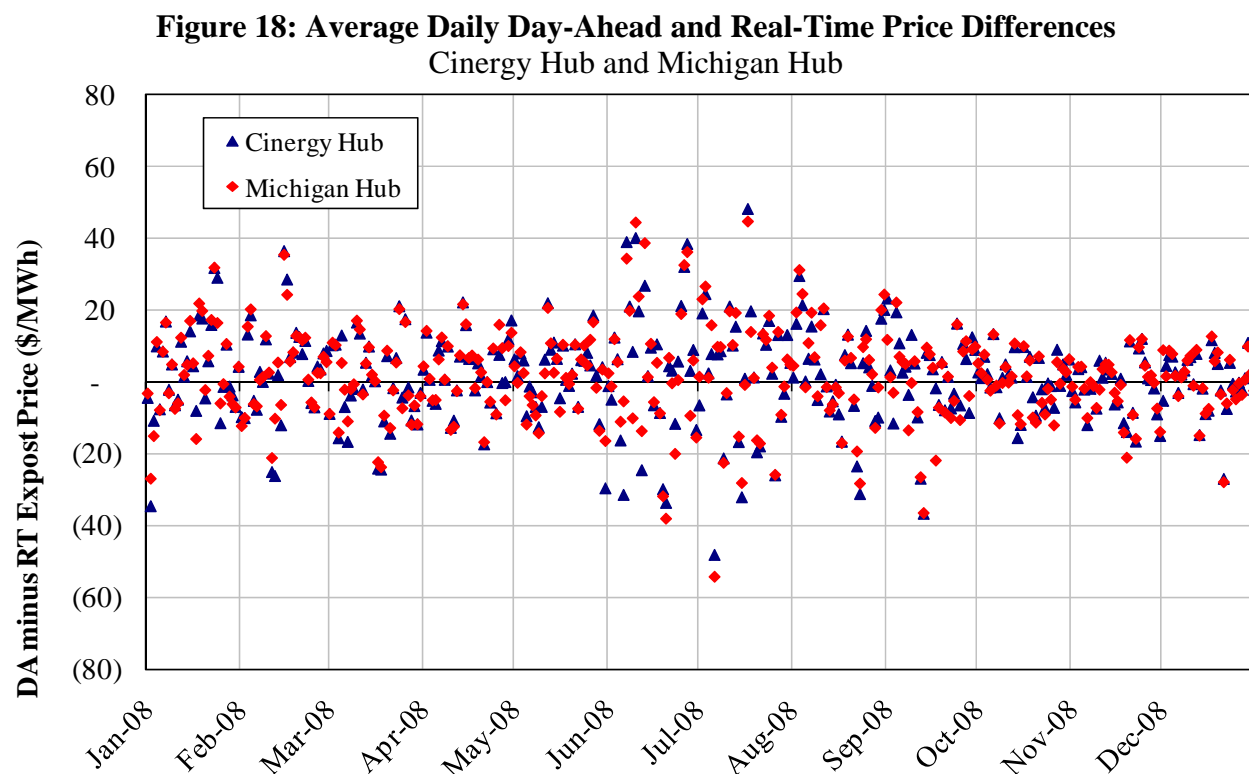
Despite steady off-peak load, day-ahead off-peak prices were particularly volatile in 2008. As a result, day-ahead hub price variance was only 13.3 percent higher during peak hours than off-peak hours, compared to 77 percent higher in 2007. Average off-peak prices were highest from January through March due to low winter temperatures and high fuel prices. Consistent with congestion patterns, off-peak prices in WUMS and Minnesota were the highest in these winter months. Fewer outages and a stable flow of imports over the Manitoba interface led to lower off-peak prices and congestion during the summer months at the Minnesota Hub.

As with peak hours, substantial storm related transmission outages caused significant off-peak congestion in June at the Cinergy and Michigan Hubs. Off-peak prices at the Cinergy and Michigan Hubs in June were \$13 per MWh higher on average than at the Minnesota Hub and WUMS area.

## **2. Day-Ahead and Real-Time Price Convergence**

Our next analysis examines convergence of day-ahead and real-time energy prices. Good convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market. Since the day-ahead market facilitates most of the energy settlements and generator commitments in the Midwest ISO region, good price convergence with the real-time market helps ensure efficient day-ahead commitments that reflect actual real-time operating needs.

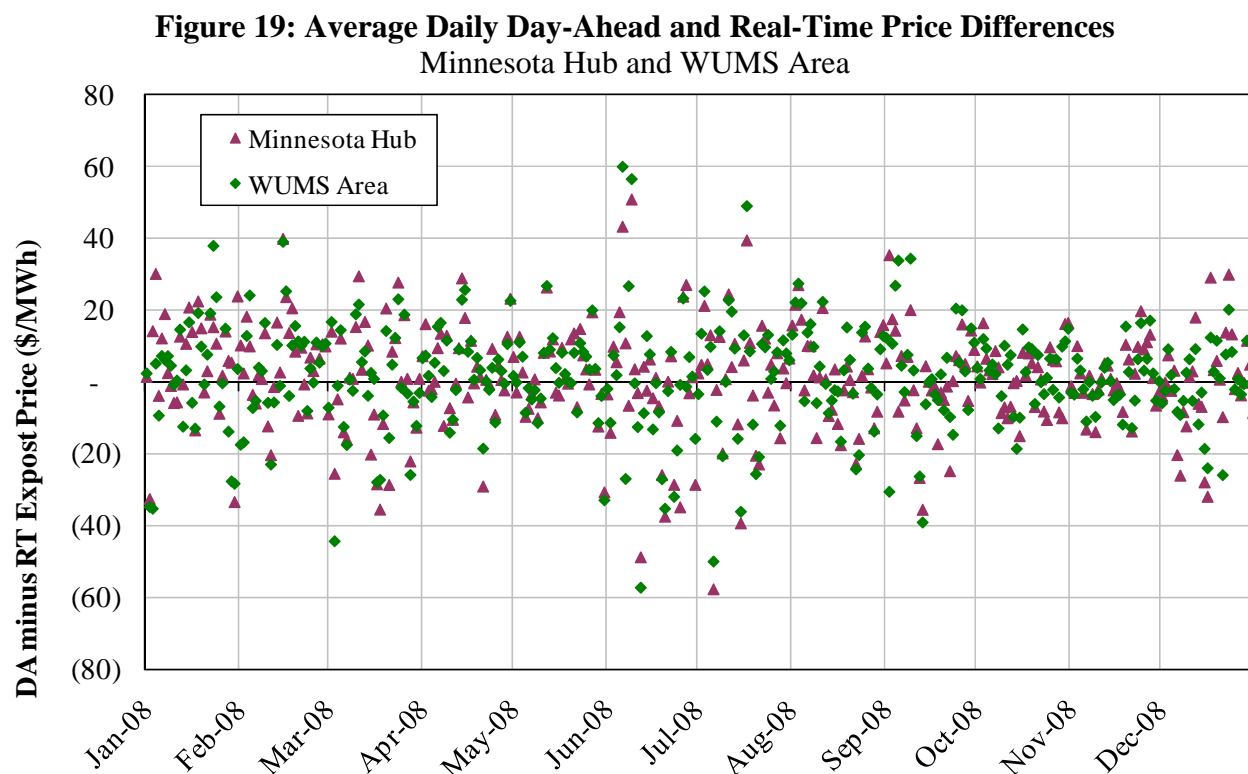
In general, good convergence is achieved when participants submit price-sensitive bids and offers in the day-ahead market that accurately forecast real-time conditions. To evaluate price convergence, we calculate the difference between the average daily day-ahead and real-time prices at four representative Midwest ISO hubs, as shown in Figure 18 and Figure 19. Figure 18 shows the daily difference between the real-time and day-ahead prices at the Cinergy and Michigan Hubs.



The daily average difference between the day-ahead and real-time prices was modest: \$1.58 per MWh for the Cinergy Hub and \$1.85 per MWh for the Michigan Hub. During the summer when prices are the most volatile, these differences were larger. In July and August, the day-ahead risk premiums averaged \$2.13 per MWh at the Cinergy Hub and \$3.64 per MWh at the Michigan Hub. Premiums are rational because entities purchasing in the real-time market are subject to RSG cost allocation. The expectation of real-time RSG charges increases in the summer, which should increase the day-ahead premium. Additionally, purchases in the day-ahead market are subject to less price volatility, which is valuable to risk-averse buyers.

Figure 19 shows the same daily convergence results for the Minnesota Hub and the WUMS area. These locations show different results from the Cinergy and Michigan Hubs because they are much more frequently affected by transmission congestion.



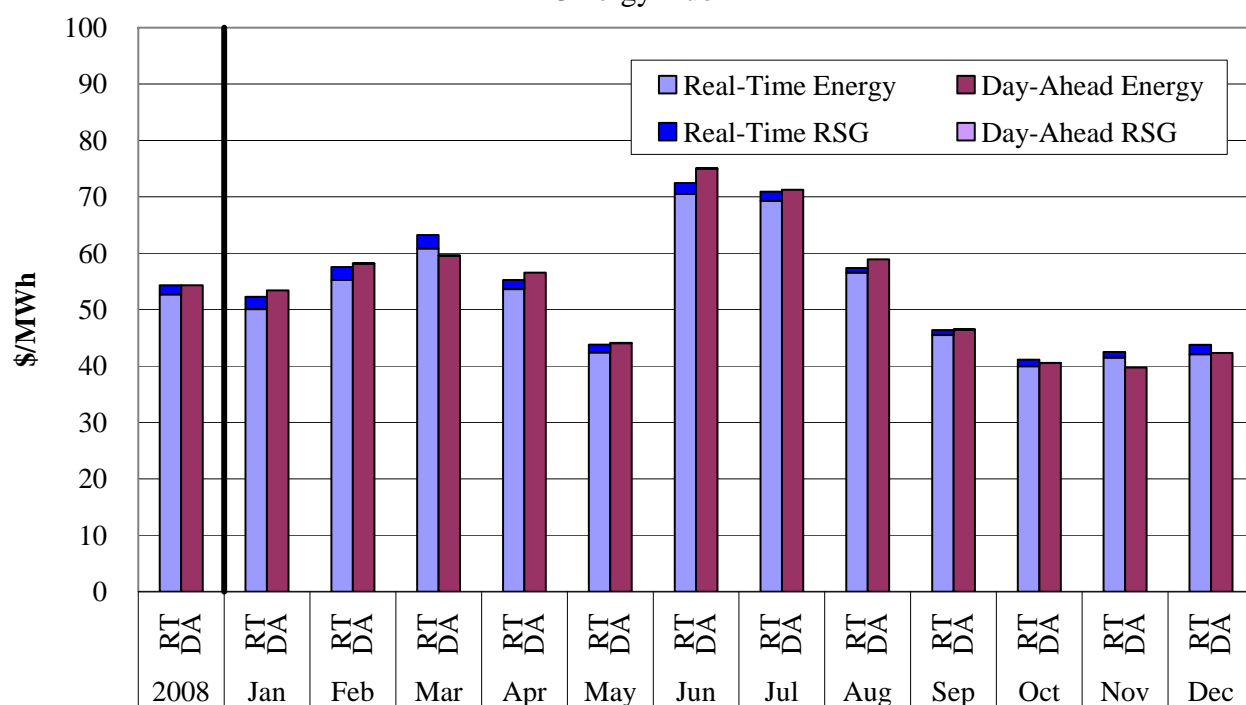


The Minnesota Hub and WUMS area have higher daily average absolute price differences compared to the Cinergy and Michigan Hubs. The daily average absolute price difference was \$10.65 per MWh in Minnesota and \$10.77 per MWh in WUMS, compared to \$9.61 per MWh for the Cinergy Hub and \$9.66 per MWh for the Michigan Hub). These average differences for the Minnesota Hub and WUMS area were comparable to the average differences in 2007 and, like the other locations, were largest during the summer when prices were most volatile. The more frequent congestion in Minnesota and WUMS resulted in higher price volatility as evidenced by the higher absolute average price differences.

Although day-ahead and real-time price differences can be large on an hourly or daily basis, it is more valuable to evaluate convergence over longer timeframes. Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day, but a variety of factors can cause the real-time prices to be significantly higher or lower than expected. While a well-performing market may not result in prices converging on a daily basis, it should lead prices to converge well on a monthly or annual basis. To evaluate convergence over these timeframes, the following figures show the average day-ahead and real-time prices on a monthly

and annual basis at four representative locations. Purchases in the real-time market are subject to allocation of real-time RSG costs (which are much larger than day-ahead RSG costs). This cost difference creates an incentive for participants to increase their purchases in the day-ahead market, leading to a day-ahead premium (excluding RSG). Hence, the bars shown in the figure reflect RSG cost allocations stacked on top of the energy price. The real-time RSG rate in the following figures is the average RSG cost per MWh that would be allocated to a participant for each MWh purchased in the real-time market during a given month. Figure 20 shows this analysis for the Cinergy Hub.

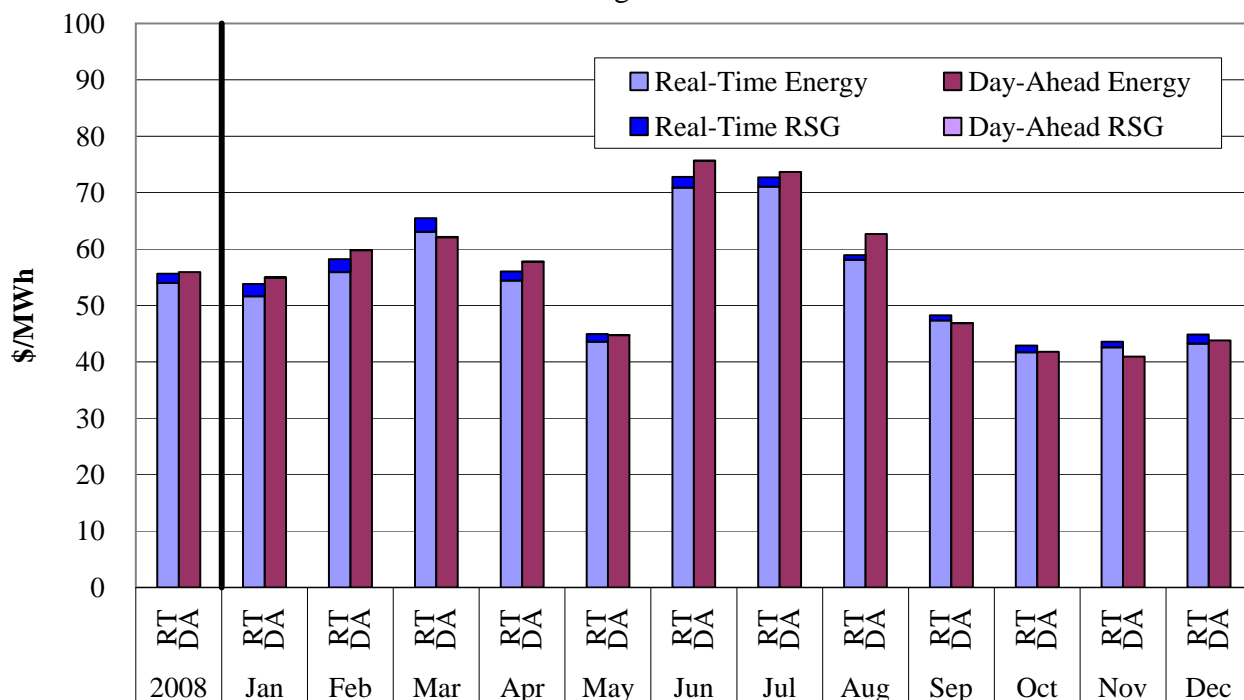
**Figure 20: Day-Ahead and Real-Time Prices**  
Cinergy Hub



The Cinergy Hub is the most liquid trading point for forward contracting in the Midwest ISO region. In 2008, the average day-ahead prices at the Cinergy Hub were \$54.31 per MWh and day-ahead RSG costs averaged \$0.02 per MWh. Real-time average prices at the Cinergy Hub were \$52.72 per MWh and average real-time RSG costs were \$1.61 per MWh. This implied an average day-ahead premium of only \$0.01 per MWh, the lowest of the four hubs. Hence, although average day-ahead energy prices were higher than average real-time energy prices for a

given month, all-in prices (which include RSG costs) were nearly identical. Figure 21 shows the same analysis for the Michigan Hub.

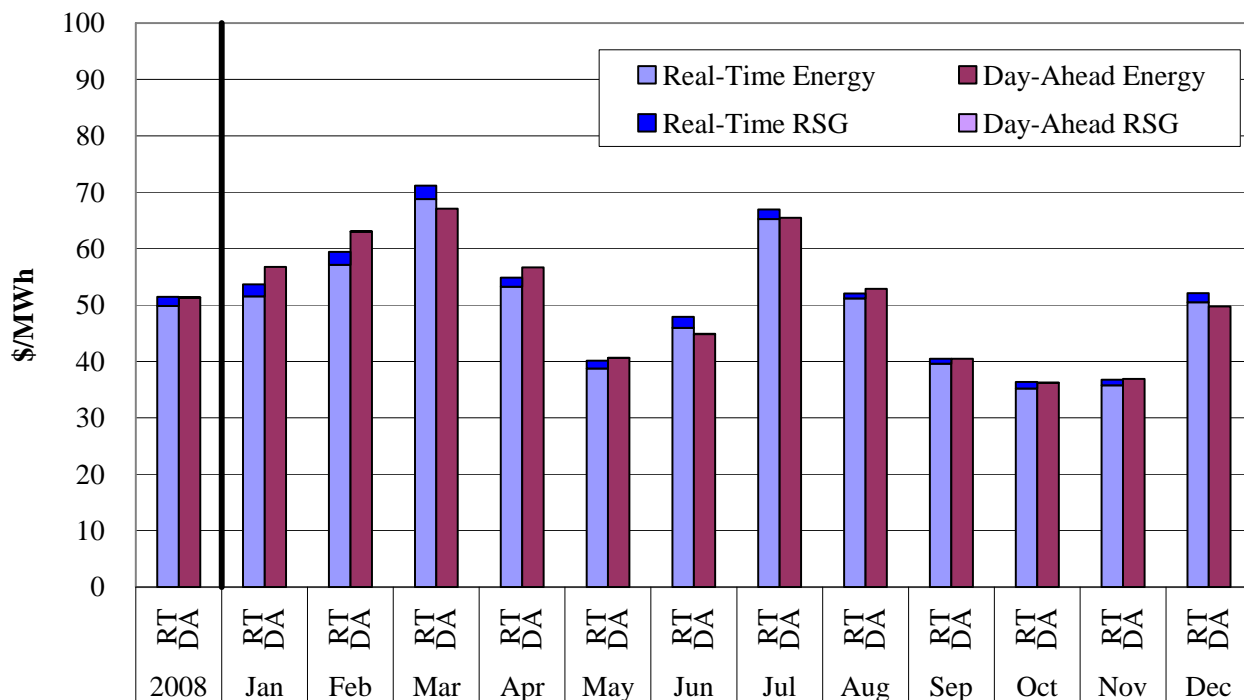
**Figure 21: Day-Ahead and Real-Time Prices**  
Michigan Hub



Monthly day-ahead and real-time energy prices at the Michigan Hub trended similarly to those at the Cinergy Hub, although the day-ahead premium was slightly larger at the Michigan Hub. Day-ahead premiums averaged \$1.85 per MWh and real-time RSG costs averaged \$1.61 per MWh. Hence, the day-ahead premium net of RSG charges was approximately \$0.25 per MWh.

Figure 22 and Figure 23 show the convergence analyses for the Minnesota Hub and WUMS area. Historically, price convergence in these locations is more difficult to achieve due to more frequent congestion which causes prices in these areas to be much more volatile than prices elsewhere in the Midwest ISO region. Less frequent congestion in these control areas compared to previous years reduced the divergence between day-ahead and real-time prices.

**Figure 22: Day-Ahead and Real-Time Prices**  
Minnesota Hub



In prior years, price convergence at the Minnesota Hub was more difficult to achieve due to prevailing congestion patterns. Reduced congestion into Minnesota coupled with reduced overall load in 2008, however, reduced the divergence between average day-ahead and real-time prices for most months with the exception of the period from January to April. In these months, more frequent congestion (also seen in WUMS) contributed to higher price volatility and larger price spreads between day-ahead and real-time prices. As mentioned previously, such spreads were much lower during the rest of the year as reductions in congestion and fuel prices reduced price volatility and improved price convergence. Over the entire year, real-time prices and RSG costs exceeded their day-ahead counterparts by only \$0.10 per MWh. Hence, price convergence was good in this area.

**Figure 23: Day-Ahead and Real-Time Prices**  
WUMS Area

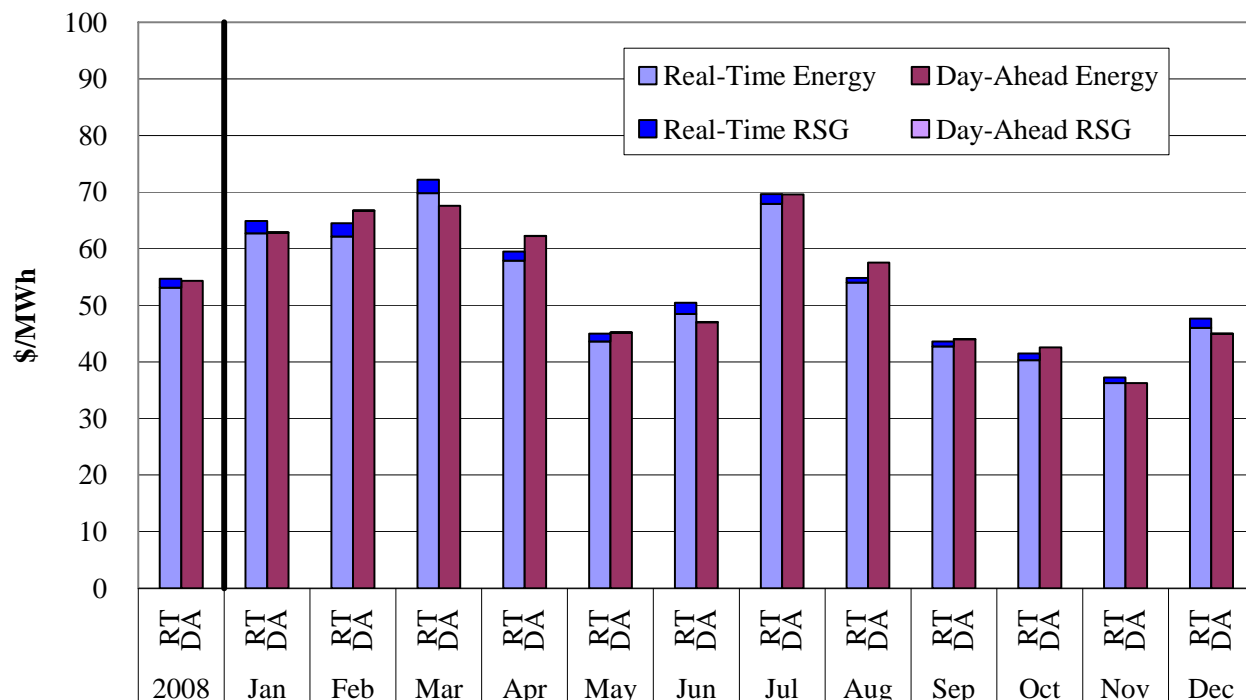


Figure 23 shows that on average, day-ahead and real-time prices in the WUMS area had good convergence, with day-ahead prices slightly exceeding the real-time prices prior to adding RSG costs. For the year, the day-ahead price averaged \$54.30 per MWh in WUMS compared to an average real-time price of \$53.09 per MWh (excluding RSG costs). Price spreads were least predictable in the summer months. Like the Minnesota Hub, price convergence in WUMS over the entire year was very good with real-time prices and RSG costs exceeding day-ahead levels by \$0.40 per MWh. The strong price convergence in the WUMS area indicates arbitrage was effective, despite the increased short-term volatility of prices.

To conclude our analysis of price convergence, we compare a variety of Midwest ISO price statistics to other markets including ISO New England, Inc. ("ISO-NE"), NYISO, and PJM. The results of this analysis are shown in Table 3.

**Table 3: Price Convergence in Midwest ISO and Other RTO Markets in 2008**

	<u>Average Clearing Price</u>			<u>Average of Hourly Absolute Price Difference</u>
	<u>Day-Ahead</u>	<u>Real-Time</u>	<u>Difference</u>	
Midwest ISO:				
Cinergy Hub	\$54.28	\$52.70	\$1.58	\$16.92
Michigan Hub	\$55.87	\$54.02	\$1.85	\$17.84
Minnesota Hub	\$51.33	\$49.85	\$1.48	\$18.61
WUMS Area	\$54.30	\$53.09	\$1.20	\$19.06
New England ISO:				
New England Hub	\$83.69	\$84.01	-\$0.32	\$14.98
Maine	\$78.77	\$78.34	\$0.42	\$13.46
Connecticut	\$88.52	\$87.17	\$1.35	\$16.15
New York ISO:				
Zone A (West)	\$61.83	\$59.95	\$1.89	\$23.59
Zone G (Hudson Valley)	\$91.15	\$89.87	\$1.28	\$25.66
Zone J (New York City)	\$101.80	\$102.61	-\$0.81	\$28.44
PJM:				
AEP Gen Hub	\$53.76	\$53.76	\$0.00	\$13.62
Chicago Hub	\$54.26	\$53.31	\$0.95	\$15.09
New Jersey Hub	\$84.20	\$84.25	-\$0.05	\$21.42
Western Hub	\$74.23	\$73.11	\$1.12	\$19.02

The table above highlights various annual prices of the Midwest ISO and other RTOs in the Eastern Interconnect. The statistics include the annual average day-ahead and real-time price, the difference between the annual average day-ahead and real-time price, and the average of the hourly absolute value of the day-ahead and real-time price difference (which shows the typical difference regardless of whether the difference was positive or negative). For each market, we show these pricing statistics for multiple locations (representing prices in select constrained and unconstrained areas in each market). Overall, these analyses indicate that price convergence in the Midwest ISO has been consistent with the other RTO markets, all of which have been operating longer.

The comparison of the average prices in the table shows that the day-ahead markets exhibit a price premium at most locations, with the exception of a few isolated locations. These premiums are consistent with the higher volatility, risk, and supplemental commitment costs associated with purchasing in the real-time market. The higher premiums in the Midwest ISO relative to other markets are primarily due to RSG cost allocations, which were \$1.59 per MWh higher in the real-time market than in the day-ahead market.

The comparison of the average absolute value of the differences shows that locations affected by congestion exhibited larger average differences, ranging from \$16 to \$28 per MWh, which is consistent with the higher volatility in these areas. In the Real-Time Market Outcomes subsection below, we discuss some reasons for differences in price volatility between markets.

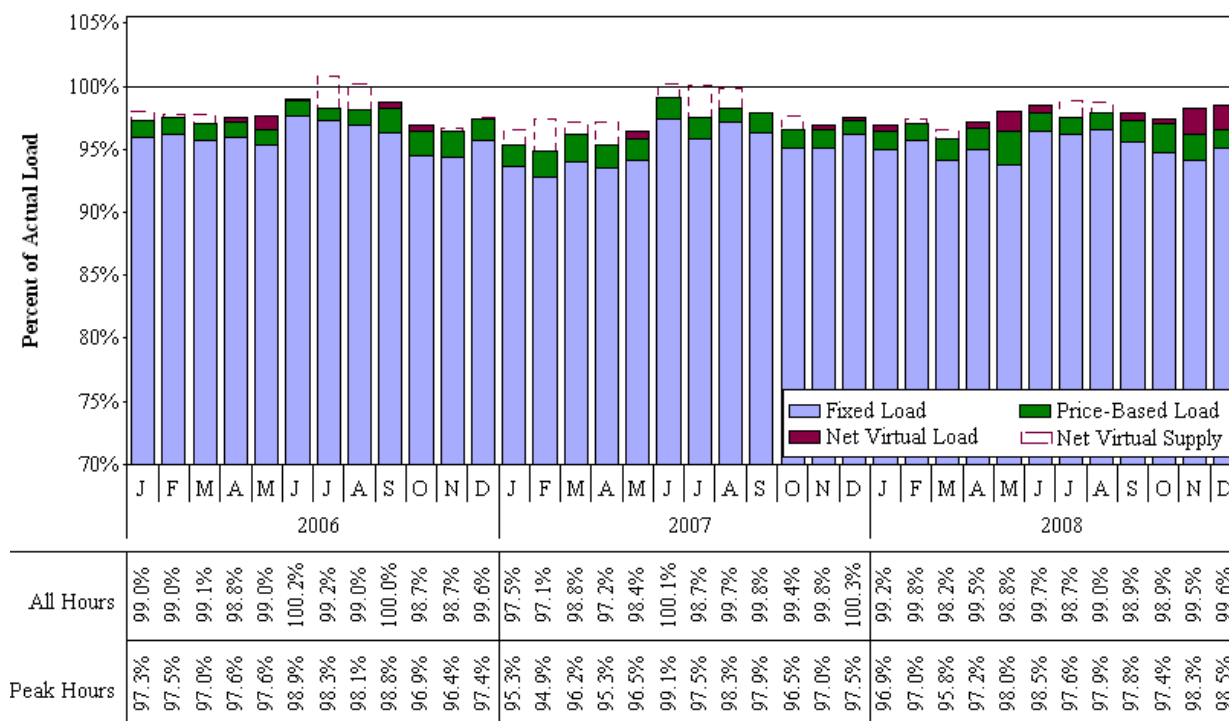
### **3. Day-Ahead Load Scheduling and Virtual Trading**

Our next analysis addresses day-ahead load scheduling and virtual trading. These aspects of the market play an important role in overall market efficiency by promoting efficient commitment and improved price convergence between day-ahead and real-time markets.

We are generally interested in comparing the net load cleared (defined as the physical load, plus virtual load minus virtual supply) in the day-ahead market as a percentage of the actual real-time load. This relationship affects commitment patterns and RSG costs. When day-ahead net load is significantly less than real-time load, particularly in the peak load hour of the day, the Midwest ISO will frequently commit peaking resources to satisfy the incremental increase in load. This contributes to suboptimal real-time pricing that results in inefficiencies. When significant quantities of generation are committed by participants or by the ISO after the day-ahead market, participants will have incentives to schedule net load at less than 100 percent. This supplemental commitment will tend to reduce real-time prices and increase RSG costs.

Day-ahead load scheduling is the demand-side of the day-ahead market. Day-ahead load schedules can be either price-sensitive or fixed. Price-sensitive load is scheduled if the day-ahead price is equal to or less than the load bid. A fixed load schedule does not include a bid price, indicating that the load should be scheduled in the day-ahead market regardless of the day-ahead price.

Figure 24 compares the peak hour day-ahead scheduled load to actual load of each month when the Midwest ISO is most likely to require additional generation.

**Figure 24: Peak Hour Day-Ahead Scheduled Load versus Actual Load**

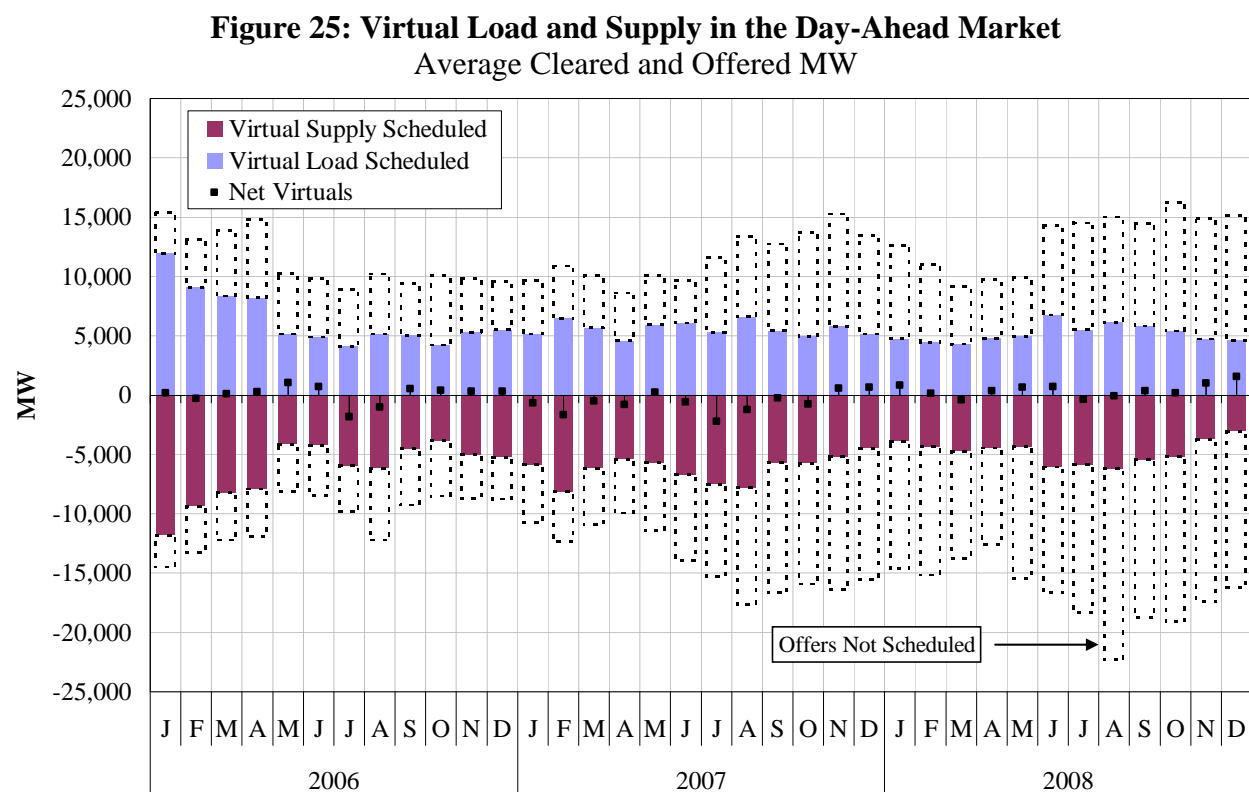
The figure shows that overall, the net load scheduled in the day-ahead market as a percent of the real-time load increased to 99.2 percent, up slightly from 98.9 percent in 2007. The vast majority of this load is “fixed”, meaning it will be purchased at any price. Price-sensitive physical load accounts for less than two percent of total load scheduled market-wide (it peaks regionally in WUMS at nine percent). During only the peak hour of each day, 97.5 percent of the actual load was scheduled on net in the day-ahead market versus 96.9 percent in 2007. These results indicate that day-ahead load scheduling improved in 2008, which contributed to lower RSG costs.

Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or physical resources. Virtual transactions scheduled in the day-ahead market are settled in the real-time. For example, if the market clears one MW of power for \$50 in the day-ahead market, the seller must then purchase one MW in real-time to cover the trade. Accordingly, if the virtual trader expects real-time prices to be lower than day-ahead prices, the trader would make virtual sales in the day-ahead market and buy in the real-time market. Likewise, if a virtual trader expects real-time prices to exceed day-ahead prices, the



trader will make virtual purchases in the day-ahead and sell in the real-time. This trading is one of the primary means of arbitraging the prices in the two markets, causing day-ahead prices to converge with real-time prices. The price convergence resulting from this arbitrage increases the efficiency of the day-ahead market.

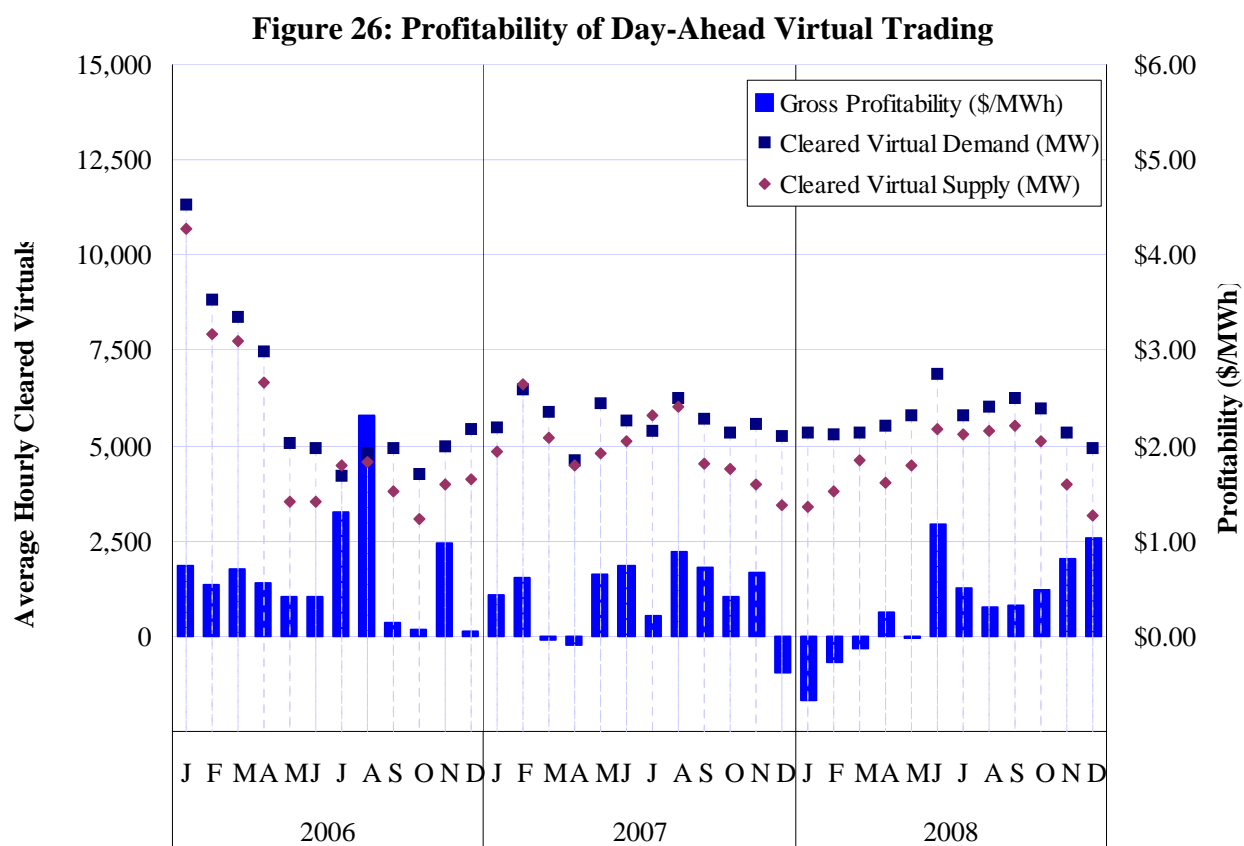
Figure 25 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It shows the components of daily virtual bids and offers and the net virtual load (cleared virtual load less virtual supply) in the day-ahead market from 2006 to 2008. The virtual bids and offers that did not clear (because they were not economic given the prevailing market prices) are shown as dashed areas at the end points of the scheduled bars.



Virtual trades in the day-ahead market ensure efficient day-ahead market results facilitating convergence between the day-ahead and real-time prices and limiting market power in the day-ahead market. Scheduled virtual trading volumes have remained steady since May 2006, fluctuating only mildly with load. Supply offers not scheduled continued to increase gradually in 2008 and fluctuate with the prevailing load, as expected. Virtual trading volumes grew rapidly

up until April 2006, when the Commission issued an order requiring the allocation of RSG costs to virtual supply. Although it directly increased only the cost of virtual supply, both scheduled virtual supply and demand quantities decreased to around five GW each per day. The Commission confirmed their initial decision in a November 2008 order resulting in additional RSG costs being allocated to virtual supply and other deviations. The impact of RSG cost allocations on virtual trading and market convergence are discussed later in this section.

We described earlier in this section how virtual trading increases the efficiency of the market. One can evaluate the liquidity of the market by analyzing the profitability of virtual trading. In a market that is fully arbitrated, profits available to virtual traders should be low. Figure 26 shows monthly average gross profitability of virtual purchases and sales, as well as the volume of virtual supply and demand that cleared the market.

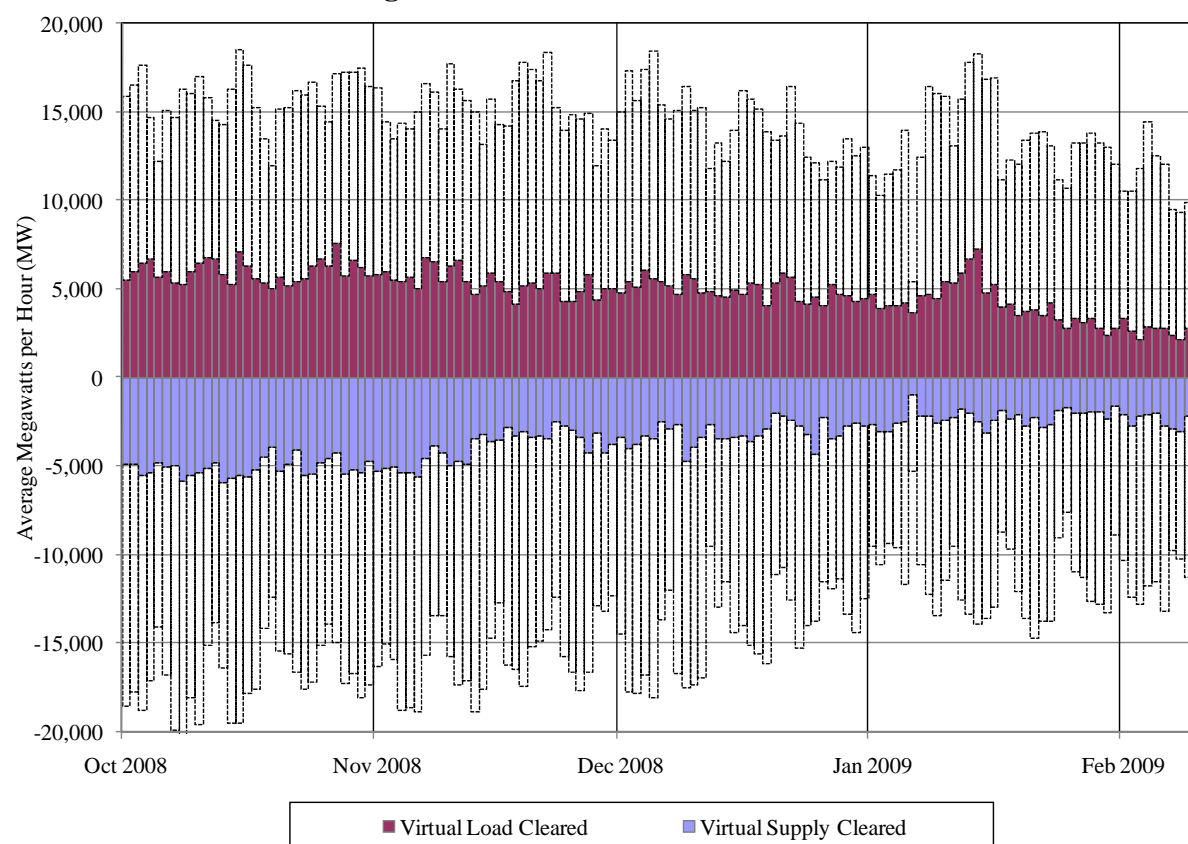


The figure shows that as the Midwest ISO markets have matured, the profitability of virtual transactions has declined. The average gross profit per cleared MWh dropped to \$0.32 per MWh

in 2008, down from \$0.43 per MWh in 2007 and \$0.69 per MWh in 2006. However, after RSG cost allocations are deducted (not shown in figure), the average net profit was negative during 2008. The declining profitability of the virtual trades provides an indication that the market has become more liquid.

We continually monitor for large losses on virtual transactions because they can indicate an attempt by a participant to manipulate the day-ahead market prices. For example, a participant may submit a high-priced virtual bid at a constrained location that causes artificial congestion in the day-ahead market. The participant will buy in the day-ahead at the high, congested price and sell the energy back at a lower, uncongested price in the real-time market. Although it is foreseeable that the virtual transaction would be unprofitable, the participant could earn net profits if it increases its FTR payments through the increased congestion. Virtual losses that warrant further investigation have been rare, and none have warranted a referral to the Commission.

As discussed above, the Commission in November 2008 ordered changes in the RSG cost allocation that established an “interim RSG cost allocation” to be used from August 2007 up until the new RSG cost allocation is implemented. The interim allocation causes substantially all real-time RSG costs to be allocated to deviations from day-ahead scheduled load, such as real-time physical load increases, virtual supply, and real-time import reductions. In addition to real-time deviations, RSG charges are also caused by peaker price setting issues, congestion, reliability needs, and outages. As a result, the interim allocation over-allocates RSG costs to deviations compared to any reasonable standard of “cost-causation”. We estimate that virtual suppliers would have borne almost 40 percent (\$120 million) of all real-time RSG costs for the period from September 2007 to December 2008 under this allocation. This change in allocation is likely the prime contributor to the reductions in virtual trading activity that are shown in Figure 27 below. Specifically, cleared virtual supply in January 2009 was almost 60 percent lower than the levels that prevailed in the fall prior to the Commission’s RSG Orders. Cleared virtual demand in January 2009 is similarly more than 30 percent lower.

**Figure 27: Virtual Transaction Volumes**

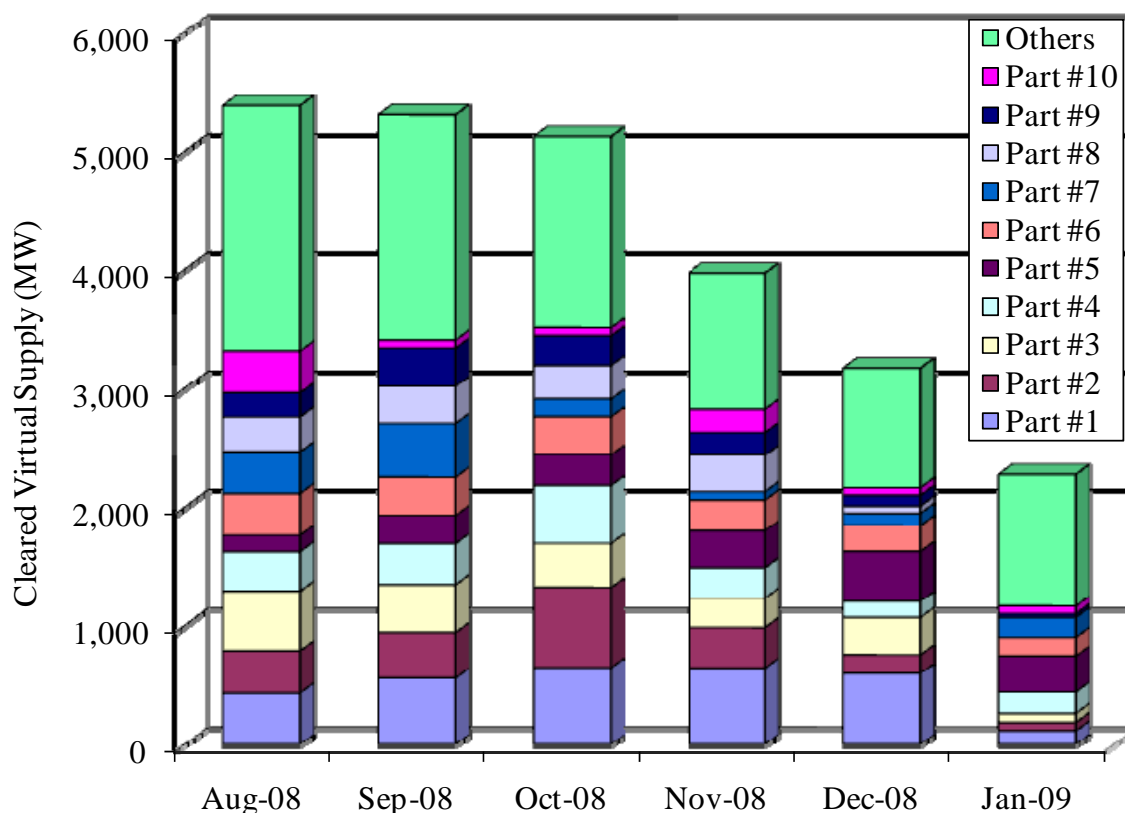
For comparison, Table 4 summarizes virtual trading activity in other RTOs in the Eastern Interconnection. Virtual trading volumes are higher in the larger Midwest ISO, but are comparable to other ISOs as a percentage of real-time load. All three ISOs experienced an overall decline in virtual trading activity, likely owing to the financial crisis that began in the summer of 2008. Specifically, the reduced availability of credit and a flight to quality reduced participants' willingness to engage in virtual trading activity. The reduction in virtual supply levels in the Midwest has been much sharper than in other markets, while the recovery in levels of virtual supply volume in the Midwest ISO has been markedly slower compared to other markets in spring 2009. Virtual load in the Midwest ISO similarly declined, with cleared load levels down over 55 percent over the surveyed period.

**Table 4: Virtual Transaction Volumes**  
Eastern Interconnection

			RT Load	Virtual Supply			Virtual Load		
				Offered	Cleared	Share	Offered	Cleared	Share
Midwest ISO	2008	9	62,648	18,225	5,493	8.8%	13,813	6,273	10.0%
	2008	10	59,045	16,899	5,123	8.7%	15,753	5,995	10.2%
	2008	11	60,880	15,773	3,992	6.6%	15,219	5,382	8.8%
	2008	12	66,510	14,245	3,174	4.8%	14,336	4,953	7.4%
	2009	1	67,556	11,400	2,280	3.4%	13,364	4,180	6.2%
	2009	2	63,081	10,347	2,155	3.4%	10,808	2,454	3.9%
	2009	3	57,674	10,765	2,599	4.5%	10,355	2,604	4.5%
	2009	4	54,561	10,631	2,310	4.2%	10,497	2,836	5.2%
ISO-NE	2008	9	14,874	4,289	1,706	11.5%	2,994	1,890	12.7%
	2008	10	13,864	4,239	1,585	11.4%	2,679	1,464	10.6%
	2008	11	14,405	4,816	1,974	13.7%	3,028	1,584	11.0%
	2008	12	15,398	4,066	1,516	9.8%	2,472	1,332	8.6%
	2009	1	16,221	3,461	1,184	7.3%	2,225	1,079	6.7%
	2009	2	15,162	3,562	1,109	7.3%	1,914	763	5.0%
	2009	3	14,145	3,869	1,404	9.9%	2,188	1,185	8.4%
	2009	4	13,223	3,718	1,318	10.0%	1,994	1,149	8.7%
NYISO	2008	9	19,197	2,537	1,932	10.1%	2,110	1,613	8.4%
	2008	10	17,169	2,553	1,739	10.1%	2,163	1,592	9.3%
	2008	11	17,602	2,633	1,711	9.7%	2,154	1,426	8.1%
	2008	12	18,823	2,726	1,603	8.5%	2,231	1,426	7.6%
	2009	1	19,570	2,400	1,646	8.4%	2,467	1,536	7.8%
	2009	2	18,630	2,930	1,843	9.9%	2,238	1,460	7.8%
	2009	3	17,508	2,984	1,899	10.8%	2,149	1,325	7.6%
	2009	4	16,704	3,229	2,034	12.2%	2,323	1,368	8.2%

These results are further illustrated in Figure 28, which shows cleared virtual supply levels by participants for the six months ending in January 2009. While the total virtual supply cleared for all participants has decreased by almost 60 percent, the amount cleared by the largest three participants decreased by more than 80 percent. These trends are cause for concern because active virtual trading in the day-ahead market promotes price convergence with the real-time market, which facilitates an efficient commitment of generating resources. In addition, active virtual supply protects the market against attempts to raise day-ahead prices by economically withholding physical generation or making excess load (or virtual load) purchases. We filed comments with the Commission related to these findings and will continue to monitor these trends.

**Figure 28: Virtual Supply Cleared**  
Top Participants



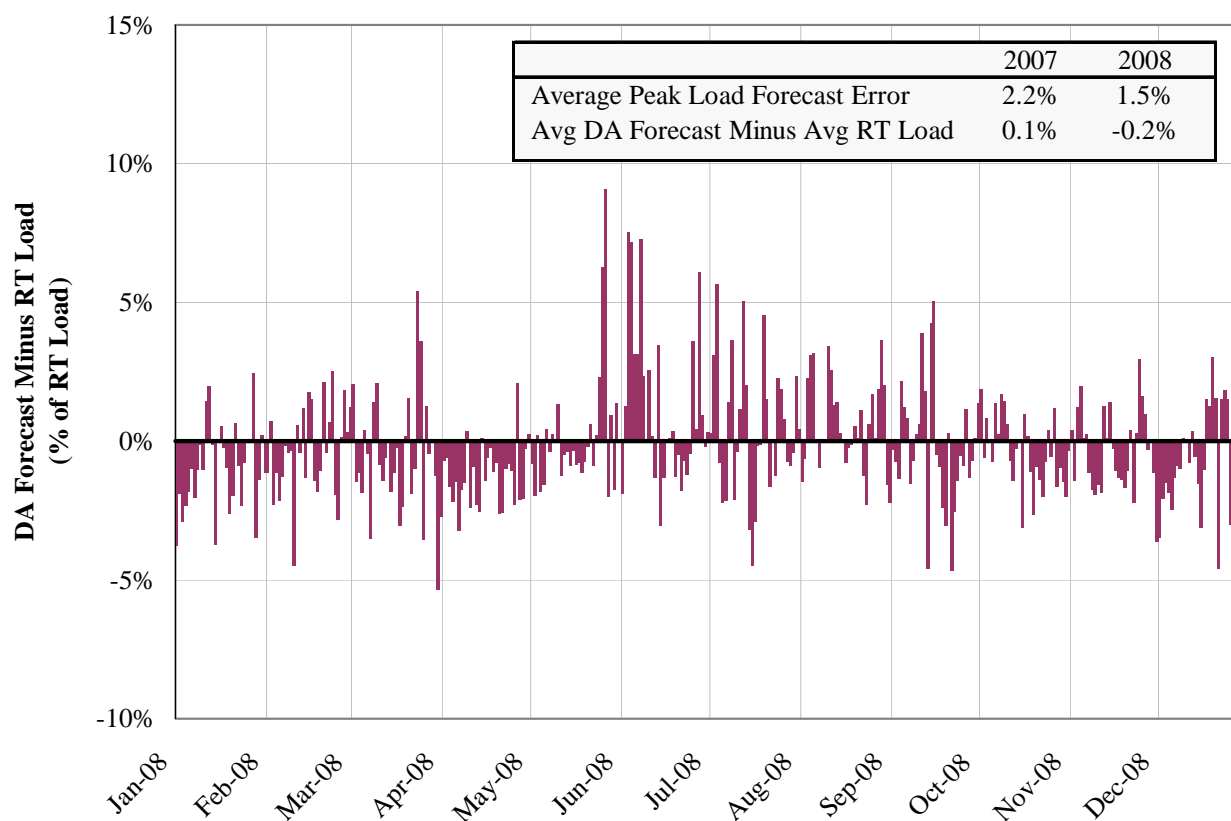
Our next analysis examines the Midwest ISO's day-ahead forecasted load. Day-ahead load forecasting is a key element of an efficient day-ahead commitment process. The accuracy of the day-ahead load forecast is particularly important for the Reliability Assessment Commitment process. Inaccurate forecasts can cause the ISO to commit unnecessary resources or not commit sufficient resources to meet demand, both of which can be costly. Some participants in the day-ahead scheduling and bidding processes may also rely on day-ahead forecasts.

Figure 29 shows the percentage difference between the day-ahead forecasted load and real-time actual load for the peak hour of each day in 2008.

The average peak-hour load exceeded the day-ahead forecast by 0.2 percent in 2008. This indicates that the forecasting was accurate. The average peak-hour forecast error was 1.5 percent (forecast error is the absolute error, regardless of direction). This is lower than the 2.2 percent forecast error recorded in 2007. These results are comparable to the performance of other RTOs.

Forecast error spikes correspond to volatility stemming from unforeseen events such as the storm outages in June 2008. Consistent with the results in the prior two years, load tended to be over-forecasted in the summer and under-forecasted in the fall. The magnitude of these seasonal biases continues to decline due to improvements in forecast techniques.

**Figure 29: Daily Day-Ahead Forecast Error in Peak Hour**  
2008



## B. Real-Time Market Outcomes

In this subsection, we evaluate real-time market outcomes. The real-time market is important because its results directly affect future day-ahead outcomes. Energy purchased in the day-ahead market (and other forward markets) is priced based on expectations of future prices in the real-time markets, and therefore higher real-time prices will lead to higher day-ahead and forward market prices. Because forward purchasing is a primary risk-management tool for participants, increased volatility in the real-time market also leads to higher forward prices by potentially raising risk premiums in the day-ahead market.

## 1. Real-Time Prices and Load

We begin this subsection by providing an overview of the daily average real-time prices and load during peak hours in Figure 30 below.

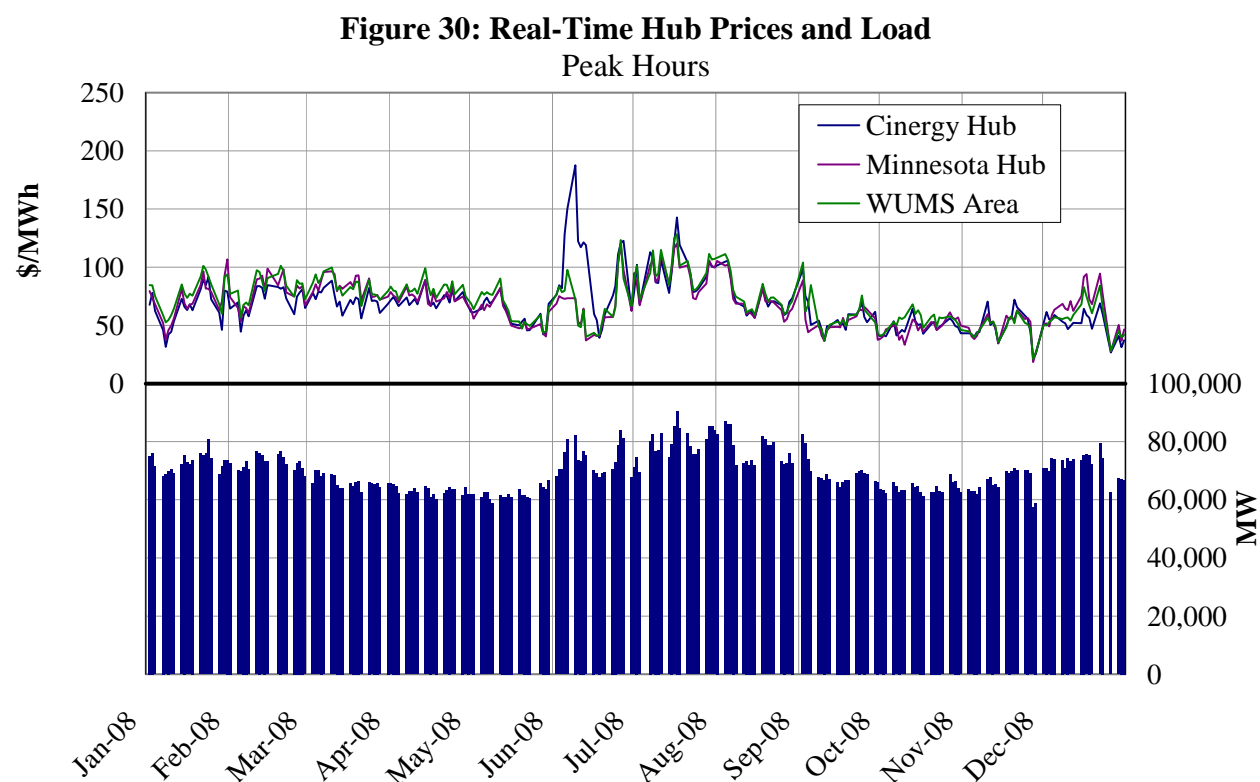
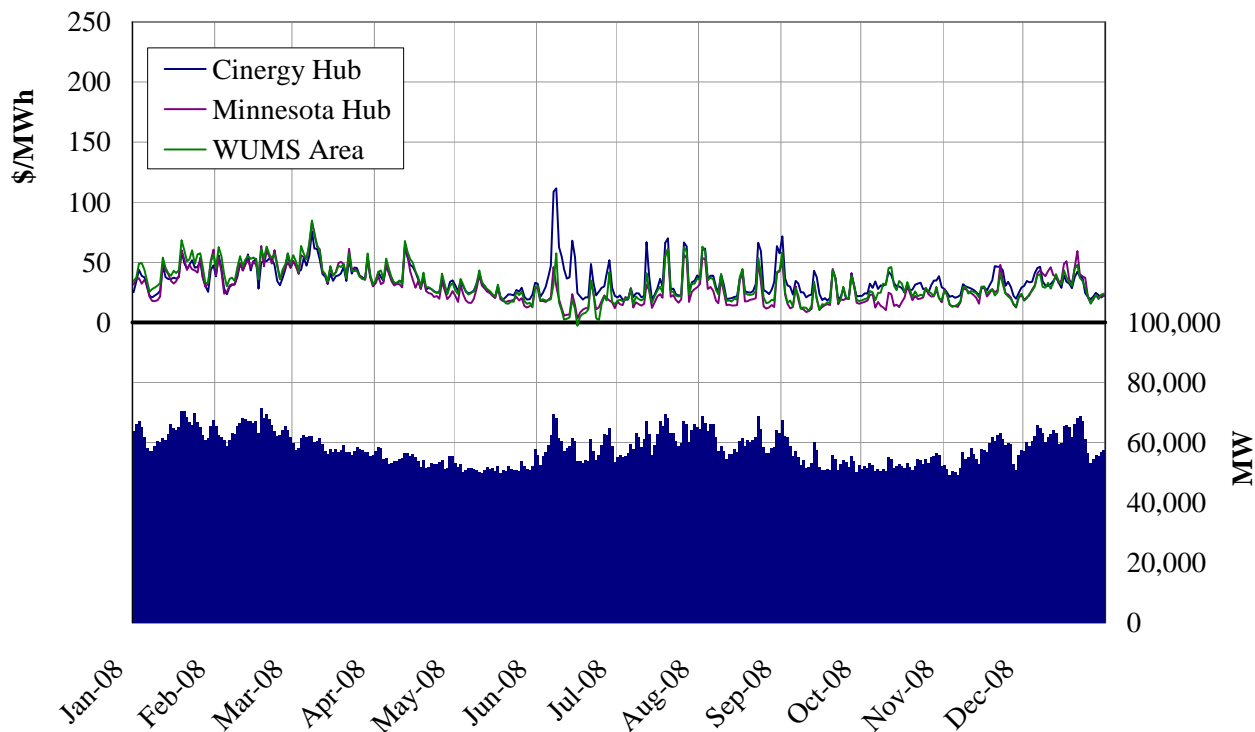


Figure 30 shows a general correlation between peak load and peak price with some notable price separations due to congestion events. As in the day-ahead market, the most substantial congestion occurred into WUMS and Michigan (not shown). This congestion resulted in modest price divergence from other regions, particularly in the January to May period. Peak prices in WUMS and Michigan averaged \$2.57 and \$2.50 per MWh higher than at the Cinergy Hub, respectively. In June, storm-related transmission outages contributed to congestion out of the Western region and WUMS area and into the Cinergy and Michigan regions. Average peak prices at Minnesota and WUMS were approximately \$32 and \$29 per MWh lower than at the Cinergy Hub in June. On the whole, real-time prices decreased considerably in all regions in the second half of the year due to lower fuel prices and reduced load (e.g., peak prices at the Cinergy Hub averaged \$52 in the fourth quarter). Figure 31 shows the same analysis for off-peak hours.



**Figure 31: Real-Time Hub Prices and Load**  
Off-Peak Hours



The figure shows that load and prices are low relative to peak hours. Coal-fired resources usually set prices in off-peak hours. The increase in coal prices, particularly Illinois Basin coal, caused off-peak prices in 2008 to increase by 7.2 percent on average relative to 2007. Storm damage in June caused significant negative price spikes at the Minnesota Hub and WUMS area due to congestion. Congestion also led to periodic negative prices at other times during the year, although such events were less frequent and less severe than those in early 2006 or 2007. Negative price spikes continue to be exacerbated by reduced bid flexibility and ramp limits that make congestion in low-load periods difficult to manage.

The following two figures show average real-time prices by time of day in the winter and summer months of 2008. To identify the drivers of the price fluctuations, the figures show the effective headroom on the system (the amount of additional energy that could be produced in the next five minutes given ramp limitations) and the average change in NSI (shown as “change in net imports”).

**Figure 32: Real-Time Prices and Headroom by Time of Day**  
Winter 2008

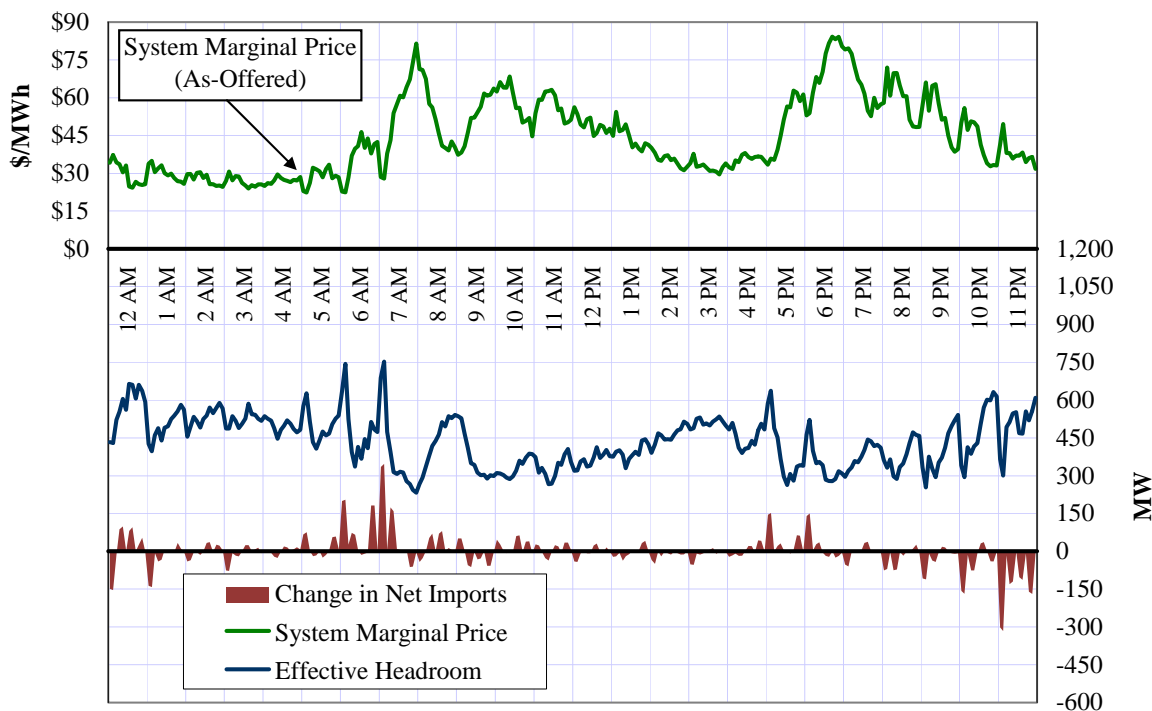
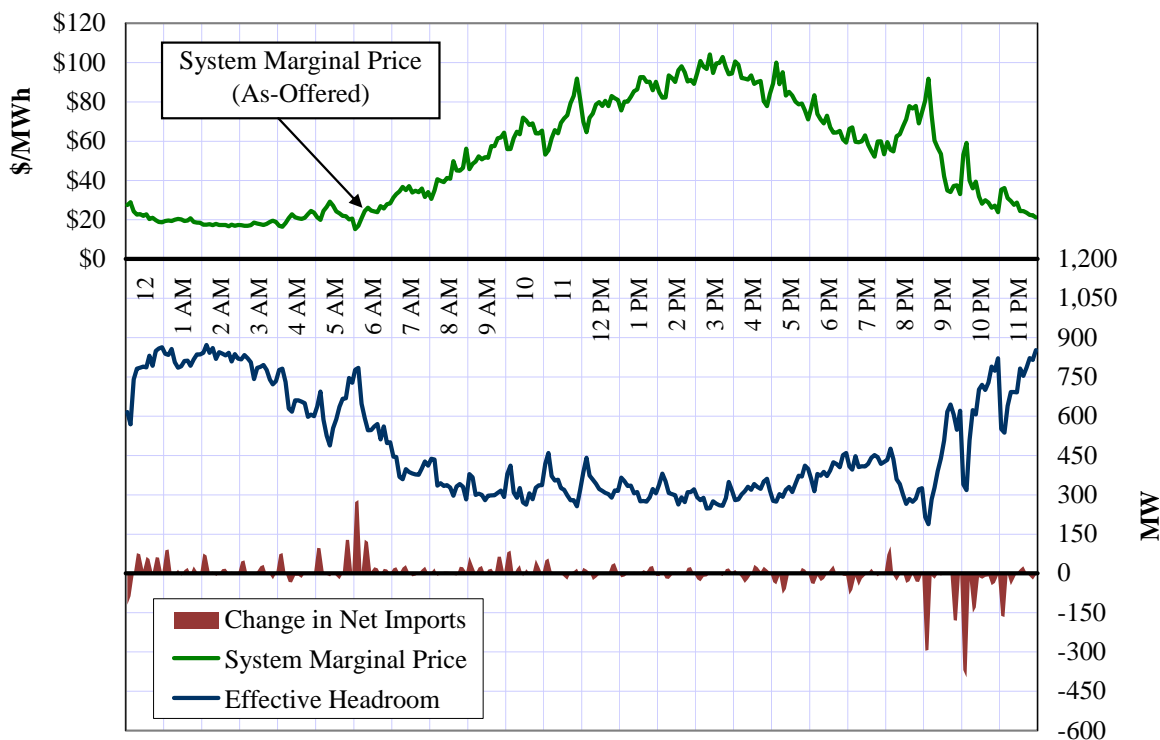


Figure 32 shows that in winter 2008, volatility in five-minute prices increases substantially at the beginning of the ramp-up hours in the morning (5 a.m.) and at the beginning of ramp-down hours in the evening (8 p.m.—hour ending 20). The sharp upward price movements that cause these patterns indicate a short-term system scarcity and are generally the result of generator operating constraints such as ramp constraints. Ramp constraints are limits to how quickly the system's generation can change in response to system conditions. These conditions include changes in interchange with adjacent areas and changes in online generation when units are committed or decommitted.

Ramp constraints are exacerbated by generator inflexibility arising from decreased offered ramp capability or offered dispatch range. In addition, changes in fuel prices can magnify price volatility. For example, larger natural gas-coal price spreads increase price volatility as the price-setting in the market moves from one class of units to the other.

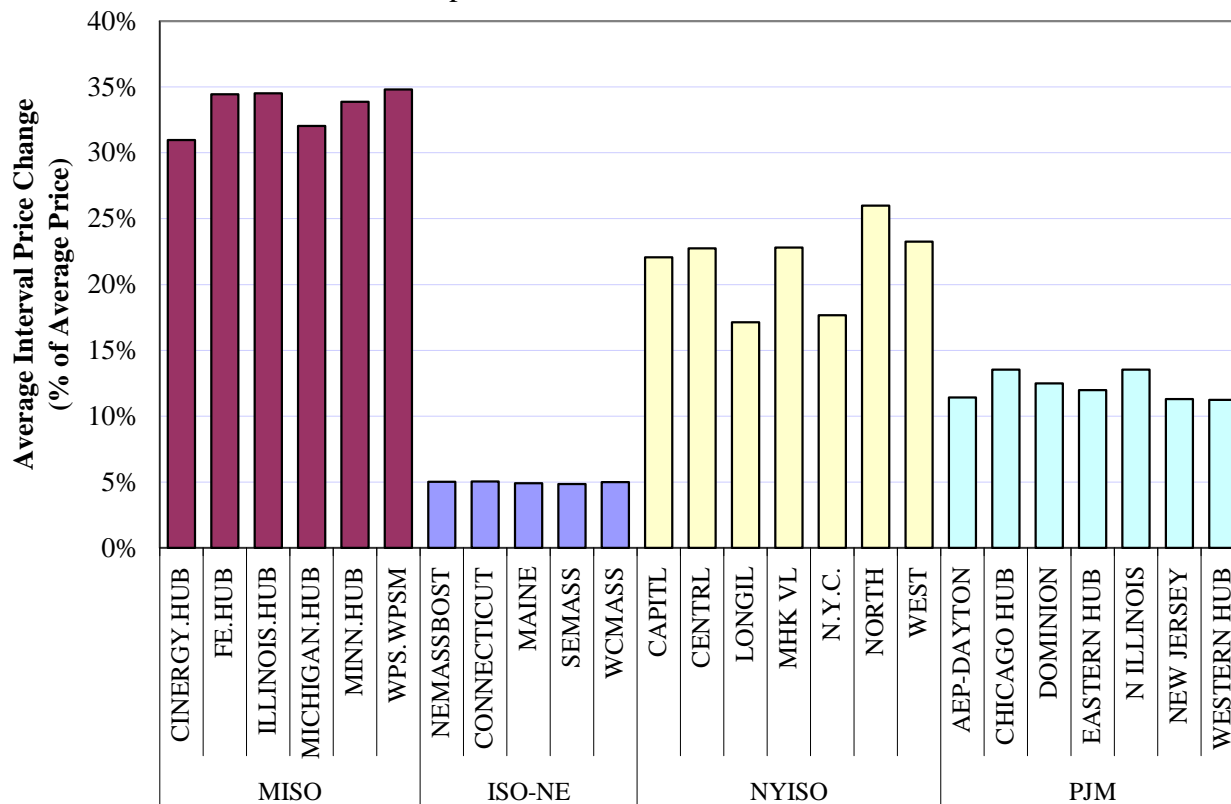
**Figure 33: Real-Time Prices and Headroom by Time of Day**  
Summer 2008



The sharp price movements shown in the figure are often the result of binding ramp constraints. Changes in real-time prices are directly related to changes in effective headroom, which accounts for the effects of ramp constraints. The relationship is expected because low levels of effective headroom typically cause the market to turn to higher-cost energy resources. The figure also indicates that a substantial portion of the changes in effective headroom is related to changes in NSI that are largest at the top of the hour. Significant changes in effective headroom also occur when large quantities of generators startup or shut down (particularly in the afternoon in the summer, and in the morning and evening in the winter). Some of this volatility has decreased under ASM because the real-time market now has the flexibility to optimize jointly the use of resources for energy and contingency reserve needs. We provide some recommendations later in this section that should further reduce the magnitude of the NSI changes and the associated volatility in prices.

To determine whether the price volatility in the Midwest is excessive, Figure 34 shows the average percentage change in real-time prices between five-minute intervals for several hubs in other RTO markets.

**Figure 34: Five-Minute Real-Time Price Volatility**  
Comparison with Other RTO Markets



The results indicate that the Midwest ISO exhibits the most price volatility and ISO-NE exhibits the least. These differences can be explained by the differences in the software and operations of the different markets. The Midwest ISO and NYISO are true five-minute markets with a new dispatch and prices set each five minutes. Ramp constraints are more likely in these markets due to the shorter timeframes for moving each system's generation. However, NYISO's real-time dispatch is a multi-period optimization that looks ahead over the following hour, so it can anticipate ramp needs and begin moving generation to accommodate them. As a result, it exhibited less price volatility in 2008 than the Midwest ISO.

We understand that PJM and ISO-NE generally produce a real-time dispatch every 10 to 15 minutes, although they produce 5-minute prices using their ex post pricing model. These systems do not alter the generation dispatch levels as frequently and are less likely to be ramp-constrained because they have 10 to 15 minutes of ramp capability to serve system demands.

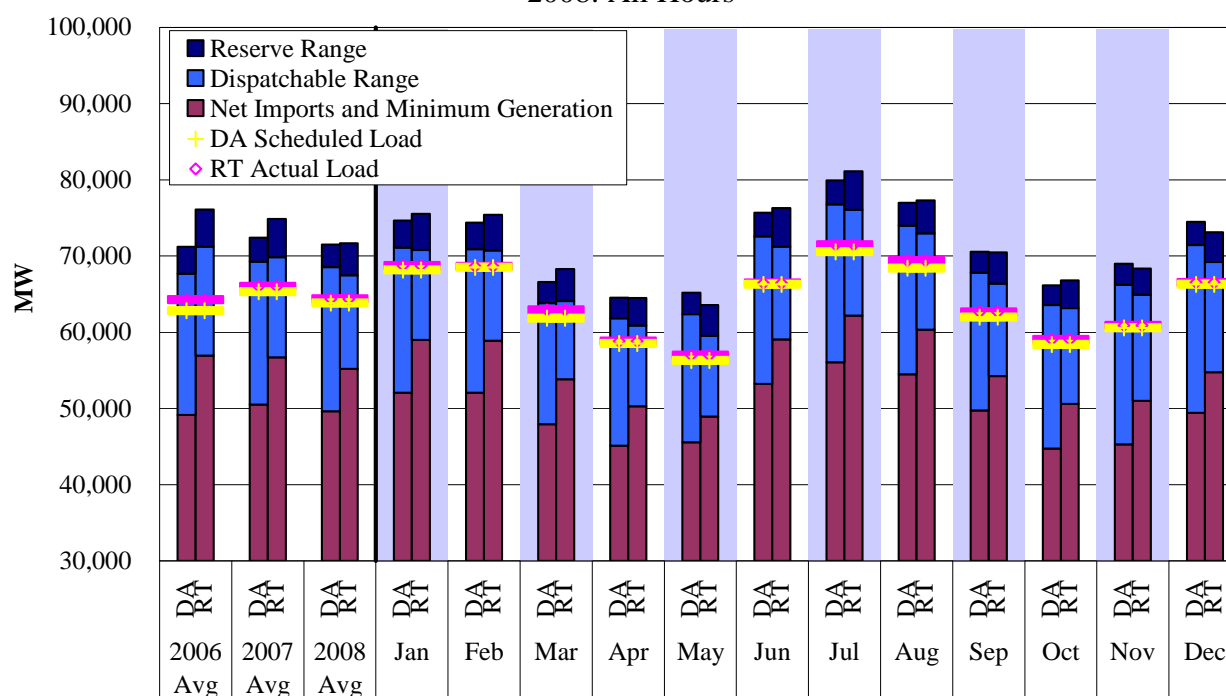
Because the systems are redispatched less frequently, these markets likely rely more heavily on regulation to satisfy shorter-term changes in load and supply.

## 2. Availability of Generation in Real-time

The availability of generation in the real-time market is important because it enables the Midwest ISO to redispatch the system to manage transmission constraints, while satisfying all energy and operating reserves requirements. In general, the day-ahead market coordinates commitment of most generation that will be dispatched in real-time. Figure 35 details the average monthly generation scheduled in the day-ahead and real-time markets.

**Figure 35: Day-Ahead and Real-Time Generation**

2008: All Hours



The figure shows that generation capability is consistently greater in the real-time market. This occurs because some resources are self-scheduled by participants after the day-ahead market and because generation is committed by the ISO after the day-ahead market. On a market-wide basis, the Midwest ISO commits generation after the day-ahead market when load is higher than expected, when load is under-scheduled in the day-ahead markets, or when net virtual supply scheduled in the day-ahead market must be replaced. In addition, intermittent generation such as

wind often increases in the real-time market. Finally, the Midwest ISO may commit additional generation to manage congestion or satisfy local reliability needs of the system.

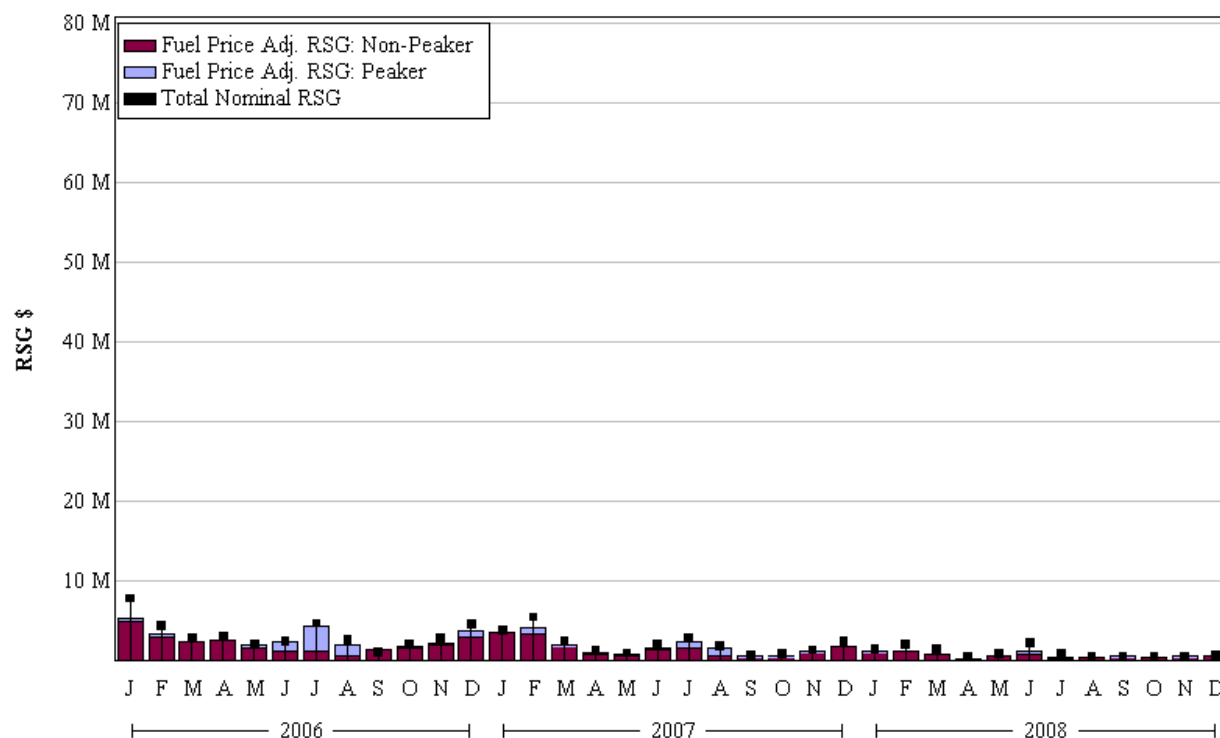
Nearly all generation dispatched in real-time in 2008 was scheduled in the day-ahead market, up from 97 percent in 2007. As the figure shows, dispatch flexibility is lost in the real-time market. The dispatchable range (EcoMax minus EcoMin) as a percentage of total online capacity declined from 29 percent in the day-ahead market to 19 percent in the real-time market. This occurs when EcoMin (the minimum dispatch level) is increased or EcoMax (the maximum dispatch level) is decreased. These values are substantially lower than the physical flexibility of the generating resources, which could physically provide a significantly wider dispatchable range. This loss in flexibility can affect the market by limiting redispatch options for managing congestion and is discussed later in the report.

### **C. Revenue Sufficiency Guarantee Payments**

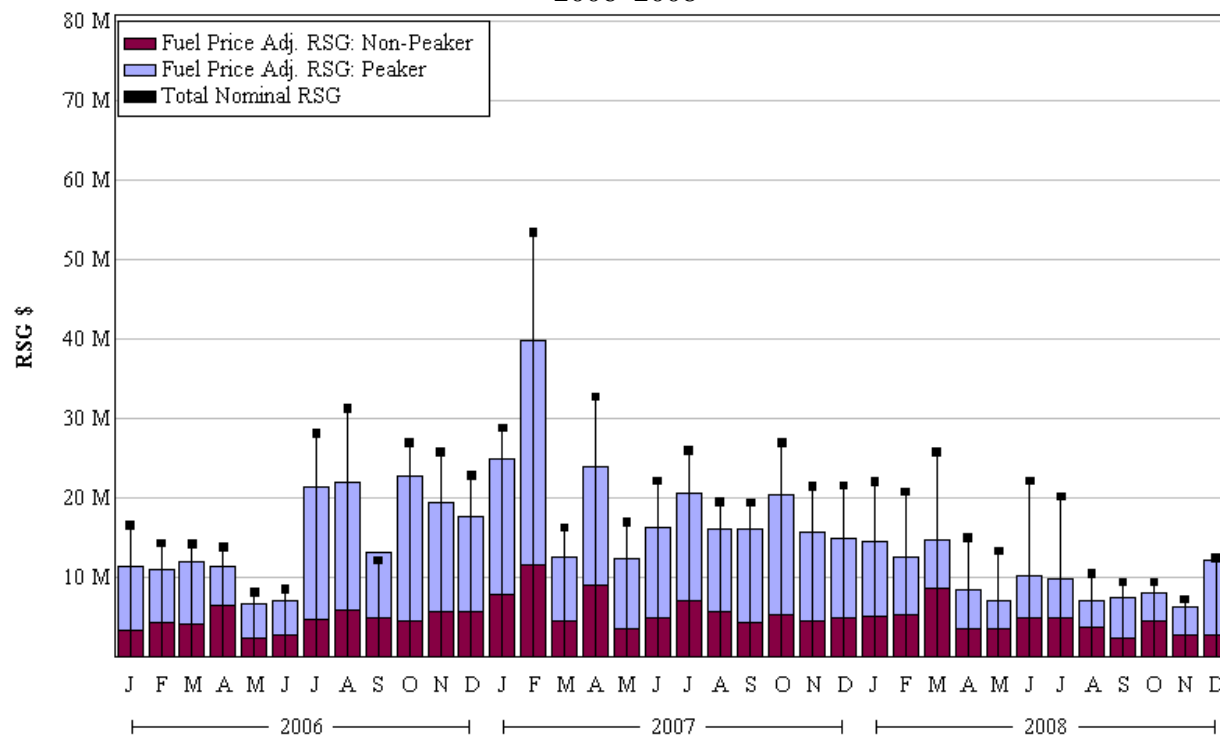
RSG payments are made to generators committed by the Midwest ISO when the LMP revenues in the applicable Midwest ISO market are not sufficient to cover generators' as-offered production costs. Resources that are not committed in the day-ahead market but must be started to maintain reliability are the most likely recipients of RSG payments. These are called "real-time" RSG payments because such units receive their LMP revenues from the real-time market. Because the day-ahead market is financial, it generates minimal RSG costs—a unit that is uneconomic will generally not be selected. Peaking resources are typically the most likely to warrant an RSG payment because they are generally the highest-cost resource and receive minimal LMP margin to cover their startup costs. Additionally, peaking resources frequently do not set the energy price (i.e., the price is set by a lower-cost unit), which increases the likelihood that an RSG payment will be warranted.

Figure 36 and Figure 37 show monthly RSG payments in the day-ahead and real-time markets, respectively. The data is split between peaking and non-peaking units.

**Figure 36: Total Day-Ahead RSG Payment Distribution**  
2006–2008

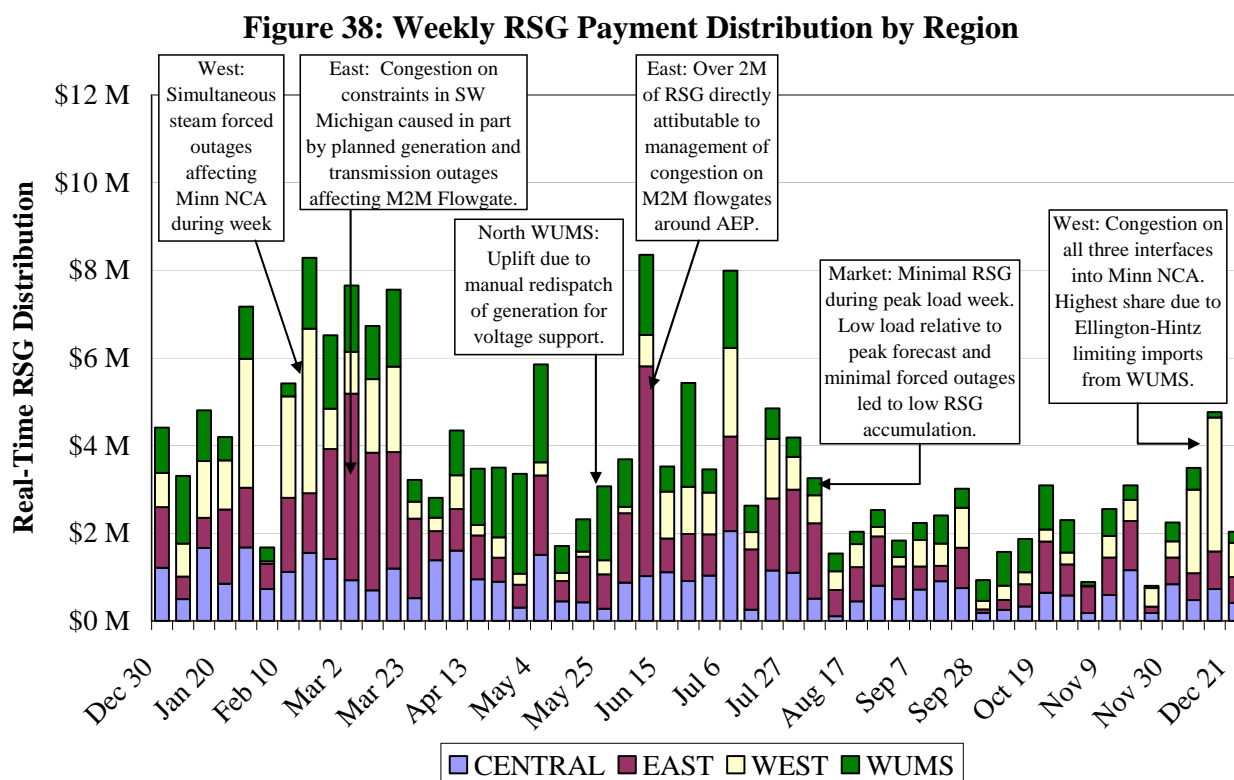


**Figure 37: Total Real-Time RSG Payment Distribution**  
2006–2008



The figures show that 92 percent of RSG costs are generated in the real-time market and most of those are paid to peaking resources. Even though they produced less than one percent of the energy generated in the Midwest ISO, peaking resources received 59 percent of RSG payments in 2008. This level declined from 70 percent in 2007 due to reduced dispatch of peaking resources resulting from lower average and peak loads. Total RSG costs dropped by 35 percent in 2008. Real-time RSG costs decreased from \$331 million to \$216 million in 2008, owing primarily to higher day-ahead load scheduling and a reduced number of commitments in the west to manage Minnesota NCA congestion (particularly during non-winter months). Day-ahead RSG costs declined 41 percent to \$16.6 million in 2008.

Figure 38 shows regional RSG payments data on a weekly basis by region to examine where RSG costs are incurred. Congestion relief is the largest generator of RSG costs. Showing the disaggregated RSG payments allows one to discern how congestion affected RSG costs.



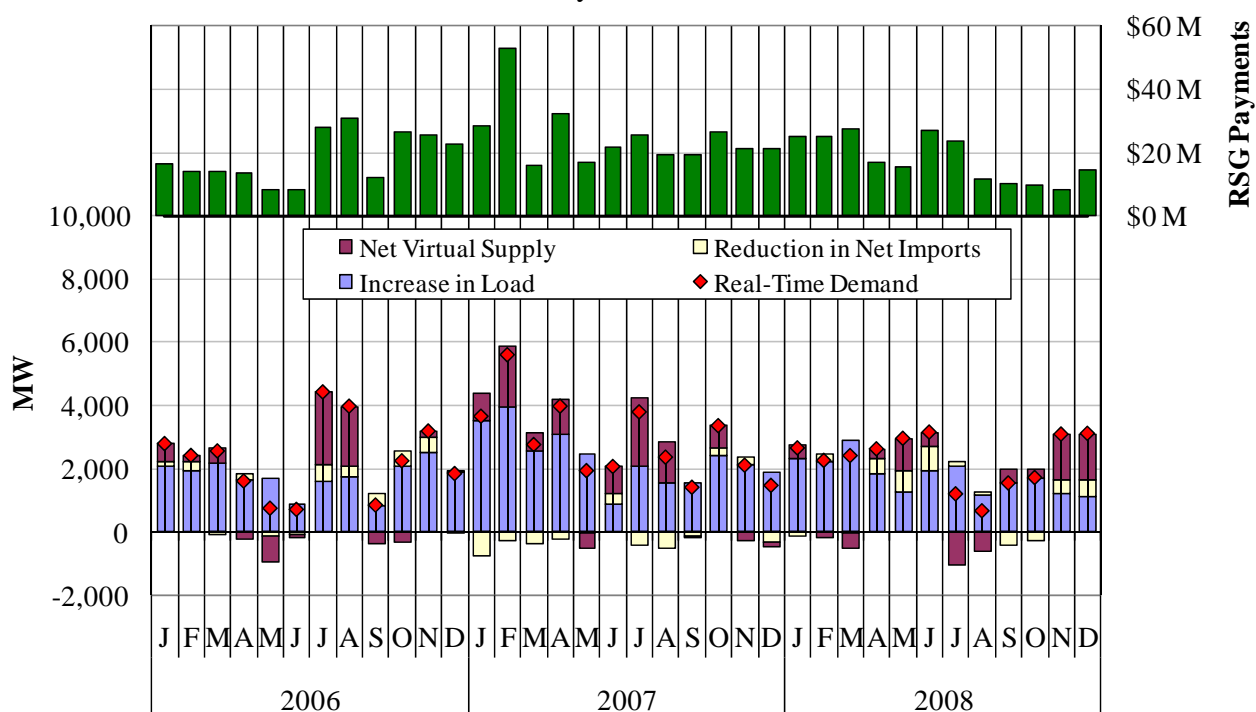
Several trends are highlighted in the figure. The summer peak was mild relative to prior years and below the forecast in the 2008 Summer Assessment. Accordingly, the RSG payments



resulting from the summer peak load weeks were minimal. Payments remained low in the fall as high day-ahead load scheduling prevailed. Transmission congestion resulting from outages was responsible for many of the highest weekly RSG costs. During many of the winter weeks, the West region incurred more RSG costs than it did during the rest of 2008 due to more extreme weather conditions and forced generation outages. The East region had the largest share of RSG costs (32 percent of total cost) due to transmission outages on market-to-market flowgates and planned outages of large nuclear resources in the region during the spring and fall. The Central region has a consistent level of RSG costs in part due to the fact that many of the lowest-cost (per MW of capacity) peaking resources are located there.

Our next analysis seeks to identify factors that explain the changes in the RSG costs. Real-time RSG cost is generally correlated with increases in actual load above the day-ahead scheduled level, which often requires the commitment and dispatch of peaking units. Figure 39 shows monthly RSG payments (in the top panel) along with average real-time demand in the peak hour of each day.

**Figure 39: Drivers of Real-Time RSG Payments**  
Daily Peak Hours



The lower panel shows the components of real-time demand, which are the various reasons that a participant would be buying energy in the real-time market, including: a) increased load from the day-ahead market; b) reduced net imports from the day-ahead market; and c) net virtual sales.

We also show the average peak-hour real-time demand.

As the stacked bars in the lower panel of Figure 39 show, the largest single contributor to real-time demand and RSG payments was under-scheduled load that must be served in the real-time market. In some months, net virtual supply also accounted for a significant share of the real-time demand. Although it is large on some days, changes in the net imports after the day-ahead market are not a significant contributor to the real-time demand.

Real-time demand and RSG payments declined modestly in 2008 due to increases in day-ahead load scheduling and decreases in net virtual supply. Significant under-scheduling can cause actual load to exceed the capability of online units committed in the day-ahead market, causing the ISO to commit substantial additional generation in the real-time. Decreases in peaking unit fuel prices from summer highs in the second half of the year and slight declines in the amount of headroom maintained by the Midwest ISO also contributed to lower RSG payments.

#### **D. Dispatch of Peaking Resources**

As explained above, real-time demand is often satisfied by supplemental generator commitments, typically in the form of quick-start peaking resources because of their low commitment costs and commitment flexibility. The dispatch of peaking resources is important because peaking resources are an important determinant of RSG costs and efficient energy pricing. In 2008, 270 MW of peaking resources were dispatched per hour on average, down from 433 MW in 2007. For the summer months, this amount rose to approximately 500 MW per hour, down from over 1,000 MW per hour in 2007.

The reduction in dispatch of peaking resources can be attributed to a number of factors, some of which have been discussed previously in this report. Load was more fully scheduled in the day-ahead market in 2008, thereby reducing the need for real-time commitments. In addition, lower overall load levels, increased imports over the Manitoba interface, and reduced congestion have all reduced the need for peaking units (to satisfy overall demand or to manage a local constraint).

**Figure 40: Average Daily Peaker Dispatch and Prices**  
All Hours

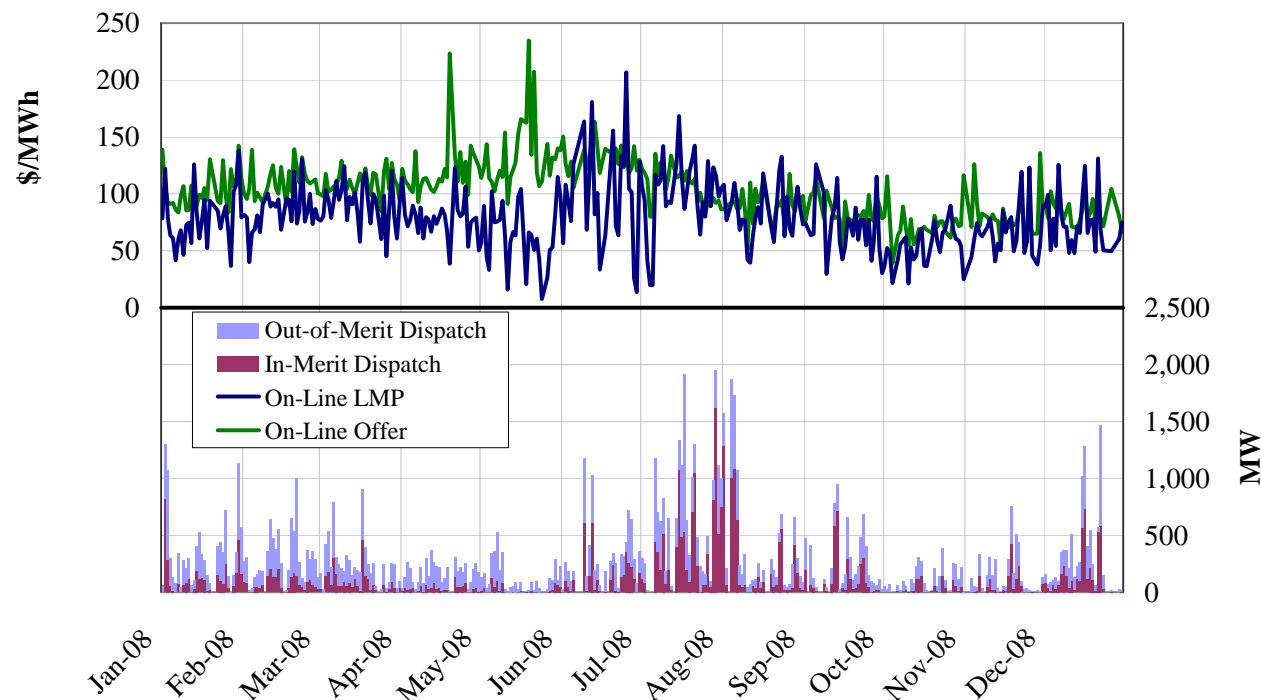


Figure 40 shows the average dispatch levels of peaking resources each day in 2008 and evaluates the consistency between peaking unit dispatch and market outcomes. In the top panel, we compare the average LMP at the peaking resources' locations to the average offer price of the dispatched peaking resources. In the bottom panel, we show the shares of the peaking resource output that are in-merit ( $LMP > \text{offer price}$ ) and out of merit ( $LMP < \text{offer price}$ ).

The figure shows that in 58 percent of all intervals, the average offer price of peaking resources is higher than the average LMP at their locations. In these hours, the peaking resources are not setting prices and many are running out of merit. This is not uncommon because gas turbines often have a narrow operating range and therefore operate at their EcoMin or EcoMax. However, it does contribute to inefficiently low real-time prices. In particular, extensive out-of-merit dispatch affects the incentives to schedule in the day-ahead market and, ultimately, the commitment of resources that is coordinated by the day-ahead market. When a suboptimal commitment arises out of the day-ahead market, real-time costs rise. Inefficiently low real-time prices when peaking resources are dispatched also distorts the incentives of participants to import and export power efficiently. We have recommended changes to improve real-time

pricing by allowing peaking resources and demand resources to set prices. The Midwest ISO has done substantial work to develop a feasible approach in this area.

### **E. Ex Ante and Ex Post Prices**

Like PJM and ISO-NE, the Midwest ISO settles its real-time market using “ex post” prices (i.e., prices that are computed after the operating period is over). The ex post prices are used in settlements and are calculated after the operating period based upon the actual power flows and output. “Ex ante prices” are produced by the real-time dispatch model and are consistent with the cost-minimizing set of dispatch instructions. The prices are set to levels that give generators an incentive to follow their dispatch instructions.<sup>22</sup> Hence, consistency between the ex ante and ex post prices is important for ensuring that suppliers have the incentive to follow the ex ante dispatch instructions.

Beginning in 2009 with the deployment of ASM, the methodology was modified again and ex ante and ex post pricing differences have been eliminated. The revised ex post pricing approach will provide the benefits of price corrections without the inefficiencies caused by other ex post pricing approaches.

Ex post prices are produced by the LMP Calculator. At the end of each interval, the LMP Calculator re-calculates dispatch quantities and prices using inputs that are different in several respects from the inputs used by the Unit Dispatch System (“UDS”). For each flexible resource, a “real-time offer price” is used in the LMP calculator in place of its offer curve.<sup>23</sup> For a resource following dispatch instructions, its “real-time offer price” in the LMP calculator equals the ex ante price at its location or, if it is operating at its maximum output level, the offer price in the LMP calculator corresponds to its actual production level. For a resource that is under-producing by a significant amount, the “real-time offer price” in the LMP calculator equals the

---

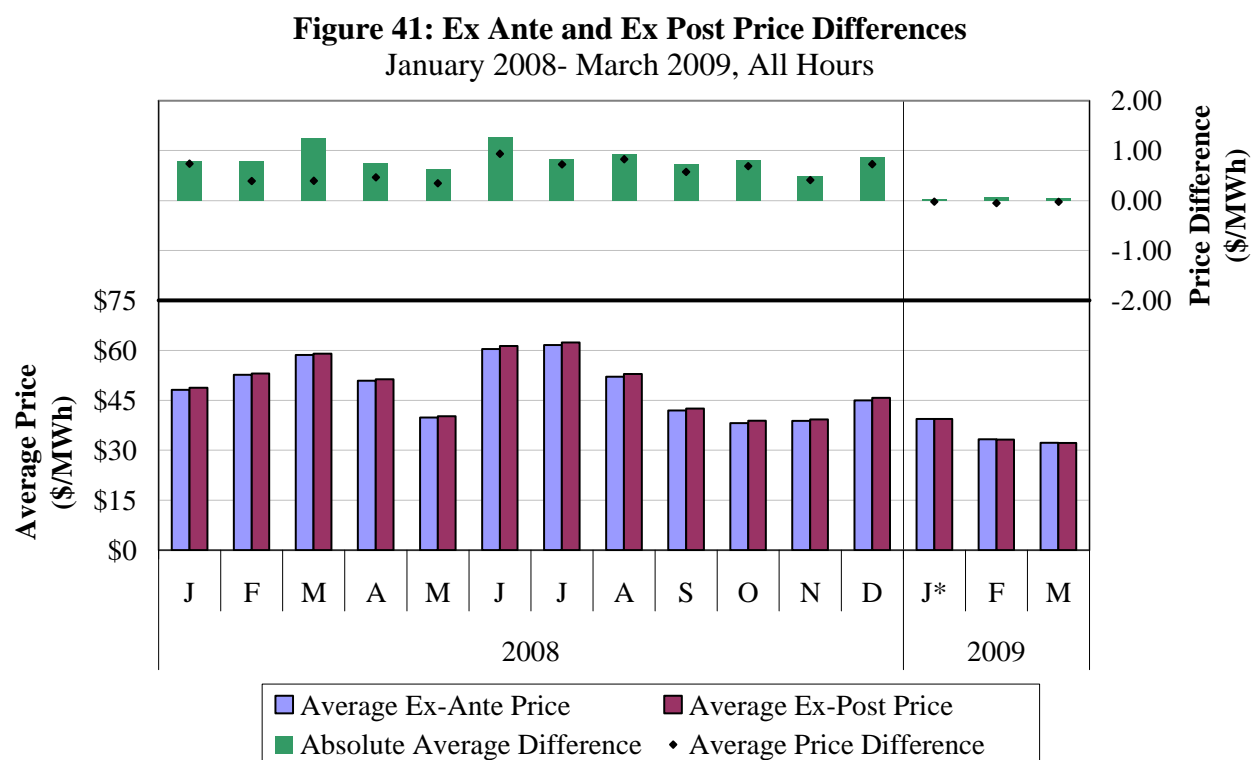
<sup>22</sup> This assumes the generators are offered at marginal cost.

<sup>23</sup> Most resources are treated as flexible if they are producing more than zero MW and they meet one of the following conditions: (i) being committed for transmission; (ii) being dispatchable and producing less than 110 percent of their dispatch instruction; and (iii) being dispatchable and having a real-time offer price at their actual production level that is less than or equal to the ex ante price.

offer price corresponding to the resource's actual production level. Each flexible resource is treated as having a small dispatchable range around its actual production level, where the upward range is much smaller than the downward range (e.g., approximately 0.1 MW up and 2 MW down). The purpose of the ex post pricing method is to generate a set of prices that is consistent with the actual production levels of generators in the market, rather than their dispatch instructions.

Our analysis seeks to evaluate the consistency between ex post and ex ante prices in 2008.

Figure 41 summarizes the results of our analysis, showing both the average difference in the five-minute ex post and ex ante prices, as well as the average of the absolute value of the hourly difference in the prices. This second metric indicates how large the differences are, regardless of the direction of the difference.



\* Note: The last five market days of Energy-Only market have been excluded from January 2009 data.

The figure shows there was a persistent bias in the ex post calculator in 2008 that caused the ex post price to be marginally higher than the ex ante price by approximately three percent. This is

due to two primary factors. First, loss factors change slightly between the ex ante price calculation and the ex post price calculation as the pattern of generation and load changes. Even though many units' "real-time offer prices" are equal to the ex ante price (which should make them economically equivalent), these changes in loss factors affect the relative offer costs of the resources. The second factor is that the dispatchable range of each resource is generally 20 to 40 times larger in the downward direction than the upward direction. Although these factors could probably have been addressed, ex post pricing provided no real value as discussed below.

Ex post pricing had been justified in part as a means to provide resources with incentives to follow dispatch instructions. However, ex post pricing does not efficiently provide such an incentive for several reasons. First, suppliers that are primarily scheduled day-ahead will not be substantially harmed by small adjustments in the real-time price. Second, with the exception of the periodic price effects in congested areas, the pricing methodology will not usually result in significant changes in prices when a unit does not follow dispatch instructions. In general, this is the case because many other units will have real-time offer prices in the ex post model equal to the ex ante price that can replace the unit following dispatch. Hence, it is highly unlikely that ex post pricing enhances incentives to follow dispatch instructions. Because ex post pricing can sometimes substantially affect prices in congested areas, it can diminish suppliers' incentives to follow ex ante dispatch instructions when prices in the congested area are volatile. Uninstructed deviation penalties are a much more efficient incentive to follow dispatch instructions.

A final theoretical concern is that ex post prices are theoretically less efficient than ex ante prices. The ex ante dispatch and prices represent the least cost dispatch of the system, given bids, offers, and binding constraints. If a unit is unable to respond to the dispatch instruction, then it implies that less supply is available to the market, and thus, the price should have been set by a more expensive offer. In other words, a higher-cost offer would have been taken if the market had known the unit could not respond. In such a case, however, the ex post pricing method would reduce the energy prices from the ex ante level.

The new ex post pricing methodology allows the Midwest ISO to calculate energy prices that correct for errors that may have been included in the ex ante dispatch and prices, removing

inefficiencies caused by other ex post pricing approaches. As Figure 41 shows, ex post prices are now much more consistent with ex ante prices after the deployment of ASM in January 2009.

## **F. Wind Generation**

Wind generation and capacity have grown rapidly in the Midwest ISO market since its inception. Wind resources now make up 4.2 percent of installed capacity (approximately 6 GW) and 3.3 percent of generation, producing up to 4,000 MW. This trend is expected to continue due to the prevalence of abundant wind resources in the western areas of the footprint, favorable existing federal and state mandates, and various subsidies and tax incentives. In addition, future federal carbon and energy policies will likely further encourage wind generation.

Wind generation produces sizable environmental benefits. As intermittent resources, however, wind generators present particular operational, forecasting, and scheduling challenges that most conventional resources avoid. These challenges are amplified as wind's portion of total generation increases. Intermittent resources are by definition prone to changes in output that can result in system reliability and congestion management problems.

In the day-ahead market, intermittent resources can submit offers (accompanied by generation forecasts) and can be committed as capacity resources under Module E of the Tariff at a 20 percent capacity factor. In real time, however, they cannot schedule offers, be committed, follow setpoint instructions, or be dispatched by the real-time market. As a result, the market generally does not coordinate the production of intermittent resources. Instead, the Midwest ISO relies on rule-based methods in the SCUC and SECD algorithm to relax lower priority requirements and when necessary resorts to manual operating procedures to ensure reliability.

To show how the output levels from wind resources have changed in 2008 and how it is scheduled in the day-ahead market, Figure 42 shows that wind scheduled in both the day-ahead and real-time markets in the top panel. The bottom panel shows the change in schedules between the day-ahead and real-time markets.

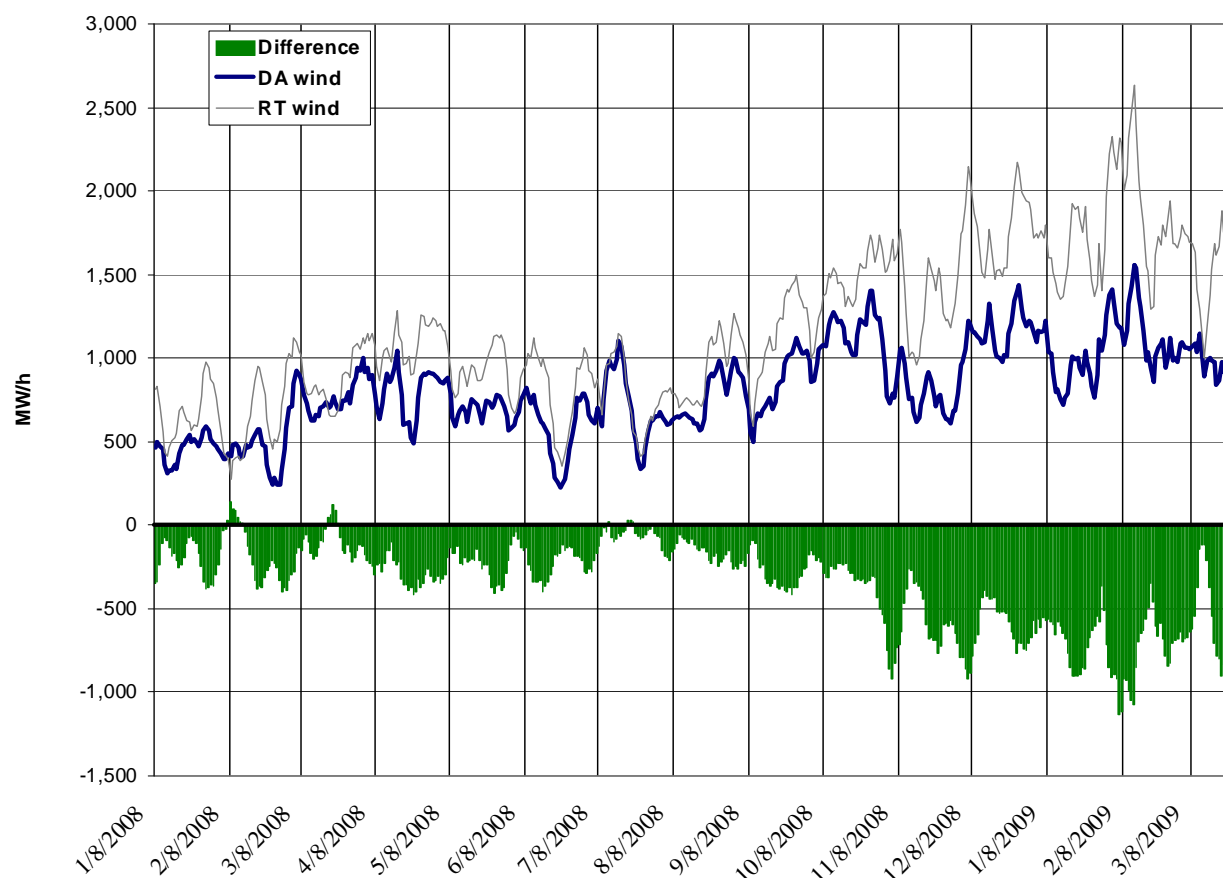
**Figure 42: Scheduling of Wind Generation in the Real-Time and Day-Ahead Markets**

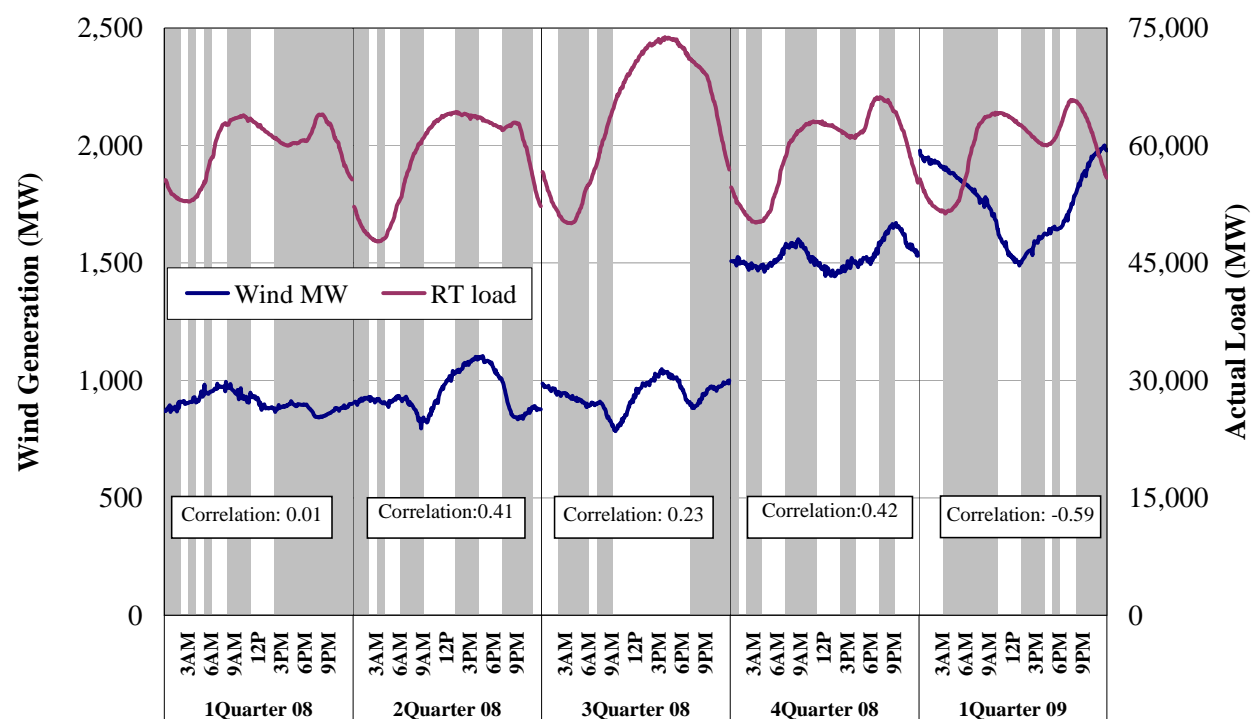
Figure 42 shows that wind generation was under-scheduled in the day-ahead market in 2008 and that this trend has grown proportionately to wind generation. Such under-scheduling in the day-ahead market can cause large price divergence between the day-ahead and real-time market. The variability in wind output can cause RSG costs by compelling the RTO to commit additional resources to manage this variability. Wind and non-wind intermittent generation resources are currently exempt from all RSG costs, including must-run, deration, excessive energy, and deficient energy deviations. The Midwest ISO is considering assessing RSG costs to deration in the future. Proper RSG cost allocation is essential to the effective integration of wind generation, but allocations must remain incentive-compatible with energy markets and should be assessed on a cost-causation basis.

Figure 43 shows average wind generation in real time by time of day versus load in the Midwest ISO in 2008. The figure confirms that wind generation is often negatively correlated with load.



Wind output in other regions such as ERCOT has also been negatively correlated with load. As the last frame of the figure demonstrates, this can at times present situations where curtailment is necessary.

**Figure 43: Wind Generation versus Load**



Although wind provides substantial environmental benefits relative to most conventional generation, it also presents significant operational challenges that need to be addressed before larger amounts of wind generation can be integrated into the market. The Midwest ISO is currently working on harmonizing this process and expects to file Tariff changes in the first quarter of 2010. We will continue to monitor the market impact of wind integration as it continues.

## G. Market Outcomes Conclusions and Recommendations

Overall, the Midwest ISO's markets performed efficiently in 2009. The nodal market accurately reflected the value of congestion in the Midwest, particularly in response to storm-related transmission outages in June. As expected, prices in the real-time market were substantially more volatile than in the day-ahead market, although this volatility has declined since the

introduction of ASM in January 2009. The performance of the real-time market is compromised by at least four factors:

- Reduced dispatch flexibility offered by many generators, which can make congestion more difficult to manage;
- The absence of a real-time model that optimizes the commitment and de-commitment of peaking resources;
- LMPs that do not always reflect the costs of peaking or DR resources when they are the marginal source of energy; and
- Difficulties faced in integrating wind resources into the Midwest ISO markets.

Many of the recent changes adopted by the Midwest ISO have improved the overall performance of the market, most notably the introduction of ASM. Ancillary services markets are jointly optimized with the energy market. This allows a more efficient allocation of resources between energy and ancillary services and sets efficient prices in both markets to reflect the economic trade-off between energy and reserves, particularly during shortage conditions. With ASM, the Midwest ISO implemented make-whole payments to ensure that generators following five-minute dispatch instructions when prices are volatile are not harmed in their hourly settlements. This provides better incentives to generators to be flexible. Another change that has improved market performance is replacing the ex post pricing methodology with an approach that utilizes ex ante prices corrected for metering or other errors. This change improves the efficiency of real-time prices and better aligns incentives of suppliers.

To further improve the performance of the real-time market, we recommend the Midwest ISO consider the following changes (we provide recommendations regarding congestion management and external transactions in subsequent sections).

***1. Develop real-time software and market provisions that allow peaking resources running at their EcoMin or EcoMax to set the energy prices when appropriate.***

Peaking resources tend to be inflexible (i.e., they have a narrow dispatch range from EcoMin to EcoMax). This reduces the likelihood that they will set prices because units dispatched at their EcoMin or EcoMax are not eligible to set prices. Properly implemented, this recommendation would allow gas turbines to set prices when they are needed (i.e., they would not be dispatched

down to zero if they were completely flexible) but would prevent those that are not needed from setting prices. Distinguishing between peaking resources that should contribute to setting prices from those that should not contribute to setting prices is a challenging modeling problem.

Ultimately, gas turbines providing energy necessary to meet market demand should be able to set prices, while gas turbines providing energy that could otherwise be provided by lower-cost online resources would not set energy prices. The Midwest ISO should be in a position to test the feasibility of a new approach in 2009. This change should improve the efficiency of the real-time prices, increase the incentives to schedule load fully in the day-ahead market, and reduce RSG costs.

**2.     *Develop a “look-ahead” capability in the real-time that would commit quick-starting gas turbines and manage the ramp capability on slow-ramping units.***

The Midwest ISO has already made operational improvements in its commitment of peaking resources. In the short-run, the commitment of these units can be further improved by improving the tool that determines the recommended “offset” parameter used to make incremental adjustments to load modeled in the real-time market. In the long-run, this recommendation involves developing a model to assist in the anticipation of ramp constraints and economic commitment of peaking resources, which should reduce out-of-merit quantities and RSG payments.

**3.     *Develop provisions that allow DR resources to set energy prices in the real-time market when they are called upon in a shortage.***

Improving real-time price setting by DR resources, particularly curtailable Type I resources that currently do not respond to real-time dispatch orders, is essential to enhancing the efficiency of the real-time market. Provisions that improve price signals in the highest-demand hours ensure that the markets send efficient long-term economic signals to develop and maintain adequate supply resources and develop additional DR capability. It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines. Additional DR recommendations are covered in Section VII.

**4.     *Improve the integration of wind resources in the Midwest ISO system.***

The growth of wind generation in the Midwest ISO footprint requires proper integration with the system in a manner that does not compromise reliability and efficiency. Congestion management is best accomplished via price signals and economic dispatch; since intermittent generation is not economically dispatchable, it is currently managed through manual dispatch. Taking steps to allow wind resources to be curtailable at a specified offer price would result in wind resources being more dispatchable and eligible to set prices in the energy market. In addition, payments for RSG and other services (e.g., reserves, regulation) should be assessed to wind generators in accordance with the costs that such generators cause in order to provide these suppliers efficient operating and investment incentives.

## **V. Transmission Congestion and Financial Transmission Rights**

One of the primary functions of the Midwest ISO energy markets is to meet load requirements with the lowest-cost resources given the limitations of the transmission network. The locational market structure in the Midwest ISO generally ensures that transmission capability is used efficiently and that energy prices reflect the marginal value of energy at each location.

Congestion costs arise when flow limits on transmission lines prevent lower-cost generation on the unconstrained side of a transmission interface from replacing higher-cost generation on the constrained side of an interface. The result is a higher LMP in the constrained area. An efficient system typically will have some congestion because investment in transmission to alleviate the congestion should only occur when the cost of such investment is less than the benefit of eliminating the congestion.

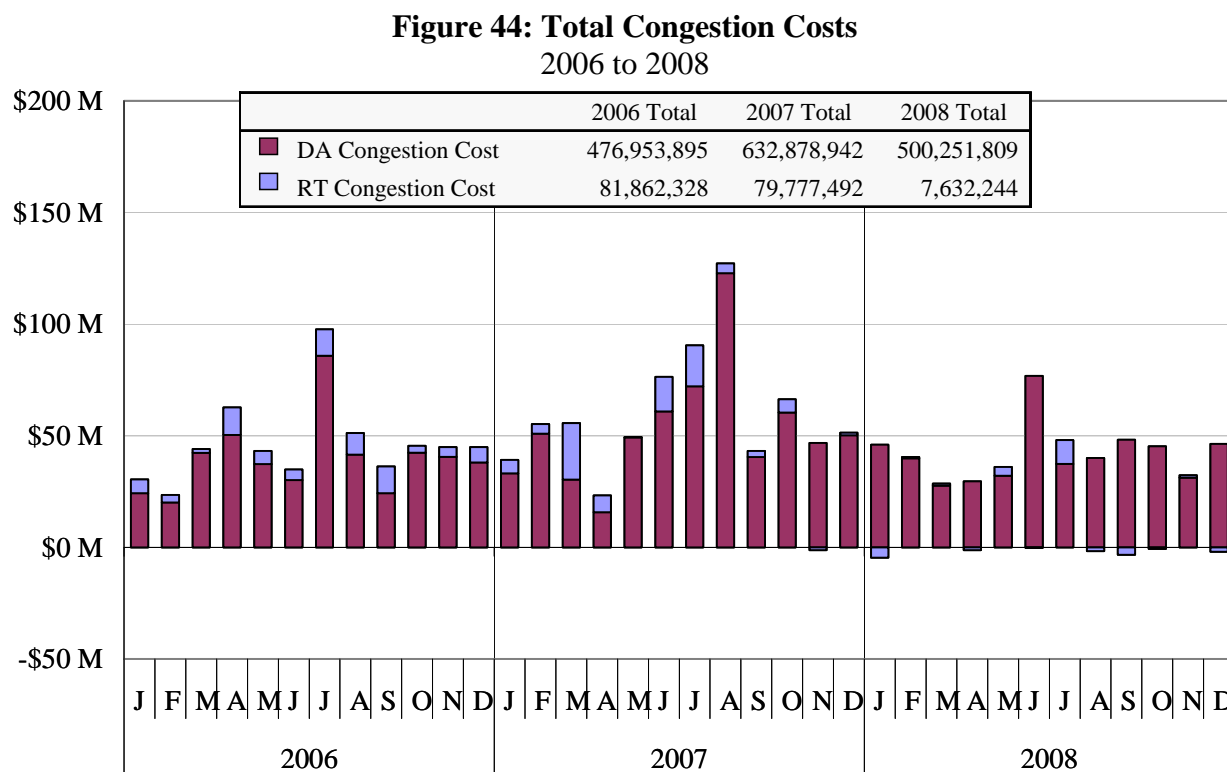
When congestion arises, the difference in prices across the interface represents the marginal value of transmission capability between the two areas. When power is transferred across the interface up to the limit, congestion costs are approximately equal to the difference in LMP prices across the interface multiplied by the amount of the transfer. These congestion costs are collected by the Midwest ISO in the settlement process through the congestion component of the LMP. Net load in the constrained area settles at the constrained area price and the net generation in the unconstrained area settles at the unconstrained price. As a result, more payments are received from the load than are paid to the generators. These excess payments are congestion costs.

Locational prices that reflect congestion provide economic signals that are important in managing congestion on the transmission network in both the short run and long run. These signals are important in the short run because they allow generation to be efficiently redispatched to manage the network flows. They are also important in the long run because they govern investment and retirement decisions.

In this section of the report, we evaluate congestion costs, FTR market results, and the Midwest ISO's management of congestion during 2008. We begin this section by presenting an overall summary of congestion costs incurred in the day-ahead and real-time markets.

## A. Real-Time Congestion Costs

Figure 44 shows the total congestion costs incurred in the day-ahead and real-time markets from 2006 through 2008.



Day-ahead congestion costs declined by \$132 million (20 percent) in 2008 compared to 2007. This occurred despite an increase in fuel prices, which should increase congestion costs because natural-gas fired units are comparatively less expensive. This decline is attributable to increased imports over the Manitoba interface and an overall decline in load that was most prominent in the fourth quarter. In addition, transmission upgrades into WUMS from Minnesota in 2008 substantially reduced the frequency of congestion on that interface.<sup>24</sup> Total congestion costs peaked in June as storms caused substantial transmission damage in the Central and East regions of the Midwest ISO, including parts of Indiana, Michigan, and Ohio.

<sup>24</sup> The Arrowhead-Weston project, completed in late January 2008, has reduced West-to-East congestion into WUMS.

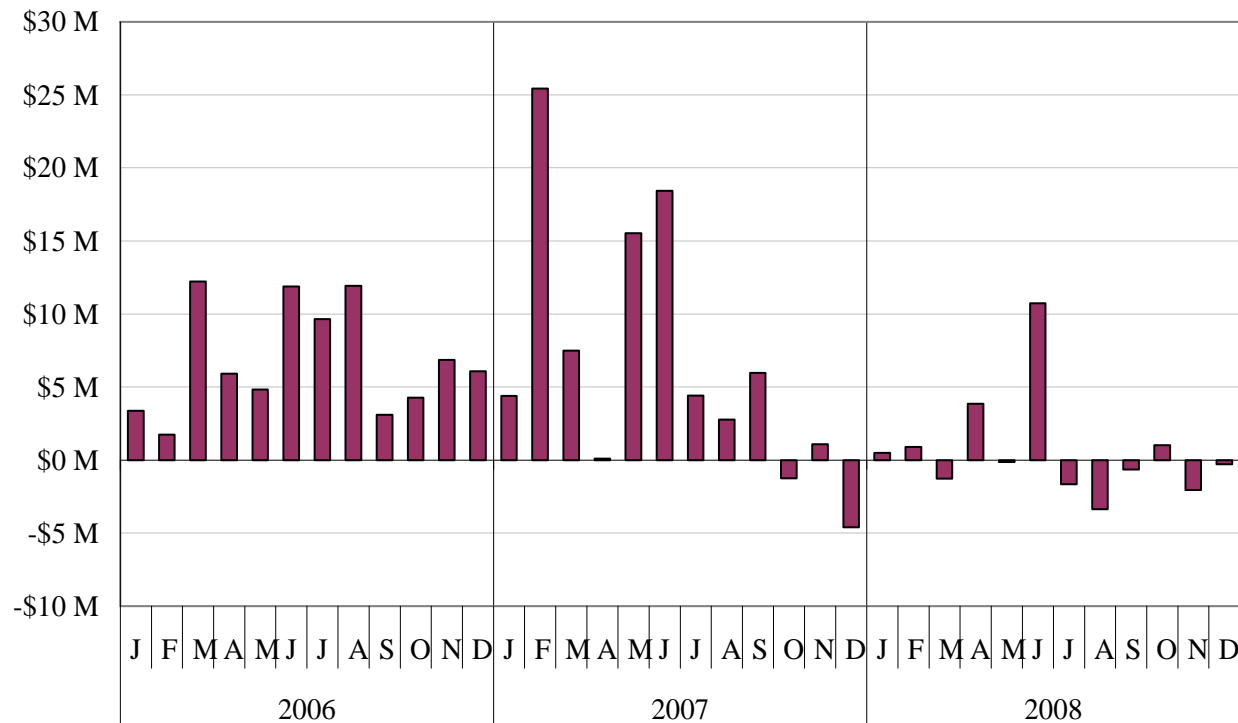
Real-time congestion (residuals) is congestion that settles based upon real-time market results. Normally, one would expect the real-time-congestion costs to be minimal if the modeling of the transmission system is consistent in the day-ahead and real-time markets. In other words, congestion costs collected in the real-time market occur only when the transmission limits decrease from those in the day-ahead market model or when loop flow (which reduces the network capability available for the Midwest ISO) increases from the levels assumed in the day-ahead market. In other words, real-time congestion costs are associated only with deviations from the day-ahead use of the transmission system. Like the settlements for load and generation, schedules in the day-ahead market are not settled again in the real-time market. Only increases or decreases from the day-ahead schedules are settled in the real-time market.

For example, if a transmission interface is fully scheduled in the day-ahead market and is congested, no additional congestion costs will be collected in the real-time market. The cost of congestion may increase or decrease (i.e., the price differences may be larger or smaller in real-time than they were in the day-ahead) but there will be no additional real-time settlement unless the flow over the interface changes in real time from the amount scheduled day-ahead. However, if the limit falls (the interface is derated) or loop flow increases over a congested interface, the Midwest ISO will incur real-time congestion costs to achieve the required reduction in real-time flows over the interface.

Balancing congestion costs have declined since 2006 due to improvements made in the day-ahead modeling of loop flow and a general decrease in congestion in 2008. In 2008 the largest balancing congestion costs occurred in June as storm-related outages and deratings were not fully reflected in the day-ahead market. Starting in late 2007, negative balancing congestion began to emerge periodically due to payments received from PJM for market-to-market coordination. Those payments from PJM totaled \$11.6 million in 2007 and nearly \$44 million in 2008. Settlement revenues are detailed in the market-to-market subsection of this report.

Figure 44 shows that real-time congestion costs decreased by 91 percent in 2008. Figure 45 shows these values on a monthly basis.

**Figure 44: Real-Time Balancing Congestion Costs**  
2006-2008



Real-time congestion declined significantly in 2008. Over 98 percent of total congestion was captured in the day-ahead market, a significant improvement compared to 2006 and 2007. This is evidence of better convergence between day-ahead market assumptions and actual real-time conditions. Based upon our review of congestion costs, we conclude that the substantial reduction in real-time congestion costs is due to more accurate loop flow assumptions in the day-ahead model. There were also continued improvements in constraint assumptions and forecasting originally incorporated in the day-ahead market modeling in late 2007.

## **B. Day-Ahead Congestion and FTR Obligations**

The economic value of transmission capacity is reflected in the FTRs. Holders of FTRs are entitled to the congestion costs collected between the source and sink locations that define a specific FTR. Hence, FTRs allow participants to manage the price risk associated with congestion. FTRs are distributed through an annual allocation process as well as through seasonal and monthly auctions. Effective on June 1, 2008, the Midwest ISO successfully introduced Auction Revenue Rights (“ARRs”) to the FTR market. This approach still allocates



the value of the FTRs to customers by allocating the revenue payments from an FTR to the customer rather than the FTR itself. However, if the customer would rather have the FTR, it can still purchase the FTR and be in the same position as it would have been had it been allocated the FTR directly. As a result, a larger proportion of the congestion rights are now auctioned on a seasonal basis to more accurately reflect load shifts.

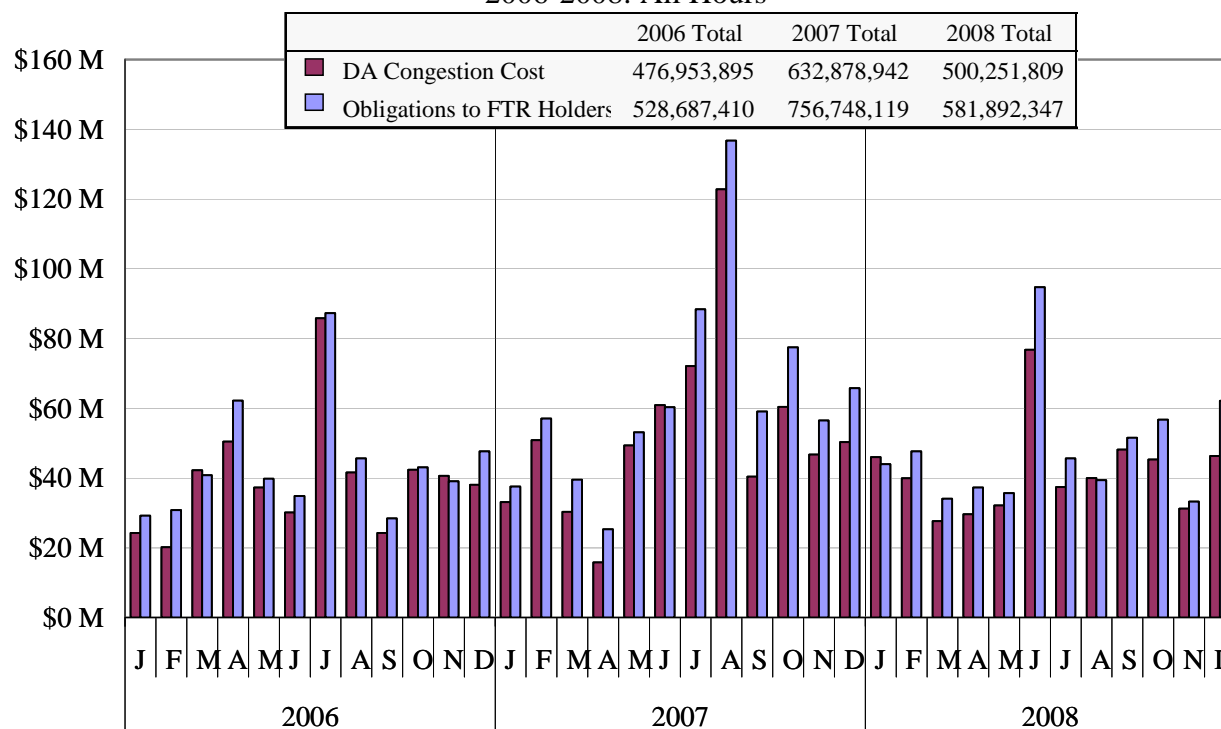
The Midwest ISO is obligated to pay FTR holders the value of the day-ahead congestion over the path that defines each FTR. In particular, the payment obligation associated with an FTR is the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.<sup>25</sup> Obligations for FTRs are paid with congestion revenues collected in the Midwest ISO day-ahead market. Surpluses and shortfalls are expected to be limited when the portfolio of FTRs held by participants generally matches the Midwest ISO power flows over the transmission system. However, when the FTR rights exceed the physical capability of the transmission system (or loop flows from activity outside of the Midwest ISO region use some of the transmission capability), the Midwest ISO may collect less day-ahead congestion revenue than it owes to the FTR holders. Congestion revenue surpluses in one month are used to fund FTR shortfalls in other months during the same year. If the Midwest ISO has a shortfall over the entire year, FTR payments are reduced *pro rata*. Figure 45 compares the monthly total day-ahead congestion revenues to the monthly total FTR obligations.

The figure shows that the day-ahead congestion collections were substantially less than FTR obligations in 2008 (more than 14 percent). In 2006 and 2007, the shortfalls were 10 and 19 percent, respectively. In 2008, the largest shortfalls occurred in June as storm-related transmission outages reduced the physical capability of the system on major West-to-East interfaces into the eastern areas of the Midwest.

---

25 An FTR obligation can be in the “wrong” direction (counter flow) and can require a payment from the FTR holder.

**Figure 45: Day-Ahead Congestion Revenue and Payments to FTR Holders**  
2006-2008: All Hours



Surpluses or shortfalls occur when the Midwest ISO sells fewer or more FTRs than the actual capability of the network in the day-ahead market. This generally occurs because:

- Transmission outages or other factors cause the capability of the system to differ from the capability assumed when the FTRs were allocated or sold; and
- Loop flows over the system caused by generators and loads outside of the Midwest ISO use more or less of the transmission capability than assumed in the FTR market model. Unanticipated loop-flow is a problem because the Midwest ISO collects no congestion revenue from transactions that cause loop flow. If the ISO allocates FTRs for the full capability on these interfaces, the loop flow will create an FTR revenue shortfall.

The Midwest ISO has continued to work on the FTR and ARR allocation processes and associated modeling to reduce the shortfalls. The changes include improving loop flow assumptions; adding additional constraints related to market-to-market and non-market constraints; and broadly reducing transmission line limits in the FTR market model to account for expected differences in FTR-modeled conditions and actual hourly results. While the improvements introduced in 2008 have contributed to lower shortfalls in congestion revenue receipts relative to 2007, we recommend further improvements be pursued.

In the Midwest ISO region, other types of transmission rights were created to protect entities with pre-existing agreements to use the transmission system (referred to as “grandfathered” agreements). These rights generally allow the holder not to have to pay congestion in the day-ahead or real-time market, which is accomplished by providing a rebate of the congestion costs associated with the rights. The rights include an alternative type of FTR with use-it-or-lose-it characteristics (known as “Option B” FTRs) and congestion “Carve-Outs”.

**Figure 46: Payments to FTR Holders**  
2006-2008: All Hours

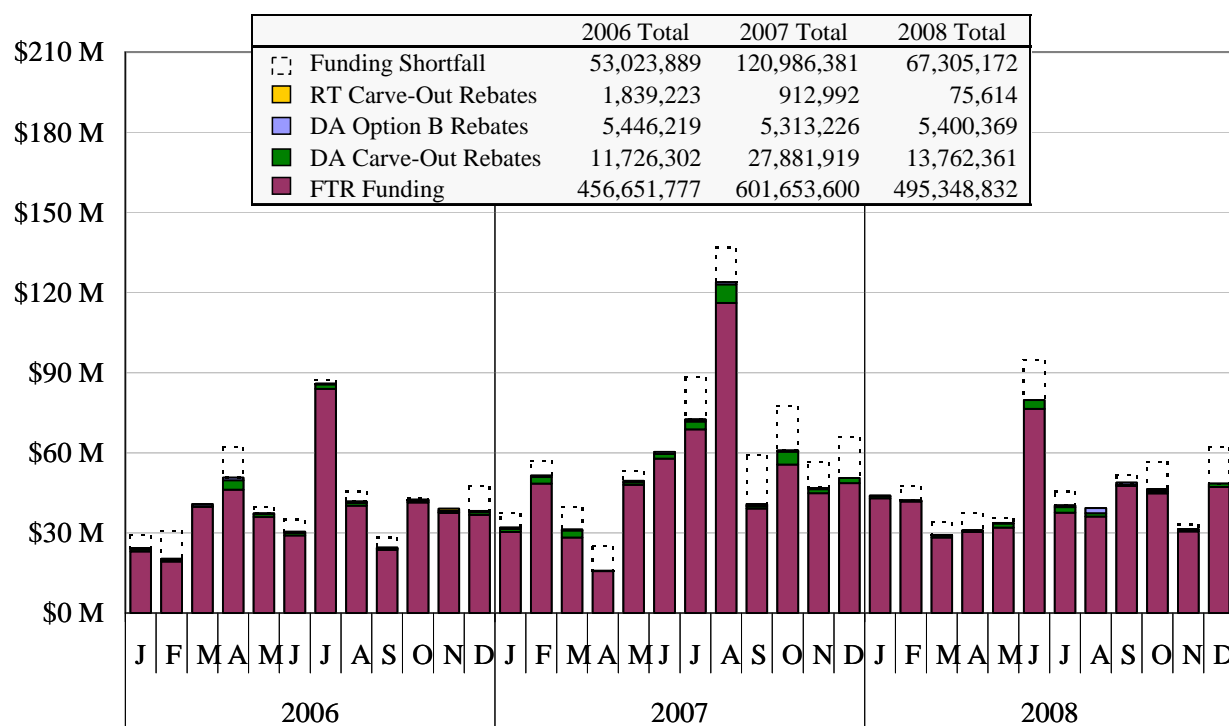


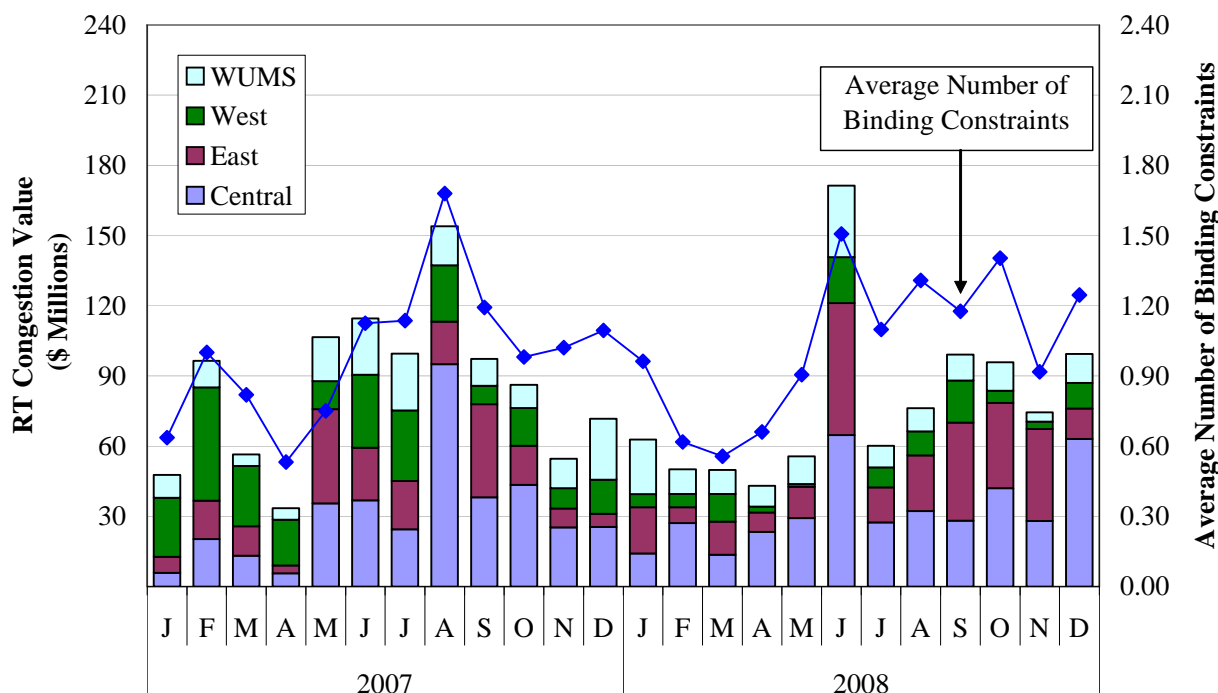
Figure 46 shows the monthly payments and obligations to conventional FTR holders, as well as the payments to Option B and Carve-Out FTRs. The figure shows that the vast majority of the payments were made to FTR holders, as opposed to payments to FTR Option B and Carve-Out FTRs. In all three years 2006-2008, approximately 95 percent of all payments were made to holders of conventional FTRs (i.e., only five percent of payments were made to holders of FTR Option B and Carve-Out FTRs). The modest payments for these other types of rights are a good outcome because they do not provide the same efficient incentives as conventional FTRs. As a percentage of total FTR payments, payments to the holders of the alternative rights declined slightly from the six percent in 2007 to four percent in 2008. As discussed above, funding

shortfalls declined in 2008. However, the \$67 million shortfall is still substantial and improvements to reduce this amount should be pursued.

### C. Value of Congestion in the Real-Time Market

In this subsection, we study congestion patterns in the real-time market. In general, we focus on the value of real-time congestion, rather than the day-ahead and real-time congestion costs collected by the Midwest ISO that were discussed in the previous subsection. This difference is important because the Midwest ISO does not collect congestion costs for all the actual flows over its system (loop flow incurs no congestion costs).<sup>26</sup> For the purposes of the analyses in this subsection, we calculate an implied “value” of real-time congestion. This value is equal to the marginal cost of the constraint (i.e., the shadow price) times the flow over the constraint in a given dispatch interval. Figure 47 shows the value of real-time congestion by region for all binding real-time constraints over the last two years.

**Figure 47: Value of Real-Time Congestion by Coordination Region**  
2007-2008



<sup>26</sup> In our discussion, congestion refers generally to the cost of a particular constraint. The term “congestion costs” specifically refers to the component of a generator’s LMP that is collected by the Midwest ISO.

The total value in 2008 of \$938 million was a decrease from \$1,018 million estimated for 2007. These values continue to be much higher than the day-ahead and real-time congestion cost collected by the Midwest ISO. This is because (1) loop flows use some of the transmission network capability without reimbursing the Midwest ISO and (2) PJM is entitled to use some of the Midwest ISO system.

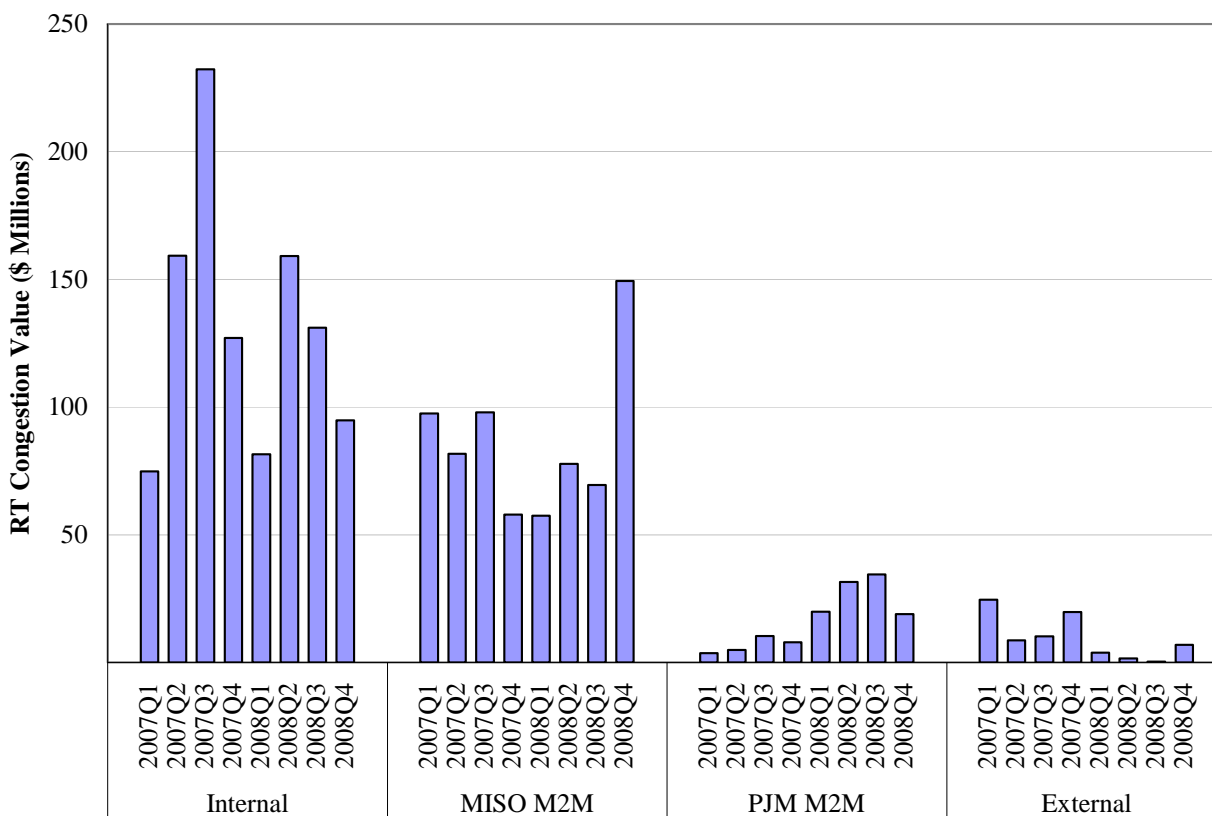
The combined Central and East regions accounted for more than one-half of the real-time congestion in both 2007 and 2008. The Central region accounted for a greater share than usual during June 2008 due to outages from severe storms. The substantial amount of congestion occurring in the West during the early part of 2007 subsided in the fourth quarter of 2007. This congestion was primarily due to reduced imports over the Manitoba interface and high winter loads. Although WUMS continues to account for a large share of total congestion (in spite of transmission improvements), it only accounts for a small portion of real-time congestion.

Figure 47 also shows that the average frequency of binding constraints (per interval) increased slightly in 2008 (from 1.0 constraints binding per interval in 2007 to 1.08 per interval in 2008). However, the frequency patterns were similar in both years, with constraints binding most frequently during the summer when the demands on the network were the greatest.

To better identify the sources of congestion, Figure 48 shows the value of congestion by type of constraint. This is computed in the same manner as congestion costs in the previous analysis. For our analysis, we define four types of constraints:

- Constraints internal to the Midwest ISO that are not coordinated with PJM. These are not market-to-market constraints and are labeled as “internal” constraints in our analysis;
- The Midwest ISO constraints coordinated with PJM. These are labeled as Midwest ISO market-to-market constraints;
- The PJM constraints coordinated with the Midwest ISO. These are labeled as PJM market-to-market constraints; and
- Constraints located on other systems that the Midwest ISO must redispatch to relieve when Transmission Loading Relief (“TLR”) is called. These are referred to as “external” constraints in our analysis. Congestion occurs on external constraints when a TLR is called on a neighboring system that causes Midwest ISO to re-dispatch its generation.

**Figure 48: Value of Real-Time Congestion by Type of Constraint**  
2007-2008



As in prior years, most of the congestion in 2008 occurred on Midwest ISO internal constraints (including the Midwest ISO market-to-market constraints). In total, the Midwest ISO constraints (internal and market-to-market) represent nearly 87 percent of the congestion value. Nearly \$70 million of congestion occurred on West-to-East Midwest ISO market-to-market constraints in the fourth quarter 2008 due to transmission outages and the extended outage of a large baseload facility. The congestion on PJM market-to-market constraints more than doubled in 2008 compared to 2007, while congestion on external constraints (generally associated with the Louisville Gas & Electric and Tennessee Valley Authority interfaces) decreased substantially.

#### **D. Market-to-Market Coordination with PJM**

The Midwest ISO and PJM currently coordinate the relief of transmission constraints affected by both systems, referred to as the market-to-market process. The market-to-market process entails the real-time exchange of congestion management information (i.e., constraint shadow prices and

requested relief) between the RTOs to ensure that the transmission constraint is managed with a least-cost dispatch. Each market's shadow price measures the per-MW cost of relieving the constraint as determined by the respective market.

When a market-to-market constraint is activated, the “monitoring RTO” (the RTO responsible for coordinating reliability for the constraint) provides its shadow price and the quantity of relief requested (the desired reduction in flow) from the other market. The other “reciprocating” RTO responds with the shadow price in its market for providing the requested relief. Each market is entitled to a certain flow on each of the market-to-market constraints. The settlement between the ISOs depends on the flows over the constraint caused by each ISO relative to its entitlement. Not only is the market-to-market process needed to ensure that generation is efficiently redispatched to manage these constraints, it is also needed to achieve consistent pricing between these two markets.

Figure 49 summarizes the frequency with which Midwest ISO market-to-market and PJM market-to-market constraints were binding and activated in 2007 and 2008. The top panel represents coordinated flowgates located in the PJM system and the bottom panel represents flowgates located in the Midwest ISO. (The darker shade in the stacked bars represents the total number of peak hours in the month when coordinated flowgates were active. The lighter shade represents the total for off-peak hours.)

The figure shows that the activity on PJM market-to-market constraints in the Midwest ISO was more frequent in 2008 than in 2007, while the activity on Midwest ISO market-to-market constraints was comparable between 2008 and 2007. The number of hours with market-to-market coordination on PJM flowgates spiked in a number of months due to storms (notably June) and transmission outages on West-to-East constraints.

PJM market-to-market constraints typically occur most frequently in the summer when the demands on the transmission system are the greatest. The Midwest ISO market-to-market constraints also bind frequently in the fall due to maintenance outages on transmission lines.

Figure 49: Market-to-Market Events

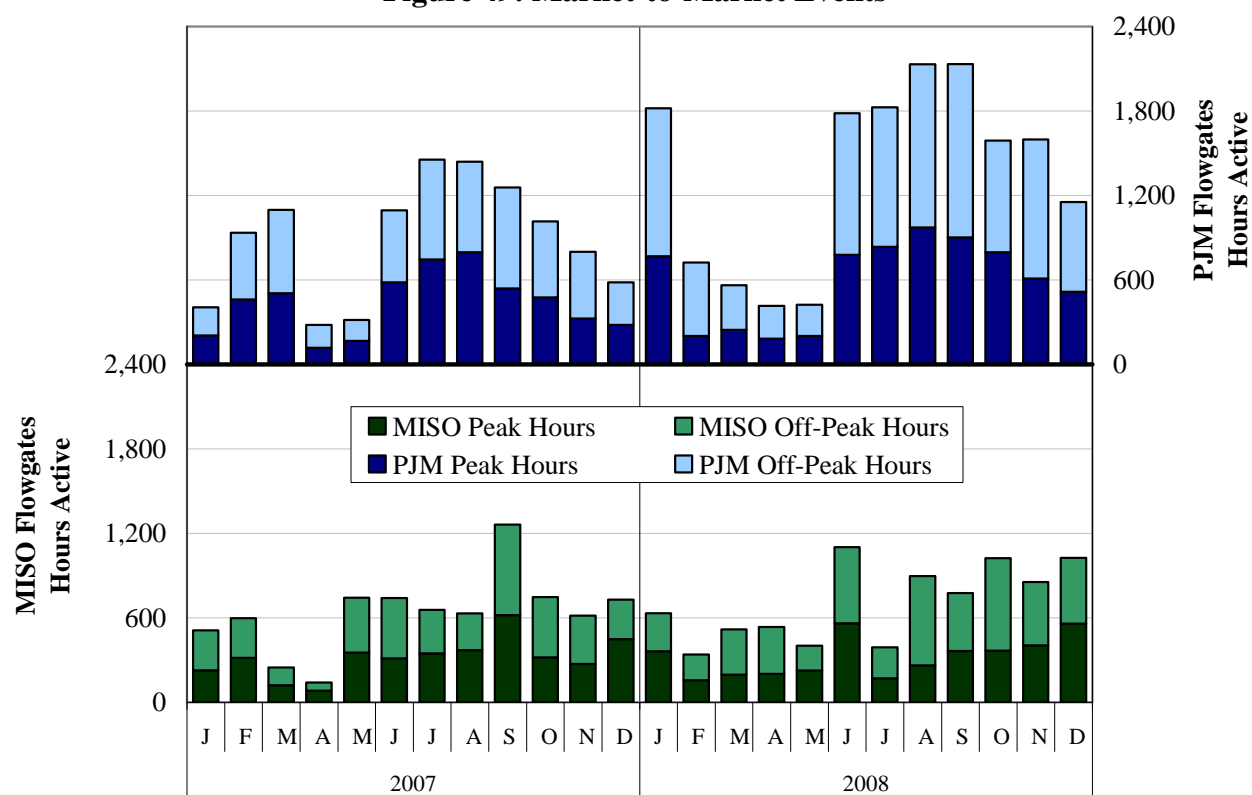
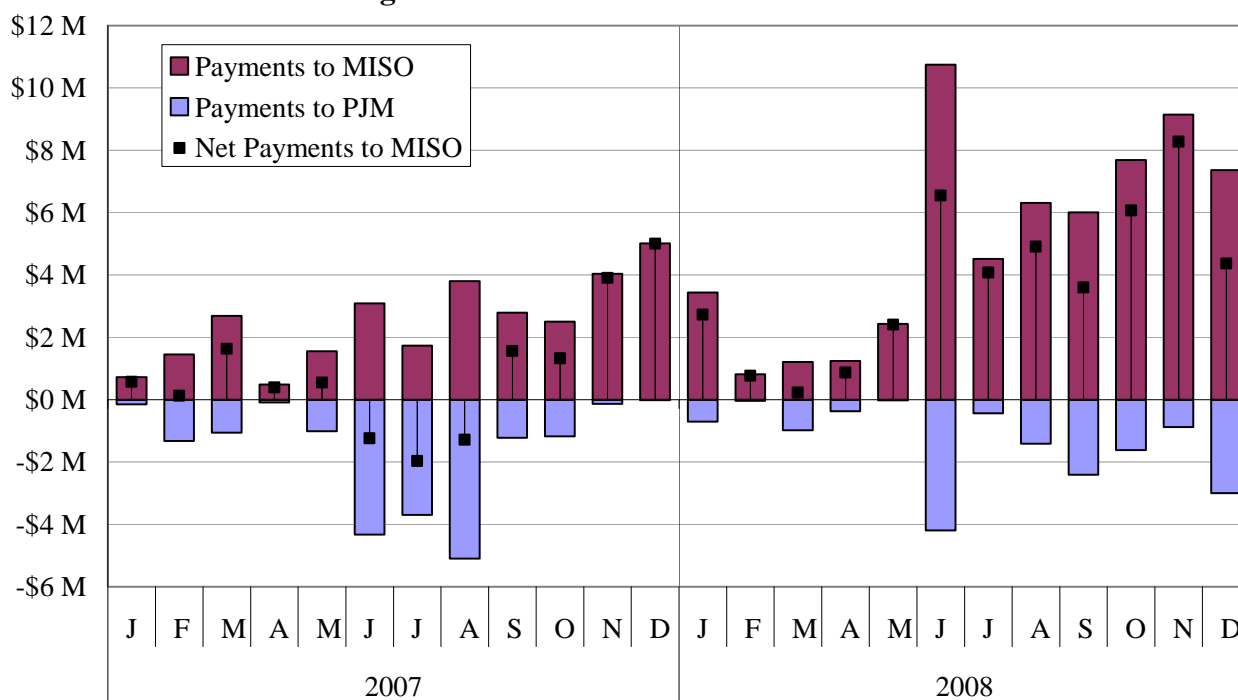


Figure 50 shows a summary of the financial settlement of market-to-market coordination. The settlement of market-to-market coordination is based upon the reciprocating RTO's actual market flows compared to its Firm Flow Entitlement ("FFE").

If the reciprocating RTO's market flow is below its FFE, then it will receive a payment for the unused portion of its entitlement at its internal cost of providing that relief. If the RTO's flow is above its FFE it will make a payment at the cost of the monitoring RTOs congestion for only the flow in excess of its FFE. In the figure, the positive values represent payments made to the Midwest ISO on coordinated flowgates and the negative values represent payments made to PJM on coordinated flowgates. The drop line shows the net payment to the Midwest ISO in each month.



**Figure 50: Market-to-Market Settlements**

The figure shows that payments from PJM were substantially higher in 2008 than in 2007, and totaled more than \$44 million. While payments in 2007 exhibited a seasonal pattern with net payments made to PJM in the summer, net payments were made to the Midwest ISO in every month during 2008. Payments in both directions were unusually large in June due to storm-related congestion on both systems. Payments made to the Midwest ISO were high in the fall due to reduced transfer capability as a result of transmission outages in which PJM's use of transmission was greater than its FFE, causing high congestion management costs.

In April 2009, The Midwest ISO identified an issue with the PJM market flow calculations that may have caused an understatement of PJM market flows that likely will require a significant resettlement. Both the market monitors and the RTOs are investigating this issue to determine its cause and effects.

To assess how well the market-to-market process has been operating, our next analysis evaluates convergence of shadow prices on coordinated flowgates between the two RTOs. We calculate average shadow prices and the amount of relief requested during market-to-market events. We calculate an "initial" shadow price as the average shadow price of the monitoring RTO that was

logged prior to the first response from the reciprocating RTO. We also calculate “post” activation shadow prices for both the monitoring RTO and the reciprocating RTO. The post shadow price is the average price in each RTO after the requested relief associated with the market-to-market process is provided.

Comparing the initial and post-activation periods measures the effects of the coordination. If the market-to-market process is operating well, the shadow prices of the two RTOs should converge after a coordinated constraint is activated. In most cases, the shadow prices should decrease from the initial value as the two RTOs collaborate to manage the constraint.

In addition to the “initial” and “post” shadow prices, we also show a drop line indicating the quantity of relief requested by the monitoring RTO in the initial period. Finally, the figure shows the percentage of hours the constraint was activated and coordinated (i.e., relief was being provided by the reciprocating RTO).<sup>27</sup> The “share of active hours coordinated” shown for each constraint is the percentage of hours the reciprocating RTO was responding with shadow prices when the monitoring RTO was seeking relief. Figure 51 shows this analysis for the PJM market-to-market constraints.

The figure confirms that the shadow prices on most constraints decreased over the duration of the event and that the majority of active intervals (54 to 79 percent) are coordinated—and relief is provided—by the Midwest ISO. The relief requested does not change significantly from the initial to the post-activation period and is roughly 100 MW regardless of the constraint involved.

---

<sup>27</sup> The statistics for the post-initialization period exclude the periods when the reciprocating RTO was not actively responding.

**Figure 51: PJM Market-to-Market Constraints**  
Relief Requested and Shadow Prices

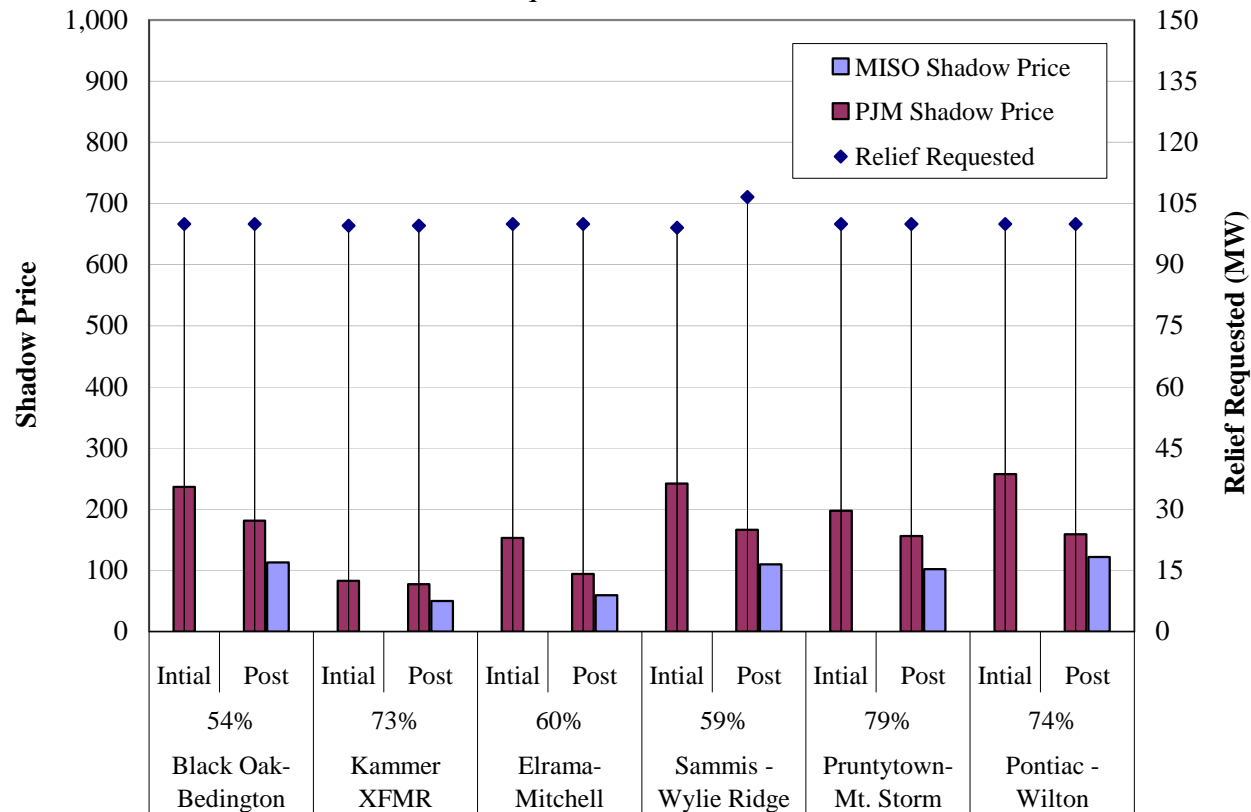


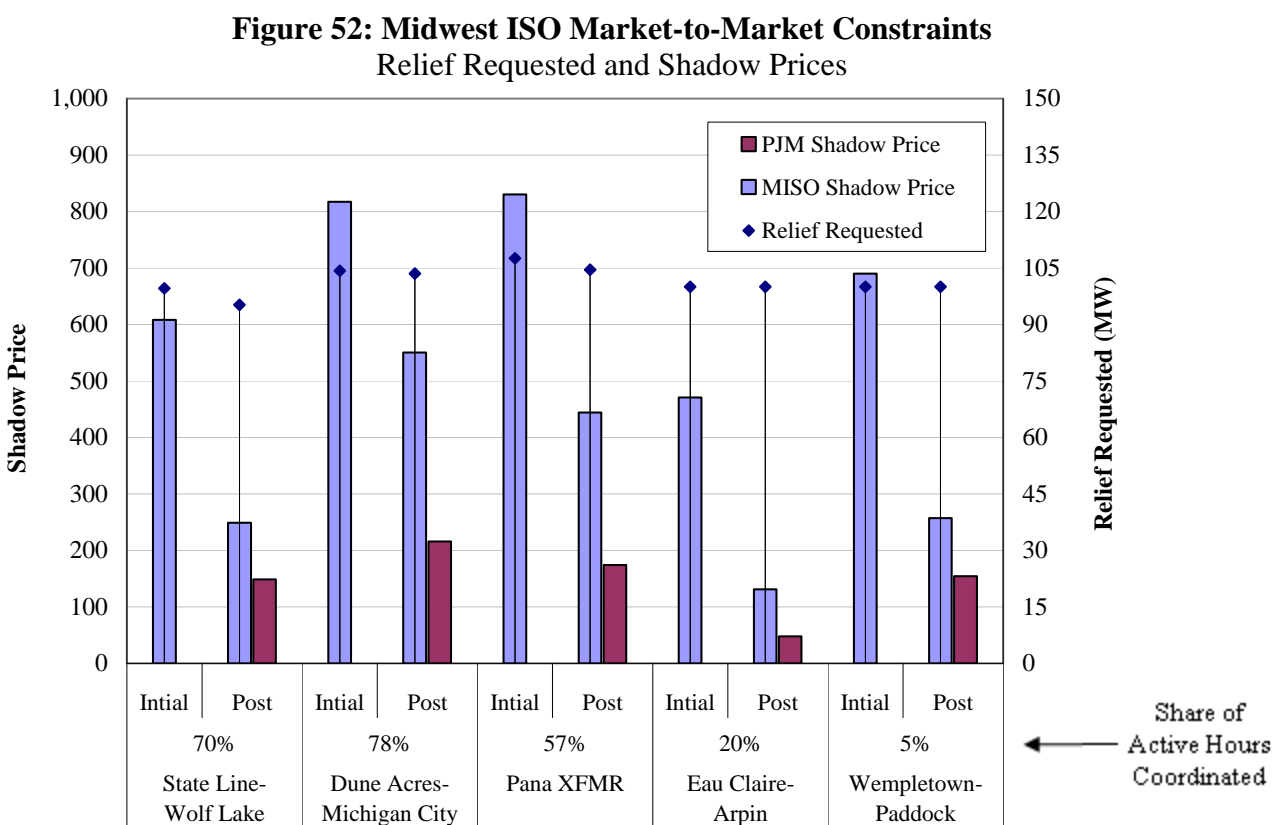
Figure 51

shows that shadow prices generally decline and converge well over the duration of the event, but some of our results raise potential concern. One concern arises when the Midwest ISO “relaxes” a PJM market-to-market constraint because it cannot provide the relief at a marginal cost lower than PJM’s shadow price. In such cases, the relaxation methodology can produce shadow prices that are not representative of the value of the congestion in PJM. This concern was addressed in early 2009 when both RTOs implemented software changes to stop relaxing the constraints in these cases. Now, the RTOs price the congestion based on the monitoring RTO’s shadow price if they cannot provide relief.

In addition, the requested relief is typically not modified significantly over the term of the event. A static quantity of relief requested can cause insufficient relief to be provided from the reciprocating RTO even when additional economic relief is available. Static relief quantities can

also cause too much relief to be provided, which can lead to constraint oscillation. Oscillation occurs when the reciprocating RTO completely relieves the constraint, causing the monitoring RTO to return a zero shadow price in the next interval, which in turn will cause the reciprocating RTO to cease providing relief. This returns the system to the initial conditions where congestion existed and the process is restarted. While the amount of relief requested appears to have been more efficiently managed in 2008 than in 2007, it still does not appear to be managed in an optimal manner. To address this issues, we support the enhancement of the market-to-market process to optimize the relief requested based upon the relative shadow prices.

Figure 52 shows the same analysis for the most frequently called market-to-market constraints on the Midwest ISO system.



Stateline-Wolf Lake and Dune Acres-Michigan City generally limit flows from West-to-East. These are the most common Midwest ISO flowgates for market-to-market coordination. Eau Claire-Arpin and Wempletown-Paddock limit imports into the WUMS area. The Pana XFMR

generally limits generation in the Central region. Like the analysis of the PJM constraints, this figure shows that the monitoring RTO's shadow price tends to decrease and converge with the reciprocating RTO's shadow price over the duration of the event.

The analysis of the Midwest ISO's market-to-market constraints raise some concerns. First, like with the PJM flowgates, the relief quantities are rarely modified, even when the Midwest ISO shadow price is higher than PJM's and more relief may be available on the PJM system. Also, PJM often returned a zero shadow price or did not respond when the Midwest ISO had an active market-to-market constraint, which indicates an inability to redispatch for the constraint. Though there were improvements from 2007, PJM continued to provide relief for only a low percentage of the intervals comprising some of the Midwest ISO's most critical constraints.

Certain modeling assumptions by PJM caused its real-time dispatch model to not accurately recognize the relief that it could provide on key Midwest ISO flowgates. For example, PJM utilized a three-percent GSF cutoff that ignores the relief that can be provided by generators with lower shift factors. As described earlier in this report, even the Midwest ISO's initial GSF cutoff of two percent raises efficiency concerns. A three-percent GSF cutoff would raise much more significant concerns.

The Midwest ISO and PJM have responded recently to a number of past recommendations which should improve the performance of the process in 2009. The RTOs made software changes to optimize and modify the relief requested based upon the relative shadow prices. PJM has also recently reduced the GSF cutoff parameter to 1.7 percent and implemented other changes that should help address these issues. Additionally, they have discontinued use of the constraint relaxation algorithm when the reciprocating RTO cannot provide relief at a cost lower than the shadow price of the monitoring RTO.

We continue to support the recommendations made in prior State of the Market reports:

- The Midwest ISO should institute a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly.

- We continue to recommend that the RTOs expand their market-to-market process to optimize interchange between markets and to better coordinate export transactions.
- The Midwest ISO should discontinue the constraint relaxation algorithm, even on market-to-market constraints that cannot be resolved by the monitoring RTO.

## **E. TLR Events**

The Midwest ISO continues to use transmission line-loading relief procedures and the NERC Interchange Distribution Calculator to support certain aspects of congestion management. Prior to the introduction of the energy markets, virtually all of the congestion management for Midwest ISO transmission facilities was accomplished through TLR procedures. When a constraint is binding, the real-time dispatch model manages the flow over the constrained transmission facility by economically redispatching generation. However, external entities contribute to the flows over the constrained internal transmission facilities. Hence, the Midwest ISO invokes a TLR procedure to ensure that the external parties contribute to reducing the flow over the constrained facility. As we have shown in previous reports, the TLR process is a much less efficient and a less controllable means to manage congestion than economically redispatching generation through LMP markets. This less efficient process leads to:

- More than three times the curtailments to manage congestion on average than the quantity of economic redispatch needed; and
- Less timely and accurate control of the system, resulting in lower reliability.

LMP markets help to efficiently manage most internal congestion through redispatch rather than the curtailment of scheduled transactions through the TLR process.

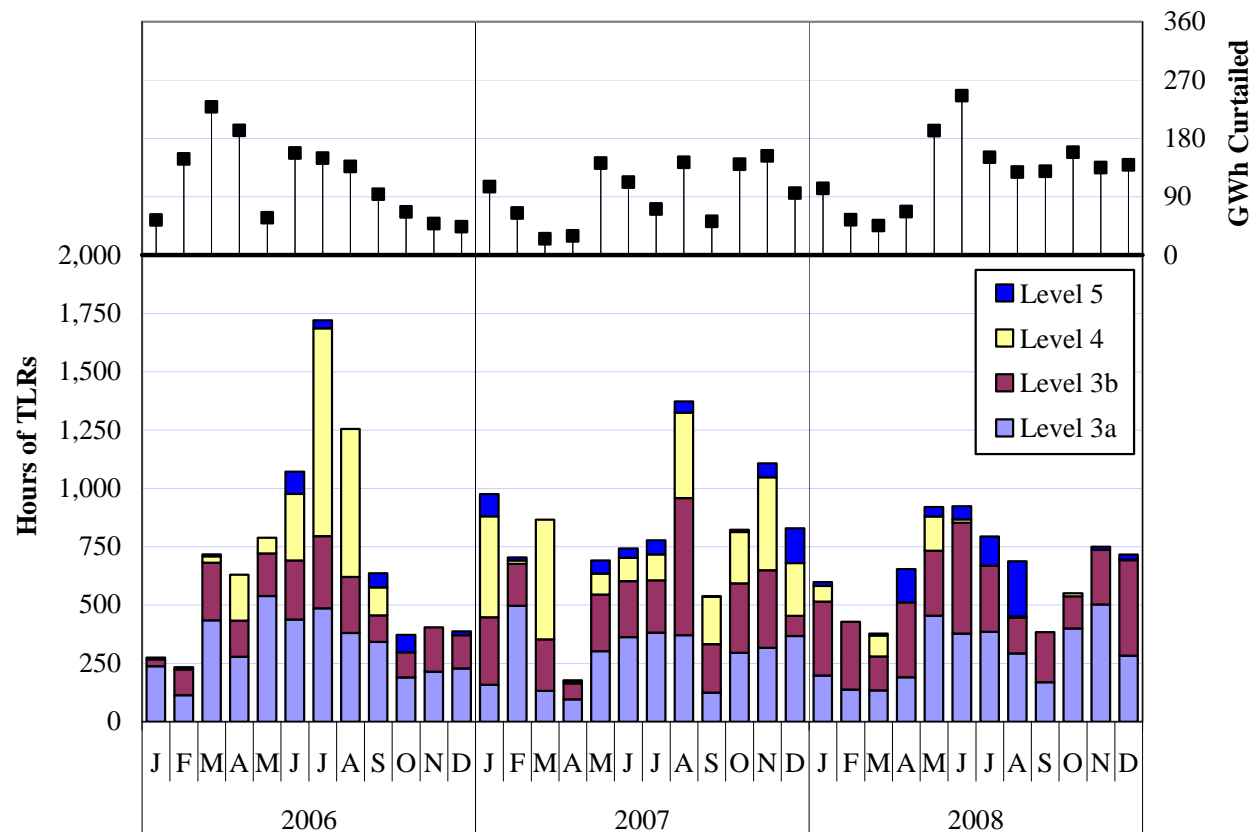
NERC's active response TLR levels include:

- Level 3 — non-firm curtailments;
- Level 4 — commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and

- Level 5 — curtailment of firm transactions.<sup>28</sup>

Our analysis of TLR activity is provided in Figure 53. The bottom panel of the figure provides the TLR activity by level during the period from 2006 to 2008. The top panel of the figure shows the quantities of scheduled energy curtailed by the TLR events.

**Figure 53: Monthly TLR Activity**  
2006 to 2008



The figure shows that total monthly GWh of TLR calls by Midwest ISO fluctuate markedly. In 2006, there were 1,378 GWh of TLR events (a 38 percent decline from 2005) and in 2007 the total TLRs declined further by 18 percent. In 2008, TLRs increased 36 percent, due in part to the storms in the East region in June; however, this level is still 30 percent lower than in 2005.

<sup>28</sup> NERC's TLR levels include four other levels: Level 1 (notification), Level 2 (holding transfers), Level 6 (emergency procedures) and Level 0 (TLR concluded).

Although significant quantities of TLRs are still invoked to ensure that transactions external to the Midwest ISO are curtailed when contributing to congestion, the Midwest ISO relies primarily on economic redispatch for managing congestion.

## **F. Congestion Manageability**

Congestion management is one of the most important activities of the Midwest ISO. The Midwest ISO monitors thousands of potential network constraints in real time throughout the region. As the flow over each of these constraints approaches its limit (or if it is anticipated to do so) in real-time, it is “activated” in the market model. The Midwest ISO’s real-time market model will then manage the flow on the activated constraints to keep the flow below its operating limit on the facility while minimizing overall production costs.

A real-time LMP-based energy market will redispatch generation subject to transmission constraints on the network. This process utilizes the redispatch capability of generators, especially those with high GSFs that have a relatively outsized impact on constraints. Constraints are at times difficult to manage if the available redispatch capability of the generators that affect the flow on the constraint is limited. The available redispatch capability is reduced when:

- Generators that are most effective at relieving the congestion are not online;
- Generator flexibility is reduced (i.e., having a narrow EcoMax to EcoMin range or low ramp rate); or
- Generators are already at their limits (e.g., operating at their EcoMax).

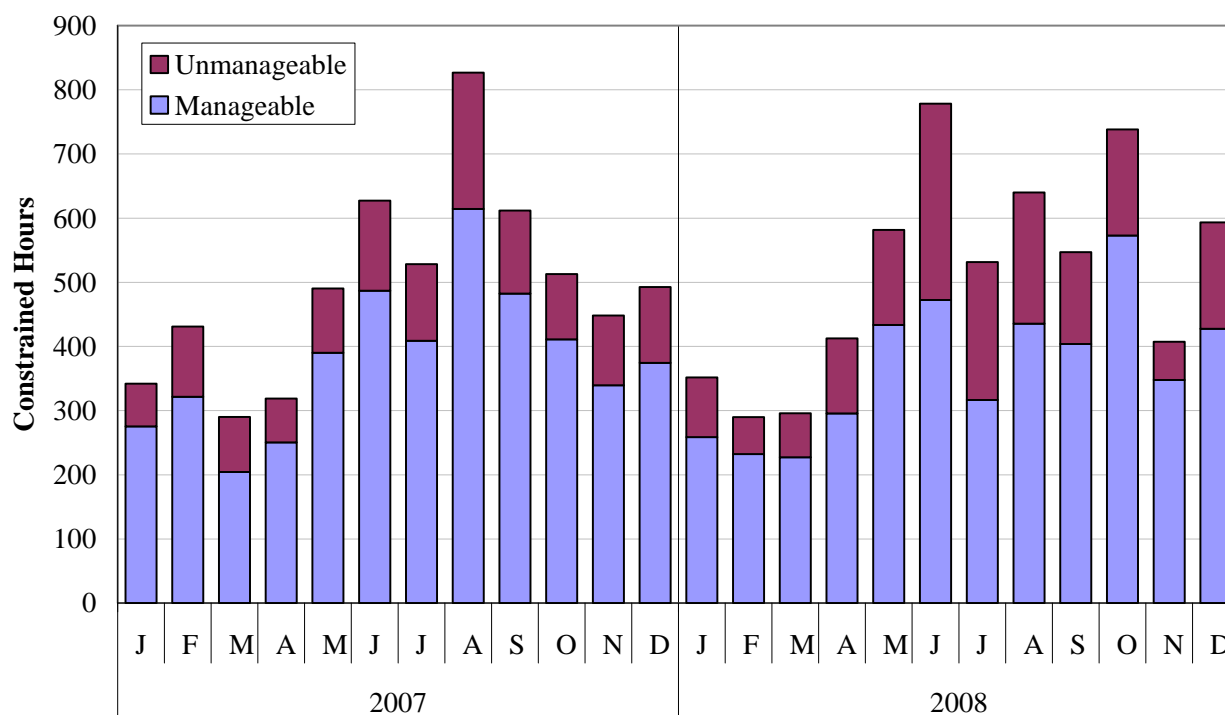
When available redispatch capability is insufficient to reduce the flow to less than the transmission limit in the next five-minute interval, we define the transmission constraint as “unmanageable”. Importantly, the presence of an unmanageable constraint does not mean the system is unreliable. The Midwest ISO performance criteria for most constraints require control within the limit in 20 minutes. If control is not obtained within 30 minutes, a reporting criterion to stakeholders is triggered. The small subset of constraints that can lead to cascading outages are controlled to limits that are more stringent than the actual security limits.



When a constraint is unmanageable in the Midwest ISO market, an algorithm is used to “relax” the limit of the constraint for purposes of calculating a shadow price for the constraint and the associated LMPs. While an unmanageable constraint is not necessarily a reliability concern, it nonetheless warrants evaluation. Figure 54 shows the frequency with which constraints were unmanageable in each month in 2007-2008. This figure shows:

- Twenty-eight percent of the congestion was unmanageable on a five-minute basis in 2008, which is an increase of five percentage points from 2007; and
- Some of the unmanageability is caused by inflexible supply offers, which we evaluate below.

**Figure 54: Unmanageable Constraints**  
2007 to 2008

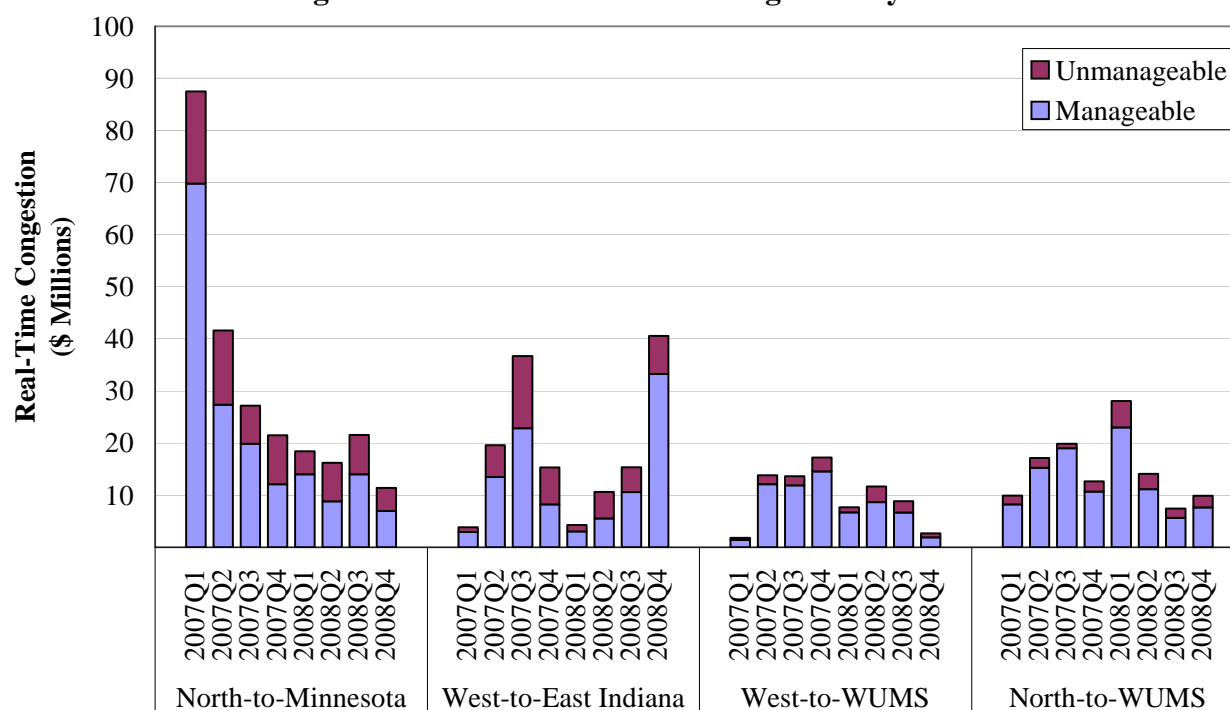


Inflexible supply offers cause some of the unmanageability. This suggests that the market may not be providing sufficient incentives for flexible generator offers. The potential incentive issue relates to the difference between the five-minute price signal the generator receives and the hourly price used for settlement. A significant change in the output of a generator associated with a sharp price change in a single five-minute interval can be unprofitable for the generator relative to the hourly settlement price.

Constraint manageability should improve in 2009 under ASM with the implementation of the Price Volatility Make Whole Payment (“PVMWP”), which will provide an incentive to offer more flexibility. The PVMWP is intended to ensure that suppliers responding flexibly to the Midwest ISO’s prices and following its dispatch signals are not harmed by doing so.

Figure 55 shows the value of real-time congestion on paths that experienced the most congestion in 2008. The chart separates manageable and unmanageable portions of real-time congestion.

**Figure 55: Value of Real-Time Congestion by Path**



This figure shows that congestion over the two-year period was greatest on the interfaces into Minnesota and most of this congestion occurred early in 2007. The total congestion into Minnesota declined by 63 percent in 2008. Of these paths, the North-to-Minnesota path was unmanageable most frequently—35 percent of the congestion in 2008 could not be managed by real-time dispatch. In 2008, the West-to-East path to Indiana experienced the most congestion, of which 26 percent was unmanageable. This was driven by a large amount of congestion in the last quarter caused by planned transmission outages. In addition, paths into WUMS were the most manageable. Almost 80 percent of the congestion into WUMS on the two paths shown in

Figure 55 was manageable in 2008.

Our next analysis evaluates two components of suppliers' offer patterns that contribute to the unmanageability of transmission constraints. The first is the submission of inflexible dispatch parameters, which limits the redispatch capability of the market model. When a participant sets EcoMin levels much higher than the physical minimum output levels (thereby preventing the market model from reducing the output of such resources), the inflexibility can contribute to unmanageable congestion and increased congestion costs.

A second factor that contributes to unmanageable congestion is low ramp rates caused by a generator setting its ramp rate at a lesser rate than the physical ramp capability of the resource (i.e., reduces the speed with which the generator can be redispatched by the market model to manage congestion). Like dispatch inflexibility, low ramp rates limit the Midwest ISO's ability to redispatch generation throughout the region to manage congestion or to meet market demand.<sup>29</sup>

To determine the effects of these two factors, we analyze the amount of congestion relief that was technically feasible but not available due to dispatch inflexibility and low ramp rates. Figure 56 shows the results of this analysis. The bars in the figure represent the amount of relief that was unavailable as a percentage of the limit. To show the significance of the unavailable relief quantities, the figure also shows the average percentage by which the flow exceeded each constraint's limit when it was unmanageable.

The results show that on most paths, the relief that could have been physically available would have been enough to manage the congestion (i.e., the bars exceed the line graph). We attribute the lack of flexibility to:

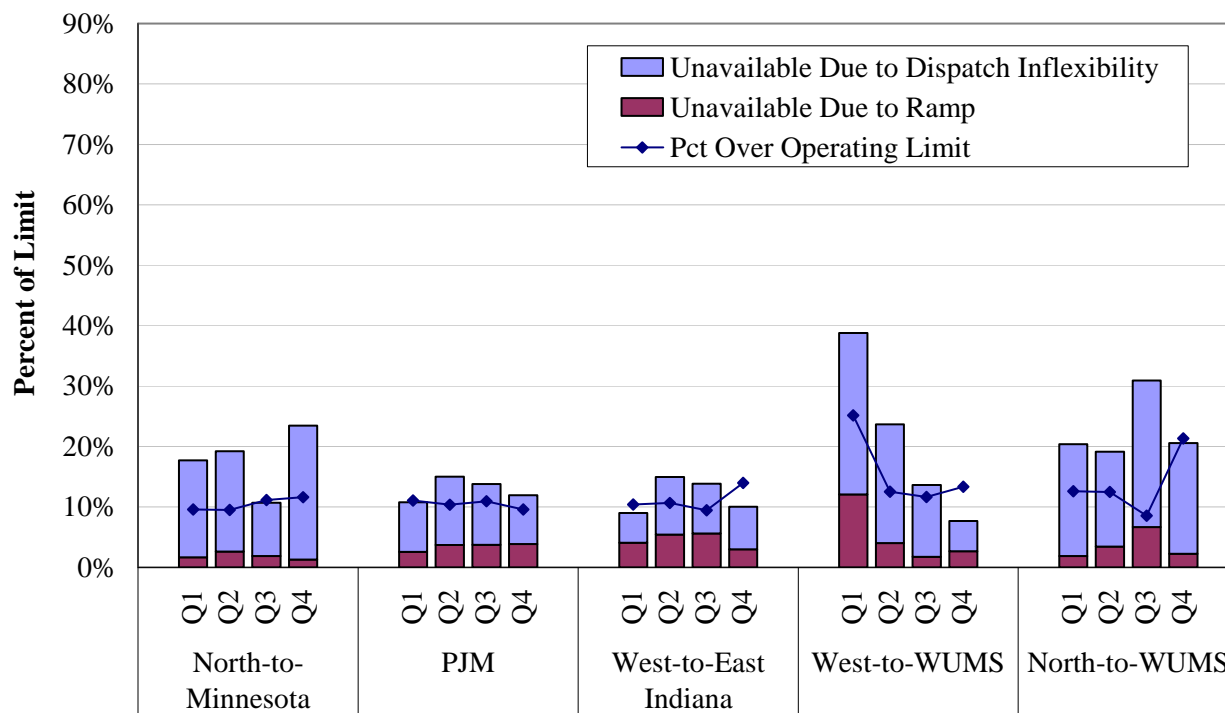
- Justifiable technical concerns in some cases;
- A desire to operate conservatively; and

---

29 The Midwest ISO has other procedures it can employ to manage the flow over constrained interfaces.

- The lack of recognition by some participants of the increased profits available from the market if they were to offer greater flexibility.

**Figure 56: Congestion Relief Unavailable Due to Offer Parameters**  
Selected Paths



As mentioned above, participants could be concerned that responding to dispatch signals when prices are volatile could reduce the supplier's profit. This issue has been addressed through the PVWHP element of the ASM implemented in 2009.

The final factor that contributes to unmanageable congestion is the parameter in the real-time market that prevents units with small effects on a constraint from being redispatched. In the real-time market at the end of 2008, units with GSFs less than 1.7 percent (or greater than -1.7 percent) are not redispatched to manage a constraint. A GSF indicates the percentage of a generator's change in output will flow on the constrained facilities. The effect of the GSF parameter is particularly large for the low-voltage constraints because GSFs are generally small and less widely distributed for low-voltage constraints—hence, the cutoff tends to exclude a larger share of the total relief. In previous reports, we showed that the average additional relief available by lowering the GSF cutoff (from two percent) was higher than the amount by which flows exceed the limits for unmanageable constraints. Hence, we recommended that Midwest

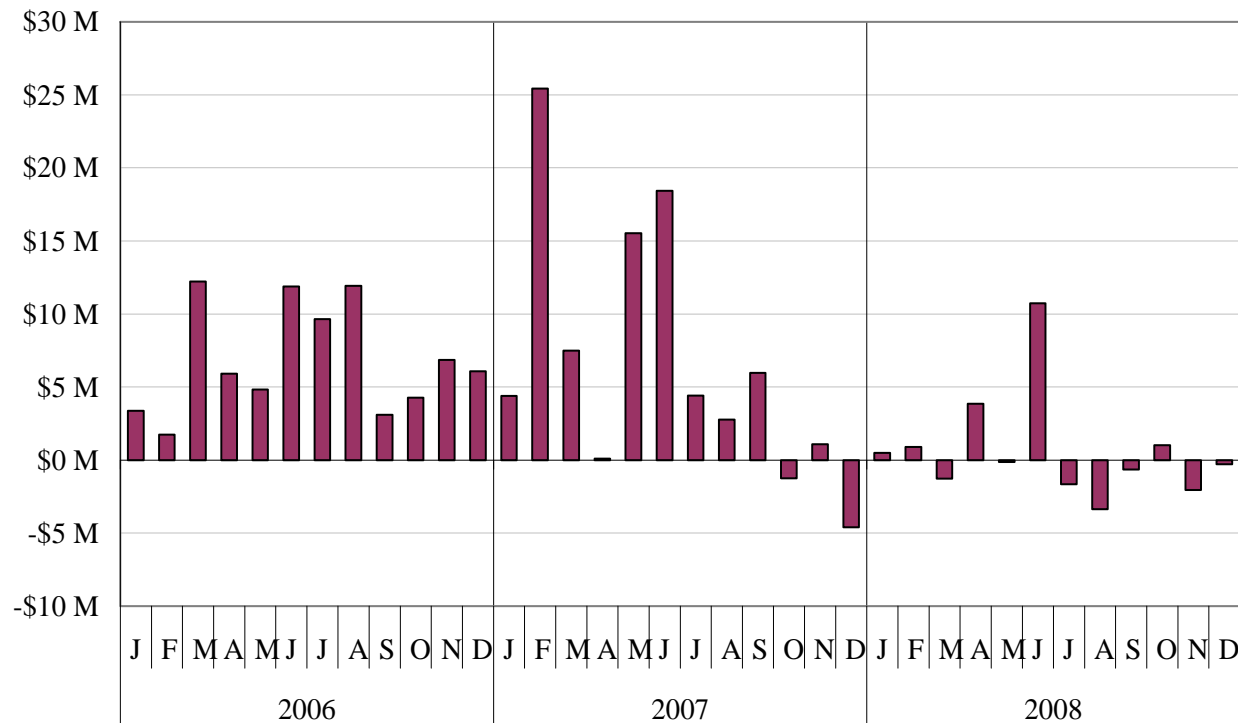
ISO reduce the cutoff as much as feasible. The Midwest ISO has received and implemented a software modification that allows it to reduce this parameter in both the real-time and day-ahead markets. In 2008 and early 2009, the Midwest ISO reduced this parameter from 2.0% to 1.6%. We are recommending that the Midwest ISO continue to reduce this parameter.

Although manageability of constraints should improve, we continue to be concerned about the market outcomes when constraints are in violation. In addition, we have studied the constraint relaxation algorithm used when a constraint is in violation to produce a shadow price for the constraint (the marginal economic value of the constraint that is used to calculate LMPs). The same algorithm is used by PJM and ISO-NE. Based upon our analysis, we have concluded that this algorithm often produces inefficient shadow prices that distort the associated LMPs. For example, in more than 21 percent of the cases studied when a constraint was violated, the relaxation procedure generated a zero shadow price (indicating no congestion).

The more efficient approach when a constraint is violated would be to set the shadow price and associated LMPs at the reliability cost of violating the constraint. Presumably, this value should correspond to the maximum cost the Midwest ISO is willing to incur to manage the constraint, which is reflected by the constraint penalty factors in the market software. To the extent the relaxation algorithm determines a lower shadow price, it is an inferior reflection of the true value of the constraint. Hence, we continue to recommend that the Midwest ISO discontinue use of the relaxation algorithm and set prices based upon the constraint penalty factors. The Midwest ISO has been evaluating this recommendation and marking certain software changes.

Balancing congestion costs have declined since 2006 due to improvements made in the day-ahead modeling of loop flow and a general decrease in congestion in 2008. In 2008 the largest balancing congestion costs occurred in June as storm-related outages and deratings were not fully reflected in the day-ahead market. Starting in late 2007, negative balancing congestion began to emerge periodically due to payments received from PJM for market-to-market coordination. Those payments from PJM totaled \$11.6 million in 2007 and nearly \$44 million in 2008. Settlement revenues are detailed in the market-to-market subsection of this report.

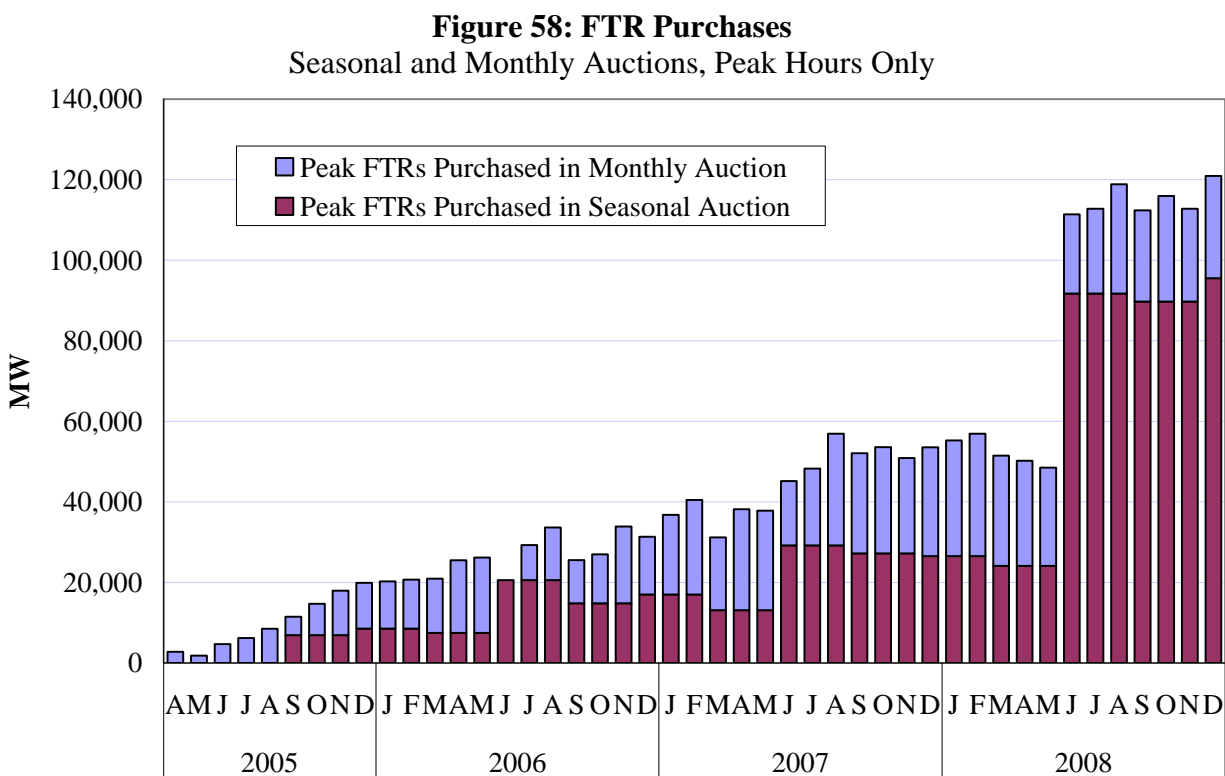
**Figure 57: Balancing Congestion Costs**  
2006-2008



### G. FTR Auction Prices and Congestion

As discussed in subsection B, above, the Midwest ISO administers a market for FTRs that allows participants to hedge the costs of congestion in the market. This subsection evaluates the performance of the FTR market. The Midwest ISO first allocates FTRs or ARRs to market participants based upon physical usage of the system on an annual basis. The Midwest ISO then auctions additional FTRs on a seasonal and monthly basis.

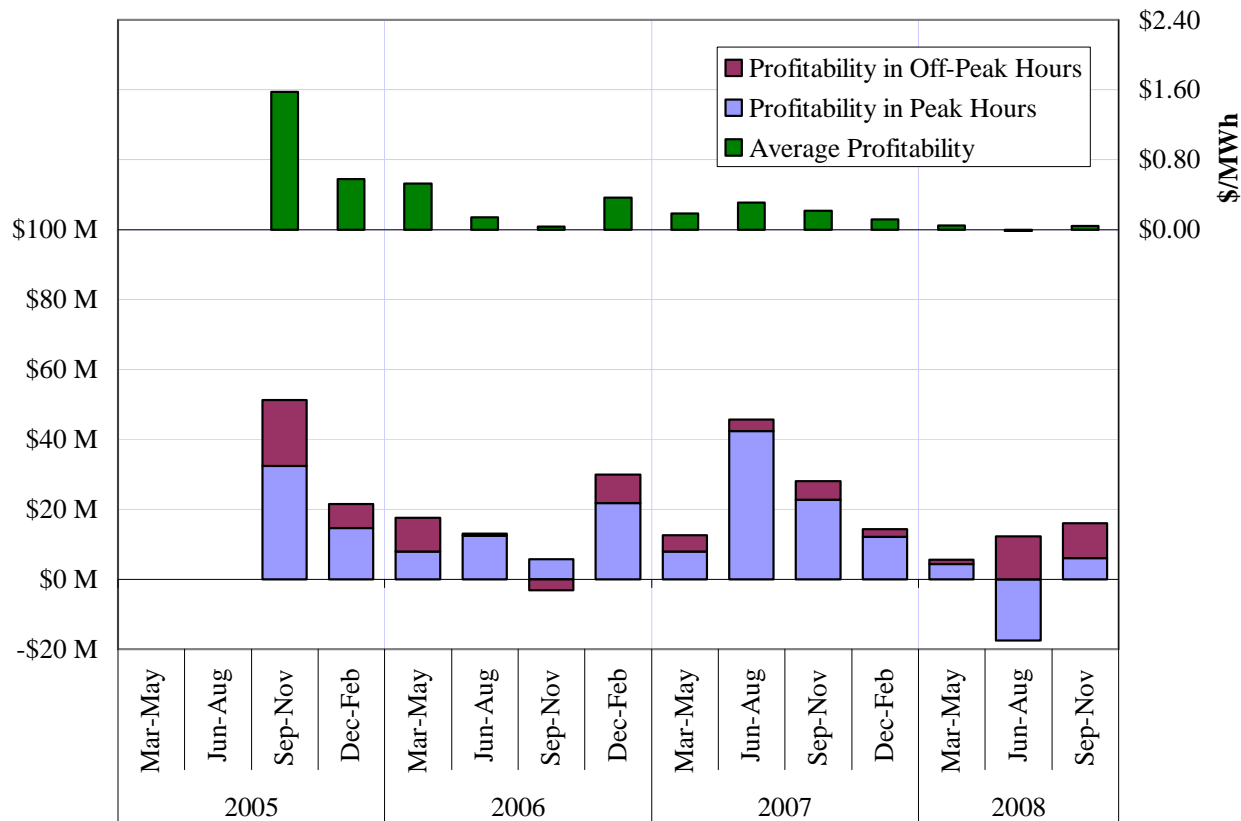
Figure 58 summarizes the quantities of FTRs for peak hours transacted in the seasonal and monthly FTR auctions. The figure shows that up to May 2008, the total quantity of FTR purchases rose steadily since the market opened in April 2005. This was due to fewer FTRs being allocated in advance of the auctions and the system being more fully subscribed.



Monthly sales were uniform in 2008. In June 2008, the sharp increase in FTRs purchased in the seasonal auction was due to the transition to allocated ARRs in place of allocated FTRs. ARRs From 2006 until May 2008, roughly one-half of the FTRs purchased were through the monthly auctions. With the transition away from allocated rights, a larger proportion of the transmission rights are now auctioned (or self-scheduled via ARRs) on a seasonal basis.

The first indicator of the liquidity of the FTR markets is the profitability of the FTR purchases. FTR profits are the difference between the costs to purchase the FTR and the payout on the FTR based upon the congestion in the day-ahead market. In a liquid FTR market, the profits should be low because the market-clearing price for the FTR should reflect the expected value of congestion payments to the FTR. The next two figures show the profitability of FTRs purchased in the seasonal FTR auctions and the monthly FTR auctions. Figure 59 shows FTR profitability for seasonal FTRs.

**Figure 59: FTR Profitability**  
Seasonal Purchases

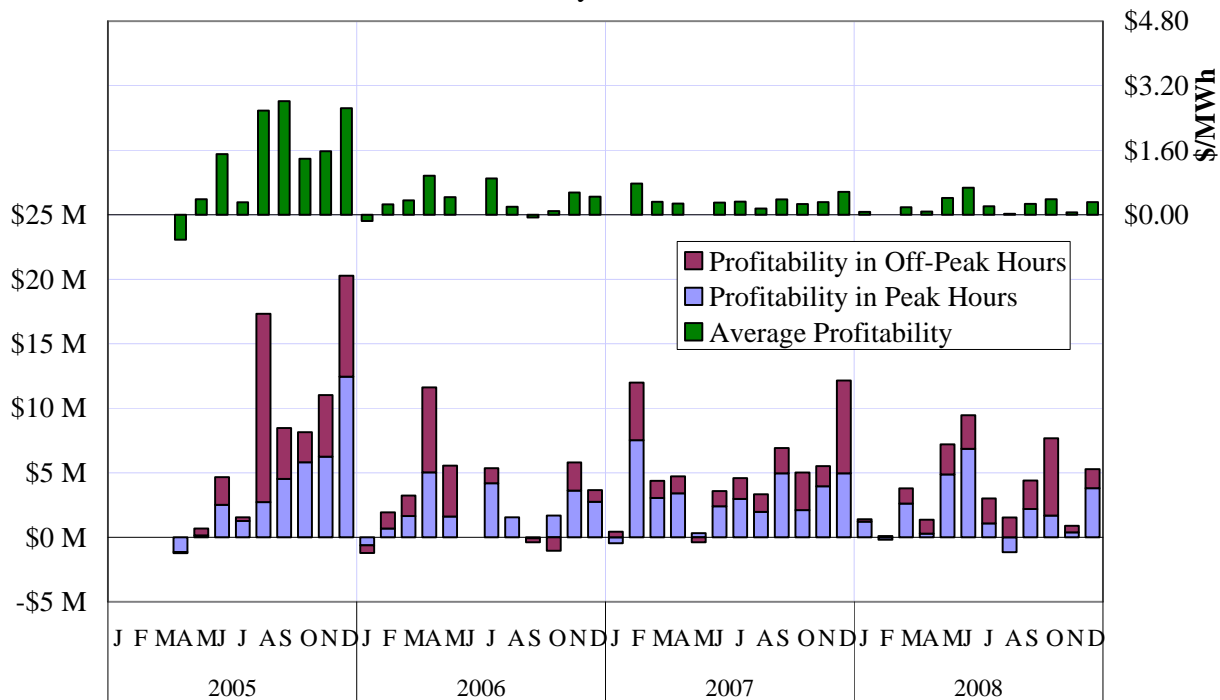


The figure shows that average FTR profitability in the seasonal auctions has declined from more than \$1.50 per MWh in the fall of 2005 to less than \$0.05 per MWh on average in 2008. The reduction in the profitability indicates that the performance of the market has improved over time as participants have gained experience, causing FTR prices to more accurately reflect their value.

Figure 60 shows the same analysis for the monthly auctions. It shows that average profitability in the monthly auction has decreased from more than \$1.30 per MWh in 2005 to less than \$0.26 per MWh in 2008. These results confirm that the liquidity and overall performance of the FTR markets has improved over time, causing FTR prices to reflect more accurately their value.



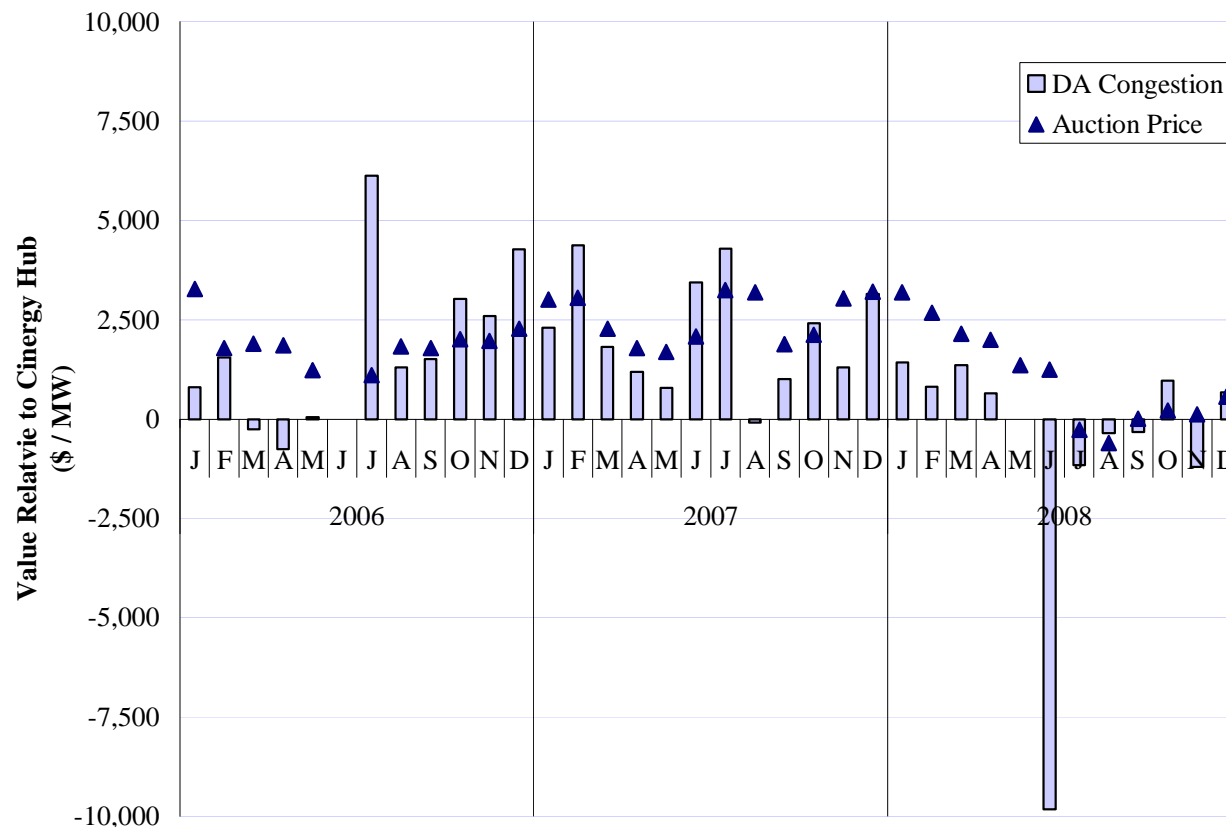
**Figure 60: FTR Profitability**  
Monthly Purchases



To provide further detail on the performance of the FTR markets, our next analysis examines the monthly FTR prices compared to day-ahead congestion that are payable to the FTR holders. As noted above, a well-functioning market should produce FTR prices that reflect a reasonable expectation of the day-ahead congestion. The profit earned by an FTR holder is the difference between the FTR price paid and the day-ahead congestion payment to the FTR holder.

The results in the following figures help explain the changes in FTR profitability shown in the analyses above. We analyze values for the WUMS area, the Minnesota Hub, and the Michigan Hub in peak and off-peak hours. Figure 61 and Figure 62 show the results of our analysis for WUMS in peak and off-peak hours, respectively. All values in the figures are computed relative to Cinergy Hub, which is the most actively traded location in the Midwest ISO.

**Figure 61: Comparison of FTR Auction Prices and Congestion Value**  
WUMS Area: Peak Hours



The most striking feature of the results is the large shift in congestion in June 2008 into eastern areas of the Midwest ISO (as shown by the large negative WUMS congestion cost relative to Cinergy). The shift was caused by storms in that month which resulted in critical generation and transmission outages. Aside from June 2008, day-ahead congestion has declined since 2006. There was more day-ahead congestion in 2007 into WUMS (relative to the Cinergy Hub) and the FTR values reflect this change. Since July 2006, the spread between auction prices and congestion has been minimal, particularly in off-peak hours. As reported last year, convergence was poor in August 2007 due to anomalously low day-ahead congestion during the month. After August, reasonably good convergence resumed. The congestion patterns were less volatile during the off-peak hours, which contributed to the stronger convergence of the FTR prices and congestion during those periods.

**Figure 62: Comparison of FTR Auction Prices and Congestion Value**  
WUMS Area: Off-Peak Hours

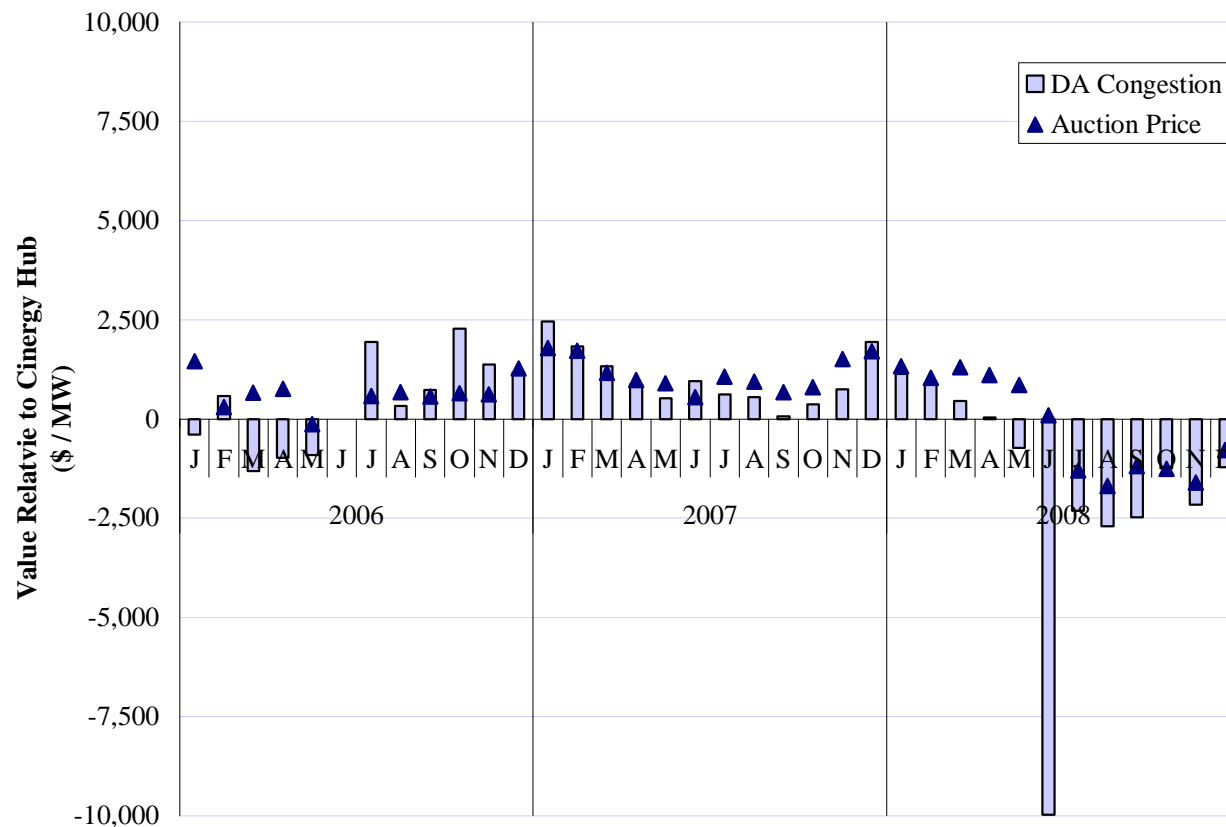
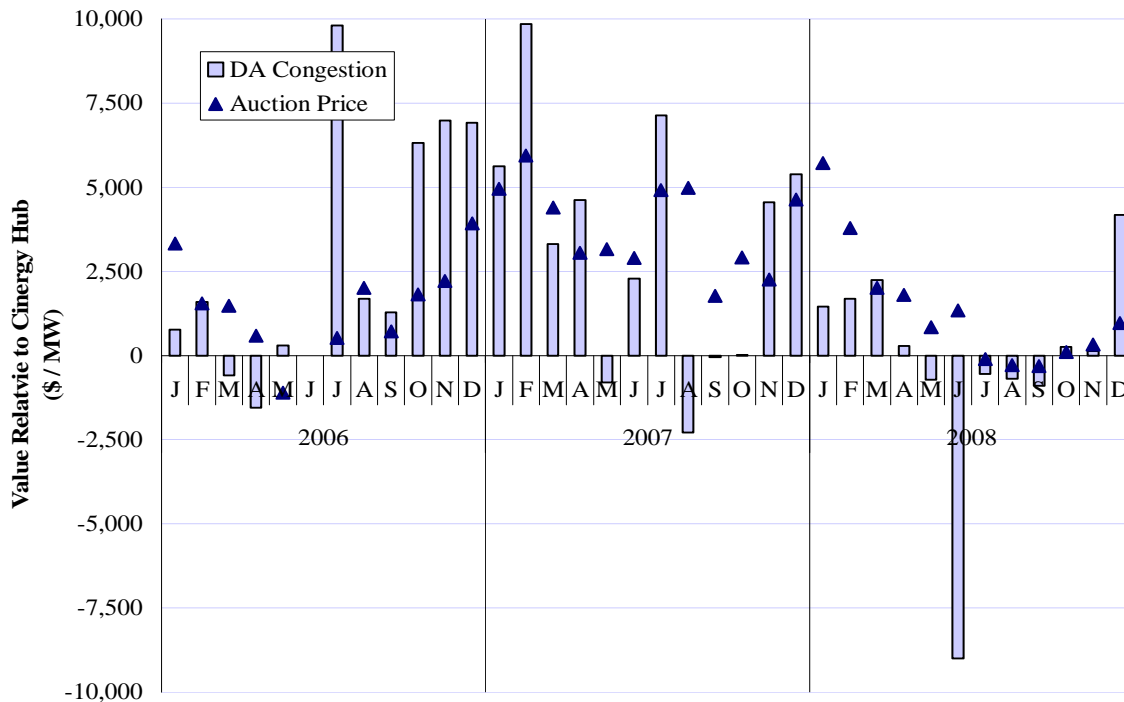


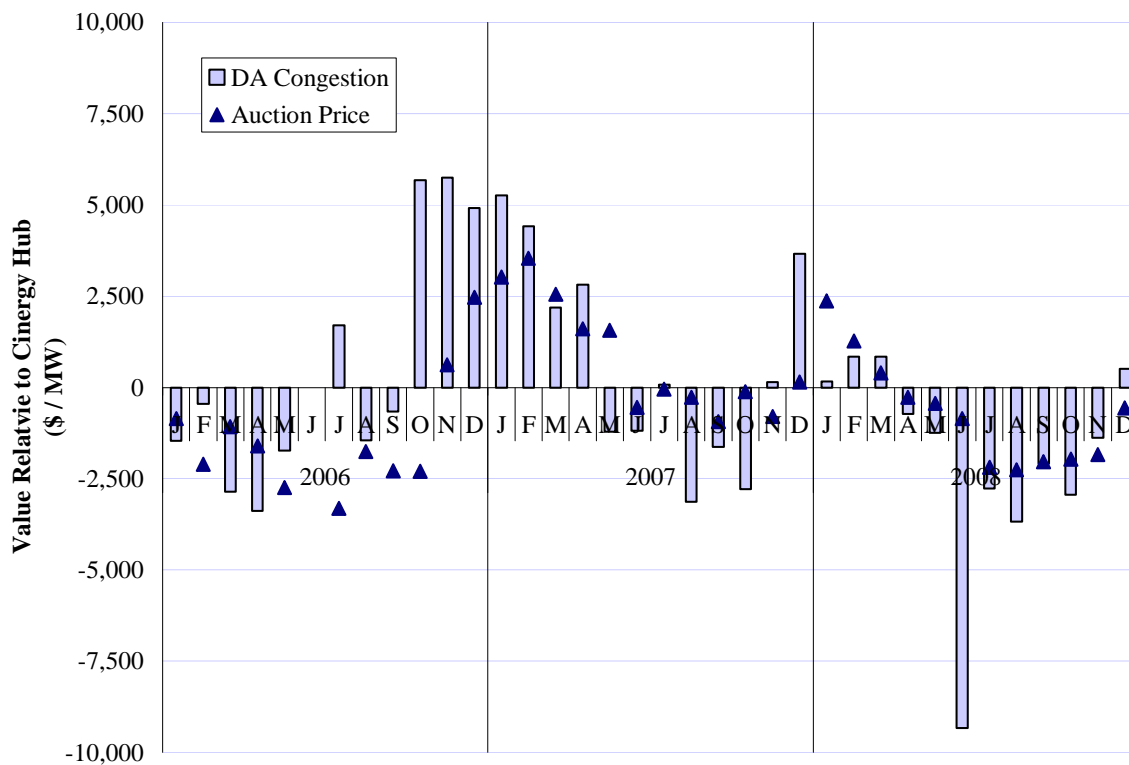
Figure 63 and Figure 64 show a similar analysis for the Minnesota Hub in peak and off-peak hours, respectively. The convergence between congestion values and FTR prices for the Minnesota Hub was affected by the volatility of congestion during 2006 and 2007 in peak hours. However, the volatility declined in 2008 and convergence has generally improved. Like WUMS, June 2008 was anomalous due to storms in the Central region affecting the Cinergy sink price. Convergence in off-peak hours was better than in peak hours due to lower volatility.

One difficulty in valuing FTRs is the fact that the congestion can change directions. As shown, some months have negative congestion while congestion is positive for other months. Both figures reveal that auction prices lag actual congestion, as one would expect, because FTRs are sold prior to the month in which the congestion occurs.

**Figure 63: Comparison of FTR Auction Prices and Congestion Value**  
Minnesota Hub: Peak Hours



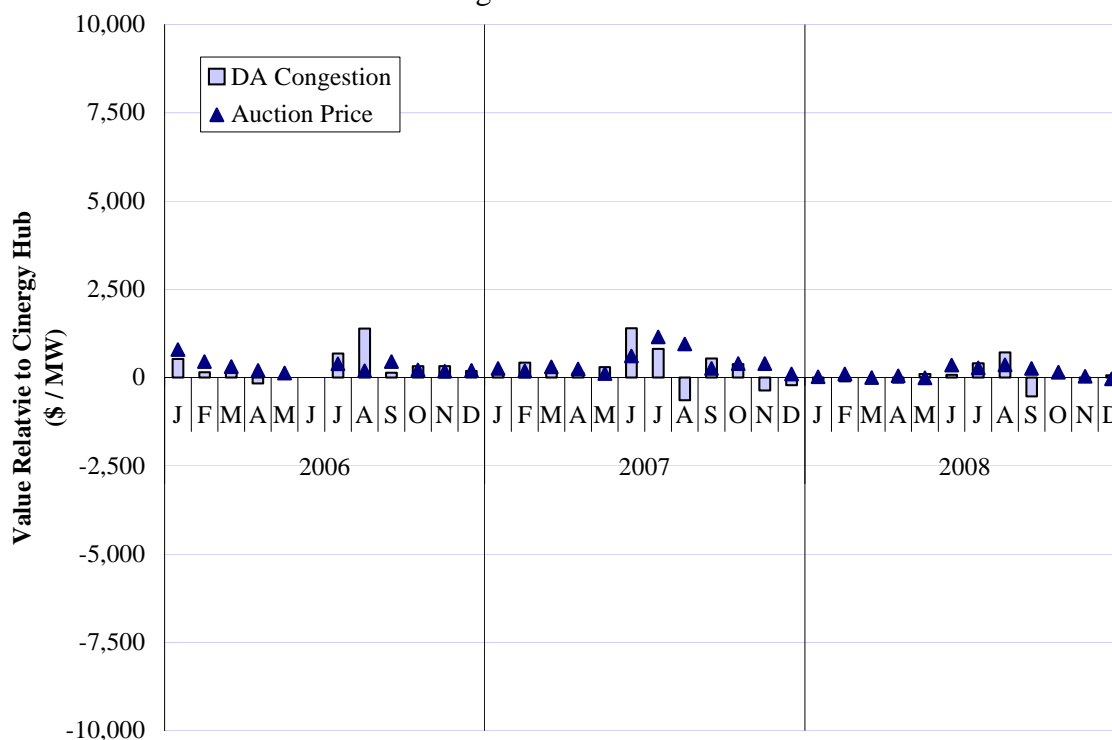
**Figure 64: Comparison of FTR Auction Prices and Congestion Value**  
Minnesota Hub: Off-Peak Hours



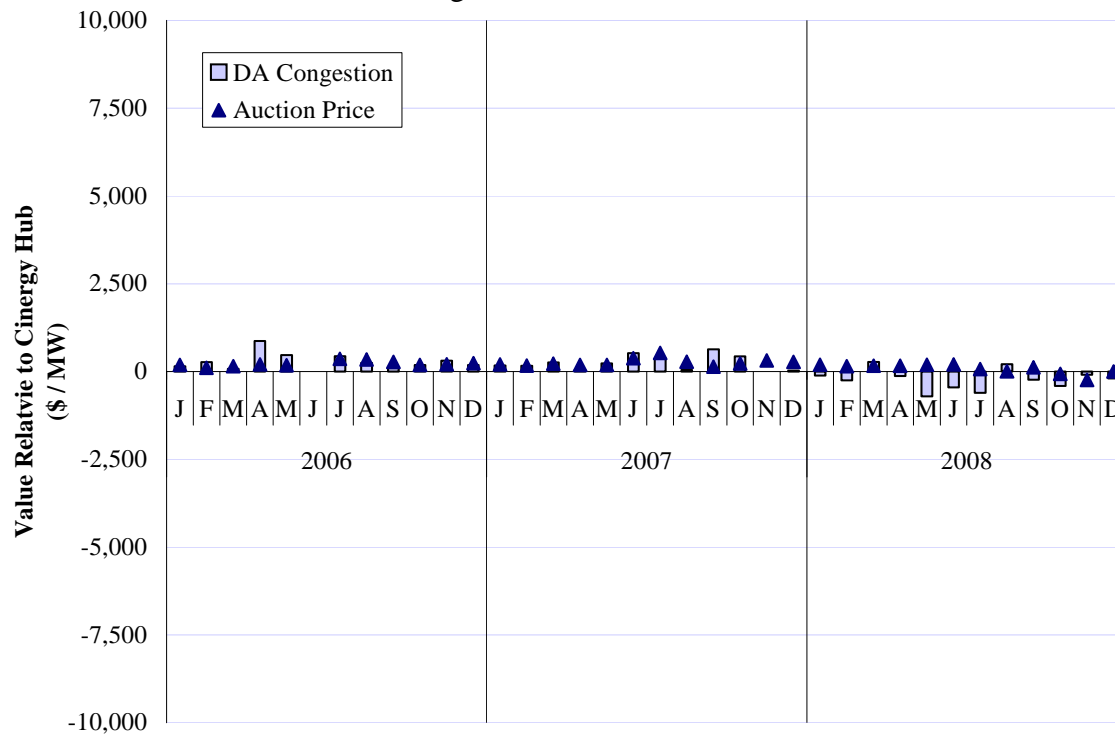
Finally, Figure 65 and Figure 66 show our analysis for FTR prices into the Michigan Hub from Cinergy in peak and off-peak hours, respectively. The congestion and FTR results for the Michigan Hub for both peak and off-peak hours indicate reasonably high convergence between FTR prices and the value of day-ahead congestion.

Convergence can be challenging on the Michigan interface because the congestion frequently switches direction. Michigan congestion is often impacted by flows around Lake Erie. Hence, when the Phase Angle Regulators (“PARs”) on the Midwest ISO-to-IESO interface are fully operational, convergence should improve. Of the four PARs currently designed to control the interface, one is in operation, two more are available but not in operation and the fourth is being repaired. Additional agreements are still needed on PAR operation and scheduling.

**Figure 65: Comparison of FTR Auction Prices and Congestion Value**  
Michigan Hub: Peak Hours



**Figure 66: Comparison of FTR Auction Prices and Congestion Value**  
Michigan Hub: Off-Peak Hours



## **VI. Competitive Assessment**

This section assesses the competitive structure and performance of the Midwest ISO markets during 2008. The competitive assessment seeks to determine whether market power exists and, if so, whether it has been exercised. This type of assessment is particularly important for LMP markets because LMP markets provide opportunities for the exercise of local market power in congested areas.

### **A. Market Structure**

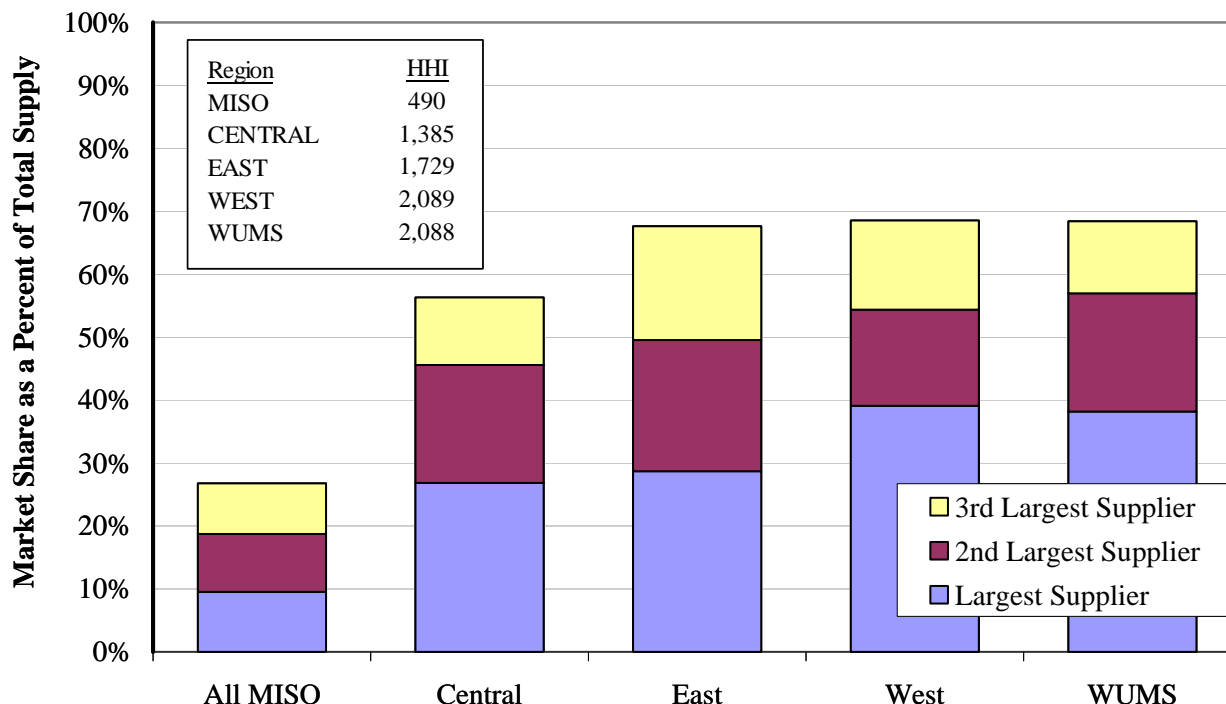
This first subsection provides three structural analyses of the market. The first is an overview of the concentration of both the Midwest ISO as a whole and the various regions within it. The remaining two analyses address the frequency with which suppliers in the Midwest ISO are “pivotal”, i.e., needed to serve load reliably or resolve transmission constraints. In general, the latter analyses provide a much more reasonable indicator of potential market power than does the market concentration analysis.

#### **1. Market Concentration**

The first analysis of market structure evaluates the market’s concentration using the Herfindahl-Hirschman Index (“HHI”). The HHI is a standard measure of market concentration calculated by summing the square of each participant’s market share. The antitrust agencies generally characterize markets with HHIs greater than 1,800 as highly concentrated.

The HHI is only a generic indicator of market concentration, not a definitive measure of market power. The most significant shortcomings of the HHI for identifying market power concerns are that it does not account for demand, network constraints, or load obligations. In wholesale electricity markets, these factors can have a profound effect on the competitiveness of the market. Figure 67 shows market shares and HHI calculations for the Midwest ISO as a whole and within each region.

**Figure 67: Market Shares and Market Concentration by Region**  
2008



The HHI in the entire Midwest ISO area of operation is 490, which is low and is indicative of a competitive market. The largest three suppliers combined have a total market share of less than 27 percent. This metric indicates that generation ownership in the Midwest ISO is not concentrated. Each of the four regions is much more concentrated than the Midwest ISO as a whole. The WUMS area and West region are highly concentrated: the top three suppliers control at least two-thirds of the market in both of these regions. The regional HHIs are higher than those in the comparable zones of other RTOs because vertically-integrated utilities in the Midwest ISO that have not divested generation tend to have substantial market shares. Divestitures of generation in other RTO zones generally reduce market concentration because the assets are typically sold to a number of different entities.

## 2. Residual Demand Index

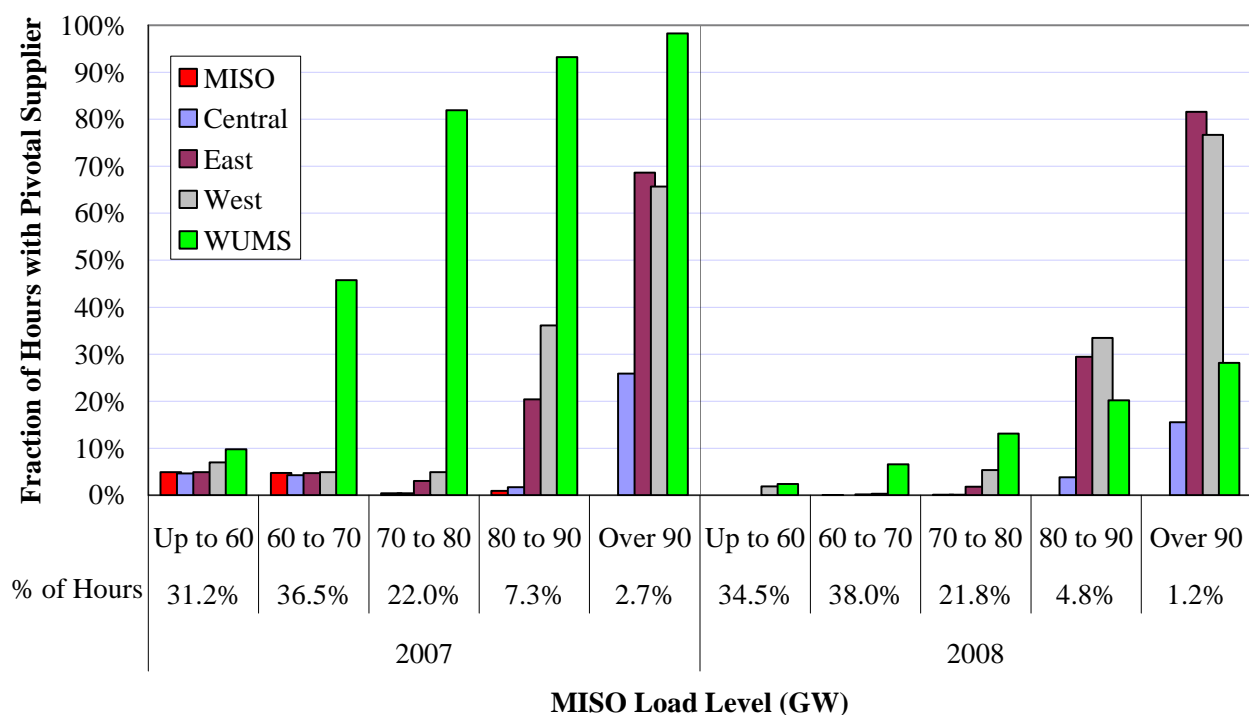
As noted above, the HHI market concentration calculation is a commonly used measure of market power. However, the HHI does not allow one to draw reliable inferences regarding the competitiveness of electricity markets because it ignores factors particularly relevant to the study



of power markets. The next two analyses more accurately reveal potential competitive concerns in the Midwest ISO energy markets.

The first metric is the residual demand index (“RDI”), which measures the portion of the load in an area that can be satisfied without the resources of its largest supplier. The RDI is calculated using all import capability into the area, not just the imports actually scheduled. In general, the RDI decreases as load increases. An  $RDI > 1$  means that the load can be satisfied without the largest supplier’s resources. An  $RDI < 1$  indicates that a supplier is “pivotal”, i.e., a monopolist over a portion of the load. Figure 68 shows pivotal supplier frequency by load level, measuring the percentage of hours when the RDI is less than one.

**Figure 68: Pivotal Supplier Frequency by Load Levels**  
2007 to 2008



In January of 2008, the Arrowhead-Weston 345 line between Minnesota and the WUMS area was placed service. Figure 68 shows that there was a dramatic decline in the fraction of hours with a pivotal supplier in 2008 in the WUMS area as a result of this new transmission capability. As expected, the frequency with which a supplier is pivotal rises sharply as load rises. This factor and the fact that prices are most sensitive to withholding under high load conditions

explain why market power concerns are the greatest when load is highest. There was no corresponding decline in the percentage of hours in which there was a pivotal supplier in the East and West regions. These percentages are slightly higher in 2008 for loads above 80 GW. The West and East regions do not exhibit a pivotal supplier in a substantial share of hours, except when load exceeded 80 GW (approximately six percent of the hours).

### **3. Constraint-Specific Pivotal Supplier Analysis**

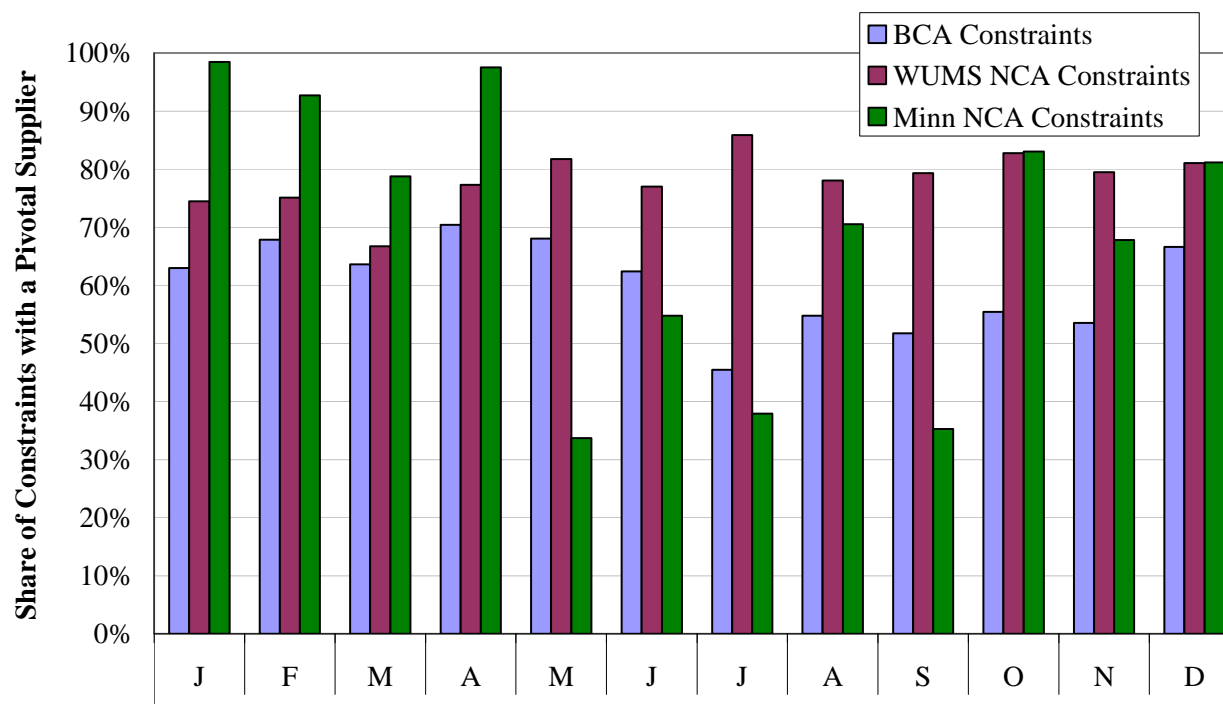
While the RDI pivotal supplier analysis in the prior subsection is useful for generally evaluating the competitiveness of the market, accurately identifying local market power requires a more detailed analysis that focuses on specific congestion issues. The analyses in this subsection seeks to detect potential local market power concerns by identifying when a supplier is pivotal relative to a particular transmission constraint.

A supplier is pivotal for a constraint when it has the resources to overload that constraint to an extent that all other suppliers combined cannot relieve the constraint. This is frequently the case for lower-voltage constraints because the resources that most affect the flow over the constraint are those that are near the constraint. If the same supplier owns all of these resources, this supplier is likely pivotal.

We focus particular attention on the two types of constrained areas that are defined for purposes of market power mitigation: Narrow Constrained Areas and Broad Constrained Areas (“BCA”). NCAs are chronically constrained areas that raise more severe potential local market power concerns (so tighter market power mitigation measures are employed), while BCAs include all other areas within the Midwest ISO that are isolated by a transmission constraint.

Figure 69 shows the portion of the active NCA constraints (into the WUMS and Minnesota areas) and BCA constraints that have at least one pivotal supplier.

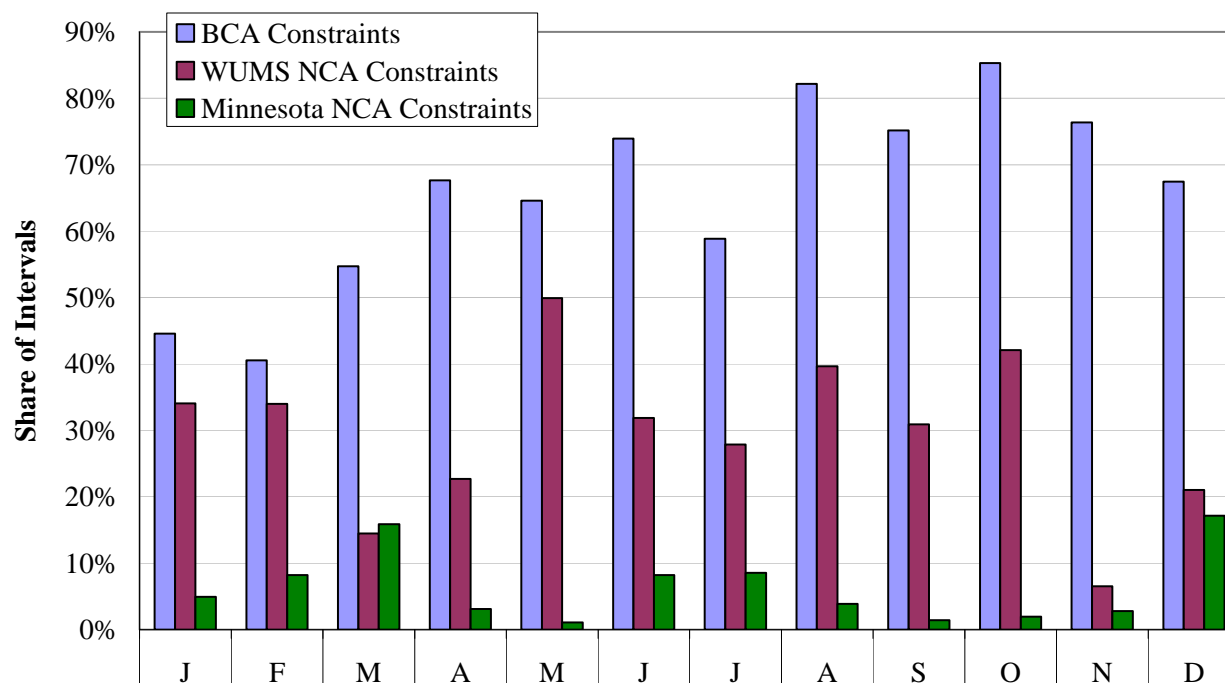
**Figure 69: Percentage of Active Constraints with a Pivotal Supplier**  
2008



This figure shows that in most months of 2008, active constraints in each of the constrained areas had a pivotal supplier more often than not. During 2008, 79 percent of the active NCA constraints into WUMS had a pivotal supplier and 69 percent of the active NCA constraints into Minnesota had a pivotal supplier. For BCAs, 59 percent of the active BCA constraints had a pivotal supplier. These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of BCA constraints in 2008 created substantial potential local market power as well.

The prior analysis showed that a supplier was frequently pivotal when a BCA constraint or NCA constraint was active. Figure 70 shows the percentage of intervals when at least one supplier was pivotal for a BCA or NCA constraint. This analysis varies from the prior analysis because it incorporates how frequently BCA and NCA constraints are active. Therefore, it measures how frequently local market power may be a problem within the Midwest ISO.

**Figure 70: Percent of Intervals with at Least One Pivotal Supplier**  
2008



This analysis shows that there was an active BCA constraint with at least one pivotal supplier in each month from 40 percent to 85 percent of hours in 2008. Overall, the average for active BCA constraints was 66 percent of the hours during 2008. The regional distribution of BCA constraints varied throughout the year, yet the total frequency was fairly constant. The analysis also indicates that there was an active NCA constraint with a pivotal supplier in 30 percent of hours into WUMS and 6.5 percent of hours into Minnesota in 2008. Pivotal suppliers into Minnesota were three times more frequent in 2007 than 2008. Aside from this decline in the Minnesota NCA, the percentages are similar to the corresponding percentages in 2007.

Overall, these results indicate that substantial potential local market power exists throughout the Midwest ISO, although it has declined in Minnesota. The results also stress the importance of BCA and NCA mitigation that are designed to prevent the exercise of such market power. The next section evaluates participants' conduct during 2008 to determine whether participants with market power attempted to exercise it.

## **B. Participant Conduct**

In this section, we analyze participant conduct to determine whether it is consistent with competitive behavior or whether it is consistent with attempts to exercise market power. We start this section with a Price-Cost Markup analysis. Then we test for two types of conduct: economic withholding and physical withholding. Economic withholding occurs when a participant offers resources substantially above competitive levels to raise market clearing prices or RSG payments. Physical withholding occurs when a unit that would be economic at the market price is unavailable to produce some or all of its output. This is usually accomplished by claiming an outage or by derating the resource.

### **1. Price-Cost Markup Analysis**

Our first analysis estimates the “markup” of real-time market prices over suppliers’ competitive costs. In this analysis, we compare the system marginal price that would result under two different sets of assumptions. We estimate the system marginal price assuming that suppliers offer at prices equal to 1) their reference levels and 2) their actual offers. The difference in the estimated system marginal prices computed under the two different sets of assumptions is the markup. This analysis is a simplified metric that does not account for physical restrictions on the units and transmission constraints, which would require re-running the market software. We then computed a yearly load-weighted average of the estimated system marginal price.

This metric is useful in evaluating the competitive performance of the market. A competitive market should produce a small mark-up because suppliers should have incentives to offer at close to their marginal cost.

We performed this analysis for the past two years and found average annual markups of less than 0.5 percent in 2007 and approximately 1.1 percent in 2008. Many factors that can cause reference levels to vary slightly from suppliers’ true marginal costs so we would not expect to see a markup exactly equal to zero. Markups of such low magnitude indicate that the markets have performed competitively over the timeframe studied.

## 2. Economic Withholding

An analysis of economic withholding requires a comparison of actual offers to competitive offers. Suppliers lacking market power maximize profits by offering resources at marginal costs, which is a generator's competitive offer price. A generator's marginal cost is the incremental cost of producing additional output. Marginal cost include inter-temporal opportunity costs, incremental risks associated with unit outages, fuel, additional O&M, and other incremental costs attributable to the incremental output. For most fossil-fuel resources, marginal costs are closely approximated by their variable production costs (primarily fuel costs, labor, and variable O&M costs). However, at high-output levels or after having run for long periods without routine maintenance, outage risks and expected increases in O&M costs can create substantial additional incremental costs. Generating resources with energy limitations, such as hydroelectric units or fossil-fuel units with output restrictions due to environmental considerations, must forego revenue in a future period to produce in the current period. These units incur inter-temporal opportunity costs associated with producing that can cause their marginal costs to be much higher than their variable production costs.

Establishing a proxy for units' marginal costs as a competitive benchmark is a key component of analyses that seek to identify economic withholding. The proxy is necessary to determine the quantity of output that is potentially economically withheld. The Midwest ISO's market power mitigation measures include a variety of means to calculate a resource's "reference levels," intended to reflect the resource's marginal costs. We use these reference levels for the analyses below. The mitigation measures also include a threshold that defines how far above the reference levels that the supplier would have to offer before potentially warranting mitigation. This threshold is used in the market power mitigation "conduct test."

To identify potential economic withholding, we calculate our "output gap" metric, based upon resources' startup, no-load, and incremental energy offer parameters. The output gap is the difference between a unit's output that is economic at the prevailing clearing price and the amount that is actually produced by the unit. In essence, the output gap shows the quantity of generation that a supplier may be withholding from the market by submitting offers above competitive levels. Therefore, the output gap for any unit would generally equal:

$Q_i^{\text{econ}} - Q_i^{\text{prod}}$  when greater than zero, where:

$Q_i^{\text{econ}}$  = Economic level of output for unit  $i$ ; and

$Q_i^{\text{prod}}$  = Actual production of unit  $i$ .

To estimate  $Q_i^{\text{econ}}$ , the economic level of output for a particular unit, it is necessary to look at all parts of the unit's three-part reference level: startup cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time.

We employ a three-stage process to determine the economic output level for a unit in a particular hour. In the first stage, we examine whether the unit would have been economic *for commitment* on that day if it had offered its true marginal costs. In other words, we examine whether the unit would have recovered its actual startup, no-load, and incremental costs running at the dispatch point dictated by the prevailing LMP (constrained by its EcoMin and EcoMax) for its minimum run time. If a unit was economic for commitment, we then identify the set of contiguous hours during which the unit was economic to dispatch. Finally, we determine the economic level of incremental output in hours when the unit was economic to run. In hours when the unit was not economic to run and on days when the unit was not economic for commitment, the economic level of output was considered to be zero. To reflect the timeframe in which commitment decisions are actually made, this assessment is based upon day-ahead market outcomes for non-quick-start units and based upon real-time market outcomes for quick-start units.

Because our benchmarks for units' marginal costs are inherently imperfect, we add a threshold to the resources' reference level to determine  $Q_i^{\text{econ}}$ . This ensures that we will identify only significant departures from competitive conduct.

$Q_i^{\text{prod}}$  is the actual observed production of the unit. The difference between  $Q_i^{\text{econ}}$  and  $Q_i^{\text{prod}}$  represents how much the unit fell short of its economic production level. However, some units are dispatched at levels lower than their three-part offers would indicate due to transmission constraints, reserve considerations, or other changes in market conditions between the unit commitment and real-time. Therefore, we adjust  $Q_i^{\text{prod}}$  upward to reflect three-part offers that

would have made a unit economic to run, even though the unit may not have been fully dispatched. Hence the output gap formula used for this report is:

$Q_i^{\text{econ}} - \max(Q_i^{\text{prod}}, Q_i^{\text{offer}})$  when greater than zero, where:

$Q_i^{\text{offer}} =$  offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, units that are subject to ramp limitations are excluded from the output gap. Figure 71 shows monthly average output-gap levels in 2007 and 2008. The output gap shown in the figure includes two types of units: 1) online and quick-start units available in real time, and 2) offline units that would have been economic to commit.

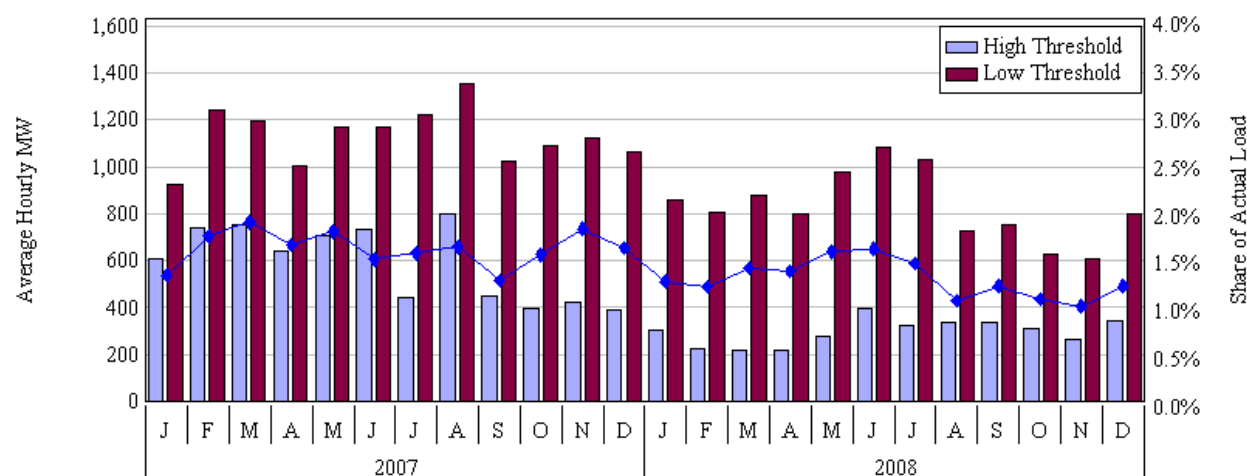
The data is arranged to show the output gap using the mitigation threshold in each area (“high threshold”), and one-half of the mitigation threshold (“low threshold”). The high threshold effective during most of 2008 was \$100 per MWh in BCAs and \$25.09 and \$26.90 per MWh in the Minnesota and WUMS NCAs, respectively. For a resource’s unscheduled output to be included in the output gap, its commitment cost per MWh or incremental energy offer must exceed the given resource’s reference plus the applicable threshold. The lower threshold would indicate potential economic withholding of output that is offered at a price significantly above its reference yet within the mitigation threshold.

Figure 71 shows that the output gap was slightly lower in 2008 compared to 2007. The quantities in both years are very low and do not increase substantially when the low thresholds are used. These levels of output gap provides little indication of significant economic withholding. However, we monitor these levels continually and have investigated many specific output gap issues. In most cases, values can be explained by competitive factors.

Despite the low output gap levels shown in the prior chart, it is useful to make a further examination. Because any measure of potential withholding will inevitably include quantities that can be justified, we generally evaluate not only the absolute level of the output gap but also how it varies with factors that can cause a supplier to have market power. This allows us to test whether a participant’s conduct is consistent with attempts to exercise temporal market power.



**Figure 71: Monthly Average Output Gap: Real-Time Market**  
2007 to 2008

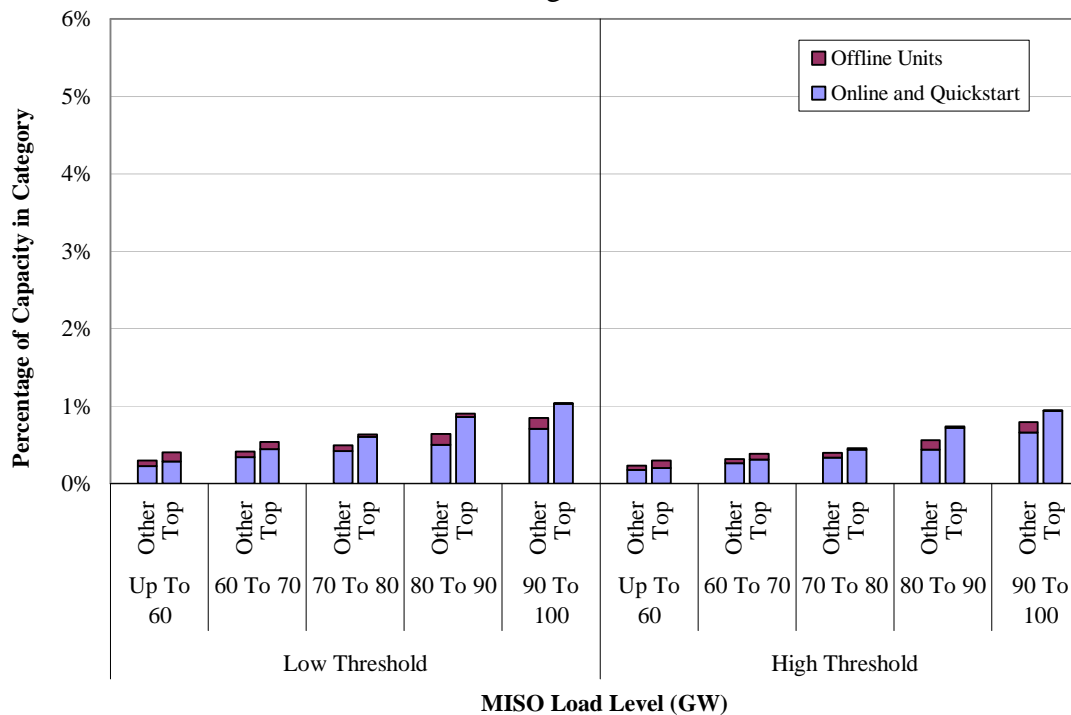


High Threshold	Commit	36	150	44	112	217	61	127	102	79	141	36	5	35	35	47	91	89	112	130	102	84	146	126	222
	On-Line	886	1,092	1,154	892	951	1,111	1,094	1,254	944	947	1,084	1,060	825	771	828	708	888	971	897	625	671	484	479	579
	Commit	13	60	20	56	127	36	42	35	34	56	9	21	17	10	25	16	31	26	73	79	65	124	83	110
	On-Line	597	682	733	586	580	697	401	767	416	341	411	366	289	213	194	203	244	373	250	257	273	189	181	235

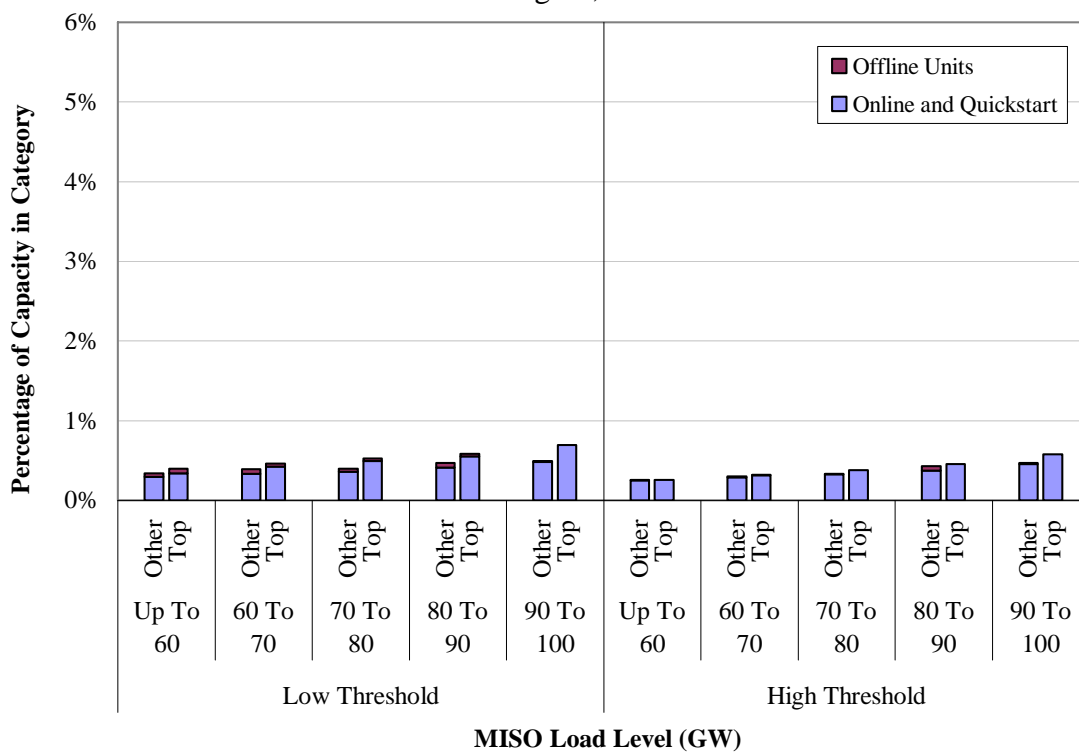
The most important factors in this type of analysis are the size of the participant and the load level. Larger suppliers generally are more likely to be pivotal and will tend to have a greater incentive to increase prices than relatively smaller suppliers. Load level is important because the sensitivity of price to withholding generally increases as the load increases. This is due, in part, to the fact that rivals' resources will be more fully-utilized serving load under these conditions, leaving only the highest-cost resources to respond to the withholding.

The effect of load on potential market power was evident earlier in this section in our pivotal supplier analyses. Accordingly, the figures below show the output gap results by load level and size of participant. The average output gap quantities are shown for the largest two suppliers in each region versus the other suppliers. The figures also show the average output gap at the mitigation thresholds and at one-half of the mitigation thresholds. Figure 72 through Figure 75 show the results of our output gap analysis for each of the Midwest ISO regions.

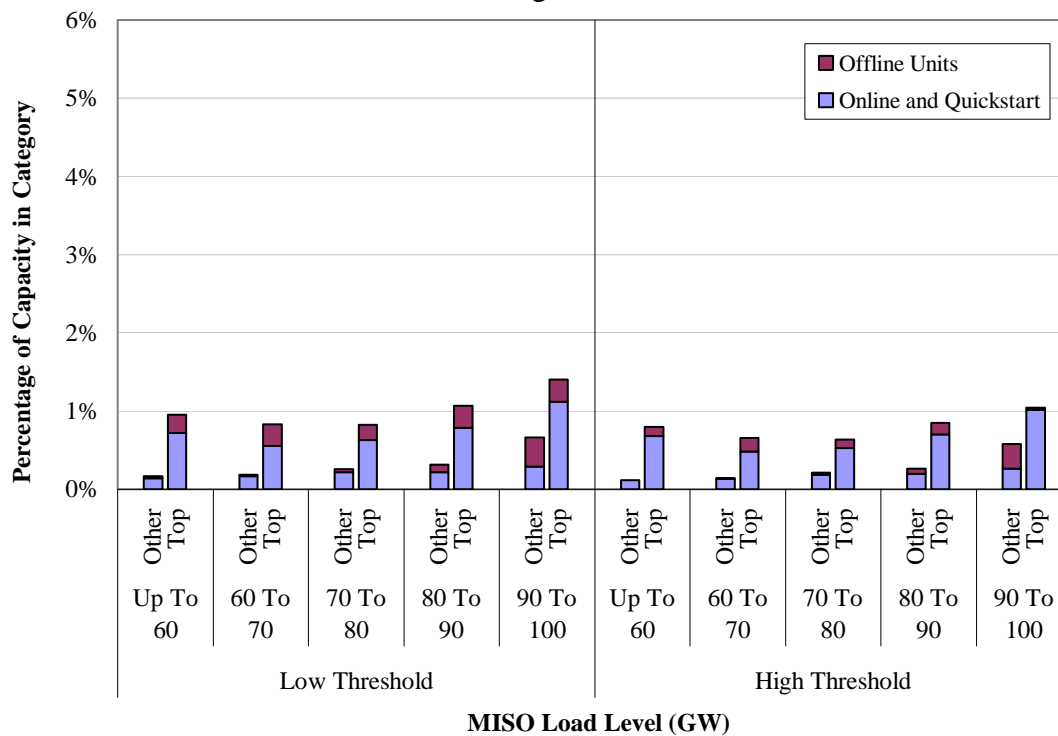
**Figure 72: Real-Time Market Output Gap**  
Central Region, 2008



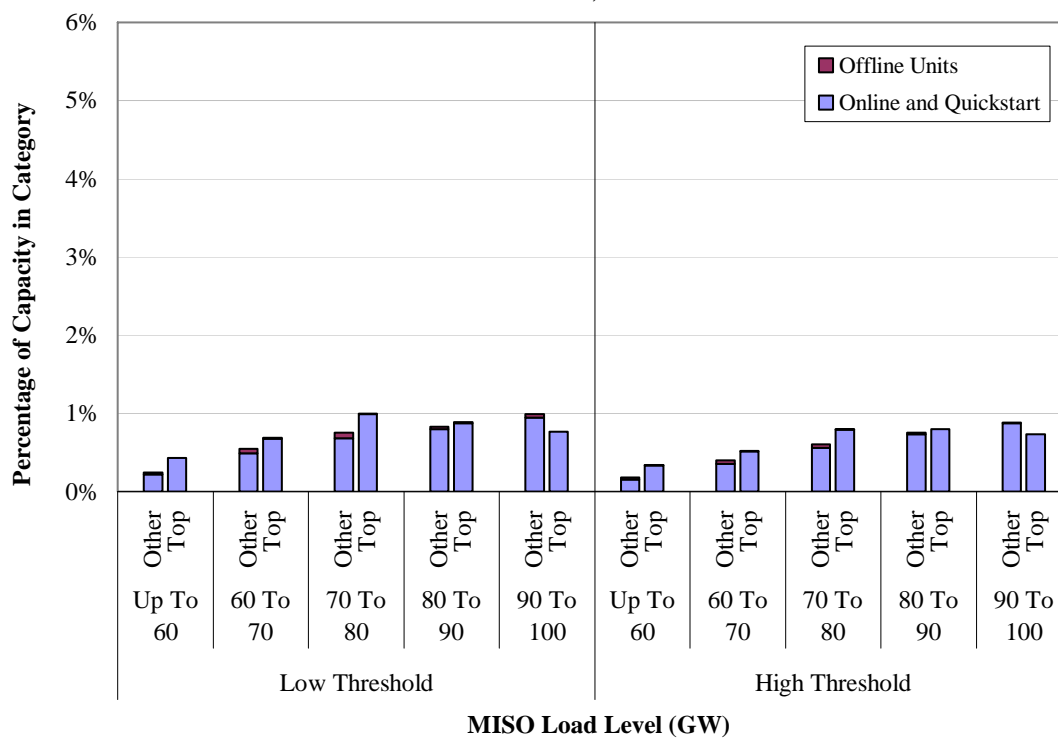
**Figure 73: Real-Time Market Output Gap**  
East Region, 2008



**Figure 74: Real-Time Market Output Gap**  
West Region, 2008



**Figure 75: Real-Time Market Output Gap**  
WUMS Area, 2008



We observe that the output gap quantities at the mitigation thresholds are less than one percent at nearly all locations and load levels. The output gap results are slightly higher in the West region in part because the thresholds applied to resources in the West region are the lower NCA thresholds, not the BCA thresholds. Given the lower thresholds applied to NCAs, the higher output gap results (exceeding 1.5 percent at higher load levels) do not raise substantial concerns.

In general, the output gap increases with load levels because the higher prices that occur at high load levels cause a much higher share of the resources to be economic. However, because this could also signal a rise in anticompetitive conduct, we will monitor any increases at higher-load levels closely on an ongoing basis. Finally, with the exception of the West, the output gap quantities for the largest suppliers were not significantly higher than for other suppliers. We thoroughly reviewed the conduct of the suppliers in the West region and did not find evidence of behavior that raised competitive concerns. These results and our subsequent investigations indicate that economic withholding was not a concern in 2008.

### **3. Physical Withholding**

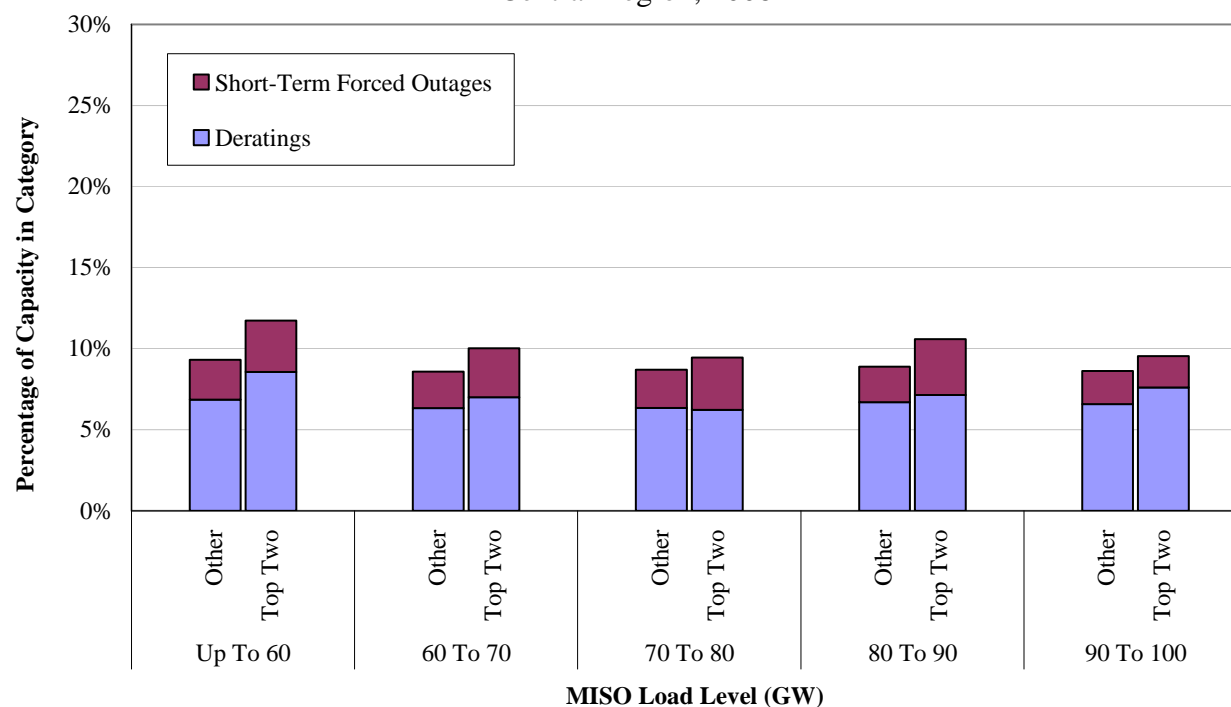
In this subsection, we examine forced outages and other unplanned deratings to assess whether participants modify the availability of resources in a manner consistent with physical withholding. Although we analyze broad patterns in outages and deratings for this report, we also monitor for potential physical withholding on a day-to-day basis and audit outages and deratings when they have a substantial affect on market outcomes.

We separately show three measures of outages and deratings to assess potential physical withholding: short-term forced outages (less than seven days), longer-term forced outages, and deratings. Like the output gap analysis above, this conduct may be justifiable or may represent physical withholding. Therefore, we evaluate them relative to load levels and participant size to detect patterns consistent with potential withholding.

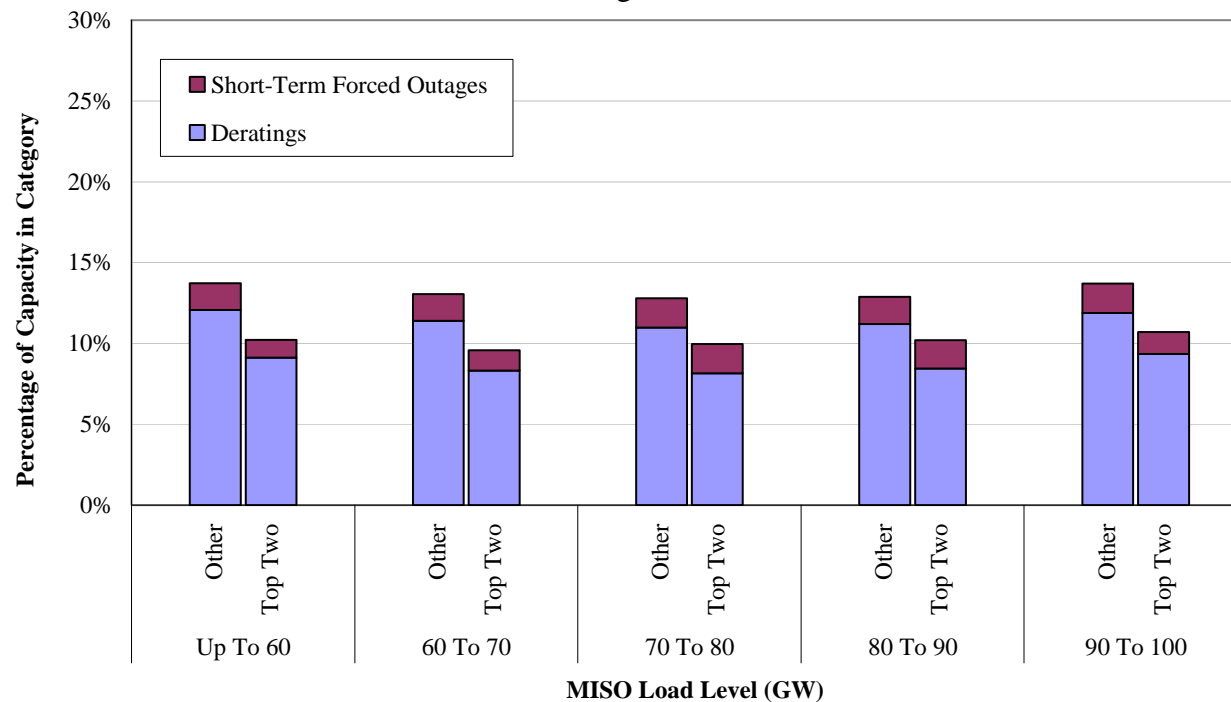
The figures below show the average share of capacity unavailable to the market due to forced outages and deratings. These statistics are calculated by load level for the top two suppliers in each region and for all other suppliers combined. Figure 76 through Figure 79 show these results for each of the Midwest ISO's four regions.

We present the data in these figures by load level because attempts to withhold would likely occur at high-load levels when prices are most sensitive to withholding. We also focus particularly on short-term outages and partial deratings because long-term forced outages are less likely to be a profitable withholding strategy. This is because taking a long-term forced outage of an economic unit would cause the supplier to forego profits on the units during hours when the supplier does not have market power.

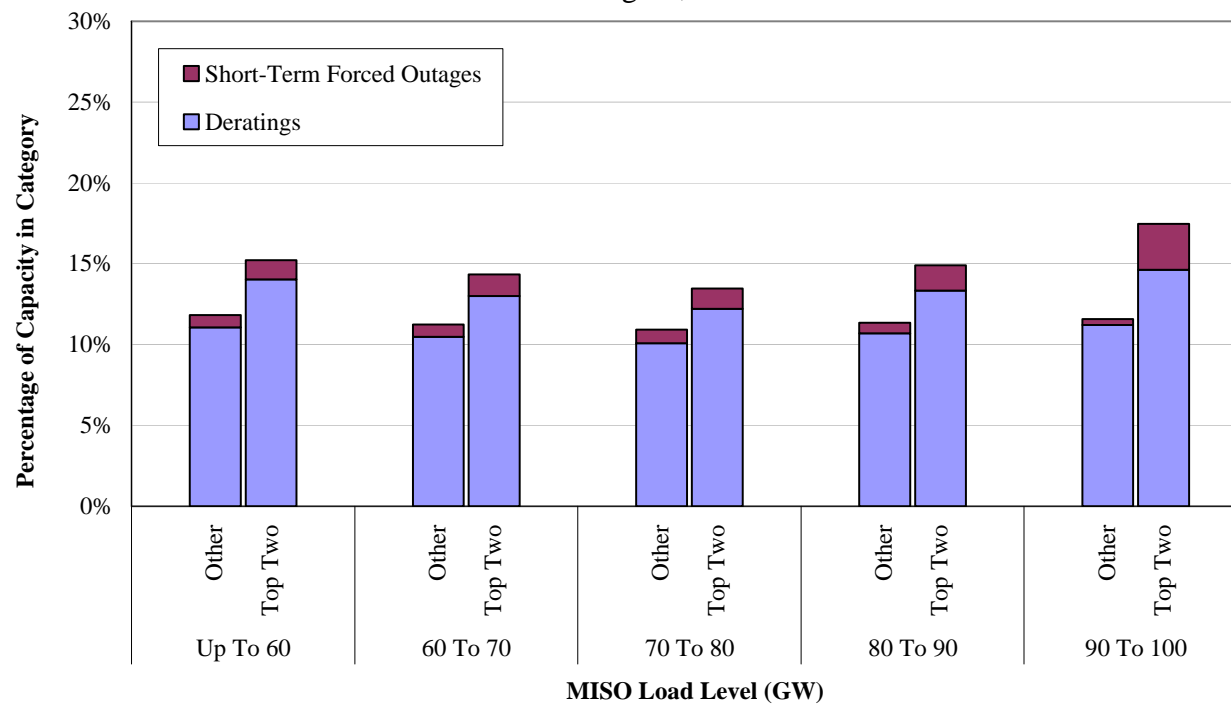
**Figure 76: Real-Time Deratings and Forced Outages**  
Central Region, 2008



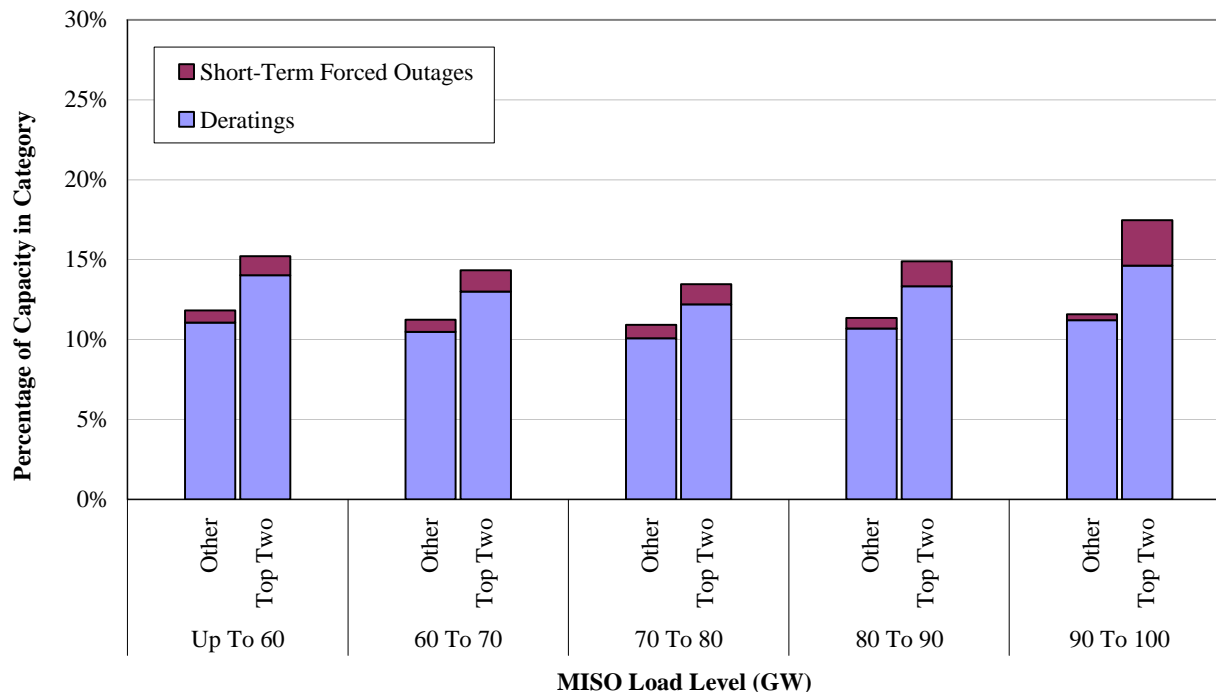
**Figure 77: Real-Time Deratings and Forced Outages**  
East Region, 2008



**Figure 78: Real-Time Deratings and Forced Outages**  
West Region, 2008



**Figure 79: Real-Time Deratings and Forced Outages**  
WUMS Area, 2008



The figures show that deratings and outages are not significantly higher under peak load conditions than they are under off-peak conditions, generally remaining under 15 percent. In the Central and East regions, derated quantities for the largest suppliers are lower or about the same as the corresponding quantities for other suppliers (those that are less likely to have market power). The patterns in these charts do not raise potential concerns. In the West region and the WUMS area, the largest suppliers generally have outages and deratings slightly higher than other suppliers (who are less likely to have market power). This warrants further investigation, so we review these particular outages and deratings. This review did not raise potential competitive concerns. We continue to investigate any outages or deratings that create substantial congestion or other price effects.

### C. Market Power Mitigation

In this subsection, we describe and summarize the frequency with which market power mitigation measures have been imposed in the Midwest ISO markets. The mitigation measures are contained in Module D of the Midwest ISO's Tariff. They are intended to preclude abuses of

locational market power while minimizing interference with the market when the market is workably competitive. The Midwest ISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages, while effectively mitigating inflated prices associated with artificial shortages that result from physical or economic withholding in transmission-constrained areas. The Midwest ISO has almost completely automated the mitigation process.

Market participants are potentially subject to mitigation specifically when transmission constraints that are binding can result in substantial locational market power. When a transmission constraint is binding, one or more suppliers may be in a position to exercise market power due to a lack of competitive alternatives. In this regard, the Midwest ISO's Tariff defines two types of constrained areas that may be subject to mitigation: BCAs and NCAs.

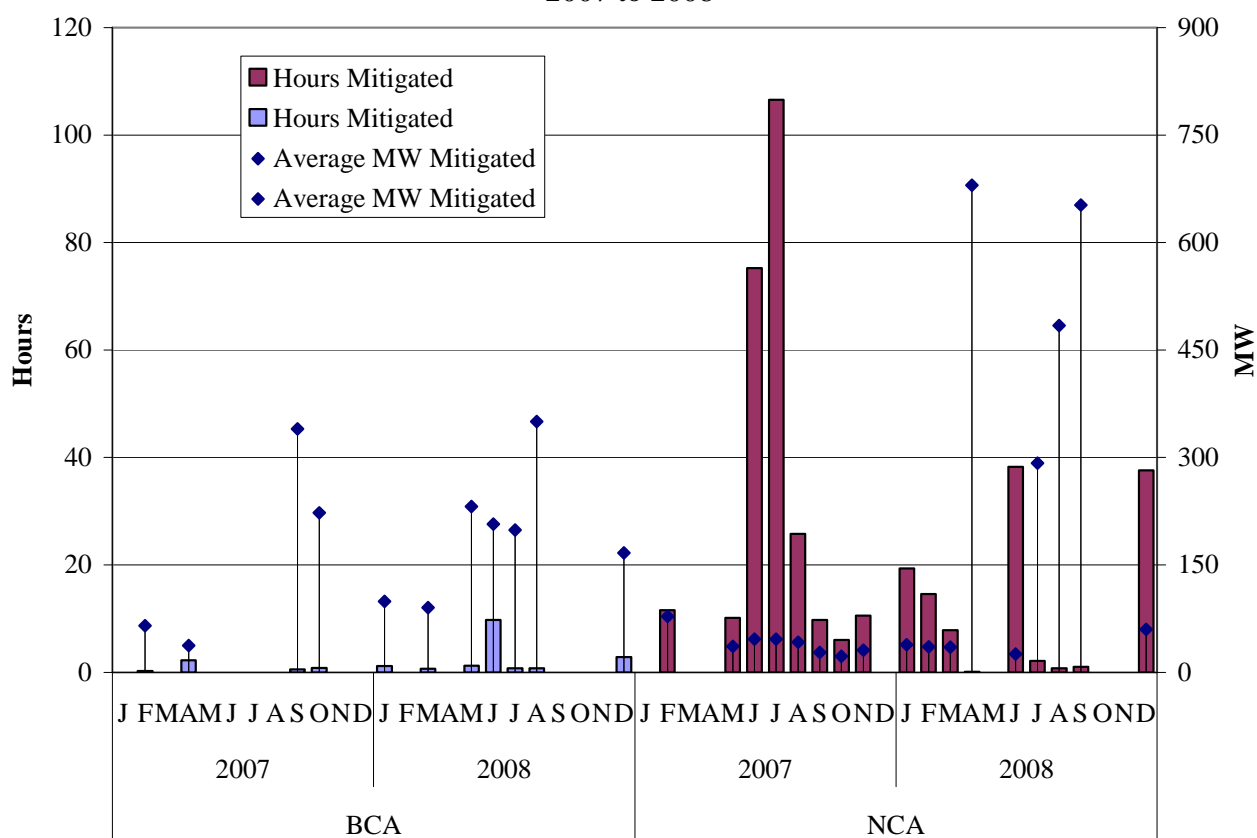
The definition of BCAs and NCAs is based upon the electrical properties of the transmission network that can lead to local market power. NCAs are chronically-constrained areas where one or more suppliers are frequently pivotal when the constraints are binding. Hence, they can be defined in advance. Market power associated with non-NCA constraints can be severe. If the constraints are not chronic, they generally raise less competitive concerns. Therefore, BCA constraints are defined dynamically as they arise on the transmission network. Due to the vast number of potential constraints and the fact that the topology of the transmission network can change significantly when outages occur, it is neither feasible nor desirable to define all possible BCAs in advance. Therefore, BCAs are defined dynamically when non-NCA constraints bind. A BCA includes all of the generating units that have a significant impact on the power flows over a constrained interface.

Because the market power concerns associated with NCAs are higher due to their chronic nature, the conduct and impact thresholds for NCAs are substantially lower than they are for BCAs. The chronic nature of the NCAs and the lower mitigation thresholds lead to more frequent mitigation in the NCAs than in the BCAs, even though there are many more BCAs. Figure 80 shows the frequency and quantity of mitigation in the real-time market by month.



The figure indicates that NCA mitigation occurred more frequently than BCA mitigation. However, mitigation in both types of areas was infrequent. There were 17 unit-hours of BCA mitigation and 122 unit hours of NCA mitigation. Most of the mitigation occurred in June and December of 2008 when a collective 70 unit-hours of mitigation occurred. However, the figure clearly shows that NCA mitigation was sharply down in 2008 from 2007. This is attributable to the reduced severity of congestion into the Minnesota NCA in 2008. An increase in imports from Manitoba (discussed in Section VIII) helped reduce the loading on the 345 kV lines entering Minnesota from Iowa. The vast majority of NCA mitigation in 2007 impacted peaking units committed to relieve congestion on these lines. BCA mitigation in 2008 was implemented more frequently than in 2007, but it was still invoked sparingly relative to NCA mitigation.

**Figure 80: Real-Time Mitigation by Month**  
2007 to 2008

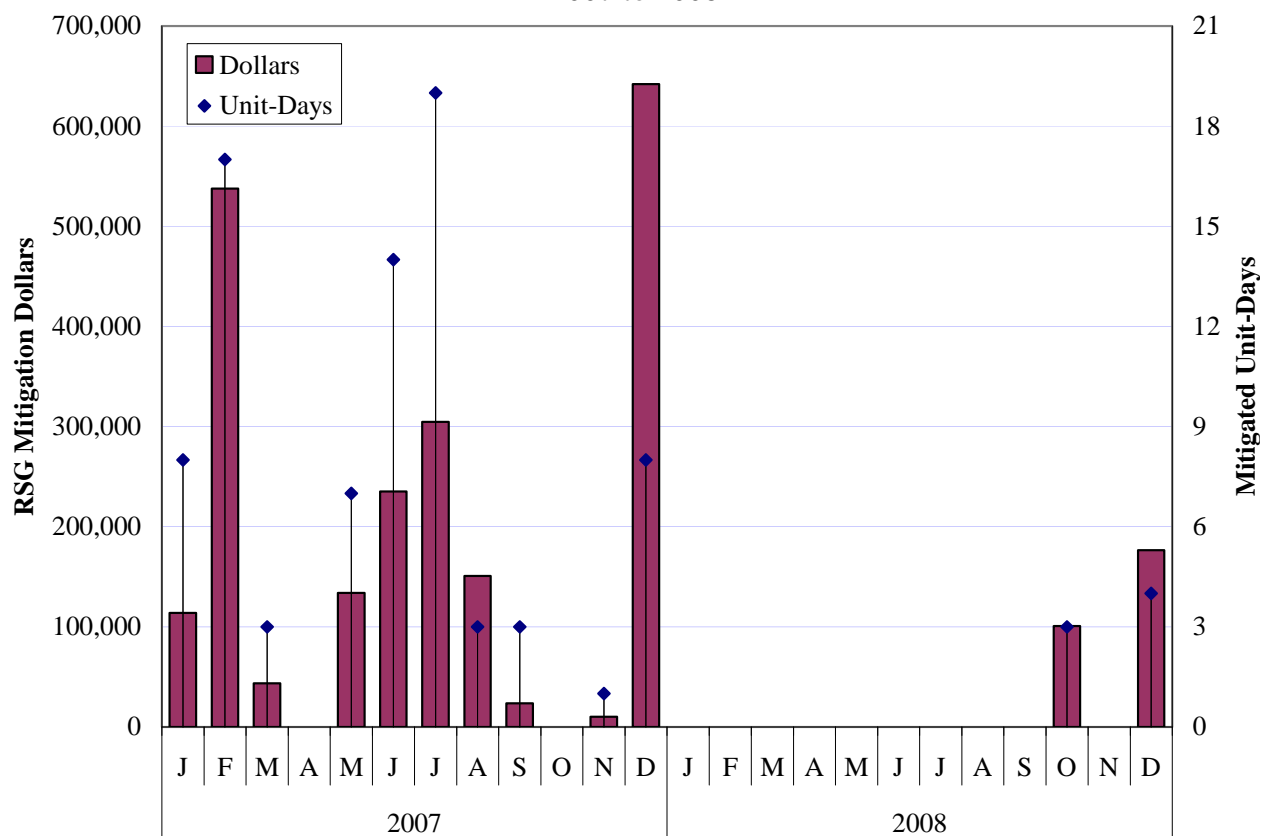


Although mitigation was infrequent during 2008, the analyses in this section continue to show that local market power is a significant concern. If exercised, local market power could have

substantial economic and reliability consequences within the Midwest ISO markets. Hence, market power mitigation measures remain essential.

The previous analysis focused on mitigation of economic withholding in the real-time energy market. Participants can also exercise market power by raising their offers when their resources must be committed to resolve a constraint or to satisfy a local reliability requirement. This can compel the Midwest ISO to make substantially higher RSG payments. The Midwest ISO designed mitigation measures to address this conduct. These mitigation measures are triggered when the following three criteria are met: 1) the unit must be committed for a constraint or a local reliability issue; 2) the unit's offer must exceed the conduct threshold; and 3) the effect of the inflated offer must exceed the impact threshold (i.e., to raise the unit's RSG payment by 200 percent on a BCA constraint). Figure 81 shows the frequency and amount by which RSG payments were mitigated in each month of 2008.

**Figure 81: Real-Time RSG Payment Mitigation by Month**  
2007 to 2008



The figure shows that no RSG payments were mitigated in most months. Mitigation occurred for only seven unit-days and resulted in slightly more than \$280,000 in RSG payments in 2008.

While mitigation of RSG payments was modest, this does not indicate a lack of locational market power; rather, it illustrates only that there were few instances where units required for local reliability reasons were mitigated for exercising locational market power.

## VII. Demand Response Programs

Demand response is comprised of actions during certain hours that can reduce consumption from normal levels. DR allows for participation in the energy markets by end users and is beneficial in many ways. Such participation contributes to reliability in the short-term and to least-cost resource adequacy in the long-term; reduces price volatility and other market costs; and mitigates supplier market power. Additionally, price-responsive demand has great potential to enhance wholesale market efficiency. Even modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the need to facilitate DR through wholesale market mechanisms and transparent economic signals.

DR resources can broadly be categorized as either “emergency DR”, which respond to capacity shortages, or “economic DR”, which respond to energy market prices. Emergency DR resources are callable by the ISO in advance of a forecasted system emergency<sup>30</sup> and thus can play an important role in supporting system reliability. However, emergency DR does not currently participate in energy markets and is not generally price-responsive. Economic DR resources respond to energy market prices not only during emergencies but any time the energy price exceed the marginal value of the consumer’s electricity consumption. Economic DR can be further categorized into two groups: those that can be dispatched in the same operational timeframes as generation (5 minutes in the case of the Midwest ISO) and those that must be notified in advance of when they are needed. Most economic DR resources require from one to 12 hours of advance notification.

The real-time market is significantly more volatile than the day-ahead market due to physical restrictions and contingencies that affect the real-time market. Given the high value of most electricity consumption, DR resources will tend to be most valuable in the real-time during abrupt periods of shortage when prices spike. In the day-ahead market where prices are less

---

30 Specifically, an EEA2 event.

volatile and there is a much wider array of supply alternatives, DR resources are generally less valuable. On a longer-term basis, however, consumers can make strategic shifts in their consumption patterns in response to day-ahead prices (from peak to off-peak period, flattening the load curve). This increases overall efficiency and reliability of the system.

### **A. DR Resources in the Midwest ISO**

The Midwest ISO had over 8,600 MW of demand response capability in 2008, most of which were legacy “reliability” DR programs administered by LSEs in the form of interruptible load. DR resources in 2008 participated in all Midwest ISO energy markets and contributed to an LSE’s resource adequacy requirement under Module E of the Tariff. In 2009, the launch of ASM provided other avenues for DR resources to participate in the Midwest ISO’s markets. In addition, LSEs will soon be able to bid DR resources into the proposed Schedule 30 Emergency Demand Response (“EDR”) initiative that was recently approved by the Commission on June 12, 2009.

#### **1. Types of DR Resources**

The Midwest ISO’s Tariff characterizes DR resources that participate in the Midwest ISO markets as either “Type I” or “Type II” resources. Type I resources are capable of supplying a specific quantity of energy or contingency reserve through physical load interruption. Type II resources on the other hand are capable of supplying energy or operating reserves over a dispatchable range, such as through controllable load or behind-the-meter generation. The two types roughly correspond to emergency DR and economic DR, respectively, as described in the previous section, although they are not exclusive.

Because Type I resources are inflexible and can only provide a specific quantity of either energy or operating reserves, they currently cannot set prices in the Midwest ISO markets. In this respect, the Midwest ISO treats Type I resources in a similar fashion as generation resources that are block-loaded for a specific quantity of energy or operating reserves. The Midwest ISO, however, is pursuing an initiative to develop an appropriate pricing methodology to allow Type I and other so-called “fixed block” offers to establish market prices. Although the Midwest ISO has a sizable amount of demand response capability, only approximately 300 MW of Type I

resources are directly administered by the Midwest ISO in the form of direct load control (“DLC”). The balance of the Type I resources are in the form of interruptible demand.

Interruptible load programs are catered toward large industrial end-users and typically require a minimum size of load reduction and a minimum level of peak demand. In an interruptible load program, customers agree to reduce consumption by (or to) a predetermined level in select ISO-determined instances in exchange for a small per-kWh reduction in their fixed rate. The Midwest ISO does not directly control this load—such programs are therefore ultimately voluntary, although penalties exist for non-compliance. DLC programs are targeted toward residential and small commercial users. They often require certain equipment end-uses, such as air conditioners or water heaters. In the event of a contingency, the LSE will manually reduce the load of certain equipment to a predetermined level.

Type II resources can set prices because they are capable of supplying energy or operating reserves over a dispatchable range; therefore, they are treated comparably to generation resources. These price-based resources are referred to as “dynamic pricing” resources. If they are dispatchable in 5-minute intervals by the Midwest ISO, they are considered economic. Dynamic pricing is the most efficient form of DR because rates formed under this approach provide customers with accurate price signals that vary throughout the day to reflect the higher cost of providing electricity during peak demand. In turn, customers can alter their usage accordingly. There are significant barriers to implementing dynamic pricing, including extensive infrastructure outlays and retail rate reform. Accordingly, only 48 MW of Type II resources are currently participating in the Midwest ISO.

Although Type I resources cannot currently bid directly into the Midwest ISO market, Module E of the Midwest ISO’s Tariff allows these resources to count toward the fulfillment of an LSE’s capacity requirements. DR resources can also be included in the ISO’s long-term planning process (e.g., Phase II of the Resource Adequacy Requirement Plan) as comparable to generation. These capabilities were included in the Midwest ISO’s resource adequacy filing made on December 28, 2007 and conditionally accepted by the Commission on March 26, 2008. The ability for all DR resources to provide capacity under Module E goes a long way toward

addressing economic barriers to DR and ensuring comparable treatment with the Midwest ISO's generation.

## **2. Recent DR Initiatives**

Several recent initiatives provide additional opportunities for demand participation in the Midwest ISO. The ASM launched in January 2009 allow LSEs to offer DR resources for operational reserve purposes similar to generation resources.<sup>31</sup> During operations, DR resources offered into ASM are called upon in merit order before any other DR resource except those that are offered in the day-ahead and real-time energy markets. If called upon during a contingency situation, LSEs are required to deliver load reductions—in the day-ahead and real-time markets, non-delivery is subject to penalties. The introduction of ASM should reduce the amount of emergency alerts issued and provide the Midwest ISO with additional flexibility in responding to contingency situations.

In addition, recent Tariff changes approved by the Commission will allow the Midwest ISO to directly curtail load in emergency situations if DR resources dispatched under ASM and LSE-administered DR programs are unable to meet the demand. In addition, the Midwest ISO filed proposed revisions to its Tariff to add a new Schedule 30 EDR initiative which allows for day-ahead emergency DR offers on December 31, 2007. These revisions were conditionally accepted by the Commission on June 12, 2009 and are currently being integrated into the Midwest ISO's system. The provisions were designed to encourage market participants with DR capabilities to submit offers to reduce load or to increase behind-the-meter generation during emergency events. EDR offers are currently submitted on a monthly basis, although the Midwest ISO is seeking to allow offers on a daily basis by summer 2009 to allow for more accurate availability of such resources.

EDR participants that reduce demand in response to a dispatch instruction will be compensated with the higher of the real-time LMP and the EDR offer price for the amount of verifiable

---

31 Only Type II resources are able to provide regulation reserves in ASM.

demand reduction provided. The provision is designed to address economic barriers to DR by ensuring that EDRs are compensated at a level that reflects the value of their curtailment to the system. Paying the full LMP in this case is higher than economically efficient, which would deduct the retail rate savings of the EDR. Absent this deduction, the Midwest ISO will be paying more than the value of the curtailment to the system and the EDR will have a greater incentive to curtail, although this could be justifiable for noneconomic reasons. Nonetheless, such provisions are an improvement. We will monitor the development of EDR to evaluate whether these compensation provisions should be changed in the future.

Finally, the Midwest ISO has been working with its stakeholders to identify and address barriers associated with specific market rules or operating procedures.

## B. Inter-ISO Comparison of DR Programs

In this section, we provide a comparison of the DR programs being held by the Midwest ISO, NYISO and ISO-NE in Table 5 below. The table shows that the Midwest ISO has an initiative for emergency DR and allows for direct participation of DR resources in all markets.

**Table 5: Comparison of DR Programs Across RTOs.**

	ISO-NE					NYISO				MISO	
	RT DRP	RT PRP	RT PrRP	DA LRP	DP	EDRP	SCR	DA DRP	DS ASP	EDR	DP
<b>RT Energy Market</b>			✓								✓
<b>DA Energy Market</b>				✓				✓			✓
<b>Emergency</b>	✓	✓				✓	✓			✓	
<b>Capacity Market</b>	✓	✓					✓				✓
<b>Ancillary Services</b>					✓				✓		✓

### Key:

**RT DRP** = Real-Time Demand Response Program, **RT PRP** = Real-Time Profiled Price Response Program, **RT PrRP** = Real-Time Price Response Program, **DA LRP** = Day-ahead Load Response Program, **EDRP** = Emergency Demand Response Program, **ICAP/SCR** = Installed Capacity / Special Case Resource Program, **DA DRP** = Day Ahead Demand Response Program, **DSASP** = Demand Side Ancillary Services Program, **EDR** = Emergency Demand Response, **DP** = Direct Participation, ✓ = Existing Participation



Table 6 below shows the existing DR by type of resource for three ISOs. It also shows the peak hour reduction in load that was achieved as a percent of the total peak load in 2006 (the last year that a peak demand event led to widespread emergency DR in the three ISO areas). This reduction ranged from 2.1 percent for ISO-NE to 2.8 percent for NYISO.

**Table 6: Comparison of Participation in ISO DR Programs**

	Program	ISO-NE	NYISO	MISO
<b>Enrollment in ISO-Administered Programs</b>	RTO Emergency (2008 MW)	1,634	2,108	300
	RTO/ISO Economic (2008 MW)	445	331	45
<b>Enrollment in LSE-Administered Programs</b>	Non-ISO Emergency (2008 MW)	270	200	8,600+
	Non-ISO Economic (2008 MW)			
<b>Realized DR ISO</b>	Annual Demand Response (2007 GWh)	235	Unknown	Unknown
	Peak Hour Reduction (2006 MW)	597	948	2,651
	Reduction as a percentage of Peak Load (2006)	2.1%	2.8%	2.3%

The table also shows that with greater than 8,600 MW, the Midwest ISO has more DR resources than any other ISO. The Midwest ISO has some of the longest standing DR programs, particularly in the area of emergency DR, although is behind others in the implementation of economic DR. This is discussed in the following subsection.

## **C. Improving DR Integration in Midwest ISO / Overcoming Barriers**

### **1. Reform of Emergency DR Role in Setting Real-Time Prices**

Prior reports have shown that when the Midwest ISO has called for load curtailments under emergency conditions, prices have generally been understated and have not efficiently reflected the shortage (or the value of the foregone consumption). One such event occurred on August 1-2, 2006, when extremely high temperatures throughout the Midwest ISO region resulted in record electricity demand. Emergency procedures were invoked by the Midwest ISO that

resulted in voluntary load reductions of close to 3,000 MW. Prices during peak hours on August 1, however, ranged from \$50 to \$150 and were less than \$100 in the highest demand hour. These prices did not reflect the conditions that triggered the load curtailments.

When DR resources do not set prices as in the example above, a key component of the economic signals needed to support investment in generation, transmission, and demand-side management is undermined. Hence, it should be a high priority of the Midwest ISO to permit DR resources to set energy and ancillary services prices at efficient levels when DR is implemented. Further integrating this capability into the market will be challenging. Work has been underway by the Midwest ISO to utilize DR most efficiently.

## **2. Retail Electricity Rate Reform**

To address the regulatory barrier discussed previously, dynamic real-time retail pricing could be introduced by the states to align consumers' incentives with true costs of their consumption to the system. Dynamic retail pricing provides incentives for demand to respond to retail pricing even though it is not as responsive as generation and avoids the benchmarking issues for the ISOs that exist in most other types of real-time DR programs.

Currently, there is little dynamic pricing in the Midwest ISO region. Residential and small C&I customers generally receive electric service at fixed retail rates. Medium-sized C&I customers also receive fixed retail rates or TOU rates, which generally do not include the capability to send varying day-ahead price signals. The regulatory reform required to expose residential and small C&I customers to the volatility of wholesale energy prices is difficult to implement politically. Additionally, implementation of dynamic rates in the Midwest ISO would likely require substantial AMI investments that can measure consumption in time intervals of one hour or less. While many large C&I customers are already equipped with interval meters, most residential and small C&I customers are not. This presents a significant technical barrier.

If dynamic retail pricing is not introduced by individual states, the Midwest ISO could evaluate alternative approaches for providing real-time economic DR resources the same incentives that they would have under a dynamic retail pricing regime. For example, the Midwest ISO may be able to expand its EDR initiative to make it a price-responsive demand program for economic

DR resources. An efficient payment in such a program is equal to the difference between the wholesale LMP and the retail customer's rate. Paying this amount aligns the load's incentives with the value of the energy to the system, which would directly address the regulatory barrier described in the prior section without requiring regulatory reform. Under such programs, the costs of the payments to responsive retail loads should be allocated to the corresponding LSE that would otherwise receive a windfall when its load curtails when prices are high. However, such programs would require significant efforts by the ISO to monitor and measure performance of the demand resources.

### **3. Aggregating Retail Load**

The Midwest ISO will also be facilitating the participation of economic DR in its wholesale market through Aggregators of Retail Customers ("ARCs"), that serve as an intermediary between the Midwest ISO and retail customers that can reduce their consumption. While the Midwest ISO currently does not have any participating ARCs, there is significant potential for DR participation to be developed and enhanced through ARCs as it has in other RTOs.

The Midwest ISO has proposed Tariff revisions that will facilitate the participation of ARCs in the Midwest ISO Markets. However, the Midwest ISO has indicated that implementing this proposal will require significant modifications to its operating systems. The need for these modifications to its operating systems will delay the Midwest ISO's ability to accommodate CSP participation in its markets prior to either the fourth quarter of 2009 at the earliest, or the first quarter of 2010. Nonetheless, the Midwest ISO has confirmed that it is committed to working with the stakeholders on finalizing the rules necessary for accommodating ARCs under this timeline.

### **4. Bidding Parameters for both Type I and Type II Resources**

The Midwest ISO's market design should satisfy the Commission's requirements for Type II DR resources as set forth in Order No. 719. However, two of the specific bidding parameters identified (a maximum number of calls per day and a maximum demand reduction that a resource may be required to provide either daily or weekly) were not available for Type I DR resources in the Midwest ISO's current Tariff. The Midwest ISO is submitting Tariff language

to address this issue. However, changes to the Midwest ISO's systems to implement these parameters cannot be completed until the fourth quarter of this year.

## **D. Conclusions**

With more than 8,600 MW of existing DR capability, the Midwest ISO has significant potential for more fully integrated DR. The Midwest ISO's existing programs and proposed initiatives address most of the barriers to DR. One particularly important change that the Midwest ISO is pursuing is a modification to the price-setting methodologies to allow emergency actions and all forms of DR to contribute to setting efficient shortage prices in the energy and ASM. Failure to set efficient shortage prices when DR resources or other emergency actions clear the market under shortage or near shortage conditions can serve as a material economic barrier to the development of new DR resources.

One additional area of improvement that the Midwest ISO could evaluate relates to providing real-time economic DR resources the same incentives that they would have under a dynamic retail pricing regime. This report raises the potential that the EDR initiative could be expanded to include economic DR resources, which would address the regulatory/economic barrier posed by fixed retail rate regimes at the state level. However, substantial work would need to be done to determine whether this kind of initiative would be feasible and beneficial.

Finally, we believe the stakeholder process that the Midwest ISO has established to identify and respond to more specific barriers related to market rules, settlement provisions, and operating requirements will be an effective means to address these barriers. In developing the new rules and requirements, however, it is important to adhere firmly to sound principles of economic efficiency. This will help ensure that the Midwest ISO will avoid adverse unintended consequences that would raise costs and harm reliability.

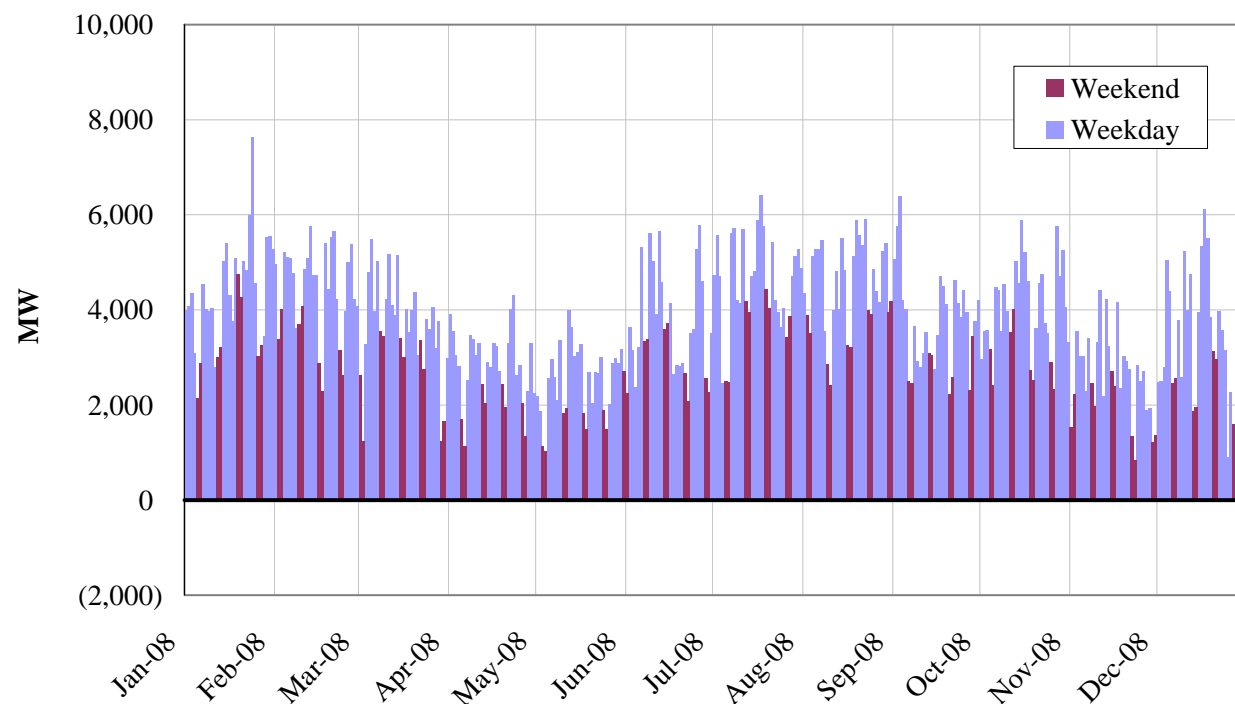
## VIII. External Transactions

As was the case in prior years, the Midwest ISO continued to rely heavily on imports to serve its load and meet its operating reserve requirements in 2008. In this section, we evaluate the interchange between the Midwest ISO and adjacent areas. In particular, we summarize the quantities of external transactions and the efficiency of the transaction scheduling processes.

### A. Import and Export Quantities

This section of the report evaluates the interchange between the Midwest ISO and adjacent areas. We summarize the magnitude of the external transactions and evaluate the efficiency with which imports and exports are scheduled. We begin this section with an overview of external transactions. Figure 82 shows the daily average of hourly net imports scheduled in the day-ahead market.

**Figure 82: Average Hourly Day-Ahead Imports**  
All Hours

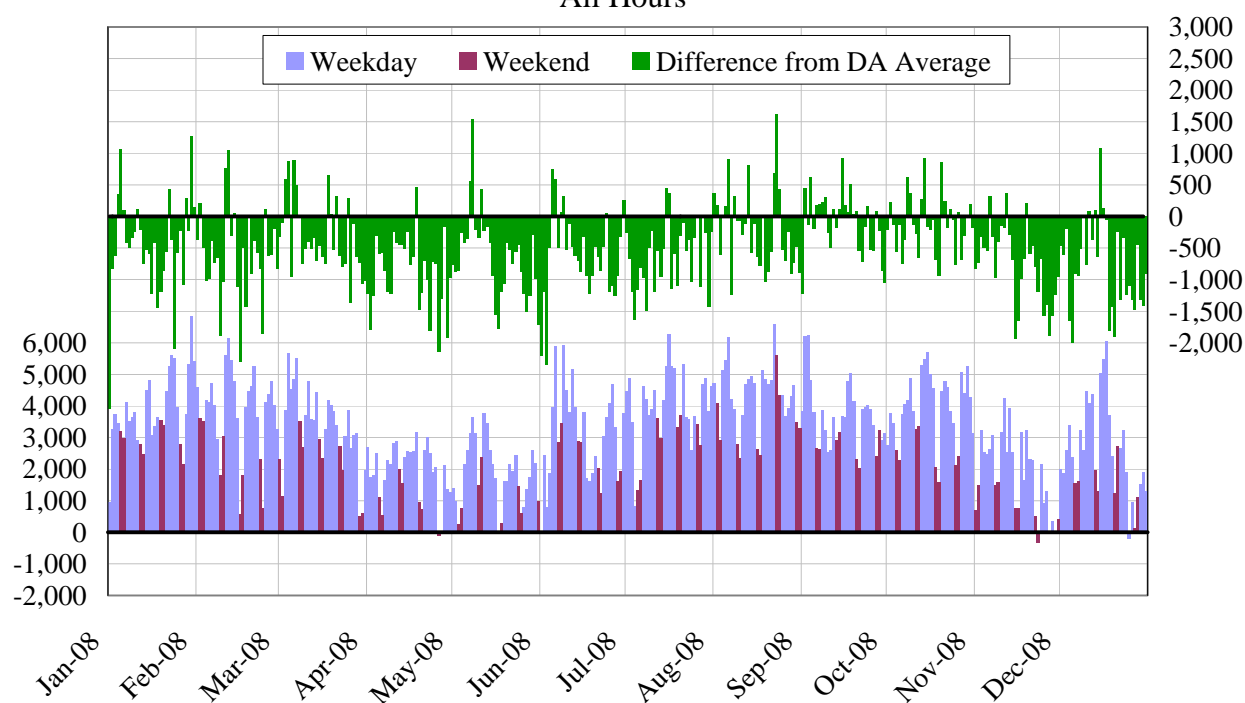


Although it is a net exporter of power to Ontario, the Midwest ISO is on the whole a net importer of power in both peak and off-peak periods due to its reliance on large imports from the West

and Manitoba. The pattern of net imports in 2008 was seasonal with the largest imports occurring during the winter and summer peak periods. Day-ahead imports averaged 3.6 GW over all hours and the daily average exceeded 5 GW during a period of 27 consecutive summer days. This indicates the degree to which the Midwest ISO relies on net imports to satisfy the demands of the market.

Net imports in the real-time market can vary substantially from the levels scheduled in the day-ahead market. Figure 83 shows the average hourly net imports scheduled in the real-time market each day over all interfaces, and the deviation of real-time imports from the day-ahead imports.

**Figure 83: Average Hourly Real-Time Imports**  
All Hours



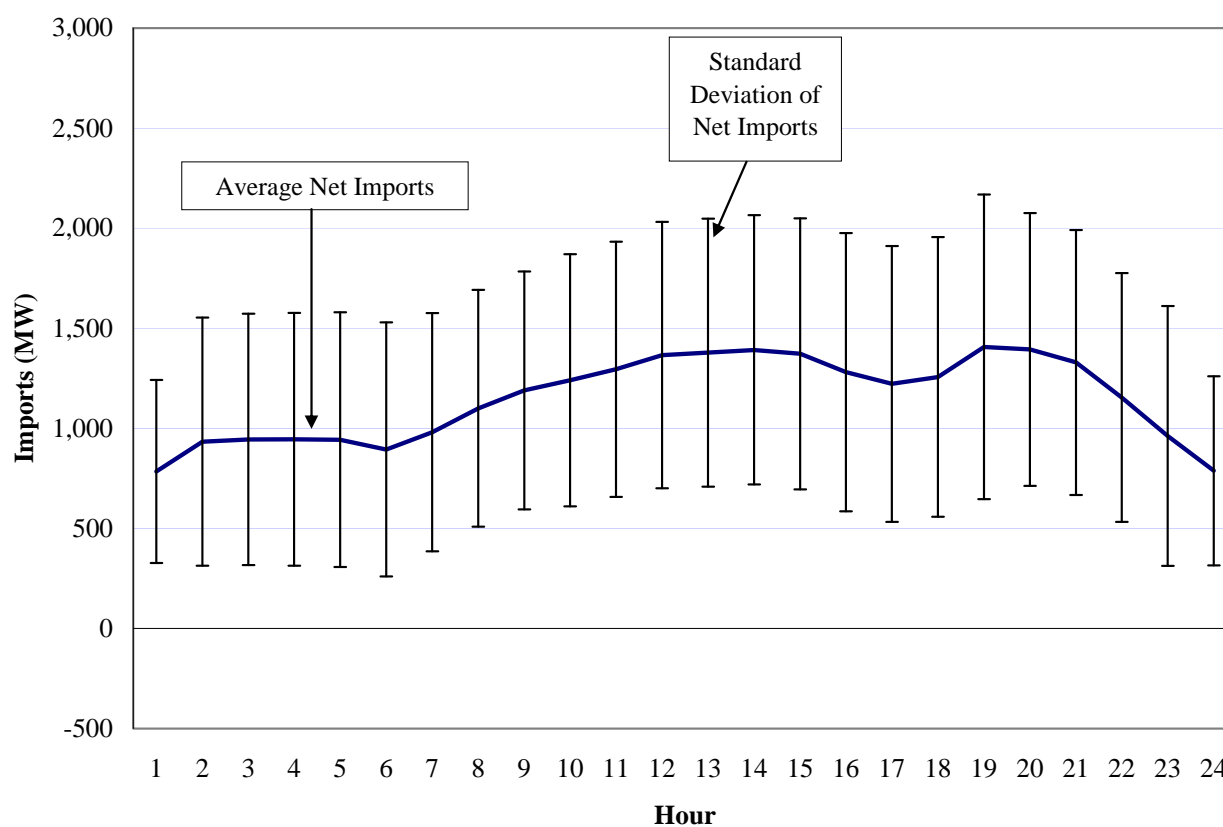
In the real-time markets in 2008, the Midwest ISO imported 4.4 GW per hour in on-peak hours and 2.1 GW in off-peak hours. The largest imports in the real-time market came from PJM (1.2 GW per hour) and Manitoba Hydro (1.1 GW per hour). The figure shows that real-time net imports generally decreased from those scheduled in the day-ahead market. On many days, average net imports decreased by more than 1,000 MW, which can create reliability issues for the Midwest ISO. Large changes in net imports can cause the Midwest ISO to commit additional

generation and rely more heavily on peaking resources. Intra-hour scheduling contributed to these changes.

The figure also shows that changes in net imports from day-ahead to real-time occurred with greater magnitude in the spring and in November and December. A large share of the reduced real-time net imports is due to scheduling at the IESO interface where net exports typically occur. Average net exports to IESO increased by 200 MW from day-ahead to real-time. IESO does not have a day-ahead market.

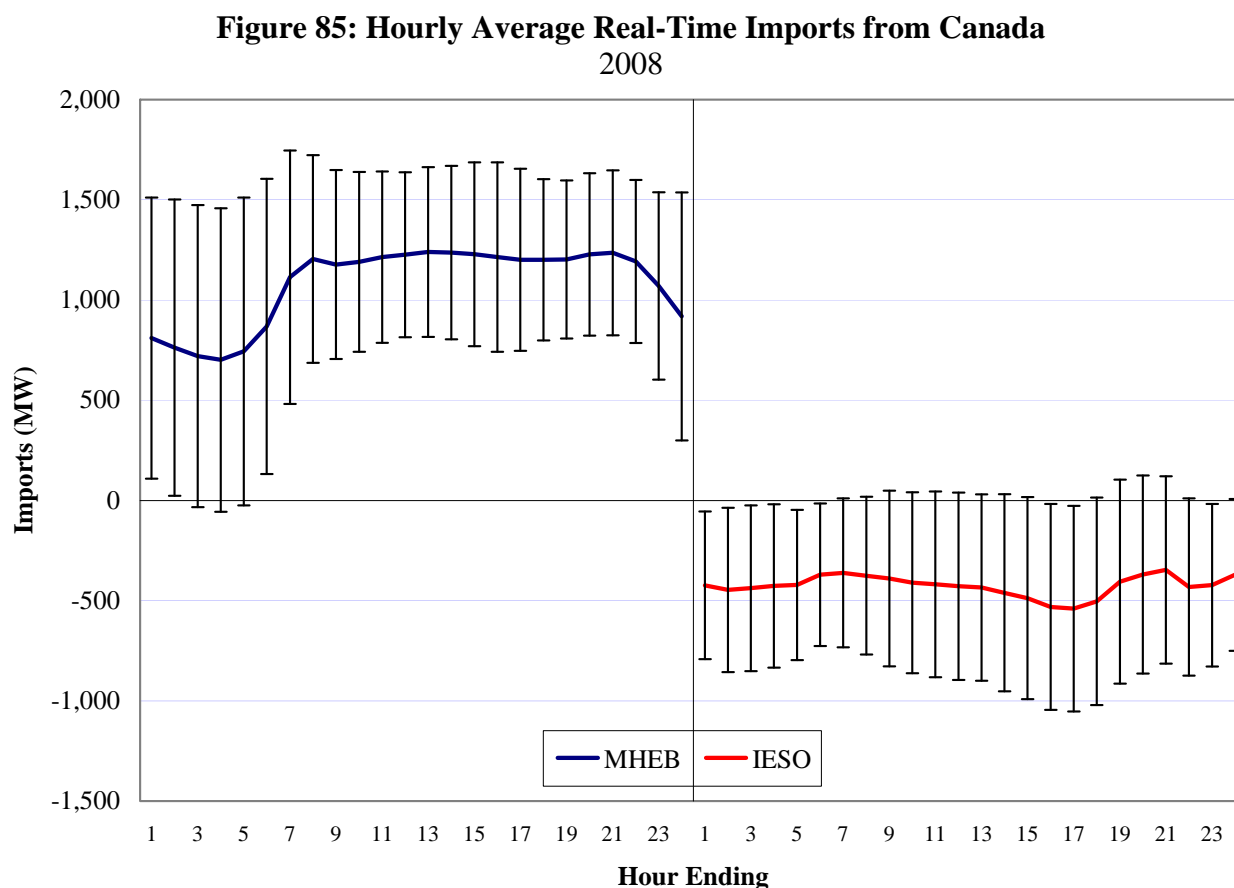
To better show where the Midwest imports and exports originate, our next analysis shows net imports by interface. The interface between the Midwest ISO and PJM, both of which operate LMP markets over wide geographic areas, is one of the most significant Midwest ISO interfaces. Accordingly, Figure 84 shows the average net imports scheduled for the Midwest ISO-PJM interface in each hour of the day.

**Figure 84: Hourly Average Real-Time Imports from PJM**  
2008



This figure shows overall that net imports of power are scheduled from PJM, with higher imports scheduled during the peak hours of the day and less power in the off-peak hours. However, the standard deviation of the net imports is substantial, indicating that the magnitude and direction of the flows between the two markets are highly variable. This characteristic of the PJM transactions is due to the similarity of the generating resources in the two areas. Hence, the prices in the two areas tend to move in a similar range. Because relative prices govern the net interchange between the two areas, movements in relative prices cause the import and export amounts to fluctuate.

Figure 85 shows the net imports across the Canadian interfaces.

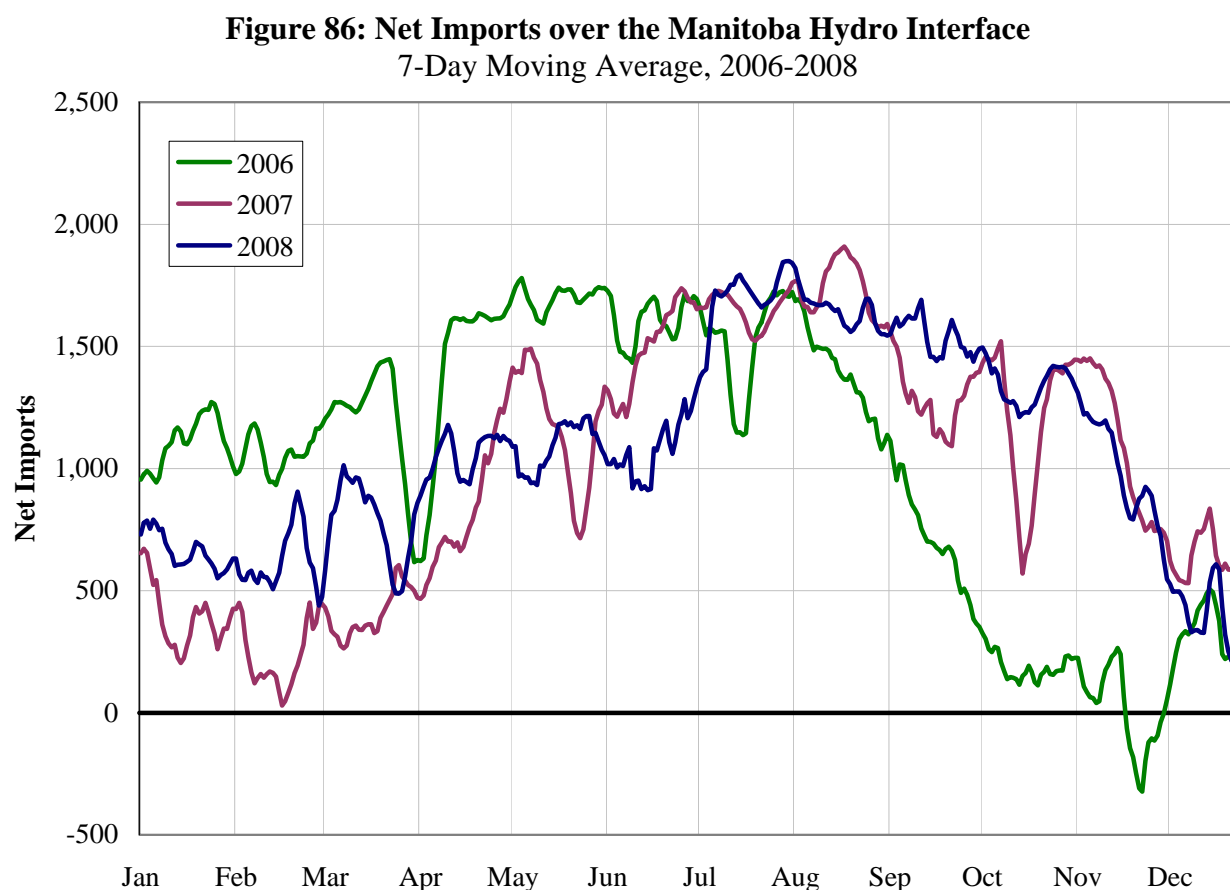


The Midwest ISO exchanges power with Canada through interfaces with the Manitoba Hydro Electricity Board (“MHEB”) and IESO. The Midwest ISO is a net importer from MHEB via a high-voltage DC connection, and a net exporter to IESO. Exports to IESO were generally



highest in off-peak hours and lowest during the evening ramp-down period (hours 19 to 21). Net imports from MHEB were typically higher in the peak hours and lower in the off-peak hours. While the shape of the hourly pattern remains similar to the pattern exhibited during prior years, the standard deviation confirms that imports from Manitoba Hydro have fluctuated moderately since 2005.

Figure 86 shows the hourly imports over the Manitoba interface between 2006 and 2008 on a seven-day moving average basis.



The figure shows that imports from Manitoba peak during the summer months, which is normally when water conditions are the best and the value of imports into the Midwest ISO is the highest. Imports were unusually low at the end of 2006 and beginning of 2007. This was due to poor water conditions that reduced the availability of hydroelectric resources. Imports returned to normal levels by the summer of 2007 and were sustained through 2008.

Imports over the Manitoba interface are important because they serve the load in the Minnesota area and are an economic source of power affecting imports into the WUMS area from the West region.<sup>32</sup> Hence, when imports over the Manitoba interface are reduced, it can contribute to congestion into Minnesota, generally from the south. These reduced imports tend to reduce the West-to-East congestion into WUMS because imports from Manitoba increase flow over this interface. Likewise, increases in imports over the Manitoba interface tend to increase congestion into WUMS. However, the addition of new Arrowhead-Weston 345 kV transmission facilities has reduced the congestion into WUMS from the West region.

## **B. Lake Erie Loop Flow**

In 2008, a number of issues related to “contract path” transaction scheduling around Lake Erie arose (schedules involving the Midwest ISO, IESO, and PJM). The adverse affects of this scheduling was primarily related to the congestion it caused in the New York ISO markets. The underlying problem in each of the cases observed in 2008 was that settlements occur based upon the scheduled path (i.e., the “contract path”), but the actual power flows also occur on other paths (the flows that result from the schedule that are not part of the contract path are generally referred to as “loop flows”).

Loop flows can cause a number of problems. Inconsistency between the physical flows that result from a transaction and the scheduled path of the transaction often distorts participants’ incentives and can lead to inefficient scheduling. The scheduling path does not alter the physical flow of the power between generation and load.. The extents to which the physical flows differ from scheduled flows are loop flows that must be accounted for by the RTO operators.

The report evaluates the two scheduling patterns that were prevalent in 2008. The first pattern involved transactions scheduled around Lake Erie in a “circuitous” manner. In general, circuitous transactions are transactions that are scheduled on indirect paths involving more wheels than the more direct path. One set of circuitous transactions were those that sourced in

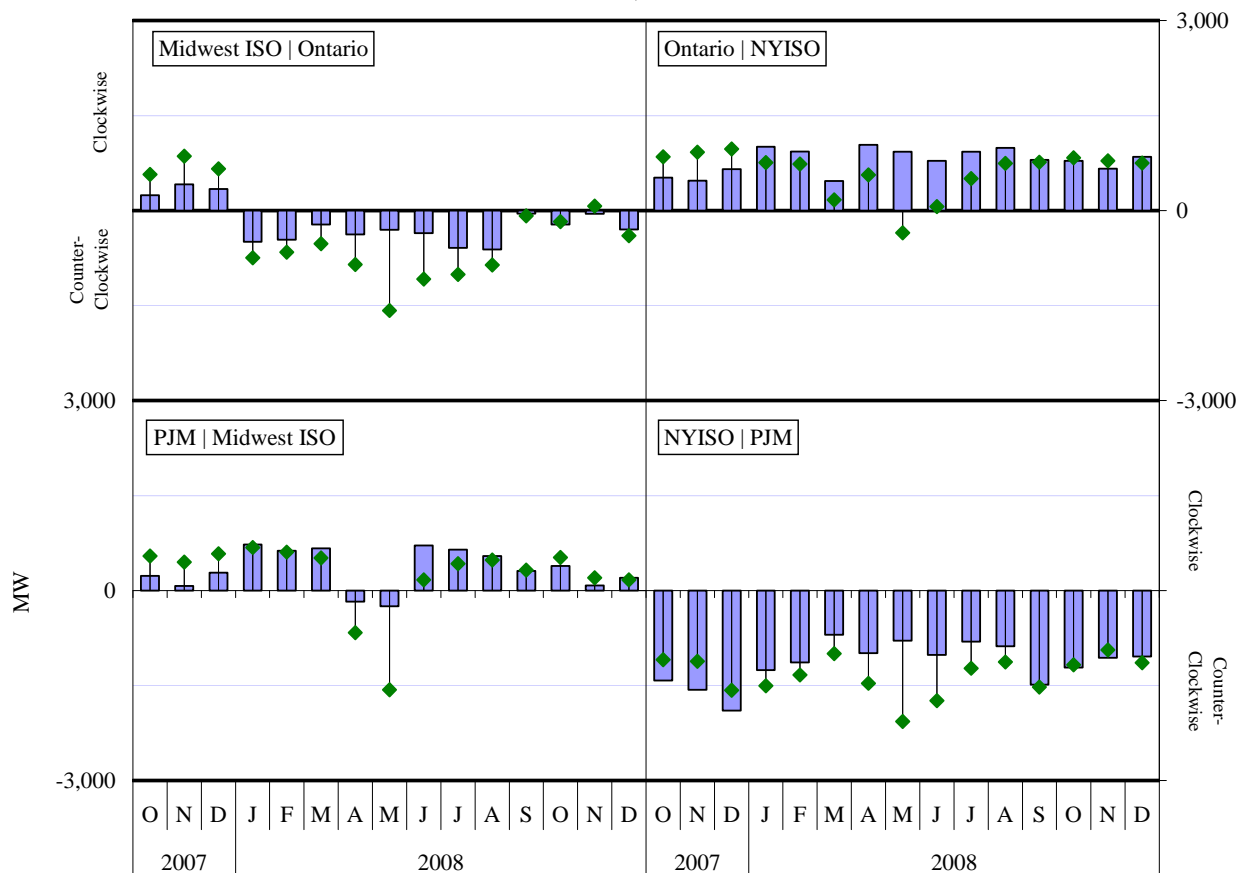
---

32 The Forbes-Dorsey 500 kV line is the largest single contingency in the Midwest ISO.

NYISO, wheeled through the IESO and the Midwest ISO, and sunk in PJM. A second set of circuitous transactions were those that sourced in the PJM, wheeled through NYISO and the IESO, and sunk in the Midwest ISO.

Figure 87 summarizes transaction scheduling involving the four control areas around Lake Erie. The circuitous schedules are shown in the cross-hatched portion of the bars in this figure. The circuitous transactions increased gradually in early 2008 before spiking in May. The vast majority of these involved the path from NYISO, through the IESO and the Midwest ISO, and into PJM. On July 21, 2008, NYISO filed under exigent circumstances to preclude scheduling of the circuitous transactions.

**Figure 87: Actual Flows Around Lake Erie**  
All Interfaces, 2007-2008

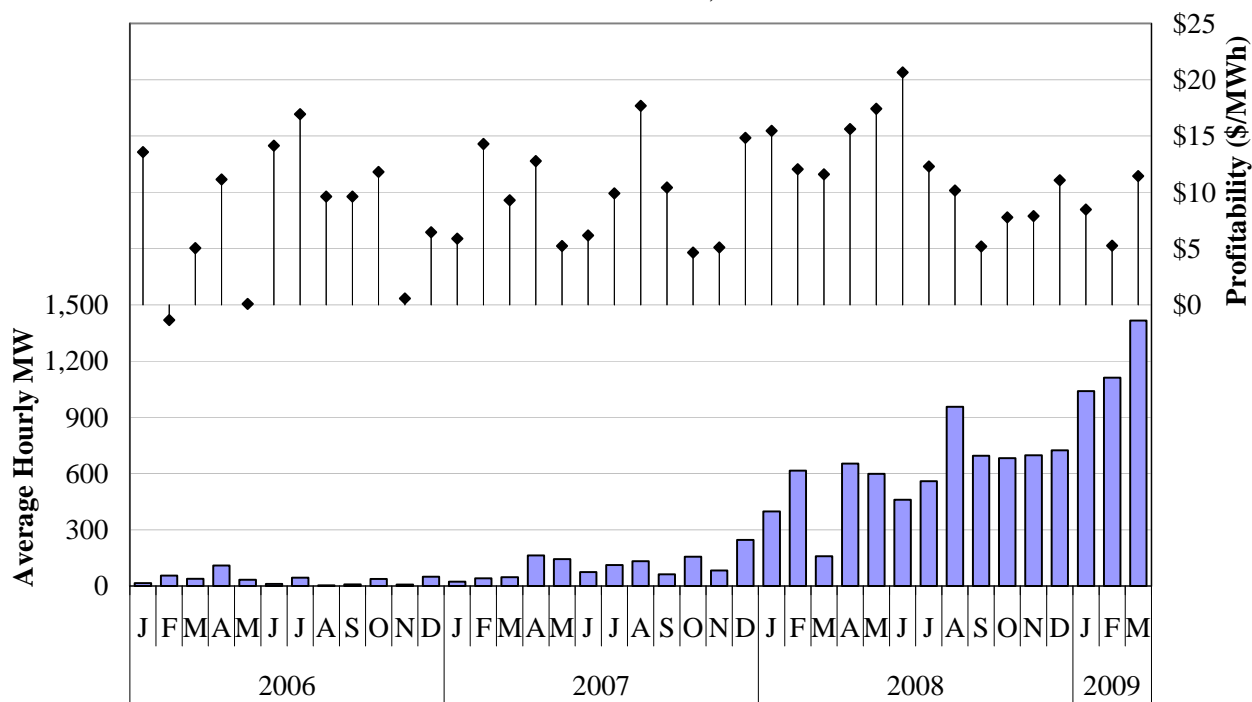


These circuitous transactions do not create flows that correspond to the reserved components of the transactions. Instead, while the reservation and schedules are around Lake Erie in the

counter-clockwise direction, the flows are predominantly in the clockwise direction. As shown in Figure 87, circuitous transactions contributed to large amounts of clockwise loop flows around Lake Erie. Clockwise loop flows can create substantial congestion, particularly in NYISO, without bearing the cost of that congestion. The figure compares the net schedules (shown in the diamonds) to the actual flows caused by the schedules (shown in the bars). As the circuitously scheduled transactions increased, the inconsistencies (i.e., loop flows) increased. These inconsistencies were largest in May when circuitous transactions were highest—loop flows were almost 1500 MW on average in May of 2008.

The underlying problem in this case and along similar circuitous paths around Lake Erie (e.g., the IESO-to-PJM transactions, discussed below) is that settlements occur based upon the scheduled path, but the actual power flows occur on other paths. This distorts participants' incentives and can lead to inefficient scheduling. When the circuitous schedules were banned by NYISO in July 2008, schedules from the IESO to PJM (across the Midwest ISO) increased. Figure 88 shows the quantity and profitability of these transactions from 2006 to early 2009.

**Figure 88: Actual Flows Around Lake Erie**  
IESO to PJM Schedules, 2007-2008



There was a significant upward trend in the volume of these transactions starting late in 2007 and continuing into 2009. The transactions are explained by their consistent profitability. Since the beginning of 2007, these transactions have netted profits between \$5 and \$15 per MWh nearly every month, averaging almost \$11 per MWh. Profitability is calculated based upon the prices in PJM and the IESO minus the Midwest ISO's wheeling charge. It does not include any charges applied by IESO.

If PJM priced the transactions at its Midwest ISO interface (instead of its current pricing method for the IESO) the average profitability would drop to -0.52 per MWh. Likewise, if these transactions had to pay for the congestion they cause in NYISO, many of them may not be profitable, which raises efficiency concerns. The large difference between the PJM, IESO, and Midwest ISO prices creates incentives to combine other transactions with these wheels to acquire the difference.

Both the circuitous scheduling issues and these issues are attributable to the inconsistency between the contract path schedules and actual power flows associated with the schedules. These inconsistencies produce loop flows that have costs that are not borne by the participants scheduling the transactions. The loop flows also create uncertainties regarding available transmission capability that must be accounted for in the real-time market, day-ahead market, and FTR markets. Phase angle regulators are in the process of being placed in operation (one of four is in service) that could help improve the consistency between the schedules and flows. However, this has been significantly delayed by the lack of necessary agreements between the relevant transmission owners/operators. The Midwest ISO is limited in its ability to facilitate these agreements.

To address the scheduling and power flow issues around Lake Erie, we recommend the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements. Unless all the RTOs around Lake Erie have compatible scheduling and settlement rules potential incentives for inefficient scheduling will persist. Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.

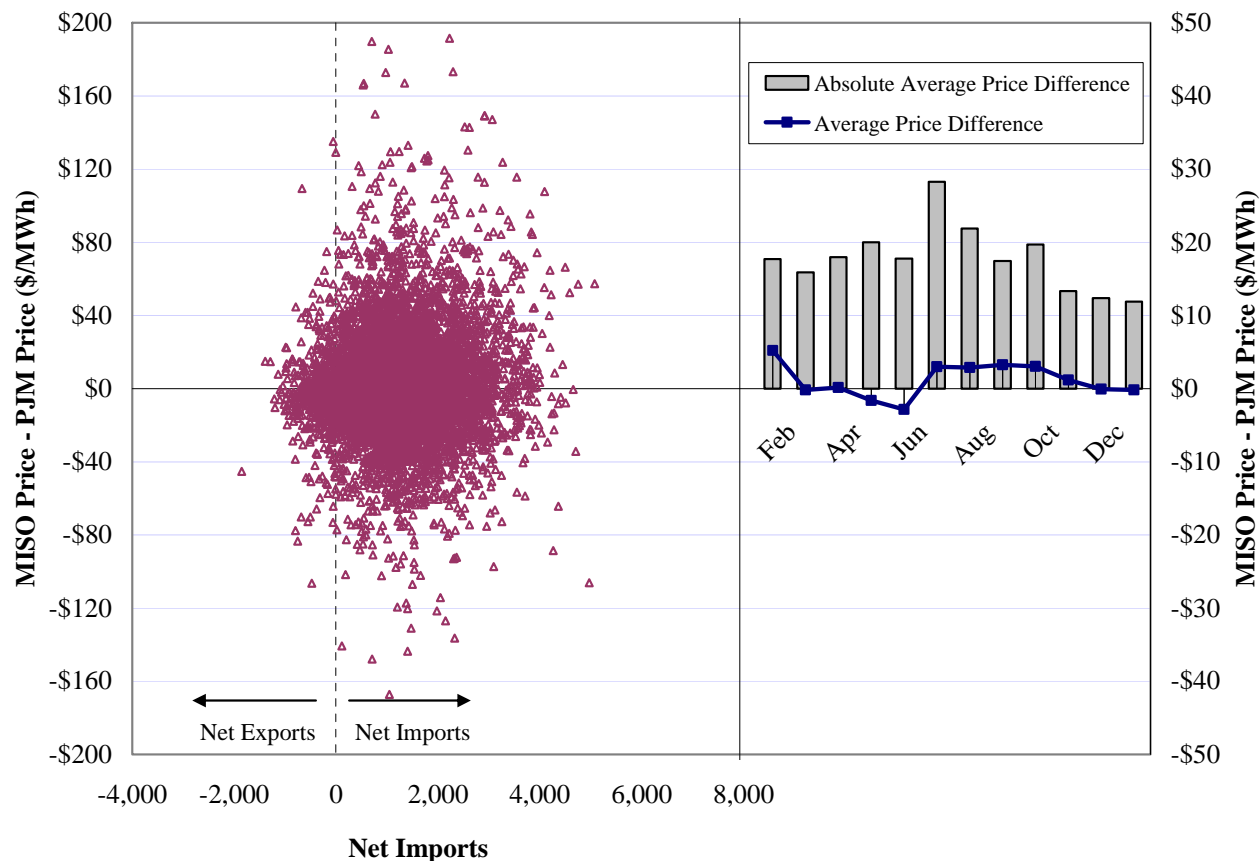
### **C. Convergence of Prices Between the Midwest ISO and Adjacent Markets**

Our next analysis evaluates the price convergence and net imports between the Midwest ISO and adjacent markets. Like other markets, the Midwest ISO relies on participants to increase or decrease their net imports to cause prices to converge between markets. Given the uncertainty regarding the difference in prices (because the transactions are scheduled in advance), one should not expect perfect convergence.

Our analysis is presented in a series of figures, each with two panels. The left panel in each is a scatter plot of the real-time price differences and the net imports in unconstrained hours. We expect to find imports into the Midwest ISO when the Midwest ISO prices are higher than prices in neighboring markets. The right panel shows the average hourly price differences and the average absolute value of the hourly price differences on a monthly basis. This provides an indication of the degree to which arbitrage has been successful, i.e., prices have converged between the two markets.

The results for the PJM interface are shown in Figure 89. The right-hand panel in the figure shows that the Midwest ISO interface prices tended to be slightly higher than PJM's, except in late spring. The left-hand-side panel in the figure shows that participants have not been fully effective at arbitraging the prices between the two areas (one would expect scatter points to be much more clustered around a zero price difference). Power is often scheduled from the higher-priced market to the lower-priced market (i.e., the lower right quadrant indicates PJM prices are higher, yet imports are positive). As discussed above, there are a number of factors inherent to the process that prevent participants from fully arbitraging the difference in prices between the two markets. Perfect convergence can therefore not be expected.

**Figure 89: Real-Time Prices and Interface Schedules**  
PJM and the Midwest ISO



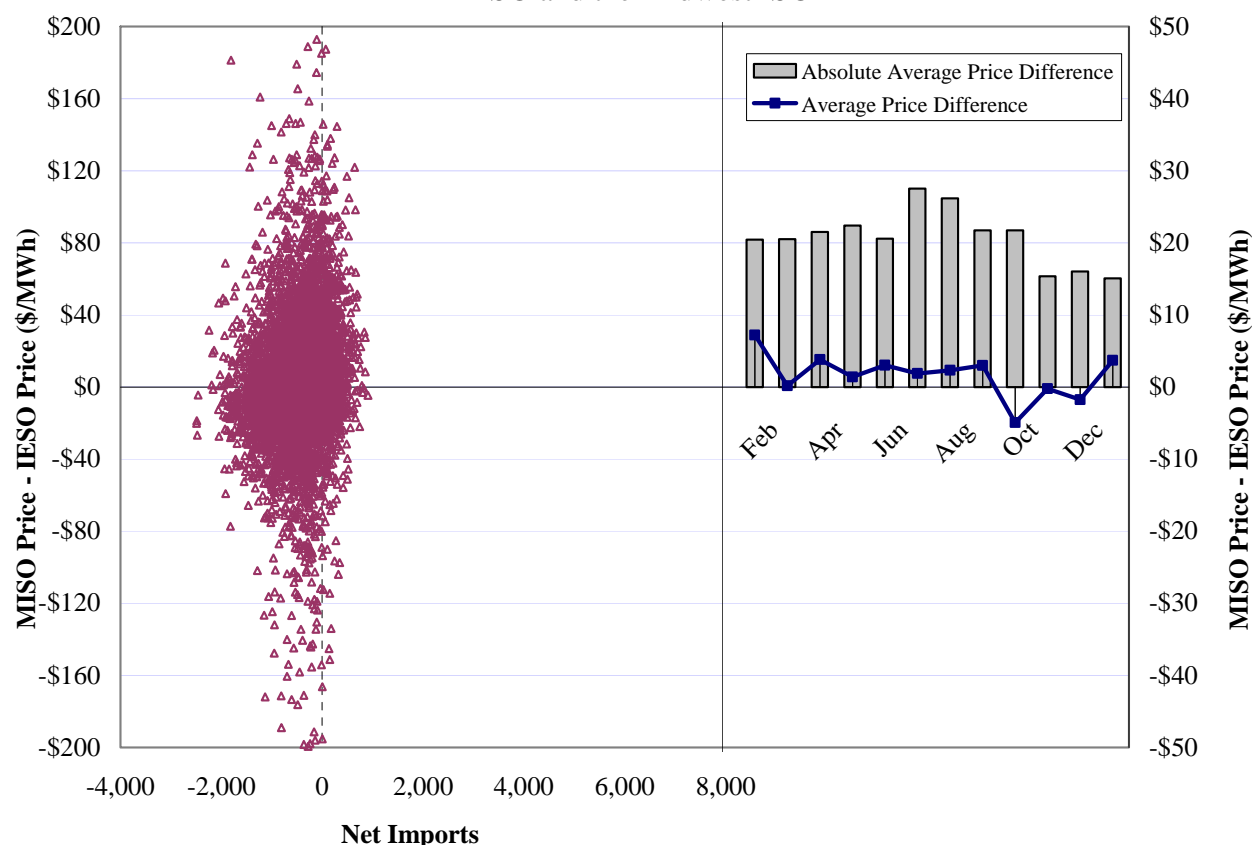
Although some improvements may be possible, we believe that substantial improvement is not possible absent more explicit coordination of the NSI between the two markets. In particular, to achieve better price convergence, we continue to recommend that the RTOs consider expanding the JOA to optimize the net interchange between the two areas. Under this approach, participants' transactions would be financial. The RTOs would determine the optimal physical interchange based upon the relative prices in the two areas. For example, the RTOs would transmit their prices at the border at each five-minute interval and the physical interchanges would be adjusted by an increment determined by the difference in prices and available ramp capability in the two markets. Settlements for the incremental transfers would be part of the market-to-market settlements between the RTOs.

This is not a proposal for the RTOs to engage in market transactions, but simply a proposal to dispatch the seam between the markets in the same way that the Midwest ISO manages flows

over internal constraints—by accepting economic load bids and generator offers. In this case, generator offers in one RTO may be accepted to serve load in the other RTO. This change would likely achieve the vast majority of any potential savings associated with jointly dispatching the generation in the two regions. The Midwest ISO has begun investigating the means to implement this recommendation.

We next analyze the external transactions with the IESO. Figure 90 shows the analysis of real-time prices and schedules between the Midwest ISO and IESO.

**Figure 90: Real-Time Prices and Interface Schedules**  
IESO and the Midwest ISO



Net exports are typically scheduled from the Midwest ISO to IESO, averaging 400 MW. On average, the Midwest ISO prices exceeded the IESO prices. However, the difference was close to zero. In October and November, IESO prices were higher on average. The dispersion of prices shows that the schedules over this interface are slow to respond to price differences.



Interpreting these results is complicated by the fact that the IESO does not have a nodal market so the IESO price may not fully reflect the true value of power imported from the Midwest ISO. Internal constraints in the IESO can cause such imports to be more or less desirable than the price would indicate. Given the current market design in the IESO, there are limited options for improving the external transactions over this interface other than the JOA option discussed above.

#### **D. Intra-Hour Scheduling at PJM Interface**

The last topic we address in this section of the report is intra-hour physical scheduling. The Midwest ISO market rules permit physical scheduling on a time increment of as short as 15 minutes. It should contribute to price convergence and efficient dispatch as market participants arbitrage the prices in adjacent areas. However, large changes in NSI caused by intra-hour schedules can lead to price volatility and operational challenges.

Intra-hour schedules affect prices because Midwest ISO may have to ramp generation up or down substantially to accommodate the schedules. Intra-hour schedules settle at the average price in the hour in which they occur. This affects participants' incentives in at least two ways:

- In the event that a schedule causes RSG, it may not bear the full costs because it is evaluated on an hourly average basis. For example, a 400-MW export for 15 minutes is treated as a 100-MW hourly export. This spreads the allocation of RSG costs across the hour, rather than being assessed solely when they are incurred (in the quarter-hour, when incremental RSG costs are probably higher).
- A 15-minute schedule may be profitable on an hourly basis, even if it is inefficient and unprofitable during the 15-minute schedule period in which it occurs.

The majority of the intra-hour schedules were occurring at the PJM interface. PJM, in coordination with the Midwest ISO implemented a prohibition against intra-hour scheduling in May 2008 by requiring that transactions be scheduled for at least one hour. This eliminated most of the 15-minute schedules.

Despite the decline in 15-minute schedules, the process by which transactions are scheduled to begin on the quarter hour still raises concerns. In particular, the scheduling deadline for transactions that begin in the 4<sup>th</sup> quarter is at a quarter past the hour. Hence, the participant

scheduling the transaction will have seen prices to be included in its hourly settlements prior to scheduling the transaction. Hence, we continue to recommend that the Midwest ISO modify its scheduling deadline to for transactions beginning in the fourth quarter of the hour to the beginning of the hour.

#### **E. Resource Adequacy and External Transactions**

This section shows that the Midwest ISO relies on a high level of net imports in operation to meet its energy needs. Therefore, it is reasonable to expect that it will rely on comparable levels of external capacity to meet its resource adequacy needs under Module E. However, our review of the Module E requirements indicates a potential problem with the requirements applied to external resources.

It is important that external resources be permitted to participate in the Midwest ISO's capacity market. The current requirement that a deliverability study be performed in advance of participation by an external entity in the capacity market is an onerous, time-intensive requirement that creates an effective barrier to entry. Hence, we recommend the Midwest ISO modify its deliverability requirement for external resources to establish a maximum amount by which an external resource can be utilized to satisfy LSEs' capacity requirements under Module E.