2007 STATE OF THE MARKET REPORT FOR THE MIDWEST ISO

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Guide to Acronyms

AFC	Available Flowgate Capacity
ARC	Adequate Ramp Capability
ASM	Ancillary Services Market
FTR	Financial Transmission Rights
GSF	Generation Shift Factors
GW	Gigawatt (1 GW = 1,000 MW)
HHI	Herfindahl-Hirschman Index
IDC	NERC Interchange Distribution Calculator
IMM	Independent Market Monitor
ISO	Independent System Operator
JOA	Joint Operating Agreement
LMP	Locational Marginal Price
MMbtu	Million British Thermal Units, a measure of energy content
MW	Megawatt
MWh	Amount of energy equal to producing 1 Megawatt for one hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NSI	Net Scheduled Interchange
NSI	Net System Interchange
OOM	Out-of-Merit
PVMWP	Price Volatility Make Whole Payment
RAC	Reliability Assessment Commitment
RDI	Residual Demand Index
RMR	Reliability Must-Run
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
TLR	Transmission Loading Relief
WUMS	Wisconsin-Upper Michigan System

I. Executive Summary

As the Independent Market Monitor ("IMM") for the Midwest ISO, we are 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 and a market for Financial Transmission Rights ("FTRs"). The energy markets produce day-ahead and real-time locational marginal prices ("LMPs") that can vary across the region to reflect local production costs, transmission congestion, and transmission losses. 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.

These markets will soon be augmented by operating reserves and regulation markets (known as Ancillary Services Markets or "ASM") scheduled to be implemented in autumn 2008. These markets will optimize the allocation of the Midwest ISO's resources between the energy and ancillary services markets. The Midwest ISO will also clarify and enforce capacity requirements under Module E of its Tariff that will help ensure economic signals that support adequate supply and demand resources over the long-term.

A. Introduction and Summary of Findings

The Midwest ISO energy markets provide substantial benefits for the region. Although the benefits are sometimes difficult to quantify, the energy markets produce substantial savings in the following areas:

- The day-ahead market provides an efficient daily commitment of generating resources in the region. Efficiency is achieved by reducing the quantity of generation that is committed and by ensuring that the most economic generation is committed.
- The energy markets cause energy to be produced from the most economic resources given the limits of the transmission system. This includes employing the lowest-cost redispatch options to manage congestion and allowing the transmission system to be fully utilized.
- The Midwest ISO energy markets improve reliability through the five-minute dispatch. This allows far more responsive and accurate control of power flows on the transmission system than the Transmission Loading Relief ("TLR") procedures used in other regions.

- Finally, the LMP markets provide transparent economic signals to guide short and long-run decisions by participants and regulators. Although these benefits are the most difficult to quantify, they may be the largest because they accumulate over time as better investment and retirement decisions are made by participants.

To achieve these benefits, the market must be competitive and efficient, which is the subject of many of the analyses in this report. These analyses lead us to the following conclusions.

Overall, we find that the market performed competitively in 2007. Although a number of suppliers throughout the Midwest ISO region have substantial local market power associated with specific transmission constraints, there was little evidence of attempts to withhold supply and exercise market power. The mitigation measures, which were designed to prevent abuses of market power, were employed relatively infrequently in 2007. The most frequent mitigation occurred in Minnesota in a new Narrow Constrained Area ("NCA") defined in January 2007.

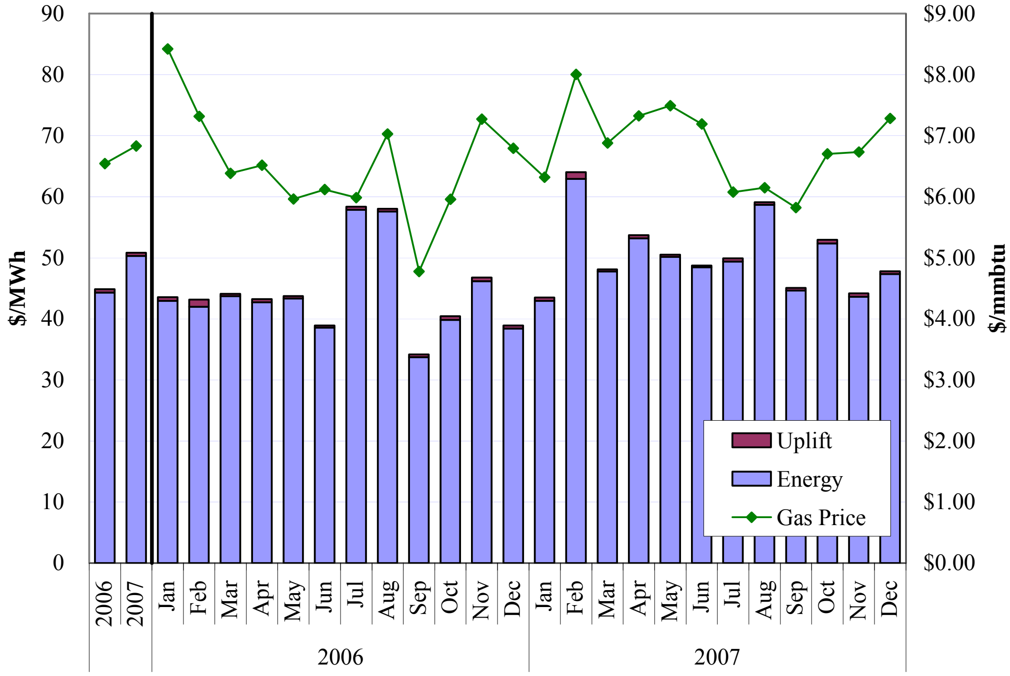
Although the market performed competitively, average energy prices increased by 13 percent. This increase was largely caused by higher fuel prices, particularly oil and natural gas prices. In well-functioning markets, electricity prices will be highly correlated with fuel prices because fuel costs constitute almost all of the marginal costs for most generating units. Since suppliers have the incentive to submit offers close to marginal costs in a competitive market, offer prices generally rise as fuel prices rise, leading to a concomitant increase in electricity prices. Higher fuel prices, together with lower available imports from Manitoba early in the year due to poor water conditions, led to significant increases in congestion costs and revenue sufficiency guarantee ("RSG") payments.

B. Market Outcomes and Long-Term Economic Signals

We summarize changes in prices and costs in Figure E-1, which shows an "all-in" price of electricity.[1] This represents the total costs of serving load. The all-in price of electricity is equal to the load-weighted average real-time price plus average real-time RSG per MW of real-time load. The figure also shows the monthly average natural gas prices.

[1] The analyses of prices in 2007 are reported in Section II.A.

Figure E-1: All-In Price of Electricity



The average all-in price was $51 per MWh in 2007, an increase from $45 per MWh in 2006. Uplift costs (i.e., real-time RSG payments) were 1 percent of the all-in price, which is comparable to the share in 2006 and substantially lower than uplift cost in 2005 when peaking resources were more heavily utilized.

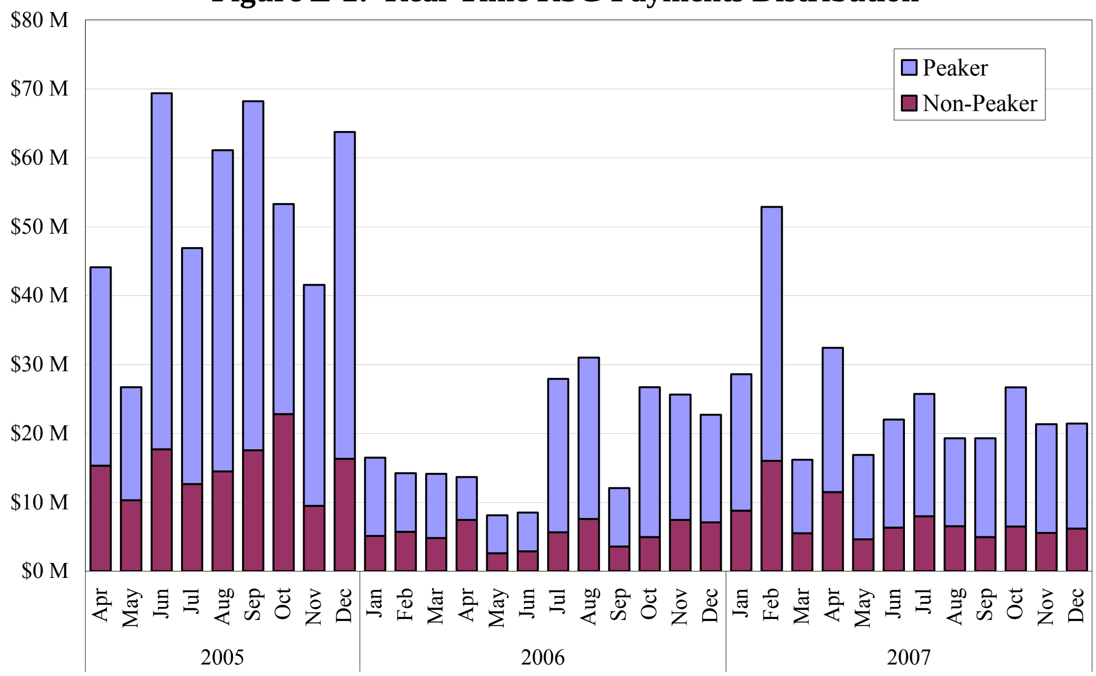
The correlation between prices and natural gas costs was weaker during the summer months when prices did not fall with the decreasing natural gas prices. Higher loads that prevail during the summer offset the effects of the lower fuel prices. In 2007, milder weather led to lower peak load levels than in 2006. In fact, February was the highest-priced month in 2007 due to extreme loads that resulted in energy emergencies on three days.

Figure E-2 shows RSG payments generated in the real-time market that were made to peaking units and non-peaking units.[2] RSG payments are made to ensure that the total market revenue a generator receives when its offer is accepted exceeds its as-offered costs. Resources started after the day-ahead market for reliability receive "real-time" RSG when their costs are not covered by the real-time market. Because the day-ahead market is a financial market, it generates very little RSG. The figure shows that most of the RSG payments are made to owners of peaking resources, even though they produced less than 1 percent of the energy generated in 2007.

2 Analyses of RSG are detailed in Section IV.C.

Peaking resources are generally on the margin (i.e., the highest-cost resources) when they are dispatched, but often do not set the energy price due to their inflexibility. Therefore, lower-cost units frequently set prices and this increases the need for RSG payments to peaking resources.

Figure E-2: Real-Time RSG Payments Distribution



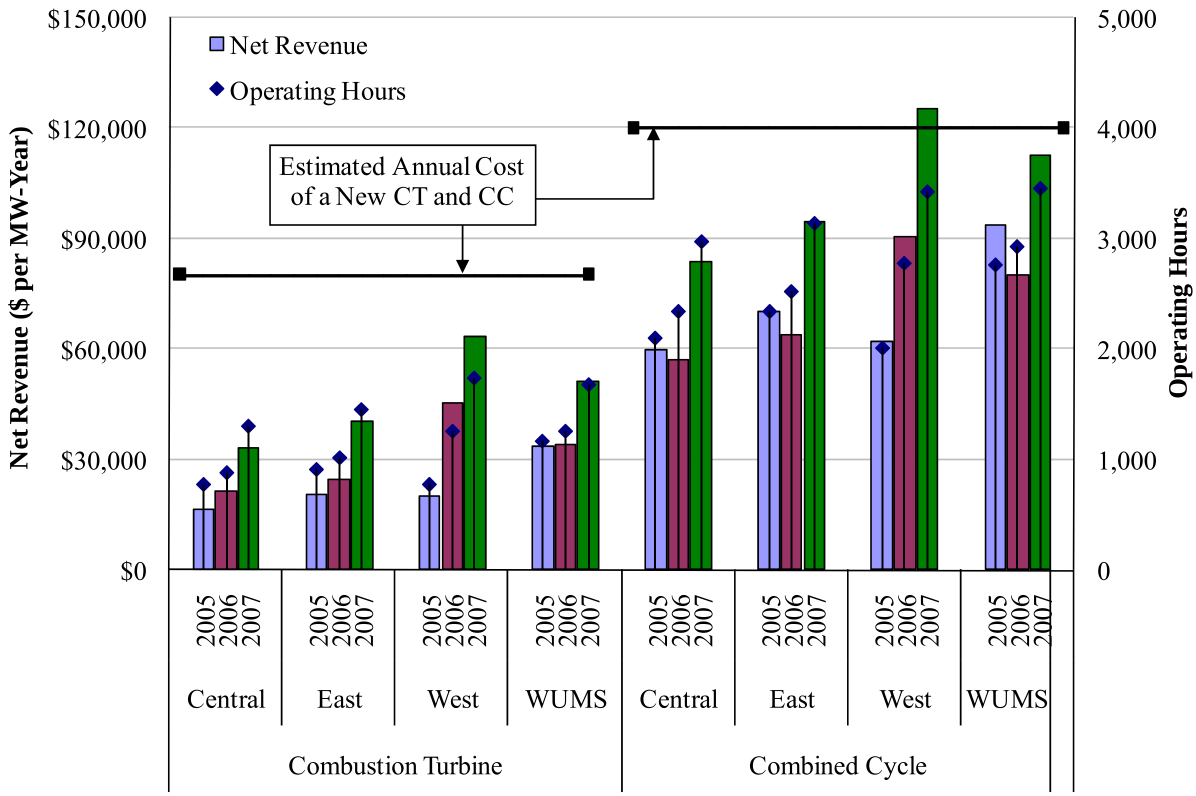
Real-Time RSG costs rose from an average of $18.4 million to $25.2 million per month from 2006 to 2007. This increase was due to higher fuel prices and increased commitment of peaking resources to manage congestion in the West. RSG costs peaked in February 2007 due to the energy emergencies, under-scheduling by loads, and congestion into the West. Together this resulted in a heavy reliance on peaking resources in that month. Day-ahead RSG costs declined from more than $40 million in 2006 to $26.4 million in 2007 and continue to reflect a small share (8 percent) of total RSG costs.

One of the most important assessments of the Midwest ISO markets is our evaluation of the economic signals they produce to maintain adequate 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.[3] 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

3 Net revenue results are discussed in Section II.B.

investment when the available resources are not sufficient to meet the needs of the system. Even when the system is in a long-run equilibrium, random factors each year will cause the net revenue to fluctuate. Figure E-3 shows estimated net revenues for a hypothetical new combustion turbine and combined cycle generator from 2005 through 2007. The figure also shows the estimated net revenue that would be needed to make these investments profitable.

Figure E-3: Net Revenue Analysis



This analysis shows that the Midwest ISO markets would not likely support investment in either combustion turbines or combined-cycle resources. Net revenues only exceeded the estimated entry costs for combined cycle resources in the West in 2007 due to the sharp increase in congestion in that region. However, the prices in the West have moderated as imports have returned to relatively normal levels over the Manitoba interface. The results are explained by the fact that a modest capacity surplus exists currently in the Midwest ISO region and the fact that the current markets do not fully reflect shortage conditions. However, two key changes are underway that should improve these price signals:

- The ASM markets will improve shortage pricing by allowing the value of foregone operating reserves to be included in energy and reserve prices when resources are insufficient to satisfy both demands; and

- Changes to Module E of the Tariff intended to clarify the capacity requirements in the region and to enforce these requirements will allow a bilateral capacity market to develop that will help ensure adequate supply and demand resources in the region.

In addition, we make other recommendations in the report below that will improve the market's price signals. The changes are important given the region's need for new supply or demand resources in the next few years.

C. Day-Ahead and Real-Time Market Performance

The day-ahead market is a critical aspect of the overall market structure because it:

- Governs most generator commitments in the Midwest ISO;
- Facilitates most of the energy bought or sold through the Midwest ISO markets; and
- Determines the entitlements of the FTR holders.

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. Ninety-seven percent of the generation dispatched in 2007 was scheduled through the day-ahead market.

Good convergence between day-ahead and real-time prices indicates efficient commitment decisions. We find price convergence in the Midwest ISO has been consistent with the other RTO markets, which have each been operating longer.[4] Active virtual supply and demand participation in the day-ahead market to arbitrage the price differences has contributed to the good price convergence in the Midwest ISO.

Prices in the real-time market are substantially more volatile than in the day-ahead market. Real-time price volatility in the Midwest ISO is nearly double that of other RTOs.[5] 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. However, because the real-time market software is limited in its ability to look ahead, the system is frequently "ramp limited" (generators are moving as quickly as they can up or down), which results in transitory sharp movements in prices up or down. A second cause of price volatility is the large changes in the Net Scheduled

4 See Section IV.A.
5 See Section IV.B.

Interchange ("NSI") or changes that occur when a large quantity of generators are either started or shutdown, which can cause ramp constraints to bind. The report includes recommendations to address both of these sources of price volatility.

D. 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.[6] The dispatch of peaking resources averaged 433 MW per hour in non-summer days and almost 1,000 MW per hour during the summer. On a number of peak-load days, however, the average dispatch was as high as 5,000 to 7,000 MW per hour. These dispatch levels are similar to those in 2006, but much lower than the levels in 2005. Higher net load scheduling in the day-ahead market and improved operating procedures are responsible for the decrease since 2005.

Our analysis also shows a large share of the peaking resources are dispatched out-of-merit. We consider a resource out-of-merit order if the offer price > LMP and we consider it in-merit order if the offer price ≤ LMP. A large share of peaking resources being out-of-merit indicates that they frequently do not set the energy price. Out-of-Merit dispatch 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. Load not scheduled in the day-ahead market must generally be satisfied by peaking resources in real time. If they do not set prices (i.e., lower prices are set by a non-peaking unit), the real-time prices will not provide the loads the incentive to purchase more in the day-ahead market. We have recommended that the Midwest ISO develop a pricing method that will allow inflexible units and demand to set prices. Over the past year, the Midwest ISO has developed promising research in this area and may be ready test the feasibility of a new approach by the end of 2008.

E. Generating Capacity and Reserve Margins

Total generating resources in the Midwest ISO market exceeded 126 GW in 2007.[7] However, this is the nameplate capacity and does include typical deratings (reductions in generators' capability). These deratings tend to be particularly large during periods of hot weather. Our

6 The dispatch of peaking resources is analyzed in Section IV.D.
7 Analysis and discussion of the Midwest ISO's generating capacity is contained in Section III.B.

report estimates the reserve margins in summer 2008 for each region, including projected additions and retirements.

When one removes the deratings and temperature sensitive capacity that may not be available at peak times, our analysis projects a reserve margin for Midwest ISO of 19 percent in 2008.[8] This assumes that all interruptible load will respond when called, which is not realistic. Without the interruptible load, the reserve margin falls to 10 percent. Because almost 10 percent of the system's capacity may be unavailable on peak days due to forced outages or because they are set aside for operating reserves, real-time conditions can be very tight. Hence, interruptible load may need to be called on under peak conditions if forced outages are higher than average.

In reality, more than half of the interruptible load has responded when called, so the real reserve margin is close to 16 percent. Reserve margins are much lower in the East and Central regions. Although the system's resources are adequate for this summer, new resources will likely be needed soon. Hence, it is important for the market's economic signals that govern new investment and retirement decisions to be efficient.

F. Transmission Congestion

One of the most significant benefits of the Midwest ISO energy markets is that they provide accurate and transparent price signals that reflect congestion on the network. Figure E-4 below shows the total congestion costs in the day-ahead and real-time markets.[9] Total congestion costs shown in this figure were $713 million in 2007, an increase of more than 25 percent from 2006. The increase was the primarily the result of: a) higher fuel prices in 2007 (which increases redispatch costs), and b) reduced of imports over the Manitoba interface that increased congestion into the West during the first half of the year.

However, the report shows that this is only roughly 70 percent of the total value of real-time congestion, indicating that loop flows caused by the dispatch of others around the Midwest ISO accounts for 30 percent of the flows over constrained interfaces.[10] Because these flows are not scheduled through the Midwest ISO markets, it collects no congestion costs for them.

8 See Section III.C.
9 Congestion costs are evaluated in Section V.A.
10 See Section V.B.

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

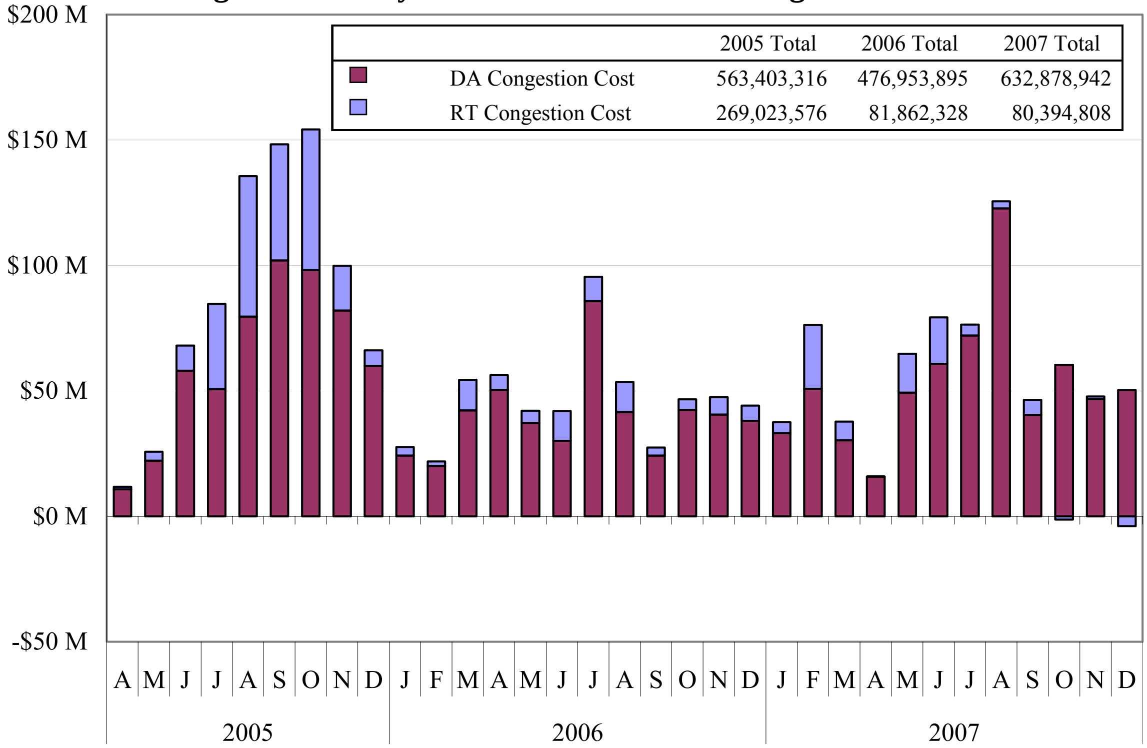


Figure E-4 also shows that nearly 90 percent of total congestion costs in 2007 was captured in the day-ahead market, a significant improvement from prior years. Residual real-time congestion costs generally arise when the day-ahead modeling of the network is not consistent with the real-time system. 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.[11] Indeed, more than 25 percent of the binding transmission constraints could not be managed on a 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 purposes 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.

11 These instances are evaluated in Section V.D.

The primary causes of these instances 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. Both of these factors are being addressed this year. First, implementation of the Price Volatility Make Whole Payments with ASM will ensure flexible suppliers are not harmed when prices and dispatch signals are changing rapidly. Second, the Midwest ISO plans to change the modeling parameter described above over the next few months.

G. Financial Transmission Rights

FTRs are very 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).[12] 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.

FTRs were under-funded in 2007 – day-ahead congestion was 19 percent less than the obligations due to FTR holders in 2007. There was a 10 percent shortfall in 2006. Two main factors contributed to the shortfall: (1) continued difficulties in accurately forecasting loop flow on the Midwest ISO network in the FTR modeling, and (2) significant unplanned unit and line outages that reduce transfer capability assumed in the FTR auctions. 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. The results of these modified assumptions will be reflected in FTR settlement results beginning in June 2008.

H. External Transactions

The Midwest ISO relies heavily on imports from adjacent areas. On average, the Midwest ISO imported almost 5 GW in on-peak hours and over 2.7 GW in off-peak hours.[13] 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, which introduces reliability issues that the Midwest ISO must

[12] See Section V.E.
[13] External transactions are evaluated in Section VII.A.

manage and contributes to increased price volatility. Large changes in net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources. Some of this variability can be traced to issues related to the scheduling and settlement of very short-term transactions (less than an hour). We recommend changes in the scheduling and settlement rules to reduce inefficient variability in net imports.

We also analyze transactions over specific external interfaces. Two of the most important interfaces are those with Manitoba and PJM. Imports over the Manitoba interface typically account for more than a one-quarter of the net imports. These imports were unusually low early in the year due to poor water conditions. This reduction contributed to substantial congestion into the West until they returned to more normal levels during the summer.

The Midwest ISO is also a net importer from PJM, although power flows across this interface frequently reverse direction. Our analysis indicates that prices in the two markets are relatively well arbitraged in most hours.[14] 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 consider expanding their Joint Operating Agreement ("JOA") to optimize net interchange between the two areas. This change would achieve most of any potential savings associated with jointly dispatching generation in the two regions.

The report also evaluates the market-to-market coordination used by the Midwest ISO and PJM to manage transmission constraints that both markets affect.[15] This process has been important in allowing these constraints to be efficiently managed. However, our analysis indicates that the process can be improved by changing how constraints are modeled, refraining from "relaxing" constraints, and modifying the dispatch assumptions to allow the Midwest ISO and PJM to provide larger quantities of relief on each other's constraints.

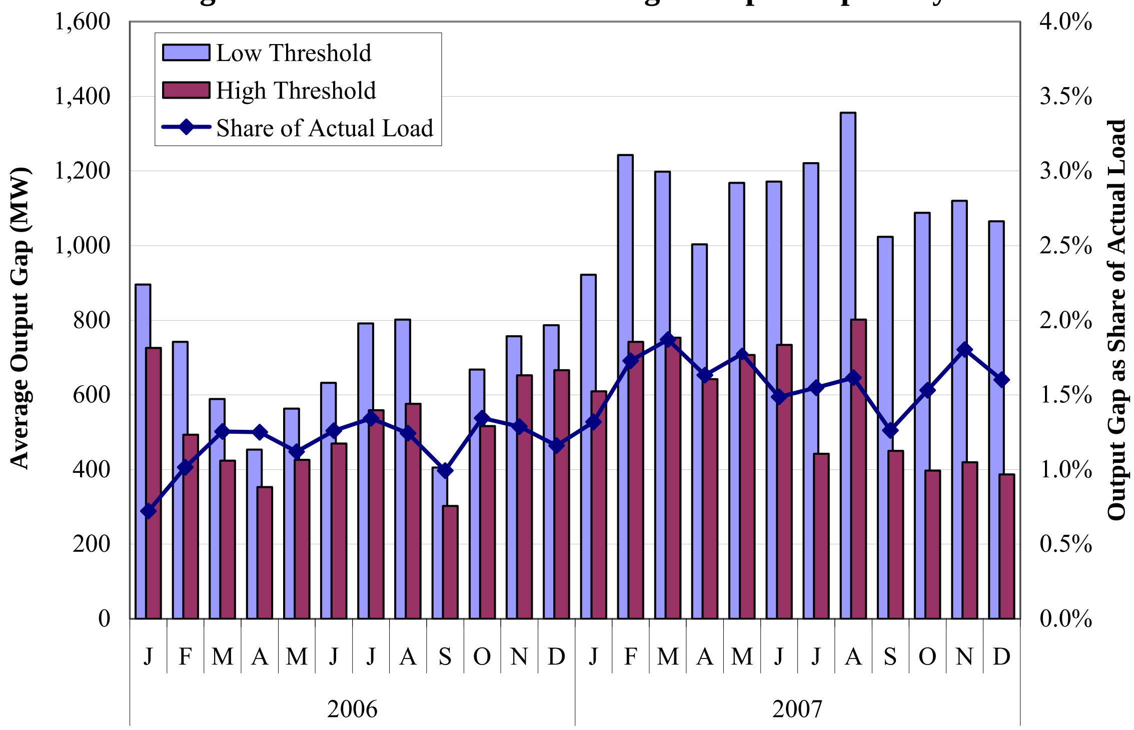
14 See the analyses in Section VII.B.
15 The market-to-market process is evaluated in Section VII.C.

I. Market Power and Mitigation

Section VI of the 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 2007.[16] Our analysis shows that market concentration is low for the overall Midwest ISO region and moderate to high in the different sub-regions.[17] 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. Our pivotal supplier analysis of constrained areas in 2007 shows that there was at least one pivotal supplier in more than one-half of the hours when congestion occurred into constrained areas. Based on these and other results, we find substantial local market power in constrained areas.

However, our evaluation of participants' conduct provides little evidence of attempts to withhold resources (either physically or economically) to exercise market power.[18] Figure E-5 shows our "output gap" metric, which we use to detect instances of potential economic withholding.

Figure E-5: Economic Withholding – Output Gap Analysis



16 See Section VI..
17 See Section VI.A.
18 See Section VI.B.

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). The increase in the output gap at the beginning of 2007 is due to the reduced thresholds used when a new NCA was designated in Minnesota, not to a general change in supplier conduct. Overall, the output gap levels generally remained at relatively low and stable levels. These results and others in the report provide little indication of significant economic or physical withholding in 2007. Nonetheless, we monitor these levels on an hourly basis and regularly investigate instances of potential withholding.

Lastly, market power mitigation in the Midwest ISO's energy market occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria.[19] Because conduct has generally been competitive, market power mitigation has been imposed infrequently.

J. 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 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 8,600 MW, or more than 40 percent of the total demand response capability in all of the U.S. RTOs. Most of this is interruptible load and was developed by utilities under regulated retail initiatives. Much of this load is only curtailable for reliability and is not price-responsive. Integrating this capability into the market will be challenging and work has been underway by the Midwest ISO to better understand this capability and how it may be utilized most efficiently. In addition, the Midwest ISO is working to facilitate demand response by:

- Allowing demand response resources to sell ancillary services or energy, and satisfy the resource adequacy requirements;
- Removing disincentives to the development of demand response resources; and
- Removing technical barriers to the expansion of demand response resources in the market.

[19] Market power mitigation measures are reviewed in section VI.C.

Finally, regardless of the type of demand response (existing curtailable load or future demand response resources), it is very important that demand response contribute to setting prices in the energy and ancillary services markets when they are appropriately curtailed. 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). This undermines a key component of the economic signals needed to support investment in generation, demand response resources, or transmission. Hence, introducing changes that allow both curtailable load and demand response resources to set energy and ancillary services prices when they are deployed should be a high priority.

K. Summary of Recommendations

As described above, the Midwest ISO is implementing a number of changes that will substantially improve the performance of the energy markets and the economic signals they provide. These changes include the introduction of ancillary services markets in September 2008 that will improve both the allocation of resources between energy and ancillary services and improve their pricing.. In addition, the Midwest ISO has worked to clarify and enforce the capacity requirements in Module E of the Tariff. This will allow a decentralized contract market to develop for satisfying these capacity requirements.

Although the markets have performed relatively well in 2007 and will perform better with the implementation of ASM and the changes to Module E, we identify the following eight improvements in the design or operation of the Midwest ISO markets.

1. Continue work to integrate demand response resources. (Section III.D.)

This recommendation includes developing centrally-coordinated demand response programs that allow demand response resources to participate more fully in the energy and ancillary services markets. Ideally, these programs would allow for the conversion of some of the legacy curtailable load that exists in the region, as well as the development of new resources.

The second element of this recommendation relates to pricing in the Midwest ISO markets when demand response resources are utilized. The Midwest ISO markets should be modified to allow interruptible load and demand response resources to set energy prices in the real-time market when they are deployed in shortage conditions. This will allow the Midwest ISO to send more efficient long-term economic signals for investment in new supply and new demand response resources. It will also improve the short-term signals to the suppliers, load, and potential importers and exporters. The response of these entities to the resulting short-term price signals is key to resolving shortages and preventing the need for further load curtailments.

2. Develop real-time software and market provisions that allow peaking resources running at their EcoMin or EcoMax to set the energy prices when appropriate. (Section IV.D.)

Peaking resources tend to be inflexible (i.e., having a narrow flexible 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 that are needed (i.e., would not be dispatched down to zero if they were completely flexible) to set prices and not allow those that are not needed to set prices. Distinguishing between peaking resources that should contribute to setting prices from those that should not is a challenging modeling problem.

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 2008. If a feasible approach is developed, this change will improve the efficiency of real-time prices, increase the incentives to schedule load fully in the day-ahead market, and reduce RSG costs.

3. 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. (Section IV.B)

The Midwest ISO has made operational improvements in its commitment of peaking resources. Commitment of these units can be further improved by reliance on an economic model in real time to commit peaking units and manage dispatch levels of slow-ramping units. Such a model should be synchronized with the real-time dispatch software (UDS), but would anticipate changes in load, congestion patterns, and the ramp needs of the system up to an hour ahead.

To the extent such a tool improves the commitment and decommitment of peaking resources, it would lower RSG. It should also reduce the price volatility because it would anticipate and satisfy the ramp needs of the system.

4. Replace the current ex post pricing methodology with an approach that would utilize the prices produced by UDS, corrected for metering or other errors. (Section IV.E.)

Like PJM and ISO New England, the Midwest ISO re-calculates prices after each interval (ex post pricing) rather than using the "ex ante" prices produced by the real-time dispatch model that are consistent with the dispatch signals that generators receive. Ex post pricing has not been shown either theoretically or empirically to improve the efficiency of real-time prices or the incentives of suppliers. Our analyses in this report indicate that the ex post prices tend to be biased upward (3 percent on average in 2007). Additionally, use of ex post prices sometimes introduces significant inconsistencies between prices at particular locations and generators' dispatch signals. Hence, this recommendation should be implemented with the ASM markets or sooner, if feasible.

5. Discontinue the constraint relaxation procedure and use the constraint penalty factor to set LMPs when a transmission constraint is unmanageable. (Section V.D.)

As described above, the constraint relaxation algorithm software frequently produces LMPs that do not efficiently reflect transmission constraints that have become unmanageable. In some cases, this algorithm causes constraints to no longer appear to be binding and, therefore, to not be reflected in the markets' LMPs. This recommendation will address this issue and ensure that congestion is efficiently priced when a constraint is overloaded. This is particularly important on market-to-market constraints where the pricing results are used in the settlements with PJM.

6. Include generation with lower effects on a constraint (i.e., GSFs less than the current 2 percent cutoff) when it redispatches generation to manage congestion. (Section V.D.)

We explain that this modeling parameter reduces the redispatch flexibility of the system and makes some constraints more difficult to manage. Hence, this recommendation is designed to increase the manageability of transmission constraints, which will tend to reduce price volatility associated with congestion.

7. Work with PJM to modify the market-to-market process to improve its effectiveness. (Section VII.C.)

Although the market-to-market process provides significant benefits by coordinating flows on constraints that both the Midwest ISO and PJM affect, our analyses showed significant room for improvement on some key constraints. Hence, we recommend Midwest ISO work with PJM in order to:

- Adjust the amount of relief each RTO requests from the other;
- Institute a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly;
- Modify current methodologies that determine available relief to ensure that PJM recognizes the relief it can provide on constraints in the West and Central regions; and
- Develop a process to coordinate external transactions over non-Midwest ISO/PJM interfaces.

In addition to these changes intended to improve the management of internal constraints on the two systems, we recommend that the Midwest ISO and PJM consider expanding the JOA to include coordination of the real-time net interchange between the two RTO areas. Such coordination could be achieved relatively simply by making small adjustments in the NSI each 5 minutes based on the most recent real-time prices in the two areas. This will improve efficiency by increasing the consistency of the prices in the two markets. It would also reduce the price volatility associated with large shifts in NSI between the markets.

8. Modify how short-term import and export transactions are scheduled and settled. (Section VII.D.)

To address incentive issues identified in the report that cause participants to schedule a large quantity of intra-hour imports and exports, we recommend that the Midwest ISO consider the feasibility of settling external transactions on a 15-minute basis. This would cause the settlement to match the prices in the 15-minute periods in which a transaction actually flows. If this is not feasible or cannot be implemented in the short-term, we recommend that the Midwest ISO modifying scheduling deadlines to ensure that no participant will observe the prices that are the basis for the hourly settlement prior to scheduling a transaction. This should address the excessive scheduling that occurs in the fourth quarter of the hour as we discuss herein.

In addition to these changes, we propose that the Midwest ISO limit acceptance of short-term transactions based on the available capability to ramp internal generation up or down in support of the transaction. If the system ramp capability cannot be tracked and forecasted in real time, the current ramp limitation used to schedule external transactions of 1000 MW in any 15-minute period should be modified to a lower level; one that is estimated based on typical availability. This will reduce price volatility in the Midwest ISO by reducing the frequency of sharp price movements caused by large changes in NSI.

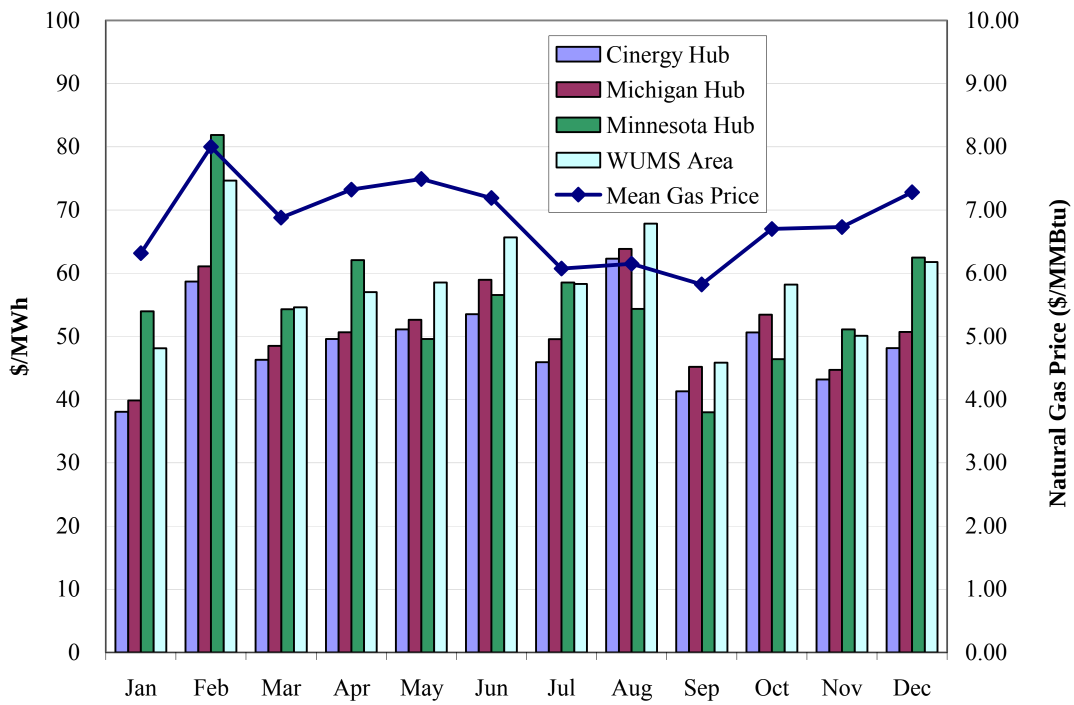
II. Prices and Revenues

The Midwest ISO completed its second full year of operating competitive wholesale electricity markets in 2007. The markets operated by the Midwest ISO include markets for day-ahead and real-time energy market and markets for FTRs. 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 the electricity prices and fuel prices for the Midwest ISO markets. Figure 1 shows average day-ahead energy prices and natural gas prices in 2007.

Figure 1: Day-Ahead Average Monthly Hub Prices

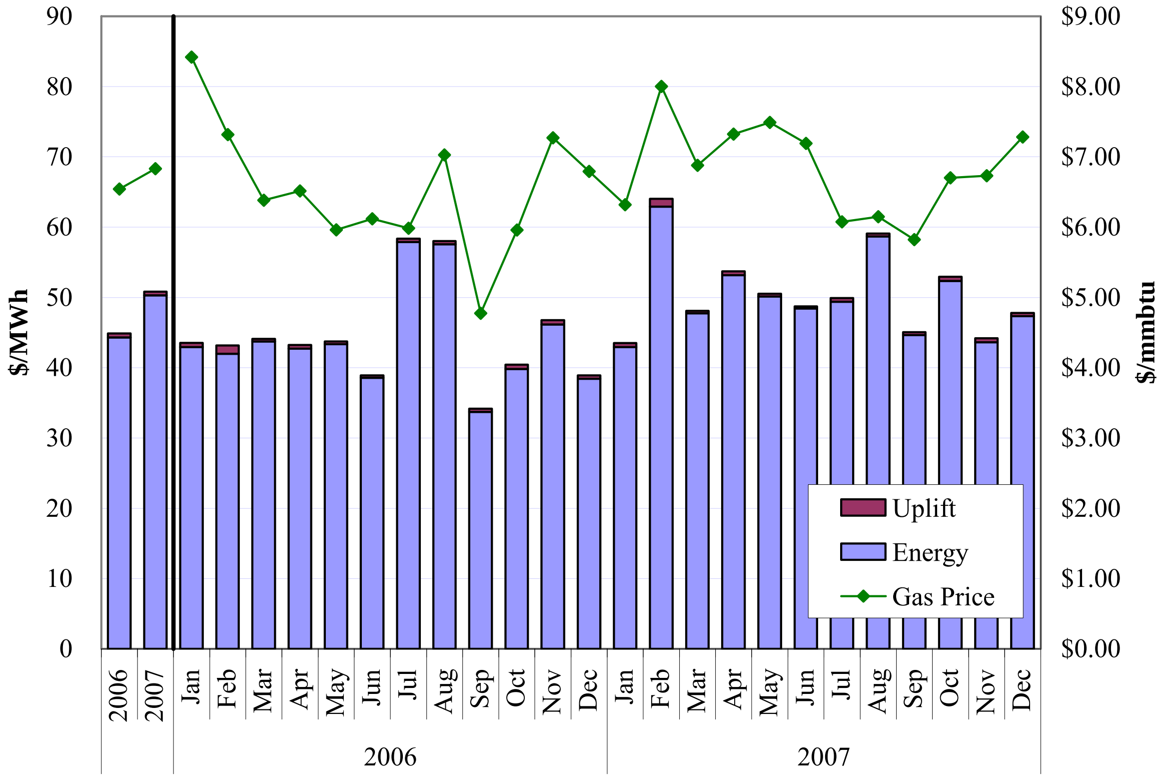


The figure shows that day-ahead prices are correlated with natural gas prices. We would expect this because fuel costs represent the majority of most suppliers' variable production costs (i.e., marginal costs) and natural gas units are often on the margin. In a competitive market, generators have incentives to offer energy at marginal cost. Hence, generators' 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 natural gas prices and electricity prices is an indication that the markets are performing efficiently. The correlation was weaker during the summer months when prices did not fall with the decreasing natural gas prices. This is attributable to the higher loads that prevail during the summer.

The figure also shows differences among the hub prices, which indicate congestion on the Midwest ISO system. Much of the day-ahead market congestion occurred on market-to-market flowgates on Midwest ISO's eastern border with PJM. This congestion generally reduces the price of energy in the East and Central regions (Cinergy and Michigan Hubs) relative to the rest of the system. The typical congestion into the Wisconsin-Upper Michigan System ("WUMS") region that occurs throughout the year is apparent as well.[20] In the West region (the Minnesota Hub), high prices prevailed due to high levels of congestion and peak loads early in the year.

The next analysis in Figure 2 summarizes the overall costs of serving load in the region by showing an "all-in" price of wholesale electricity.

Figure 2: All-In-Price of Wholesale Electricity
2006 - 2007



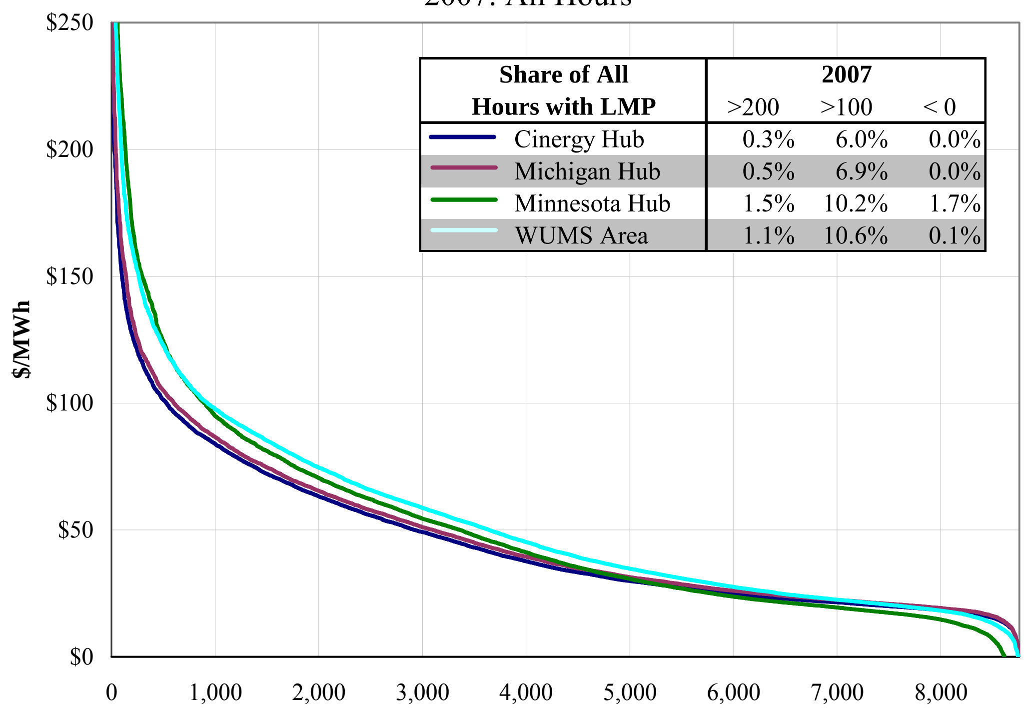
20 Unless specifically noted otherwise, we use the WPSM load zone price to represent prices in the WUMS area.

The all-in price includes both energy prices and "uplift" (average RSG costs per MWh). The all-in price does not include ancillary services and capacity costs because the Midwest ISO currently lacks these markets.[21] The all-in price of electricity is equal to the load-weighted average real-time price plus average real-time RSG per MW of real-time load.

The all-in price was approximately $51 per MWh in 2007. This is a 13 percent increase over the all-in price of $45 per MWh in 2006. The major contributing factors to these annual changes are changes in fuel price and load levels. The analysis also shows that uplift costs are a small share of the all-in price -- close to 1 percent of the average all-in price in both years.

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 Cinergy hub crosses $50 per MWh on the vertical axis at approximately the 3000-hour level. Therefore, in approximately 3000 hours during 2007, the Cinergy hub price exceeded $50 per MWh. Figure 3 shows the real-time price-duration curves for each of the Midwest ISO hubs.

Figure 3: Real-Time Price-Duration Curve
2007: All Hours



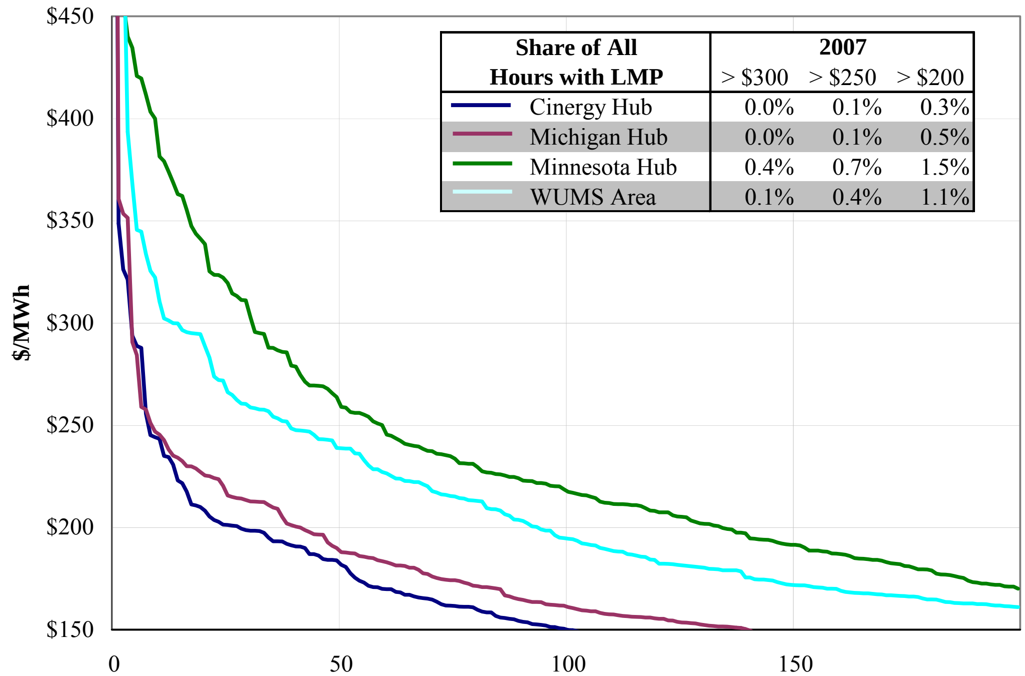
21 Ancillary services markets are currently expected to be operational in the autumn of 2008.

The differences between these curves are due to congestion and losses that cause prices to vary by location. WUMS and Minnesota prices are the highest due to the frequent congestion into these areas – over ten percent of the hours exhibit prices above $100 per MWh at these locations versus six and seven percent at the Cinergy and Michigan hubs, respectively.

Congestion affected Minnesota more than any other hub during 2007 due primarily to the reduced imports over the interface with Manitoba Hydro. It had the highest number of hours with prices above $200 per MWh (1.5 percent of hours). The number of hours exceeding $200 per MWh increased from 2006 at all locations due primarily to higher fuel prices. Additionally, congestion from Minnesota into WUMS caused Minnesota to have many hours when prices were less than zero (1.7 percent of hours). This is an improvement over 2006 when 2.4 percent of hours at the Minnesota hub exhibited negative prices. Nonetheless, the number of hours in 2007 with negative prices at the Minnesota hub was ten times more than at any other hub.

Prices in peak hours play a critical role in sending the economic signals that govern investment and retirement decisions. Hence, we show the real-time price-duration curve for the highest-priced hours for each hub in Figure 4.

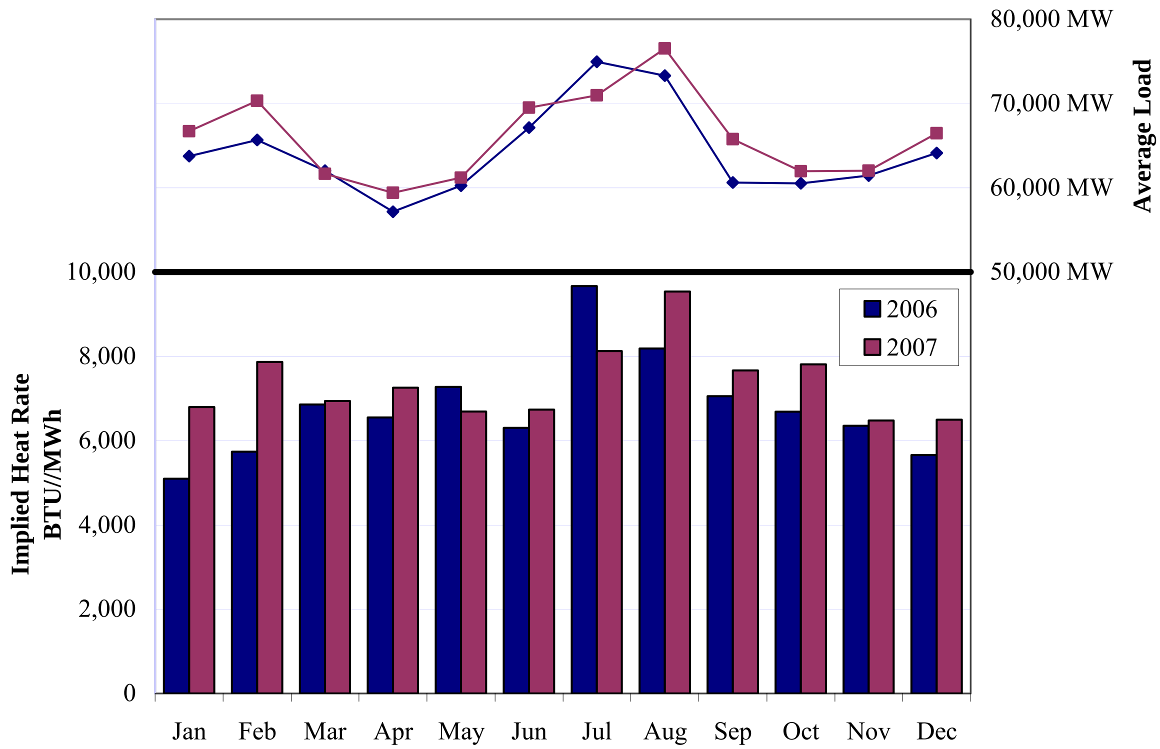
Figure 4: Real-Time Price Duration Curve
2007: High Price Hours



Congestion causes prices in Minnesota and WUMS to be higher in the peak hours than the prices at other locations in the Midwest ISO. However, prices throughout the Midwest ISO were above \$300/MW in a very small number of hours – ranging from four hours at the Cinergy hub to 30 hours at the Minnesota hub. If the low frequency of peak pricing events continues in the future, the Midwest ISO markets will not provide efficient incentives for new investment in generation or demand response resources. Improvements in the peak energy pricing provisions in the ASM markets and recommended changes in market rules will improve the economic signals and contribute to resource adequacy.

As discussed above, fluctuations in natural gas prices are highly correlated with changes in electricity prices. This impact can obscure the underlying electricity market performance. To identify changes in electricity prices that are not driven by changes in natural gas prices, we calculate the marginal heat rate that would be implied if natural gas were always the marginal fuel. The Implied Heat Rate metric is equal to the real-time energy price divided by the natural gas price. The Implied Heat Rate metric highlights variations in electricity prices that are due to factors other than fluctuations in natural gas prices. Figure 5 shows the implied heat rates and average load levels for 2006 and 2007.

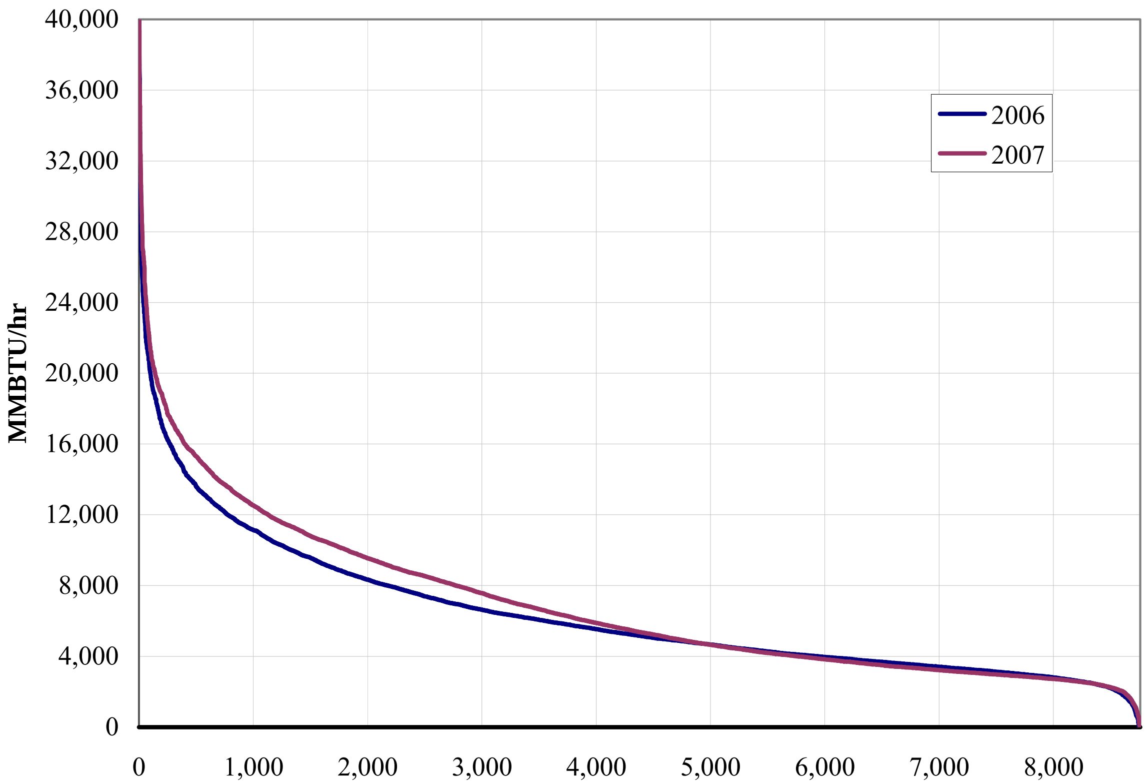
Figure 5: Implied Heat Rate of Real-Time Energy Prices



Once we account for fuel price changes, the figure shows the importance of changes in load. In both years, the implied heat rate rises and falls with monthly load levels. In all but one of the twelve months, the implied heat rate is higher in the year with the higher load. For example, from August to December, the figure shows that implied heat rates in 2007 were higher than those in 2006, as is the load during that period. Substantial increases in coal prices late in 2007 also contributed to the higher implied heat rates because coal-fired units are on the margin and setting prices in a large share of the off-peak hours.

To understand how hourly prices changed from 2006 to 2007, adjusting for changes in fuel prices, we show implied heat rate duration curves in Figure 6 for 2006 and 2007.

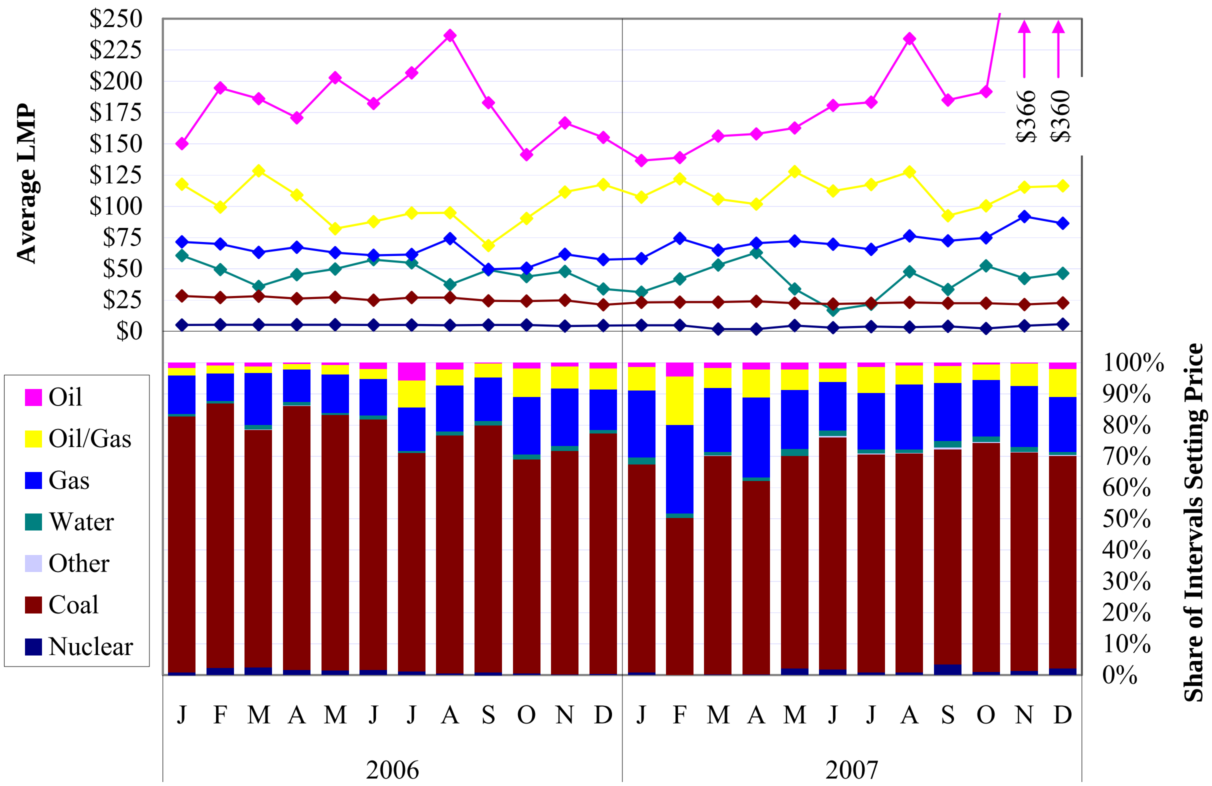
Figure 6: Implied Heat Rate Duration Curve



This figure shows that the hourly implied heat rates were higher during the peak hours in 2007. The primary cause of this increase was higher load levels in 2007. Although the peak load in 2007 was lower than 2006, the average loads in 2007 were significantly higher. Additionally, the reduced imports over the Manitoba interface early in the year led to higher overall prices and more congestion. Finally, natural gas transportation issues during the winter compelled many dual-fueled resources to burn oil and set higher prices.

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 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.

Figure 7: Price Setting by Unit Type



This figure shows that coal units set prices in more than two-thirds of the hours (including virtually all of the off-peak hours). Natural gas and oil units set prices during the highest-load hours. Hence, these fuel prices have a larger effect on the load-weighted average prices than the percentages would suggest.

In February 2007, natural gas-fired units set prices in a larger share of hours than any other month. This was due to the lower day-ahead scheduling levels and high winter loads in February, which caused the Midwest ISO to rely heavily on quick-start combustion turbines. Most of these units are fired by natural gas or oil.

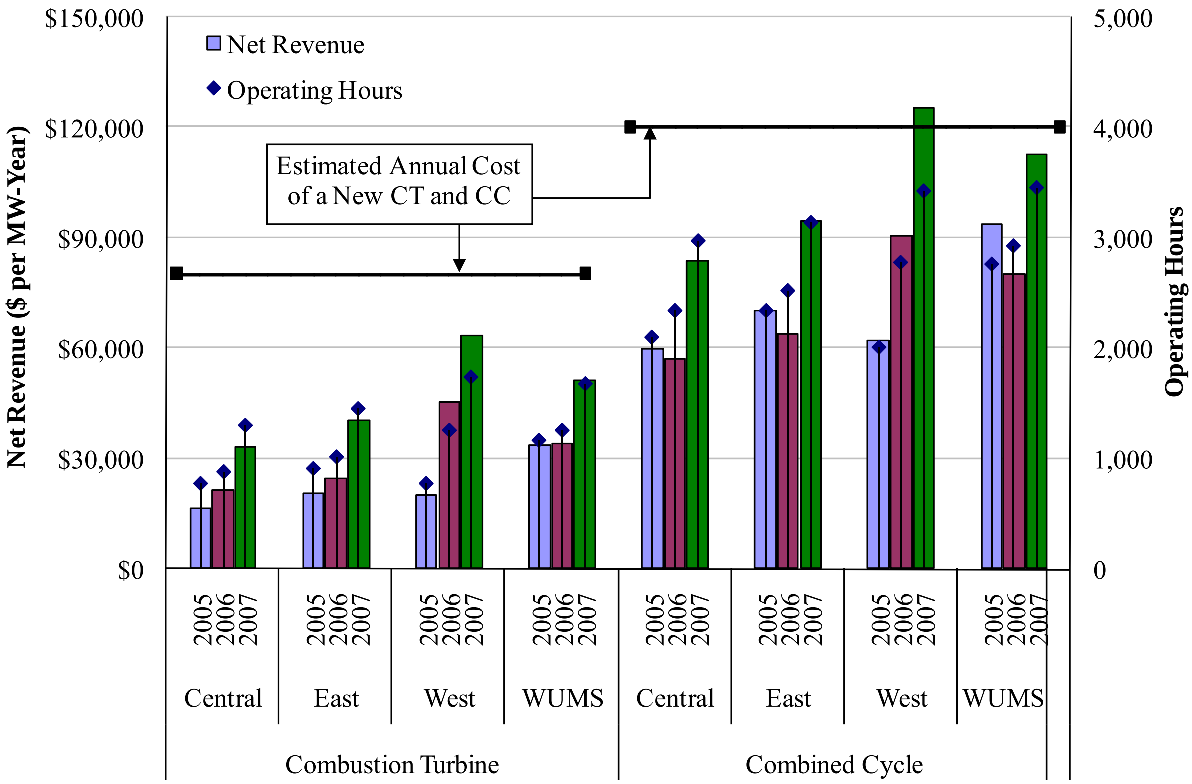
B. Net Revenue Analysis

In the previous subsection, we provided a summary of the Midwest ISO energy market prices in 2007. We now evaluate the resulting economic signals associated with these prices. Our evaluation uses the "net revenue" metric. Net revenue is the revenue that a new generator would earn above its variable production costs if it were to operate only when its variable production costs are less than the energy price.

A well-designed market should allow a new entrant to earn a level of net revenues that are 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 for the Midwest ISO because the Midwest ISO markets do not currently include capacity or ancillary services markets.

Our analysis examines the economics of two types of new units: a natural gas combined-cycle unit with an assumed heat rate of 7,000 BTU/KWh and a natural gas combustion turbine with an assumed heat rate of 10,500 BTU/KWh. We also incorporate standardized assumptions for calculating net revenues put forth by the Federal Energy Regulatory Commission ("the Commission") that account for variable O&M costs, fuel costs, and forced outages. However, the analysis does not consider start-up costs, minimum run-times, or other physical limitations. Figure 8 shows net revenue provided by the Midwest ISO market over the first nine months of operation in 2005 through the end of 2007.

Figure 8: Net Revenue and Operating Hours
2005 – 2007



To determine whether these net revenue levels would support investment in new resources, the figure also shows the annualized cost of a new unit (which equals the annual net revenue a new unit would need to earn to make the investment economic). The net revenue analysis indicates that with the exception of the West, neither a combustion-turbine nor a combined-cycle unit would have earned net revenues sufficient to justify new investment. In the West region, revenue was high enough to support investment in a new combined-cycle unit due to the sizeable increase in congestion into the West recently.

This outcome would be expected if the Midwest ISO region were exhibiting a substantial surplus of generating capability or if the peak load levels in 2007 were unexpectedly low, neither of which was true. When shortage conditions occur, the current market prices do not fully reflect them because operating reserve shortages and interrupted load do not contribute to setting prices. The ASM markets will improve shortage pricing because they will include 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 being introduced to Module E of the Midwest ISO transmission tariff will also improve the long-term market signals needed to maintain adequate resources. The Midwest ISO is clarifying the capacity requirements and introducing enforcement provisions that should allow a decentralized market to develop to meet the Midwest ISO's capacity requirements. Our analysis does not include revenue earned through Module E transactions, which were likely modest in 2007. We will include such revenues in our analysis as this market develops in the future.

Because combined-cycle generators have substantially lower production costs than simple-cycle combustion turbines, they run more frequently (over 37 percent of all hours in 2007 and close to 40 percent in the WUMS and West regions). Hence, a new combined-cycle generator would receive higher net revenues ranging from more than \$83,000 to \$126,000 per MW-year for various locations. In contrast, the net revenues for combustion turbines in 2007 ranged from \$33,000 to \$63,000. Compared to 2006, the net revenues in 2007 were higher in all regions for a combustion turbine due to higher load levels and congestion in 2007.

To check the reasonableness of the net revenue estimates, we compared the actual operating statistics of existing combustion turbines and combined-cycle generating units in 2007 to the run hours that we estimate in the net revenue analysis. We found that actual operating hours were slightly lower than the estimated run hours. For example, run hours for the most efficient Midwest ISO combustion turbines were lower in the West and WUMS (15 percent of actual hours versus 19 percent estimated), where turbines generally run the most. Combined-cycle run hours were also slightly lower in the East (36 percent of actual hours versus 38 percent in the net revenue calculation). These differences in run hours are generally attributable to the start-up costs and physical restrictions that prevent the units from running in all profitable hours.

As excess capacity in the region declines, it will be important that the Midwest ISO have markets in place to send efficient long-term signals. Hence, the introduction of the ASM markets and the proposed changes to Module E should remain among the Midwest ISO's highest priorities.

III. Load and Resources

In the 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 over 70 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 on 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 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 WUMS; and
- WUMS -- the Midwest ISO control areas located in the WUMS region.

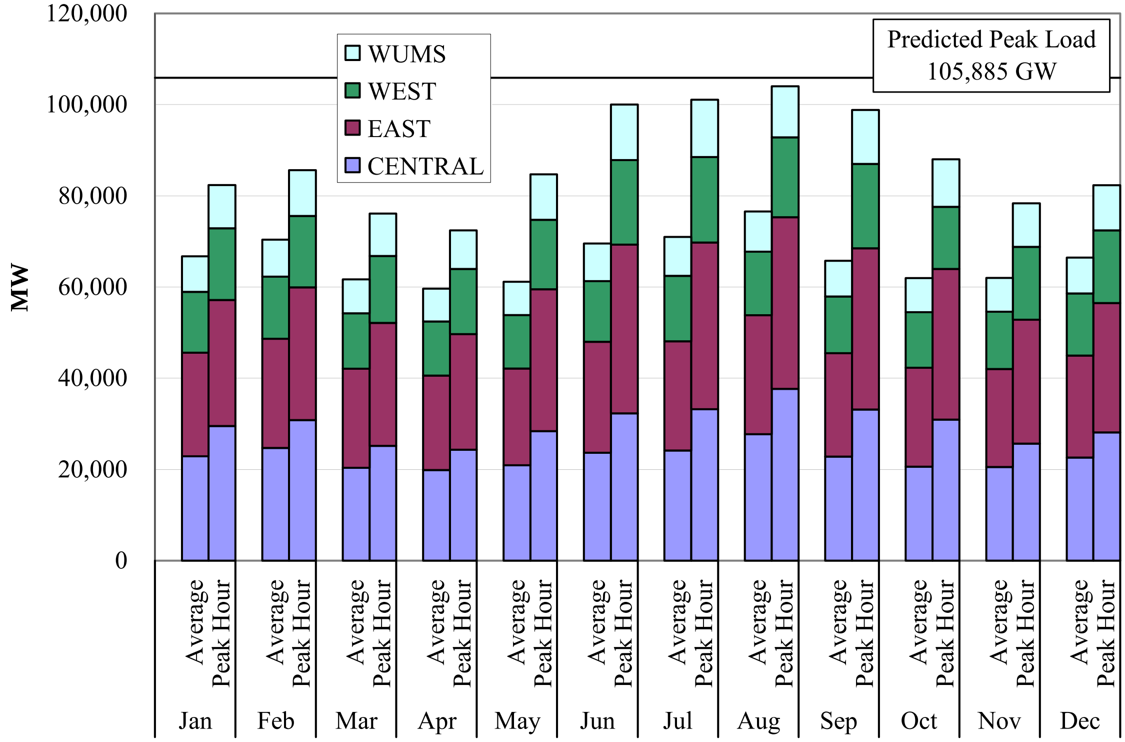
It should be emphasized that these four regions should not be viewed as distinct geographic markets. This point is particularly important for the data presented below concerning generation ownership concentration in these regions. Concentration in these regions does not allow one to draw reliable competitive conclusions. An accurate market power analysis would require analyses beyond calculating market share and concentration statistics. Such analyses are reported in Section VI.

A. Load Patterns

Our first analysis in this section summarizes load patterns throughout the Midwest ISO region in 2007. Figure 9 shows the Midwest ISO monthly peak load and average load by region.

Figure 9: Monthly Maximum and Average Load

2007

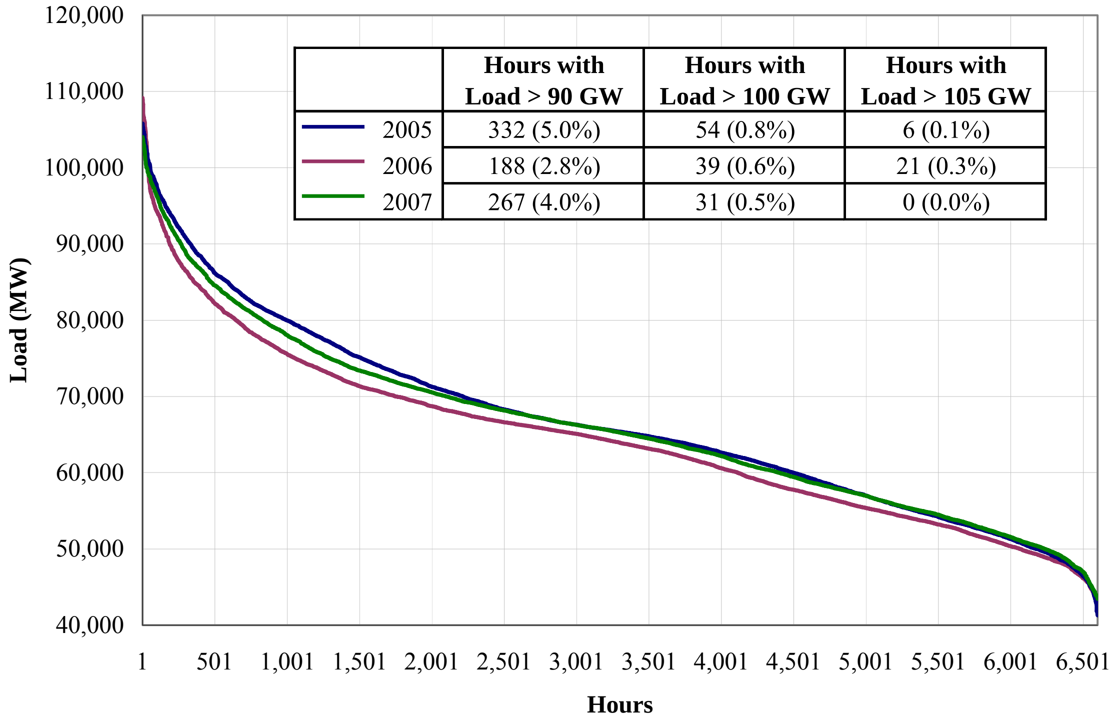


The figure shows that most of the load in the Midwest ISO is in the Central and East regions (74 percent together). The figure also shows that the Midwest ISO is a summer peaking region. In the months of July and August, the peak load was 101 and 104 GW, respectively. This peak was below the predicted peak load for 2007 of 105.9 GW, which is indicated by the horizontal line in the figure.

The figure also shows that peak load levels were substantially higher than average load levels, a characteristic of electricity markets. During the summer months, the peak load levels were 41 percent higher than the average loads. Because electricity cannot be stored, the market generally relies on intermediate and peaking resources to meet these demands.

To better understand how load varies on an hourly basis, our next analysis shows hourly load duration curves. A load duration curve is a relationship showing the number of hours (horizontal axis) in which load is greater than an indicated level (vertical axis). We construct these similar to the way we constructed the price duration curves, above. These results are shown in Figure 10 for 2005, 2006 and 2007.

Figure 10: Load Duration Curves
2005 - 2007



To make the data for each year comparable, it includes only the hours from April to December because the Midwest ISO markets were implemented in April 2005. In order to make the 2005 and 2006 curves comparable to 2007, LGE system load is removed from the 2005 and 2006 data when it was a member of the Midwest ISO.

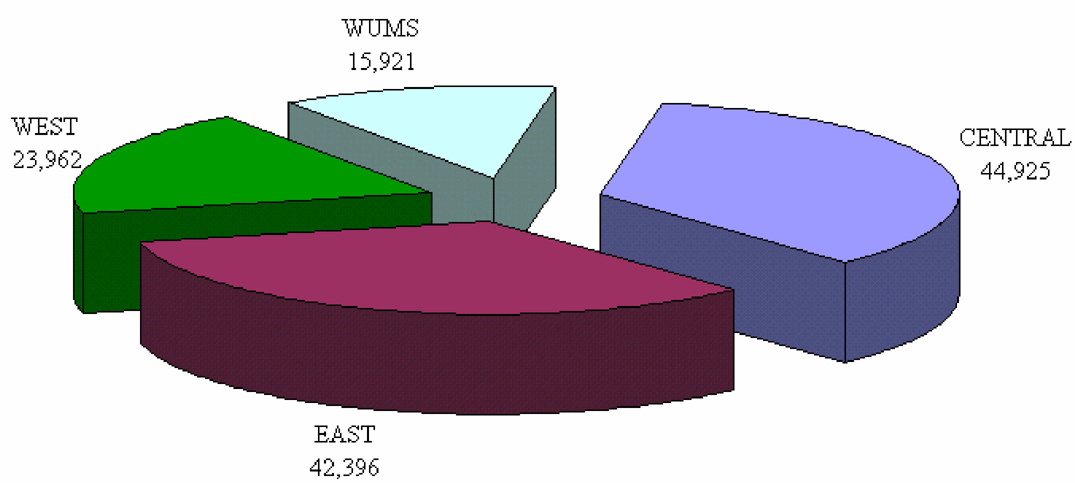
The figure shows 2006 had a greater number of extreme loads hours (hours above 105 GW), while 2007 did not exhibit any such hours. However, the peak load levels (e.g., the top 2000 hours) were generally higher in 2007 than in 2006. Mild summer weather resulted in fewer hours with extreme demand levels in 2007. There were 267 hours when actual loads exceeded 90 GW in 2007 versus 188 hours in 2006.

Finally, the figure shows 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 5 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.

B. Generation Capacity

Generating resources in the Midwest ISO market footprint totaled 127 GW by the end of 2007. Figure 11 shows the distribution of this capacity by coordination region.

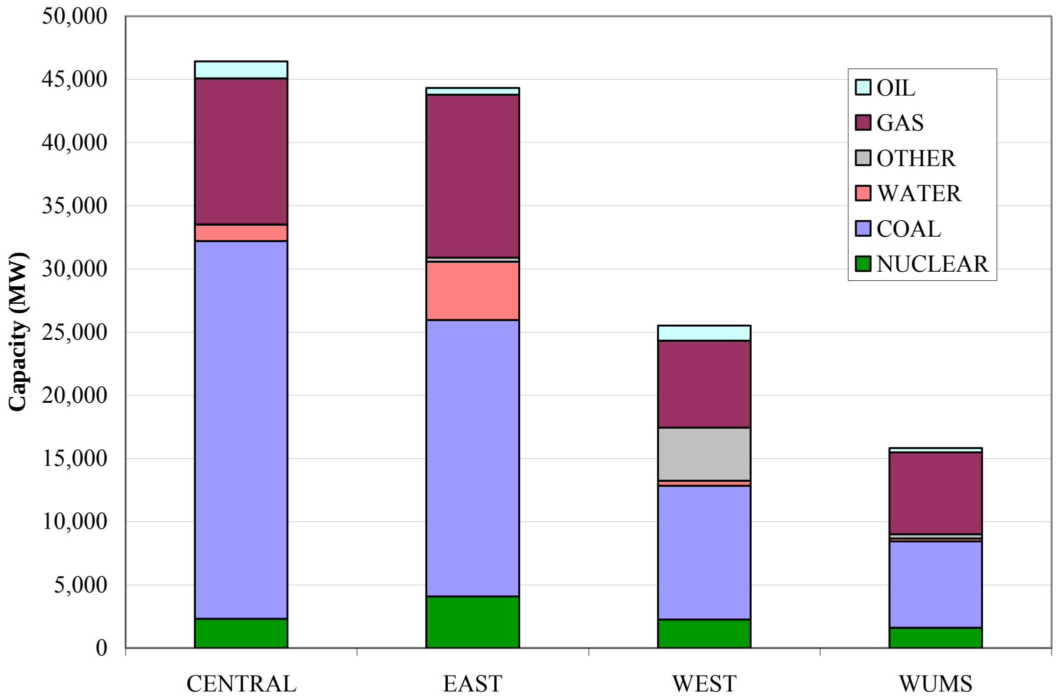
Figure 11: Generation Capacity by Coordination Region



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. NPPD, 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 would be more than 170 GW.

In addition to the location of the generation, the fuel used by the Midwest ISO generators is important because it determines their marginal costs and, ultimately, the patterns of prices in the Midwest ISO region. Our next analysis shows the Midwest ISO's generating capacity by fuel type. Figure 12 shows the generating capacity located in the four primary regions in the Midwest.

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



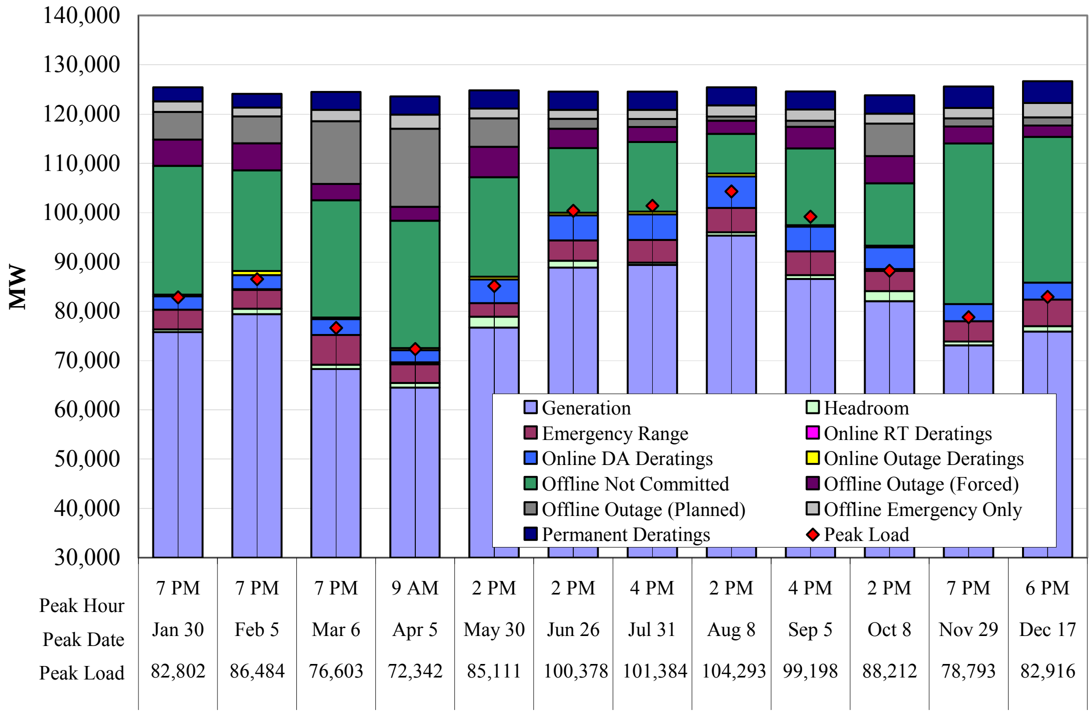
The Midwest ISO continues to rely heavily on coal-fired generating resources (approximately 52 percent of the Midwest ISO generation capacity is coal-fired). Because coal units are generally baseload, coal-fired resources generate an even larger proportion (77 percent) of total energy produced. The next most common fuel-type is natural gas, which accounts for almost 29 percent of the generating resources in the Midwest. Because these resources are higher-cost than most of the other resources in the Midwest ISO, they produce less than 5 percent of the energy in the region. However, they frequently set the price in peak hours. Nuclear units account for approximately 8 percent of capacity, but produce 14 percent of the generation because they are the lowest-cost resources and run in all hours.

The mix of generation is relatively homogeneous across the regions. However, the West region hosts most of the wind resources, while the East has the largest quantity of nuclear resources.

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 2007.

Figure 13: Availability of Capacity during Peak Hours
2007

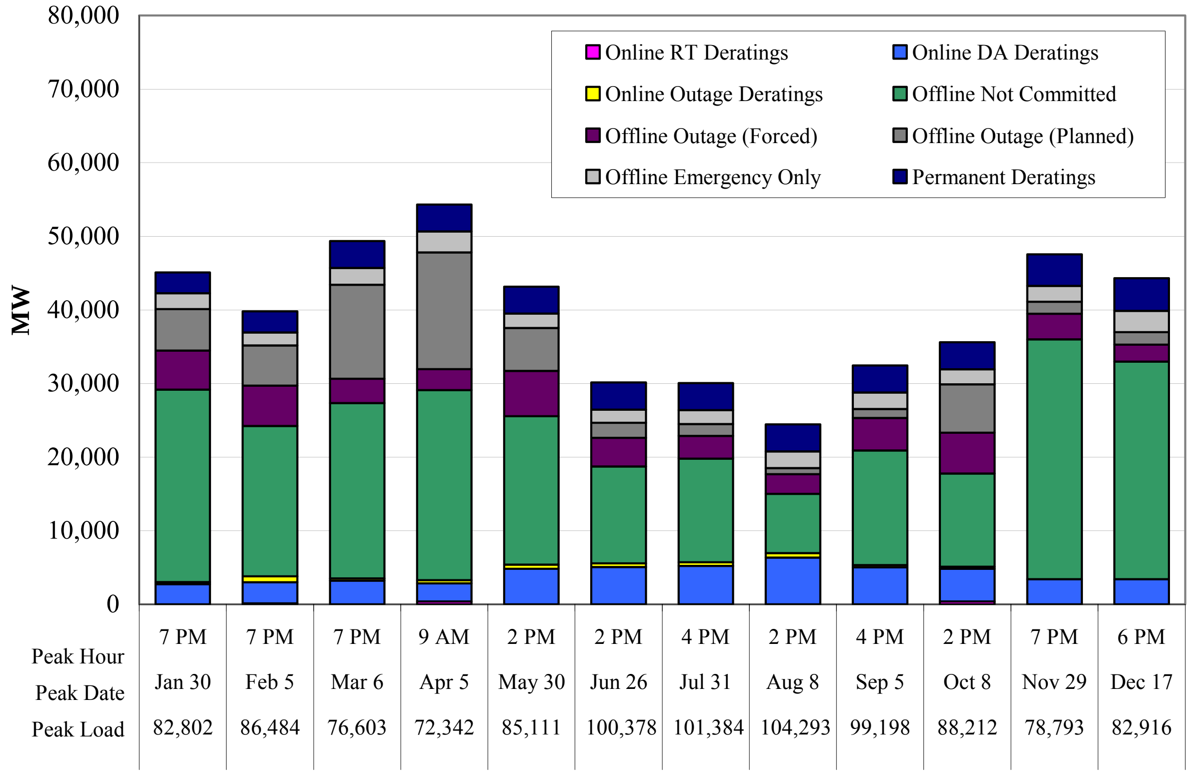


For reference, the peak load in each hour is shown as a red diamond. Most of the load is served by Midwest ISO generation, as indicated by the bottom (blue) segment of each bar. The next two segments are (1) "headroom", which is the amount of capacity remaining on the committed units above their dispatch point, and (2) the emergency output range. These three segments together represent the total online capacity. The other segments are the capacity that is unavailable for different 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 on imports to satisfy the 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. There were no conditions requiring demand side management during the summer peak periods.

However, a peak-load event occurred in February that resulted in demand curtailments in the West.

Next we evaluate *unavailable* capacity in peak hours. This evaluation is in Figure 14, which shows only the deratings and outages.

Figure 14: Capacity Unavailable during Peak Hours
2007

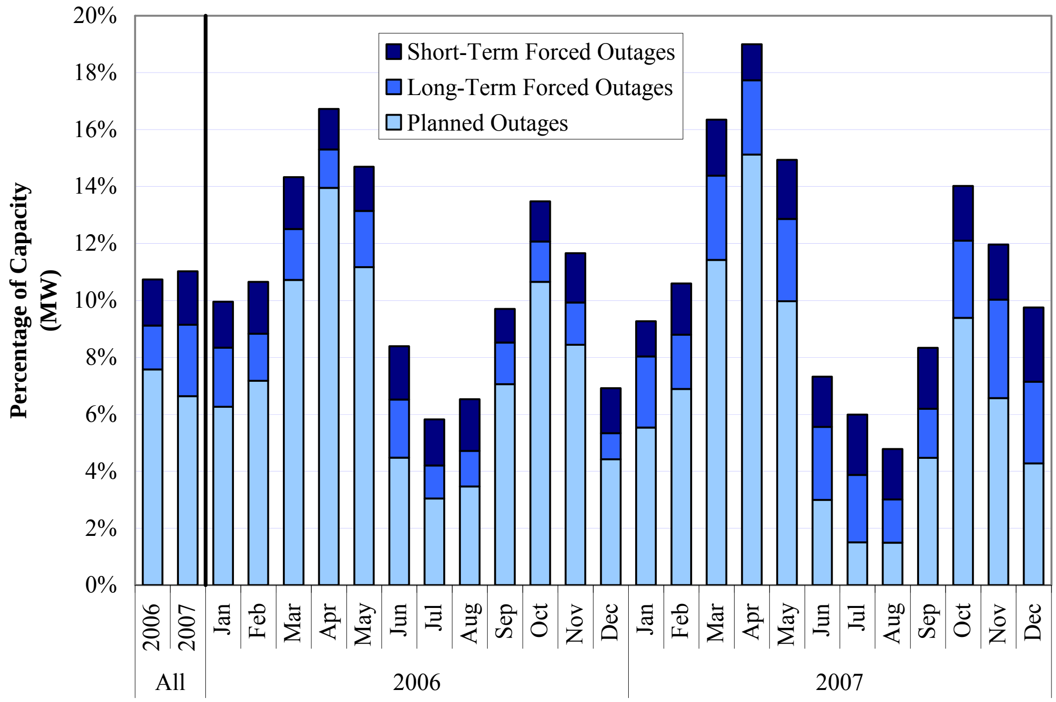


The figure indicates that deratings in the day-ahead market were highest during July and August, which is likely due to high temperatures. These peak summer deratings were less than the deratings that occurred in 2006, when summer temperatures were higher during peak periods than in 2007. In 2006, high temperatures and environmental restrictions resulted in additional deratings of baseload capacity that did not occur in 2007. In addition, roughly 3.6 GW of capacity is permanently derated (relative to nameplate capacity ratings) and unavailable for dispatch in any hour.

Finally, we review forced and planned generator outages for 2007. 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 7 days) and long-term (7 days or longer).

Figure 15: Generator Outage Rates in 2006 - 2007



Similar to 2006, the annual combined outage rate was almost 11 percent for the three categories of outages. The figure shows that the largest total outage levels occurred in the spring and fall because planned outages are generally scheduled during periods of low load. Planned outages were 12 percent during the spring and 7 percent in fall. Total planned and forced outages peaked in April at almost 19 percent. Planned outages were lowest (1.5 percent) in the peak load months of July and August. The forced outage rate did not substantially increase during the summer. It remained close to 4 percent, which is relatively low.

Because outages and deratings can be a means to withhold resources and exercise market power, they 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 summer of 2008. We evaluate generator availability by analyzing outages in 2007. For purposes of evaluating resource adequacy, we note that the maximum capacity levels planners assume will be optimistic if all potential deratings are not fully reflected. In particular, capacity levels during very high temperature conditions can be significantly lower than typically assumed, leading to lower reserve margins. Many resources during peak-load events must be derated in response to environmental restrictions or due to the effect of high ambient temperatures. We have attempted to take these effects into account in our analysis in this section.

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

Table 1: Capacity, Load, and Reserve Margins for each the Midwest ISO Regions

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temperature Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin
East								
Internal Load	39,268	1,271	42,396	11.2%	39,484	3.8%	38,915	2.3%
Internal Demand[3]	36,221	1,271	42,396	20.6%	39,484	12.5%	38,915	10.9%
Central								
Internal Load	39,084	711	44,925	16.8%	41,144	7.1%	39,762	3.6%
Internal Demand	37,285	711	44,925	22.4%	41,144	12.3%	39,762	8.6%
West								
Internal Load	20,803	3,119	23,962	30.2%	19,304	7.8%	19,304	7.8%
Internal Demand	18,670	3,119	23,962	45.1%	19,304	20.1%	19,304	20.1%
WUMS								
Internal Load	13,554	1,189	15,921	26.2%	15,329	21.9%	14,763	17.7%
Internal Demand	12,287	1,189	15,921	39.3%	15,329	34.4%	14,763	29.8%
MISO								
Internal Load	108,255	6,290	127,204	23.3%	115,261	12.3%	112,744	10.0%
Internal Demand	100,009	6,290	127,204	33.5%	115,261	21.5%	112,744	19.0%

[1] Estimated by the Midwest ISO using Day Ahead Market offer data and observed derates in 2007. Midwest ISO Summer Relibility Assessment 2007. Includes known planned outages for 2008.

[2] The Midwest ISO estimated derates from Nameplate and for temperature are included in the Available Capacity. We have estimated additional High Temperature derate based on capacity offered on August 1, 2006 for units available in the Day-Ahead market.

[3] Net Internal Demand is internal load less behind-the-meter load and demand-side management.

Table 1 includes separate reserve margins calculated based on *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 on internal demand will include the effects of demand response capability and those based on internal load will not. We calculate the reserve margin as follows:

Reserve margin = {(Capacity plus Firm Imports) ÷ 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 23 percent based on Internal Load and 34 percent based on Internal Demand (which includes curtailable load). The reserve margin in the Midwest ISO subregions varies from 11 percent to 30 percent based on Internal Load and from 21 percent to 45 percent based on Internal Demand.

These results would lead one to conclude that the Midwest ISO has a substantial surplus. However, when one removes the typical deratings and the temperature sensitive capacity that has not been available under peak-demand conditions, we find the reserve margin projected for 2008 for the Midwest ISO region is 10 percent based on Internal Load and 19 percent based on Internal Demand. We also find that in each of the regions, the reserve margin varies from 2 percent to 18 percent based on Internal Load and from 9 percent to 30 percent based on Internal Demand. These results indicate that the Midwest ISO's resources will be adequate for this summer. However, because almost 10 percent of the capacity will likely be unavailable due to forced outages and set aside for operating reserves, real-time conditions may be very tight on peak days. Hence, interruptible load will likely need to be interruptible under extreme conditions or if forced outages are higher than average at peak times.

Although these results indicate that the system's resources are adequate for this summer, new resources will likely be needed soon. This raises a concern because the results of the Net Revenue analysis presented in the prior section indicate that the long-term economic signals do not currently support new entry. Consistent with these signals, relatively little conventional capacity has been added in the last few years. Hence, the pricing changes designed to improve the efficiency of the market's economic signals are important.

Table 2 shows the new capacity additions planned for all of 2008. In total, 2.7 GW of additions and 900 MW of retirements are expected in 2008. More than one GW of the new natural gas and oil fired capacity is being added in the West. This should improve the Midwest ISO's ability to manage congestion into the area.

Table 2: Planned Capacity Additions 2008

	Coal	Gas	Oil	Oil/Gas	Other	Waste	Water	Wind
ALTW								130
AMIL		3						
CWLD								6
DECO								53
GRE			27					117
MDU								20
MP					25			50
NIPS								131
NSP			50	1,044			24	489
OTP								179
SMP						4		
WEC								145
WPS	150							99

Although a total capacity addition of 2.7 GW appears substantial, much of the new capacity is wind. The intermittent nature of wind causes it to contribute less to reliability than conventional supply or demand response. In fact, large quantities of wind resources added in other regions have caused significant congestion management issues and other operational issues.

E. Demand Response

Demand participation in the market is beneficial in many ways. It contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power. 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 8,600 MW, or more than 40 percent of the total demand response capability in all of the U.S. RTOs. Most of this is interruptible load and was developed by utilities under regulated retail initiatives. Much of this load is only curtailable for reliability purposes and is not price-responsive. Integrating this capability into the market will be challenging and work has been underway by the Midwest ISO to better understand this capability and how it may be utilized most efficiently. In addition, the Midwest ISO is working to facilitate demand response by:

- Allowing demand response resources to sell ancillary services and/or energy, and to satisfy the resource adequacy requirements;
- Removing disincentives to the development of demand response resources; and
- Removing technical barriers to the expansion of demand response resources in the market.

Finally, regardless of the type of demand response (existing curtailable load or future demand response resources), it is very important that demand response contribute to setting prices in the energy and ancillary services markets when they are appropriately deployed. 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). This undermines a key component of the economic signals needed to support investment in generation, demand response resources, and/or transmission. Hence, it should be a high priority to allow both curtailable load and demand response resources to set energy and ancillary services prices at efficient levels when they are implemented.

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 characteristics, (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 revenue sufficiency guarantee payments, the dispatch of peaking resources in real-time, and ex ante/ex post real-time pricing issues. We conclude this section with a number of suggested improvements intended to enhance efficiency and the overall performance of the markets.

A. Day-Ahead Market Performance

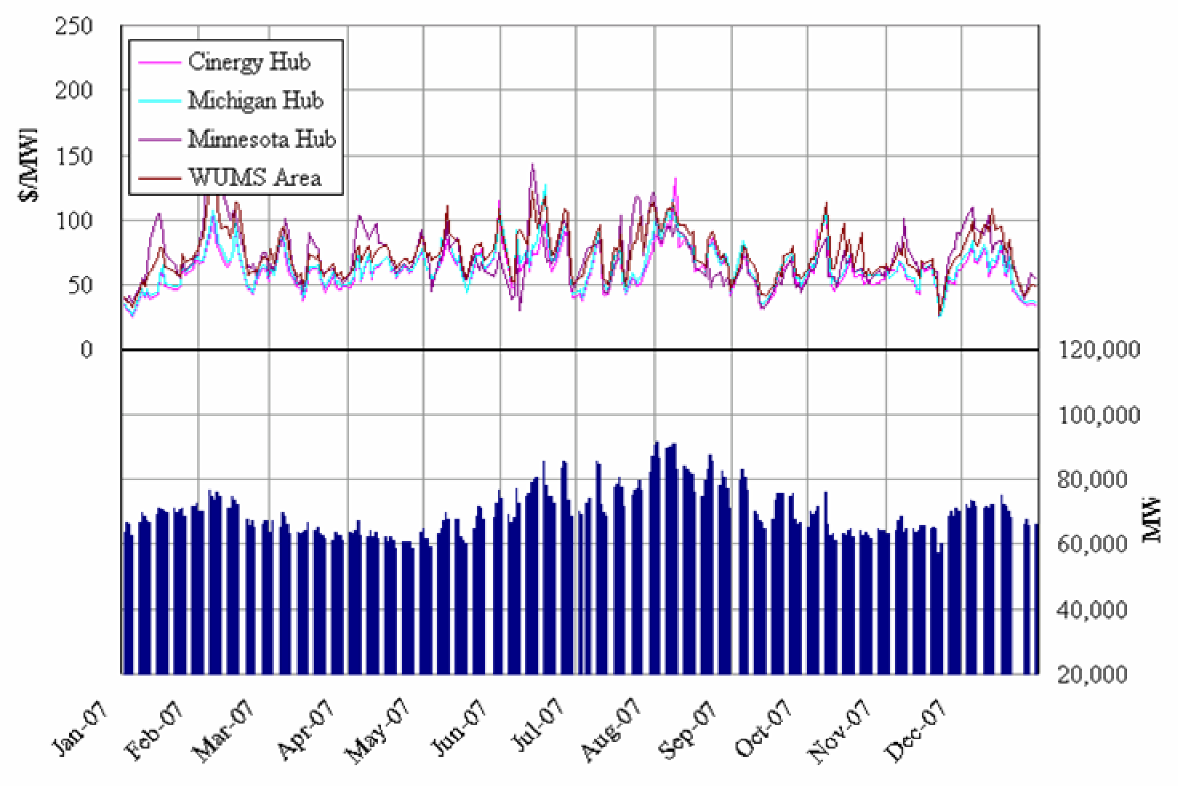
The day-ahead market allows participants to make forward purchases and sales of power for delivery in real time. This market allows participants to hedge their portfolios and manage risk. For example, loads can insure against volatility in the real-time market by purchasing in the day-ahead market and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

The performance of the day-ahead market is very important because most of the power that is procured through the Midwest ISO markets is settled in the day-ahead market. In addition, FTRs are settled based on day-ahead market results. Finally, the day-ahead market plays a crucial role in coordinating generator commitments as 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 AM-10 PM on weekdays) and the corresponding scheduled load (which includes net cleared virtual demand).

Figure 16: Day-Ahead Hub Prices and Load
Peak Hours: 2007

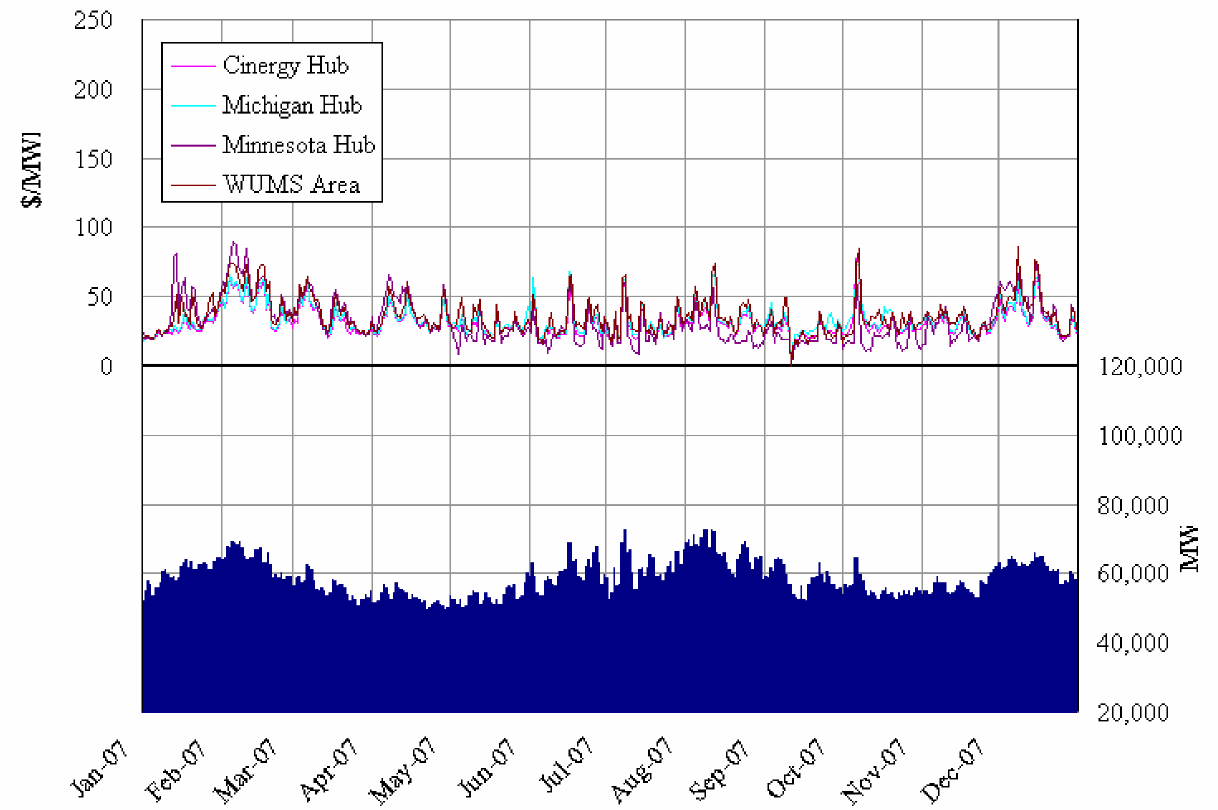


The figure indicates that the Minnesota and WUMS hubs generally experienced higher prices. Indeed, peak prices were about $4 to $5 per MWh higher at the Minnesota and WUMS hubs than at the Michigan and Cinergy hubs.

For Minnesota, this can be explained by congestion during the winter months. This was primarily due to the reduced imports over the Manitoba interface during the first six months of 2007. In addition, Minnesota's load is relatively high in winter and suppliers experienced periods of non-firm natural gas transportation issues that resulted in oil-fired turbines setting price. Imports over the Manitoba interface increased later in the year, which contributed to the reduction of congestion during the summer and autumn of 2007.

Prices in WUMS were high throughout the year due to frequent congestion on south-to-north constraints into WUMS from ComEd. There were also significant periods of increased congestion from the West into WUMS during the fall due to forced outages. The most frequent day-ahead constraint (the Black Oak-Bedington line) was binding in more than 25 percent of hours and contributed to the relatively low day-ahead prices at Cinergy hub. As shown in the figure, high load during both the winter peak and summer peak periods led to higher prices and volatility throughout the footprint. Figure 17 shows the same analysis for off-peak hours.

Figure 17: Day-Ahead Hub Prices and Load
Off-Peak Hours: 2007



Although off-peak hour load achieves its maximum during August, the highest off-peak loads during the winter months are almost as high due to the cold overnight temperatures. Day-ahead average off-peak prices were more than $50 per MWh in February and more than $40 per MWh in December. In contrast, the highest average off-peak price in the summer months was $38 per MWh in August. The higher winter prices were largely due to an increase in natural gas prices during the winter months.

Congestion patterns had a significant effect on off-peak prices at the Minnesota Hub. Congestion *to* Minnesota led to higher prices during winter months while congestion *from* Minnesota led to lower off-peak prices during summer months. The changes in congestion patterns were largely related to changes in outages and imports over the Manitoba interface.

Well-functioning LMP markets provide transparent signals regarding prevailing market conditions, even under atypical conditions. For example, the congestion that typically occurs from Minnesota to WUMS reversed directions in many periods in 2007 and the Minnesota Hub prices substantially exceeded price levels in adjacent areas.

One final noteworthy aspect of the patterns shown in these figures is price volatility. A comparison of Figure 16 and Figure 17 indicates more volatility in the peak-hour prices. In fact, daily hub price volatility was 77 percent higher during peak hours than off-peak hours in the day-ahead market.

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. The day-ahead market manages most of the energy settlements and generator commitments in the Midwest ISO region. Hence, good convergence of day-ahead and real-time prices 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 fully reflect expected real-time conditions. To evaluate price convergence, we calculate the difference between day-ahead and real-time prices. Figure 18 and Figure 19 show the average daily day-ahead to real-time price differences (day-ahead minus real-time prices) at the four Midwest ISO hubs.

Figure 18: Average Daily Day-Ahead and Real-Time Price Differences
Cinergy Hub and Michigan Hub

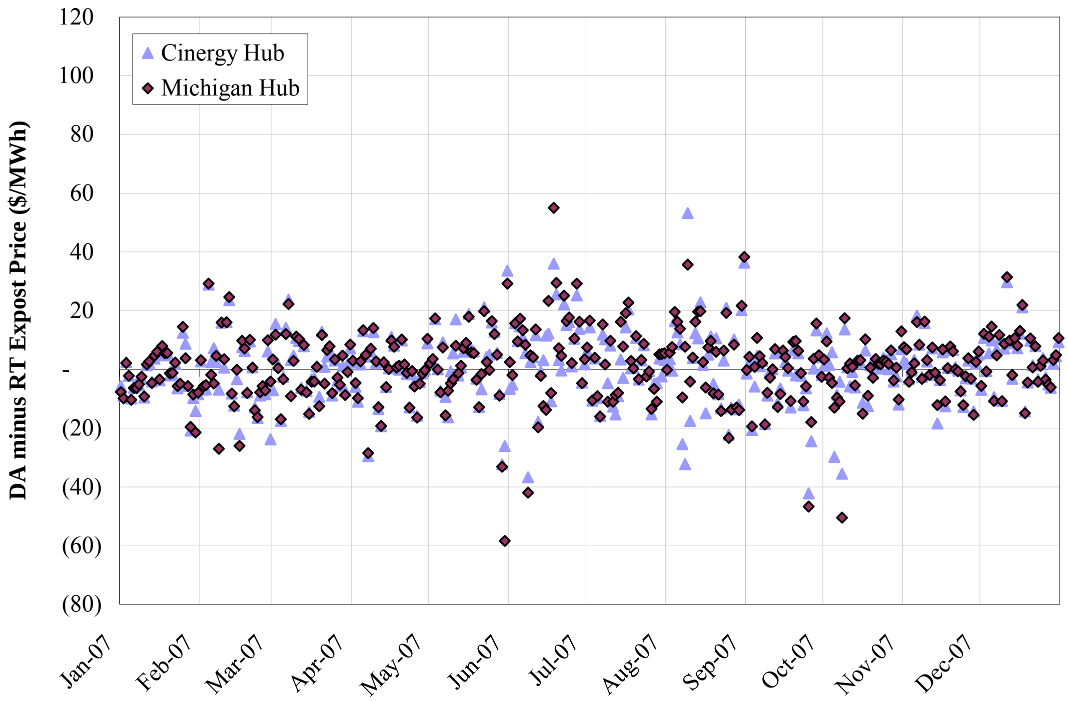
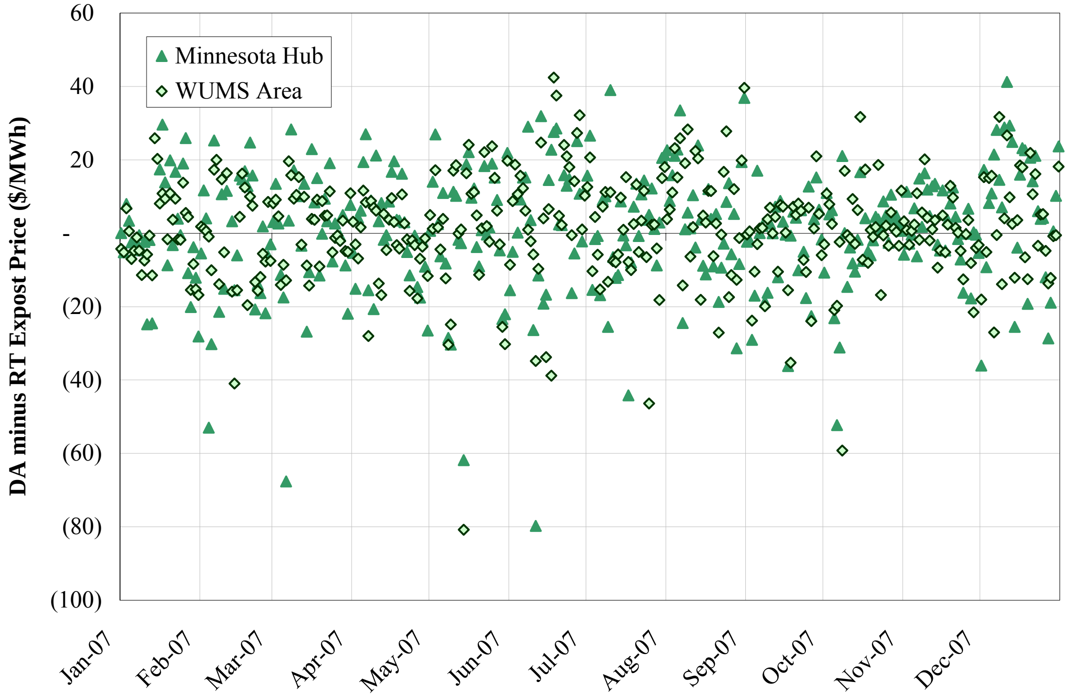


Figure 18 shows the results for the Cinergy and Michigan hubs. The average difference between the day-ahead and real-time prices is relatively small: $0.30 per MWh for the Cinergy Hub and $0.79 per MWh for the Michigan Hub. During the summer, when prices are the most volatile, these differences were larger. In July and August, the day-ahead premiums averaged $0.90 per MWh and $2.95 per MWh for the Cinergy and Michigan hubs, respectively.

Day-ahead premiums are rational because entities purchasing in the real-time market are subject to RSG uplift cost allocation. The expectation of RSG costs 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.

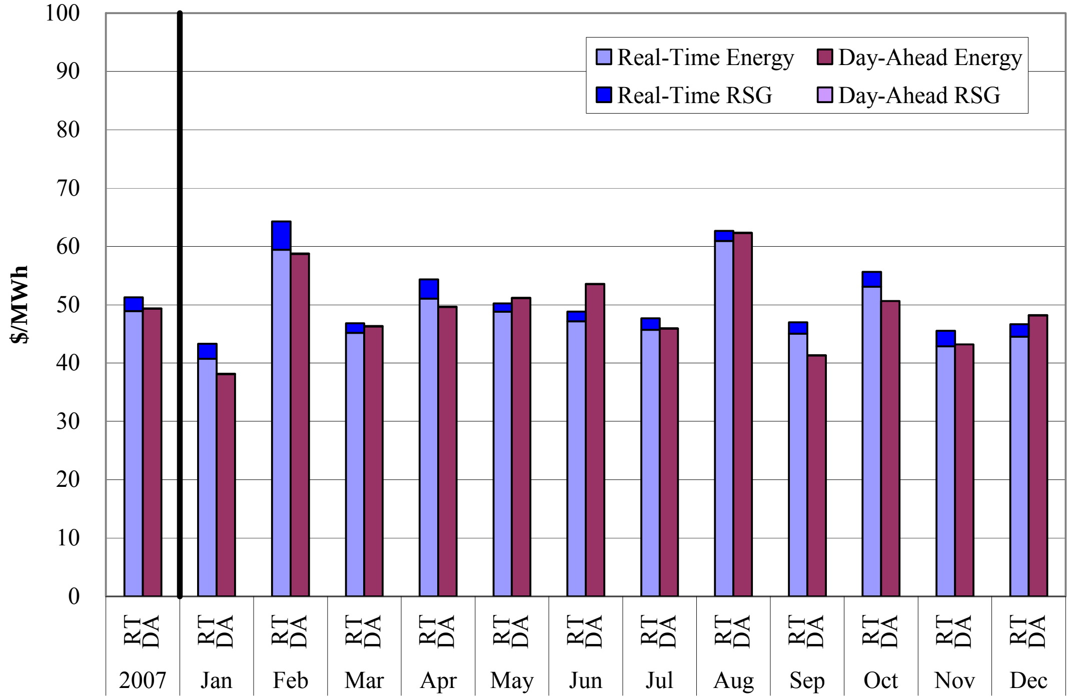
Figure 19: Average Daily Day-Ahead and Real-Time Price Differences
Minnesota Hub and WUMS Area



The more frequent congestion in Minnesota and WUMS results in higher price volatility in these areas. This volatility is evident in the figure and in the underlying statistics. For example, the standard deviation of the price differences was $11.55 at Cinergy, while the standard deviation of the price differences was $16.93 per MWh and $14.35 per MWh in Minnesota and WUMS, respectively. In addition, these two hubs have higher average price differences compared to the other hubs. The average price difference was $1.55 per MWh in Minnesota and $1.05 per MWh in WUMS (compared to $0.30 per MWh for the Cinergy Hub and $0.79 per MWh for the Michigan Hub). These average differences for the Minnesota and WUMS hub were very close to the average differences in 2006. Like the other locations, the differences were the largest during the summer when prices were most volatile.

Although day-ahead and real-time price differences can be relatively large on an hourly or daily basis, it is more informative 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, Figure 20 shows the average day-ahead and real-time prices on a monthly and annual basis at the Cinergy hub.

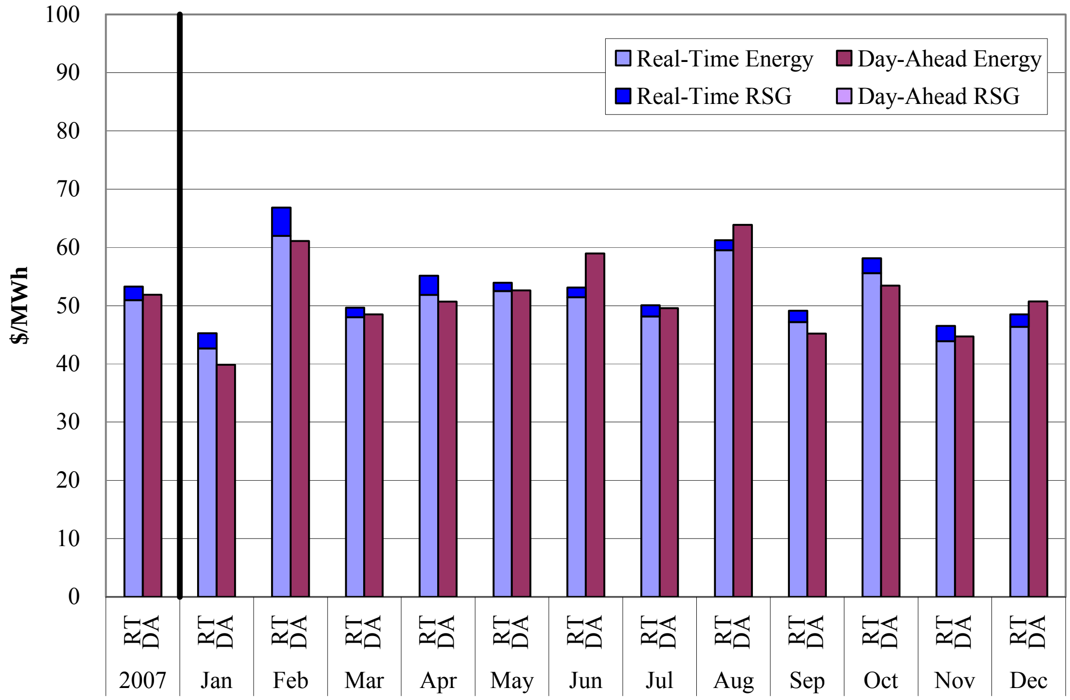
Figure 20: Day-Ahead and Real-Time Prices
Cinergy Hub



Cinergy hub is the most liquid trading point for forward contracting in the Midwest ISO region. Purchases in the real-time market are subject to costs associated with the allocation of real-time RSG (which is 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. To account for RSG, these figures show the average RSG allocations on top of the energy price in each market. The real-time RSG allocations (real-time RSG rate) are the RSG cost per MWh that would be allocated to a participant for each MWh purchased in the real-time market.

Although the average day-ahead prices were slightly higher than real-time prices, the total real-time price is slightly higher when RSG costs are included. The largest real-time premiums (including RSG costs) occurred in months with the largest RSG cost allocations. This indicates that the days with the largest RSG costs are difficult to foresee and, thus, are not fully reflected in the day-ahead prices. Figure 21 shows the same analysis for the Michigan hub.

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



The real-time prices at Michigan hub followed a similar monthly pattern to those at the Cinergy Hub. For 2007, the average day-ahead prices at the Michigan hub, including RSG payments, were $51.87 per MWh and day-ahead RSG costs averaged $0.05 per MWh. Real-time average prices at the Michigan hub were $50.91 per MWh and average real-time RSG costs were $2.55 per MWh.

The prior two figures showed the price convergence at two locations that experience limited levels of congestion. The next two figures show the convergence at the Minnesota and WUMS locations, which are more significantly affected by transmission congestion.

Figure 22 and Figure 23 show the convergence analyses for the Minnesota hub and WUMS region. Price convergence in these areas is more difficult to achieve because congestion causes the prices in these areas to be much more volatile than prices elsewhere in the Midwest ISO region.

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

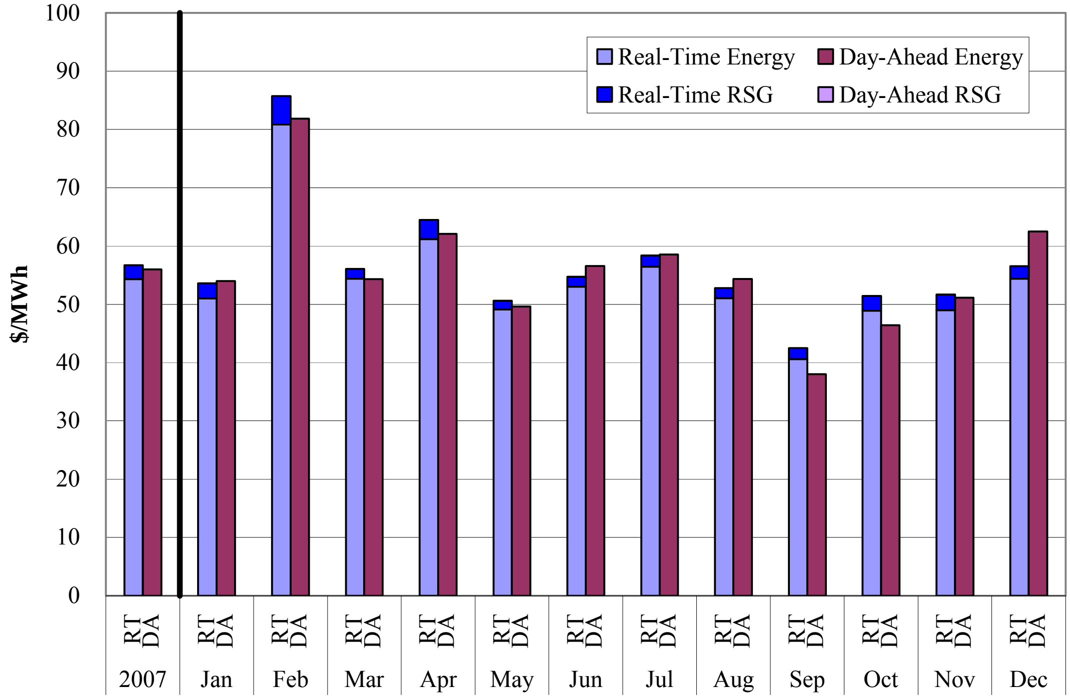
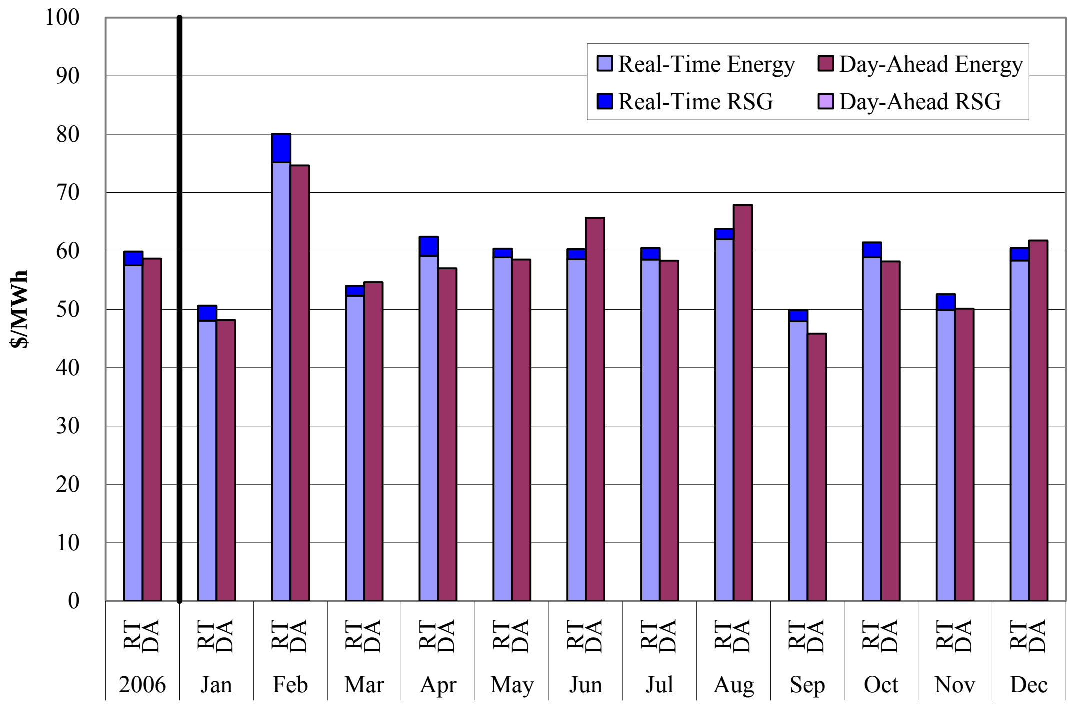


Figure 23: Day-Ahead and Real-Time Prices
WUMS



Although congestion at the Minnesota hub contributed to larger fluctuations in the monthly price differences, Figure 22 shows price convergence over the entire year was comparable to that at the Cinergy hub. This indicates that arbitrage has been effective over the longer-term, despite the increased short-term volatility of the prices at these locations.

Figure 23 shows that average prices in WUMS for the year in the day-ahead and real-time markets were relatively close in magnitude, with the day-ahead prices slightly exceeding the real-time prices prior to accounting for RSG costs. For the year, day-ahead prices averaged $58.71 per MWh in WUMS compared to real-time prices of $57.54 per MWh excluding RSG costs. Price differences were most variable in the summer months. Like the Minnesota Hub, price convergence in WUMS over the entire year was comparable to the convergence at the Cinergy and Michigan hubs. This pattern indicates relatively effective arbitrage.

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

Table 3: Price Convergence –Midwest ISO and Neighboring Markets in 2007

	Average Clearing Price			Average of Hourly
	Day-Ahead	Real-Time	Difference	Absolute Price Difference
Midwest RTO:				
Cinergy Hub	$46.07	$45.62	$0.38	$14.31
Michigan Hub	$48.47	$47.57	$0.84	$15.28
Minnesota Hub	$51.97	$50.24	$1.64	$20.50
WUMS Area	$54.75	$53.52	$1.17	$18.94
New England ISO:				
New England Hub	$67.97	$66.72	$1.25	$10.26
Maine	$64.35	$63.65	$0.69	$9.92
Connecticut	$71.70	$71.75	-$0.06	$12.93
New York ISO:				
Zone A (West)	$53.02	$52.35	$0.67	$15.66
Zone G (Hudson Valley)	$72.26	$72.54	-$0.27	$20.62
Zone J (New York City)	$77.21	$77.60	-$0.39	$22.58
PJM:				
AEP Gen Hub	$43.38	$44.15	-$0.76	$11.41
Chicago Hub	$45.40	$45.76	-$0.36	$11.84
New Jersey Hub	$63.45	$65.63	-$2.17	$18.45
Western Hub	$56.91	$59.77	-$2.85	$17.02

The table shows various statistics, including the average day-ahead and real-time prices from 2007, the difference in the annual average day-ahead and real-time prices, and the average of the hourly absolute value of the day-ahead and real-time price difference (which shows the typical difference regardless of the sign). For each market, we show these pricing statistics for several locations (representing prices in constrained and unconstrained areas in each market).

The comparison of the average prices in the table shows the day-ahead markets exhibit a price premium at most locations, with the exception of PJM and some locations in NYISO. These premiums are consistent with the higher volatility, risk, and supplemental commitment costs (like RSG costs) associated with purchasing in the real-time market.

The comparison of the average absolute value of the differences shows that with the exception of PJM, the locations affected by congestion exhibited larger average differences, ranging from $18 to $22 per MWh, which is consistent with the higher volatility in these areas. In the Real-Time Market Performance section below, we discuss some reasons for differences in pricing patterns between markets.

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.

3. Day-Ahead Load Scheduling and Virtual trading

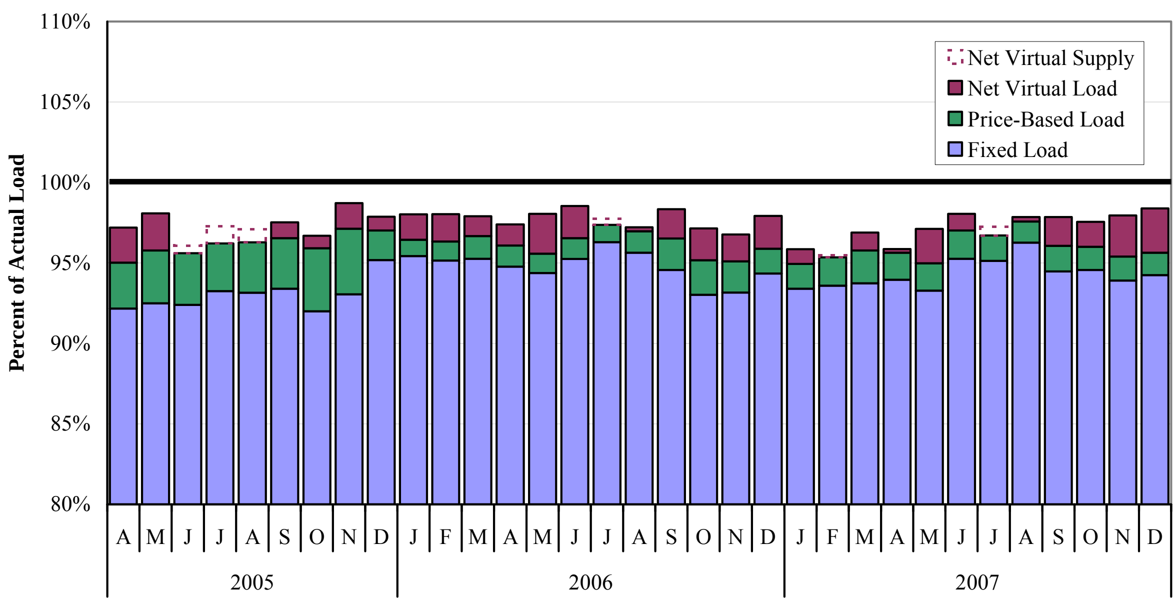
Our next analysis addresses day-ahead load scheduling and virtual trading. These aspects of the market play an important role in overall market efficiency by promoting efficient commitment and improved price convergence between day-ahead and real time markets, with the benefits discussed above.

We are generally interested in comparing the net load cleared in the day-ahead market as a percentage of the actual real-time load. This relationship affects commitment patterns and RSG. When day-ahead net load is significantly less than 100 percent of the 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. Participants will have incentives to schedule net load at less than 100 percent when significant quantities of generation are committed by participants or by the ISO after the day-ahead market (because this will tend to reduce real-time prices). In addition, high-cost units (such as peaking resources) do not set prices when dispatched in the real-time market, which reduces the incentive to schedule fully day ahead.

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 is a comparison of the monthly average day-ahead scheduled load and the monthly average actual load, showing the various components of the day-ahead schedules.

Figure 24: Day-Ahead Load Scheduling versus Actual Load

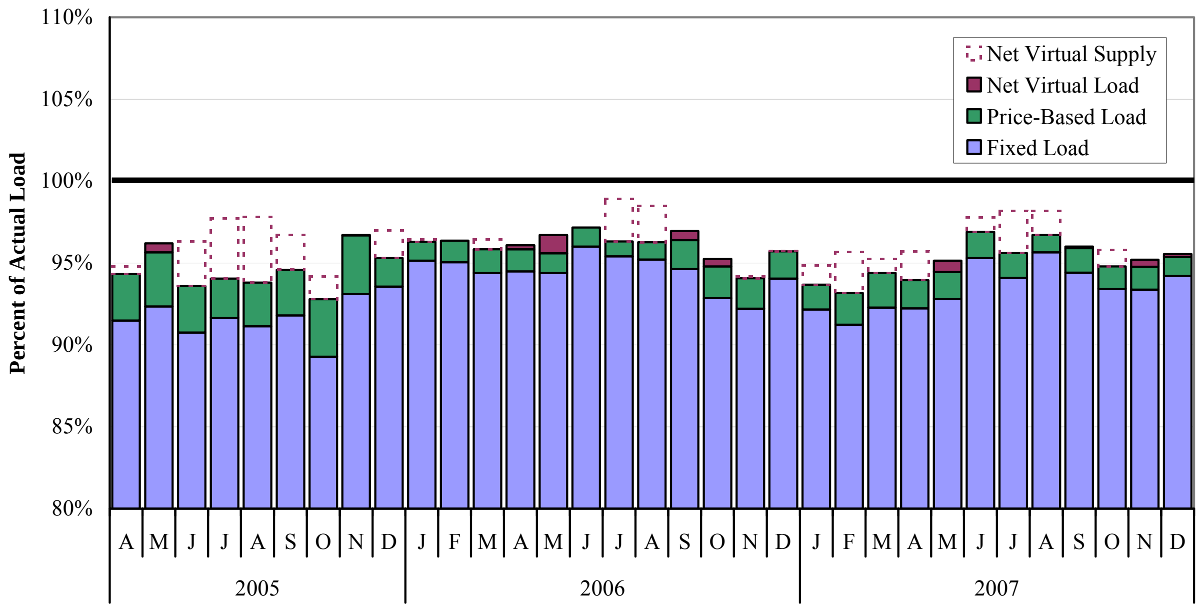


The figure shows that the vast majority of load scheduled in the day-ahead market is fixed, i.e., will be purchased at any price. Price-sensitive physical load accounts for less than two percent of total load scheduled market-wide and is highest in WUMS at eight percent. Virtual bids and offers increased throughout 2007 and play an important role in arbitraging day-ahead and real-time prices.

The net load (total load net of virtual supply) scheduled in the day-ahead market as a percent of the real-time load declined slightly from 2006. In particular, 97.1 percent of the actual load was scheduled on net in 2007 in all hours, down slightly from 97.7 percent in 2006. This slight reduction may reflect the fact that the Midwest ISO committed more supply after the Day-Ahead market in 2007 to manage congestion.

Figure 25 shows the comparison of day-ahead to actual load for peak hour of each month.

Figure 25: Peak Hour Day-Ahead Scheduled Load versus Actual Load

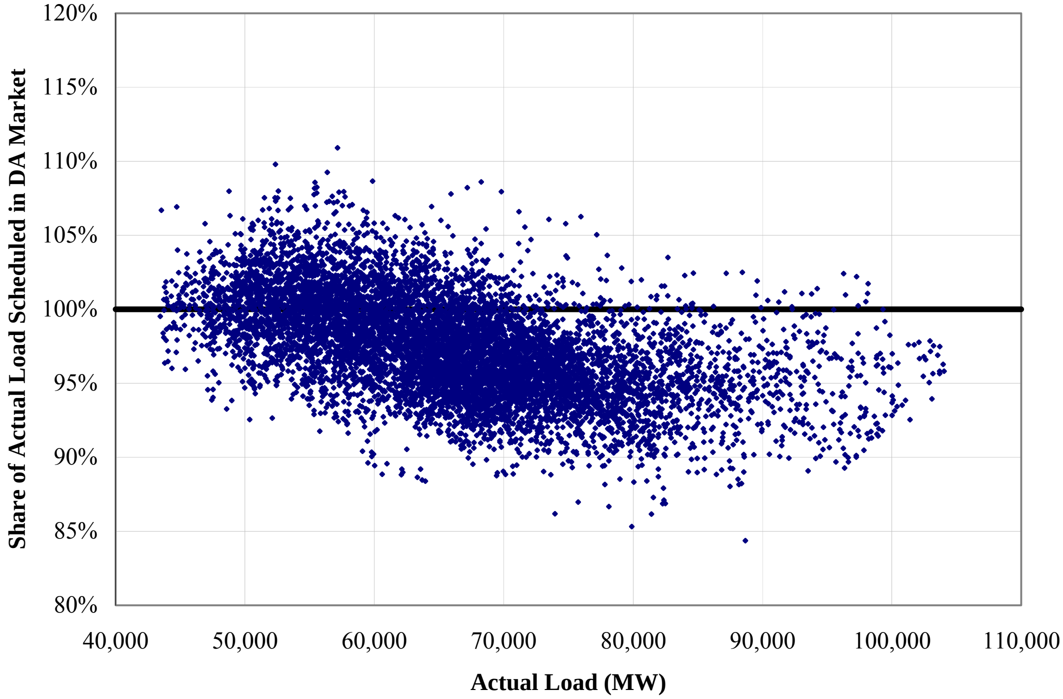


The figure shows that in the peak hour of each day (which is the hour that is most likely to require Midwest ISO to commit additional generation), 95.1 percent of the actual load was scheduled on net in the day-ahead market versus 96.1 percent in 2006 and 94.5 percent in 2005.

Much of the decrease from 2006 to 2007 was due to low scheduling levels in February (93.2 percent), which exhibited the highest RSG costs of the year. With the exception of February, higher scheduling levels since 2005 have reduced the Midwest ISO's reliance on peaking resources in the real-time, which led to the lower RSG costs in 2006 and 2007.

Figure 26 shows the percentage of real-time load scheduled in the day-ahead market relative to the actual real-time load on an hourly basis.

Figure 26: Net Load Scheduled Day-Ahead vs. Real-Time Load

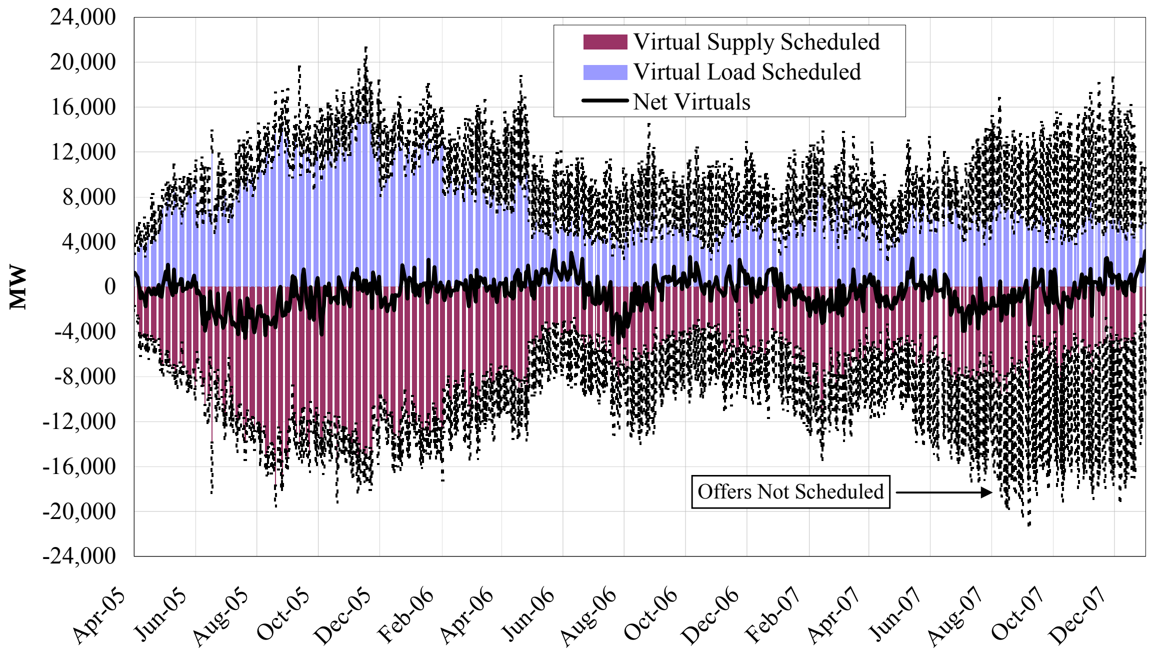


The figure indicates that the percentage of load scheduled generally decreased as the load increased in 2007. This pattern is likely caused, in part, by the increased reliance on peaking resources in the highest-load periods. Such resources set prices when they are needed in the day-ahead market. However, they frequently do not set prices in the real-time market due to their inherent operational inflexibility. This creates economic incentives for participants to reduce their net scheduled load in the day-ahead market. We are working with the Midwest ISO to develop pricing provisions that will correct these incentives by allowing peaking resources to set prices more frequently when they are economic in the real time.

Virtual trading in the day-ahead market are 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 a MW of power for $50 in the day-ahead market, the seller must then purchase a 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 means of arbitraging the prices in the two markets, and it causes day-ahead prices to converge with real-time prices. The price convergence resulting from this arbitrage increases efficiency in the day-ahead market.

Figure 27 shows the components of daily virtual bids and offers and the net virtual load (cleared virtual load less virtual supply) for the peak hours of each day from April 2005 through December 2007. 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.

Figure 27: Virtual Load and Supply in the Day-Ahead Market
2005 – 2007: Peak Hours



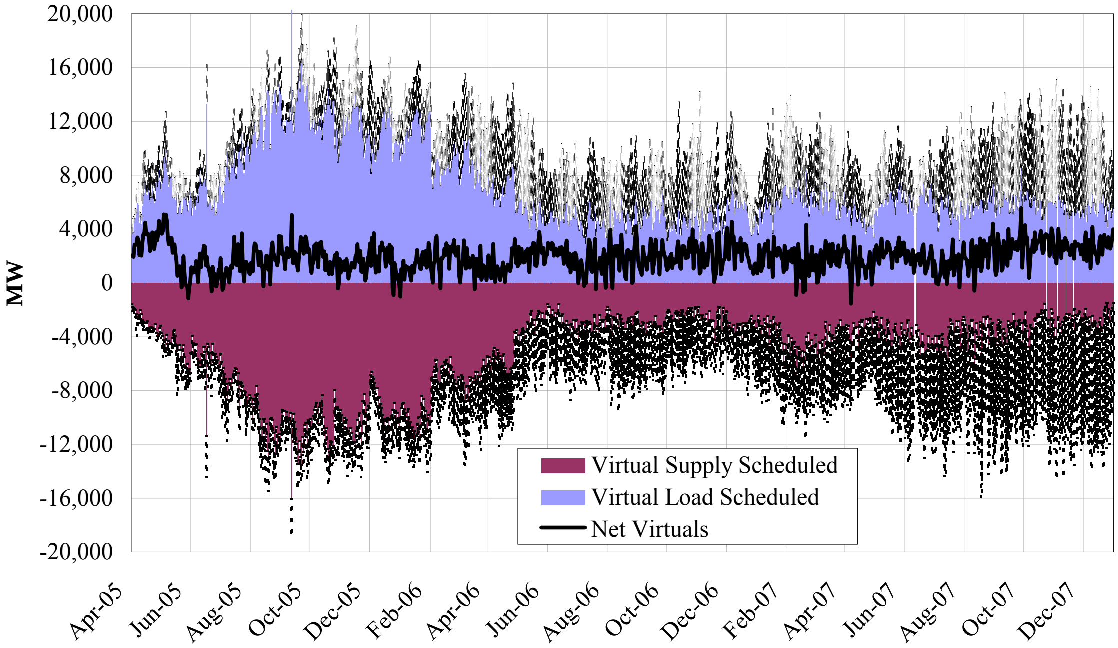
After virtual trading volumes grew rapidly in 2005, the Commission issued an Order in April 2006 requiring the allocation of RSG costs to virtual supply. Although the Commission order should have only affected virtual supply costs, both virtual supply and demand quantities initially decreased. The total and cleared virtual bids and offers declined by roughly 50 percent between April and the end of 2006.

While cleared quantities in 2007 have not changed significantly from 2006 levels, virtual offers have increased substantially. The reduced volume of virtual trades that prevailed after April

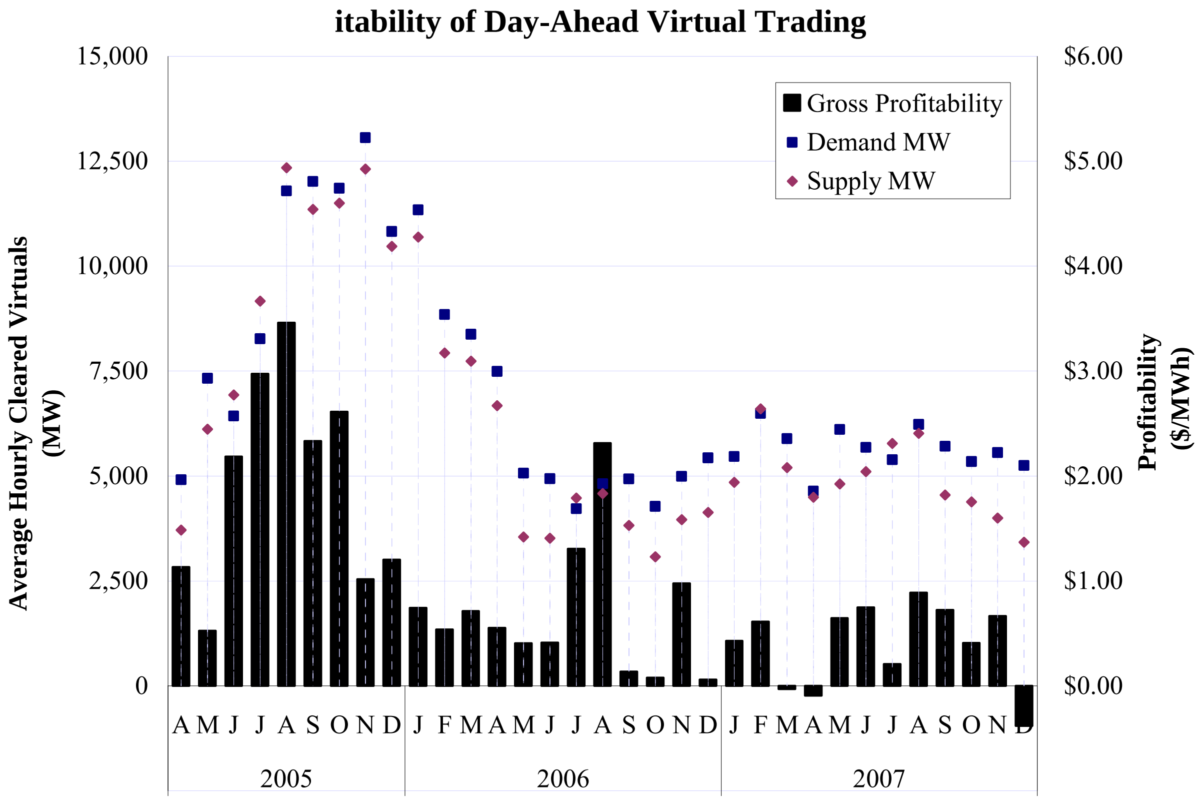
2006 has not undermined the convergence of prices between the day-ahead and real-time markets.

Figure 28 shows the same analysis, but for off-peak hours instead of peak hours. The off-peak volumes show a similar increase through the first nine months of Day 2 operations, followed by a precipitous decline beginning in the spring of 2006.

Figure 28: Virtual Load and Supply in the Day-Ahead Market
2005 - 2007: Off-Peak Hours



We described above how virtual trading increase the efficiency of the market. One can evaluate the liquidity of the market by analyzing the profitability of the virtual trading. In a market that is fully arbitraged, profits available to the virtual traders are very low. **Error! Reference source not found.** shows monthly average gross profitability of virtual purchases and sales, as well as the volume of virtual supply and demand that cleared the market.

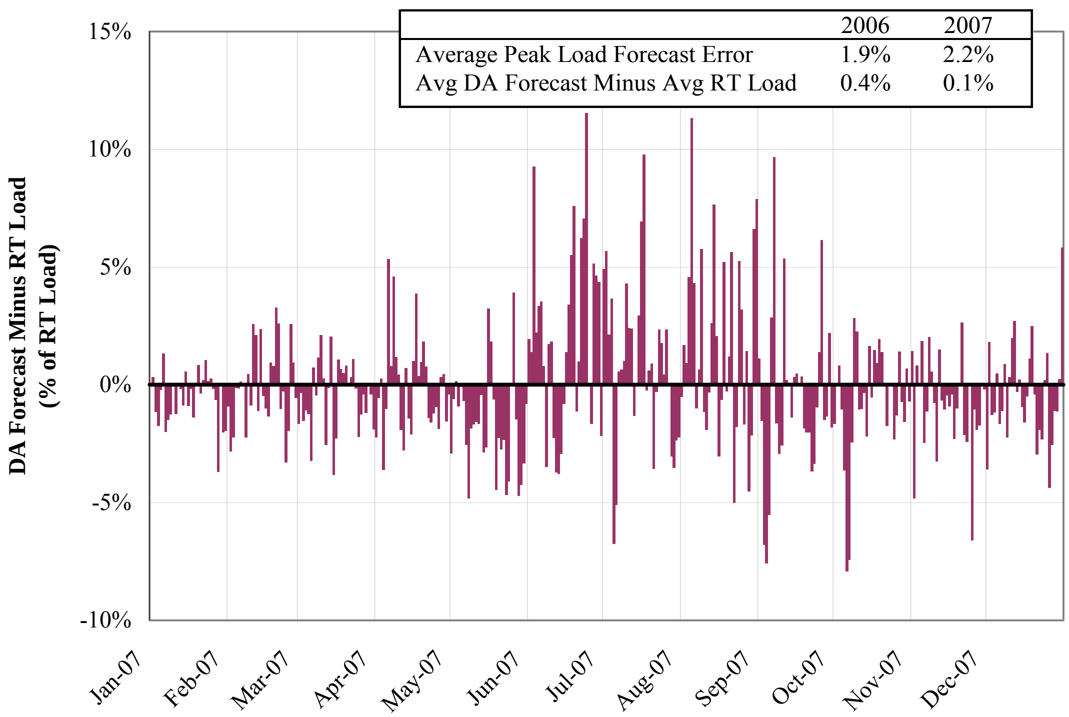


The figure shows that as the Day 2 markets have matured, the profitability of virtual transactions has declined. For virtual transactions, the average gross profit per cleared MWh decreased slightly from $0.69 per MWh in 2006 to $0.43 per MWh in 2007. However, after RSG allocations are deducted, the average net profit was negative during 2007. 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 foreseeable that the virtual transaction would be unprofitable, the participant could earn net profits if it increases its FTR payments or the value of a financial position. Virtual losses that warrant further investigation have been rare, and none have warranted a referral to the Commission.

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 ("RAC") 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 for 2007.

Figure 29: Daily Day-Ahead Forecast Error in Peak Hour
2007



The day-ahead forecast exceeded the average real-time peak load by 0.01 percent in 2007. This indicates that the forecasting was relatively accurate. The average peak-load forecast error was 2.2 percent (forecast error is the magnitude of the error, regardless of direction). This is slightly higher than the 1.9 percent forecast error in 2006. These results are comparable to the performance of other RTOs. Consistent with the results in the prior two years, the figure shows that the load tended to be over-forecasted in the summer and under-forecasted in the fall. However, the magnitude of these seasonal tendencies has declined.

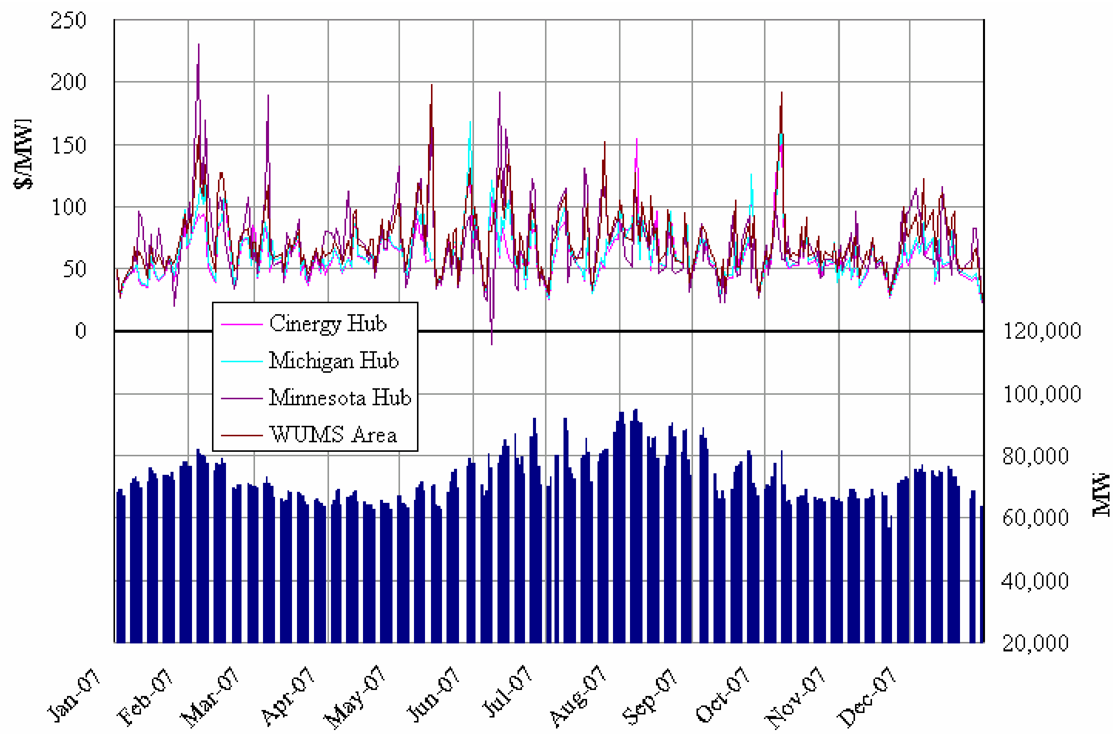
B. Real-Time Market Outcomes

In this subsection, we evaluate real-time market outcomes. The real-time market is important because its results are the primary driver in subsequent day-ahead and forward electricity markets. Energy purchased in the day-ahead market or other forward markets is a substitute for energy purchased 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 encouraging more risk-averse scheduling 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, shown in Figure 30.

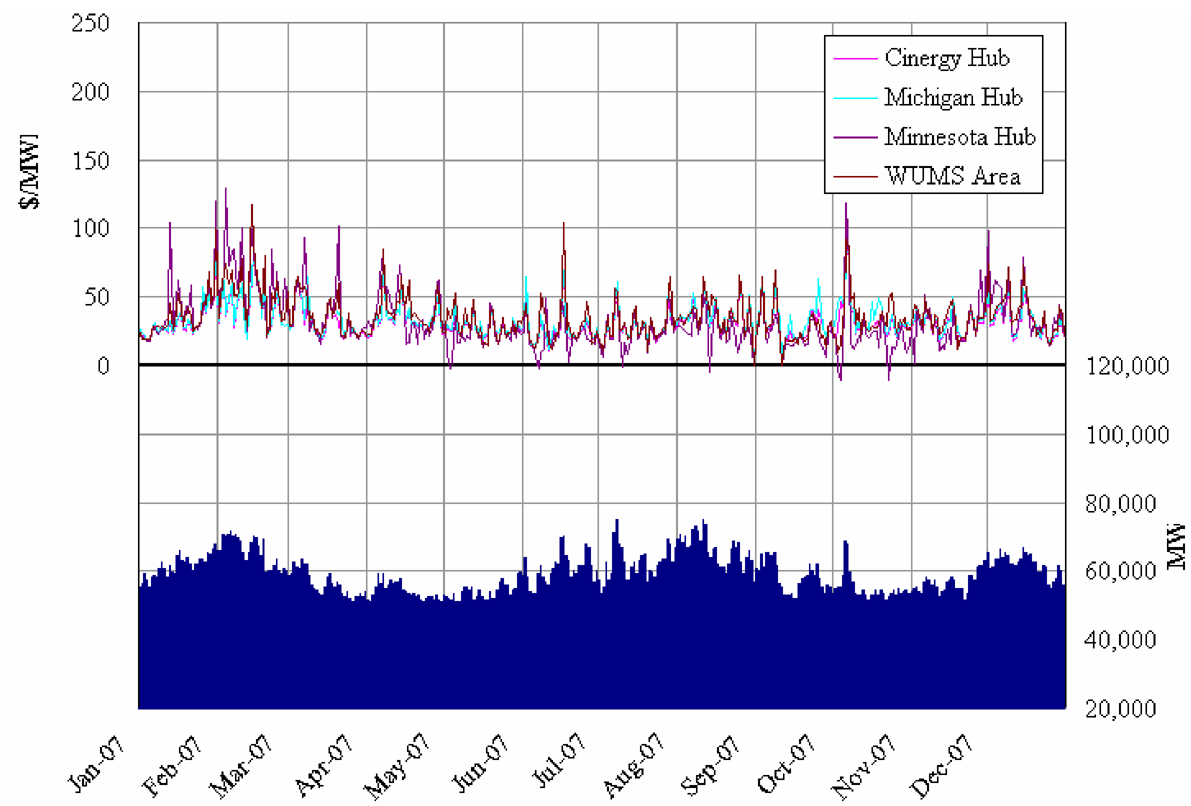
Figure 30: Real-Time Hub Prices and Load
Peak Hours



The figure 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 Minnesota, resulting in substantial price divergence from other regions. In the first half of the year, the average price in WUMS and Minnesota exceeded $75 per MWh, over $13 per MWh higher than the average prices at the Cinergy hub. Prices declined in the second half of 2007. Average peak prices at Minnesota Hub between July and December decreased over $8 per MWh from the first half of 2007. This decline can be attributed to increased imports over the Manitoba interface during the second half of the year. See Section VII that analyzes external transactions in detail.

WUMS region prices also fell during the second half of 2007 by $1.40 per MWh. This decrease would have been larger, but generator forced outages increased congestion later in the year. Local price volatility in the real-time market is due, in part, to reduced bid flexibility and ramp limits that tend to exacerbate congestion in the real-time market. This is particularly true during ramp-up and ramp-down periods when the system has less ability to ramp in general because generators are already moving to satisfy load. Ramp constraints can cause high-cost units to set prices for transitory periods when lower-cost units are ramping as quickly as possible. Figure 31 shows the same analysis for the off-peak hours.

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

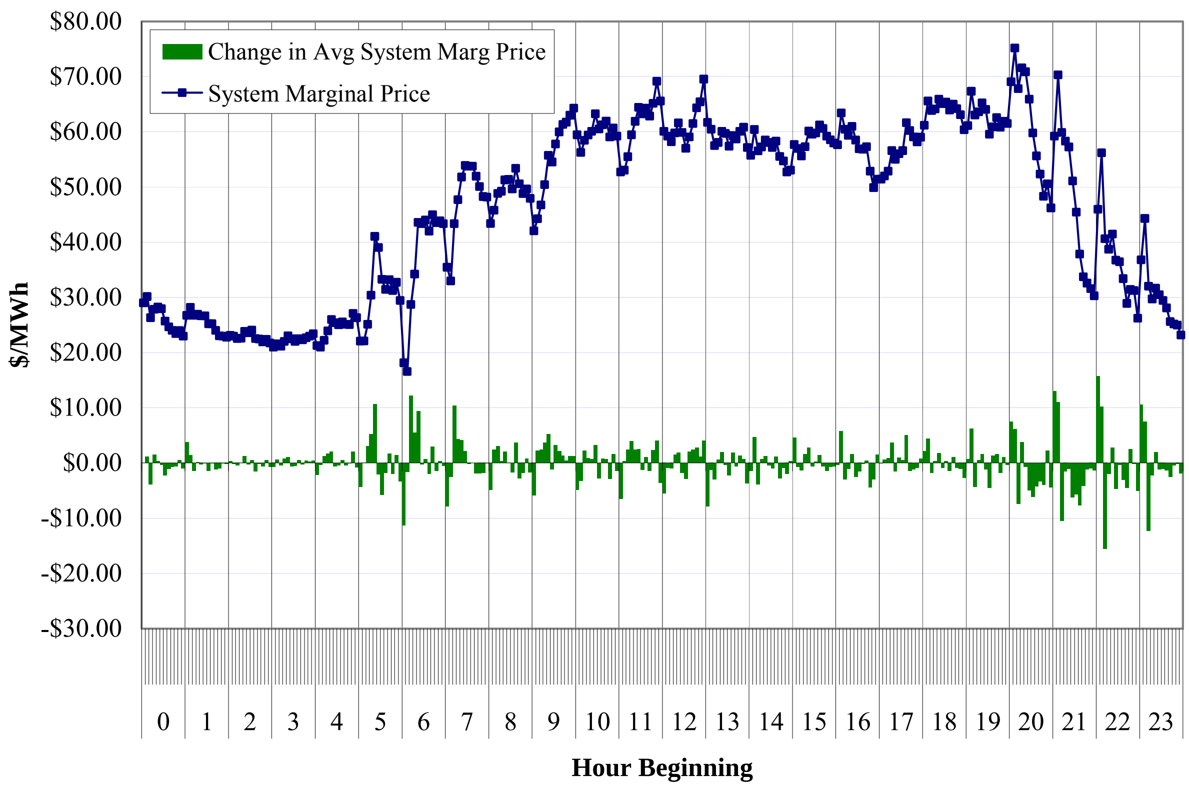


The figure shows that load and prices are relatively low and less volatile in these hours as expected. Prices are usually set by coal-fired resources in off-peak hours. Higher prices in late-January, February and early-December were due to high-load conditions causing natural gas-fired resources to set prices in many hours. Given the climate in the northern portions of the Midwest ISO region, the load can be relatively high during the winter nights.

There were several negative price spikes at the Minnesota Hub due to congestion from Minnesota into WUMS. These negative events were less frequent and less severe than those in early 2006. The congestion in 2006 was exacerbated by reduced bid flexibility and ramp limits, both of which can make congestion more difficult to manage.

Our next analysis examines price volatility in the Midwest ISO energy markets. Figure 32 presents the average system marginal price during each of the 288 daily five-minute intervals.

Figure 32: Average Five-Minute Prices by Time of Day



The figure shows volatility in the five-minute prices increases substantially at the beginning of the ramp-up hours in the morning (5 AM) and at the beginning of ramp-down hours in the evening (8 PM -- hour ending 20). The sharp price movements that cause these patterns are generally the result of binding ramp constraints. Ramp constraints are limits in 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.

To better understand the causes of the price fluctuations at certain times of day, we next evaluate these price patterns by season, together with some potential causes. Figure 33 shows average real-time prices by time of day in winter months of 2007. Figure 34 shows the same results for summer 2007. To identify the drivers of the price fluctuations, the figure shows the effective headroom on the system (the amount of additional energy that can be produced in the next five minutes given ramp limitations) and the average change in Net System Interchange.

Figure 33: Real-time Prices and Headroom by Time of Day
Winter 2007

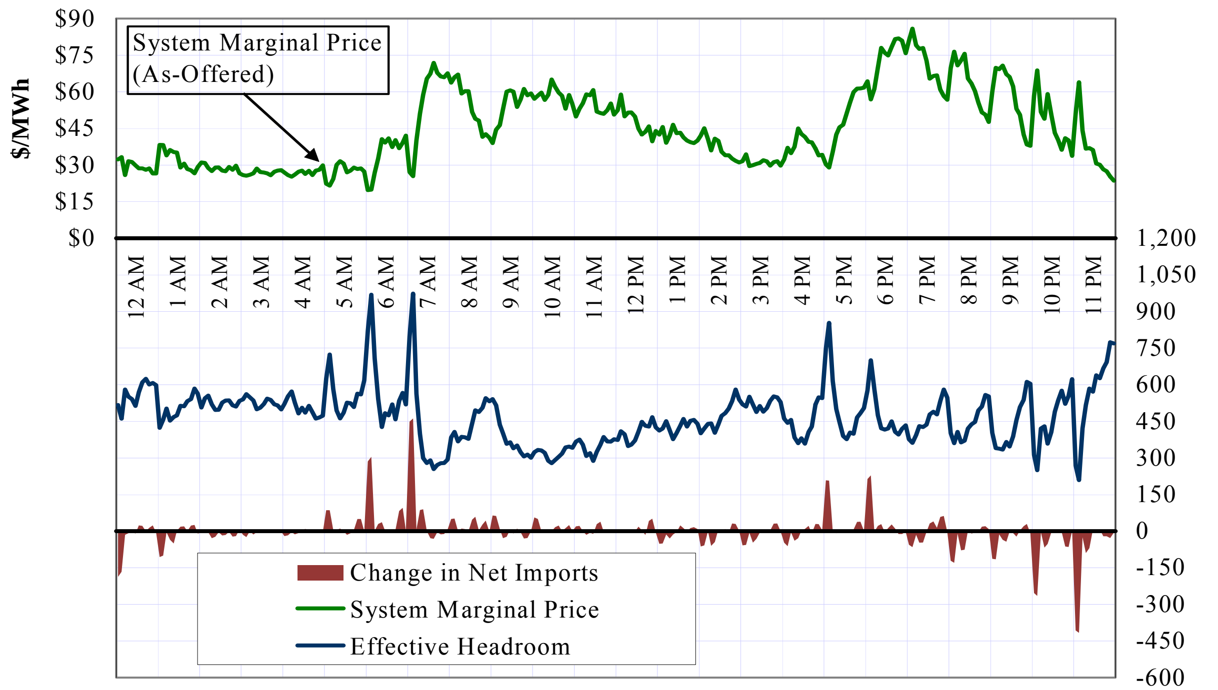
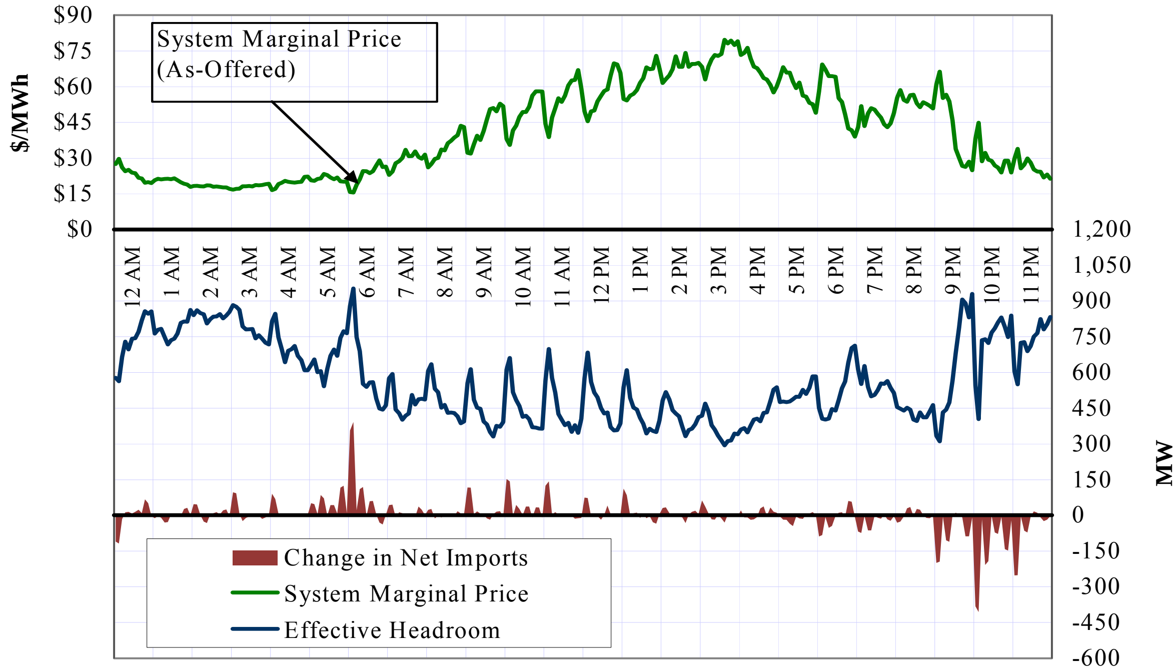


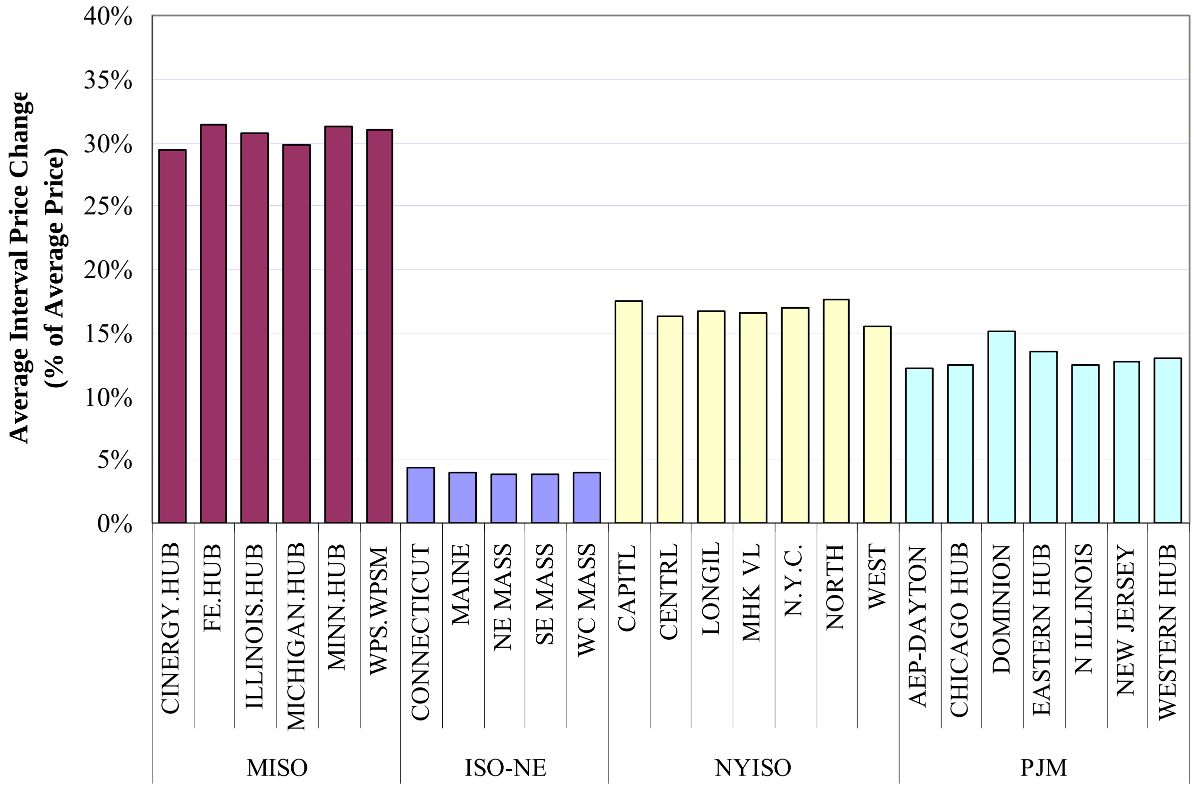
Figure 34: Real-time Prices and Headroom by Time of Day
Summer 2007



These figures show that prices fluctuate the most when load is ramping up or down near the peak-load hours (afternoon in the summer, and dual peaks in morning and evening in the winter). We also observe that the changes in real time prices are directly related to changes in effective headroom. The relationship of prices to headroom is expected because low levels of effective headroom typically cause the market to turn to relatively high-cost energy. The figure also indicates that a substantial portion of the changes in effective headroom are related to changes in NSI that are largest at the top of the hour. Substantial changes in effective headroom also occur when large quantities of generators start-up or shutdown at the same time. These effects are largest late in the day when generators are shutting down. We provide some recommendations later in this section that should 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 35 shows the average percentage change in real-time prices between five-minute intervals for several hubs in neighboring markets.

Figure 35: Five-Minute Real-Time Price Volatility
Comparison with Neighboring Markets



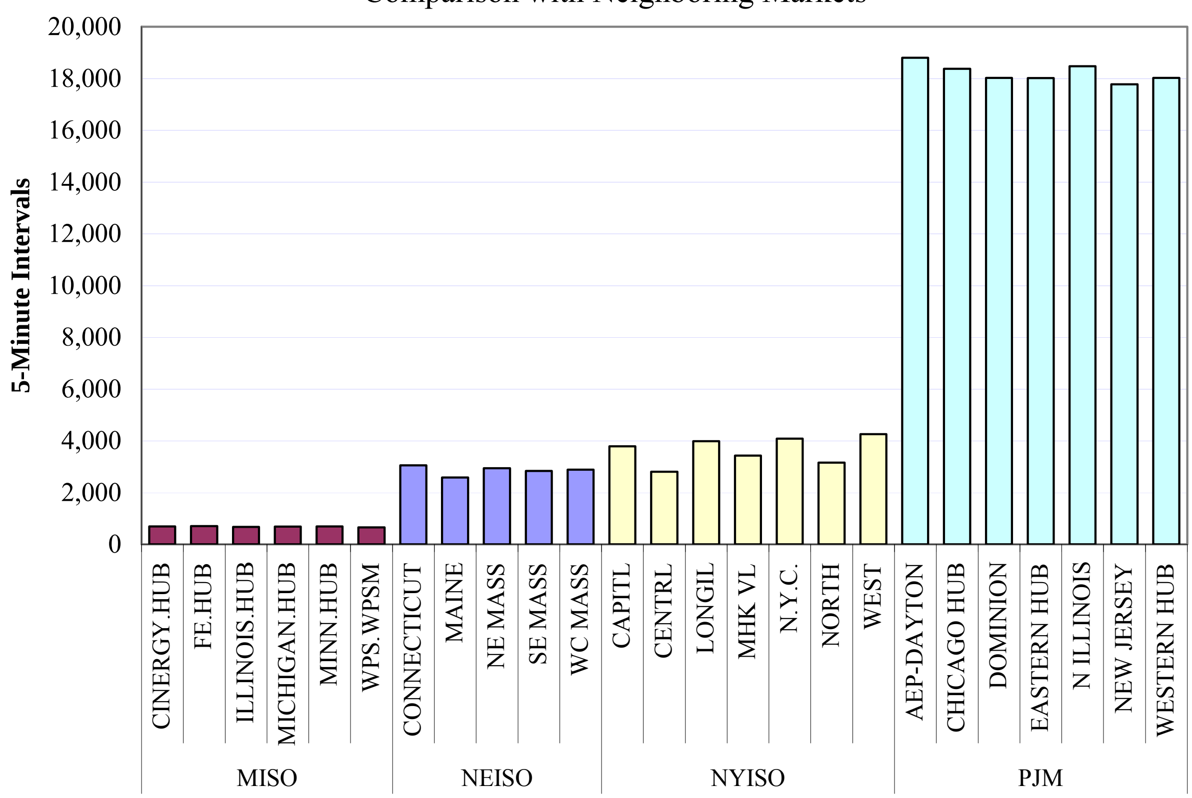
The results indicate that the Midwest ISO exhibits the most price volatility and ISO-New England ("ISO-NE") exhibits the least. These differences can be explained by the differences in the software and operations of the different markets. Midwest ISO and NYISO are true five-minute markets with a new dispatch and prices set each five minutes. Ramp constraints are more likely in these markets due to the shorter timeframes for moving the systems' generation. However, the 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.

We understand that PJM and ISO-New England 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 service to satisfy intra-interval changes in load and supply.

One final factor that may contribute to price volatility is the frequency with which 5-minute prices are approved and published. To evaluate this factor, one can measure how often real-time prices change from one interval to the next. If a price changes from one interval to the next, this suggests the pricing software is producing prices based on changes in underlying market conditions. If prices do not change from one interval to the next, this suggests that the pricing software is not running or the results are not being posted by the ISO. The Midwest ISO runs its real-time dispatch model and calculates 5-minute prices with its ex post price calculator every 5 minutes. Some of the other RTOs run their real-time dispatch model less frequently, but still calculate prices each 5 minutes. In general, a system that is redispatched more frequently will produce prices that more accurately reflect real-time conditions, although they will also likely be more volatile.

Figure 36 shows how frequently five-minute prices remain fixed in Midwest ISO and other RTO markets in the eastern interconnect.

Figure 36: Frequency of Unchanged Five-Minute Market Solutions
Comparison with Neighboring Markets



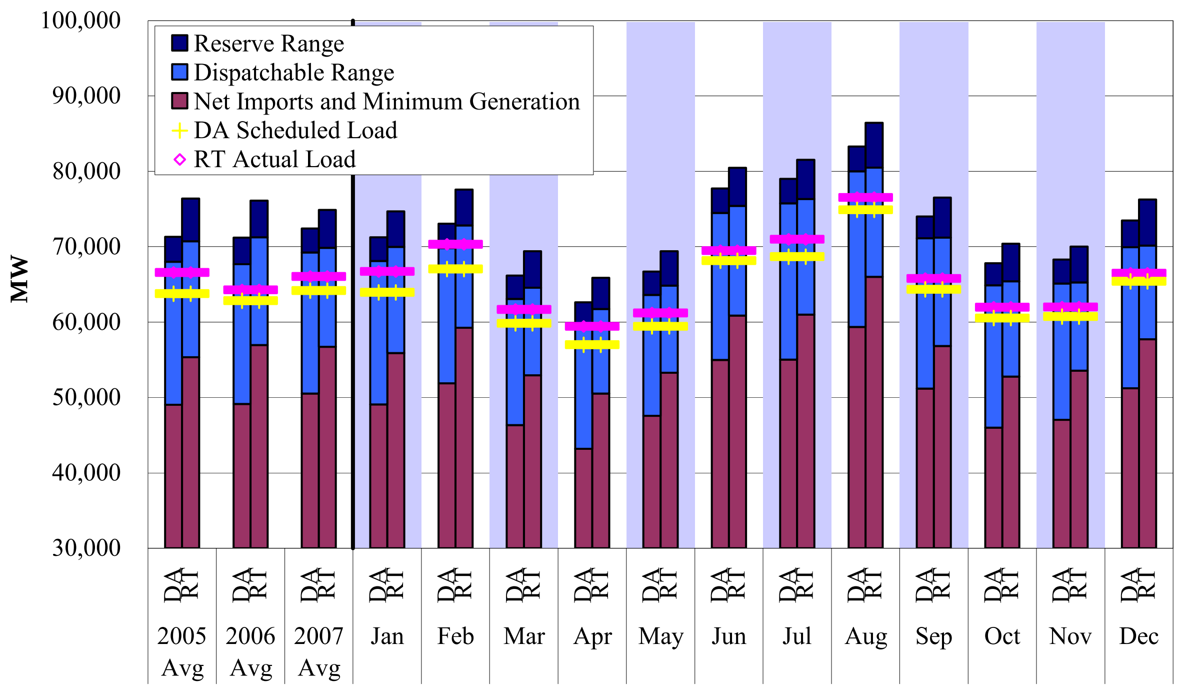
PJM has the most frequent instances of prices not changing from interval to interval. This occurred in 18,000 intervals during 2007. This is roughly 17 percent of the intervals, which is surprising and should be examined. The Midwest ISO solved its market in over 99 percent of intervals during 2007, which helps explain why its prices tend to be more volatile.

2. Availability of Generation in Real Time

The availability of generation in the real-time market is important because it is the basis of the Midwest ISO's ability to redispatch supply to manage transmission constraints, while satisfying all energy and operating reserves requirements of the system. In general, the day-ahead market coordinates commitment of most generation that will be dispatched in real time. Figure 37 details the average monthly generation scheduled in the day-ahead and real-time markets.

Figure 37: Day-Ahead and Real-Time Generation

2007: All Hours



The figure shows that generation capability is generally 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. Additionally, the Midwest ISO may commit generation to manage congestion or satisfy local reliability needs of the system.

Ninety-seven percent of generation dispatched in real-time is scheduled in the day-ahead market. The figure also shows that dispatch flexibility is lost in the real-time market. The dispatchable range (EcoMax minus EcoMin) as a percentage of total online capacity declines from 29 percent in the day-ahead market to 20 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 dispatchable range of 50 to 60 percent. This loss in flexibility can affect the market by limiting redispatch options for managing congestion.

C. Revenue Sufficiency Guarantee Payments

Revenue Sufficiency Guarantee 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 their 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 "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 very little RSG – 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 on the margin (i.e., the highest-cost resource) and receive very little margin to cover their start-up 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 38 and Figure 39 shows monthly RSG payments in the day-ahead and real-time markets, respectively. The data is divided between peaking units and others.

Figure 38: Total Day-Ahead RSG Distribution
2005 – 2007

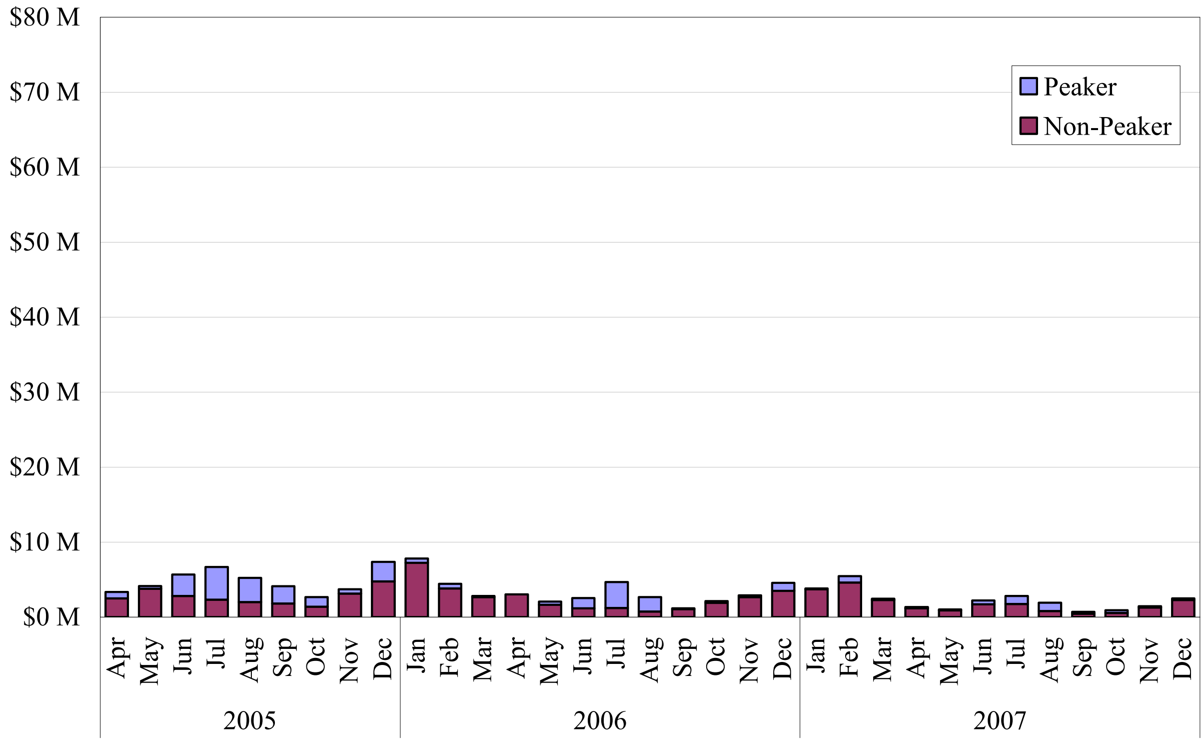
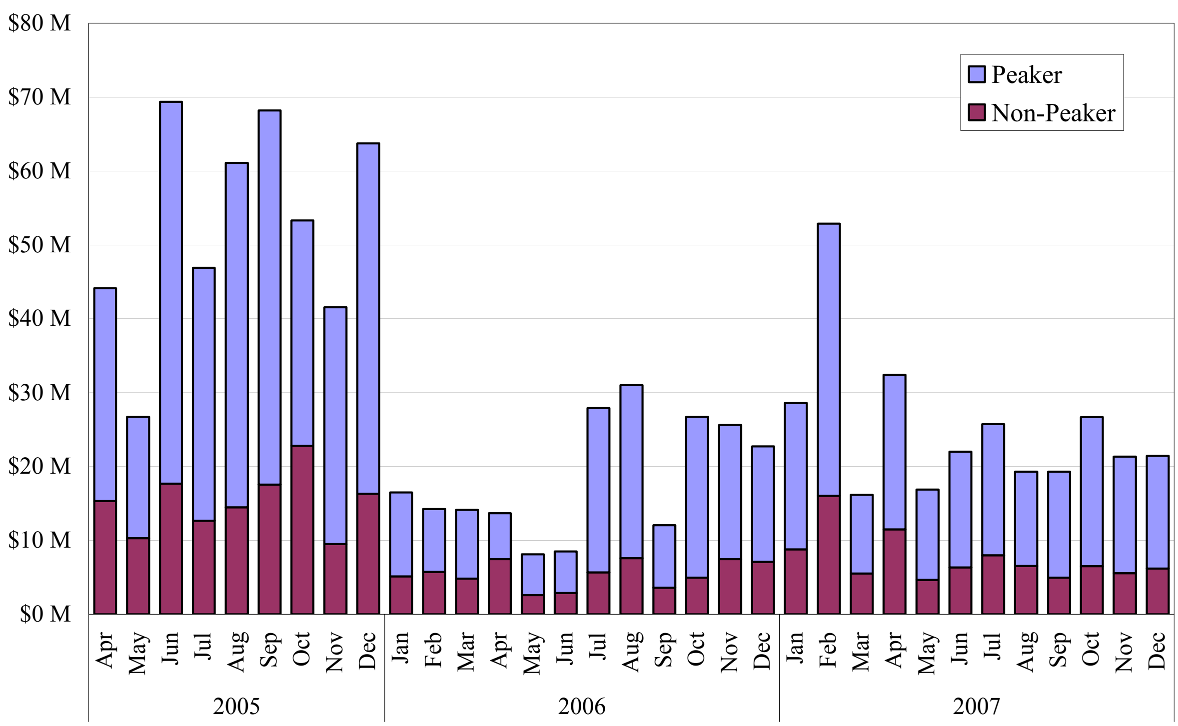


Figure 39: Total Real-Time RSG Distribution
2005 – 2007

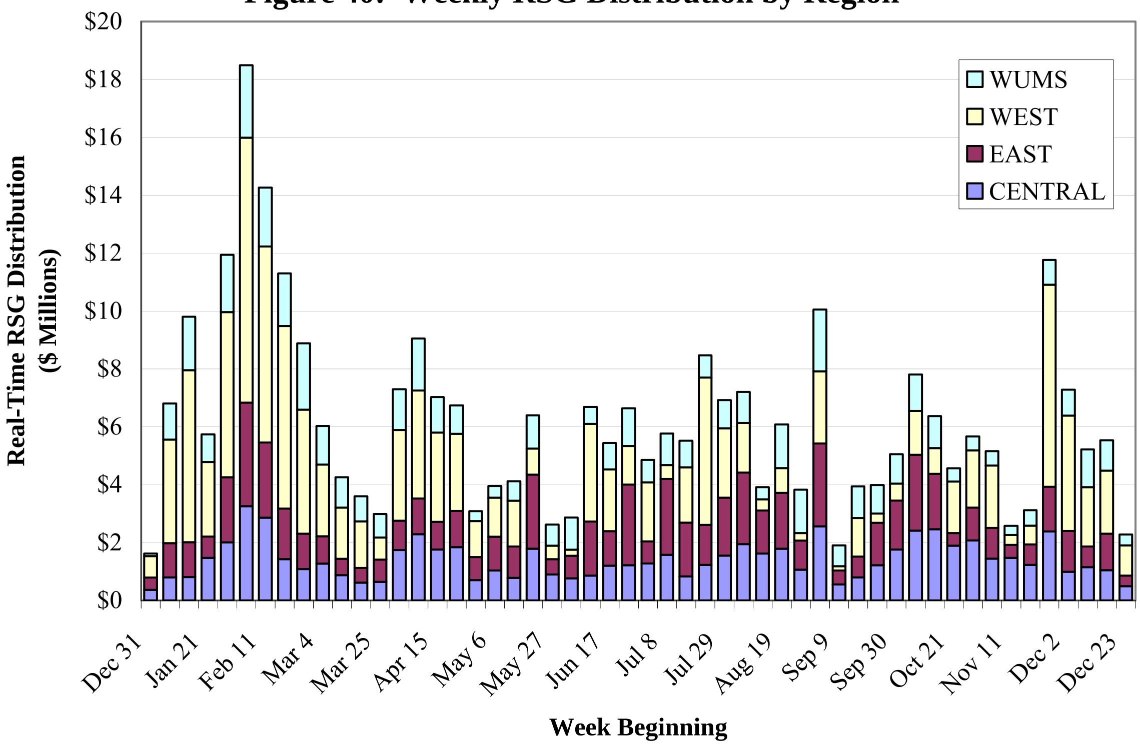


The figures show that the vast majority of RSG costs are generated in the real-time market and are paid to peaking resources. RSG payments to peaking resources accounted for 70 percent of RSG payments in 2007, although they produced less than 1 percent of the energy generated in the Midwest ISO. This is expected because peaking resources are generally the highest-cost resources and must be relied on in real time to meet the reliability needs of the system.

Real-time RSG costs increased from $18.4 million per month in 2006 to $25.2 million per month in 2007. This was due to higher congestion during the first six months of 2007. Peaking resources were committed more frequently in the West to manage congestion caused, in part, by lower imports over the Manitoba interface. Day-ahead RSG payments declined by an average $1.2 million per month during 2007 to $2.2 million per month. RSG in the day-ahead market continues to be a small percentage (8.1 percent) of total uplift costs to the market as expected. In total, RSG cost from both markets increased by more than $67 million.

To examine where the peaking resources are needed, Figure 40 shows regional RSG payments data on a weekly basis by region. Showing the RSG payments on a weekly, regional basis allows one to discern how congestion affected RSG costs.

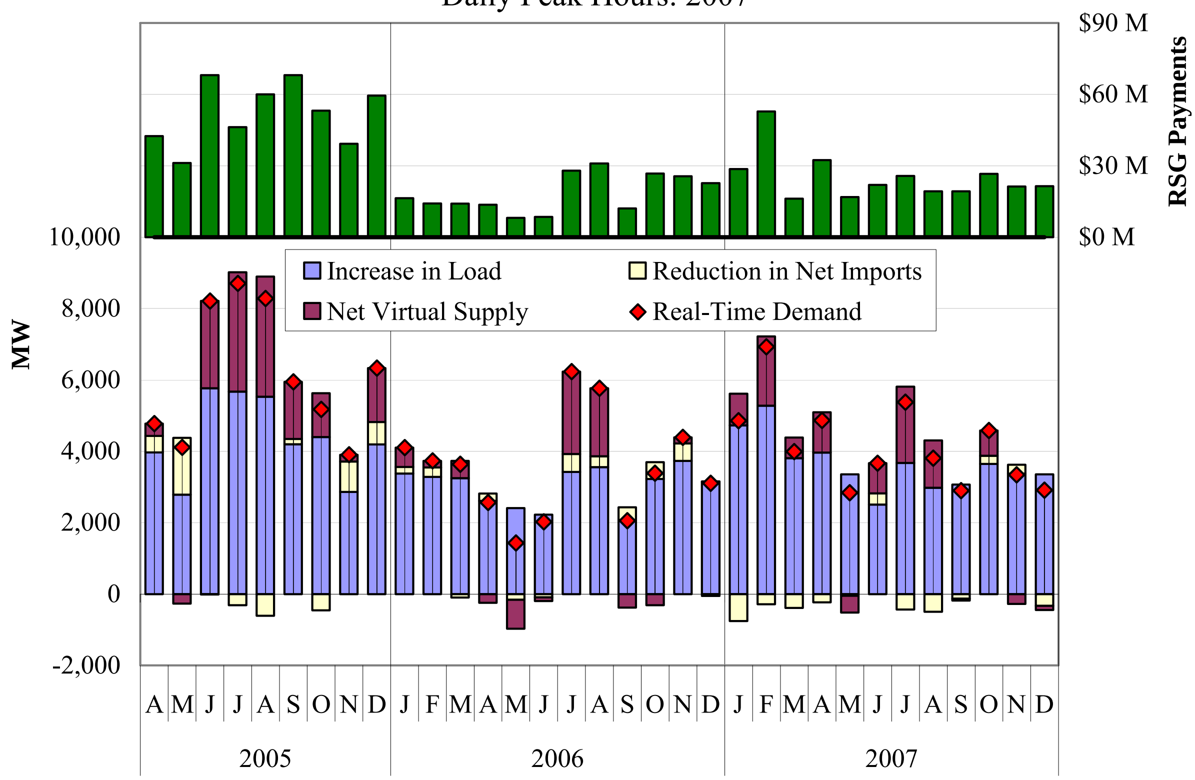
Figure 40: Weekly RSG Distribution by Region



Much of the highest RSG costs were caused by transmission congestion in 2007. Early in 2007, congestion into Minnesota and WUMS required supplemental commitment of peaking resources in those areas and resulted in higher RSG costs. This congestion was associated with south-to-north constraints in Iowa, which were binding frequently as a result of imports decreasing over the Manitoba interface in early 2007. Certain transmission and generation outages also contributed to the congestion. Although not all the RSG payments in Minnesota and WUMS were due to congestion, the majority of the increase early in the year was due to congestion.

Our next analysis seeks to identify factors that explain the changes in the RSG costs. Real-time RSG is generally correlated with increases in load from the day-ahead scheduled levels, which often requires the commitment and dispatch of peaking units. Figure 41 shows monthly RSG payments (in the top panel) along with average real-time demand in the peak hour of each day. 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.

Figure 41: Drivers of Real-Time RSG
Daily Peak Hours: 2007



The figure indicates that the changes in the real-time demand are the key drivers of RSG. The largest single contributor to the real-time demand 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 was highest in the summer in 2005-2006. During 2007, real-time demand and RSG both peaked in February. Peak-hour net load scheduling in the day-ahead market was close to 93 percent during February, which is the lowest level since the start of the market in 2005. This under scheduling caused actual load to exceed the capability of online units committed in the day-ahead market, causing the ISO to commit substantial additional generation.

The prior figure evaluates real-time demand, which is frequently satisfied by supplemental generator commitments in real time. These commitments are almost always peaking resources because they have the lowest commitment costs and quickest start-up times. The next section reviews and evaluates the dispatch of peaking resources.

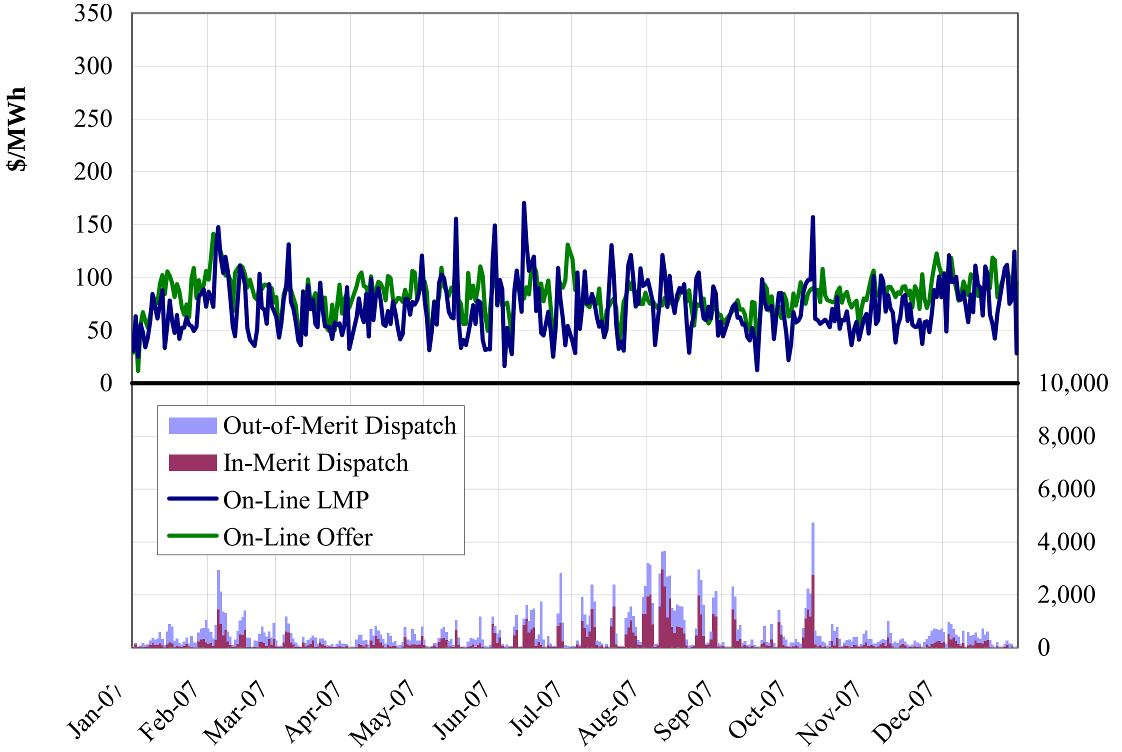
D. Dispatch of Peaking Resources

The dispatch of peaking resources is important because peaking resources are an important determinant of RSG costs and efficient energy pricing. In 2007, an average of almost 1,000 MW of peaking resources were dispatched per hour in the summer and an average of 433 MW were dispatched per hour in other months. These averages are much lower than the levels in 2005 and slightly higher than the levels in 2006.

Figure 42 shows the average dispatch levels of peaking resources each day in 2007 and evaluates the consistency between peaking unit dispatch and market outcomes. In the top panel, we compare of the average LMP at the peaking resources' locations to the average offer price of the dispatched peaking resources.

Figure 42: Average Daily Peaker Dispatch and Prices

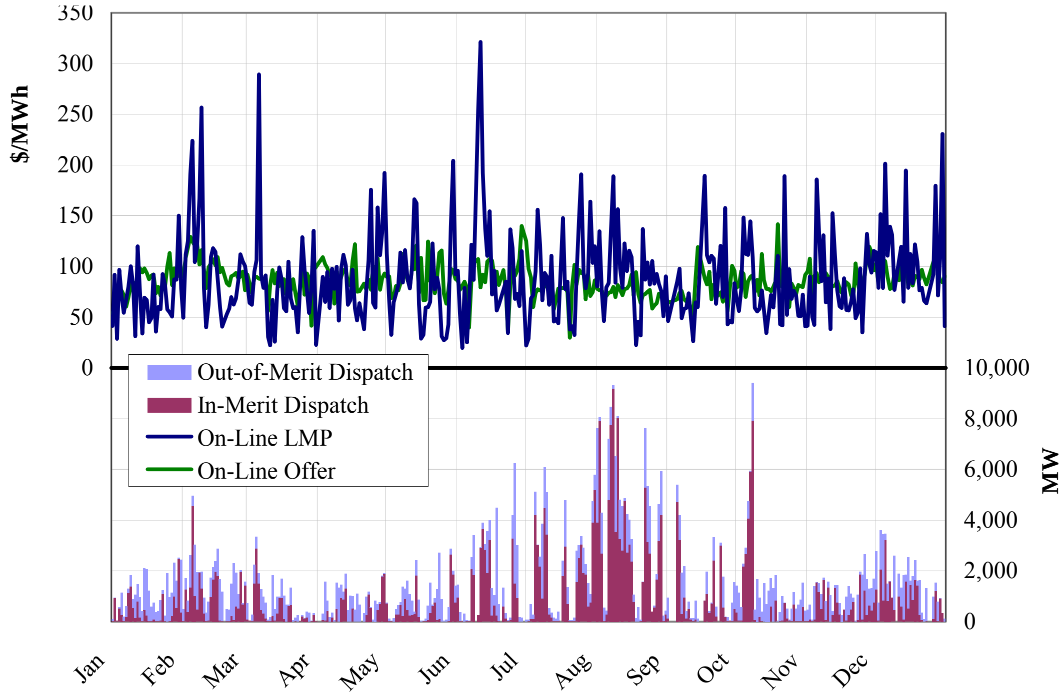
All Hours



The figure shows that in a significant portion of the 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 likely to be running out-of-merit order. In the bottom panel, we identify the share of the peaking resources that is in-merit order (i.e., LMP > peaking unit offer) and the share that is out-of-merit order (i.e., LMP < peaking unit offer). This analysis indicates that only 45 percent of the peaking resources were in-merit, indicating that they frequently do not set the energy price. A larger share of peaking resources (54 percent) is in-merit when they are heavily relied on in the summer. We discuss the implications of out-of-merit peaking resources more below.

Figure 43 summarizes the same information for the daily peak load hour. During peak hours, peaking resources are more likely to be dispatched in-merit order.

Figure 43: Daily Peaker Dispatch and Prices
Peak Load Hour



This figure shows that more peaking resources are dispatched in the peak-load hours, as expected, averaging 1,515 MW in 2007. The figure also shows that a larger share of the peaking resources were in-merit order in these hours – on average, 59 percent were in-merit order in these hours.

E. Ex ante and Ex post Prices

Like PJM and New England, 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 for settlements and are calculated after the operating period based on 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.[22] Hence, consistency between the ex ante and

22 This assumes the generators are offered at marginal cost.

ex post prices is important for ensuring that suppliers have the incentive to follow the ex ante dispatch instructions.

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 UDS. For each flexible resource, a "real-time offer price" is used in place of its offer curve.[23] For a resource following dispatch instructions, its "real-time offer price" equals the ex ante price at its location or, if it is operating at its maximum output level, the offer price corresponding to its actual production level. For a resource that is under-producing by a significant amount, the "real-time offer price" equals the 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.

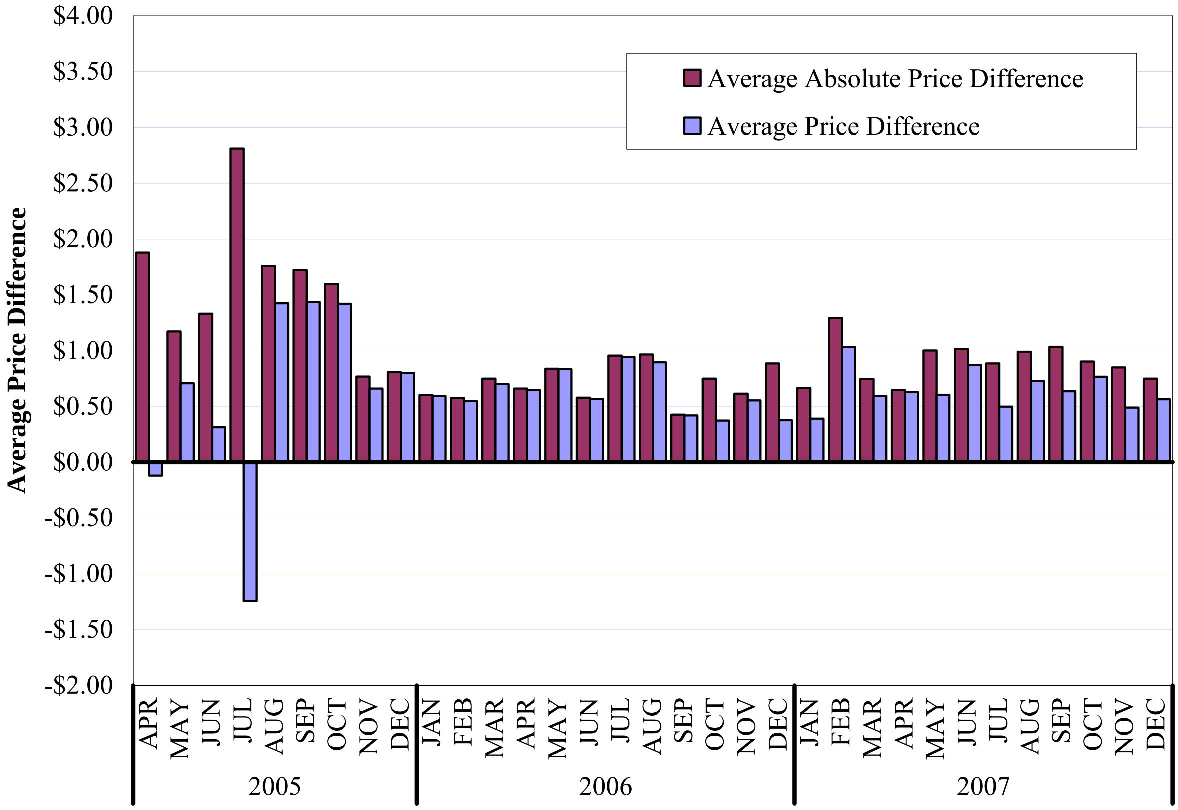
Our analysis seeks to evaluate the consistency between ex post and ex ante prices. Figure 44 summarizes the results of our analysis, showing both the average difference in the five-minute ex post and ex ante prices, as well as the average of the absolute value of the hourly difference in the prices. This second metric indicates how large the differences are, regardless of the direction of the difference.

The figure shows there is a persistent bias in the ex post calculator that causes the ex post price to be generally higher than the ex ante price by approximately three percent. The persistent bias results from a combination of two 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

23 Most resources are treated as flexible if they are producing more than 0 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.

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.

Figure 44: Ex Ante and Ex Post Price Differences
2005- 2007: All Hours



In a typical interval, there may be 100 or more flexible resources. At locations where the loss factors increase the most from the ex ante to the ex post model, resources will appear most costly and be moved downward in the ex post model. Since the downward dispatchable range is much larger than the upward dispatchable range, many resources will be ramped up to their maximum to replace the unit that is ramped down. In a random interval we examined without congestion, three units were moved down and more than 70 units were moved up. As the units moving up reach their assumed maximum, increasingly more expensive units will set the ex post prices. Hence, the resource that is marginal in the ex post calculation usually has a loss factor that is higher than in the ex ante calculation, thereby leading to an upward bias in prices.

Ex post pricing has 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 very unlikely that the ex post pricing enhances incentives to follow dispatch instructions.

In fact, 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. A much more efficient means to send targeted incentives to respond to dispatch instructions is the use of uninstructed deviation penalties.

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 ex post pricing methodology is designed to satisfy two objectives. First, it allows the Midwest ISO to calculate energy prices that correct for errors that may have been included in the ex ante dispatch and prices. Second, it re-solves prices, adjusting for generation that is not following dispatch instructions. While the correction of errors in the ex ante solution is beneficial, the other changes made by the ex post pricing methodology are inefficient. Ex post pricing methodologies in general result in real-time prices that are inconsistent with the market's dispatch instructions, which can undermine generators' incentives to follow such instructions. Hence, we recommend that the Midwest ISO replace the current ex post pricing methodology with an approach that would utilize the ex ante prices produced by UDS, corrected for metering or other errors.

F. Adequate Ramp Capability Procedures

The Commission approved the Adequate Ramp Capability ("ARC") procedure effective January 8, 2007. The procedures are intended to allow the Midwest ISO to use operating reserve capacity to alleviate ramp constraints under certain conditions. The Midwest ISO put the ARC in place on March 20, 2007. The first ARC event was invoked on June 8, 2007. This section analyzes the experience with ARC in its first year.

During 2007, the ARC procedures were called on 16 times for a total of 96 intervals – equivalent to 6.75 hours and less than 0.2 percent of all intervals. Through the end of March 2008, there were an additional 12 events during 95 intervals also representing less than 0.2 percent of all intervals. Table 4 summarizes the events in 2007. As part of the ARC process, a proxy peaker price is used to set prices. Accordingly, the table shows the proxy peaker price during each event.

Table 4: Summary of ARC Events in 2007

Date	Peaker Proxy Price	Comments
6/8/07	$370.54	From 04:10 EST through 04:25 EST due to a 2,400 MW NSI change over a ten minute period created by schedule changes and TLR schedule reloads. Up to 20 percent of the available ARC operating reserves were utilized. There were no ARS events.
6/20/07	$317.43	From 15:15 EST through 15:55 EST due to 900 MW NSI change over a ten minute period created by schedule changes and 805 MW of generations forced off line. Up to 86 percent of the available ARC operating reserves were utilized. There were no ARS events.
8/11/07	$317.91	From 09:15 EST through 09:50 EST due to loss of 1,300 MW NSI change over a ten minute period created by schedule changes due to TLR curtailments. Up to 73 percent of the available ARC operating reserves were utilized. There were no ARS events.
8/14/07	$333.56	From 22:25 EST through 22:45 EST due to loss of 2,200 MW NSI change over a ten minute period created by schedule changes and TLR scheduled curtailments and 550 MW of generation coming off line earlier than planned. Up to 43 percent of the available ARC operating reserves were utilized. There were no ARS events.
8/21/07	$304.04	From 17:10 EST through 17:35 EST due to loss of 2,800 MW NSI change over a ten minute period created by schedule changes due to TLR curtailments. Up to 76 percent of the available ARC operating reserves were utilized. There were no ARS events.

Date	Peaker Proxy Price	Comments
8/21/07	$304.04	From 20:10 EST through 20:40 EST due to loss of 800 MW NSI change over a ten minute period created by schedule changes and evening peak load came in higher than forecasted. Up to 63 percent of the available ARC operating reserves were utilized. There were no ARS events.
8/22/07	$281.96	From 23:25 EST through 23:45 EST due to loss of 1000 MW NSI over a ten minute period created by schedule changes and generation coming off line earlier than in plan. Up to 44 percent of the available ARC operating reserves were utilized. There were no ARS events.
9/3/07	$278.26	From 11:35 EST through 12:25 EST due to a large NSI change over a ten minute period and load continuing to climb over forecast. Up to 96 percent of the available ARC operating reserves were utilized. There were no ARS events.
9/8/07	$287.03	From 07:23 EST through 07:42 EST due to 1) loss of generation and 2) curtailment of imports during the morning load pickup. Up to 44% of the available ARC operating reserves were utilized. There were no ARS events.
9/17/07	$330.7	From 19:35 EST through 20:15 EST due to 700 MW NSI over a ten minute period and evening peak load coming in 1,100 MW higher than projected. Up to 75% of the available ARC operating reserves were utilized. There were no ARS events.
9/18/07	$345.36	From 15:30 EST through 20:15 EST due to 1,100 MW NSI change over a ten minute period created by TLR curtailments. Up to 85% of the available ARC operating reserves were utilized. There were no ARS events.
10/4/07	$381.8	From 19:00 EST through 19:30 EST due to a temporary capacity shortage. Up to 83% of the available ARC operating reserves were utilized. There were no ARS events.
10/16/07	$403.04	From 06:55 EST through 07:25 EST due to a 1,000 MW Net Schedule Interchange and actual load came in higher then forecasted. Up to 79% of the operating reserves were utilized . There were no ARS events during this procedure.
12/5/07	$638.74	From 17:50 EST through 18:30 EST due to a loss of 920 MW of generation. Up to 88% of the operating reserves were utilized. There was one ARS event during this procedure.
12/8/07	$385.04	From 17:55 EST through 18:15 EST due to higher than anticipated load. Up to 83% of the operating reserves were utilized . There were no ARS events during this procedure.
12/26/07	$342.78	The Midwest ISO invoked the ARC for net schedule interchange of 1,000 MW and actual load was 2,000 MW higher than forecasted load. Up to 84% of the operating reserves were utilized . There were no ARS events during this procedure.
1/9/08	$467.58	From 00:20 EST through 00:35 EST due to a 1,000 MW NSI change over a ten minute period created by schedule changes and 250 MW of generation forced off line. Up to 65 percent of the available ARC operating reserves were utilized. There were no ARS events.
1/17/08	$405.49	From 19:00 EST through 19:20 EST due to a 1,100 MW NSI change created by TLR curtailments. Up to 89 percent of the available ARC operating reserves were utilized. There were no ARS events.
1/30/08	$382.73	From 7:40 EST through 08:00 EST due to a 2,100 MW NSI change created by TLR curtailments. Up to 65 percent of the available ARC operating reserves were utilized. There were no ARS events initiated during the event although there was an active ARS event that was started prior to event.
2/2/08	$358.4	From 10:00 EST through 10:20 EST due to a 500 MW NSI and actual load coming in higher than forecasted load. Up to 70 percent of the available ARC operating reserves were

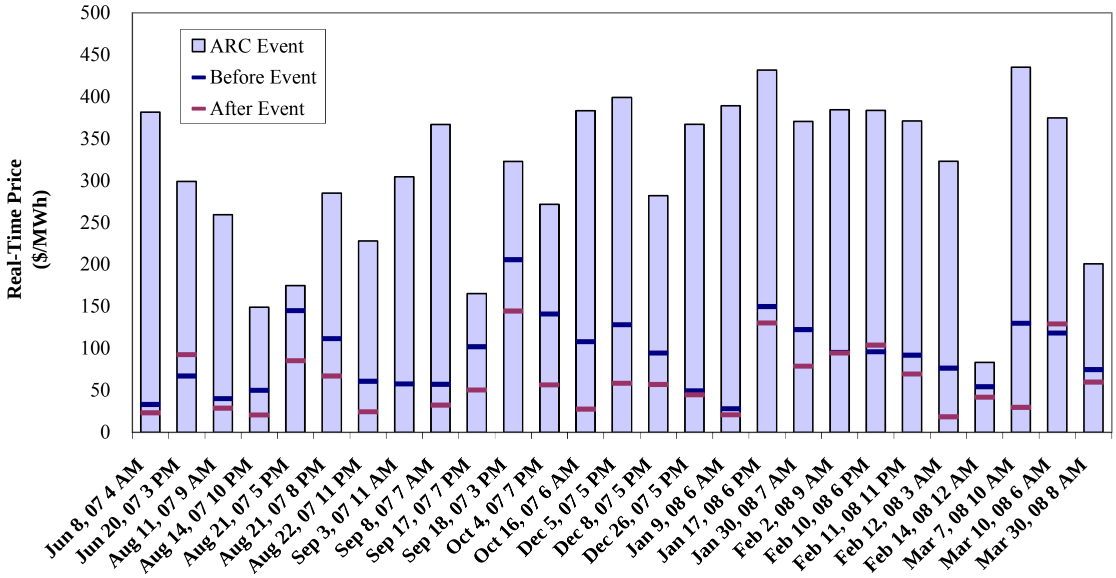
Date	Peaker Proxy Price	Comments
		utilized. There were no ARS events initiated during the event.
2/10/08	$368.3	From 18:50 EST through 19:20 EST when actual load came in greater than forecasted load. Up to 75 percent of the available ARC operating reserves were utilized. There were two ARS events in progress during the event.
2/11/08	$366.93	From 23:25 EST through 23:55 EST due to 1,000 MW NSI change over a ten minute period created by schedule changes and 300 MW of generation forced off line. Up to 56 percent of the available ARC operating reserves were utilized. There were no ARS events.
2/12/08	$381.92	From 03:15 EST through 03:30 EST due to a 2,000 MW NSI change over a ten minute period created by schedule changes and TLR curtailments. Up to 50 percent of the available ARC operating reserves were utilized. There were no ARS events.
2/14/08	$381.03	From 00:20 EST through 00:35 EST due to a 1,000 MW NSI change over a ten minute period created by schedule changes and 250 MW of generation forced off line. Up to 65 percent of the available ARC operating reserves were utilized. There were no ARS events.
3/7/08	$406.3	From 10:05 EST through 10:30 EST due to a 1,000 MW NSI change over a ten minute period created by schedule changes. Up to 65 percent of the available ARC operating reserves were utilized. There were no ARS events.
3/10/08	$406.86	From 06:45 EST through 07:05 EST due to a 700 MW NSI change over a ten minute period created by schedule changes and load ramped up higher then projected by 500 MW. Up to 84 percent of the available ARC operating reserves were utilized. There was one ARS event during the ARC procedure.
3/30/08	$418.32	From 08:15 EST through 08:35 EST due to a 1,000 MW NSI change over a ten minute period created by schedule changes. Up to 57 percent of the available ARC operating reserves were utilized. There were no ARS events during the ARC procedure.

Overall, the ARC events are relatively rare and brief. The average event duration is 27 minutes, the longest event was 50 minutes and the shortest event was 15 minutes. The maximum portion of ARC operating reserves used during ARC events in the first year ranged from 20 percent to 89 percent.

The relatively few ARC events were expected since the procedures for implementing ARC are limited to specific conditions. These conditions are (1) the loss of import schedules, (2) large forced outage of generation, and/or (3) significant under-forecasting of short-term load. In addition, though ARC is explicitly limited to less than one hour, the events have proven to be short lived. The brevity of these events is consistent with the intended use of the procedures.

Figure 45 shows average real-time energy prices before, during, and after ARC events. The "before" prices are the average ex ante prices in the 30 minutes prior to the ARC event, and the "after" prices are the average ex ante prices in the 30 minutes after the ARC event.

Figure 45: Real-time Prices during ARC Events
March 2007 – March 2008



The figure shows that during ARC events, the price signals are consistent with shortage pricing signals. However, the peaker proxy prices are considerably higher than typical incremental energy offers by peaking units. This is because the peaker proxy prices are calculated in a manner specified in the tariff that allocates start-up costs to a small portion of the unit's capability. This process results in a relatively high proxy price.

The figure also shows that prices before and after the ARC events are generally much lower than during the ARC event. The prices before and after the ARC events generally would not support the commitment of peaking units. This highlights the benefit of the ARC procedure, which reduces the need for committing peaking units at prices that would not support their operation. These benefits are accrued in the course of daily operation (not just during ARC events) as operators do not have to be as proactive in committing peaking resources in anticipation of operational issues.

The operating reserves dispatched during ARC events are generally dispatched based on an offer price set equal to the peaker proxy price. During ARC events, the offer price of one-half the available operating reserves range is set equal to the higher of the incremental energy offer or the peaker proxy price. Table 4, above, shows the peaker proxy price for each event.

The peaker proxy prices are significantly greater than typical energy offers for peaking resources because of the methodology in the tariff. As described in Module C, Section §§ 40.2.15, "Shortage Conditions and Emergencies in the Real-Time Energy Market", the peaker proxy price is calculated based on the average of day-ahead and real-time offers of combustion turbines in the previous 30 days, indexed using daily natural gas spot prices based on the Chicago City Gate LDC price. The offers used in the peaker proxy price are not screened for conduct or impact and are not subject to the mitigation measures in Module D. The calculation for the peaker proxy price includes incremental energy, "no-load", and startup offer components. Startup and no-load offer components are allocated based on the dispatchable range of the turbine. For turbines with no dispatchable range, the startup and no-load costs are distributed for to the entire economic capacity.

While peaker proxy prices were intended to represent scarcity offers, the formulae for calculating the peaker proxy price has resulted in prices higher than we anticipated. In particular, the allocation of startup and no-load costs has led to inputs into the peaker proxy price calculation that are much higher than incremental energy offers of even the most expensive peaking resources. The relatively high peaker proxy prices are due to the formula in Section §§ 40.2.15. Indeed, while the individual offer components are below the offer cap, the allocation of startup and no-load to the dispatchable range results in average per-MWh costs that may exceed the offer cap.

We also examined the level of original offers that are ultimately mitigated in the peaker proxy price calculation to estimate the potential impact on the peaker proxy price calculation. Overall, during this time period, there were nearly 550 unit offers mitigated for combustion turbines in the real-time market, most of which occurred in NCAs. There were no combustion turbines mitigated in the day-ahead market. The number of mitigated offers therefore is very small compared to the number of offers included in the peaker proxy price calculation. We have estimated that the impact of including unmitigated offers in the peaker proxy price is considerably less than $1 per MWh.

Despite these shortcomings, we do not recommend changes in ARC Procedures, because ARC will no longer be in effect after implementation of the ASM markets. However, absent ASM, we would likely recommend changes in the peaker proxy price calculation. In particular, it would be more appropriate to allocate no-load and startup costs to the entire economic maximum capacity rather than the dispatchable range.

G. Market Outcomes Conclusions and Recommendations

In its third year, the Midwest ISO's markets performed well. The nodal market accurately reflected the value of congestion in the Midwest – the most substantial congestion was into WUMS and into Minnesota in the first half of the year. Prices in the real-time market were substantially more volatile than in the day-ahead market, as expected. Real-time prices were also more volatile than the prices in neighboring markets. The performance of the real-time market is compromised in some cases by:

- Reduced dispatch flexibility offered by many generators, which can make congestion more difficult to manage;
- Less than optimal commitment and de-commitment of peaking resources;
- The fact that prices do not always reflect the marginal value of energy when the system must rely on relatively inflexible peaking resources or load curtailments;
- The lack of ancillary services markets that are jointly optimized with the Midwest ISO's energy markets; and
- The ex post pricing methodology that has served to increase prices slightly and produce periodic inconsistencies between the real-time prices and dispatch signals.

The Midwest ISO is scheduled to introduce ancillary services markets in September 2008. Ancillary services markets that are jointly optimized with energy will allow the market to allocate resources more efficiently between the two services. Ancillary services markets will also set efficient prices in both markets to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions. With ASM, the Midwest ISO will implement make-whole payments to ensure that generators following five-minute dispatch instructions when prices are volatile are not harmed in their hourly settlements. This should provide better incentives to be flexible.

To improve the performance of the real-time market, we recommend the Midwest ISO consider the following changes to the real-time market (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. (Section IV.D.)

Peaking resources tend to be inflexible (i.e., having a narrow flexible 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 that are needed (i.e., would not be dispatched down to zero if they were completely flexible) to set prices and not allow those that are not needed to set 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.

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 2008. If a feasible approach is developed, this change will 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. (Section IV.B)

The Midwest ISO has made operational improvements in its commitment of peaking resources. The commitment of these units can be further improved by reliance on an economic model in real time to commit the units and manage the dispatch levels of slow-ramping units. Such a model should be synchronized with the real-time UDS, but would anticipate changes in load, congestion patterns, and the ramp needs of the system up to an hour ahead.

To the extent that such a tool improves the commitment and decommitment of peaking resources, it would lower RSG. It should also reduce the price volatility in the Midwest ISO region because it would be anticipating and satisfying the ramp needs of the system,

3. Replace the current ex post pricing methodology with an approach that would utilize the prices produced by UDS, corrected for metering or other errors. (Section IV.E.)

Like PJM and ISO New England, the Midwest ISO re-calculates prices after each interval (ex post pricing) rather than using the ex ante prices produced by the real-time dispatch model that are consistent with the dispatch signals that generators receive. Ex post pricing has not been shown either theoretically or empirically to improve the efficiency of real-time prices or the incentives of suppliers. Our analyses in this report indicate that the ex post prices tend to be biased upward (3 percent on average in 2007). Additionally, using ex post pricing sometimes introduces significant inconsistencies between prices at particular locations and generators' dispatch signals. Hence, this recommendation should be implemented with the ASM markets or sooner, if feasible.

V. Transmission Congestion and Financial Transmission Rights

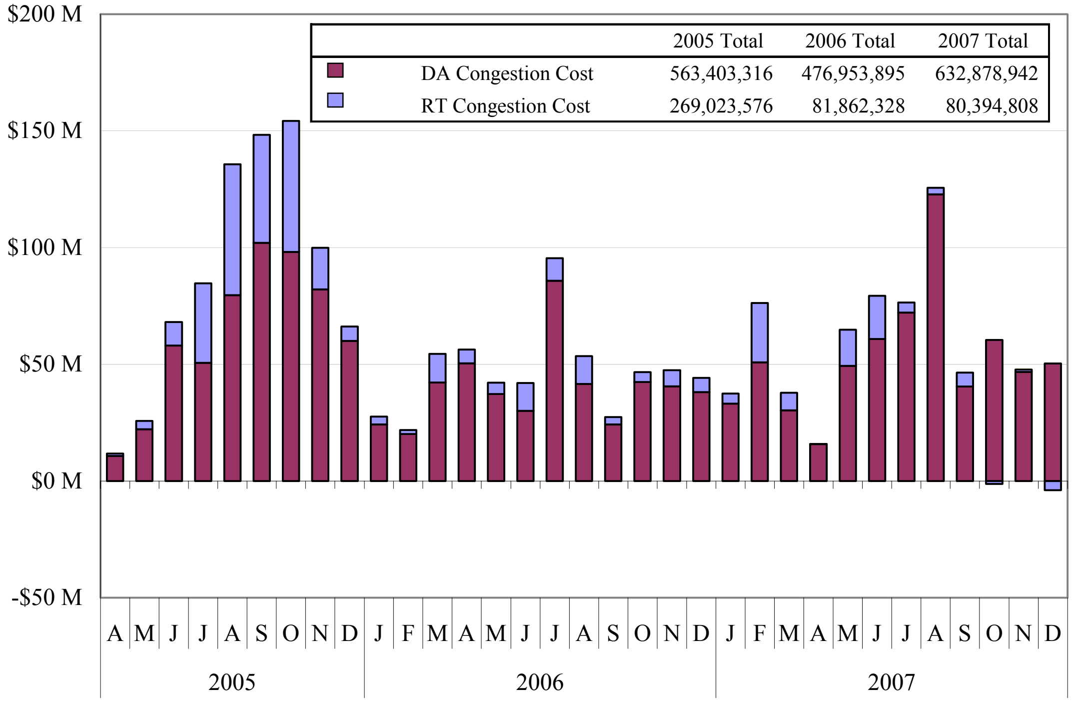
One of the primary functions of the Midwest ISO energy markets is to meet load requirements with the lowest-cost resources given the limitations of the transmission network. The locational market structure in the Midwest ISO generally ensures that the transmission capability is efficiently utilized and that prices reflect the marginal value of energy at each location. Congestion costs arise in the presence of transmission constraints that require higher-cost units to increase output on the constrained-side of a transmission interface (resulting in a higher locational price in the constrained area) while lower-cost units decrease output on the unconstrained side of the interface (resulting in a lower locational price in the unconstrained area). An efficient system typically will have some congestion because investment in transmission should only occur when the cost of the investment is less than the congestion cost.

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, congestion costs are approximately equal to the difference in LMP prices between the locations multiplied by the amount of the transfer. These congestion costs are collected by the Midwest ISO naturally through the settlement process. 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 (i.e., more payments are received from the load than are paid to the generators).

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 on a long-term basis because they govern investment and retirement decisions.

This section of the report evaluates congestion costs, FTR market results, and the Midwest ISO's management of congestion during 2007. We begin this section by presenting an overall summary of congestion costs incurred in the day-ahead and real-time markets. Figure 46 shows a summary of these costs from 2005 through 2007.

Figure 46: Total Congestion Costs
April 2005 to December 2007



In 2005, the congestion costs were relatively high due to a number of factors, including high natural gas prices after Katrina and due to PJM's exports to TVA that were not well coordinated with the Midwest ISO. In 2007, day-ahead congestion costs increased to $633 million from $477 million in 2006. The increase in congestion costs in 2007 was the result of two primary factors. First, higher natural gas prices prevailed, which increased congestion by increasing redispatch costs. Second, reduced imports over the Manitoba interface into the West and certain outages contributed to increased congestion during the first half of the year.

Real-time congestion costs in 2007 roughly equaled those in 2006 after a sharp decline from 2005. Nearly 90 percent of total congestion costs were realized in the day-ahead market, a significant improvement from 2005. Normally, one would expect the real-time-congestion costs to be very low 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 are relatively large 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. 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. 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 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. Based on our review of congestion costs, we conclude that the continued reduction in congestion costs collected in the real-time market was due to reasonably accurate loop flow assumptions in the day-ahead model.

A. Day-Ahead Congestion and FTR Obligations

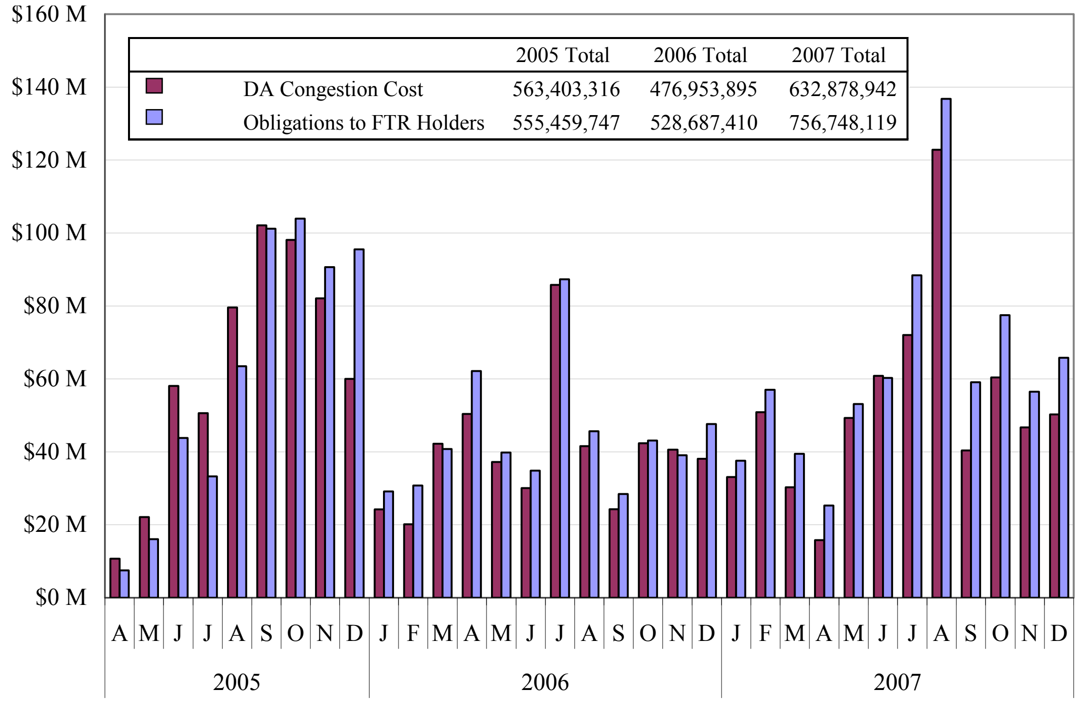
The economic value of transmission capacity is reflected in the FTRs. Holders of FTRs are generally entitled to the congestion costs collected between the source and sink locations that define a given FTR. Hence, FTRs allow participants to manage the price risk associated with congestion.

FTRs are distributed through an annual allocation process and through seasonal and monthly FTR auctions. The Midwest ISO is obligated to pay FTR holders for 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.[24] 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

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

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. If the Midwest ISO has a shortfall over the entire year, FTR payments are reduced *pro rata*. Figure 47 compares the monthly total day-ahead congestion revenues to the monthly total FTR obligations.

Figure 47: Day-Ahead Congestion Revenue and Payments to FTR Holders
2005 - 2007: All Hours



	2005 Total	2006 Total	2007 Total
DA Congestion Cost	563,403,316	476,953,895	632,878,942
Obligations to FTR Holders	555,459,747	528,687,410	756,748,119

The figure shows that the day-ahead congestion revenues were substantially less than FTR obligations in 2007 (a shortfall of 19 percent). The shortfall in 2006 was 10 percent. As noted, surpluses and shortfalls occur when the FTRs held by participants differ substantially from the capability of the system. 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:

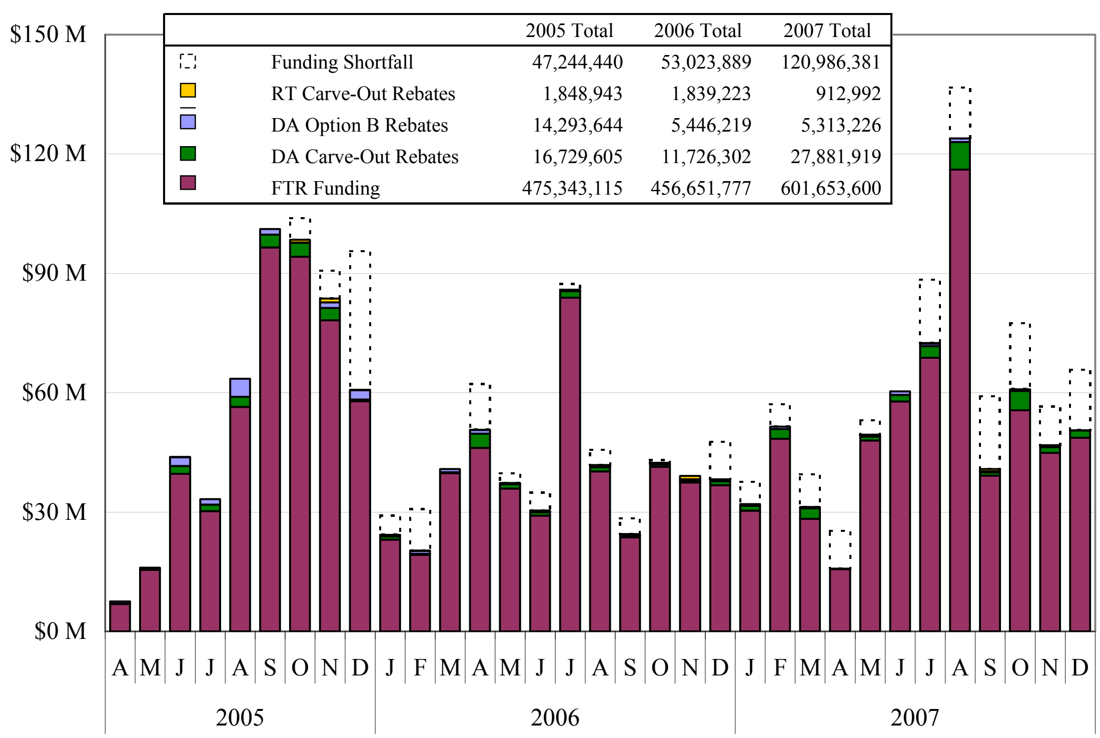
- Transmission outages or other factors cause the capability of the system to differ from the capability assumed when the FTRs were allocated or sold; and
- Loop flows over the system caused by generators and loads outside of the Midwest ISO use more or less of the transmission capability than assumed in the FTR market. Unanticipated loop-flow is a problem because the Midwest ISO collects no congestion

> revenue from entities 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 issues. This effort has included making modeling changes to reduce the shortfalls, which should be fully reflected in the June 2008 funding results. The changes will improve loop flow assumptions, add additional constraints related to market-to-market and non-market constraints, and broadly reduce transmission line limits to account for expected differences in FTR-modeled conditions and actual hourly results.

In the Midwest ISO region, other types of transmission rights were created to protect entities that have pre-existing agreements that provide various forms of entitlements to use the transmission system (commonly 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 (Option B FTRs) and congestion “carve-outs”. Figure 48 shows the monthly payments and obligations to FTR holders, including the payments to FTR Option B and Carve-Out FTRs.

Figure 48: Payments to FTR Holders
2005 - 2007: All Hours



The figure shows that the vast majority of the payments were made to conventional FTR holders (95 percent of all payments). Payments to the holders of the alternative rights (including the "rebates") almost doubled, but still amounted to only about five percent of the total FTR payments. Making relatively small payments on the other types of rights is good because they do not provide efficient incentives like conventional FTRs.

B. Value of Congestion in the Real-Time Market

In this subsection, we evaluate the congestion patterns that occurred in the real-time market. In general, we focus on the value of real-time congestion, rather than 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 of the flows over its system (loop flow incurs no congestion costs). 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. The next two figures show the value and shares of real-time congestion by region. Figure 49 shows the value of real-time congestion by region for all binding real-time constraints. Figure 50 shows the same data, but it is shown as a share of total monthly congestion costs.

Figure 49 shows that the total value of real-time congestion increased slightly in 2007 from 2006. We estimated $984 million of real-time congestion in 2007, up slightly from $960 million in 2006. This is a much smaller increase than the increase in congestion costs shown in the prior subsection. This result suggests that loop flow over congested interfaces decreased in 2007, bringing the value of congestion into better alignment with the congestion costs collected by the Midwest ISO.

Congestion on transmission constraints in the Central region was substantial during the summer months and in late 2007. In total, congestion in the Central region accounted for the largest share of the real-time congestion. However, more than one-half of the congestion between October 2006 and April 2007 was related to transmission constraints into the West region. This congestion was primarily due to reduced availability of imports over the Manitoba interface and high winter loads. Relative to its load, WUMS accounted for a large share of total congestion, which is consistent with results for prior years.

Figure 49: Value of Real-Time Congestion by Coordination Region
2006 - 2007

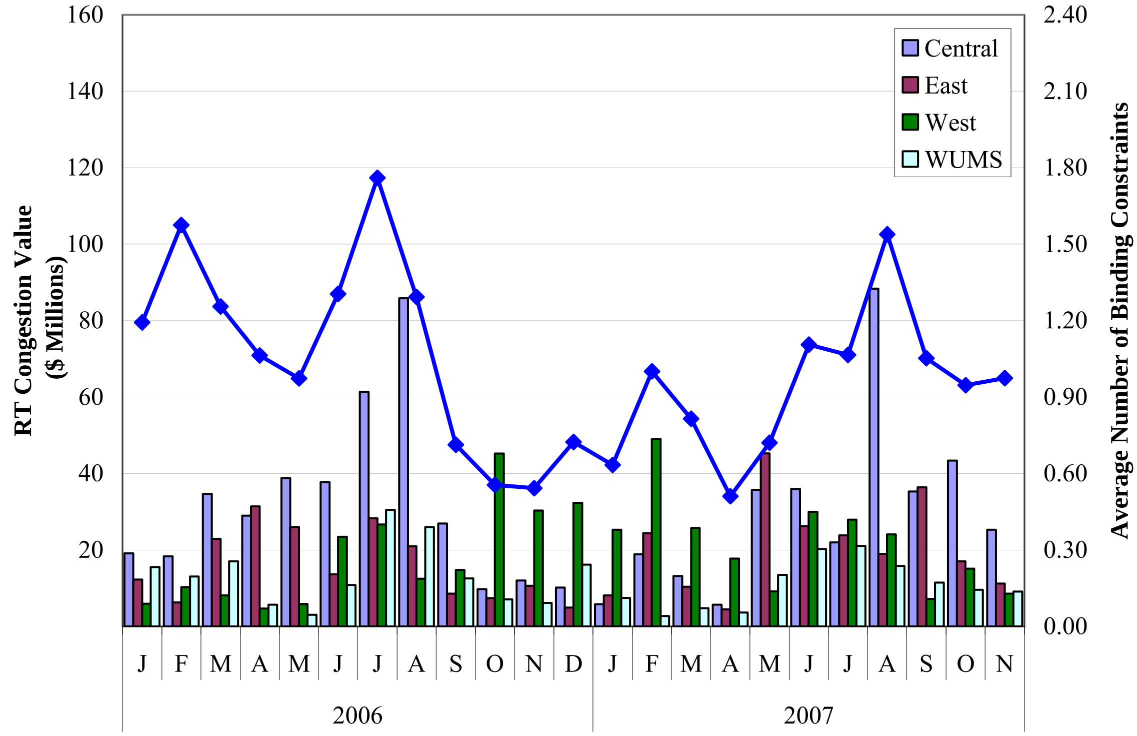


Figure 50: Share of Real-Time Congestion by Region

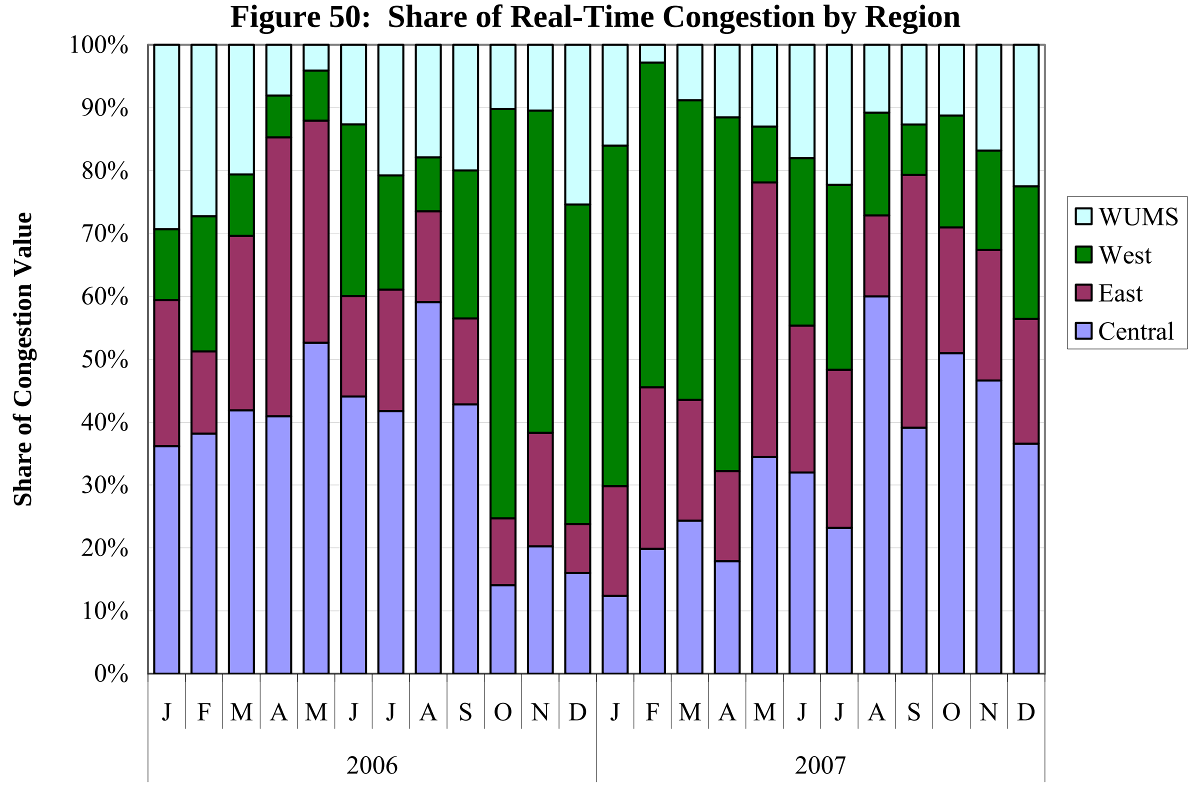
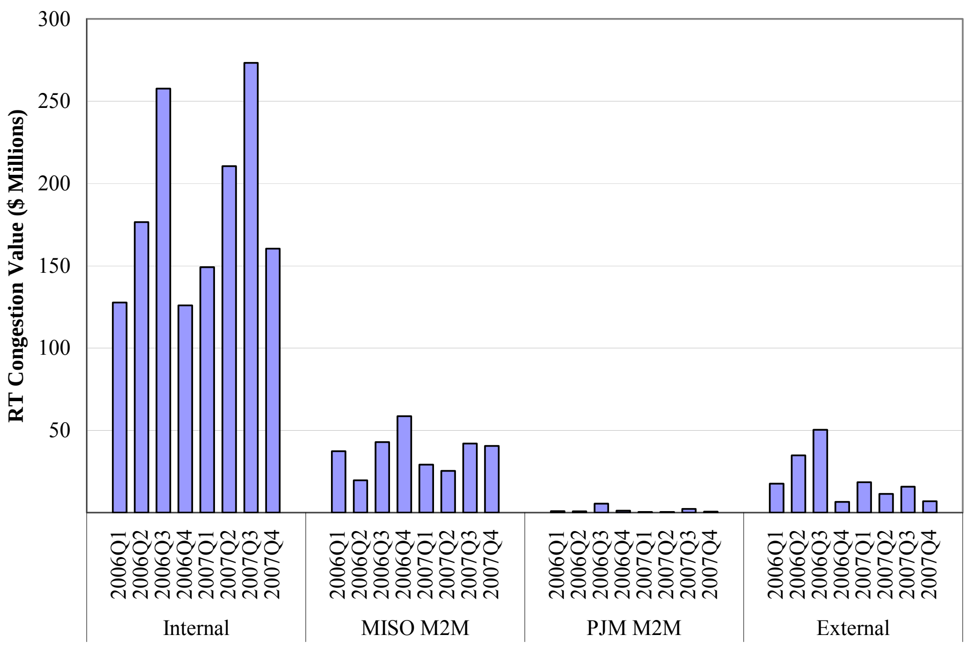


Figure 49 also shows that the average frequency of binding constraints (per interval) decreased slightly in 2007 (from 1.08 constraints binding per interval in 2006 to 0.93 per interval in 2007). However, the frequency patterns were similar in both years, peaking during the summer when the demands on the network are the greatest.

To better identify the sources of congestion, Figure 51 shows the value of congestion by type of constraint. For our analysis, we define four types of constraints:

- Constraints internal to the Midwest ISO that are not coordinated with PJM. These are non-market-to-market constraints and are referred to as "Internal" constraints in our analysis;
- The Midwest ISO constraints that are coordinated with PJM. These are referred to as Midwest ISO market-to-market constraints (abbreviated as "the Midwest ISO M2M" constraints in our analysis);[25]
- The PJM constraints that are coordinated with the Midwest ISO. These are referred to as PJM market-to-market constraints (abbreviated as "PJM M2M" constraints in our analysis); and
- Constraints located on other systems that the Midwest ISO must redispatch to relieve when a TLR is called. These are referred to as "External" constraints in our analysis.

Figure 51: Value of Real-Time Congestion by Type of Constraint
2007



25 Each Midwest ISO and PJM internal constraint is subject to a series of tests under the JOA to determine whether it should be defined as a market-to-market constraint.

The figure shows that most of the congestion in 2007 occurred on the Midwest ISO internal constraints (including the Midwest ISO market-to-market constraints). This is similar to past years' results. On a combined basis, the congestion value associated with the Midwest ISO constraints (internal and market-to-market) represents more than 94 percent of the total congestion value. Most of the remaining congestion is associated with external interfaces, with the LG&E and TVA interfaces accounting for the largest shares of this congestion. We review market-to-market results in detail in the next subsection.

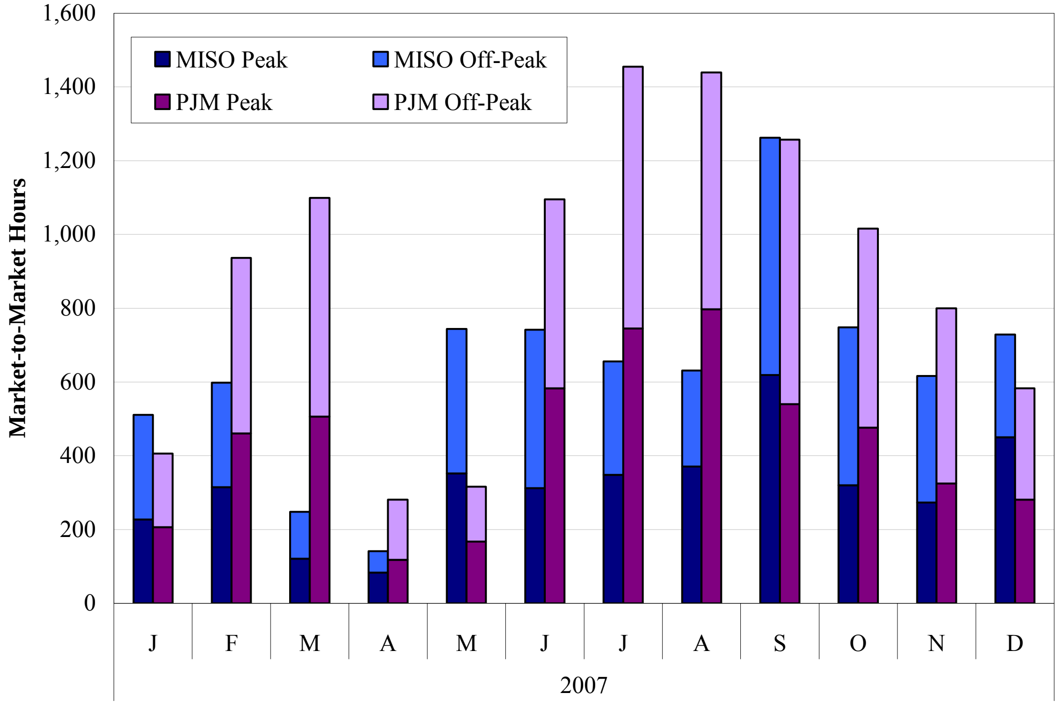
C. Market-to-Market Coordination with PJM

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) between the RTOs to ensure that the transmission constraint is managed with 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 the 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 the ISOs relative to their entitlements. 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 prices between these two markets. Figure 52 summarizes the frequency with which market-to-market constraints were binding and activated in 2007.

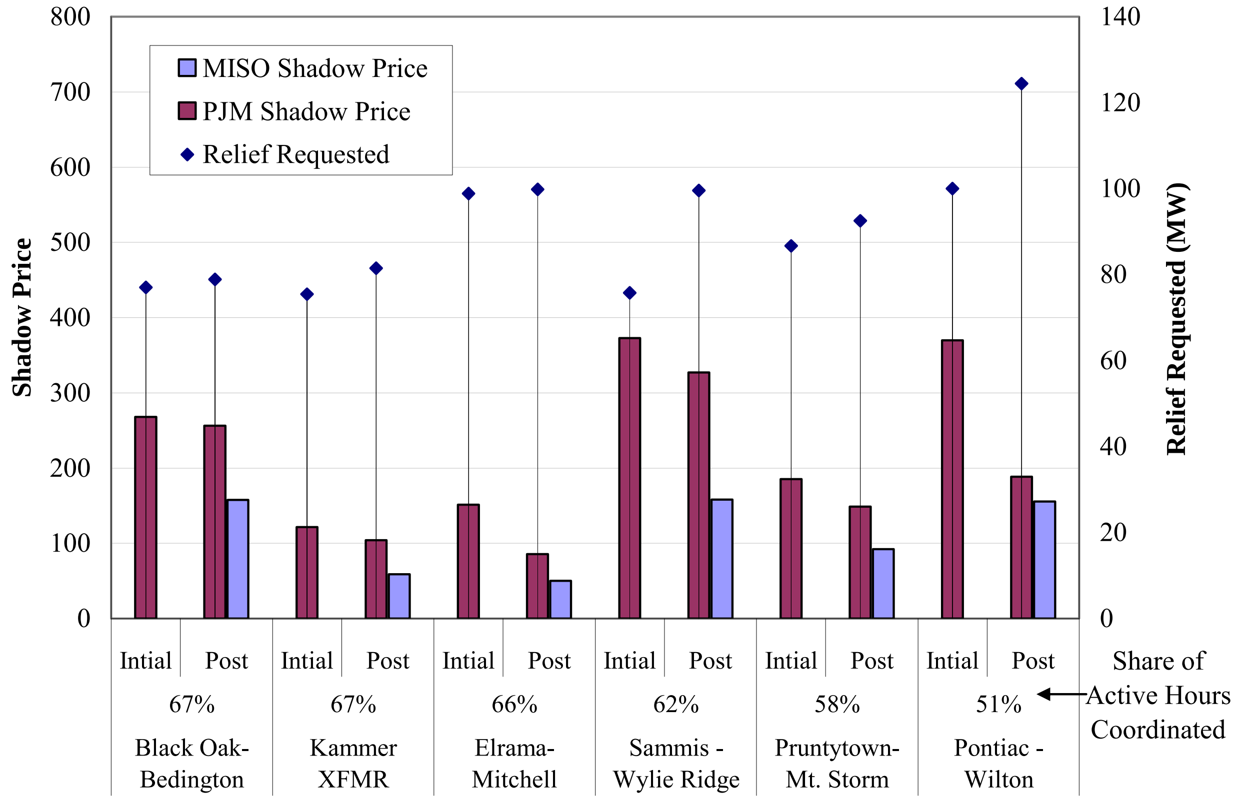
Figure 52: Market-to-Market Events



The market-to-market constraints for both RTOs were divided relatively equally between peak and off-peak hours. The PJM market-to-market constraints (where PJM is the monitoring RTO and the Midwest ISO is the reciprocating RTO) were most frequent in the summer when the demands on the transmission system are the greatest. The Midwest ISO's market-to-market constraints were binding most frequently during the fall.

To assess how well the market-to-market process has been working, our next analyses evaluate 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 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. Our analysis is shown in Figure 53 for the PJM constraints.

Figure 53: PJM Market-to-Market Constraints
Relief Requested and Shadow Prices



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 being coordinated (i.e. relief was being provided by the reciprocating RTO).[26] The "share of active hours coordinated" shown for each constraint is the percentage of hours the reciprocating RTO was responding with shadow prices from their market divided by the total number of hours the monitoring RTO was seeking relief.

Comparing the initial and post-initialization 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.

26 The statistics for the post-initialization period exclude the periods when the reciprocating RTO was not actively responding.

Figure 53 shows that the shadow prices decreased and moved toward convergence over the duration of the event and that the percentage of active intervals that are coordinated (where relief is received) is substantial on the PJM flowgates. The relief requested increased from the initial and post-initialization periods and this is consistent with the convergence and efficient coordination.

While Figure 53 shows that shadow prices generally decline and converge relatively well over the duration of the event, 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.

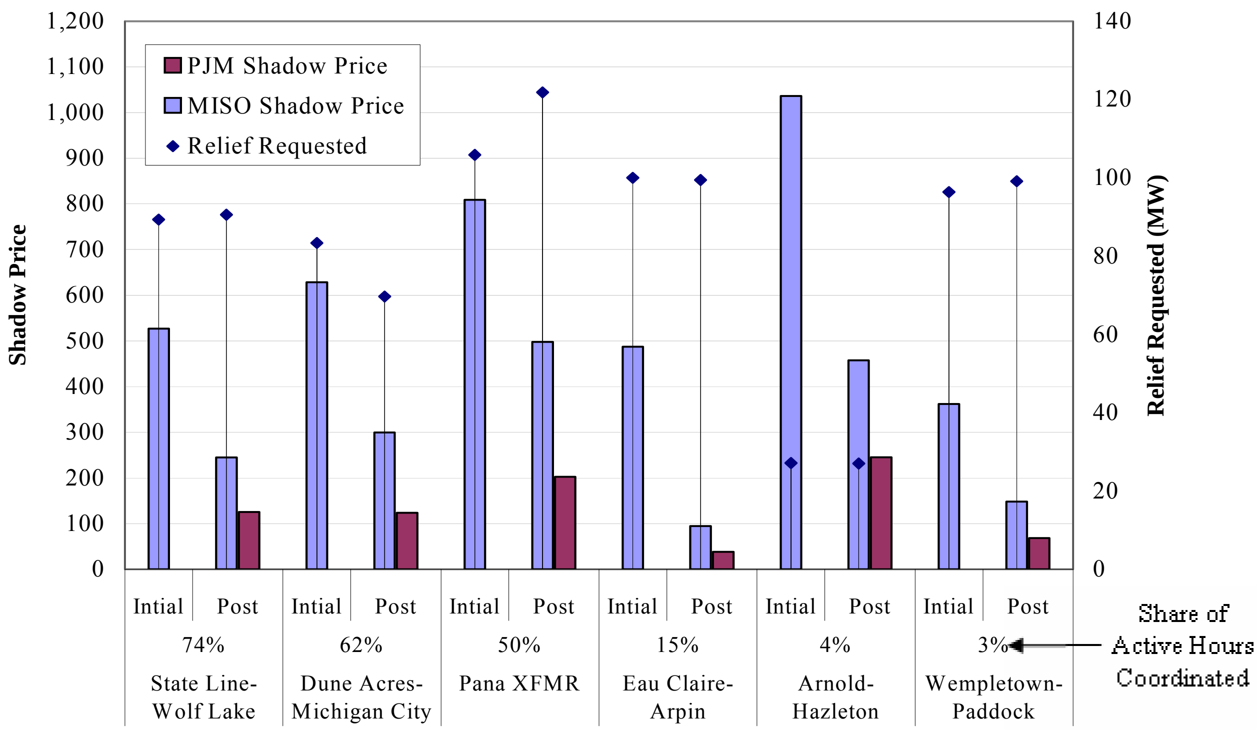
Another concern arises when the Midwest ISO responds to a PJM shadow price by redispatching and pricing the constraint even after the constraint is no longer binding in PJM (i.e., there is no congestion in the PJM prices). This is apparently caused by PJM sending shadow price information that is not consistent with its LMP calculations.

Finally, 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 second 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 second RTO completely relieves the constraint, causing the first RTO to return a zero shadow price in the next interval, which in turn will cause the second 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 2007 than in 2006, it still does not appear to be managed in an optimal manner.

To address these issues, we recommend the market-to-market process be enhanced to optimize the relief requested based on the relative shadow prices. We also recommend the constraint relaxation algorithm be discontinued and the Midwest ISO LMPs be based on the PJM shadow price when the requested relief cannot be provided at a lower marginal cost. This will substantially improve the convergence of the prices affected by the market-to-market constraints.

Figure 54 shows the same analysis for the most frequently called market-to-market constraints on the Midwest ISO system.

Figure 54: Midwest ISO Market-to-Market Constraints
Relief Requested and Shadow Prices



Stateline-Wolf Lake and Eau Claire-Arpin (combining for over 1500 hours) were the most frequently activated market-to-market constraints. Stateline-Wolf Lake also had the highest percentage of coordinated hours at 74 percent while Eau Claire-Arpin was one of the lowest at 15 percent. Like the analysis of the PJM constraints, the figure shows that the shadow prices tend to decrease and move toward convergence over the duration of the event.

Our analysis of the Midwest ISO's market-to-market constraints raises some concerns. First, the relief quantities are rarely modified, even when the Midwest ISO's shadow price is higher than PJM's and more relief may be available. Further, PJM sometimes 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. The analysis shows that PJM provides relief less than five percent of the time on two of the most frequently binding constraints on the

Midwest ISO system. As discussed below, we are investigating why PJM so seldom provides relief on these flowgates with PJM's assistance.

We continue to support the following recommendations intended to improve the market-to-market process:

- The market-to-market process be should enhanced to modify the relief requested based on the relative shadow prices;
- The constraint relaxation algorithm should be discontinued -- prices should be set based on the PJM shadow price when the requested relief cannot be provided at a lower cost; and
- The Midwest ISO should institute a process to monitor more closely the information being exchanged with PJM to identify quickly cases where the process is not operating correctly.

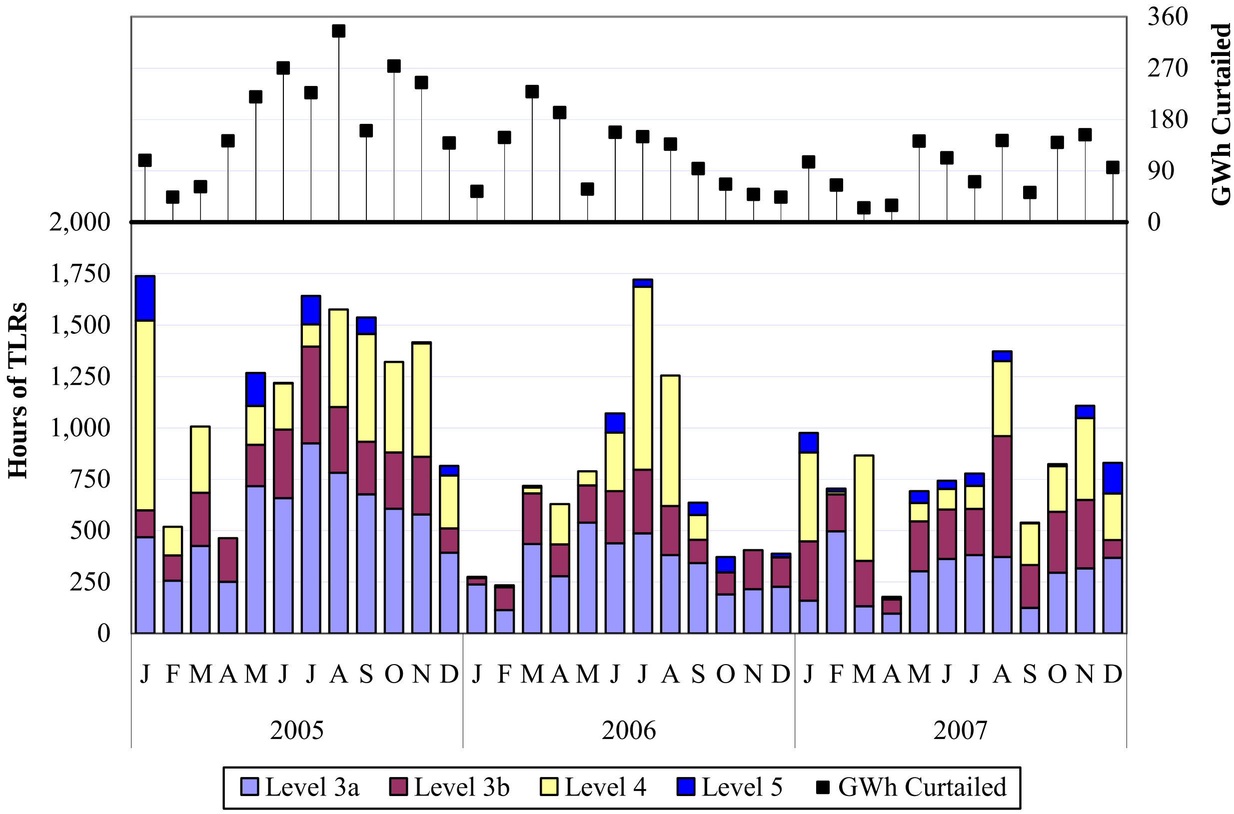
Additionally, based on our preliminary investigation, we believe that certain modeling assumptions by PJM cause its real-time dispatch model to not accurately recognize the relief that it can provide on key Midwest ISO flowgates. For example, PJM utilizes a three-percent GSF cutoff that ignores the relief that can be provided by generators with lower shift factors. As described earlier in this report, even the Midwest ISO's current GSF cutoff of two percent raises efficiency concerns. A three-percent GSF cutoff would raise much more significant concerns. Hence, pending the findings of this investigation, we recommend that PJM make modeling changes to recognize more fully the relief that it can provide on the Midwest ISO's key flowgates.

D. TLR Events

The Midwest ISO continues to use transmission line-loading relief procedures and the NERC Interchange Distribution Calculator ("IDC") to support certain aspects of congestion management. Prior to Day-2 markets, virtually all of the congestion management for Midwest ISO transmission facilities was accomplished through TLR procedures. When a constraint is binding under the Day-2 markets, 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 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.

Our analysis of TLR activity is provided in Figure 55 . The bottom panel of the figure provides the TLR activity by level during the period from 2005 to 2007. The top panel of the figure shows the quantities of scheduled energy curtailed by the TLR events.

Figure 55: Monthly TLR Activity
2005 to 2007

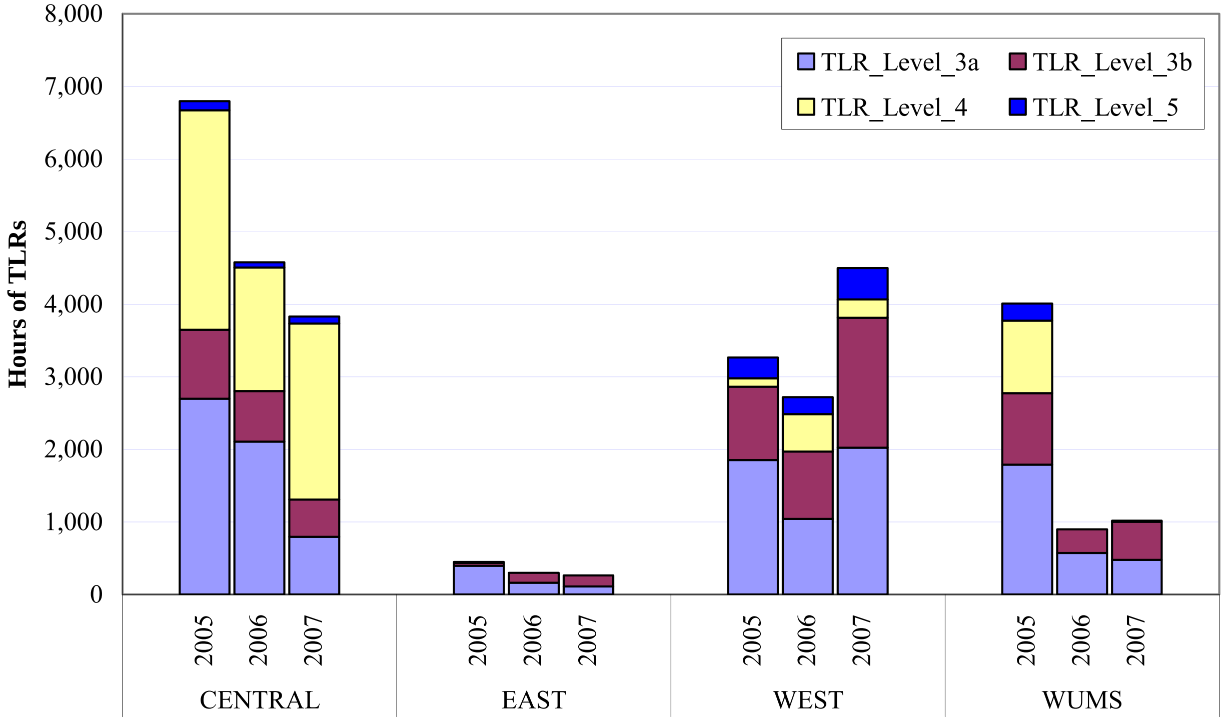


This figure shows that the TLR calls by the Midwest ISO decreased after the implementation of the energy markets in 2005. The implementation of the markets was not expected to reduce the TLR calls substantially because the Midwest ISO was still to invoke TLRs to ensure others outside of the Midwest ISO assist in relieving congestion.

Although the significant quantities of TLR events are still invoked, economic redispatch has become the primary means for managing congestion. The reduction in TLR events has translated into fewer schedule curtailments. Curtailments in 2007 were almost 50 percent lower than in 2005 and 18 percent lower than the curtailments in 2006. With regard to the patterns of

TLR activity in 2007, the figure shows TLR activity increased early in the year as congestion into the West increased. TLR activity also increased in October and November of 2007 due to problems with Available Flowgate Capacity ("AFC") calculations on flowgates in the West region. Figure 56 shows the number of TLR events by region during 2005 - 2007.

Figure 56: TLR Events by Duration
2005 to 2007



The figure shows that in all regions except the West, TLR activity has decreased substantially since 2005. In the West region, congestion increased markedly in 2007 due to reduced availability of imports over the Manitoba interface and high winter loads in early 2007. In addition, errant AFC calculations caused over-scheduling of import capability in the day-ahead market. This over-scheduling compelled the Midwest ISO to invoke TLRs to curtail real-time schedules in late 2007.

Level-4 TLR events have been eliminated in WUMS. Prior to the Midwest ISO markets, American Transmission Company redispatched generation when level 4 TLR events were called. This redispatch is now accomplished through the Midwest ISO energy markets.

E. Congestion Manageability

Congestion management is one of the most important activities of the Midwest ISO. In real-time, the Midwest ISO is monitoring thousands of potential network constraints throughout the region. As the flows over these constraints approach their limit (or if they are anticipated to do so) in real-time, they are "activated" in the market model. The Midwest ISO's real-time market model will then manage the flows on the activated constraints to keep the flows below the operating limits on the facilities while minimizing overall production costs.

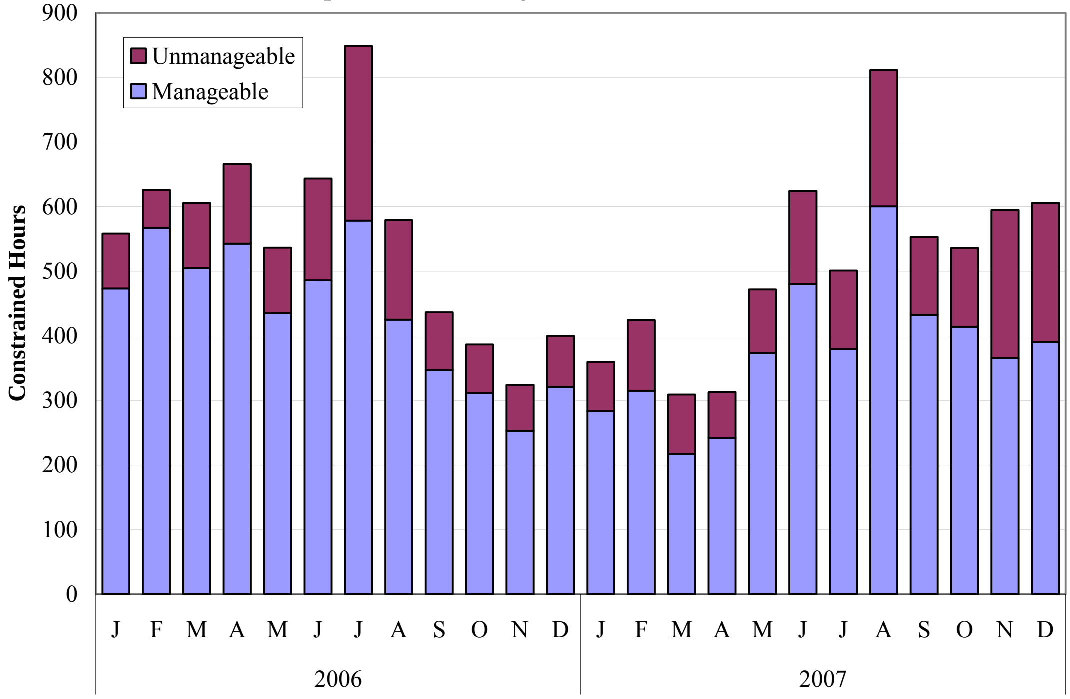
A real-time LMP-based energy market will redispatch generation subject to transmission constraints on the network. This process utilizes the redispatch capability of generators, especially ones with relatively large impacts on the constraints. The available redispatch capability is reduced when:

- The generators most effective at relieving the congestion are not online;
- Their flexibility is reduced (i.e., narrow EcoMax to EcoMin range or low ramp rate); or
- Generators are already at their limits (e.g., generators in the constrained area 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 – reliability standards require the flow to be less than the limit within 30 minutes (not within five minutes). 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 warrents evaluation. Figure 57 shows the frequency with which constraints were unmanageable in each month.

Figure 57: Unmanageable Constraints
April 2005 through December 2006

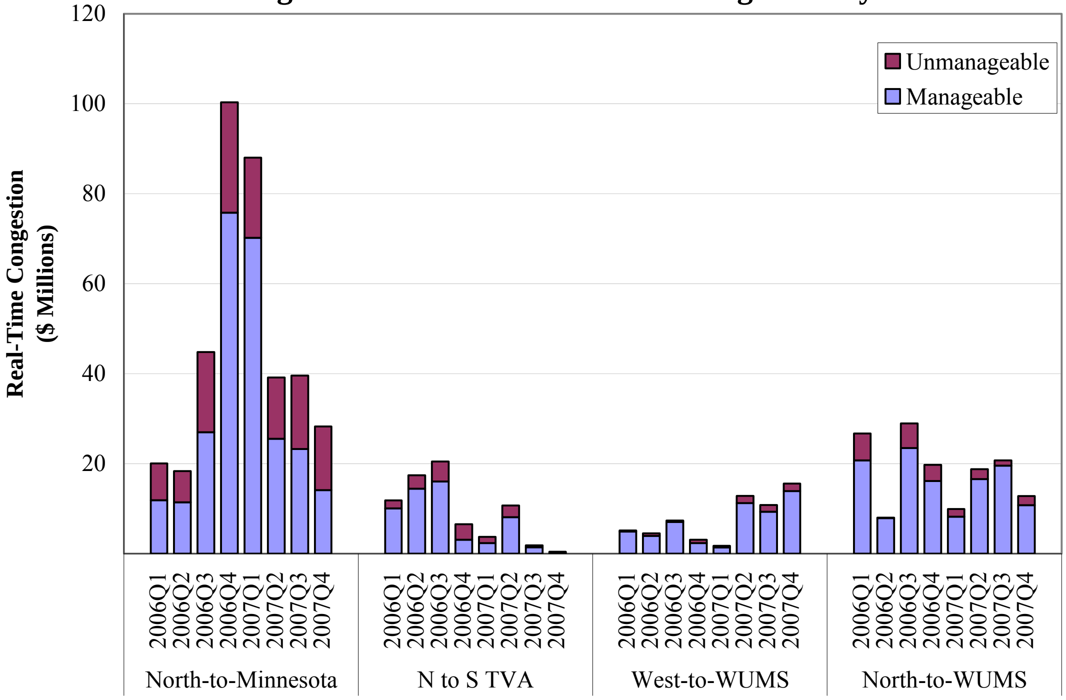


Our analysis indicates that 74 percent of the congestion was manageable on a five-minute basis in 2007, which represents a decrease from 80 percent in 2006. Inflexible supply offers cause some of the unmanageability, which indicates a potential concern with the incentives the markets provide to be flexible. This 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.

The Price Volatility Make Whole Payment ("PVMWP") element of the ASM should address this incentive issue and cause suppliers to offer greater flexibility that will ultimately improve the manageability of congestion on the Midwest ISO system. The PVMWP is intended to ensure that suppliers responding flexibly to the Midwest ISO's prices and dispatch are not harmed by doing so.

In order to show how the manageability of congestion varies at different locations, our next analysis illustrates the share of the congestion on selected interfaces that was manageable. This is shown in Figure 58.

Figure 58: Value of Real-Time Congestion by Path



This figure shows that congestion in 2006 and 2007 was greatest on the interfaces into Minnesota and into the WUMS NCA. Thirty-two percent of congestion on the North-to-Minnesota path during these two years was unmanageable, compared to only 12 percent for the western interface into WUMS and 15 percent for the north-to-WUMS interface. The Commission approved the Minnesota NCA designation in January 2007 in response to the increased frequency of the congestion into the area. The manageability on WUMS constraints improved substantially in 2007 due in part to transmission additions that reduced flows on the Eau Claire-Arpin line.

The north-south congestion to TVA was a significant factor during the first two years of Day 2 operations. During 2007, however, the total congestion along this path declined by more than 70 percent due to better coordination with PJM and changes in market demands.

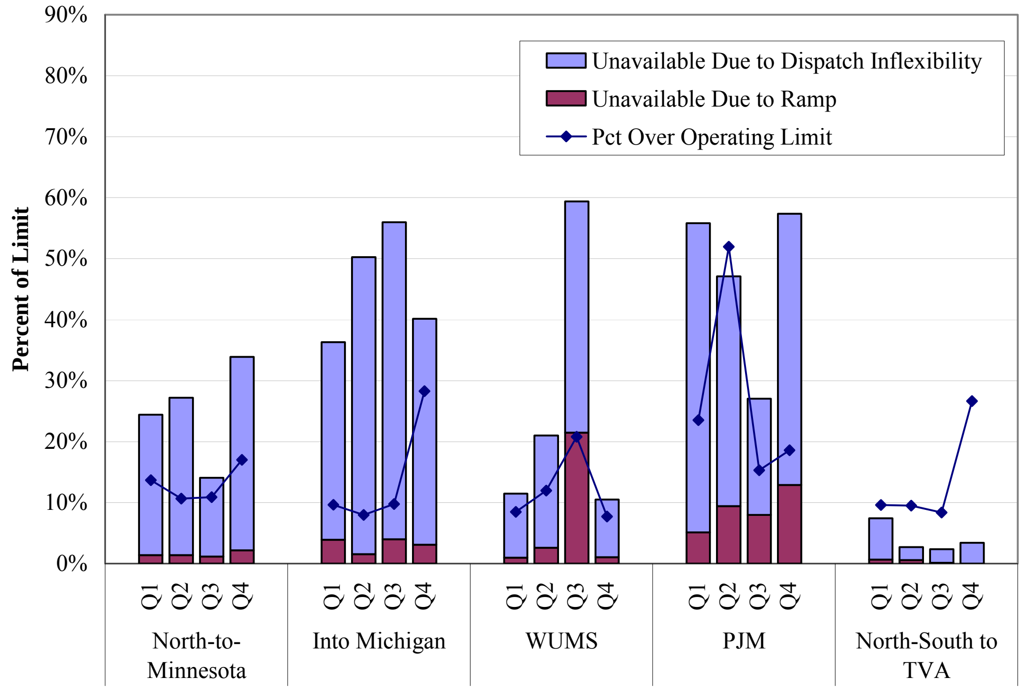
Our next analysis evaluates two components of suppliers' offer patterns that contribute to the unmanageability of transmission constraints. The first is the submission of inflexible dispatch parameters, which removes redispatch capability from the market model. When a participant sets EcoMin levels much higher than the physical minimum output levels (i.e., prevents the market model from reducing the output of a resource), 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 participant setting its ramp rates at a much slower rate than the physical ramp capability of a resource (i.e., reduces the speed with which generation 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.[27]

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. The results of this analysis are shown in Figure 59. The bars in the figure represent the amount of relief that was unavailable as a percent 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.

Figure 59: Congestion Relief Unavailable Due to Offer Parameters

Selected Paths



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

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

As mentioned previously, participants could be concerned that responding to dispatch signals when prices are volatile could reduce the supplier's profit. This issue is being addressed though the Price Volatility Make While Payment element of ASM.

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. Currently in the real-time market, units with generation shift factors ("GSFs") less than two percent (or greater than -2 percent) are not redispatched to manage a constraint. A generation shift factor indicates the amount by which the flow on a constraint will change when the output of a unit changes. 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 last year's report, we showed that the average additional relief available by lowering the GSF cutoff 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 recently received a software modification that will allow it to reduce this parameter in both the real-time and day-ahead markets. Although manageability of constraints should improve, we continue to be concerned about the market outcomes when constraints are in violation.

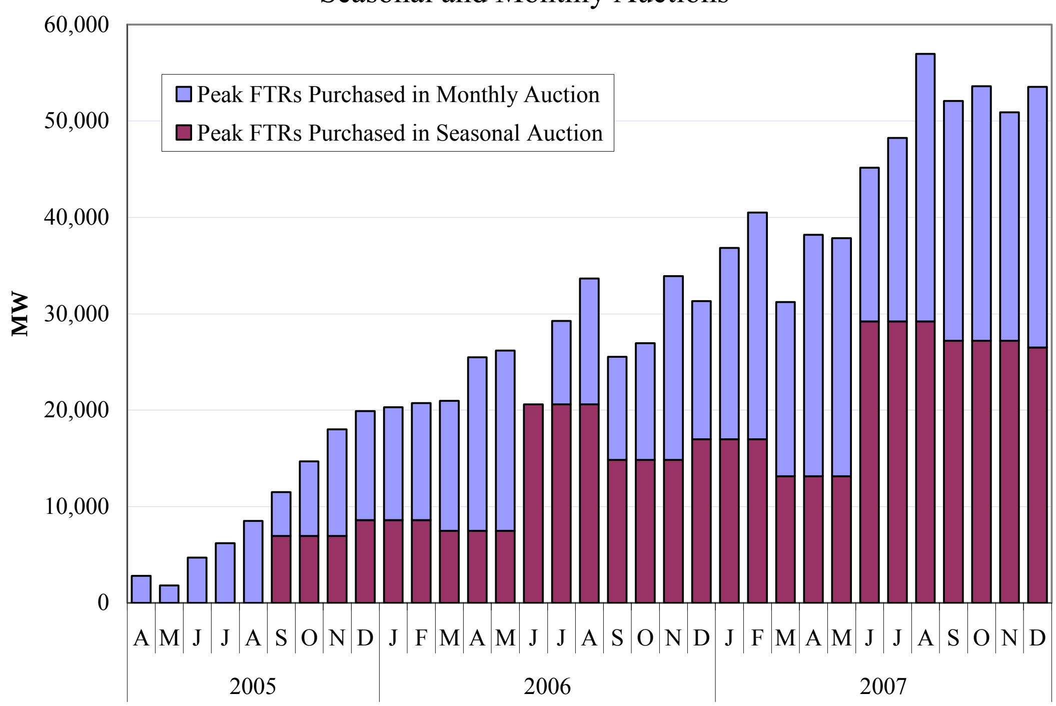
In addition, we have studied the constraint relaxation algorithm used when a constraint is in violation to produce a shadow price for the constraint (the marginal economic value of the constraint that is used to calculate LMPs). The same algorithm is used by PJM and New England. Based on our analysis, we have concluded that this algorithm often produces inefficient shadow prices that distort the associated LMPs. For example, in more than 20 percent of the cases when a constraint is violation, the relaxation produces a zero shadow price (indicating no congestion). The more efficient approach in this case is 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 on the constraint penalty factors.

F. FTR Auction Prices and Congestion

As discussed in subsection V.A, above, the Midwest ISO administers a market for Financial Transmission Rights that allow 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 to market participants based upon physical uses of the system [by network customers?] on an annual and monthly basis. The Midwest ISO then auctions additional FTRs on a seasonal and monthly basis. Figure 60 summarizes the quantities of FTRs for peak hours that were sold in the various FTR auctions.

Figure 60: FTR Purchases

Seasonal and Monthly Auctions



The figure shows that the total quantity of FTR purchased in the Midwest ISO auctions have been rising relatively steadily from 2005 to 2007 because fewer FTRs are being allocated in advance of the auctions. This is also caused by full subscription of the system. A large portion of the increased purchases in 2007 were made through the monthly auctions. The larger monthly sales allow the Midwest ISO to use more timely information on the state of the network when it determines the quantity of FTRs to sell, which should reduce the FTR surpluses and shortfalls. The increased quantities may indicate that the liquidity of the FTR markets is increasing, which should improve their performance. A well-performing market will produce prices that efficiently reflect expectations of congestion on the network. The rest of the analyses in this section is designed to evaluate the performance (and liquidity) of the FTR markets.

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 on the congestion in the day-ahead market. In a liquid FTR market, the profits should be relatively low because the market-clearing price for the FTR should reflect the expected value of congestion payments to the FTR. Figure 61 shows FTR profitability for seasonal FTRs.

Figure 61: FTR Profitability: Seasonal Purchases

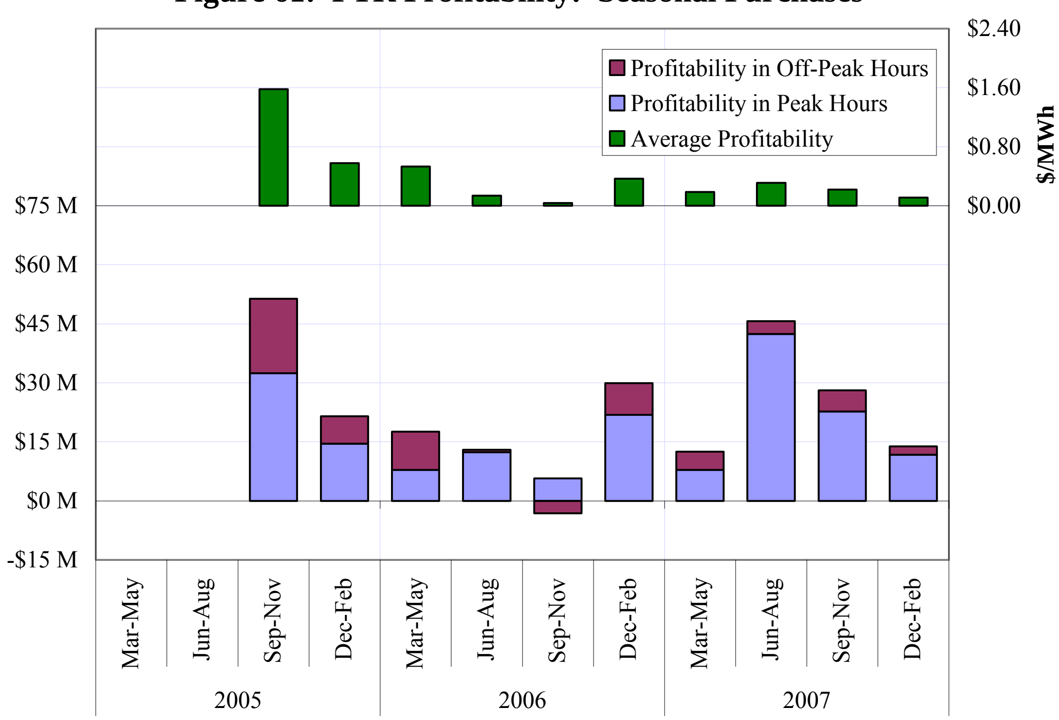
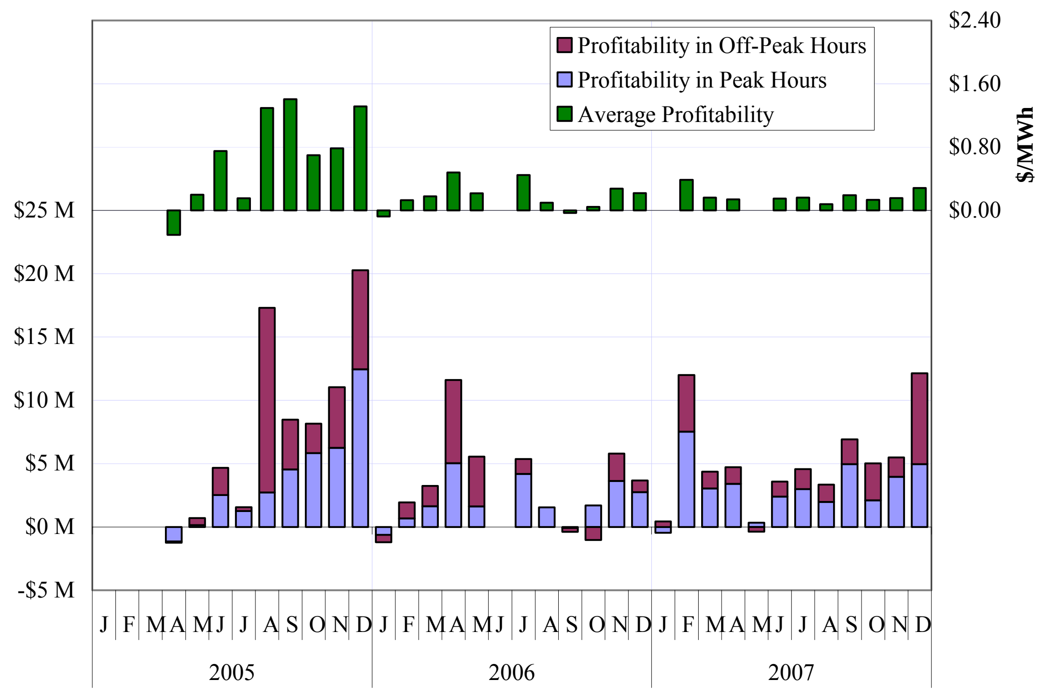


Figure 61 shows that average FTR profitability has declined from more than \$1.50 per MW in the fall of 2005 to less than \$0.30 per MW on average in 2007. Profitability is greater in peak hours than off-peak hours primarily because congestion is greater and more volatile in the peak hours. The reduction in the profitability indicates that the performance of the market has improved over time as participants have gained experience.

Figure 62, shows the same analysis for the monthly auctions. It shows that average profitability has decreased from more than \$1.30 per MW in three months late in 2005 to less than \$0.20 per MW in most months in 2007. 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 62: FTR Profitability: Monthly Purchases



To further evaluate the performance of the FTR markets, our next analysis compares the monthly FTR prices to day-ahead congestion. As noted above, a well-functioning market should produce the FTR prices that reflect a reasonable expectation of the day-ahead congestion. The results of our next analysis explain the changes in FTR profitability shown above. Figure 63 and Figure 64 show the results of our analysis for WUMS in peak and off-peak hours, respectively. All the values in the figures are computed relative to the Cinergy hub.

Figure 63: Comparison of FTR Auction Prices and Congestion Value
WUMS Area: Peak Hours

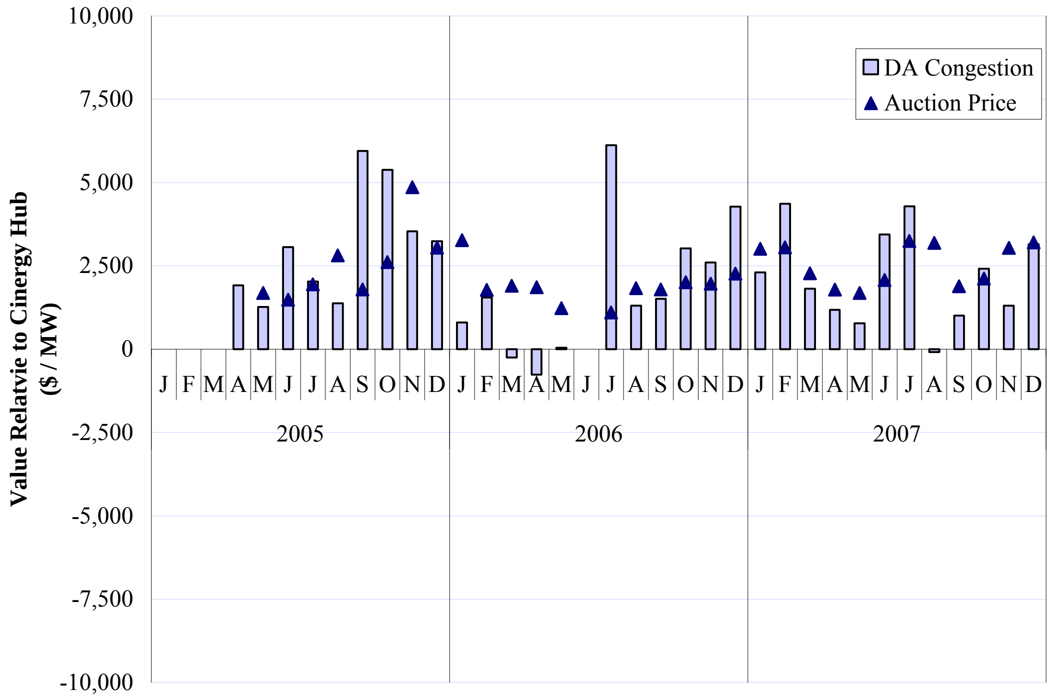
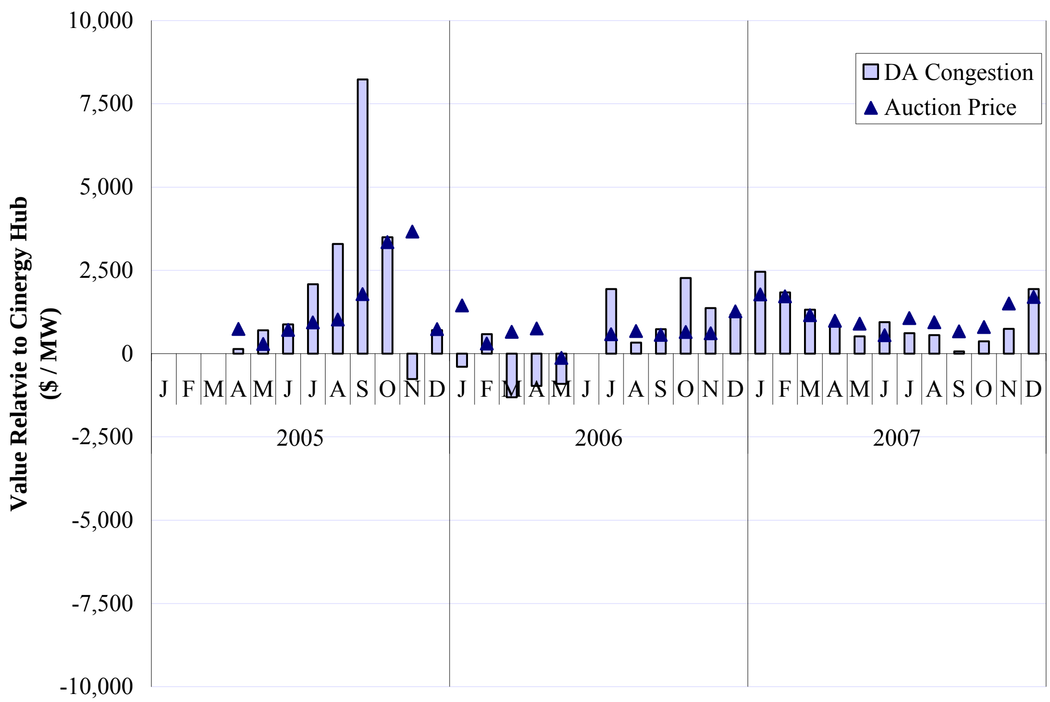


Figure 64: Comparison of FTR Auction Prices and Congestion Value
WUMS Area: Off-Peak Hours



There was slightly more day-ahead congestion in 2007 into WUMS and the FTR values reflect this change. From July 2006 to December 2007, convergence between auction prices and congestion has been strong, particularly in off-peak hours. The only month in which peak-hour FTR prices and congestion costs did not converge well was August. However, the lack of convergence was not due to unreasonable FTR prices, but to anomalously-low day-ahead congestion into WUMS during the month. 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 65 and Figure 66 show our analysis for the Minnesota Hub in peak and off-peak hours, respectively. The figures show that congestion has fluctuated substantially throughout the period from 2005 to 2007. In addition to volatility, the difficulties in valuing the FTRs are exacerbated by the fact that the congestion can change directions. The Minnesota hub exhibited negative congestion of nearly $10,000/MW during off-peak hours in August 2005. The negative congestion in 2005 was due to congestion into WUMS that was often difficult to manage, particularly in off-peak hours, due to dispatch inflexibility.

Congestion reversed direction (from negative to positive) in the fall 2006 due to increased south-to-north constraints into Minnesota that continued until spring 2007. In both peak and off-peak periods, auction prices rose during each month between September 2006 and February 2007. The increased congestion into Minnesota was largely due to the reduced availability of imports over the Manitoba interface. Minnesota exhibited positive congestion of nearly $10,000/MW during peak hours of February 2007. This spike in positive congestion occurred during an energy emergency when winter peak loads were very high and imports over the Manitoba interface were limited. However, this event was unusual so it is not surprising that it was not fully anticipated in the FTR prices.

Both figures show that FTR prices into Minnesota responded to changes in congestion patterns with a lag, as one would expect (because FTRs are sold prior to the month in which the congestion occurs). These results are comparable to the results in other parts of the Midwest ISO region.

Figure 65: Comparison of FTR Auction Prices and Congestion Value

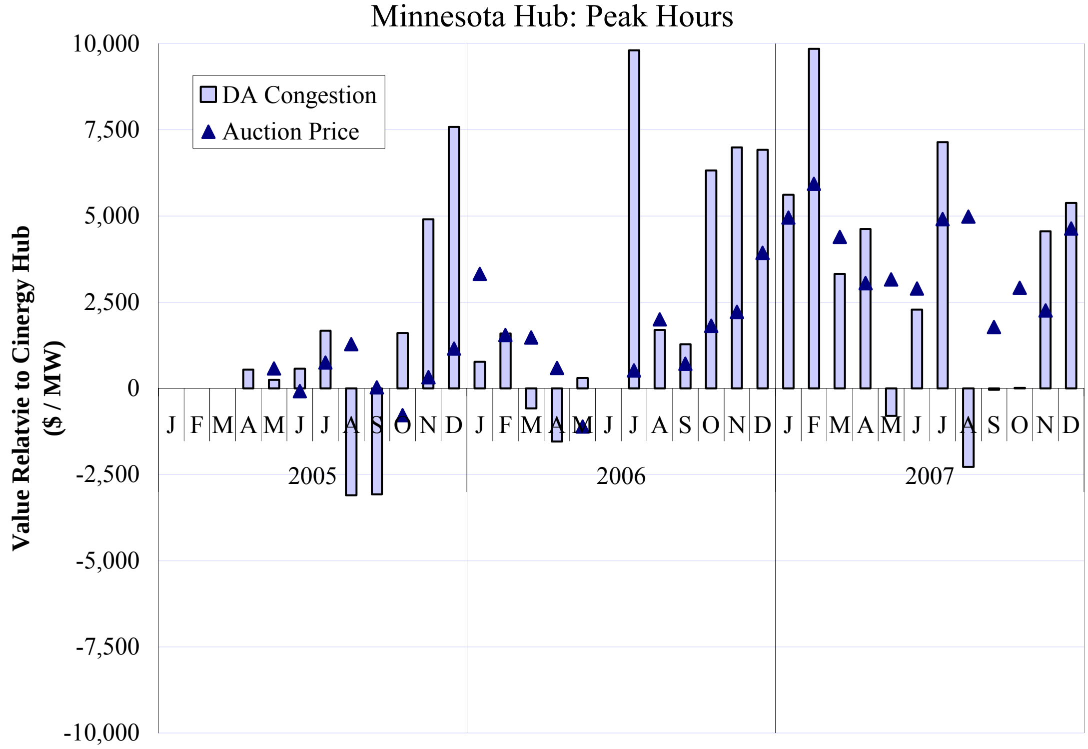
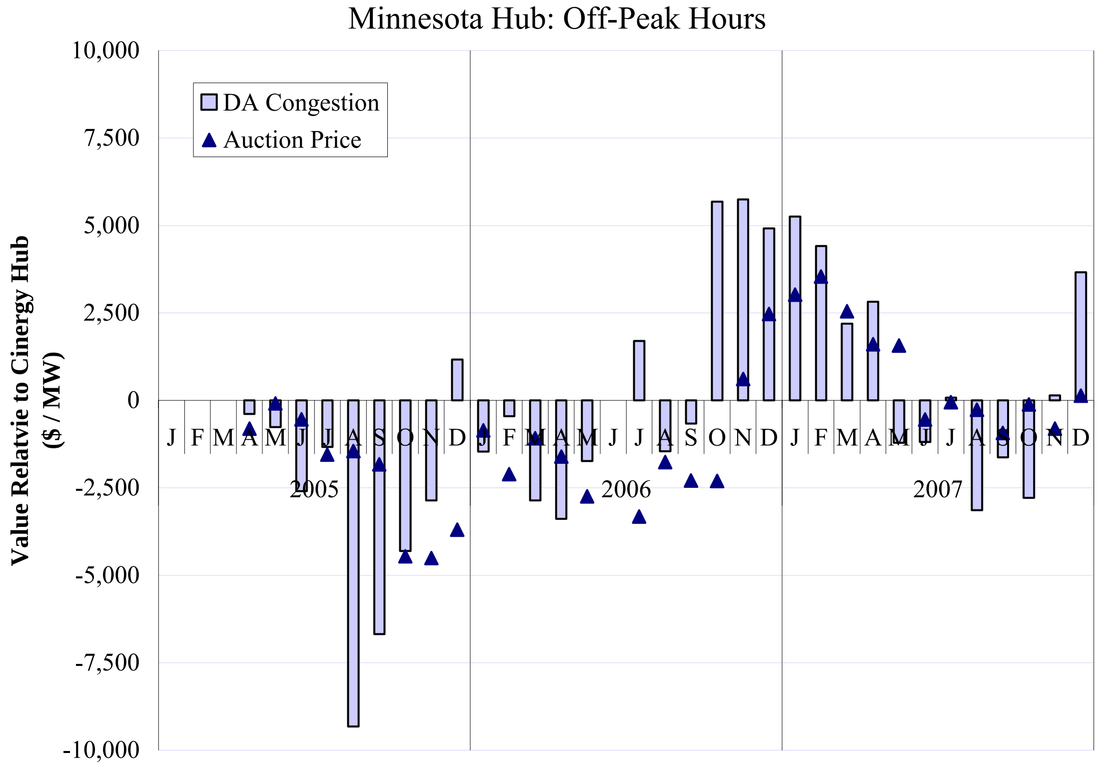


Figure 66: Comparison of FTR Auction Prices and Congestion Value



VI. Competitive Assessment

This section assesses the competitive structure and performance of the Midwest ISO markets during 2007. 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 incentives for the exercise of local market power in congested areas.

A. Market Structure

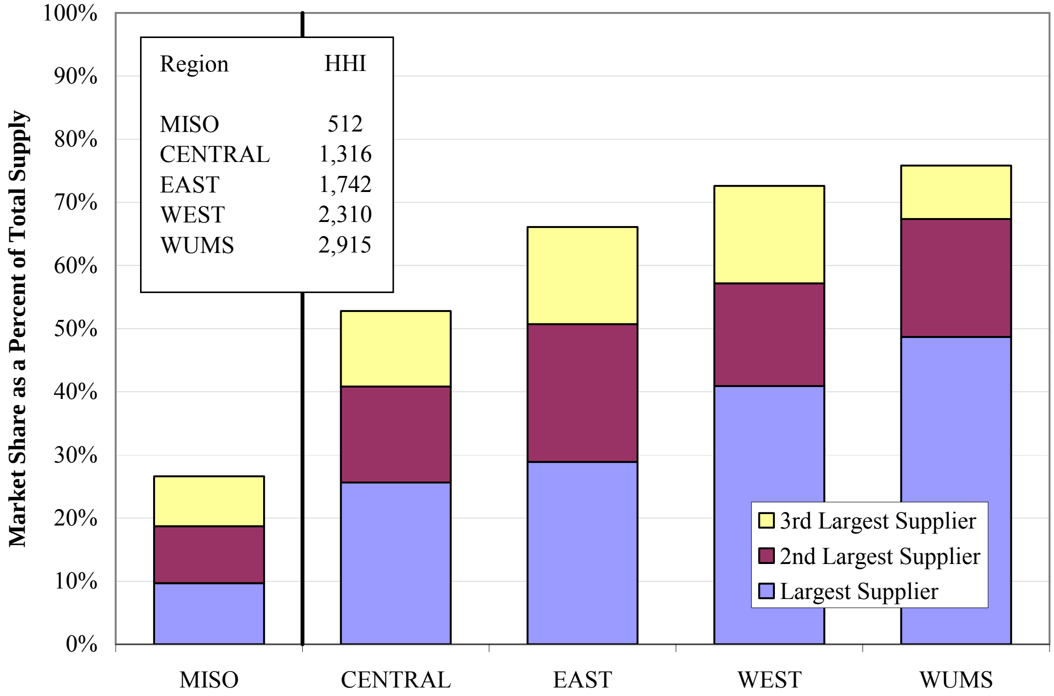
This first subsection provides three structural analyses of the market. The first is an overview of the concentration of both the Midwest ISO region as a whole and the various sub-regions within it. The remaining two analyses address the frequency with which suppliers in the Midwest ISO region are "pivotal", i.e., needed to serve load reliability or resolve transmission constraints. In general, the latter analyses provide a much more reliable 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 is 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



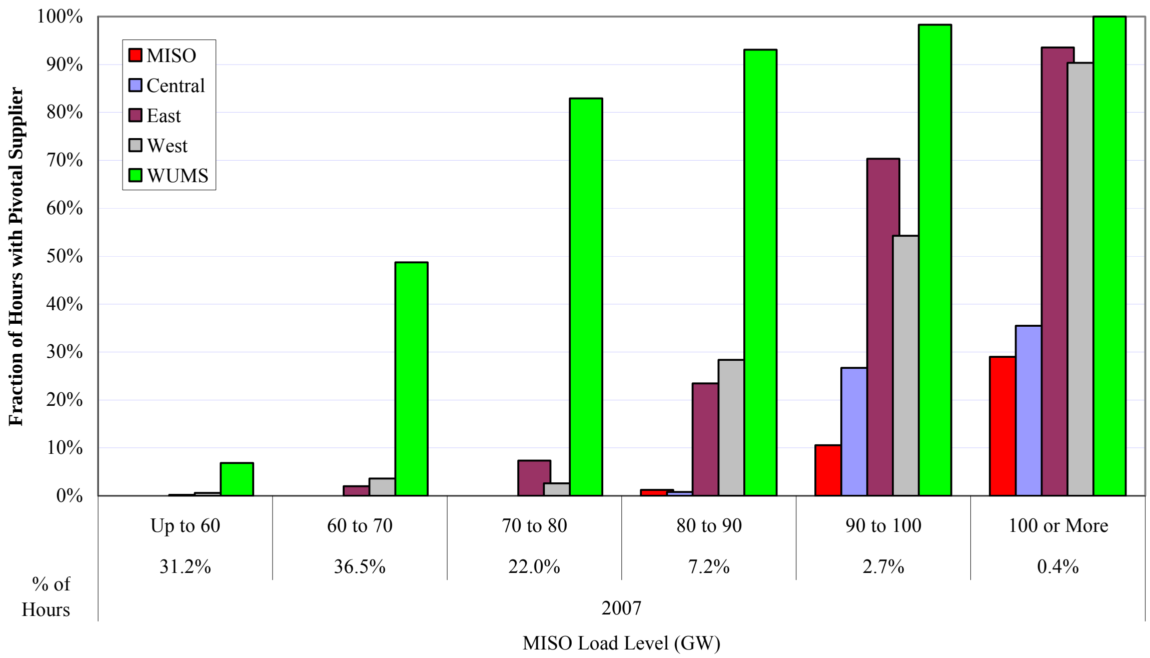
The HHI in the entire Midwest ISO region is 512, which is relatively low. The largest three suppliers combined have a total market share of less than 30 percent. These metrics indicate that the region is generally not concentrated. With the exception of the Central region, however, each of the Midwest ISO sub-regions is highly concentrated. The sub-regional HHIs are higher than those in the sub-regions of other RTOs because vertically-integrated utilities in the Midwest ISO that have not divested generation tend to have relatively high market shares. Divestitures of generation in other RTO regions generally reduce market concentration because the assets are typically sold to a number of different entities.

2. Residual Demand Index

As noted above, while the HHI market concentration calculation is a commonly-used measure of market power, it does not allow one to draw reliable inferences regarding the competitiveness of electricity markets because it ignores factors particularly relevant for such an assessment. The next two analyses more accurately reveal potential competitive concerns in the Midwest ISO energy markets.

The first metric relies upon 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.

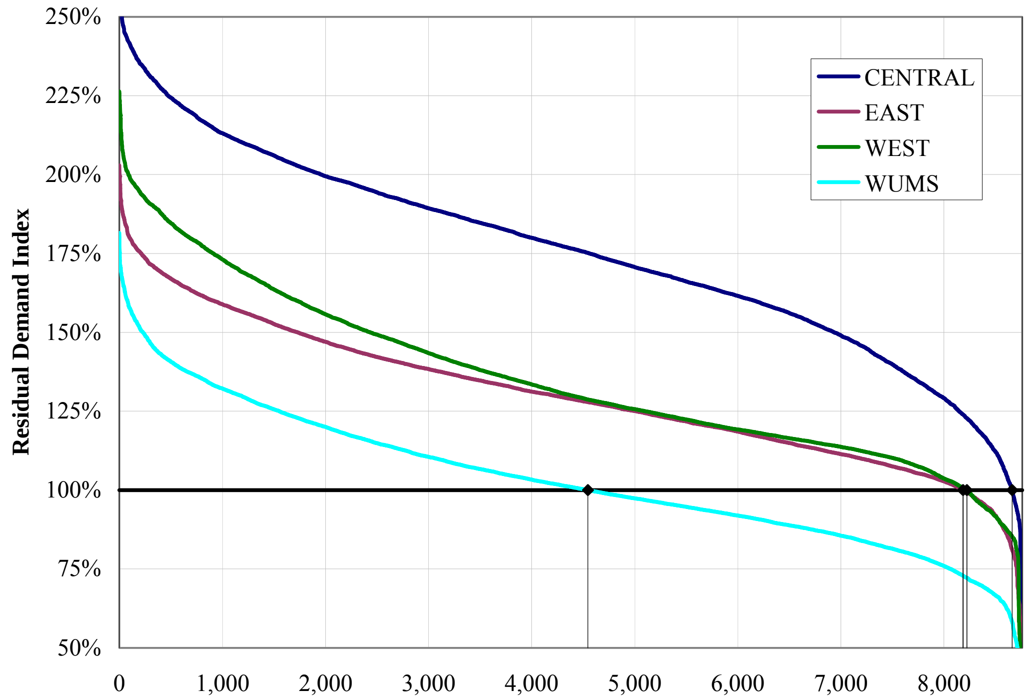
Figure 68: Pivotal Supplier Frequency by Load Levels
2007



The figure shows that in 2007 there was limited competition in the WUMS region at all load levels. When load was higher than 70 GW (about 1/3 of the time), there was a pivotal supplier in WUMS more than 90 percent of the hours. The West and East regions do not exhibit a pivotal supplier in a substantial share of hours, except when load exceeded 80 GW (approximately 10 percent of the hours).

To provide additional information regarding the frequency with which the largest suppliers are pivotal, Figure 69 shows the hourly RDI as an hourly duration curve from its highest (most competitive) to lowest index value (least competitive).

Figure 69: Residual Demand Index Duration Curves
2007: All Hours



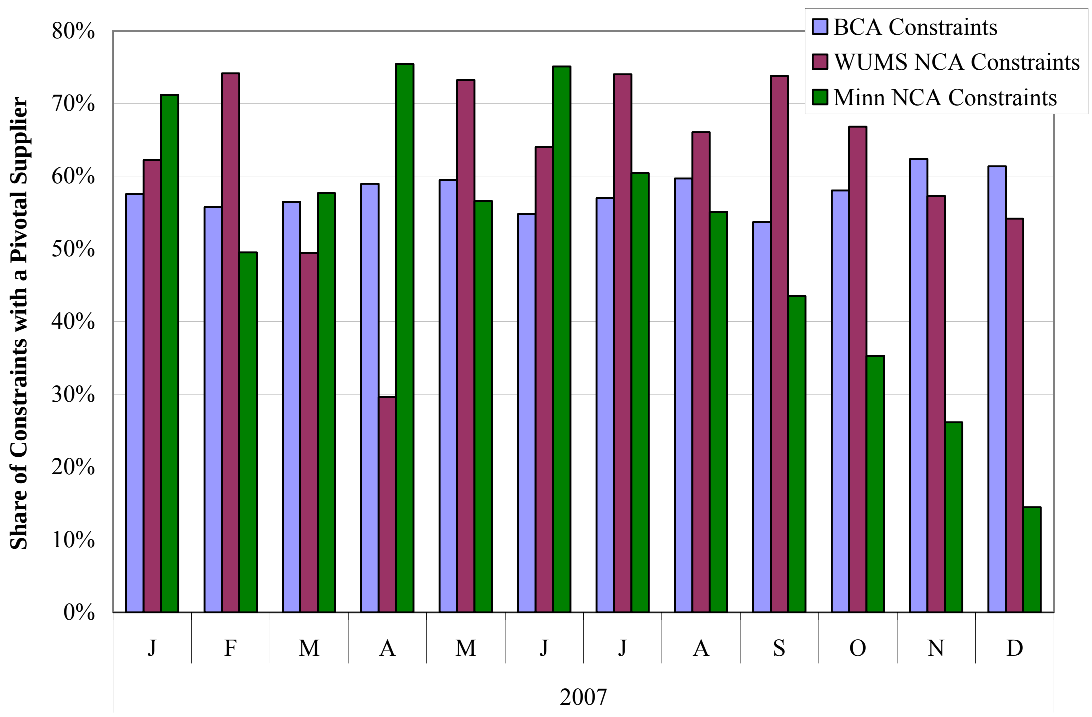
The figure shows the number of hours the RDI for the largest supplier in the given region is greater than 100 percent. For example, the figure shows that for the WUMS region, the RDI was greater than 100 percent in almost 50 percent of hours during 2007. This is one reason WUMS is an NCA under the mitigation measures in the Midwest ISO tariff. The East had a pivotal supplier nearly seven percent of the hours. The West had a pivotal supplier in six percent of hours (the Western region includes the Minnesota NCA that was defined in early 2007 as well as other areas). There were very few hours with a pivotal supplier in the Central region (slightly over 1 percent of the hours).

3. Constraint-Specific Pivotal Suppler Analysis

While the RDI analysis in the prior sub-section is useful for generally evaluating the competitiveness of the market, accurately identifying local market power requires a more detailed analysis focused on specific congestion issues. Accordingly, the analyses in this sub-section seeks to detect potential local market power concerns by identifying when a supplier is pivotal relative to a particular transmission constraint. A supplier is considered pivotal for a constraint when its resources are needed to manage the transmission constraint (i.e., it has the ability to overload the constraint such that other suppliers cannot unload it). 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 these resources are all owned by the same supplier, this supplier is likely to be pivotal.

Figure 70 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 70: Percentage of Active Constraints with a Pivotal Supplier

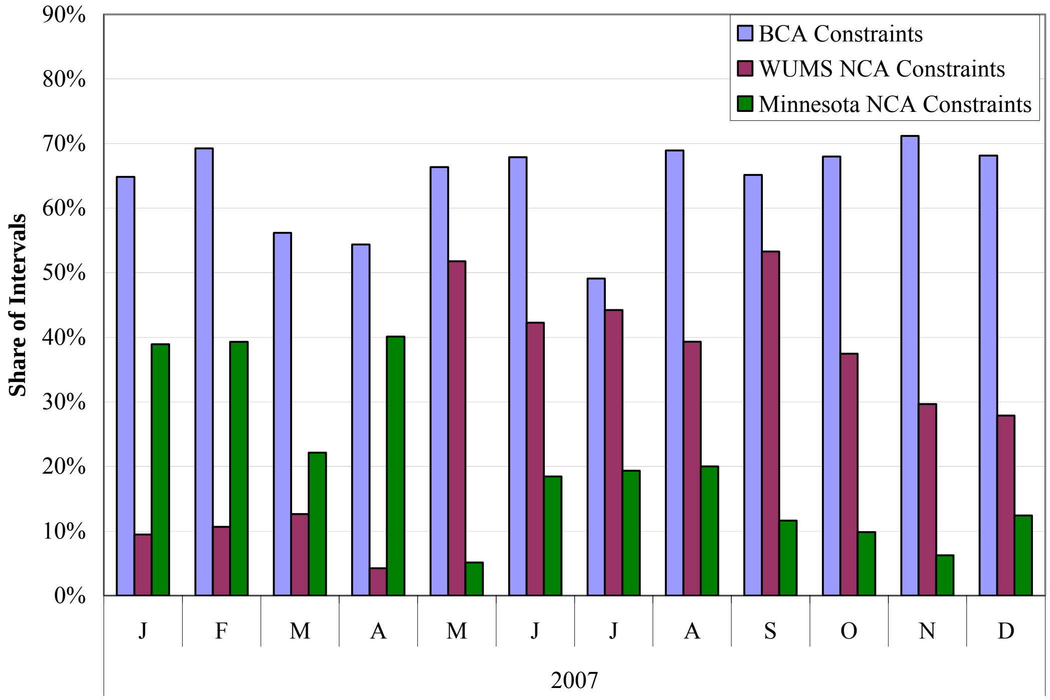


This figure shows that in 2007, 62 percent of the active NCA constraints into WUMS had a pivotal supplier and 52 percent of the active NCA constraints into Minnesota had a pivotal supplier. For BCAs, 58 percent of the active BCA constraints had a pivotal supplier.

These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of BCA constraints in 2007 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 71 shows the percentage of intervals during the market's operation in 2007 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 71: Percent of Intervals with at Least One Pivotal Supplier



This analysis shows that there was an active BCA constraint with at least one pivotal supplier in 66 percent of the hours during 2007. The regional distribution of BCA constraints varied throughout the year, yet the total frequency was relatively constant. The analysis also indicates that there was an active NCA constraint with a pivotal supplier in 30 percent of hours into WUMS and 20 percent of hours into Minnesota in 2007.

Overall, these results indicate that potentially substantial local market power exists throughout the Midwest ISO area. 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 2007 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 generally 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. 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, including 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 operating and maintenance costs). However, at high-output levels or after having run 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. The threshold is used in the market power mitigation "conduct test."

To identify potential economic withholding, we estimate the "output gap" metric, based on resources' start-up, no-load, and incremental energy offer parameters. The output gap is the difference between the 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 is withheld from the market due to the supplier submitting offers above competitive levels. Therefore, the output gap for any unit would generally equal:

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

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

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

To estimate Q_i^{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: start-up 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 start-up, 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 on day-ahead market outcomes for non-quick-start units, and based on real-time market outcomes for quick-start units.

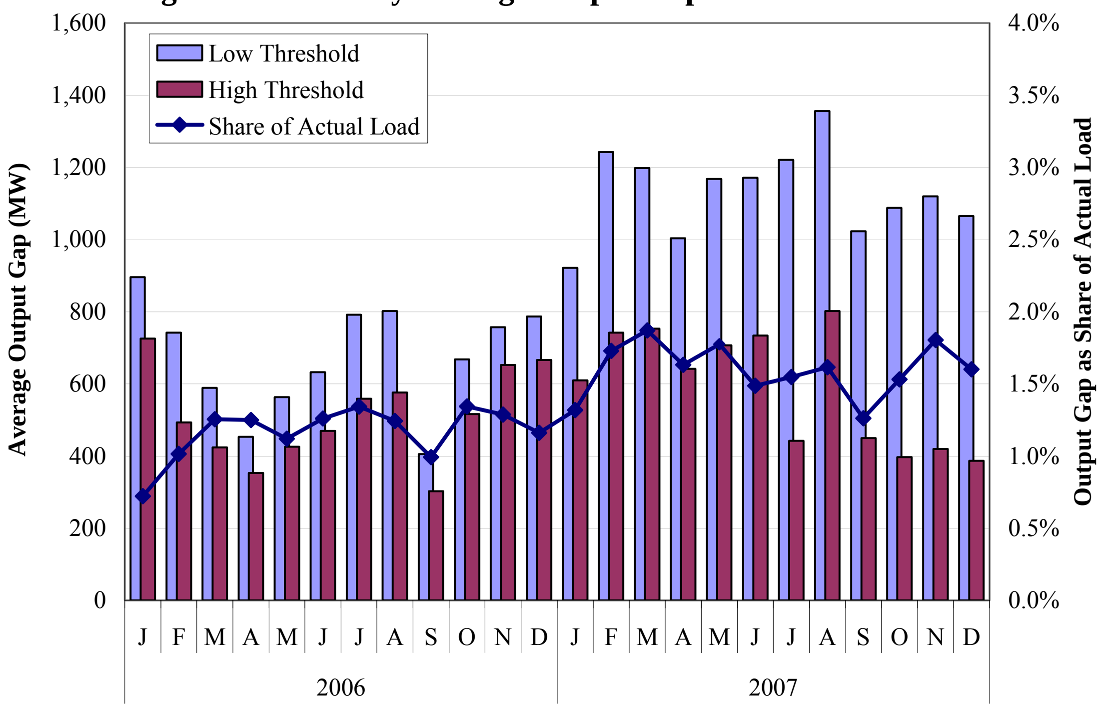
Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some units are dispatched at levels lower than their three-part offers would indicate due to transmission constraints,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

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

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

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 72 shows monthly average output-gap levels in 2006 and 2007.

Figure 72: Monthly Average Output Gap: Real Time Market



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 lower threshold would indicate potential economic withholding with offers slightly below the mitigation threshold.

This analysis shows that the output gap rose modestly at the beginning of 2007. This was primarily due to the designation of the Minnesota NCA, which resulted in lower thresholds used to calculate the output gap for 2007 in this area. Other than this effect, the output gap levels were stable. These levels provide 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 relatively 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 market power.

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 small suppliers. Load level is important because the sensitivity of prices 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 high-cost resources (or no resources) that can respond to the withholding.

The effect of load on potential market power was evident early in this section in our pivotal supplier analyses. Therefore, 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 73 through Figure 76 show the results of our output gap analysis for each of the Midwest ISO sub-regions.

Figure 73: Real-Time Market Output Gap
Central Region

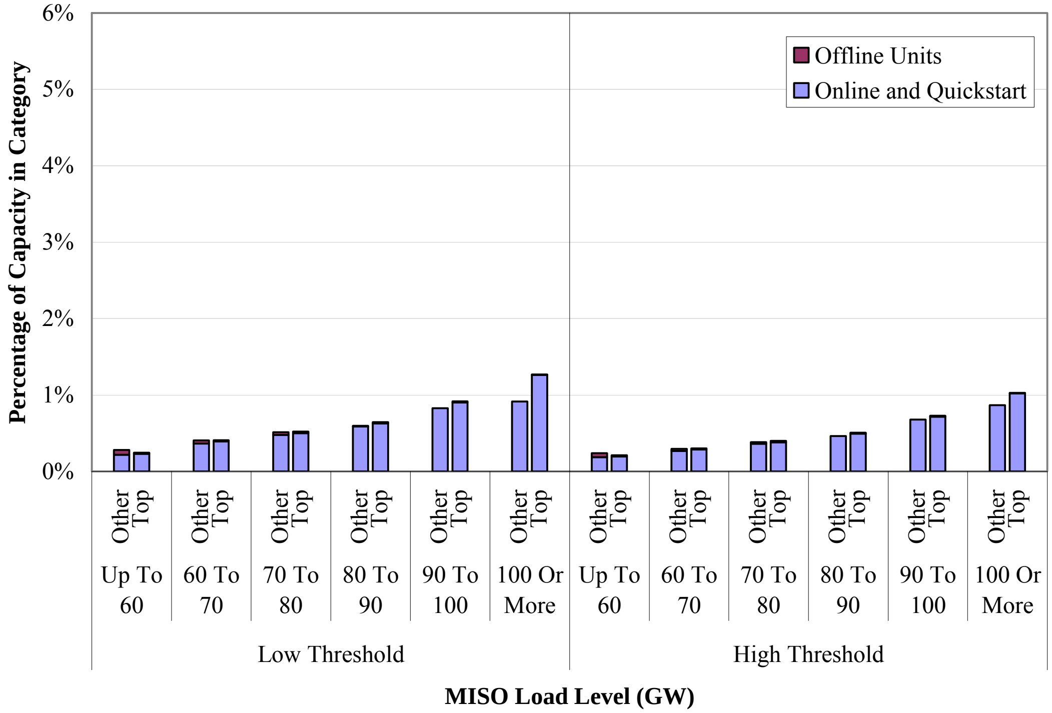


Figure 74: Real-Time Market Output Gap
East Region

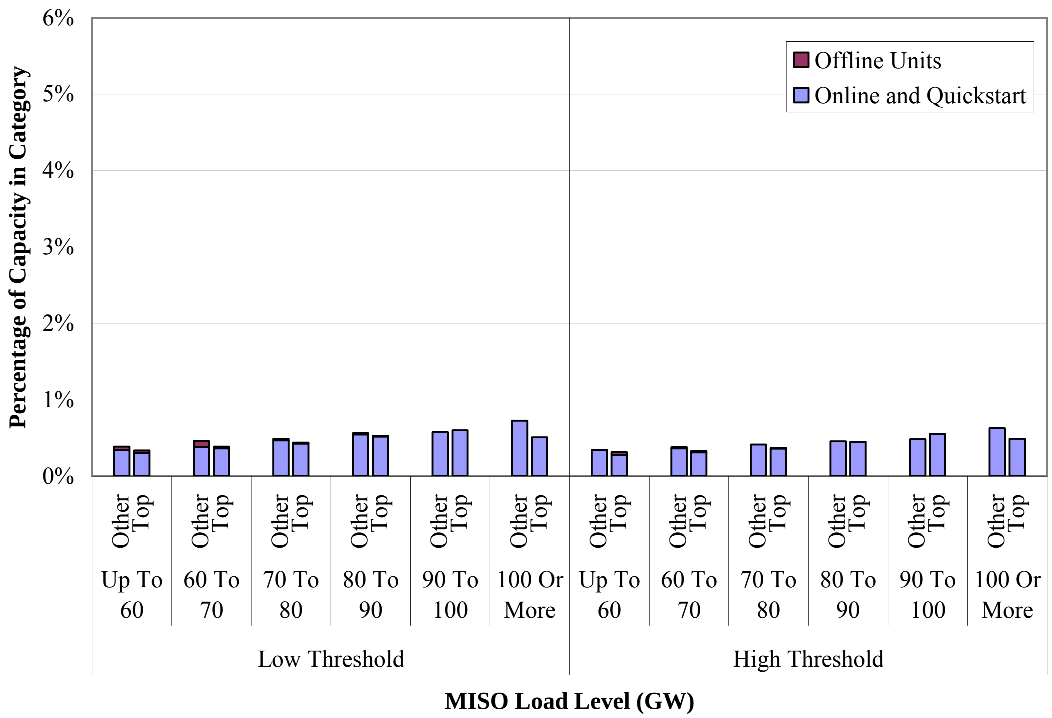


Figure 75: Real-Time Market Output Gap
West Region

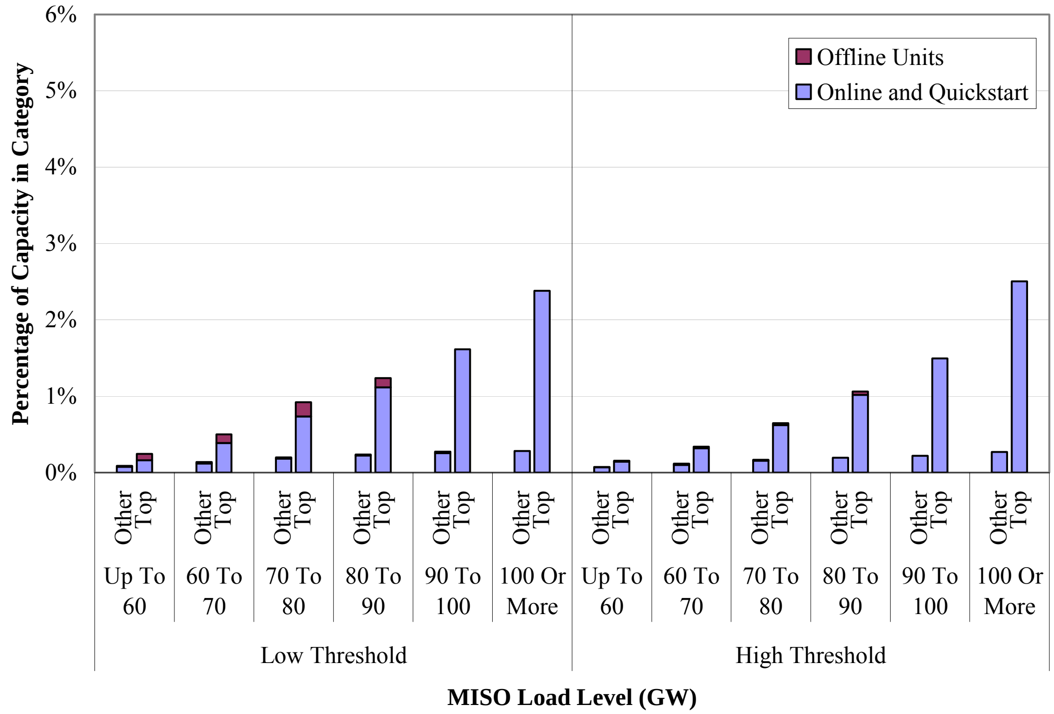
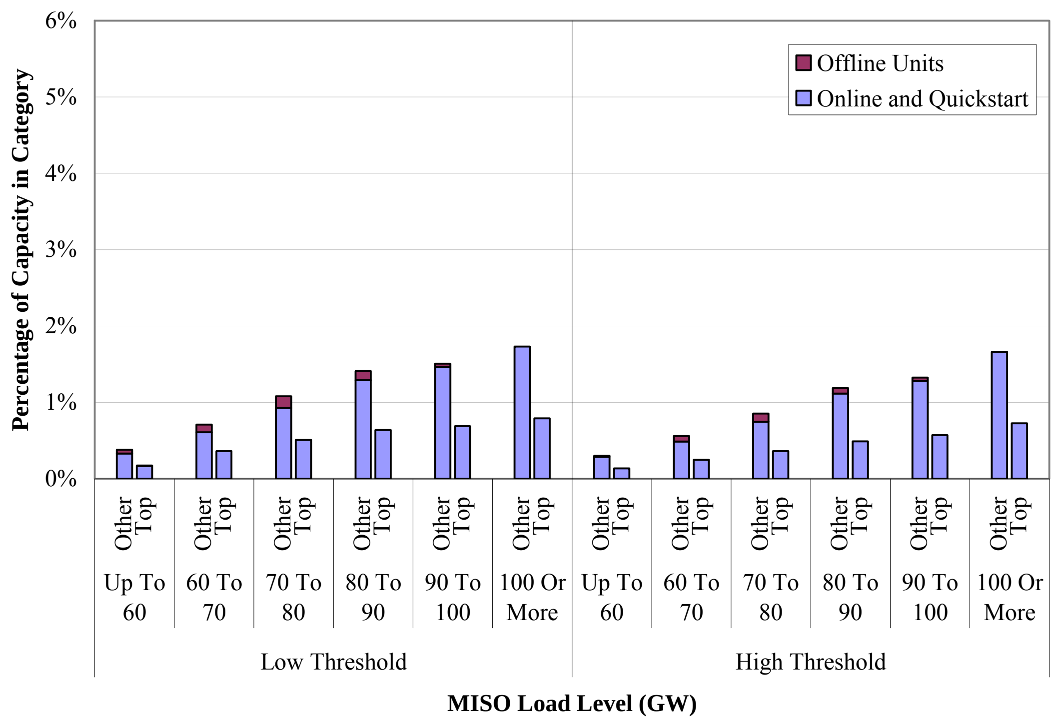


Figure 76: Real-Time Market Output Gap
WUMS



We observe that the output gap quantities at the mitigation thresholds are less than 1 percent at nearly all locations and load levels, with the exception of WUMS and the West. The output gap results are higher in WUMS and the West in part because the thresholds applied to resources in WUMS and the West are the NCA thresholds, not the BCA thresholds. Given the lower thresholds applied to NCAs, the higher output gap results (exceeding 2 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 monitor any increases at higher-load levels very closely on an ongoing basis. Finally, with the exception of the West, the output gap quantities for the largest suppliers are not significantly higher than for other suppliers. The conduct in the West raises some concerns and has been investigated. These results and our subsequent investigations indicate that economic withholding has not been a concern in 2007.

2. Physical Withholding

In this sub-section, we examine forced outages and other unplanned deratings to assess whether participants manipulated 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 market manipulation.

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 all other suppliers combined. Figure 77 through Figure 80 display these results for each of the Midwest ISO's four regions.

Figure 77: Real-Time Deratings and Forced Outages
Central Region

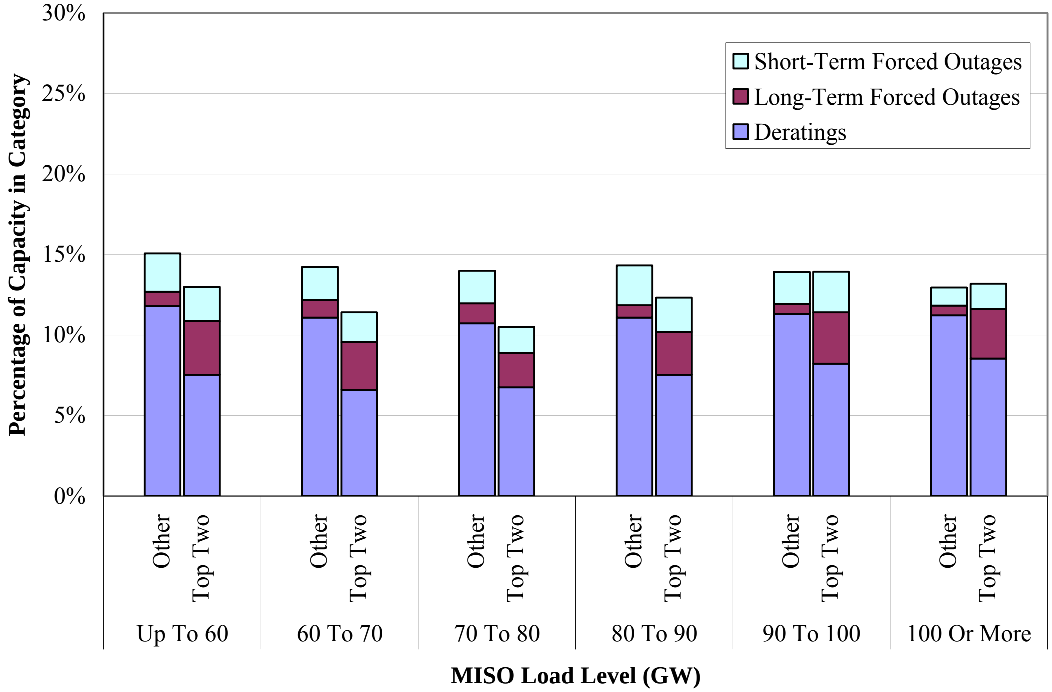


Figure 78: Real-Time Deratings and Forced Outages
East Region

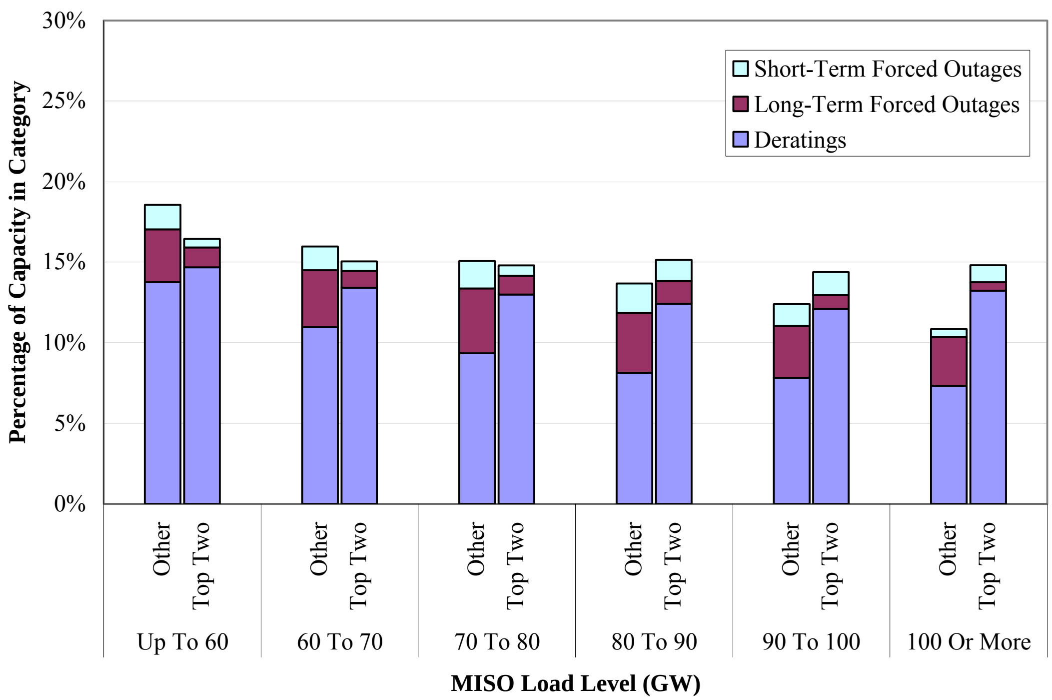


Figure 79: Real-Time Deratings and Forced Outages
West Region

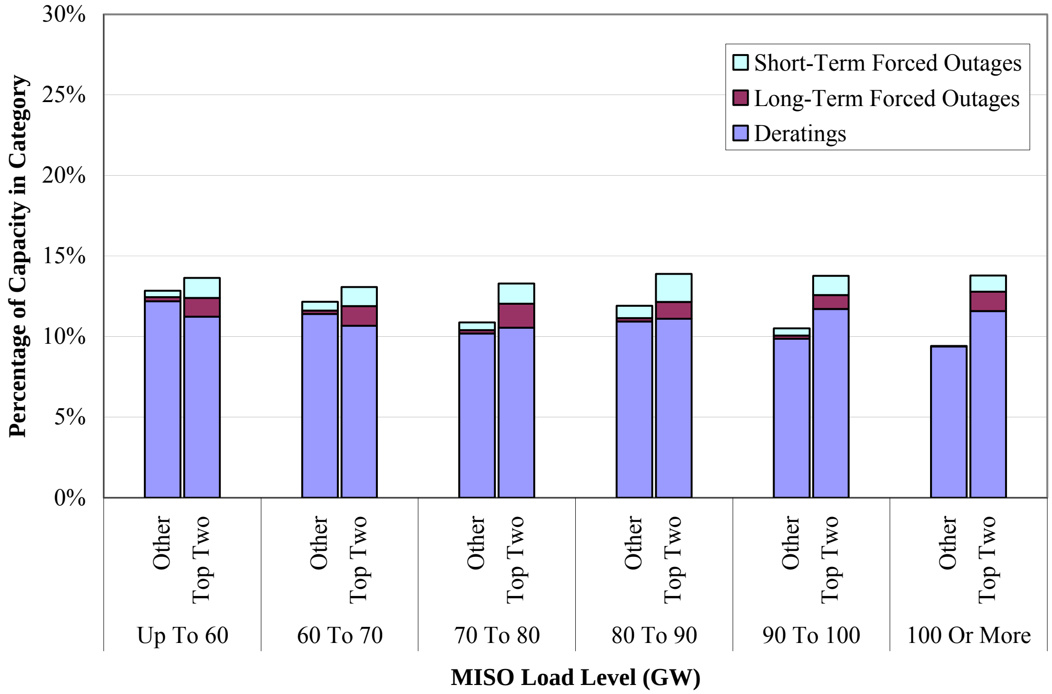
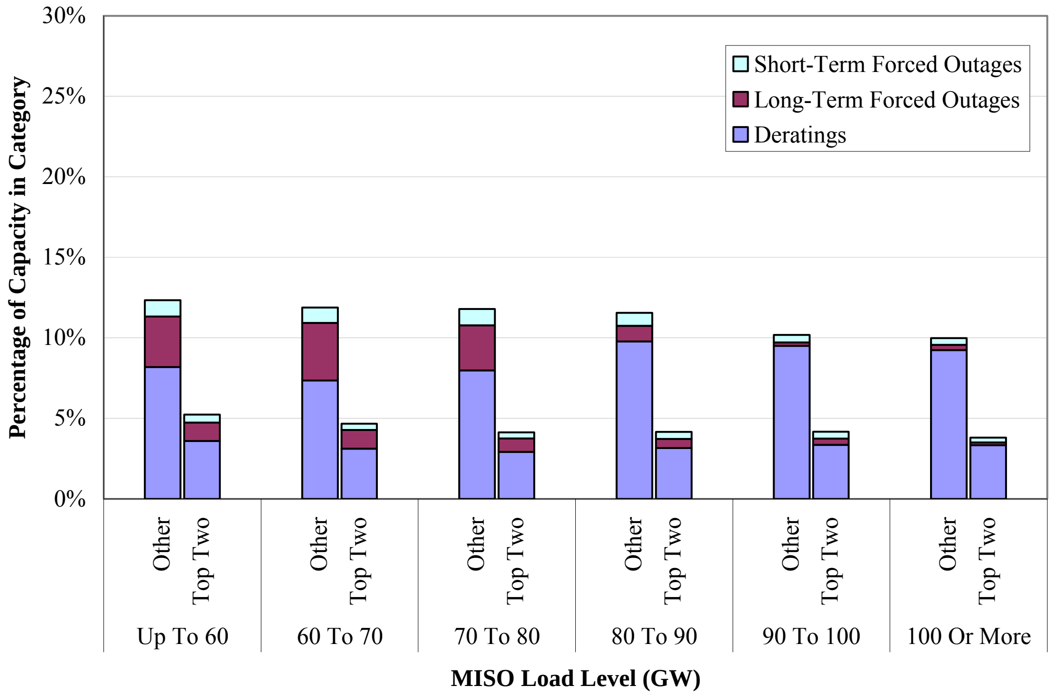


Figure 80: Real-Time Deratings and Forced Outages
WUMS



The data in these figures are presented 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. Taking a long-term forced outage of an economic unit would cause the supplier to miss profits on the units during hours when the supplier does not have market power.

As the figures show, deratings and outages are not significantly higher under peak load conditions, generally remaining under 15 percent. The quantities for the largest suppliers are generally lower than for other suppliers (those that are less likely to have market power). The exception is in the West region, where the largest suppliers generally have outages and deratings slightly higher than other suppliers (who are less likely to have market power). This raises potential concerns. We continue to investigate any outages or deratings that create substantial congestion or other price effects. Audits and investigations have not uncovered any significant attempts to physically withhold generation in 2007.

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 tariff. They are intended to preclude abuses of locational market power while minimizing interference with the market when the market is workably competitive. To that end, the mitigation measures are only imposed 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.

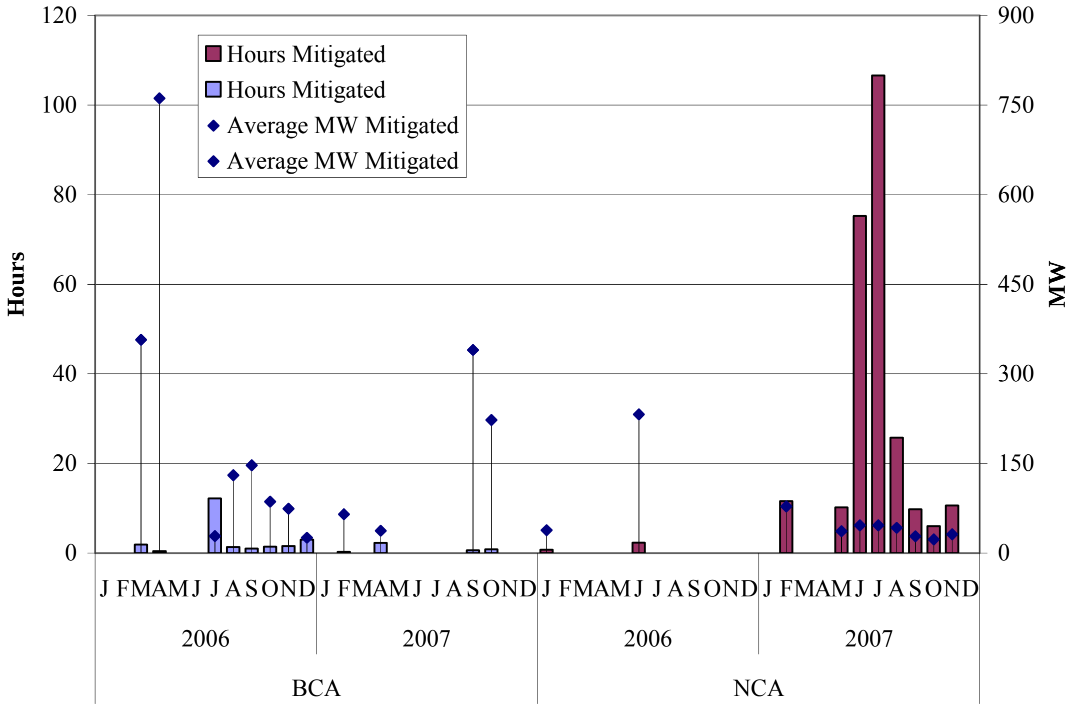
Market Participants are potentially subject to mitigation only when transmission constraints are binding that can create substantial locational market power. When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive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

The definition of BCAs and NCAs is based on 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, but 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 not feasible or desirable to define all possible BCAs in advance. Therefore, BCAs are defined dynamically when non-NCA constraints bind. BCAs include all of the generating units that have a significant impact on the power flows over the constrained interface.

Because the market power concerns associated with NCAs are higher due to their chronic nature, the conduct and impact thresholds are substantially lower than 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 81 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, both classes of mitigation were relatively infrequent. There were 27 unit-hours of BCA mitigation and 256 unit hours of NCA mitigation. Most of the mitigation occurred in June and July 2007 when 182 unit-hours of mitigation occurred, which contributed to the substantial increase in the NCA mitigation in 2007. This increase was largely due to the newly-defined Minnesota NCA in January 2007. Mitigation of conduct in Minnesota accounted for most of the NCA mitigation that occurred in 2007.

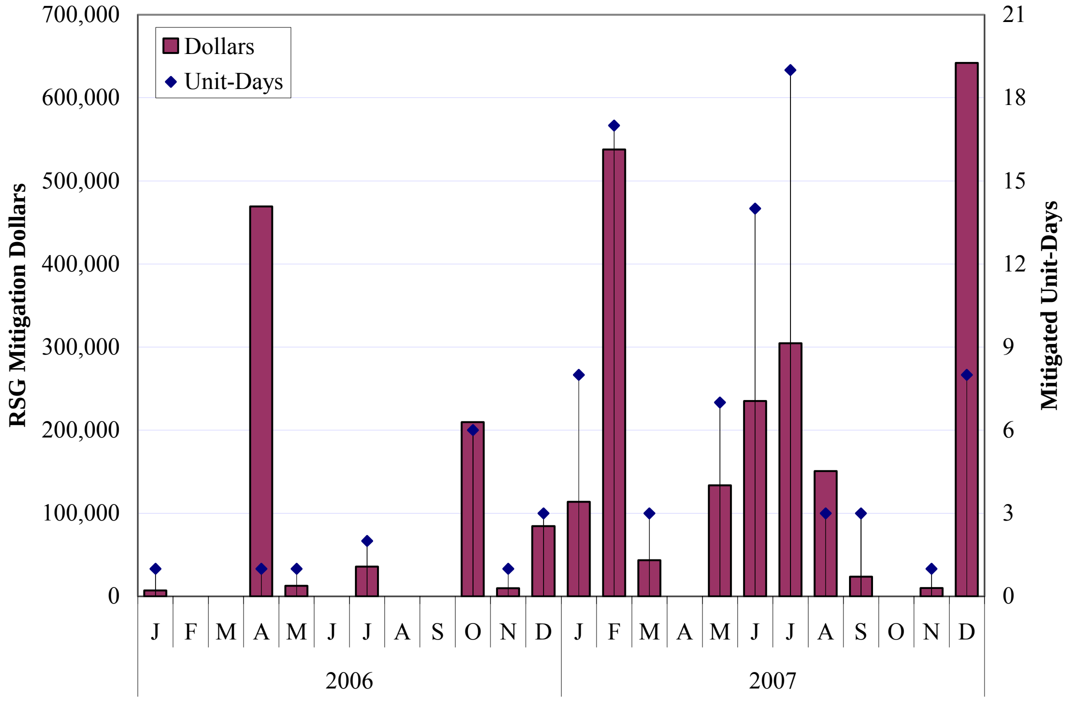
Figure 81: Real-Time Mitigation by Month



Although mitigation was relatively infrequent during 2007, 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 satisfy a local reliability requirement. This can compel the Midwest ISO to make substantially higher RSG payments. The mitigation measures designed to address this conduct are triggered when three conditions are satisfied. These are: (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 82 shows the frequency and amount by which RSG payments were mitigated in each month of 2007.

Figure 82: Real-Time RSG Mitigation by Month



The figure shows that only modest amounts of the total RSG payments were mitigated in most months. Mitigation occurred for 98 unit-days and affected slightly more than $3 million in RSG payments in 2007. While mitigation of RSG was modest, this does not indicate a lack of locational market power.[28]

[28] RSG mitigation in the Minnesota NCA began to be tested at the 50 percent impact threshold in January 2007.

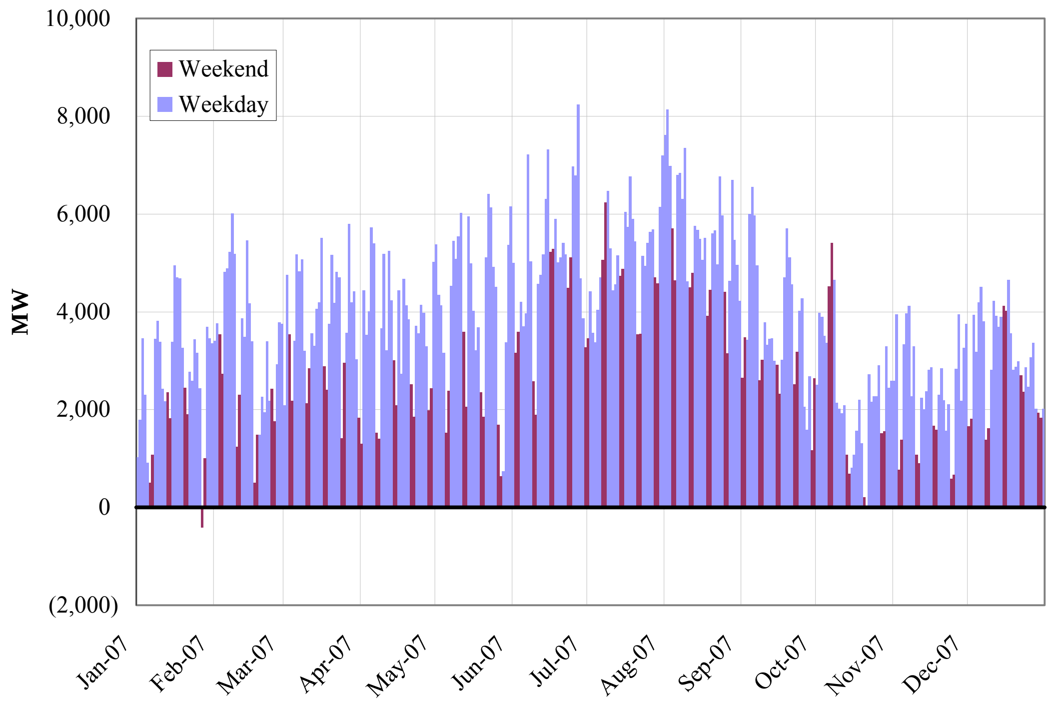
VII. External Transactions

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 2007. 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

We begin this section with an overview of external transactions. Figure 83 shows the average hourly net imports scheduled in the day-ahead market.

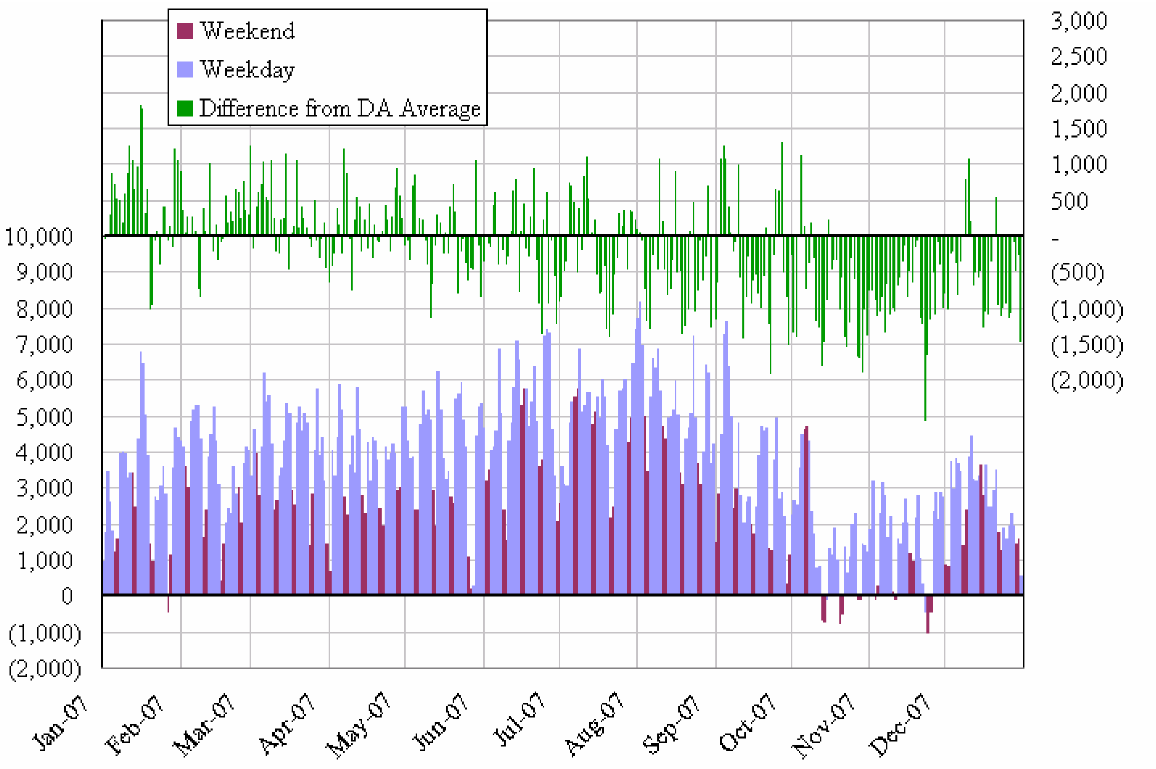
Figure 83: Average Hourly Day-Ahead Imports
All Hours



The figure shows the Midwest ISO is a net importer of power in both peak and off-peak periods due to its reliance on large imports from the West and Canada. As in 2005 and 2006, the pattern of net imports during 2007 was seasonal, with the largest imports occurring during the summer peak-load conditions. Day-ahead hourly imports averaged 3.7 GW and exceeded 6 GW during many peak hours in the summer.

Net imports in the real-time market can vary substantially from the levels scheduled in the day-ahead market. Figure 84 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 84: Average Hourly Real-Time Imports
All Hours



In the real time, the Midwest ISO imported almost 5 GW in on-peak hours and over 2.7 GW in off-peak hours in 2007, with more than a one-quarter of net imports coming from Manitoba. However, real-time net imports decreased more than 200 MW on average from those scheduled in the day-ahead market. On many days, the average net imports decreased by more than 1000 MW. Such large reductions in imports can create reliability issues that often compel the Midwest ISO to commit peaking resources.

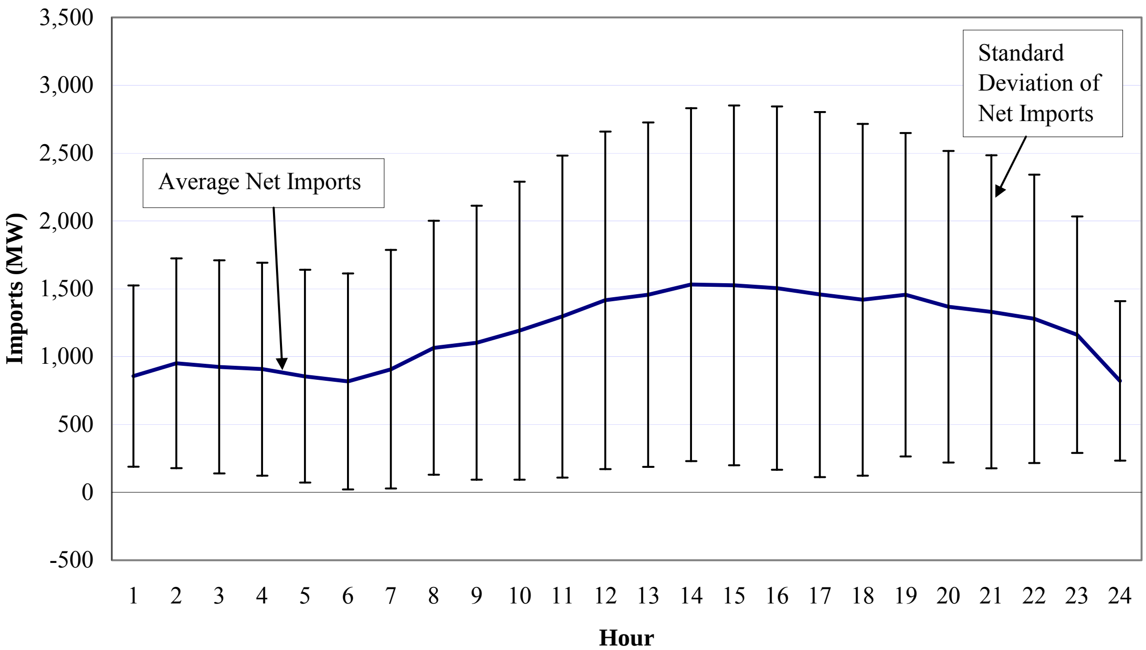
The figure also shows that the largest changes in net imports from day-ahead to real-time occurred in the last three months of the year. The reductions in net imports in real time was largely due to problems with AFC calculations by an adjacent transmission provider that resulted in over-scheduled day-ahead imports into the West region that had to be curtailed in the real-time. The problems with the AFC calculations were corrected in December of 2007, and the

Midwest ISO has developed a process for reviewing these calculations to identify any similar inaccuracies in the future.

However, there was a consistent bias toward over scheduling day-ahead imports relative to real-time imports. Real-time imports averaged 3.0 GW, a 10 percent difference on average from imports scheduled in the day-ahead market. The majority of this 300 MW average real-time difference was due to lower real-time import scheduling into WUMS (a 220 MW average difference) and the West region (a 130 MW average difference). The East region averaged slightly higher real-time imports than day-ahead imports. Similar to the effect of underbidding load in the day-ahead market or high scheduling of virtual supply, reductions in net imports from the day-ahead market to the real-time market increase the need for the Midwest ISO to rely on peaking resources to meet real-time load.

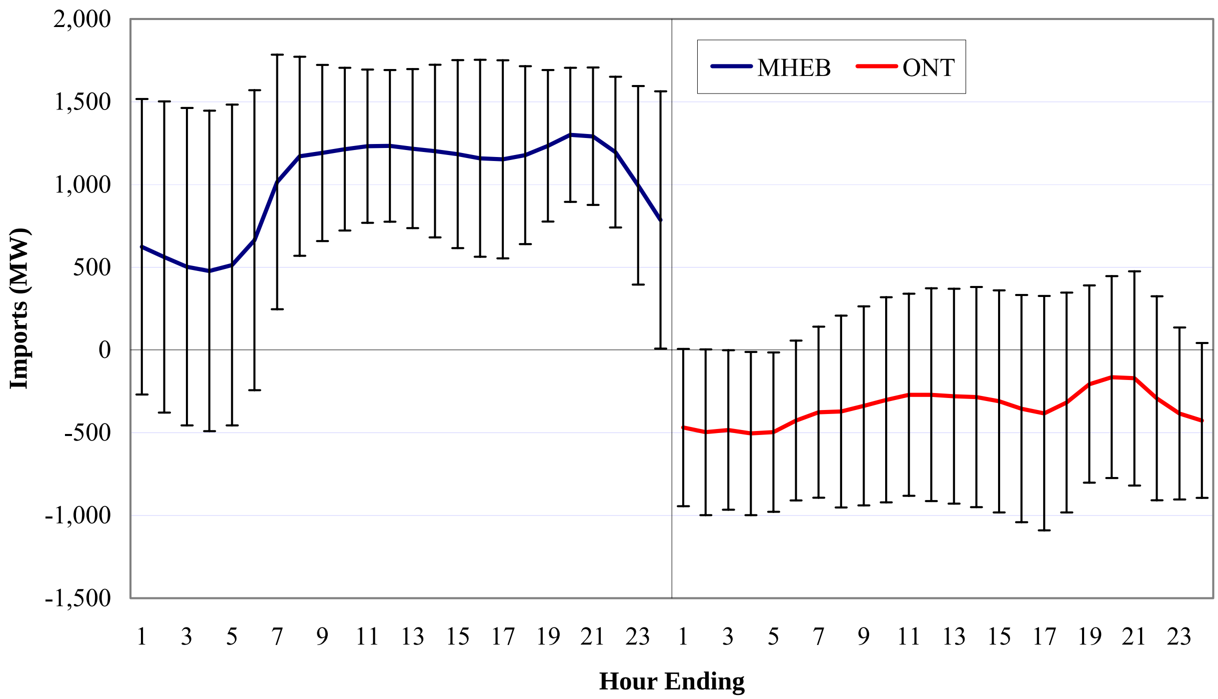
To better show where the Midwest imports and exports originate, our next analysis shows net imports by interface. The interface between the Midwest ISO and PJM, both of which operate LMP markets over relatively wide geographic areas, is one of the most significant Midwest ISO interfaces. Accordingly, Figure 85 shows the average net imports scheduled for the Midwest ISO-PJM interface in each hour of the day.

Figure 85: Hourly Average Real-Time Imports from PJM
2007



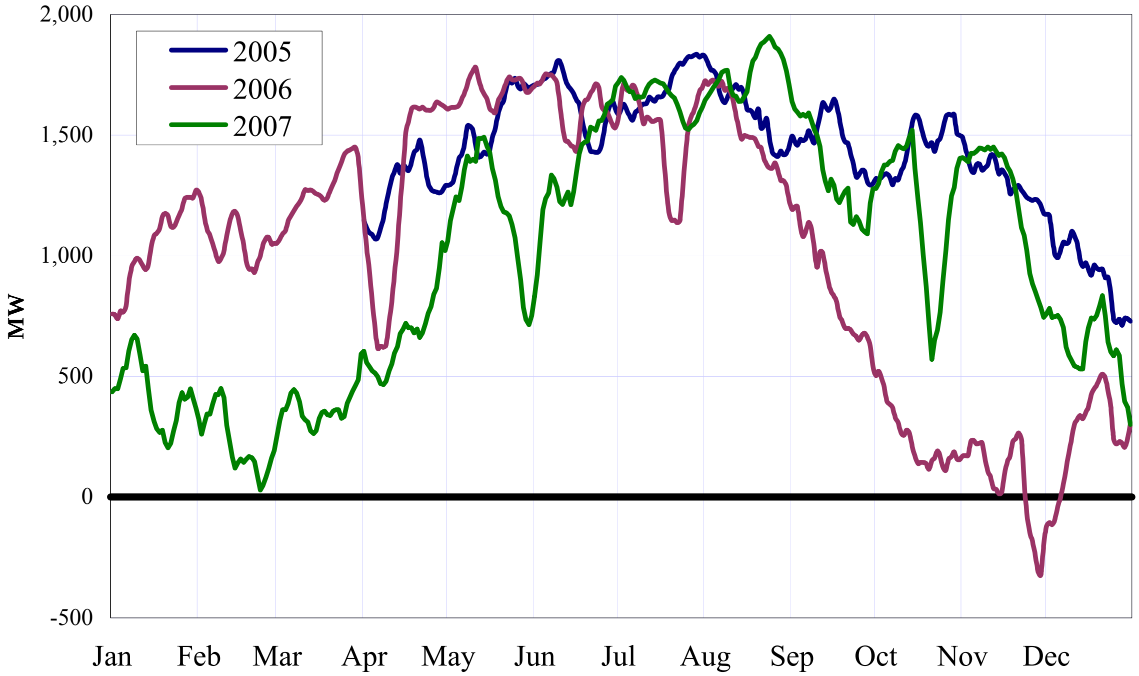
This figure shows overall that the Midwest ISO is a net importer of power from PJM, generally importing more power during the peak hours of the day and less power in the off-peak hours. However, the standard deviation of the net imports is large, indicating that the magnitude and direction of the flows between the two markets is 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 86 shows the net imports across the Canadian interfaces.

Figure 86: Hourly Average Real-Time Imports from Canada
2007



The Midwest ISO exchanges power with Canada through interfaces with the Manitoba Hydro Electricity Board ("MHEB") and the Ontario Independent Electricity System Operator ("IESO"). The Midwest ISO is a net importer from MHEB via a high-voltage DC connection, and a net exporter to the Ontario IESO. Exports to Ontario were generally highest in off-peak hours, and lowest during the evening ramp-down period (hours 19 to 21). Net imports from MHEB were generally higher in the peak hours and lower in the off-peak hours. While the hourly pattern remains similar to the pattern exhibited during prior years, imports from Manitoba Hydro have been somewhat variable since 2005. Figure 87 shows the hourly imports over the Manitoba interface between 2005 and 2007 on a seven-day moving average basis.

Figure 87: Net Imports over the Manitoba Hydro Interface
7-Day Moving Average: 2005 - 2007



The figure shows that imports were unusually low at the end of 2006 and the beginning of 2007. This was due to poor water conditions that reduced the availability of hydroelectric resources. In 2007, imports generally returned to near-normal levels by the summer. However, forced generation and transmission outages contributed to periods of sharp reductions in a number of cases throughout the year.

Imports over the Manitoba interface are very important because they serve the load in the Minnesota area and are an economic source of power affecting imports into the WUMS region from the West region[29]. 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 low-cost power is less available in the West region. Likewise, increases in imports over the Manitoba interface tend to increase

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

congestion into WUMS. However, the addition of new Arrowhead-Weston 345 transmission facilities should reduce the congestion into WUMS from the West region.

B. 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 the PJM prices. 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 are the same between the two markets.

The results for the PJM interface are shown in Figure 88 and Figure 89 below. The relatively wide dispersion of prices in Figure 88 indicates that participants have not been fully effective at arbitraging the real-time prices between the two areas. In fact, power is often scheduled from the higher-priced market to the lower-priced market. 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. 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.

Figure 89 indicates that the day-ahead prices in the two areas are relatively well arbitraged, likely because these prices are less volatile and easier to forecast than real-time prices. The Midwest ISO interface prices were slightly higher than PJM's on a consistent basis for the first three quarters of 2007, but that difference became smaller in the fourth quarter.

Figure 88: Real-Time Prices and Interface Schedules
PJM and the Midwest ISO

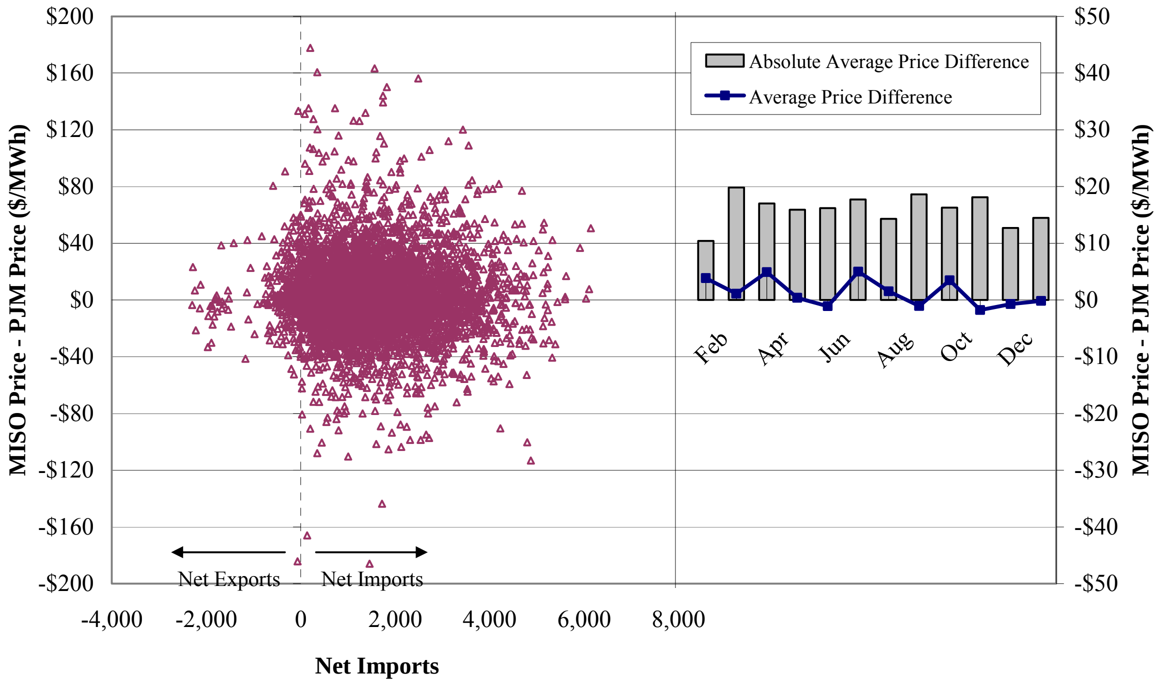
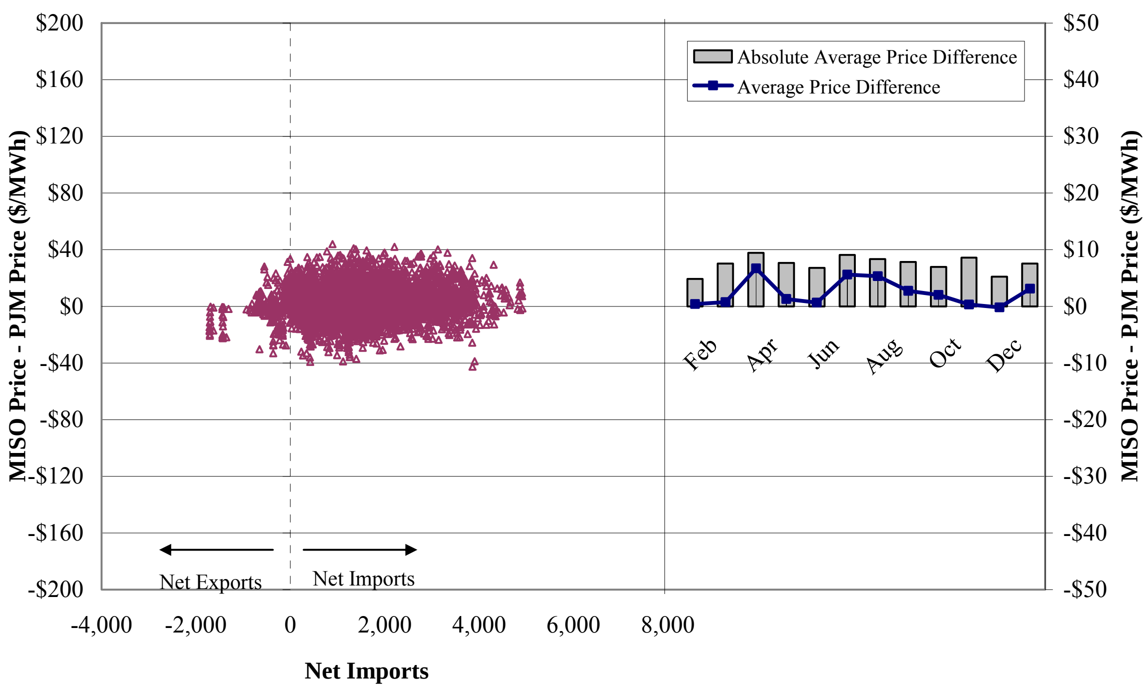


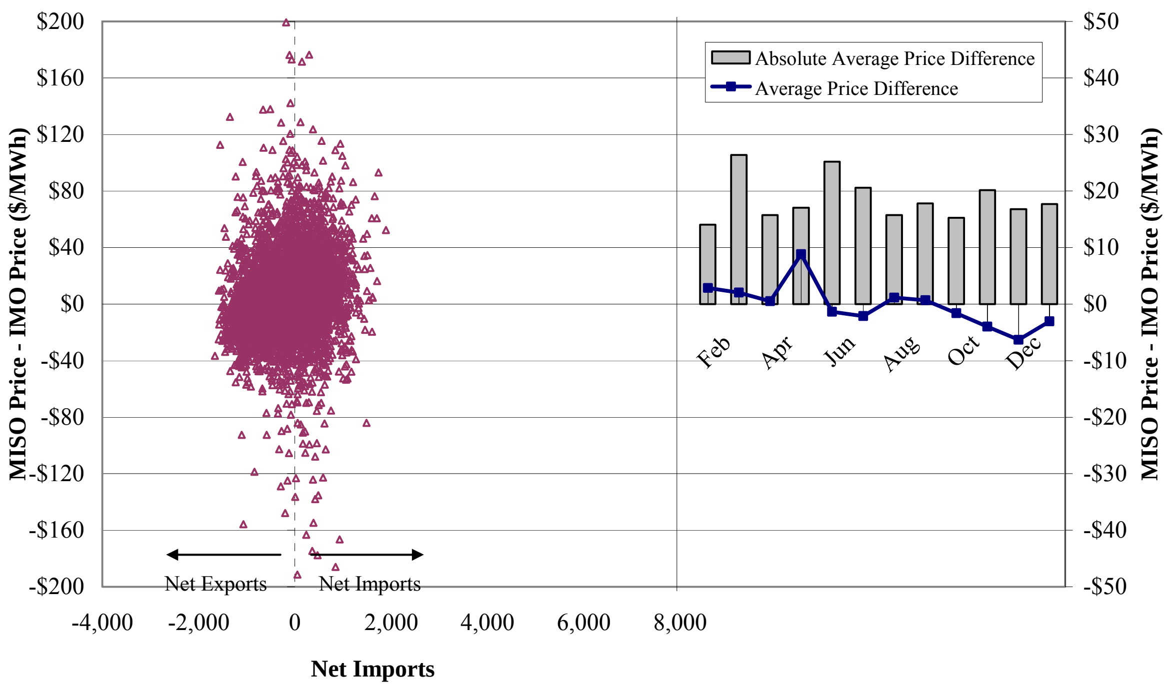
Figure 89: Day-Ahead Prices and Interface Schedules
PJM and the Midwest ISO



To achieve better real-time price convergence, we 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 on 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.

We next analyze the external transactions with Ontario. 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
Ontario IESO and the Midwest ISO



For the year, the Midwest ISO was a net exporter of power to IESO, exporting an average of 350 MW per hour. In the first three quarters, the average Midwest ISO prices exceeded the IESO prices and exports averaged 170 MW. During the last quarter, the average IESO prices were higher than the Midwest ISO prices. Exports averaged 860 MW per hour. The increase in exports was a rational response to the relative prices. However, the dispersion of prices shows that the schedules over this interface are relatively unresponsive to the price differences in the short-term.

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

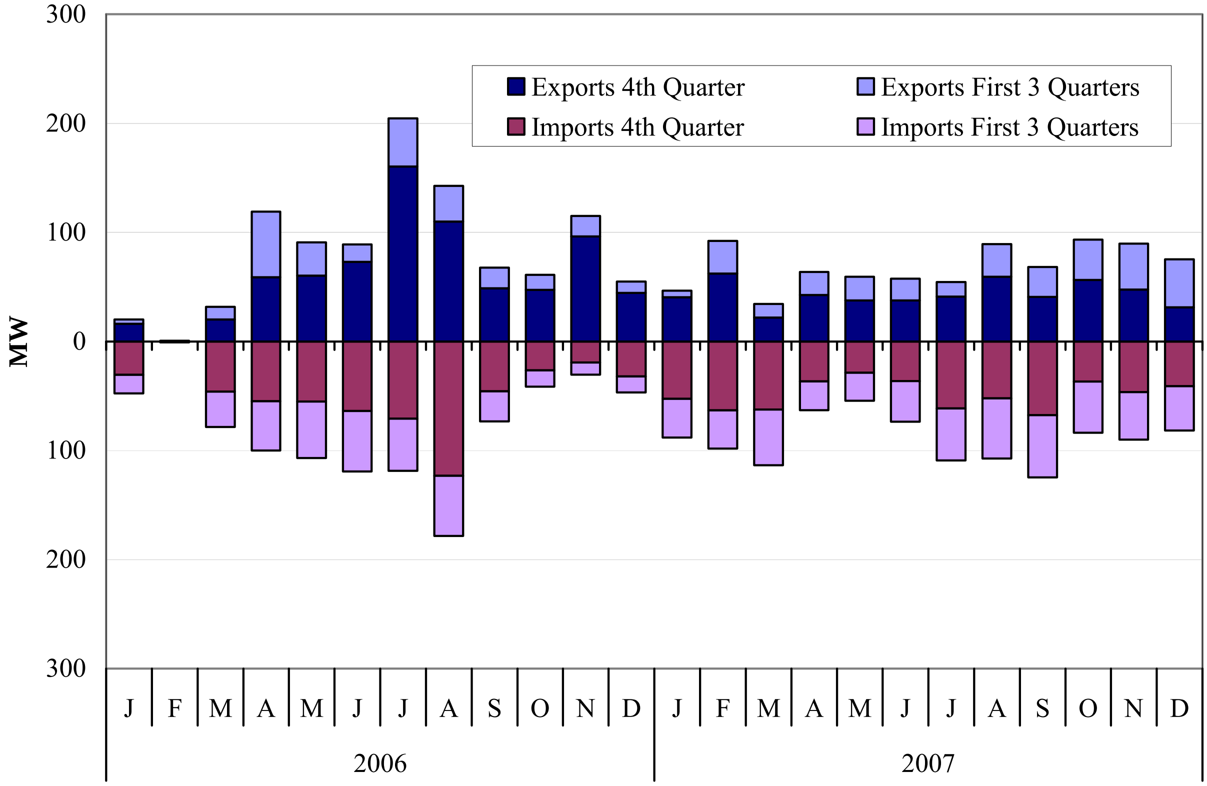
C. Intra-Hour Scheduling at PJM Interface

This subsection addresses the extent and impact of intra-hour real-time import and export schedules. Physical schedules determine the NSI between the Midwest ISO and its neighbors and are a critical element of the Midwest ISO market. The Midwest ISO market rules permit physical scheduling on a time increment as short as 15 minutes. The majority of the intra-hour schedules are occurring at the PJM interface.

Intra-hour scheduling 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 the Midwest ISO may have to ramp generation up or down substantially to accommodate these schedules.

Intra-hour schedules settle at the average price and quantity in the hour in which they occur, even though the transaction may only flow during part of the hour (e.g., a 15-minute export of 400-MW is treated as a 100-MW hourly export and is paid the hourly-integrated price). The divergence between the actual flows and the financial treatment of flows may create inefficient participant incentives. For example, a 15-minute schedule may be profitable on an hourly basis, even if it is inefficient and unprofitable during the 15-minute schedule period. Additionally, an intra-hour schedule may not bear the full cost of the schedules' impact on RSG because the impact on NSI from the schedule is effectively divided by four in the hourly settlement. Figure 91 provides a summary of intra-hour scheduling for the past two years between the Midwest ISO and PJM.

Figure 91: Intra-Hour Scheduling Levels
Monthly Average, 2006 - 2007



The chart shows the average intra-hourly schedule quantity divided between those occurring in the first 45 minutes of each hour ("First three Quarters") and those occurring in the last 15 minutes of the hour ("4th Quarter").[30] The figure shows that most intra-hour schedules occurred in the 4th quarter of the hour (almost 60 percent). The predominance of 4th quarter schedules is likely due to the fact that the scheduling deadline is 30 minutes in advance of the beginning of the schedule. Hence, the entity is able to schedule 4th quarter transactions after it has seen the

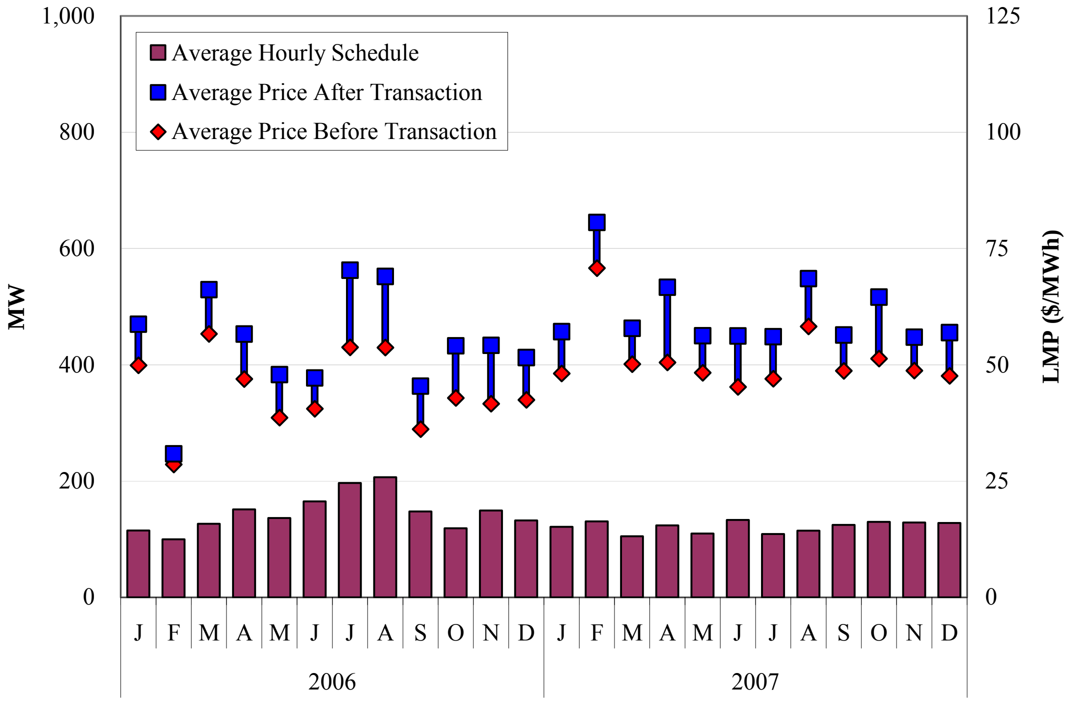
30 The quantities shown in this figure are the amount flowing when it is scheduled, not the hourly settlement amount.

prices at the beginning of the hour that will be included in the hourly settlement for the transactions. The volume of intra-hour schedules remained fairly constant throughout 2007.

Exports and imports had substantial impacts on the Midwest ISO prices and operations in 2007. During ramp-up periods, export schedules of 400 MW or more can use all of the available ramp capability and one-half or more of the available headroom. The largest price effects occur when the intra-hour scheduling utilizes a substantial portion of the Midwest ISO's capability to ramp generation up or down. Exports may also contribute to the Midwest ISO commitment of peaking resources to meet forecasted load, including net exports.

Our next analysis examines intra-hour scheduling and its relationship to exports and imports. We examine prices at the Midwest ISO – PJM proxy bus before and during intra-hour schedules. Figure 92 shows the price impact of exports on intra-hourly scheduling.[31]

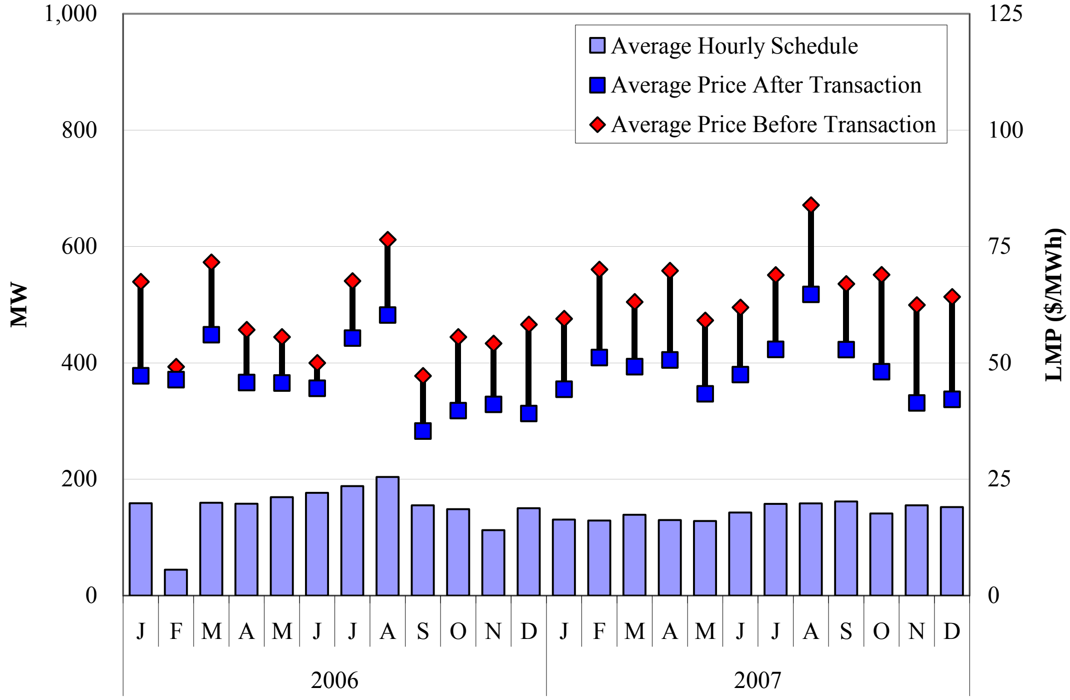
Figure 92: Intra-Hour Scheduling: Price Impact of Exports
Monthly Average, 2006 - 2007



31 The quantities shown in this figure are the hourly settlement amount in only those hours when intra-hour transactions are scheduled. Hence, the quantities that actually flow would be significantly higher if most of the transactions only flow for 15 minutes.

The figure shows that when the intra-hour exports are being scheduled, the prices are consistently higher -- by an average of almost $20 per MWh. The price effects are largest during peak periods. Figure 93 shows the same analysis for intra-hour imports.

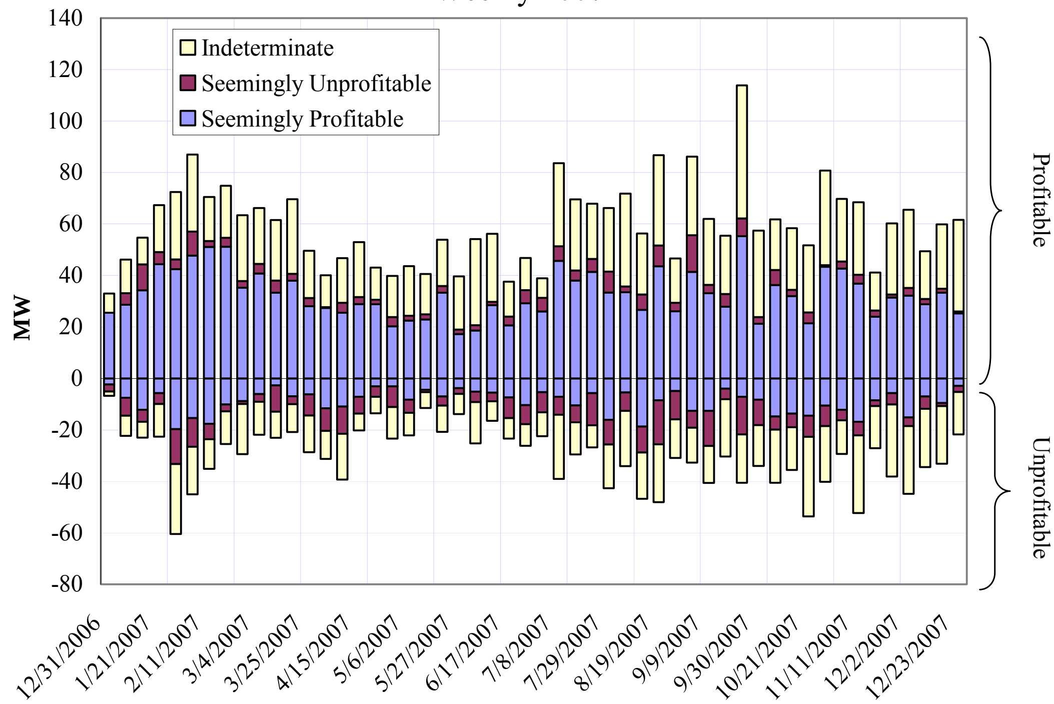
Figure 93: Intra-Hour Scheduling: Price Impact of Imports
Weekly Average, 2006 - 2007



The figure shows that when imports are being scheduled on an intra-hour basis, prices are consistently lower during the schedule than before the schedule, which is consistent with the Midwest ISO reducing generation to accommodate the import. Overall, this analysis shows that the intra-hour schedules have large price impacts. Therefore, it is important to assess whether they are being scheduled efficiently.

To evaluate whether the intra-hour transactions are being scheduled efficiently, we determine whether they have been profitable. Scheduling transactions unprofitably suggests that the market is not providing efficient incentives or that the participant was deriving other benefits from the transactions. The latter explanation would raise market manipulation concerns. Accordingly, we examined intra-hour transactions between the Midwest ISO and PJM, which account for the bulk of the intra-hour transactions. Our evaluation focuses on the apparent profitability of the transactions based on differences in the 5-minute proxy prices for the Midwest ISO and PJM. A participant scheduling a transaction between the Midwest ISO and PJM would settle with each RTO and receive the difference in prices. We consider a transaction "indeterminate" when it begins in the first 45 minutes of the hour because the entity will not have seen any prices for the hour prior to scheduling it. Our analysis is shown in Figure 94.

Figure 94: Predictable Profitability of Intra-Hour Schedules
Weekly 2007



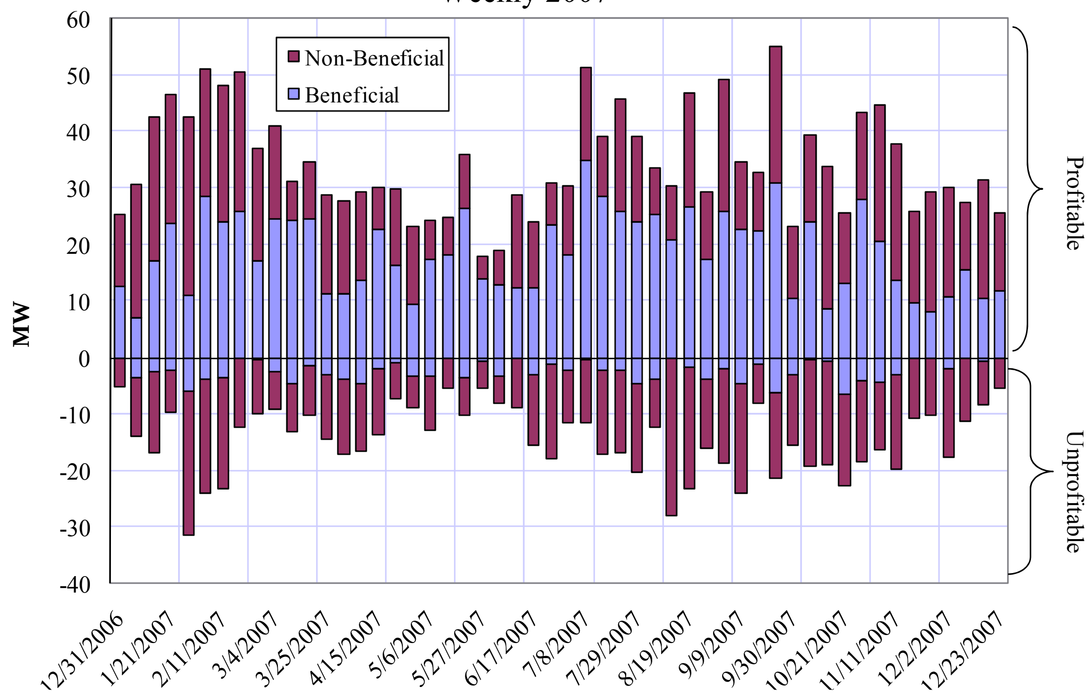
Our analysis indicates that approximately 80 percent of both the import and export transactions were scheduled when they appeared to be profitable. Of those that did not appear to be profitable in advance, about 40 percent were ultimately profitable based on the hourly settlement.

Overall, these results indicate that the level of intra-hour scheduling is modest and that the majority of 15-minute transactions appear to be rational (i.e., the participant had a reasonable expectation of profit from the transaction). With regard to the subset of transactions that did not appear to be profitable, the results did not show a sustained or consistent pattern by any participants that would suggest market manipulation. However, the settling of 15-minute transactions on an hourly basis and the rules governing the scheduling of such transactions do raise some potential concerns. The hourly settlement can affect participants' incentives to schedule intra-hour transactions, which can cause them to engage in inefficient (albeit profitable) transactions.

Although our analysis does not indicate potential manipulation concerns, our next analysis addresses the efficiency implications of the intra-hour schedules. We examine the extent to which the intra-hour transactions contributed to price convergence between PJM and the Midwest ISO when the transaction is flowing. We use only transactions taking place in the last fifteen minutes of each hour and divide them into profitable and unprofitable transactions (based on the hourly settlement). We then determine whether the transactions were beneficial. Transactions are beneficial when the power flows in the direction of the higher-priced market (which will contribute to price convergence). Figure 95 shows the results of our analysis.

Figure 95: Efficiency of Intra-Hour Schedules

Weekly 2007



The results indicate that in 2007, only 43 percent of all intra-hour schedules in the fourth quarter of the hour were beneficial (i.e., contributed to price convergence). Further, only slightly more than one-half of the "profitable" transactions were beneficial. This indicates that the settlement incentives are resulting in inefficiencies and likely contributing to increased price volatility.

In summary, our analyses regarding intra-hour transactions support the following conclusions:

- The majority of intra-hour transactions are rational based on profitability -- there is not a consistent pattern of unprofitable transactions by any participants. Hence, there is little evidence of potential market manipulation.
- However, scheduling and settlement rules governing intra-hour transactions result in a substantial quantity of intra-hour transactions that are not beneficial. Transactions can be profitable even when they are not beneficial because transactions are settled at hourly average quantities and prices (rather than the quantity and price prevailing when the transaction is flowing).
- The timing of the market exacerbates the prior issue because transactions in the last 15 minutes of the hour are scheduled after the prices in the first 15 minutes of the hour are known.[32]
- The large changes in NSI that are sometimes caused by these transactions contribute to increased price volatility.

To address the inefficiency of the non-beneficial transactions and the price volatility caused by large changes in NSI, we have several recommendations:

- In the long-term, the Midwest ISO should consider the feasibility of settling intra-hour transactions on a 15-minute basis to align the incentives of participants with those of the system.
- In the short-run, the Midwest ISO should require that intra-hour transactions be scheduled by the beginning of the hour (45 minutes in advance) to prevent participants from seeing prices before scheduling the transactions.
- To limit large NSI changes, the Midwest ISO should reconsider its scheduling criteria (which allow up to 1,000 MW of NSI changes in each 15 minutes). If the system ramp capability cannot be tracked and forecasted in real time, the current ramp limitation used to schedule external transactions of 1000 MW in any 15-minute period should be modified to a lower level that is estimated to be typically available.

These changes will reduce price volatility in the Midwest ISO by reducing the frequency of sharp price movements caused by large changes in NSI. In addition, they should alleviate operational problems caused by the ramp demands that large changes in NSI cause, and improve the price convergence with PJM.

32 PJM tried to reduce 4th quarter transactions by requiring that intra-hour transactions be scheduled for at least 45 minutes. However, this will not be effective because participants can schedule overlapping transactions in opposite directions that nullify the effect of this change.